Board Staff Interrogatory #1

Ref: Ex. B

Issue Number: 1.1
Issue: Is the rate base appropriately determined in accordance with regulatory and accounting requirements?

Interrogatory

Section 5.1 of Regulation 53/05 authorizes a deferral account that records for the period up to the effective date of the Board's first order the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan. Section 6(2)7 lists four items that are to be included in the calculation of the revenue requirement impact. As at December 31, 2007, the deferral account balance was $131 million made up of the following items ($ millions).

Return on rate base	$ 75
Depreciation expense	54
Fuel expense	(5)
Capital tax	3
Interest expense	4
	$ 131

Page 11 of OPG's 2007 financial statements indicates that the "return on rate base" component of the deferral account is based on a five per cent return on equity.

a) Five per cent of the $1,386 million increase in the fixed asset and nuclear waste management liability, which was required by a new reference plan as at December 31, 2006, equals $69.3 million. Please provide the calculation of OPG's figure of $75 million.

b) Did any of the $1,386 million increase in the fixed asset and nuclear waste management liability relate to OPG's Bruce nuclear plant? If so, was that amount excluded from OPG's calculation of "rate base" for purposes of the section 5.1 deferral account?

c) Regulation 53/05 does not contain any provisions on how OPG is to calculate "rate base" for purposes of this deferral account. Are there any differences between the rate base calculation used for section 5.1 purposes and the rate base calculation proposed for the test years?

[1] All section references going forward are to O. Reg. 53/05

Response

a) The “return on rate base” is comprised of a cost rate for both the debt and equity components financing rate base. The equity component of the deferral account is based on a five per cent return on equity and the debt component is based on a six percent cost of debt. The $75.4M return was calculated as: average fixed asset amount multiplied by the weighted average cost of capital (WACC).

The following table outlines the calculation details:

		M$
1	opening balance	1,386
2	annual depreciation	(54)
3	closing balance	1,332
4	average - (open + close) /2	1,359
	Return on Rate Base LN 4 * LN 11	**75**
		%ages
5	return on equity	5%
6	equity ratio - per Ex. C	45%
7	effective rate	2.25%
8	interest rate	6%
9	debt ratio per Ex. C	55%
10	effective rate	3.30%
11	Return on Rate Base LN 7 + LN 10	5.55%

b) Yes, a portion of the $1,386M increase in the fixed asset and nuclear waste management liability relates to the Bruce nuclear station ($878M). The Bruce component is included in the deferral account because the nuclear decommissioning liability associated with the Bruce facilities belongs to OPG. O. Reg 53/05 requires OPG to record amounts in the deferral account that pertain to OPG's total nuclear decommissioning liability.

c) The calculation of rate base for purposes of the deferral account is the same as the calculation of the test period rate base in Exhibit B. OPG’s rate base is comprised of its prescribed facilities and working capital. The test period revenue requirement for the nuclear facilities is reduced by the Bruce Lease revenues net of costs. The test period revenue requirement for the nuclear facilities is reduced by the amount that revenues earned with respect to lease of the Bruce Nuclear Generating Stations exceed the costs OPG incurs with respect to those Stations (O. Reg 53/05, Section 6(2) 10). The Bruce Lease rate base is determined on the same basis as rate base for OPG’s prescribed facilities (ref. Ex. G2-T2-S1, Table 2). Both are based on a simple average of the opening and closing net book values.

Board Staff Interrogatory #2

Ref: Ex. C

Issue Number: 2.1
Issue: What is the appropriate capital structure for OPG's regulated business for the 2008 and 2009 test years? Should the same capital structure be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure is appropriate for each business?

Interrogatory

Footnote 95 (p. 85) references Standard & Poor's Key Credit Factors: Assessing US Vertically Integrated Utilities' Business Risk Drivers. Please provide a copy of this document.

Response

A copy of Standard & Poor's "Key Credit Factors: Assessing US Vertically Integrated Utilities' Business Risk Drivers" is attached as Attachment 1.

Filed: 2008-04-09
EB-2007-0905
L-1-2
Attachment 1

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RESEARCH

Key Credit Factors:

Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers

Publication date: 14-Sep-2006
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The methodology that Standard & Poor's Ratings Services uses to rate vertically integrated electric, gas, and combination investor-owned utilities in the U.S. is based on the same precepts that we have used for many years, though the emphasis has changed as the utility industry has evolved. The fundamental methodology encompasses two basic components--business risk and financial risk--and their relationship. Where a utility presents a strong business risk profile, the financial profile can be less robust for any given rating. Likewise, where a utility's business risk profile is weaker, its financial performance must be stronger for any given rating. For combination utilities, the gas operations may have a stabilizing influence on credit quality, but since the electric business is typically significantly larger, it is the major credit driver. (For details on Standard & Poor's analytical approach to gas utilities, see "Key Credit Factors For Natural Gas Distributors" published Feb. 28, 2006.)

Often, an integrated utility is a part of a larger holding company structure that also owns other businesses, frequently unregulated electricity generation. This fact does not alter how we analyze the utility, but it may affect the ultimate rating outcome due to any credit drag that the unregulated activities may have on the utility. Such considerations include the freedom and practice of management with respect to shifting cash resources among subsidiaries and the presence of ring-fencing mechanisms that may protect the utility.

Five Factors Determine The Business Profile

Five basic characteristics define a vertically integrated utility's business profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Standard & Poor's is most concerned about how these elements contribute individually and in aggregate to the predictability and sustainability of financial performance, particularly cash flow generation relative to fixed obligations. While considerable attention has focused in recent years on companies in states that deregulated in the late 1990s and the early part of this decade and the related credit consequences of disaggregation and nonregulated generation, 27 states (plus four that formally reversed, suspended, or delayed restructuring) have retained the traditional regulated model. For utilities operating in those states, the quality of regulation and management loom considerably larger than markets, operations, and competitiveness in shaping overall financial performance. Policies and practices among state and federal regulatory bodies will be key credit determinants. Likewise, the quality of management, defined by its posture towards creditworthiness, strategic decisions, execution and consistency, and its ability to sustain a good working relationship with regulators, will be key. Importantly, however, it is virtually impossible to completely segregate each of these characteristics from the others; to some extent they are all interrelated.

On Standard & Poor's business profile scale (where '1' is excellent and '10' is vulnerable), vertically integrated utilities generally have satisfactory business profiles of '5' or '6'. (See tables 1 and 2 in the Appendix below for business profile benchmarks plus a list of utilities we rate and their business profile scores.) We view a company that owns regulated generation, transmission, and distribution operations, as positioned between companies with relatively low-risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum. What typically distinguishes one vertically integrated utility's business profile score from another is the quality of regulation and management.

Regulation

Regulation is a critical aspect that underlies integrated utilities' creditworthiness. Decisions by state public service commissions can profoundly affect financial performance. Standard & Poor's assessment of the regulatory environments in which a utility operates is guided by certain principles, most prominently consistency and predictability, as well as efficiency and timeliness. For a regulatory scheme to be considered supportive of credit quality, commissions must limit uncertainty in the recovery of a utility's investment. They must also eliminate, or at least greatly reduce, the issue of rate-case lag, especially when a utility engages in a sizable capital expenditure program and incurs substantial deferrals of fuel costs.

Standard & Poor's evaluation encompasses the administrative, judicial, and legislative processes involved in state and federal regulation, and includes the political environment in which commissions render decisions. Regulation is assessed in terms of its ability to satisfy the particular needs of individual utilities. Rate-setting actions are reviewed case-by-case with regard to the potential effect on credit quality. As frequently postulated in prior years, our evaluation of regulation focuses on the willingness and ability of regulation to provide cash flow and earnings quality adequate to meet investment needs, earnings stability through timely recognition of volatile cost components such as fuel and satisfactory returns on invested capital and equity. Regulators' authorization of high rates of return is of little value unless returns are realistic and achievable. Allowing high returns based on noncash items does not benefit bondholders. A regulatory jurisdiction that permits incentives whereby utilities are allowed to earn a return based on their ability to sustain rates at competitive levels is viewed favorably. In addition to performance-based rewards or penalties, flexible plans could include market-based rates, price caps, index-based prices, and rates premised on the value of customer service. Also important is the ability to enter into long-term arrangements at negotiated rates without having to seek regulatory approval for each contract.

Because the bulk of a utility's operating expenses relate to fuel and purchased power, of primary importance to rating stability is the level of support that state regulators provide to utilities for fuel cost recovery, particularly as gas and coal costs have risen. Utilities that are operating under rate moratoriums, or without access to fuel and purchased-power adjustment clauses or with fixed-fuel mechanisms, or face significant regulatory lag, also are subject to reduced operating margins, increased cash flow volatility, and greater demand for working capital. Companies that are granted fuel true-ups may be required to spread recovery over many years to ease the pain for the consumer. Standard & Poor's notes that fuel-adjustment mechanisms have become more common in the industry, but not all are created equal. While some jurisdictions permit recovery on a dollar-for-dollar basis over a defined time period, certain jurisdictions, such as Washington State, impose a deadband in which the company absorbs all the risk and rewards of fuel costs above and below the established recovery rate. Beyond the deadband there is a sharing of risks and rewards with ratepayers. In Arizona, Arizona Public Service Co. has a 90/10 sharing mechanism between the company and ratepayers, respectively, for all costs passed through the power supply adjuster. The mechanism is triggered based on a date (once a year in February 2006) and not on a threshold level of deferrals. The annual adjustment is also subject to a lifetime cap of 4 mils per kilowatt-hour, which has led to power deferrals.

In addition to fuel cost recovery filings, regulators will have to address significant rate increase requests related to new generating capacity additions, environmental modifications, and reliability upgrades. Current cash recovery and/or return by means of construction work in progress support what would otherwise be a sometimes significant cash flow drain and reduces the utility's need to issue debt during construction.

Moreover, allowing rate recovery of projected costs with subsequent periodic updates for actual results reduces lags in cost recovery. Also supportive of credit quality is the ability of the utility, commission staff,

Filed: 2008-04-09
EB-2007-0905
L-1-2
Attachment 1

consumer advocates, and other major interveners to reach a comprehensive settlement before construction of new base load capacity. Certain states, such as Indiana, Texas, Kansas, and Minnesota, have adopted environmental tracking mechanisms and other riders that allow companies to reflect in rates capital costs associated with environmental compliance equipment without having to file a formal rate case. Creditworthiness can also be enhanced when a company has the authority to timely recover unanticipated costs, such as those incurred for repairing storm damage, as in Florida. While the Alabama Public Service Commission does not currently employ a separate storm repair cost recovery mechanism to ensure rapid recovery of storm repair costs, it has shown a willingness to work with utilities to help them recover at least some of these costs on a timely basis and to start replenishing storm reserves. Finally, the greater the percentage of a utility's rates that are recovered through fixed charges rather than volume-based charges, the greater the support for credit quality.

For utilities that own a natural gas business, automatic and timely pass-through of commodity costs provides the strongest level of credit support. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels.

Due to the extreme volatility and high gas prices over the past few heating seasons, more regulators have revised gas adjustment clauses to provide monthly gas adjustments rather than awaiting the end of the heating season to begin reimbursement. This expedited treatment helps the utility to reduce any regulatory lag to recover costs and streamlines working capital needs, which in turn should allow the firm to modestly temper rising gas bills to their customers.

Both regulators and natural gas companies are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and companies are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting the company's bottom line and still allow utilities to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Key success factors include:

- Alternative ratemaking/flexibility,
- Attention to credit quality,
- Timely and consistent rate treatment,
- Support for fuel cost recovery,
- Support for a reasonable cash return on investment, and
- Support for rapid return on investment.

Markets

Assessing market dynamics begins with an economic and demographic evaluation of the service area in which a utility operates. Strength of long-term demand for energy is examined from a macroeconomic perspective, which enables Standard & Poor's to measure the affordability of rates and the staying power of demand. Distribution by classification according to total number of customers, revenues, and margins is closely scrutinized to assess the depth and diversity of the utility's customer mix. For example, heavy industrial concentration is viewed with some caution because the utility may be exposed to cyclical volatility and face competitive alternatives. A large residential component, on the other hand, produces a more stable and predictable revenue stream. The utility's largest customers are identified to determine their stability and importance to the bottom line because the loss of one large customer could adversely affect the utility's financial position. Moreover, large customers may turn to self-generation, potentially leading to less financial protection for the utility.

Standard & Poor's also analyzes any long-term consumption trends and the reasons behind them. Factors addressed include the market's size and growth rate, the franchise's strength, historical and projected growth rates, income levels and trends in population, employment, and per capita income. A utility with a healthy economy and customer base, as illustrated by diverse employment opportunities, average or above-average wealth and income statistics, and low unemployment, will be better able to support its operations.

For the gas business, Standard & Poor's also examines customer saturation. Firms that operate in service areas with low growth potential still can expand at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to companies operating in low population growth service areas.

Despite the review of market characteristics, they are clearly a secondary consideration to regulation. In Nevada, for years the country's fastest growing state, Nevada Power Co. and Sierra Pacific Power Co. struggled to recover capital expenditures on a timely basis, and were accordingly rated as low investment-grade credits. In Florida, which has competed with Nevada for years in its pace of growth, the Florida Public Service Commission established polices of quick recovery of capital investments and, on a stand-alone basis, the state's utilities' credit metrics have remained strong.

Critical success factors include:

- A healthy and growing economy,
- Growth in population and number of customers,
- An attractive business environment, and
- An above-average residential base.

Operations

Standard & Poor's focuses on cost, reliability, safety, and quality of service when assessing a utility's operations. Management is always under pressure to optimize the use of resources, and if it is not cost-effective in meeting service standards and reliability, regulatory or competitive pressures are likely to increase. Consequently, Standard & Poor's emphasizes areas that require heightened and ongoing management attention, in the absence of which political, regulatory, or competitive problems are likely to arise.

The status of utility plant investment is reviewed with regard to generating station availability, efficiency, and utilization, as well as for compliance with existing and potential environmental and other regulatory standards. The record of plant outages, system losses, equivalent availability, load factors, heat rates, and capacity factors are examined. Important considerations include the projected capital improvements and plant additions necessary to provide high-quality, reliable service. The general condition of the assets and how well such assets are maintained are also important considerations.

Emphasis is placed on reserve margins, fuel mix, fuel contract terms, purchased-power arrangements, and system operators. Moreover, the quality and concentration of capacity is just as important as the size of reserves. Standard & Poor's recognizes that reserve requirements differ among companies, depending upon individual operating and load characteristics.

Fuel diversity provides flexibility in a changing environment. Supply disruptions and price hikes can raise rates and ignite political and regulatory pressures that ultimately lead to erosion in financial performance. Thus, the ability to switch generating sources to take advantage of cheaper fuels is viewed favorably. Dependence on any single fuel, or asset concentration in one or two large generating stations, can cause significant swings in a company's financial performance. Similarly, utilities that rely on nuclear generation receive an elevated degree of attention due to the scale, technical complexity, and politically sensitive nature of nuclear facilities. Indeed, the sound operation of nuclear units can define a utility's operational risk profile and its ability to achieve projected financial results. Standard & Poor's seeks to distinguish between those operators that have exhibited sound and stable operational performance, and the likelihood that it will continue, and those whose nuclear operations are vulnerable to problems that may impair financial results.

But having a large concentration of capacity based on fossil fuels also imposes certain risks. Coal-fired capacity is burdened with increased environmental costs related to reducing sulfur dioxide, nitrogen oxide, mercury, and eventually carbon dioxide emissions. Gas-fired capacity presents its own challenges, particularly the extreme volatility and significant increase in gas prices over the past few years. Buying power may be a more appropriate option for a utility than new plant construction because the utility avoids construction costs and the financial risks posed by regulatory lag when seeking recovery of costs. Purchasing power may enhance supply flexibility, fuel resource diversity, and maximize load factors. Utilities that plan to meet demand projections with a portfolio of supply-side options also may be better able to adapt to future growth uncertainties. Despite these benefits, such a strategy does commit the utility to a fixed obligation, which Standard & Poor's captures analytically through certain adjustments to financial statements. We calculate the net present value of future annual capacity payments (discounted at the company's cost of debt) over the life of the contract. Standard & Poor's then applies a risk factor against this value and adds the result to the utility's balance sheet. The risk factor is largely a function of the strength of the regulatory recovery mechanisms established to address procurement costs.

Other operational characteristics that will support an above-average evaluation for vertically integrated companies are assets that are in good physical condition and are well maintained. In addition, capital expenditures for necessary system improvements must be at manageable levels, yet sufficient to provide for constant renewal and refurbishment of the system. Operating performance, reliability statistics (such as outage duration and frequency), and efficiency measures are expected to meet industry and regional averages. Having interconnections that provide access to low-cost and diverse power supply sources is viewed favorably, as is limited environmental exposure.

For a gas company, drawing from a single interstate pipeline or relying on a particular gas basin exposes it to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects the utility from such disruptions. Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. Gas distributors benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Outdated systems requiring extensive maintenance and capital expenditures lower profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, operational efficiencies can be obtained through the use of new technology.

Critical success factors include:

- Well-maintained assets,
- Solid plant performance,
- Fuel diversity,
- Adequate generating reserves, and
- Compliance with environmental standards.

Competitiveness

For vertically integrated utilities, competitive factors include percentage of firm wholesale revenues that are most vulnerable to competition, industrial load, and revenue concentrations, particularly in energy intensive industries; exposure of key customers to alternative suppliers; commercial concentrations; rates charged to various customer classes; rate design and flexibility; production costs, both marginal and fixed; the regional capacity situation; and transmission constraints. A regional focus is evident, but high costs and rates relative to national averages are also of significant concern because of the potential for electricity substitutes over time.

Electricity competes with other fuels--particularly natural gas--for certain segments of the market like space heating, water heating, and cooking. Thus, high electricity prices, which can be attributed to inefficient operations, are cause for concern if customers have access to alternative energy sources. Self-generation has been a risk, as large commercial and industrial customers may take advantage of cogeneration technologies to reduce their reliance on, and in some cases to disconnect from the system. In the future, technology could pose a greater threat. Bypass risk, too, may grow if distributed generation, microgeneration, and self-generation prove more economically attractive for smaller customers.

Due to their proximity to interstate gas pipelines, some large customers can directly tie into a transmission line and completely bypass gas distributors' services. Although such pipelines provide key sources of gas supply for these companies, it is important to recognize this bypass risk. Ideally located gas companies have adequate transmission access but have industrial customers far from interstate pipelines.

Critical success factors include:

- Low cost structure,
- Limited bypass risk, and
- Management's commitment to lowering costs.

Management

Evaluating management is of paramount importance to Standard & Poor's analysis because management decisions affect all areas of a company's operations and financial health. Although regulation, the economy, and other outside factors certainly influence results, the quality of management ultimately determines a company's success. Standard & Poor's private meetings with senior management significantly augment the public record in the effort to appraise management. Meetings are very useful for the candid interpretation of recent developments and, importantly, to provide executives with a forum for the presentation of goals, objectives, and strategies.

Management assessment is based on tenure, turnover, industry experience, financial track record, corporate governance, a grasp of industry issues, and knowledge of regulation, of customers, and their needs. Management's ability and willingness to develop workable strategies to address system needs, and to execute reasonable and effective long-term plans are assessed. Management quality is also indicated by thoughtful balancing of multiple--and often incompatible--priorities; a record of credibility; and effective communication with the public, regulatory bodies, and the financial community.

Standard & Poor's also focuses on management's ability to achieve cost-effective operations and commitment to maintaining credit quality. This can be assessed by evaluating accounting and financial practices, capitalization and common dividend objectives, and the company's philosophy regarding growth and risk-taking.

In addition, a company's accounting and financing practices are critical to Standard & Poor's analysis. For example, proactive management will likely adopt accounting practices that are more appropriate in a competitive environment such as higher depreciation rates for electric generation equipment. Large, growing cost deferrals or regulatory assets are viewed more negatively. Management can enhance its financial condition by taking any number of discretionary actions, such as selling common equity, reducing the common dividend payout, and deleveraging. A utility's management will also be evaluated on cost-cutting ability and creativity in entering into strategic alliances that improve efficiency.

Strong corporate governance, reflected in active, independent board of directors that participate in determining and monitoring corporate controls, help to support management's credibility and corporate financial disclosure. If it is evident that a company's board is passive and does not exercise proper oversight, it weakens the checks and balances of the organization and may detract from credit quality. Included in Standard & Poor's review of corporate governance is the proportion of independent directors on the board, the breadth and depth of the directors' experience, the proportion of independent directors on the board's audit committee, and directors' compensation.

Some vertically integrated utilities have felt compelled to invest outside their traditional businesses to increase earnings, especially as stock prices have underperformed market indices. Participation in higher-risk, unregulated activities such as merchant generation, exploration and development, gathering and processing, or marketing and trading can significantly detract from the consolidated entity's credit profile. In this regard, credit ratings are not based on the regulated business only, but on the qualitative and quantitative fundamentals of the consolidated entity. Standard & Poor's considers the ratings of the regulated businesses as being less vulnerable to the negative credit influence of other affiliates and holding company activities, as relevant, where very strong structural and/or regulatory insulation exists, which tends to be more the exception than the rule.

Critical success factors include:

- Commitment to credit quality,
- Credibility,
- Strong corporate governance, and
- Conservative financial policies, especially regarding nonregulated activities, if relevant.

Effect On Ratings

In summary, Standard & Poor's examines the key business risk drivers for vertically integrated utilities--regulation, markets, operations, competitiveness, and management--in conjunction with financial measures when assigning credit ratings. The credit quality of most vertically integrated utilities is solidly investment grade. This is a primarily a function of the existence of regulation. As discussed above, the factors that further differentiate ratings among this sector include their markets, operational track record, competitive posture, and management's risk appetite. Vertically integrated utilities generally have satisfactory business risk profile scores, with only a few having strong or weak business positions.

Appendix

Table 1

Industry Benchmarks

Business Profile	AA		A		BBB		BB	
Adjusted FFO interest coverage (x)								
1	3.0	2.5	2.5	1.5	1.5	1.0	< 1.0	< 1.0
2	4.0	3.0	3.0	2.0	2.0	1.0	< 1.0	< 1.0
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9	N/A	N/A	10.0	7.0	7.0	4.0	4.0	2.8
10	N/A	N/A	11.0	8.0	8.0	5.0	5.0	3.0
Adjusted FFO/average total debt (%)								
1	20.0	15.0	15.0	10.0	10.0	5.0	< 5.0	< 5.0
2	25.0	20.0	20.0	12.0	12.0	8.0	< 8.0	< 8.0
3	30.0	25.0	25.0	15.0	15.0	10.0	10.0	5.0
4	35.0	28.0	28.0	20.0	20.0	12.0	12.0	8.0
5	40.0	30.0	30.0	22.0	22.0	15.0	15.0	10.0
6	45.0	35.0	35.0	28.0	28.0	18.0	18.0	12.0
7	55.0	45.0	45.0	30.0	30.0	20.0	20.0	15.0
8	70.0	55.0	55.0	40.0	40.0	25.0	25.0	15.0
9	N/A	N/A	65.0	45.0	45.0	30.0	30.0	20.0
10	N/A	N/A	70.0	55.0	55.0	40.0	40.0	25.0
Adjusted total debt/total capital (%)								
1	48.0	55.0	55.0	60.0	60.0	70.0	> 70.0	> 70.0
2	45.0	52.0	52.0	58.0	58.0	68.0	> 68.0	> 68.0
3	42.0	50.0	50.0	55.0	55.0	65.0	65.0	70.0
4	38.0	45.0	45.0	52.0	52.0	62.0	62.0	68.0
5	35.0	42.0	42.0	50.0	50.0	60.0	60.0	65.0
6	32.0	40.0	40.0	48.0	48.0	58.0	58.0	62.0
7	30.0	38.0	38.0	45.0	45.0	55.0	55.0	60.0
8	25.0	35.0	35.0	42.0	42.0	52.0	52.0	58.0
9	N/A	N/A	32.0	40.0	40.0	50.0	50.0	55.0

10	N/A	N/A	25.0	35.0	35.0	48.0	48.0	52.0

Note: Business profile scores are characterized from '1' (excellent) to '10' (weak). FFO--Funds from operations. N/A--Not applicable.

Table 2

Vertically Integrated Utilities

Company	Corporate credit rating	Business profile score
Aquila Inc.	B/CW-Pos/B-2	6
AGL Resources Inc.	A-/Negative/A-2	4
Alabama Power Co.	A/Stable/A-1	4
ALLETE Inc.	BBB+/Stable/A-2	5
Ameren Corp.	BBB+/CW-Neg/A-2	6
Appalachian Power Co.	BBB/Stable/--	5
Arizona Public Service Co.	BBB-/Stable/A-3	6
Atmos Energy Corp.	BBB/Stable/A-2	4
Black Hills Power Inc.	BBB-/Negative/--	6
Central Illinois Light Co.	BBB+/CW-Neg/--	7
Central Vermont Public Service Corp.	BB+/Stable/--	6
CILCORP Inc.	BBB+/CW-Neg/--	7
Cincinnati Gas & Electric Co.	BBB/Positive/A-2	6
Cleco Power LLC	BBB/Negative/--	6
Cleveland Electric Illuminating Co.	BBB/Stable/--	6
Consolidated Natural Gas Co.	BBB/Stable/A-2	6
Consumers Energy Co.	BB/Stable/--	6
Dayton Power & Light Co.	BB+/Positive/--	5
Detroit Edison Co.	BBB/Stable/A-2	6
Duke Power Co. LLC	BBB/Positive/A-2	4
El Paso Electric Co.	BBB/Stable/--	6
Empire District Electric Co.	BBB-/Stable/A-3	6
Energy East Corp.	BBB+/Negative/A-2	3
Enogex Inc.	BBB+/Stable/--	7
Entergy Arkansas Inc.	BBB/Negative/--	5
Entergy Gulf States Inc.	BBB/Negative/--	6
Entergy Louisiana LLC	BBB/Negative/--	5
Entergy Mississippi Inc.	BBB/Negative/--	6
Entergy New Orleans Inc.	D/--/--	8
Equitable Resources Inc.	A-/CW-Neg/A-2	8
Florida Power & Light Co.	A/CW-Neg/A-1	4
Georgia Power Co.	A/Stable/A-1	4
Green Mountain Power Corp.	BBB/CW-Pos/--	5
Gulf Power Co.	A/Stable/--	4
Hawaiian Electric Co. Inc.	BBB+/Negative/A-2	5
IDACORP Inc.	BBB+/Negative/A-2	5
Idaho Power Co.	BBB+/Negative/A-2	5
Indiana Michigan Power Co.	BBB/Stable/--	6
Indianapolis Power & Light Co.	BB+/Positive/--	4
Interstate Power & Light Co.	BBB+/Stable/A-2	5
IPALCO Enterprises Inc.	BB+/Positive/--	4
Kansas City Power & Light Co.	BBB/Stable/A-2	6
Kansas Gas & Electric Co.	BB+/Positive/--	6
Kentucky Power Co.	BBB/Stable/--	5
Kentucky Utilities Co.	BBB+/Stable/A-2	5
Louisville Gas & Electric Co.	BBB+/Stable/--	5

Madison Gas & Electric Co.	AA-/Stable/A-1+	4
Michigan Consolidated Gas Co.	BBB/Stable/A-2	4
MidAmerican Energy Co.	A-/Stable/A-1	5
Mississippi Power Co.	A/Stable/A-1	4
Monongahela Power Co.	BB+/Positive/--	5
Montana-Dakota Utilities Co.	BBB+/Stable/--	6
National Fuel Gas Co.	BBB+/Stable/A-2	7
Nevada Power Co.	B+/Positive/--	6
New York State Electric & Gas Corp.	BBB+/Negative/A-2	3
NiSource	BBB/Stable/--	4
Northern Indiana Public Service Co.	BBB/Stable/--	5
Northern States Power Co.	BBB/Stable/A-2	5
Northern States Power Wisconsin	BBB+/Stable/--	4
Ohio Edison Co.	BBB/Stable/A-2	6
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	5
Pacific Gas & Electric Co.	BBB/Stable/A-2	5
PacifiCorp	A-/Stable/A-1	5
Pennsylvania Power Co.	BBB/Stable/--	6
Pinnacle West Capital Corp.	BBB-/Stable/A-3	6
PNM Resources Inc.	BBB/Negative/A-3	6
Portland General Electric Co.	BBB+/Negative/A-2	5
Progress Energy Carolinas Inc.	BBB/PositiveA-2	5
Progress Energy Florida Inc.	BBB/Positive/A-2	4
PSI Energy Inc.	BBB/Positive/A-2	4
Public Service Co. of Colorado	BBB/Stable/A-2	4
Public Service Co. of New Hampshire	BBB/Stable/--	5
Public Service Co. of New Mexico	BBB/Negative/A-3	6
Public Service Co. of Oklahoma	BBB/Stable/--	5
Puget Energy Inc.	BBB-/Stable/--	4
Puget Sound Energy Inc.	BBB-/Stable/A-3	4
Questar Market Resources Inc.	BBB+/Stable/---	8
Rochester Gas & Electric Corp.	BBB+/Negative/--	3
San Diego Gas & Electric Co.	A/Stable/A-1	5
Savannah Electric & Power Co.	A/Stable/--	4
SCANA Corp.	A-/Stable/--	4
Sierra Pacific Power Co.	B+/Positive/--	6
Sierra Pacific Resources	B+/Positive/B-2	6
South Carolina Electric & Gas Co.	A-/Stable/A-2	4
Southern California Edison Co.	BBB+/Stable/A-2	6
Southern Co.	A/Stable/A-1	4
Southern Indiana Gas & Electric Co.	A-/Stable/--	4
Southwestern Electric Power Co.	BBB/Stable/--	5
Southwestern Public Service Co.	BBB/Stable/A-2	5
System Energy Resources Inc.	BBB-/Negative/--	7
Tampa Electric Co.	BBB-/Stable/A-3	4
Toledo Edison Co.	BBB/Stable/--	6
Tucson Electric Power Co.	BB/Stable/B-2	6
TXU U.S. Holdings Co.	BBB-/Negative/--	8
Union Electric Co.	BBB+/CW-Neg/A-2	5
Union Light Heat & Power Co.	BBB/Positive/--	5
Vectren Utility Holdings Inc.	A-/Stable/A-2	3
Virginia Electric & Power Co.	BBB/Stable/A-2	5

Westar Energy Inc.	BB+/Positive/--	5
Wisconsin Electric Power Co.	A-/Negative/A-2	4
Wisconsin Energy Corp.	BBB+/Negative/A-2	5
Wisconsin Power & Light Co.	A-/Stable/A-2	4
Wisconsin Public Service Corp.	A+/CW-Neg/A-1	4
Xcel Energy Inc.	BBB/Stable/A-2	5

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Board Staff Interrogatory #3

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

With respect to its prescribed assets, OPG is requesting an ROE of 10.5%. Revenues associated with the incentive mechanism are associated with production from the prescribed hydroelectric facilities. While the application notes that OPG's current ROE in relation to its prescribed assets is 5%, footnote #10 in Table 1 of C1-T2-S1 appears to clarify that OPG earned an "incremental" ROE of 2.21% in 2006 on output from its prescribed hydroelectric assets over the 1900 MWh threshold for a total ROE of 7.21%. Is that interpretation of Table 1 correct? Does OPG expect the incremental ROE to occur under its proposed incentive mechanism during the test years? If so, what is the anticipated value of the incremental ROE for the test years?

Response

The 7.21 percent quoted in the interrogatory comes from footnote #10 of Ex. C1-T1-S1, Table 1 from the original evidence dated November 30, 2007. The comparable value in the updated evidence dated March 14, 2008 (per Ex. C1-T2-S1, Table 1 footnote #13), shows the total ROE in 2006 as 7.17 percent.

The interpretation that the difference from 5 percent ROE is attributable to the incentive mechanism is not correct. Actual 2006 ROE was 5.70 percent (Ex. C1-T1-S1, Table 5). Therefore, the incremental ROE amount attributed to the incentive mechanism would be 7.17% - 5.70% = 1.47%.

OPG expects to earn incentive revenue during the test period. However, due to uncertainty with respect to the timing of any Board approval of the proposed mechanism in 2008 the impact in 2008 cannot be determined at this time. For 2009, using the $12M expected value of the gross incentive revenues as presented in Ex. I1-T1-S1, page 15, lines 19 - 20, the incremental impact on the 2009 ROE is expected to be about 0.3 percent.

Board Staff Interrogatory #4

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Ms. McShane notes on page 92: "In order to estimate the common equity ratio for OPG that would permit the application of the benchmark return to its regulated operations, I selected a sample of vertically integrated utility companies with significant generation operations in order to estimate the incremental cost of equity for regulated generation company like OPG" and concludes at page 95: "the incremental equity returns at a 45% equity ratio are at the upper end of the range, i.e. in the range of approximately 1.25% to 1.50%." Is the "benchmark" ROE based on utilities that are primarily "wires"? Were the vertically integrated utilities listed in Schedule 28 used to establish a premium of 1.50%? If not, what premium was added in relation to Schedule 28? What is the average cost of capital for the utilities in Schedule 28?

Response

Yes, the benchmark ROE was based on utilities that are primarily wires. As stated on page 91, "The U.S. companies used to derive the benchmark return are also largely low risk wires and pipes utilities." The asset breakdown for the sample of benchmark U.S. utilities is provided on page 91.

Yes. The vertically integrated utilities listed on Schedule 28, Ex. C2-T1-S1, page 256 which were selected according to the criteria set out in Appendix I (page 192), were used to establish the premium. The premium of 1.5 percent (which is the upper end of the range of 1.25 percent to 1.50 percent, as set out at page 95 and explained in more detail in Appendix I), is based on the derived betas of those companies' generation operations.

As indicated on page 193, the average cost of equity based on the CAPM only for the companies on Schedule 28, Ex. C2-T1-S1, page 256 was estimated at 10.5 percent. Based on a marginal long-term debt cost of 6.5 percent and the companies' average 55/45 debt/equity capital structure, the sample average cost of capital based on the CAPM only would be approximately 8.3 percent. For the generation-only operations, the estimated cost of equity based solely on CAPM, as shown on page 197, was 11.1 percent. Based on the same marginal long-term debt cost of 6.5 percent as for the integrated utility and the companies' average 55/45 debt/equity capital structure, the sample average cost of capital based on the CAPM only would be approximately 8.6 percent.

Board Staff Interrogatory #5

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Ms. McShane relied upon U.S. utilities in arriving at her conclusion concerning cost of capital. Given that OPG's regulated operations consisting of 9,938 MW of generation (6,606 MW of nuclear and 3,332 MW of hydroelectric), please advise why the following were considered comparable utilities.

a) Allete – A total of 1,761 megawatts of generation, of which 74% steam-electric stations, 20% purchased, 6% derived from hydroelectric, and 0% from nuclear. It also appears to be involved in the real estate business.

b) Black Hills – A total of 1,000 MW of power generation capacity with 0% nuclear and 0% hydroelectric.

c) Empire District – A total of 1,255 MW with 0% nuclear.

d) DACORP – "IDACORP, Inc. is an energy-focused holding company… an investor in affordable housing and other real estate investments, and Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects…Idaho Power is a combination hydro-thermal utility with 17 hydroelectric developments, two natural gas-fired plants, one diesel-powered generator, and part ownership in three coal-fired generating plants." (Copied from the IDACORP website).

Response

OPG's regulated generation business (the prescribed assets) comprises two separate types of generation, hydroelectric and nuclear. There are no companies that have a similar mix of generation, nor, in fact are there any companies that have solely regulated generation operations. Virtually all of the companies that could be considered potentially comparable to OPG still have a significant wires component. Thus it was determined to be more important to select companies with a high proportion of generation assets than to select companies with a specific generation portfolio to serve as proxies for OPG's unique regulated hydroelectric/nuclear generation portfolio. All four referenced utilities were selected as comparables because they have high percentages of generation assets. With specific respect to the reference to Allete's real estate operations, as per

Schedule 28, Ex. C2-T1-S1, page 256, operations other than electricity operations account for only 12.5% of Allete's total assets. With respect to IDACORP, it is the sole publicly-traded U.S. electric utility with significant (as a percent of total assets) hydroelectric generation, which makes it an important part of the sample in light of OPG's regulated hydroelectric generation portfolio.

Board Staff Interrogatory #6

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

On page 45-46, Ms. McShane's report states that a financing flexibility allowance of 50 basis points needs to be added to the "bare-bones" ROE:

"The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return…In the absence of an adjustment for financial flexibility, the application of a "bare-bones" cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition… As a government-owned utility, OPG has not raised equity capital in the public equity markets; therefore it does not incur out-of-pocket equity financing and market pressure costs … The addition of an allowance for financing flexibility of 50 basis points to the "bare-bones" return on equity estimate of 9.25-10.25% derived from both the DCF and equity risk premium tests respectively, results in an estimate of the fair return on equity of 9.75%-10.75%."

Given that, as a government-owned utility, OPG has not raised equity capital in the public equity markets and does not incur financing and market pressure costs, and given that the fairness principle is cited in relation to competitive firms, why would it be appropriate for the Board to approve a financing flexibility allowance for OPG?

Response

The reference above is a brief summary of the rationale for including a financing flexibility allowance for OPG. Appendix G (Ex. C2-T1-S1, page 181) expands on this summary, explaining in detail the applicability of the financing flexibility adjustment to OPG.

OPG's equity ownership is similar to the majority of regulated electric transmission and distribution utilities in Ontario which are government-owned and which have not raised capital in the public equity markets. A number of them have also raised debt in a similar manner, that is, they have issued promissory notes to their government owners. While

OPG's current long-term debt is primarily sourced through the OEFC, OPG is developing plans to issue new incremental corporate debt into the public market and intends to be in a position to issue corporate debt in 2009 should OPG's updated long-term borrowing requirements turn out to be greater than currently forecast. (see Ex. C1-T2-S2, page 3, lines 26 - 29). The OEB has adopted a 50 basis point financing flexibility adjustment to the ROE for all of the other government-owned utilities in Ontario; for both financial integrity and comparability purposes, the financial flexibility component of OPG's ROE should be no less than that allowed for other similarly situated utilities.

Board Staff Interrogatory #7

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Ms. McShane noted the following on page 54:

> "The proper application of the stand-alone principle to the determination of the deemed capital structure (and return on equity) for OPG's regulated operations ignores the happenstance of ownership; the capital structure should reflect the business risks of OPG's regulated operations irrespective of the identity of the shareholder. This approach ensures that the shareholder is properly compensated for the total risk borne."

The Government Backgrounder (23 February, 2005) stated the following:

> "The Ontario government has established prices for electricity produced by Ontario Power Generation (OPG) effective April 1, 2005. These prices are designed to:
>
> a) Better reflect the true cost of producing electricity
>
> b) Ensure a reliable, sustainable and diverse supply of power in Ontario
>
> c) Protect Ontario's medium and large businesses by ensuring rates are stable and competitive
>
> d) Provide an incentive for OPG to contain costs and to maximize efficiencies
>
> e) Allow OPG to better service its debt while earning a rate of return that balances the needs of customers and ensures a fair return"

Based on the above, Board staff has the following questions:

a) The Government/shareholder established the current ROE of 5% and a capital structure of 45% equity and 55% debt. In forming her opinion concerning the current cost of capital, did Ms. McShane consider any of the above listed policy objectives, initially considered by the Government/shareholder? If not, why not? If the underlying purpose of an ROE is to compensate shareholders properly, of what significance is the fact that it was the Government/shareholder which set the ROE?

b) In the Government Backgrounder, the rate of return set was described as balancing the needs of the customers and ensuring a ‘fair return’. Please describe the events which have occurred since April 2005, and/or those events which are anticipated, which cause the return to no longer be fair.

c) Standard & Poor’s stated: “The government’s demonstrated willingness to financially assist the publicly owned generator is reflected in a two-notch rating enhancement to the stand-alone long-term corporate credit rating on OPG.” (A2/T3/S1/Attach. C) Dominion Bond Rating Service stated about the ownership of OPG: “The implied support of the Province provides significant support to OPG’s credit ratings.” (A2/T3/S1/Attach. A)

Ms. McShane’s report takes the position that “the happenstance of ownership” should be ignored.

As the primary purposes of an appropriate cost of capital is to permit the regulated entity to maintain an investment grade credit rating, and as credit rating agencies do <u>consider</u> ownership to be a significant factor when assigning a rating, please explain why the ownership of OPG is not a factor to be considered when determining the appropriate cost of capital.

<u>Response</u>

a) Ms. McShane was aware of the policy objectives listed in the Government Backgrounder (23 February, 2005). The objective of establishing prices that “<u>better</u> reflect the true cost of producing electricity” supports OPG’s assertion that the 5% was a transitional rate established until the later of March 31, 2008 or the effective date of the OEB’s first order establishing payment amounts for OPG’s prescribed assets. Power at cost is a government policy. The term “better” is significant as it implies progress towards an objective. A second objective of the interim payment amounts is to “allow OPG to <u>better</u> service its debt…”. Again this objective in setting the interim payment amounts was to provide an improvement in OPG’s ability to service its debt. As noted in Ex. C1-T2-S2, OPG is developing plans to be in a position to be able to issue long-term debt in the capital markets in 2009 should additional financing be required. OPG requires payment amounts established with the objective of allowing OPG to service its debt in order to be able to attract capital on reasonable terms and conditions.

Ms. McShane’s recommended ROE and capital structure: reflect the true price of electricity; ensure a reliable, sustainable and diverse supply of power in Ontario; and allow OPG to service its debt while earning a rate of return that balances the needs of customers and ensures a fair return. All support the adoption of a capital structure and return on equity that are compatible with OPG’s business risks and reflect a cost of capital that is comparable to that of similar risk entities. Ms. McShane views the achievement of the objective of protecting Ontario's medium and large businesses by ensuring rates are stable and competitive as met through the combination of setting regulated payments for the prescribed assets and a competitive return on those assets. In sum, Ms. McShane is of the view that these objectives are generally compatible with the determination of a capital structure and ROE that reflect the application of the same criteria that are applied in determining the returns allowed for other regulated companies in Ontario, including other government-owned companies. The criteria for a fair return are: the opportunity to earn a return commensurate with those available to entities of comparable risk, maintenance of financial integrity and the ability to attract capital on reasonable terms and conditions.

The principles of public utility regulation as enunciated by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, in their *Principles of Public Utility Rates, 2nd Edition*, Public Utilities Reports, Inc., Arlington, Virginia, 1988, emphasize that utility rates should accurately reflect cost of service. Getting the price right is a central premise of economics. Only if prices accurately reflect cost will the amount demanded and supplied be resource-efficient. If prices are artificially reduced below costs, then in comparison to economically efficient outcomes, demand, infrastructure investment and emissions will be higher, while conservation will be lower.

While the government may have considered other goals (e.g., social objectives) in setting the ROE for the transitional period, Ms. McShane's recommendations were based on an independent analysis that reflects the established stand-alone and fair return criteria that underpin the opportunity cost of principle.

b) Ms. McShane disagrees with the premise of the question, that is, that the 5% ROE represented a fair return on equity. The payment amounts were not established to enable OPG to service its debt, rather they were established to provide some progress towards that objective. An ROE that does not enable a company to service its debt cannot be considered "fair". The interim period for which the Province set payments outside of a regulatory forum is over. Nevertheless, the principal change that has occurred since April 2005 that bears on the determination of the appropriate return to be reflected in the regulated payments is the assumption of the authority for setting those payments by the OEB effective April 1, 2008. As with the other regulated utilities for which the OEB sets rates, OPG's costs, including its cost of capital, will be subject to independent and arms' length scrutiny. In that context, OPG's cost of capital should be determined by the OEB subject to the same criteria that underpin the determination of the cost of capital for all other regulated companies in Ontario, including Hydro One and the municipally owned electricity distributors (many of which have debt and equity provided by their municipal government shareholder). In so doing, the OEB applied the stand-alone principle and adopted capital structures and ROEs that were comparable to those it had previously adopted for the investor-owned utilities under its jurisdiction. It would not be appropriate for the OEB to interpret or infer the social objectives the government may have used in determining the transitional ROE, and assume that they should be applied until otherwise advised by the Government.

c) Ms. McShane's conclusion that the happenstance of ownership should be ignored reflects her opinion that the appropriate capital structure and ROE for OPG should (1) be determined on the basis of the fundamental risks to which OPG is exposed and (2) ensure that the taxpayers, who are the ultimate shareholders in OPG, do not subsidize OPG's cost of capital. This approach parallels the stand-alone approach that is followed for investor-owned utilities such as Enbridge Gas and Union Gas. Neither company's capital structure nor ROE reflect the owners' financial strength or willingness to support the utility, despite the fact that both utilities' S&P debt ratings are tied to those of their ultimate parents, Enbridge Inc. and Spectra Energy. If Enbridge Gas were sold to an entity whose rating was AA, and which provided undertakings that ensured future financial support for the utility (e.g., to make equity infusions as required to maintain the deemed capital structure), Ms. McShane would not expect the OEB to lower or increase the allowed common equity ratio or ROE as a result of the change in ownership.

Adherence to the stand-alone principle in setting the financial parameters is a means of ensuring that OPG is fully self-sufficient going forward and not dependent on the taxpayers for financial support. The cost of capital is not reduced when the rate of return on equity of a government-owned utility is capped at below market rates or when government loans and/or guarantees are substituted for a competitive rate of return on debt. In such circumstances, part of the true cost of capital is disguised and becomes the responsibility of others. The "cost of capital" charged to ratepayers is less, but the disguised costs and foregone revenues are borne by the taxpayer. In such circumstances, the taxpayer subsidizes the ratepayer, but the subsidies are delivered inefficiently, ineffectively and not transparently. Taxpayers bear real costs, as the cost that the provincial government must pay for its debt increases above what it otherwise would have been and the provincial government, as shareholder, receives less revenue, in the form of reduced dividends. If utility prices do not fully capture the cost of service, the ratepayers receive a subsidy paid for by the taxpayers.

To the extent that subsidies are viewed as appropriate, they should be provided externally to the rate setting process, and they should be transparent, not disguised. Subsidies can sourced through the dividends a government-owned utility earning a competitive rate of return on equity can pay its shareholder. Ideally, subsidies should not be tied to utility rates since doing so artificially increases demand. It is more efficient and effective to target financial subsidies towards economically-challenged industries and less affluent households than to provide lower utility rates to everyone, which provide greater subsidies to large users regardless of their specific economic circumstances. If subsidies are deemed to be appropriate, they should be structured so as to not distort price signals

d) Ms. McShane disagrees that the primary purpose of setting the cost of capital is to permit the regulated entity to maintain an investment grade credit rating. The three purposes of the determination of the cost of capital are listed in response to L-1-7 b); each of the three is of equivalent importance. In this regard, it bears noting that the OEB specifically noted in EB-2005-0421, *In the Matter of an Application by Toronto Hydro-Electric System Limited for Electricity Distribution Rates 2006, Decision with Reasons*, April 12, 2006, "And, as a matter of law, utilities are entitled to earn a rate of return that not only enables them to attract capital on reasonable terms but is comparable to the return granted other utilities with a similar risk profile." This conclusion is equally applicable to OPG.

Board Staff Interrogatory #8

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Ms. McShane's analysis underlying the cost of capital recommendations appears to be premised on the treatment of OPG as a typical generation utility, with the most appropriate benchmark or peer in Canada identified as TransAlta (page 88). Within this context, Ms. McShane appears to imply that if the Board approved the application as is, OPG would receive an "A" rating from the credit rating agencies.

a) If OPG is a typical utility, with ownership an attribute that is not relevant, can Ms. McShane please explain why the rating of OPG by DBRS (A-low) has not changed at all since 2003 while OPG's ROE has increased from negative 0.6% to positive 13.5% and cash flow/total gross debt has improved from negative 3.4% to 26.6%?

b) Also, given that DBRS has not changed its rating following this significant improvement in OPG's financial position and credit metrics, can Ms. McShane please elaborate on why the approval of a change in ROE from 5% to 10.5% to its prescribed assets would have a credit rating impact?

c) The McShane report finds TransAlta Corp. to be the most appropriate Canadian benchmark. Given that TransAlta Corp has a generation mix of 58% coal-fired, 29% gas, 9% hydro, 4% wind and no nuclear, why is it considered to be the closest peer for OPG's regulated operations? What impact would the difference between the number and scope of deferral and variance accounts between the two have on the comparison?

d) While the McShane report discusses the risks associated with nuclear generation (page 55-78), it does not mention risks OPG's base load hydro and nuclear generation avoid which other generators, including TransAlta, face. For example, one of the major challenges fossil generators (e.g., coal and natural gas) face are the existing and future environmental compliance costs associated with acid rain, smog and climate change. Morningstar's title of a recent (November 2007) credit rating report on TransAlta Corp states "Industry economics and the risk of emissions legislation challenge TransAlta" suggests that this risk is significant. Please advise if the absence of this risk was taken into account in the relative business risk analysis. If not, why not?

Response

a) Ms. McShane recognizes that the credit rating agencies take account of what they perceive as implied government support, as they will with any close relationship between owner and subsidiary. Please see response to L-1-007 for explanation of the context in which the happenstance of ownership should not be relevant for the purpose of setting the capital structure and return on equity. Ms. McShane has recommended financial parameters that are compatible with a stand-alone A rating; the proposed financial parameters are also compatible with the comparable returns standard.

b) As the credit ratings actually reflect implied government support, that support effectively placed a floor on the ratings in past years, as noted by DBRS in its August 2006 report. The same report noted that the improvement in the financial parameters of OPG meant that the then prevailing rating was more reflective of a stand-alone rating, driven by a more favourable regulatory environment. While the implied government support acts as a floor, the continued improved financial strength of OPG would permit the ratings to rise.

c) Ms. McShane considered Transalta Corporation and TransAlta Utilities to be OPG's closest Canadian peers because they are the only conventional corporations (as contrasted with an income trust) whose business is virtually all generation, a significant portion of which is subject to cost of service style Purchased Power Arrangements. Ms. Mcshane indicated only that the capital structure of TransAlta Corporation provided some insight into the capital structure for a generation company and a BBB rating; she did not do a detailed analysis of the similarities and differences between the business risks of TransAlta and OPG largely because of the BBB ratings of TransAlta Corporation. Nevertheless, TransAlta does not have the same access to deferral or variance accounts, and thus everything else equal, OPG would face lower short-term cost recovery risk.

d) Ms. McShane has not seen the report on TransAlta to which the question refers, but notes that in the November 2007 DBRS report on TransAlta Utilities, the debt rating agency indicated, that although the cost impact of more stringent environmental measures would be material, to a large extent the increase in costs would flow through to the holders of the PPAs in Alberta via the change in law provision. In any event, Ms. McShane did not rely to any material extent on a comparison between OPG and TransAlta and thus has not performed a detailed analysis of the relative risks.

Board Staff Interrogatory #9

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Page 71 of Ms. McShane's report states: "OPG faces significant risk of lost revenues due to longer and more frequent than anticipated outages and higher than expected costs to maintain and repair existing nuclear facilities. Every one TWh shortfall in production at a variable payment of $40 per MWh … is equal to an approximately $40 million reduction in revenues ... A 2.5 TWh production shortfall translates into a reduction in ROE of approximately 1.5 percentage points." In the Ontario market, lost nuclear output tends to be replaced by production from another facility owned by OPG. This understanding appears to be confirmed by the President and CEO of OPG in a May 18, 2007 press release:

'The flexibility of OPG's diversified portfolio of generating assets was clearly demonstrated in the first quarter as our fossil stations increased their production to offset lower nuclear production …." said President and CEO Jim Hankinson'.

What is the adjustment to risk that would result if it was assumed the outages losses were replaced by production from other OPG assets?

Response

Lost nuclear output can be replaced in a number of ways, one of which is from other OPG-owned generation. The comment attributed to Jim Hankinson simply illustrates that in this case, other OPG generation sources increased production to offset the lower nuclear output. His comment should not be taken to imply that other OPG generation was the only source of replacement generation. There is no evidence that lost nuclear production is consistently replaced by another OPG owned generation facility.

There would be no adjustment, even if the nuclear outage loss were replaced by another OPG owned generation facility. The assessment of the incremental equity risk premium for OPG (translated into an equity ratio) was made using samples of integrated utilities with a relatively high proportion of assets in diversified generation portfolios. The estimates of the incremental risk premium that Ms. McShane made are applicable to companies with diversified generation portfolios and with an ability to replace production from a plant experiencing an outage with production from other generating plants.

Board Staff Interrogatory #10

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

On page 39 of her report, Ms. McShane concludes "an expected equity risk premium estimate for a benchmark Canadian utility in the approximate range of 5.0-5.5%". Prior to that, the report notes the achieved utility equity risk premiums were 4.1-4.8% for Canadian electric and gas utilities from 1956-2006. It is unclear how the substantial difference relative to historic equity risk premiums was arrived at. Please clarify.

Response

The historic utility equity risk premiums underlying the final range of 5.0-5.5% were as follows:

	Period Covered	Arithmetic	Geometric
Canadian Electric & Gas Utilities	1956-2006	4.8%	4.1%
U.S. Electric Utilities	1947-2006	5.2%	4.5%
U.S. Gas Utilities	1947-2006	6.2%	5.5%

In addition, based on the expected bond return of 5.0-5.25% and a utility equity return of 11.0-12.0%, the indicated equity risk premium was estimated at approximately 6.0-6.75%.

As stated on page 39, the range of 5.0-5.5% was developed "[f]ocusing on the arithmetic average risk premiums, and recognizing that historic bond returns overstate the expected bond return" in both Canada and the U.S. and not solely on the achieved Canadian utility equity risk premiums.

Board Staff Interrogatory #11

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

In arriving at an ROE of 10.5%, Ms. McShane notes on page 50: "I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests". The report further notes "the results of the comparable earnings test are also entitled to significant weight". Please quantify "significant weight" in terms of the 12.5% comparable earnings test results.

Response

Ms. McShane has given approximately 25% weight to the comparable earnings test.

Board Staff Interrogatory #12

Ref: Ex. C

Issue Number: 2.2
Issue: What is the appropriate return on equity (ROE) for OPG's regulated business for the 2008 and 2009 test years? Should the ROE be the same for both OPG's regulated hydroelectric and nuclear businesses? If not, what is the appropriate ROE for each business?

Interrogatory

Ms. McShane notes on page 59 that there are other generators whose marginal costs are similarly low, which can result in OPG's regulated facilities not being dispatched and concludes "That risk will rise as additional low marginal cost generation" becomes available. Is this referring to the natural gas generators that have recently contracted with the OPA as being lower marginal cost generation relative to OPG's nuclear and hydro facilities? If so, please identify some examples that would pose dispatch risk for OPG's nuclear and hydro facilities. If not, please clarify the reference to "additional" generation.

Response

In this context, low marginal cost generation is in reference to the announced new wind power projects and the Bruce A refurbishment project. These generators can offer a low marginal cost but they will receive a price specified in their Power Purchase Agreement with the OPA. These units may pose a dispatch risk for OPG's nuclear and hydro facilities during periods of low demand.

Board Staff Interrogatory #13

Ref: Ex. C

Issue Number: 2.5
Issue: What are the implications of the deferral and variance accounts on OPG's financial risk? How should the implications be considered when determining the appropriate return on equity?

Interrogatory

It appears that Ms. McShane, in arriving at her cost of capital recommendations, has assumed that all of the nine variance and deferral accounts requested by OPG will be approved and also concluded that approval of those accounts does not result in a reduction of risk and therefore no reduction in the cost of capital. Specifically, Ms. McShane notes on page 62, "The use of deferral and variance accounts … does not change the utility's fundamental risks." Please explain why the use of these deferral and variance accounts does not change the risk to OPG.

Response

Ms. McShane's comment with respect to fundamental risks is recognition that regulation can mitigate the impact of the market demand, production, supply risks and operating risks on the shareholder through regulatory mechanisms such as deferral and variance accounts, but the fundamental market demand, production, supply and operating risks remain. To illustrate using an example other than OPG, the National Energy Board can mitigate the short-term cost recovery risks of gas pipelines by approving full cost of service tariffs, but it cannot alter the fundamental long-term supply risk faced by the pipelines as a result of the declining reserves in the Western Canada Sedimentary Basin.

The entirety of the paragraph to which the question makes reference is as follows:

> "The use of deferral and variance accounts can mitigate forecasting risks related to costs over which the utility has no control, but does not change the utility's fundamental risks. Moreover, the ability to create a variance or deferral account and accrue differences between forecast and actual costs does not guarantee recovery of those costs. The extent to which deferral accounts lower the forecasting risk faced by a utility and thus cost of capital is a function of the scope of the accounts and the materiality of the costs that are covered by those accounts." Ms. McShane did take into account the risk mitigating impacts on the cost of capital of the applied-for deferral accounts. For example, at page 67 of 261, the testimony states, "Given the potential differences between forecast and actual water and the resulting impacts on hydroelectric production and cost recovery, the operation of the variance account is a key risk mitigator for OPG. I have assumed

the continuation of this mechanism (Water Conditions Deferral Account) as proposed by OPG for purposes of establishing an appropriate capital structure and return on equity."

Board Staff Interrogatory #14

Ref: Ex. D1-T1-S1, page 3

Issue Number: 3.1
Issue: Are the costs and financial commitments OPG is seeking to recover under section 6(2)4 incurred to increase the output of, refurbish or add operating capacity to a prescribed facility?

Issue Number: 3.2
Issue: If so, are the costs and financial commitments within project budgets approved for that purpose by the board of directors of OPG?

Interrogatory

The Application refers to "slower than expected progress" with the Niagara Tunnel project in 2006. In note 15 to the 2007 audited financial statements the difficulties are described as slower than expected progress by the tunnel boring machine through a fractured rock formation, resulting in 'considerable uncertainty' with respect to the construction schedule and a delay in the in-service date. The note advises that the uncertainty will remain until the tunnel boring machine advances sufficiently to establish a consistent tunneling performance; that there is a 'potential that the schedule delay could impact the project cost'; and that the contractor is investigating alternatives, including the re-alignment of the tunnel, to mitigate the impact of the schedule delay.

a) Has a consistent tunneling performance been established? If not, when does OPG anticipate that will occur?

b) What are the alternatives that are being explored by the contractor, and to what extent will they mitigate the impact of the schedule delay? What is the impact of these alternatives on the project costs and costs associated with other related projects that would be incurred by OPG in the test period?

Response

a) No, as stated in Ex. D1-T1-S1, page 3, lines 10–21, consistent tunneling performance has not yet been established. Progress of the tunnel boring machine (TBM) has continued to be slow through the rock conditions encountered under the buried St. David's Gorge. Considerable uncertainty will remain with respect to the schedule until the TBM advances sufficiently beyond the St. David's Gorge (at approximately the 2.3 kilometre mark) and establishes consistent tunneling performance.

b) As stated in Ex. D1-T1-S1, page 3, lines 16-18, the contractor is investigating changing the alignment of part of the tunnel to minimize the length of tunneling in the upper Queenston rock formation and shorten the overall length of the tunnel by about

200 metres. To further mitigate the impact of schedule delay, the contractor will start to install the permanent concrete lining behind the TBM once the TBM has advanced to about the 3 kilometre mark. This will allow for boring and lining activities to proceed simultaneously. OPG does not expect that these mitigation actions will have a significant impact on OPG's project costs.

Board Staff Interrogatory #15

Ref: Ex. D2-T1-S1 Chart 1and Table 1

Issue Number: 3.1
Issue: Are the costs and financial commitments OPG is seeking to recover under section 6(2)4 incurred to increase the output of, refurbish or add operating capacity to a prescribed facility?

Issue Number: 3.2
Issue: If so, are the costs and financial commitments within project budgets approved for that purpose by the board of directors of OPG?

Interrogatory

Please confirm that the entries for P2/P3 Isolation Project on line 4 in chart 1 includes operating costs as well as capital in contrast to table 1 which only includes capital.

Response

We confirm that line 4 in chart 1 includes project OM&A costs as well as capital.

Board Staff Interrogatory #16

Ref: Ex. D1-T1-S1, Attachment F, page 4

Issue Number: 3.2
Issue: If so, are the costs and financial commitments within project budgets approved for that purpose by the board of directors of OPG?

Interrogatory

The Application refers to the end of the "25 Hz market" in 2009 which is currently served by two units at the Sir Adam Beck 1 (SAB 1) station. What are OPG's assumptions for the use of these 25Hz units after April 1, 2009?

Response

With the end of the 25Hz market in April 2009, OPG plans to shut down units G1 and G2 and place them into a safe and environmentally sound condition. Equipment that can be used in the potential rebuilding of G1 and G2 as 60Hz generators will be placed in a preserved state. The potential rebuilding of G1 and G2 would take place after the test period.

Board Staff Interrogatory #17

Ref: Ex. D

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

The application notes that, prior to beginning work on a project, approval is required for the release of funds to undertake the work and the documentation for seeking approval consists of a business cases summary (BCS). Considerations during the review and assessment of the proposal include looking at the quality of the project cost estimates and proposals for measurement and verification of the claimed project benefits. Those considerations do not appear to include assessing whether the estimated benefits exceed the costs. Please explain if such a cost-benefit assessment is carried out, particularly for "discretionary investments" in the "value enhancing" category? If not, can OPG please explain why?

Response

Cost-benefit assessments are carried out as part of OPG investment proposals. Business cases require a financial evaluation to be conducted including calculation of NPV (net present value of benefits minus costs). For a non-discretionary investment (e.g., regulatory), the lowest cost alternative meeting the requirements is generally selected. For a value enhancing project, the alternative with the highest positive NPV is generally selected.

Board Staff Interrogatory #18

Ref: Ex. D

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

What amount of indirect cost is attributed to construction work in progress (CWIP) in 2005, 2006 and 2007 on an actual basis and in 2008 and 2009 on a forecast basis? Please provide the basis of allocation for such indirect costs to CWIP. In your response please identify any amounts attributable to activities in the corporate office, including but not limited to: the board of directors, executive office, and corporate functions such as legal, finance and human resources.

Response

OPG's capitalization eligibility procedure provides for the capitalization of overhead costs that are directly attributable to the acquisition or construction of an asset, consistent with Generally Accepted Accounting Principles. Overhead costs that are not directly attributable to the acquisition or construction of an asset such as the cost of the Board of Directors, executive management, and support functions including finance, legal, office management and administration, and human resources, are expensed as incurred. When costs incurred by the above groups are directly attributable to the acquisition of construction of an asset, OPG may capitalize them. OPG did not attribute indirect costs to construction work in progress in 2005, 2006 and 2007 on an actual basis and in 2008 and 2009 on a forecast basis. For additional details regarding capitalization of support functions costs, see L-14-50 part (g).

Board Staff Interrogatory #19

Ref: Ex. D

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

Please provide a breakdown of the interest carrying charge amounts added to CWIP and other capital assets in each rate-regulated business segment in 2005, 2006 and 2007 on an actual basis and in 2008 and 2009 on a forecast basis.

Response

The table below provides the actual interest carrying charge amounts added to CWIP for the period 2005 - 2007 and the interest carrying charge amounts forecast to be added to CWIP for the period 2008 and 2009 in each of the rate-regulated business segments:

Year	($M)	
	Nuclear	Regulated Hydroelectric
2005 Actual	23.1	1.6
2006 Actual	7.7	6.9
2007 Actual	11.7	14.1
2008 Forecast	8.9	17.8
2009 Forecast	18.1	31.0

OPG does not apply interest carrying charges to its in-service capital assets.

Please refer to the response to interrogatory L-1-20 for discussion of the interest rate applied to CWIP to calculate the carrying charges above.

Board Staff Interrogatory #20

Ref: Ex. D

Issue Number: 3.6
Issue: Will OPG's accounting policies result in capitalization of an appropriate amount of costs incurred in 2008 and 2009 with respect to the construction or acquisition of capital assets?

Interrogatory

What was the interest rate(s) used for each year/period, how were these rates determined and what was the source?

Response

The rate used to record interest carrying charges added to CWIP for the nuclear and regulated hydroelectric segments for the years 2005, 2006, and 2007 was 6.0 percent. This rate represents the cost of debt submitted to the Province of Ontario by OPG for purposes of establishing payment amounts under O. Reg. 53/05, which are in effect until the later of March 31, 2008 and the effective date of the OEB's first rate order.

However, for the reasons set out in L-1-113, OPG proposes to move to the weighted average cost of capital in its approved capital structure as the rate to calculate carrying charges added to CWIP in the future.

Board Staff Interrogatory #21

Ref: Ex. E1-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

What is the historical relationship between deviations in forecasted OPG production and deviations from forecast median water levels?

Response

A comparison of forecast and actual production and river flows is presented in the following table. River flow is the measure that most appropriately reflects water levels in this context. For Saunders, deviations in production and flows follow very similar trends. At Niagara, the flow and production relationship is affected by water diversion capacity limitations (i.e. physical inability to use OPG's entire water entitlement), which will be mitigated by the Niagara Tunnel). The portion of OPG's flow entitlement that exceeds the Beck diversion conveyance capacity cannot be diverted to the generating stations for electricity production. As a result, the deviation in production is slightly less, on average, than the deviation in river flows.

Comparison of Forecast vs Actual Results for Production and River Flows: 2002 to 2007

	2002	2003	2004	2005	2006	2007	Average
Niagara (Niagara Complex only)							
Budget Production (GWh)	10,273	10,099	10,344	10,544	10,190	10,048	
Actual Production (GWh)	10,485	10,104	10,758	10,751	10,648	10,506	
% Actual/Budget	102%	100%	104%	102%	104%	105%	103%
Budget Annual Mean Flow (m³/s)	5,208	5,187	5,306	5,774	5,308	5,282	
Actual Annual Mean Flow (m³/s)	5,570	5,323	5,672	5,753	5,699	5,628	
% Actual/Budget	107%	103%	107%	100%	107%	107%	105%
Saunders							
Budget Production (GWh)	6,130	5,802	6,415	6,786	6,484	6,387	
Actual Production (GWh)	6,656	6,381	7,050	6,857	6,869	6,684	
% Actual/Budget	109%	110%	110%	101%	106%	105%	107%
Budget Annual Mean Flow (m³/s)	6,341	5,972	6,718	7,252	6,825	6,700	
Actual Annual Mean Flow (m³/s)	6,974	6,578	7,375	7,222	7,176	7,042	
% Actual/Budget	110%	110%	110%	100%	105%	105%	107%
Total Regulated [1, 2]							
Budget Production (GWh)	17,451	17,051	17,885	18,477	17,730	17,479	
Actual Production (GWh)	18,314	17,662	19,026	18,747	18,408	18,214	
% Actual/Budget	105%	104%	106%	101%	104%	104%	104%

1 Total Regulated Production values include DeCew production.
2. Mean flow not shown since the flows for Niagara and Saunders are different and cannot be averaged.

Board Staff Interrogatory #22

Ref: Ex. E1-T1-S1

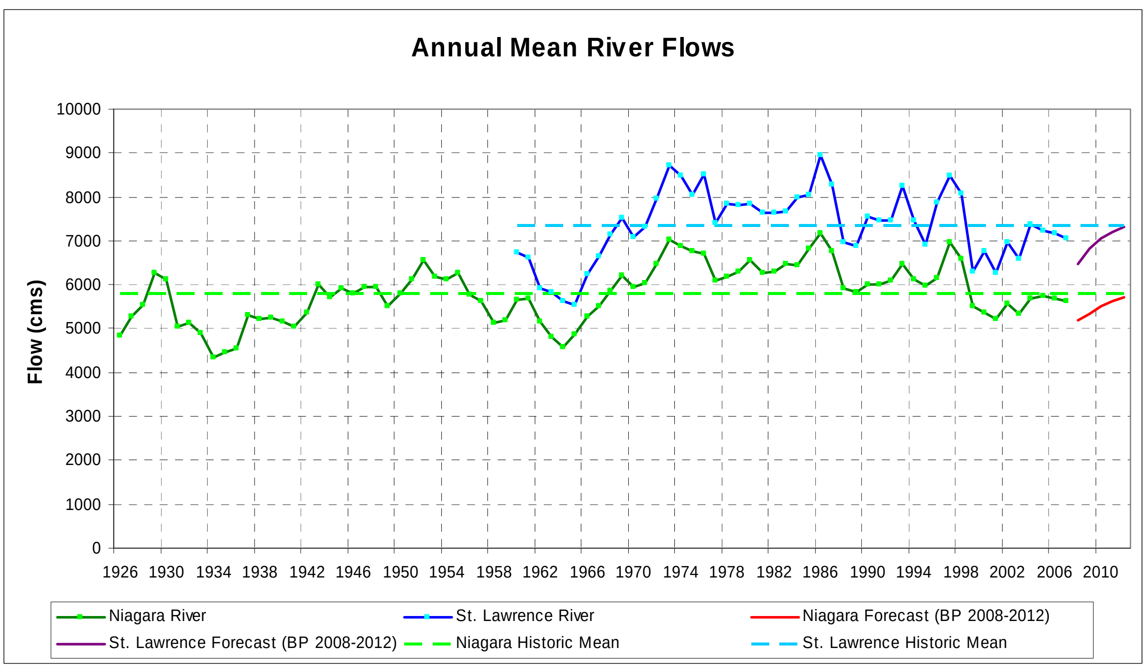
Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

What is the historical long-term trend for Lake Erie outflows and St. Lawrence River flows? Does the current forecast reflect this longer- term trend? If not, why not?

Response

Forecast flows used as the basis for OPG's 2008 to 2010 Business Plan are presented along with historic flow trends for the Niagara and St. Lawrence rivers in the following chart. Flows on the Niagara and St. Lawrence rivers had been below normal for several months prior to undertaking the 2008 forecast in the fall of 2007 (Monthly mean flows ranked as lower quartile on both systems during the summer of 2007). Consequently, below normal flows were predicted for 2008, trending towards normal flows in subsequent years.



Board Staff Interrogatory #23

Ref: Ex. E1-T1-S1, Table 1: Comparison of Production Forecast – Regulated Hydroelectric

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Regulated hydroelectric has different values for 2005, 2006 and 2007 Budget production levels from the forecast information filed with the OEB. Deviations of actual production from this original forecast that are the result of weather and water conditions are accumulated in a variance account. Has OPG used a different forecast for hydroelectric production in its application than it used in the original forecast?

Response

The budget production values presented for 2005, 2006, and 2007, in Exhibit E1 are based on updated forecasts that were produced in the business plan for that year. Energy variances reported in the Variance Account (Exhibit J) are based on the forecast information as of Q3/2004 referenced in Section 5.(1) of O. Reg. 53/05.

Board Staff Interrogatory #24

Ref: Ex. E1-T1-S1, Table 1: Comparison of Production Forecast – Regulated Hydroelectric

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Can OPG provide a table that shows the actual production deviations from the original forecast levels and attribute reasons for these deviations?

Response

Actual annual production for 2005 to 2007 is compared with the original Q3/2004 forecast in the following table. Actual production deviates from forecast due to changes in flow, changes in outage plans (unit and power canal), market conditions, system requirements, etc.

Comparison of Q3/2004 Forecast with Actual Production: 2005 to 2007

	2005	2006	2007
DeCew Production (GWh)			
Q3/2004 Forecast Production	1,107	1,036	1,108
Actual Production	1,139	890	1,024
% Actual/ForecastPlan	103%	86%	92%
Niagara Production (GWh)			
Q3/2004 Forecast Production	10,331	10,568	10,701
Actual Production	10,751	10,648	10,506
% Actual/ForecastPlan	104%	101%	98%
Saunders Production (GWh)			
Q3/2004 Forecast Production	6,518	6,786	6,913
Actual Production	6,857	6,869	6,684
% Actual/ForecastPlan	105%	101%	97%
Total Regulated Production (GWh)			
Q3/2004 Forecast Production	17,956	18,390	18,722
Actual Production	18,747	18,408	18,214
% Actual/ForecastPlan	104%	100%	97%

Board Staff Interrogatory #25

Ref: Ex. E1-T1-S1, Table 1: Comparison of Production Forecast – Regulated Hydroelectric

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

OPG states that:

> "the annual mean flows for both the Niagara and St. Lawrence Rivers in 2005 were very similar to the annual mean flow corresponding to the 2005 budget forecast"

Actual production exceeded the budget by about 0.3 TWh and actual production deviates from original forecast levels by 0.7 TWh. According to section 5(1) (a), deviations from the original forecast are recoverable only if caused by deviations of actual water conditions from the forecast. Has OPG booked deviations from forecast in the variance account that are based on the original forecast?

Response

Yes, as described in Ex. J1-T1-S1, page 3, section 3.1.1, paragraphs 1 and 2.

Board Staff Interrogatory #26

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

How often over the last 5 to 10 years has an approved Integrated Plan (IP) been adjusted because of impacts on the two-year outage planning horizon? What is the probability that the current IP will be adjusted for the Test Years because of outage planning?

Response

The approved Integrated Plan is adjusted relative to the previously approved Integrated Plan for the two year planning horizon for almost every year. Ex. E2-T1-S1, Section 2.2 lays out the dynamic nature of the planning process where new factors are considered in developing the Integrated Plan as the period of execution approaches. The Integrated Plan has changed relative to the previous approved plan by an average of 2 - 3 percent over the past 5 years, being negatively impacted by Pickering A Return to Service, new inspection findings related to feeders, scope assumptions for major containment outages, fuel channel work at Pickering and outage scope deferrals.

The current 2008 approved Integrated Plan was established at the end of 2007, and was adjusted from last year's previously approved Integrated Plan. The adjustment reflected an expectation for improved outage performance, reversing the trend from previous years.

Board Staff Interrogatory #27

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Does OPG co-ordinate its outages with Bruce Nuclear?

Response

No, OPG does not co-ordinate its outages with Bruce Nuclear.

Board Staff Interrogatory #28

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Does OPG share critical maintenance resources with Bruce Nuclear? If so, how does this affect OPG's outage planning? How is OPG compensated for the use of these resources?

Response

OPG's IMS division provides inspection and maintenance services to both OPG and Bruce Power.

IMS assesses and balances its available resources against the inspection and maintenance needs for outages at OPG and Bruce Power, which may place constraints on the timing and scheduling of OPG and Bruce Power outages.

OPG is compensated for the use of IMS resources. As discussed in Ex. G2-T1-S1 and Ex. G2-T2-S1, Bruce Power has contracted with IMS for the provision of inspection and maintenance services on a commercial basis.

Board Staff Interrogatory #29

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Has the IESO ever rejected an OPG outage schedule? If so, on what grounds?

Response

The IESO does not accept or reject an OPG outage schedule. They reject or revoke outage requests for individual generation units for a specific time window based on system security and adequacy relative to the position of the request in the outage 'queue'.

The IESO can reject an outage request prior to giving advance approval or can revoke an outage request after it has received advance approval.

The IESO has rejected and revoked OPG generator outage requests on numerous occasions in the past. OPG outages have been rejected/revoked by the IESO to address issues of system security and adequacy.

Board Staff Interrogatory #30

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

OPG has a Fleet Level Uncertainty Adjustment of 0.5 TWh/year (1% of forecast production). Does OPG change this level over time to reflect ageing factors?

Response

No. OPG does not change this level over time to reflect aging factors.

Known unit specific aging issues are addressed in planned unit outage scope and other site specific aging issues are factored into the forced loss rate assumption

Board Staff Interrogatory #31

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

OPG states that because of concurrent or unexpected events over the last few years, actual lost production has exceeded the budgeted adjustment of 0.5 TWh/year. Why does OPG expect that recent reforms to outage management processes will be effective in reversing this trend when previous reforms did not?

Response

Please see response to L-1-32.

Board Staff Interrogatory #32

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

Given that actual outages exceeded planned outages by 12% in 2005, 52% in 2006, and 40% in 2007 why does OPG believe that the forecast number of planned outage days for 2008 and 2009, described in the evidence as 'a significant improvement' from those experienced in 2005 and 2006 and a reduced "forced loss rate" from 2007 levels by 2009, is likely to be realized?

Response

OPG is unable to verify the numbers stated in the question. The variance of budget to actual outage days over the period 2005 - 2007, expressed as a percentage, is summarized below. The information below is based on the planned outage days, forced extension of planned outage ("FEPO") days and forced loss rate ("FLR") equivalent days provided in Ex. E2-T1-S2.

	2005 Budget	2005 Actual	% Change	2006 Budget	2006 Actual	% Change	2007 Budget	2007 Actual	% Change
Planned Outage Days	432.3	345.8	-20.0%	348.5	323.5	-7.2%	318.2	331.2	4.1%
FEPO Days	0	39.8	n/a	0	167	n/a	0	131.2	n/a
FLR Equivalent Days	234.5	196.9	-16.0%	224.3	236.5	5.4%	190.6	203	6.5%
TOTAL*	666.8	582.5	-12.6%	572.8	727	26.9%	508.8	665.4	30.8%

*2007 actual FLR equivalent days are shown without the two major non-recurring events (ISTB and resin excursion)

OPG's production has not achieved budgeted levels over the years 2005 - 2007 but OPG expects that recent reforms to outage management processes will be effective in reversing this trend.

In 2007, the FLR equivalent days included the impact of two major one-time extraordinary events that had significant generation impacts at Pickering but that are not expected to recur (Ex. E2-T1-S2 page 4). Actual 2007 FLR equivalent days with these two major one-time non recurring events was 484 days.

Past planned outages have been extended and forced outage losses have been incurred due to inadequate planning, uncertainties with respect to material condition and human performance issues, as described in greater detail in Ex. E2-T1-S2, Appendix C.

While OPG has been focused on continuous improvement in outage planning and performance, the organization was faced with significant challenges as it underwent a heavy outage load due to fuel channel work at Pickering B, the work to move Darlington to a three year outage cycle and the work to address material condition issues for Pickering A which resulted following a seven-year lay-up. The nuclear organization is now in a period of more stable, routine outage work which is steady state and shorter in nature than the past few years – giving staff more time and ability to focus on improved outage planning.

OPG has recognized in its plan the benefits of the investment it has made in improvements to the outage management process as presented in Ex. E2-T1-S1, Section 4.0. These improvements include implementing industry best practices, standardizing processes and templates, implementing a greater challenge process in scope definition, improving human performance practices and establishing outage control centers for outage execution. In addition, aside from improvements in the outage planning and execution processes, OPG is also recognizing benefits from the significant effort invested in improving supply chain processes (getting the right material to the work force on time) and addressing material condition issues (backlogs and inspections). There is also greater management review and oversight in addressing issues that could negatively impact outage durations and generation output.

OPG senior management sets challenging production targets, with the goal to stretch the organization to achieve maximum generation while ensuring safe and reliable operations. However OPG will not trade-off safety for the sake of generation.

OPG believes that this approach is working. As an example of performance improvement, Darlington was successful in 2007 in bringing units back ahead of schedule (ref. Ex. E2-T1-S2, Appendix C).

Board Staff Interrogatory #33

Ref: Ex. E2-T1-S1

Issue Number: 4.1
Issue: Is the methodology used by OPG to generate the proposed hydroelectric and nuclear business production forecasts appropriate?

Interrogatory

When does OPG expect to know whether it will reschedule planned outages for Pickering A in 2008 and 2009? What impact would this new schedule have on costs in 2008 and 2009?

Response

OPG expects to finalize whether it will reschedule planned outages for Pickering A in 2008 and 2009 by no later than the end of May following receipt of a Canadian Nuclear Safety Commission response to OPG's proposed Pickering A outage realignment.

At that time, OPG will update the OEB on whether it will be rescheduling the planned outages and any associated changes to the 2008 and 2009 outage schedules and costs.

Board Staff Interrogatory #34

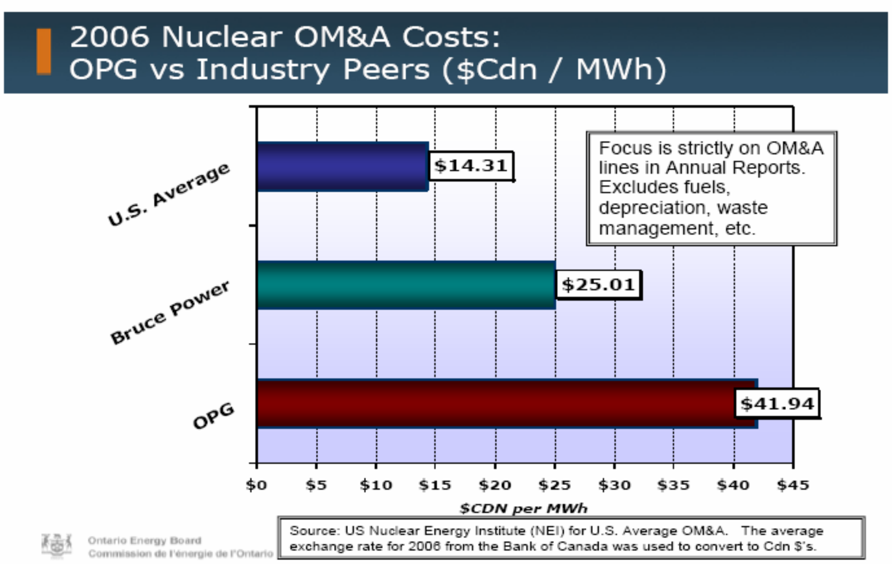
Ref: Ex. F

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

The following chart shows OM&A costs per MWh for OPG Nuclear, Bruce Power and the U.S. Nuclear Average for 2006. The information regarding Bruce Power is from its Annual Report. The latter is based on public information from Global Energy Decisions posted on the Nuclear Energy Institute (NEI) website and has been converted to $2006 CDN. The chart excludes costs associated with nuclear waste management and depreciation at both Bruce and the US nuclear generators. The chart focuses strictly on the nuclear OM&A lines – as well as output (TWh) – of the Annual Reports and the NEI, and compares, to the extent possible, the same costs. Based on this comparison, OPG is about three-fold higher than the U.S. Nuclear average and almost twice as high as Bruce Power.

Please explain the reasons that contribute to the cost differential between a) the average costs of US nuclear generators; and b) the costs of Bruce Power? Does OPG see the differential narrowing or growing over the next five years?



Bruce Power: www.brucepower.com/uc/GetDocument.aspx?docid=2429
NEI:
www.nei.org/filefolder/u.s._electricity_production_costs_and_components.xls

Response

OPG does not know what is included in the Bruce Power OM&A cost shown in the above chart. For example, capitalization policies can vary from company to company. This will influence the OM&A cost.

The data for the quoted NEI industry benchmarks is gathered from FERC Form 1 filings. Not all generators are required to make this filing and for some of the FERC Form 1 filings not all of the performance data fields are completed. In order to arrive at industry benchmarks, there is a strong reliance on using a) historical data (from past filings), for the missing data fields or b) analytical models to interpolate missing data and missing utilities based on best available information. In addition, the FERC data definitions do not typically capture all relevant operating costs such as corporate indirect costs.

As noted in evidence at Ex. A1-T4-S3, Section 9, OPG uses Electric Utility Cost Group ("EUCG") information, for cost comparison. This organization is recognized as the industry standard for cost information. All U.S. commercial nuclear operators provide data to this organization in accordance with standard rules for data submission. These data submissions are subject to reviews for data integrity and consistency. The EUCG information provides for an "apples to apples" comparison of costs.

The value for OPG shown in the above chart is a combined fleet average. It is more meaningful, however, to benchmark costs based on a "plant to plant' comparison, using plants with similar size units, as discussed at Ex. A1-T4-S3. Unit size will affect production costs due to economies of scale. As per WANO Q4 2007 Report, the average size of a U.S. nuclear operating unit is approximately 900 MWs, while the Bruce Power average is around 840 MWs and OPG average is 700 MWs. As per the data shown (2006) in Ex. A1-T4-S3, Section 9, Chart 3, Darlington compares favorably with its U.S. peers (CDN $26 MWh). The evidence in Ex. A1-T4-S3 also addresses the reasons for higher PUEC costs at Pickering A and B. Other factors that must be considered when assessing benchmarks between OPG and US reactors include CDN/US exchange differences, accounting differences and technological differences between US pressurized water reactors/boiling water reactors and CANDU reactors.

OPG does not have forward-looking information regarding the U.S. or Bruce Power cost trends. OPG cannot, therefore, predict what the differential between the OPG fleet cost, the U.S industry cost, and Bruce Power cost will be going forward. As noted above, Darlington has already achieved cost equivalency and its cost performance is expected to improve further as capacity factors improve. As capability factors go up for Pickering A and B, the non-fuel cost per MW (excluding inflation) is anticipated to trend lower. (For capacity performance trend and supporting information, please see Ex. E2-T1-S1, Table 1). The exception to this trend will be the years when a Vacuum Building Inspection is required because this requires that all units at a station be out of service at the same time.

Board Staff Interrogatory #35

Ref: Ex. F

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Please identify the primary drivers underlying the following trends in relation to nuclear OM&A (F2/T1/S1/Table 1):

a) Excluding the one-time extraordinary item (P2/3 Impairment Charges/Write-Off) in 2005, Total OM&A increases by 25.6% ($442.5M) from 2005 to 2009;

b) Base OM&A increase of 32% ($331.6M) from 2005 to 2009; and

c) Allocation of Corporate costs up by 20.8% ($74M) from 2005 to 2009.

Response

a) Total OM&A costs increases are driven primarily by higher base OM&A costs and corporate allocated costs (see response to b) and c) below), which account for $405.6M of the $442.5M increase from 2005 - 2009.

Of the remaining $36.9M of the increase, the most significant OM&A cost components are project OM&A (-$18.8M from 2005 - 2009) and outage OM&A (+$44.9M from 2005 - 2009), neither of which reflects a consistent trend. Specifically, outage costs are driven by factors such as outage scope and the number of planned outage days that may vary from year to year. Project OM&A costs vary based on the specific projects underway in any one year and are impacted by the split in any one year between OM&A and capital projects.

b) The primary drivers underlying the trend of base OM&A costs in nuclear from 2005 - 2009 are:

1. Labour escalation – as indicated in Table 2 of Ex. F2-T2-S1, escalation in labour costs from 2005 - 2009 in aggregate is approximately $165M (50 percent of base OM&A increase). Labour escalation includes the negotiated increases in the labour contracts with the PWU and Society and estimates of labour burden for such benefits as pension, health and dental.

2. Increased costs for Generation Development – The cost associated with the investigation of nuclear plant refurbishment projects and new nuclear generation

development opportunities is $88M higher in 2009 as opposed to 2005 (see Table 1 in Ex. F2-T2-S1), net of labour escalation. This increase represents 27 percent of the base OM&A increase from 2005 - 2009 and reflects planned increases in expenditures as outlined in Ex. D2-T1-S3.

3. Increased costs for Support Divisions – The $39M increase in support group base OM&A (12 percent of base OM&A increase, net of escalation), is primarily for increased security expenditures to meet CNSC requirements, and increased training program requirements. Further details of these programs are provided in Ex. F2-T2-S1.

c) The primary drivers underlying the $74.0M increase in corporate costs allocated to the nuclear business are as follows:

- $22.6M increase in CIO costs largely due to contractually mandated cost escalation for outsourced services provided by New Horizon System Solutions based on cost-of-living allowance adjustments and the Consumer Price Index, special initiatives such as the relocation of multiple data centers, and increasing company-wide requirements for IT services.

- $15.7M increase in centrally-held pension and other post employment benefits costs largely due to changes in the discount rate and mortality assumptions, expected growth, and actual experience.

- $11.3M increase in labour costs across all corporate functions due to general escalation such as annual wage increases.

- $9.7M increase in Corporate Affairs costs largely due to activities associated with the OEB payment amounts proceeding, community engagement initiatives, and initiatives related to community and sponsorship advertising.

- $7.7M increase in IESO non-energy charges largely due to the inclusion of the Global Adjustment and OPG Rebate in 2008 - 2009 budgets.

For additional detail on over-year-over variances in corporate costs allocated to the nuclear business, please refer to Sections 4.0 and 5.0 of Ex. F3-T1-S2.

Board Staff Interrogatory #36

Ref: Ex. F

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Please identify the primary drivers underlying the following trends in relation to hydroelectric OM&A (F1/T1/S1/Table 1):

a) Base OM&A increase of 22.4% ($10.6M) from 2005 to 2009;

b) Project OM&A rising by 83.3% ($5.5M) from 2005 to 2009; and

c) Allocation of Corporate costs up 69.6% ($19.2M) from 2005 to 2009. Please also explain why this percentage increase is over triple the percentage increase for nuclear operations of 20.8%.

Response

a) Period-over-period changes in regulated hydroelectric base OM&A are described in Ex. F1-T2-S2. The increase in base OM&A costs from 2005 - 2009 shown in Ex. F1-T1-S1, Table 1 is primarily due to increases in standard labour rates as described in Section 8.0 of Ex. F3-T4-S1, labour rate increases described in Section 6.0 of Ex. F3-T4-S1 and pension and other post employment benefits described in Section 7.3 of Ex. F3-T4-S1. As shown in Ex. F1-T2-S1, Table 2, staffing levels and non-labour costs exhibit relatively small changes from 2005 to 2009.

b) Period-over-period changes in regulated hydroelectric project OM&A are described in Ex. F1-T3-S2. The increase in regulated hydroelectric project OM&A costs from 2005 - 2009 shown in Ex. F1-T1-S1, Table 1 is primarily due to the number and value of projects in the Niagara Plant Group. As described in Ex. F1-T3-S2, project OM&A spending is expected to increase from 2005 - 2009 mainly due to the addition of civil repair projects at the DeCew Falls and Sir Adam Beck I Generating Stations.

c) The primary drivers underlying the $19.2M increase in corporate costs allocated to the regulated hydroelectric business are as follows:

- $3.9M increase largely due to the allocation of costs across various corporate cost categories to which OPG applies the blended OM&A/capital expenditure cost driver as part of its cost allocation methodology as endorsed by an external review (refer to Ex. F4-T1-S1). The cost driver is weighted more heavily toward regulated hydroelectric in the later years of the 2005 - 2009 period due to higher capital expenditures related to the Niagara Tunnel project.

- $3.2M increase in CIO costs largely due to contractually mandated cost escalation for outsourced services provided by New Horizon System Solutions based on cost-of-living allowance adjustments and the consumer price index, special initiatives such as the relocation of multiple data centers, and increasing company-wide requirements for IT services.

- $2.6M increase in Corporate Affairs costs largely due to activities associated with the OEB payment amounts hearing, and initiatives related to water safety, community and sponsorship advertising.

- $1.6M increase in Finance costs largely due to the establishment of a dedicated controllership group to support the increasing demands of the hydroelectric business (including the Niagara Tunnel project and First Nations negotiations).

- $1.6M increase in labour costs across all corporate functions due to general escalation such as annual wage increases.

- $1.6M increase in IESO non-energy charges largely due to the inclusion of the Global Adjustment and OPG Rebate in 2008 - 2009 budgets.

- $0.8M increase in centrally-held pension and other post employment benefits costs largely due to changes in the discount rate and mortality assumptions, expected growth, and actual experience.

The significant percentage increase in corporate costs allocated to the regulated hydroelectric business, as compared to the nuclear business, is primarily due to the impact of costs associated with the OEB payment amounts hearing, the change in the OM&A/capital expenditure cost driver, and the establishment of a dedicated hydroelectric controllership group. The higher costs associated with the OEB payment amounts hearing allocated to regulated hydroelectric contribute significantly more to increasing the total corporate costs allocated to regulated hydroelectric than they do for the total corporate costs allocated to nuclear. This is due to the fact that the total amount of costs allocated to hydroelectric in 2005 was much smaller than the amount allocated to nuclear, resulting in a higher percentage increase for hydroelectric over the period in question. The change in OM&A/capital expenditure cost factor is described above, and the costs associated with the dedicated hydroelectric controllership group are directly attributed to the hydroelectric business, thereby not impacting corporate costs attributed to nuclear.

For additional detail on over-year-over variances in corporate costs allocated to the regulated hydroelectric business, please refer to sections 2.0 and 3.0 of Ex. F3-T1-S2.

Board Staff Interrogatory #37

Ref: Ex. F

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Please identify the primary drivers underlying the following increases in relation to Corporate OM&A (F3/T1/S1/Table 1) from 2005 to 2009:

a) CIO ($40.8M, 27.3%);

b) Finance ($12.3M, 21.9%); and

c) HR ($14.5M, 87.9%)

Response

a) The primary drivers underlying the $40.8M company-wide CIO OM&A increase from 2005 to 2009 are as follows:

- $19.1M increase due to contractually mandated cost escalation for outsourced services provided by New Horizon System Solutions (NHSS) based on cost-of-living allowance adjustments and Consumer Price Index;
- $18.2M increase due to higher company-wide requirements for IT services;
- $10.0M for special initiatives such as the relocation of multiple data centres.

Above increases are partially offset by a decrease of $13.0M as a result of credits received from NHSS related to prior years.

b) The primary drivers underlying the $12.3M company-wide Finance OM&A increase from 2005 to 2009 are as follows:

- $8.2M increase in labour costs due to general escalation such as annual wage increases;
- $2.0M increase related to internal audit and internal control programs;
- $0.9M increase due to the establishment of a dedicated controllership group to support the increasing demands of the hydroelectric business (including the Niagara Tunnel project and First Nations negotiations).

b) OPG understands that the corporate function to which this sub-part of the question relates is Corporate Affairs, not Human Resources. The primary drivers underlying the

$14.5M company-wide Corporate Affairs OM&A increase from 2005 to 2009 are as follows:

- $8.0M increase due to activities associated with OEB payment amounts hearing;
- $6.0M increase related to community engagement initiatives and initiatives related to water safety, community and sponsorship advertising;
- $2.0M increase in labour costs due to general escalation such as annual wage increases.

The above increases are partially offset by a decrease of $3.9M as a result of the dissolution of the Sales and Marketing group within Corporate Affairs in 2006. The group was no longer required because of the change in OPG's business priorities.

Board Staff Interrogatory #38

Ref: Ex. F2-T1-S1, Table 1 and Ex. F2-T2-S1, Table 3

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Comparing the Total Regular Staff FTEs in the two tables (Line 14 in Table 1 and Line 41 in Table 3, respectively), it is noted that the staff numbers for the years 2005, 2006 and 2007 are different in the two tables. Please confirm which numbers are correct or, alternatively, provide an explanation for the apparent anomaly.

Response

Both numbers are correct. The values in Ex. F2-T1-S1, Table 1 reflect FTEs (Full Time Equivalents) and reflect the level of full time employee efforts for the year in question. In Ex. F2-T1-S1, Table 3, the historical years in question represent actual headcounts at the end of each year. Full Time Equivalents numbers are generally different than year-end headcount numbers since they reflect the impact of changing staff headcount throughout the year. For example, a staff member hired on July 1 would represent a year-end headcount of 1 but an FTE count of only 0.5.

Note that for the test period, both tables reflect FTEs and are consistent in 2008 and 2009.

Board Staff Interrogatory #39

Ref: Ex. F2-T1-S1, Table 1 and Ex. F2-T2-S1, Table 3

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Table 1 of Ex. F2/T1/S1 indicates a significant planned increase (567) in Total Regular Staff FTEs in 2008 compared to 2007 with a corresponding planned decrease in Non-Regular Staff FTEs. What are the implications on operating costs and, possibly planned work programs, if the planned staffing targets are not achieved or if staffing levels have to be augmented through increased non-regular staff FTEs? What are the implications on the hiring of new full time employees related to potential changes in the capital and OM&A projects schedules, including the deferrals described in the cover letter of the evidence update?

Response

The plan for 2008 reflects a need to hire regular staff but should that hiring not progress as planned, the work programs will continue to be delivered through a combined use of non-regular staff and overtime. The impact of this alternative resourcing has no significant impact on cost of the work.

It is expected that staffing requirements will remain stable even if there are changes in the capital and OM&A project schedules or changes to the Pickering A outage schedule as described in the cover letter to the evidence update. The project portfolio has stabilized at $290M as indicated in Ex. D2-T1-S1 page 2 lines 1 - 8 and the portfolio management process administers specific project work within this level of project expenditure. The stable project staffing expectation is confirmed in Ex. F2-T2-S1, Table 3, where the Projects & Modifications organization had 366 staff at year-end 2007 which is the same as the number of FTEs planned for 2009.

Board Staff Interrogatory #40

Ref: Ex. F2-T1-S1, Table 1 and Ex. F2-T2-S1, Table 3

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

At the bottom of Table 1 in F2/T1/S1, the number of Nuclear FTEs is provided for each year. There has been a relatively constant increase in the "Total Regular Staff FTEs – Nuclear" from 7,311.7 in 2005 to 8,109.1 in 2008. While it declines to 7,933.8 in 2009, there is a net increase of 8.5% or 622 FTEs (about 155.5 per year).

a) Over the same period, there is a coincident decline of a similar magnitude for "Non-Regular Staff FTEs". Is this trend a matter of contract staff being made permanent? If not, please explain the reason(s) for the increase in Regular Staff FTEs.

b) Similar FTE figures, by year, were not provided for the regulated hydroelectric business in Table 1 in F1/T1/S1. Please provide those FTE figures.

Response

a) The downward trend in non-regular staff FTEs reflects actual or planned hiring of regular staff to fill vacancies, such that non-regular (temporary) staff currently performing the duties are no longer required.

b) Total FTEs for the regulated hydroelectric business are presented in Ex.F1-T2-S1 Tables 1 and 2. Further detail for regular and non-regular FTEs is provided in Chart 1 below.

Chart 1

Regulated Hydroelectric
Regular and Non-Regular FTEs

	2005 Actual	2006 Actual	2007 Actual	2008 Plan	2009 Plan
Niagara					
Regular FTEs	225.0	219.6	215.9	230.6	231.0
Non-Regular FTEs	5.2	3.8	12.9	5.6	2.0
Niagara Total FTE's	**230.2**	**223.4**	**228.8**	**236.2**	**233.0**
Saunders					
Regular FTEs	69.2	63.9	63.9	67.1	67.8
Non-Regular FTEs	3.3	1.7	1.6	0.7	0.7
	72.5	**65.6**	**65.5**	**67.8**	**68.5**
Regulated Hydroelectric Total FTEs	**302.7**	**289.0**	**294.3**	**304.0**	**301.5**

Board Staff Interrogatory #41

Ref: Ex. F2-T2-S1, Table 3

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Table 3 shows that the number of Operations FTEs for Pickering A in 2008 and 2009 are comparable to those planned for Pickering B and Darlington in those years and, in fact, are higher than those for Pickering B. While it is recognized that staffing numbers for a two-unit station such as Pickering A can not be simply pro-rated from those for a four-unit station, please explain why the Pickering A Operations FTEs are as high as indicated.

Response

Operations FTE's (from Ex. F2-T2-S1 – Table 3)

	2008 Plan	**2008 CS**	**2009 Plan**	**2009 CS**
Darlington	402		413	
Pickering B	374	475	359	460
Pickering A	385	284	386	285

(Note: 'CS' reflects total Operations FTEs, including allocation of Common Services from Pickering A to Pickering B based on benefit received.)

As outlined below using 2008 data, the Pickering A Operations FTE data includes staff over and above those required to operate the nuclear units.

Pickering A Nuclear Unit Operators

- Operations Management, Supervision, Certified Staff, Field Operators: 233

Pickering Site Common Services Operators

- Management and Engineering 17
- Maintenance 61
- Operations 74
  - o Common Services Total 152

Total Pickering A Operations: 385

Included in the Pickering A Operations FTE count is a group referred to as Common Services. Common Services, as the name implies, provides support to both Pickering A and Pickering B (all 8 units) in the following areas:

- Heavy water upgrade and management (includes operations, maintenance and technical support for 3 heavy water upgraders).
- Waste collection and processing (conventional and nuclear).
- Operation of the Pickering auxiliary power system.
- Management of active liquid waste system.

The Common Services organization was organizationally assigned to Pickering A to allow a more equal distribution of work activities between Pickering A and B. When Common Services FTEs are allocated proportionately to Pickering A and Pickering B (a ratio of 33 percent Pickering A and 67 percent Pickering B), a more consistent inter-station comparison is presented in the column marked “CS” in the table above.

With this adjustment, the ratio of the number of operators benefiting Pickering A (284 FTEs) compared to the four unit Pickering B and Darlington stations is in the range of 60 percent to 70 percent.

Board Staff Interrogatory #42

Ref: Ex. F2-T2-S1, Chart 2 (page 37) and Chart 3 (page 38)

Issue Number: 5.1
Issue: Are the Operation, Maintenance and Administration ("OM&A") budgets for the prescribed hydroelectric and nuclear business appropriate?

Interrogatory

Chart 2 indicates that the number of elective backlogs per unit for Pickering B increased in 2007 compared to 2006 and that they will remain relatively high in 2008 and 2009, compared to the industry standard of 350 work orders per unit. Given these projections, please confirm that the relatively lower base OM&A costs for Equipment Performance Improvement Initiatives planned for Pickering B in 2008 and 2009 (compared to those for Darlington and Pickering A), and as indicated in Chart 3, are appropriate.

Response

The base OM&A costs for Equipment Performance Improvement Initiatives planned for Pickering B in 2008 and 2009 are appropriate, and reflect the amount of backlog reduction work that can be carried out cost-effectively during the test period. OPG anticipates that Pickering B will reach target backlog levels no earlier than the end of 2011.

Board Staff Interrogatory #43

Ref: Ex. F3-T2-S1, pages 4 - 6

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

Please explain the steps taken by OPG to implement the recommendations of Gannett Fleming contained in their report "Review of Ontario Power Generation Inc. Depreciation Review Process", dated March 1, 2007. If OPG has not implemented all of the recommendations, please advise which recommendations have not been implemented and the reasons why.

Response

While Gannett Fleming made several recommendations to refine OPG's Depreciation Review Process in its report dated March 1, 2007, Gannett Fleming concluded that "OPG's current Depreciation Review Process results in the depreciation expense component of the revenue requirement that reasonably and appropriately reflects the consumption of the average service of OPG's regulated assets." (Ex. F4-T2-S1, p. III-2) Gannett Fleming also concluded that "[OPG's] DRC process is adequate in meeting the generally accepted regulatory objectives regarding depreciation for regulated North American utilities." (Ex. F4-T2-S1, p. III-2)

In order to address the recommendations made by Gannett Fleming on p. III-1 of its report, OPG has taken the steps outlined below.

- Recommendation Related to "Transparency and Understandability"

  Gannett Fleming's recommendation in this area suggested that OPG's Depreciation Review Committee ("DRC") reports do not contain "a discussion of the company's policy and overall objectives regarding depreciation and the DRC process, as well as additional detail for explanations and justification of average life estimates." (p. III-1) In response to this recommendation, OPG has: 1) provided a discussion of OPG's depreciation policy in Section 3.0, Ex. F3-T2-S1; 2) prepared a separate DRC report for its regulated assets in 2007 (Appendix B, Ex. F3-T2-S1); and 3) included additional detail regarding justification of DRC's recommendations and the underlying rationale in the 2007 DRC report for its regulated assets. Gannett Fleming also noted that principles underlying the selection of assets reviewed by DRC should be included in information filed in the regulatory forum (p. II-8). OPG notes that in preparation for its first OEB payment amounts hearing, OPG made a decision to focus specifically on overall station lives in the 2007 review since station lives are the largest driver for the depreciation expense of OPG's regulated operations. Nuclear station lives are determined largely by the condition of several specific asset classes that have a significant impact on each station's end of life date. (These significant asset classes are referred to as the "life-limiting components".) Hydroelectric station lives are determined largely by the condition of the associated dams. As the scope of the review was station lives rather than assets, documentation of specific criteria for selection of assets on a class-by-class basis was not required as part of the process to develop the 2007 DRC report for regulated operations. OPG will document the criteria used for asset selection in subsequent DRC reports.

- Recommendation Related to "Effectiveness"

Gannett Fleming's report recommended that OPG incorporate benchmarking of estimated asset service lives for certain of its regulated assets. In particular, the report refers to components of hydroelectric plants (p. II-7) and certain components of nuclear plants for which meaningful comparable data is available (p. II-7). The report recognizes the limitations on benchmarking nuclear plant assets that are specific to CANDU technology (p. II-7). In 2007, OPG's Depreciation Review Committee focused its review on overall estimated useful lives of the stations determined largely by the condition of the life-limiting components. Since these life-limiting components for nuclear stations are specific to CANDU technology, Gannett Fleming's benchmarking recommendation was not applicable to the 2007 Depreciation Review Process for nuclear station lives.

Results of technical assessments and inspections of the dams were the prime source of evidence for OPG's 2007 DRC recommendations for hydroelectric stations lives, as the condition of individual dams varies by station. In addition, OPG concluded that the lives of regulated hydroelectric stations recommended by the DRC based on technical data were reasonable when compared to lives used by other hydroelectric energy generating utilities for depreciation purposes. When individual components of regulated hydroelectric stations are reviewed in the future, OPG will consider benchmarking against other utilities.

- Recommendation Related to "Independence from Bias"

Gannett Fleming recommended that a Depreciation Approval Committee or similar internal governance structure be formally set up within OPG to oversee the Depreciation Review Process (p. II-11). However, Gannett Fleming's report also acknowledged that "the current DRC report is filed for review and approval with a number of senior executives of the company (the CFO and line of business EVPs [Executive Vice Presidents])." (p. II-11) The report further states that "this approval results in a reasonable level of scrutiny of the DRC process by various stakeholders in the organization, and thus serves to promote impartiality of the process." (p. II-11)

Based on the above, OPG notes that the recommendation in this area is largely one of form, since the activities of the formal committee proposed by Gannett Fleming are already largely carried out by OPG's senior executives. Nevertheless, in 2007, OPG established an Approval Committee that now includes the Senior Vice President, Corporate Affairs (who is responsible for OPG's regulatory function) in addition to the senior executives identified above. The Committee approved the focus of the 2007 DRC review on overall station lives, endorsed the composition of DRC members, and approved the DRC's final recommendations.

Board Staff Interrogatory #44

Ref:

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

Please provide a schedule detailing the amortization rates of all components and major subcomponents of property, plant and equipment of the company's rate-regulated business segments, showing separately: tangible capital asset type, net book value (as of December 31, 2007), useful life years, amortization rate, effective date and the date last reviewed by the company's Depreciation Review Committee including explanations of any changes to useful life and amortization rate.

Response

The requested schedule detailing the property, plant and equipment of OPG's rate-regulated facilities, by asset class, is provided. For each asset class, the schedule includes a description, the net book value as of December 31, 2007, total useful life, amortization rate and depreciation method, the year the class was last reviewed by OPG's Depreciation Review Committee ("DRC") since 2005, and an explanation of the results of the last DRC review. OPG has not provided historical information prior to 2005 for the reasons given in L-12-6. The effective date, which was also requested in the interrogatory, can only be determined at the individual asset level since capital assets are depreciated commencing on the particular date they come into service. Hence, this information is not provided.

The attached schedules detail property, plant and equipment for each of the prescribed hydroelectric facilities, for each of the prescribed nuclear facilities and related common nuclear assets, as well as for Bruce Nuclear Generating Stations and related common Bruce nuclear assets. For depreciation purposes, the useful lives of most nuclear asset classes (as noted in the attached schedule) are limited by end-of-life dates of the station to which they relate. The following end-of-life dates for nuclear stations limit the useful lives of the nuclear asset classes effective January 1, 2008:

Bruce A – December 31, 2035
Bruce B – December 31, 2014
Darlington – December 31, 2019
Pickering A – December 31, 2021
Pickering B – September 30, 2014

Regulated Hydroelectric

Niagara Plant Group - Property, Plant and Equipment by Asset Class

Class	Description	Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
10100000	Hydro Electric - Land	19,042,028	N/A	N/A	N/A	
10101000	Hydro Electric - Excavation, Dredging, Riprapping, Grouting	979,200,513	100	Straight Line	2007	No change to useful life or amortization rate
10200000	Hydro Electric - Substructures & Superstructures	430,761,052	100	Straight Line	2006	No change to useful life or amortization rate
10205000	Hydro Electric - Outdoor Structures	7,810,394	75	Straight Line	N/A	
10210000	Hydro Electric - Service & Equipment Buildings	46,150,272	50	Straight Line	N/A	
10300000	Hydro Electric - Canal, forebay, retaining wall lining	62,666,710	75	Straight Line	N/A	
10301000	Hydro Electric - Lining of tunnels & permanent shafts	237,476,028	75	Straight Line	2006	No change to useful life or amortization rate
10302000	Hydro Electric - Spillways, sluices, flumes	9,137,408	75	Straight Line	2006	Certain assets from class 10302000 were moved to new class 10302100 with a reduced useful life of 15 yrs based on assessment of history of operating conditions.
10302100	Hydro Electric - Public Safety/Warning Booms	59,946	15	Straight Line	2006	Certain assets from class 10302000 were moved to new class 10302100 with a reduced useful life of 15 yrs based on assessment of history of operating conditions.
10306000	Hydro Electric - Surgetank, pipeline, conduit, penstock	90,559,101	75	Straight Line	N/A	
10311000	Hydro Electric - Dams-Earth & Rockfill	38,925,362	100	Straight Line	2007	No change to useful life or amortization rate
10312000	Hydro Electric - Dams-Concrete	29,517,878	100	Straight Line	2007	No change to useful life or amortization rate
10315000	Hydro Electric - Steel Racks	2,365,700	40	Straight Line	N/A	
10318000	Hydro Electric - Gates, Stoplogs & Operating Mechanisms	93,443,019	50	Straight Line	2006	No change to useful life or amortization rate
10400000	Hydro Electric - Turbines & Governors	87,972,078	75	Straight Line	N/A	
10405000	Hydro Electric - Turbine Runners	26,441,235	40	Straight Line	N/A	
10500000	Hydro Electric - Main Rotating Electrical Plant - Windings	16,853,326	40	Straight Line	N/A	
10501000	Hydro Electric - Main Rotating Electrical Plant - Machine (except windings)	99,182,532	75	Straight Line	2006	No change to useful life or amortization rate
10502000	Hydro Electric - Bus, Switching & Power Cable	43,941,945	45	Straight Line	2006	No change to useful life or amortization rate
10503000	Hydro Electric - High Voltage (HV) Switching	5,678,126	40	Straight Line	2006	No change to useful life or amortization rate
10503100	Hydro-Revenue Metering - HV Switching, Control Boards/Switchboards	4,552,567	30	Straight Line	N/A	
10504000	Hydro Electric - Control Boards & Switchboards	13,852,382	25	Straight Line	2006	No change to useful life or amortization rate
10505000	Hydro Electric - Station Service Electrical Equipment	17,037,852	50	Straight Line	2006	No change to useful life or amortization rate
10510000	Hydro Electric - Main Power & Station Service - Transformers	67,420,281	50	Straight Line	2006	No change to useful life or amortization rate
10531000	Hydro Electric - Circuit Breakers	574,896	50	Straight Line	2006	No change to useful life or amortization rate
10601000	Hydro Electric - Mechanical Equipment - Cranes & Followers	14,297,436	55	Straight Line	N/A	
10700000	Hydro Electric - Auxiliary Systems	48,665,937	30	Straight Line	2006	No change to useful life or amortization rate
10709000	Hydro Electric - Owned Bridges, Railway Track, Wharves	42,439,546	65	Straight Line	N/A	
16100000	Admin & Serv Bldgs - Lands	141,758	N/A	N/A	N/A	
16550000	Admin & Serv Bldgs - LAN Cable	71,999	10	Straight Line	N/A	
16560000	Admin & Serv Bldgs - Administrative System Software	45,827	5	Straight Line	2006	No change to useful life or amortization rate
18400000	Communications - Power Line Carrier Equipment	8,055	15	Straight Line	N/A	
18460000	Communications - Data Acquisition & Man Machine Interface Equipment	47,444	15	Straight Line	N/A	
18500000	Communications - Radio Equipment	641	15	Straight Line	N/A	
18540000	Communications - Administrative Telecom Equipment	171,956	7	Straight Line	N/A	
18541000	Communications - Administrative Telecom Equipment - Revenue Metering	14,544	7	Straight Line	N/A	
18600000	Communications - Wood Pole, Communication Cable, Apparatus & Booths	3,059	40	Straight Line	N/A	
18633000	Communications - Optical Wire - Revenue Metering	351,498	30	Straight Line	N/A	
Total Major Fixed Assets		**2,536,882,329**				
Minor Fixed Assets						
COMP1	Computers	27,973	5	Declining 40%	N/A	
OFFICE1	Office Furniture & Fixtures	14,466	3	Straight Line	N/A	
SERV1	Service Equipment	606,906	5 - 10	Straight Line	N/A	
T&WE1	Transport & Work Equipment	81,387	10	Declining 9% to 30%	N/A	
Total Minor Fixed Assets		**730,732**				
Total Niagara Plant Group Property, Plant and Equipment		**2,537,613,061**				

Regulated Hydroelectric

Saunders GS - Property, Plant and Equipment by Asset Class

Class #	Description	Net BookValue Dec. 31, 2007 ($)	Asset Class Useful Life (Years)	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since April 1, 2005	Results of Last DRC Review
Major Fixed Assets						
10100000	Hydro Electric - Land	2,898,051	N/A	N/A	N/A	
10101000	Hydro Electric - Excavation, Dredging, Riprapping, Grouting	310,965,034	100	Straight Line	2007	No change to useful life or amortization rate
10200000	Hydro Electric - Substructures & Superstructures	397,272,031	100	Straight Line	2006	No change to useful life or amortization rate
10210000	Hydro Electric - Service & Equipment Buildings	7,151,777	50	Straight Line	N/A	
10302000	Hydro Electric - Spillways, sluices, flumes	508,635	75	Straight Line	2006	No change to useful life or amortization rate
10306000	Hydro Electric - Surgetank, pipeline, conduit, penstock	26,657	75	Straight Line	N/A	
10311000	Hydro Electric - Dams-Earth & Rockfill	36,417,507	100	Straight Line	2007	No change to useful life or amortization rate
10312000	Hydro Electric - Dams-Concrete	326,617,405	100	Straight Line	2007	No change to useful life or amortization rate
10318000	Hydro Electric - Gates, Stoplogs & Operating Mechanisms	64,177,079	50	Straight Line	2006	No change to useful life or amortization rate
10400000	Hydro Electric - Turbines & Governors	30,702,515	75	Straight Line	N/A	
10405000	Hydro Electric - Turbine Runners	26,735,367	40	Straight Line	N/A	
10500000	Hydro Electric - Main Rotating Electrical Plant - Windings	31,020,358	40	Straight Line	N/A	
10501000	Hydro Electric - Main Rotating Electrical Plant - Machine (except windings)	21,010,412	75	Straight Line	2006	No change to useful life or amortization rate
10502000	Hydro Electric - Bus, Switching & Power Cable	4,544,289	45	Straight Line	2006	No change to useful life or amortization rate
10503000	Hydro Electric - High Voltage (HV) Switching	8,476,041	40	Straight Line	2006	No change to useful life or amortization rate
10503100	Hydro-Revenue Metering - HV Switching, Control Boards/Switchboards	680,802	30	Straight Line	N/A	
10504000	Hydro Electric - Control Boards & Switchboards	4,803,507	25	Straight Line	2006	No change to useful life or amortization rate
10505000	Hydro Electric - Station Service Electrical Equipment	6,600,247	50	Straight Line	2006	No change to useful life or amortization rate
10510000	Hydro Electric - Main Power & Station Service - Transformers	16,448,262	50	Straight Line	2006	No change to useful life or amortization rate
10531000	Hydro Electric - Circuit Breakers	1,685,893	50	Straight Line	2006	No change to useful life or amortization rate
10601000	Hydro Electric - Mechanical Equipment - Cranes & Followers	7,183,451	55	Straight Line	N/A	
10700000	Hydro Electric - Auxiliary Systems	13,793,125	30	Straight Line	2006	No change to useful life or amortization rate
10709000	Hydro Electric - Owned Bridges, Railway Track, Wharves	13,558,990	65	Straight Line	N/A	
16550000	Admin & Serv Bldgs - LAN Cable	34,248	10	Straight Line	N/A	
16560000	Admin & Serv Bldgs - Administrative System Software	4,583	5	Straight Line	2006	No change to useful life or amortization rate
18200000	Communications - Buildings	53,398	50	Straight Line	N/A	
18460000	Communications - Data Acquisition & Man Machine Interface Equipment	38,951	15	Straight Line	N/A	
18540000	Communications - Administrative Telecom Equipment	15,429	7	Straight Line	N/A	
18541000	Communications - Admin Telecom Equipment - Revenue Metering	2,381	7	Straight Line	N/A	
18633000	Communications - Optical Wire - Revenue Metering	98,003	30	Straight Line	N/A	
Total Major Fixed Assets		**1,333,524,426**				
Minor Fixed Assets						
COMP1	Computers	5,975	5	Declining 40%	N/A	
OFFICE1	Office Furniture & Fixtures	3,936	3	Straight Line	N/A	
SERV1	Service Equipment	164,907	5 - 10	Straight Line	N/A	
T&WE1	Transport & Work Equipment	57,421	10	Declining 9% to 30%	N/A	
Total Minor Fixed Assets		**232,239**				
Total Saunders GS Property, Plant and Equipment		**1,333,756,665**				

Bruce NGS - Property, Plant and Equipment by Asset Class

Bruce A

Class	Description	Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15810000	Nuclear - Heavy Water	222,870	100	Straight Line	N/A	
Various	Adjustment for Nuclear Waste/Used Fuel/Decom Costs	1,057,448,958	*	Straight Line	N/A	
Total Bruce A Fixed Assets		**1,057,671,828**				

*** Useful lives of individual assets within each major fixed asset class are limited by Bruce A station end-of-life date of December 31, 2035 for depreciation purposes**

Bruce NGS - Property, Plant and Equipment by Asset Class

Bruce B

Class	Description	Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15120000	Nuclear - Yard Facilities	767,941	50	Straight Line	N/A	
15121000	Nuclear - Electronic Site Security System	917,679	15	Straight Line	N/A	
15200000	Nuclear - Buildings and Structures	45,737,764	50	Straight Line	N/A	
15300000	Nuclear - Reactor Vessels	5,511,820	40	Straight Line	N/A	
15310000	Nuclear - Fuel Channel Assemblies	9,163,599	25	Straight Line	N/A	
15320000	Nuclear - Calandria Tubes - Pick B, Bruce B, Darl	552,247	40	Straight Line	N/A	
15330000	Nuclear - Reactivity Control Units	2,311,756	40	Straight Line	N/A	
15340000	Nuclear - Process Systems	31,383,885	40	Straight Line	N/A	
15350000	Nuclear - Steam Generators - Bruce	10,806,936	25	Straight Line	N/A	
15360000	Nuclear - Irradiated Fuel Bays	20,013,926	40	Straight Line	N/A	
15400000	Nuclear - Turbines, Auxiliary Equipment, Steam Reheater Tube	27,307,234	40	Straight Line	N/A	
15410000	Nuclear - Turbine Blades & Diaphragms - Bruce	3,401,003	35	Straight Line	N/A	
15420000	Nuclear - Generator Rotors, Stators & Auxiliary Systems	13,214,968	40	Straight Line	N/A	
15430000	Nuclear - Exciters	1,411,633	30	Straight Line	N/A	
15432000	Nuclear - Generator Rotor Windings	635,232	30	Straight Line	N/A	
15433000	Nuclear - Generator Stator Windings-Pick A, Bruce B, Darl	1,768,746	40	Straight Line	N/A	
15451000	Nuclear - Feedwater Heater Tubing	1,264,735	30	Straight Line	N/A	
15452000	Nuclear - Condenser Tubing - Bruce B, Darl	451,521	30	Straight Line	N/A	
15460000	Nuclear - Auxiliary Systems	6,015,352	40	Straight Line	N/A	
15500000	Nuclear - Main Power Output System	4,186,586	35	Straight Line	N/A	
15510000	Nuclear - Station Service Main Transformation & AC Power Distribution System	3,458,743	40	Straight Line	N/A	
15530000	Nuclear - Building Electrical Services Supply	1,413,600	40	Straight Line	N/A	
15540000	Nuclear - Electrical Auxiliary System	7,823,431	40	Straight Line	N/A	
15550000	Nuclear - Reactor Building Cabling	2,522,421	40	Straight Line	N/A	
15560000	Nuclear - AC Standby Power	3,398,093	40	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	27,969,614	30	Straight Line	N/A	
15700000	Nuclear - Circulating Water	2,328,644	40	Straight Line	N/A	
15701000	Nuclear - Service Water & Fire Protection System	4,242,334	25	Straight Line	N/A	
15710000	Nuclear - Water Treatment Plant	156,186	20	Straight Line	N/A	
15720000	Nuclear - Common Service Systems	6,381,909	35	Straight Line	N/A	
15810000	Nuclear - Heavy Water	53,458,707	100	Straight Line	N/A	
18541000	Communications - Administrative Telecom Equipment - Revenue Metering	5,650	7	Straight Line	N/A	
18600000	Communications - Wood Pole, Communication Cable, Apparatus & Booths	111,640	40	Straight Line	N/A	
18633000	Communications - Optical Wire - Revenue Metering	25,749	30	Straight Line	N/A	
Various	Adjustment for Nuclear Waste/Used Fuel/Decom Costs	(189,138,223)	*	Straight Line	N/A	
Total Bruce B Fixed Assets		**110,983,062**				

*** Useful lives of individual assets within each major fixed asset class are limited by Bruce B station end-of-life date of December 31, 2014 for depreciation purposes**

Bruce NGS - Property, Plant and Equipment by Asset Class

Bruce Common

Class		Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15100000	Nuclear - Land	999,989	N/A	N/A	N/A	
15110000	Nuclear - Site Improvements and Easements	337,438	75	Straight Line	N/A	
15120000	Nuclear - Yard Facilities	636,778	15	Straight Line	N/A	
15121000	Nuclear - Electronic Site Security System	1,842,494	15	Straight Line	N/A	
15200000	Nuclear - Buildings and Structures	1,907,912	50	Straight Line	N/A	
15340000	Nuclear - Process Systems	4,254,161	40	Straight Line	N/A	
15350000	Nuclear - Steam Generators - Bruce	2,196,476	25	Straight Line	N/A	
15460000	Nuclear - Auxiliary Systems	20,957	40	Straight Line	N/A	
15510000	Nuclear - Station Service Main Transformation & AC Power Distribution System	2,415	40	Straight Line	N/A	
15530000	Nuclear - Building Electrical Services Supply	105,250	40	Straight Line	N/A	
15540000	Nuclear - Electrical Auxiliary System	892,245	40	Straight Line	N/A	
15560000	Nuclear - AC Standby Power	1,900,603	40	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	1,011,879	30	Straight Line	N/A	
15700000	Nuclear - Circulating Water	976	40	Straight Line	N/A	
15701000	Nuclear - Service Water & Fire Protection System	161,052	25	Straight Line	N/A	
15710000	Nuclear - Water Treatment Plant	649,421	20	Straight Line	N/A	
15720000	Nuclear - Common Service Systems	819,446	35	Straight Line	N/A	
15721000	Nuclear - Common Service Systems - Air Compressors	42,897	20	Straight Line	N/A	
16210000	Admin & Serv Bldgs - Permanent Buildings, Roads, Site Improvements	2,229,279	50	Straight Line	N/A	
16230000	Admin & Serv Bldgs - Buildings - Frame & Metal Clad	29,731	25	Straight Line	N/A	
16310000	Admin & Serv Bldgs - Nuclear Training Simulators	3,102,692	45	Straight Line	N/A	
16500000	Admin & Serv Bldgs - Distribution System	3,913	35	Straight Line	N/A	
16630000	Admin & Serv Bldgs - Building Systems & Equipment	2,882,627	20	Straight Line	N/A	
18630000	Communications - Optical Wire	56,371	25	Straight Line	N/A	
Total Bruce Common Fixed Assets		**26,087,003**				
Total Bruce NGS Property, Plant and Equipment		**1,194,741,893**				

*** Useful lives of individual assets within each major fixed asset class are limited by Bruce B end-of-life date of December 31, 2014 for depreciation purposes**

Inspection and Maintenance Services - Property, Plant and Equipment by Asset Class

Class	Description	Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15200000	Nuclear - Buildings and Structures	6,550,617	50	Straight Line	2006	No change to useful life or amortization rate
Total Major Fixed Assets		**6,550,617**				
Minor Fixed Assets						
COMP1	Computers	138,936	5	Declining 40%	N/A	
OFFICE1	Office Furniture & Fixtures	51,758	3	Straight Line	N/A	
SERV1	Service Equipment	47,458,081	5 - 10	Straight Line	N/A	
T&WE1	Transport & Work Equipment	507,593	10	Declining 9% to 30%	N/A	
Total Minor Fixed Assets		**48,156,368**				
Total Inspection and Maintenance Services Property, Plant and Equipment		**54,706,985**				

Darlington NGS - Property, Plant and Equipment by Asset Class

Class	Description	Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15120000	Nuclear - Yard Facilities	21,192,321	50	Straight Line	N/A	
15121000	Nuclear - Electronic Site Security System	22,875,580	15	Straight Line	N/A	
15200000	Nuclear - Buildings and Structures	252,817,821	50	Straight Line	2006	No change to useful life or amortization rate
15300000	Nuclear - Reactor Vessels	14,095,913	40	Straight Line	N/A	
15310000	Nuclear - Fuel Channel Assemblies	16,307,534	25	Straight Line	2007	No change to useful life or amortization rate
15320000	Nuclear - Calandria Tubes - Pick B, Bruce B, Darl	1,199,938	40	Straight Line	N/A	
15330000	Nuclear - Reactivity Control Units	6,642,739	40	Straight Line	N/A	
15340000	Nuclear - Process Systems	111,013,280	40	Straight Line	2006	No change to useful life or amortization rate
15341200	Nuclear - Moderator Heat Exchangers - Darlington	1,067,925	30	Straight Line	N/A	
15351100	Nuclear - Steam Generators - Pickering B & Darlington	15,660,403	30	Straight Line	2007	No change to useful life or amortization rate
15352100	Nuclear - Shutdown Cooling System Heat Exchangers - Darlington	10,068,183	30	Straight Line	N/A	
15360000	Nuclear - Irradiated Fuel Bays	8,125,332	40	Straight Line	N/A	
15370000	Nuclear - Tritium Removal Facility	3,230,097	40	Straight Line	N/A	
15400000	Nuclear - Turbines, Auxiliary Equipment, Steam Reheater Tube	64,932,608	40	Straight Line	N/A	
15412000	Nuclear - Turbine Blades & Diaphragms - Darlington	8,191,065	30	Straight Line	N/A	
15420000	Nuclear - Generator Rotors, Stators & Auxiliary Systems	38,457,034	40	Straight Line	N/A	
15430000	Nuclear - Exciters	3,703,702	30	Straight Line	N/A	
15432000	Nuclear - Generator Rotor Windings	1,666,666	30	Straight Line	N/A	
15433000	Nuclear - Generator Stator Windings-Pick A, Bruce B, Darl	4,153,724	40	Straight Line	N/A	
15451000	Nuclear - Feedwater Heater Tubing	172,556	30	Straight Line	N/A	
15452000	Nuclear - Condenser Tubing - Bruce B, Darl	1,203,756	30	Straight Line	N/A	
15460000	Nuclear - Auxiliary Systems	23,235,488	40	Straight Line	N/A	
15500000	Nuclear - Main Power Output System	9,474,086	35	Straight Line	N/A	
15501000	Nuclear - Revenue Metering Main Power Output and Instrumentation & Control - Pick/Darl	3,093,637	30	Straight Line	N/A	
15510000	Nuclear - Station Service Main Transformation & AC Power Distribution System	12,496,991	40	Straight Line	N/A	
15521000	Nuclear - Station Service Main Transformation & Power Distribution System	1,265,530	20	Straight Line	N/A	
15530000	Nuclear - Building Electrical Services Supply	7,610,897	40	Straight Line	N/A	
15540000	Nuclear - Electrical Auxiliary System	36,649,975	40	Straight Line	N/A	
15550000	Nuclear - Reactor Building Cabling	8,923,710	40	Straight Line	N/A	
15560000	Nuclear - AC Standby Power	14,124,156	40	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	70,638,091	30	Straight Line	2006	No change to useful life or amortization rate
15700000	Nuclear - Circulating Water	7,849,569	40	Straight Line	N/A	
15701000	Nuclear - Service Water & Fire Protection System	53,806,024	25	Straight Line	N/A	
15710000	Nuclear - Water Treatment Plant	3,261,205	20	Straight Line	N/A	
15720000	Nuclear - Common Service Systems	46,122,650	35	Straight Line	N/A	
15721000	Nuclear - Common Service Systems - Air Compressors	1,775,193	20	Straight Line	N/A	
15990000	Nuclear - Alternate Spares	536,467	*	Straight Line	N/A	
16210000	Admin & Serv Bldgs - Permanent Buildings, Roads, Site Improvements	116,703	50	Straight Line	2006	No change to useful life or amortization rate
16310000	Admin & Serv Bldgs - Nuclear Training Simulators	735,681	45	Straight Line	N/A	
16630000	Admin & Serv Bldgs - Building Systems & Equipment	850,037	20	Straight Line	N/A	
18400000	Communications - Power Line Carrier Equip	9,858	15	Straight Line	N/A	
18460000	Communications - Data Acquistion Equipment, Man Machine Interface Equipment	19,474	15	Straight Line	N/A	
18500000	Communications - Radio Equipment	1,912,961	15	Straight Line	N/A	
18541000	Communications - Administrative Telecom Equipment - Revenue Metering	5,311	7	Straight Line	N/A	
18633000	Communications - Optical Wire - Revenue Metering	26,355	30	Straight Line	N/A	
Various	Adjustment for Nuclear Waste/Used Fuel/Decom Costs	126,773,916	*	Straight Line	N/A	
Total Major Fixed Assets		**1,038,092,140**				
Minor Fixed Assets						
COMP1	Computers	80,371	5	Declining 40%	N/A	
OFFICE1	Office Furniture & Fixtures	496,892	3	Straight Line	N/A	
SERV1	Service Equipment	50,679,413	5 - 10	Straight Line	N/A	
T&WE1	Transport & Work Equipment	479,456	10	Declining 9% to 30%	N/A	
Total Minor Fixed Assets		**51,736,132**				
Total Darlington NGS Property, Plant and Equipment		**1,089,828,272**				

*** Useful lives of individual assets within each major fixed asset class are limited by Darlington station end-of-life date of December 31, 2019 for depreciation purposes**

Pickering NGS - Property, Plant and Equipment by Asset Class

Pickering A

Class		Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15120000	Nuclear - Yard Facilities	54,215	50	Straight Line	N/A	
15200000	Nuclear - Buildings and Structures	8,921,027	50	Straight Line	2006	No change to useful life or amortization rate
15300000	Nuclear - Reactor Vessels	7,084,374	40	Straight Line	N/A	
15311000	Nuclear - Fuel Channel Assemblies - Pickering	13,471,014	25	Straight Line	2007	No change to useful life or amortization rate
15322000	Nuclear - Calandria Tubes - Pick A, Bruce Unit 1&2	42,679	40	Straight Line	N/A	
15330000	Nuclear - Reactivity Control Units	3,550,983	40	Straight Line	N/A	
15340000	Nuclear - Process Systems	165,793,973	40	Straight Line	2006	No change to useful life or amortization rate
15341100	Nuclear - Moderator Heat Exchangers - Pickering	33,700,346	25	Straight Line	N/A	
15351000	Nuclear - Steam Generators - Pickering A	4,992,458	40	Straight Line	2007	No change to useful life or amortization rate
15352000	Nuclear - Shutdown Cooling System Heat Exchangers - Pickering	2,143,191	25	Straight Line	N/A	
15360000	Nuclear - Irradiated Fuel Bays	753,418	40	Straight Line	N/A	
15400000	Nuclear - Turbines, Auxiliary Equipment, Steam Reheater Tube	1,618,940	40	Straight Line	N/A	
15411000	Nuclear - Turbine Blades & Diaphragms - Pickering	447,990	40	Straight Line	N/A	
15420000	Nuclear - Generator Rotors, Stators & Auxiliary Systems	212,901	40	Straight Line	N/A	
15430000	Nuclear - Exciters	247,056	30	Straight Line	N/A	
15431000	Nuclear - Exciters - Pickering	201	25	Straight Line	N/A	
15432000	Nuclear - Generator Rotor Windings	16	30	Straight Line	N/A	
15433000	Nuclear - Generator Stator Windings - Pick A, Bruce B, Darl	548,695	40	Straight Line	N/A	
15450000	Nuclear - Condenser Tubing - Pick, Bruce A	93,594,403	30	Straight Line	2006	No change to useful life or amortization rate
15460000	Nuclear - Auxiliary Systems	14,542,250	40	Straight Line	N/A	
15500000	Nuclear - Main Power Output System	7,598,603	35	Straight Line	N/A	
15501000	Nuclear - Revenue Metering Main Power Output and Instrumentation & Control - Pick/Darl	69,324	30	Straight Line	N/A	
15510000	Nuclear - Station Service Main Transformation & AC Power Distribution	2,624,456	40	Straight Line	N/A	
15530000	Nuclear - Building Electrical Services Supply	42,907	40	Straight Line	N/A	
15540000	Nuclear - Electrical Auxiliary System	131,607	40	Straight Line	N/A	
15550000	Nuclear - Reactor Building Cabling	48,735,552	40	Straight Line	N/A	
15560000	Nuclear - AC Standby Power	16,481,487	40	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	152,615,612	30	Straight Line	2006	No change to useful life or amortization rate
15700000	Nuclear - Circulating Water	1,335,495	40	Straight Line	N/A	
15701000	Nuclear - Service Water & Fire Protection System	87,851,105	25	Straight Line	N/A	
15720000	Nuclear - Common Service Systems	35,956,223	35	Straight Line	N/A	
16310000	Admin & Serv Bldgs - Nuclear Training Simulators	7,714,849	45	Straight Line	N/A	
16311000	Admin & Serv Bldgs - Nuclear Simulators-Design Upgrades	693,021	10	Straight Line	N/A	
18460000	Communications - Data Acquistion Equipment, Man Machine Interface Equipment	19,317	15	Straight Line	N/A	
18541000	Communications - Administrative Telecommunication Equipment-Revenue Metering	14,505	7	Straight Line	N/A	
18633000	Communications - Optical Wire - Revenue Metering	24,681	30	Straight Line	N/A	
Various	Adjustment for Nuclear Waste/Used Fuel/Decom Costs	151,448,521	*	Straight Line	N/A	
Total Pickering A Major Fixed Assets		**865,077,395**				

*** Useful lives of individual assets within each major fixed asset class are limited by Pickering A station end-of-life date of December 31, 2021 for depreciation purposes**

Pickering NGS - Property, Plant and Equipment by Asset Class

Pickering B

Class		Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15120000	Nuclear - Yard Facilities	17,003	50	Straight Line	N/A	
15121000	Nuclear - Electronic Site Security System	357,612	15	Straight Line	N/A	
15200000	Nuclear - Buildings and Structures	27,462,771	50	Straight Line	2006	No change to useful life or amortization rate
15300000	Nuclear - Reactor Vessels	1,423,069	40	Straight Line	N/A	
15310000	Nuclear - Fuel Channel Assemblies	1,333,027	25	Straight Line	2007	No change to useful life or amortization rate
15320000	Nuclear - Calandria Tubes - Pick B, Bruce B, Darl	175,233	40	Straight Line	N/A	
15330000	Nuclear - Reactivity Control Units	13,552,415	40	Straight Line	N/A	
15340000	Nuclear - Process Systems	21,961,216	40	Straight Line	2006	No change to useful life or amortization rate
15341100	Nuclear - Moderator Heat Exchangers - Pickering	527,298	25	Straight Line	N/A	
15351100	Nuclear - Steam Generators - Pickering B & Darlington	9,466,499	30	Straight Line	2007	No change to useful life or amortization rate
15352000	Nuclear - Shutdown Cooling System Heat Exchangers - Pickering	346,485	25	Straight Line	N/A	
15360000	Nuclear - Irradiated Fuel Bays	137,830	40	Straight Line	N/A	
15400000	Nuclear - Turbines, Auxiliary Equip, Steam Reheater Tube	9,585,811	40	Straight Line	N/A	
15411000	Nuclear - Turbine Blades & Diaphragms - Pickering	1,067,003	40	Straight Line	N/A	
15420000	Nuclear - Generator Rotors, Stators & Auxiliary Systems	4,073,388	40	Straight Line	N/A	
15431000	Nuclear - Exciters - Pickering	169,544	25	Straight Line	N/A	
15432000	Nuclear - Generator Rotor Windings	193,459	30	Straight Line	N/A	
15433000	Nuclear - Generator Stator Windings - Pick A, Bruce B, Darl	282,760	40	Straight Line	N/A	
15434000	Nuclear - Generator Stator Windings - Pick 6-7, Bruce A	262,094	40	Straight Line	N/A	
15450000	Nuclear - Condenser Tubing - Pick, Bruce A	117,034	30	Straight Line	2006	No change to useful life or amortization rate
15451000	Nuclear - Feedwater Heater Tubing	258,333	30	Straight Line	N/A	
15460000	Nuclear - Auxiliary Systems	15,358,913	40	Straight Line	N/A	
15500000	Nuclear - Main Power Output System	6,740,118	35	Straight Line	N/A	
15501000	Nuclear - Revenue Metering Main Power Output and Instrumentation & Control - Pick/Darl	134,856	30	Straight Line	N/A	
15510000	Nuclear - Station Service Main Transformation & AC Power Distribution System	4,703,667	40	Straight Line	N/A	
15530000	Nuclear - Building Electrical Services Supply	316,488	40	Straight Line	N/A	
15540000	Nuclear - Electrical Auxiliary System	2,272,167	40	Straight Line	N/A	
15550000	Nuclear - Reactor Building Cabling	806,701	40	Straight Line	N/A	
15560000	Nuclear - AC Standby Power	123,528,543	40	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	43,254,384	30	Straight Line	2006	No change to useful life or amortization rate
15700000	Nuclear - Circulating Water	4,285,932	40	Straight Line	N/A	
15701000	Nuclear - Service Water & Fire Protection System	36,634,102	25	Straight Line	N/A	
15710000	Nuclear - Water Treatment Plant	2,996,422	20	Straight Line	N/A	
15720000	Nuclear - Common Service Systems	11,488,858	35	Straight Line	N/A	
15910000	Nuclear - Interim Capital	97,986	15	Straight Line	N/A	
16310000	Admin & Serv Bldgs - Nuclear Training Simulators	2,527,985	45	Straight Line	N/A	
18460000	Communications - Data Acquistion Equipment, Man Machine Interface Equipment	13,912	15	Straight Line	N/A	
18541000	Communications - Administrative Telecommunication Equipment-Revenue Metering	19,903	7	Straight Line	N/A	
18633000	Communications - Optical Wire - Revenue Metering	16,252	30	Straight Line	N/A	
Various	Adjustment for Nuclear Waste/Used Fuel/Decom Costs	126,321,030	*	Straight Line	N/A	
Total Pickering B Major Fixed Assets		**474,288,103**				

*** Useful lives of individual assets within each major fixed asset class are limited by Pickering B station end-of-life date of September 30, 2014 for depreciation purposes**

Pickering NGS - Property, Plant and Equipment by Asset Class

Pickering Common

Class		Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15120000	Nuclear - Yard Facilities	15,135,592	50	Straight Line	N/A	
15121000	Nuclear - Electronic Site Security System	17,880,069	15	Straight Line	N/A	
15200000	Nuclear - Buildings and Structures	46,781,963	50	Straight Line	2006	No change to useful life or amortization rate
15300000	Nuclear - Reactor Vessels	1,319,945	40	Straight Line	N/A	
15310000	Nuclear - Fuel Channel Assemblies	93,784	25	Straight Line	2007	No change to useful life or amortization rate
15340000	Nuclear - Process Systems	4,010,683	40	Straight Line	2006	No change to useful life or amortization rate
15432000	Nuclear - Generator Rotor Windings	112,331	30	Straight Line	N/A	
15460000	Nuclear - Auxiliary Systems	78,221	40	Straight Line	N/A	
15501000	Nuclear - Revenue Metering Main Power Output and Instrumentation & Control - Pick/Darl	3,307,168	30	Straight Line	N/A	
15510000	Nuclear - Station Service Main Transformation & AC Power Distribution System	3,207,579	40	Straight Line	N/A	
15530000	Nuclear - Building Electrical Services Supply	52,968	40	Straight Line	N/A	
15540000	Nuclear - Electrical Auxiliary System	338,447	40	Straight Line	N/A	
15560000	Nuclear - AC Standby Power	217,722	40	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	4,589,947	30	Straight Line	2006	No change to useful life or amortization rate
15700000	Nuclear - Circulating Water	8,752	40	Straight Line	N/A	
15701000	Nuclear - Service Water & Fire Protection System	227,365	25	Straight Line	N/A	
15710000	Nuclear - Water Treatment Plant	2,033,215	20	Straight Line	N/A	
15720000	Nuclear - Common Service Systems	11,189,911	35	Straight Line	N/A	
15990000	Nuclear - Alternate Spares	5,374,298	*	Straight Line	N/A	
16210000	Admin & Serv Bldgs - Permanent Buildings, Roads, Site Improvements	8,428,838	50	Straight Line	2006	No change to useful life or amortization rate
16230000	Admin & Serv Bldgs - Buildings - Frame & Metal Clad	680,422	25	Straight Line	N/A	
16310000	Admin & Serv Bldgs - Nuclear Training Simulators	8,871,783	45	Straight Line	N/A	
16311000	Admin & Serv Bldgs - Nuclear Simulators - Design Upgrades	853,459	10	Straight Line	N/A	
16540000	Admin & Serv Bldgs - Administrative Telecomm Equipment	844,650	7	Straight Line	N/A	
16550000	Admin & Serv Bldgs - LAN Cable	380,345	10	Straight Line	N/A	
16551000	Admin & Serv Bldgs - LAN Electrical Connecting Devices	1,096	5	Straight Line	N/A	
16630000	Admin & Serv Bldgs - Building Systems & Equipment	6,623	20	Straight Line	N/A	
Total Pickering Common Major Fixed Assets		**136,027,174**				
Minor Fixed Assets						
COMP1	Computers	107,921	5	Declining 40%	N/A	
OFFICE1	Office Furniture & Fixtures	655,297	3	Straight Line	N/A	
SERV1	Service Equipment	30,775,300	5 - 10	Straight Line	N/A	
T&WE1	Transport & Work Equipment	677,209	10	Declining 9% to 30%	N/A	
Total Minor Fixed Assets		**32,215,726**				
Total Pickering NGS Property, Plant and Equipment		**1,507,608,398**				

*** Useful lives of individual assets within each major fixed asset class are limited by Pickering A station end-of-life date of December 31, 2021 for depreciation purposes**

Nuclear Support Divisions - Property, Plant and Equipment by Asset Class

Class	Description	Net Book Value Dec. 31, 2007 ($)	Asset Class Useful Life (Years)*	Amortization Rate/ Depreciation Method	Year Last Reviewed by DRC since 2005	Results of Last DRC Review since 2005
Major Fixed Assets						
15200000	Nuclear - Buildings and Structures	462,693	50	Straight Line	2006	No change to useful life or amortization rate
15340800	Nuclear - Fuel - Pickering	1,807,602	25	Straight Line	N/A	
15340900	Nuclear - Fuel - Pick B, Bruce Unit 3-8, Darl	3,414,451	25	Straight Line	N/A	
15600000	Nuclear - Instrumentation and Control	1,709,912	30	Straight Line	2006	No change to useful life or amortization rate
15810000	Nuclear - Heavy Water	117,881,823	100	Straight Line	N/A	
16210000	Admin & Serv Bldgs - Permanent Buildings, Roads, Site Improvements	459,041	50	Straight Line	2006	No change to useful life or amortization rate
16211000	Admin & Serv Bldgs - Buildings - Leased	4,556,722	10	Straight Line	N/A	
16220000	Admin & Serv Bldgs - Buildings	40,336	10	Straight Line	N/A	
16230000	Admin & Serv Bldgs - Buildings - Frame & Metal Clad	51,392	25	Straight Line	N/A	
16310000	Admin & Serv Bldgs - Nuclear Training Simulators	1,215,802	45	Straight Line	N/A	
16311000	Admin & Serv Bldgs - Nuclear Simulators - Design Upgrades	80,303	10	Straight Line	N/A	
16550000	Admin & Serv Bldgs - LAN Cable	2,441,797	10	Straight Line	N/A	
16560000	Admin & Serv Bldgs - Administrative System Software	20,208,301	5	Straight Line	2006	No change to useful life or amortization rate
16630000	Admin & Serv Bldgs - Building Systems & Equipment	14,302	20	Straight Line	N/A	
Total Major Fixed Assets		**154,344,478**				
Minor Fixed Assets						
COMP1	Computers	742,427	5	Declining 40%	N/A	
OFFICE1	Office Furniture & Fixtures	1,558,961	3	Straight Line	N/A	
SERV1	Service Equipment	14,186,176	5 - 10	Straight Line	N/A	
T&WE1	Transport & Work Equipment	2,435,484	10	Declining 9% to 30%	N/A	
Total Minor Fixed Assets		**18,923,048**				
Total Nuclear Support Divisions Property, Plant and Equipment		**173,267,526**				

*** Useful lives of individual assets within each major fixed asset class are limited by either the end-of-life of the station to which they directly relate or, in the case of assets not directly associated with a particular station, by the latest end-of-life date of the three stations owned and operated by OPG (Pickering A, Pickering B and Darlington).**

Board Staff Interrogatory #45

Ref:

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

Please identify and describe which processes or review criteria used for historic changes to end of useful life were used for the prescribed hydroelectric and nuclear stations (or relevant groups of units in each station) and, are expected to be used in the future management of those assets.

Response

OPG convenes an annual internal Depreciation Review Committee ("DRC") to review prescribed nuclear and hydroelectric stations lives. The DRC also reviews individual asset classes related to these stations over a five year cycle, generally reviewing a portion of OPG's individual assets each year. As discussed in Ex. L-1-44, the useful lives of most of OPG's nuclear assets are limited by the estimated end-of-life dates of the associated nuclear stations. The review of both prescribed nuclear and hydroelectric station lives involves an assessment of the condition and expected remaining life of certain key components (referred to as "life-limiting components"), in conjunction with an estimate of the expected operation of the stations. For the prescribed nuclear stations, the life-limiting components, the process for their review, and the basis for DRC's conclusions regarding changes (if any) to prescribed nuclear stations' lives are described in detail in Ex. L-1-47. Overall, pressure tubes have been determined to be the life-limiting component for nuclear stations, and it is their expected operating lives that determine the prescribed nuclear stations' end-of-life dates.

For hydroelectric stations, dams are considered to be the life-limiting component. Engineering inspections and assessments of the dams are the primary source of evidence reviewed by the DRC in formulating recommendations regarding changes, if any, to station lives for prescribed hydroelectric stations. The results of engineering inspections and assessments of the dams are documented in dam performance reports reviewed by the DRC. The inspections are carried out annually by OPG's engineers, and surveillance checks are conducted monthly or quarterly throughout the year by station personnel. Dam behaviour is also monitored by installed instruments, and instrument data is reviewed and documented on an ongoing basis by technical staff. OPG also considers the reasonability of the lives of hydroelectric stations vis-à-vis other hydroelectric energy producing utilities.

In addition to the technical factors noted above, past operating experience, economic viability and applicable external factors are also considered by the DRC in formulating its recommendations for end-of-life date changes for nuclear and hydroelectric stations.

Starting in 2007, the DRC conducts annual reviews of all prescribed and hydroelectric station lives. The DRC is comprised of representatives from each of the business units with operational and technical expertise as well as staff from the finance and regulatory affairs functions. The DRC prepares separate reports for OPG's regulated operations and unregulated operations starting in 2007. The scope, composition and recommendations of the DRC are approved by an Approval Committee, which consists of the Chief Operating Officer, the Chief Financial Officer, Executive Vice Presidents of Nuclear, Hydroelectric and Fossil business units, and Senior Vice President, Corporate Affairs (who is responsible for the regulatory affairs function). Approved recommendations of the DRC are typically implemented on January 1 of the year following the year of the DRC review.

The process followed by the DRC in reviewing station end-of-life dates and individual asset useful lives has been reviewed by an external consultant, Gannett Fleming Inc. (the report by Gannett Fleming is provided in Ex. F4-T2-S1). Gannett Fleming concluded that "processes, procedures and methods used by the DRC as part of OPG's Depreciation Review Process are sufficient to address generally accepted depreciation objectives for rate regulated companies." (p. I-2) Gannett Fleming also concluded that "OPG's current practices should result in a reasonable determination of average service lives and a reasonable and appropriate amount of depreciation expense to be included in OPG's revenue requirement." (p. I-2)

The main change to the current DRC process being considered by OPG relates to the use of benchmarking, as recommended by Gannett Fleming to enhance the current DRC process. However, OPG notes that this recommendation is generally applicable to individual asset class life assessments rather than overall station life determination. The benchmarking and other recommendations made by Gannett Fleming are discussed in Ex. L-1-43.

The 2006 and 2007 DRC reports have been provided in Appendices A and B to Ex. F3-T2-S1, respectively.

Board Staff Interrogatory #46

Ref:

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

Please provide a table showing the date to which each of the units in the OPG nuclear prescribed assets is currently licensed and the date to which the unit is currently planned to be in service for depreciation purposes. Please explain any differences between these dates.

Response

Prescribed Nuclear Facility	Unit	CNSC License End Date	Depreciation End of Life Date as of January 1, 2008
Darlington	Unit 1	February 28, 2013*	December 31, 2019
Darlington	Unit 2	February 28, 2013*	December 31, 2019
Darlington	Unit 3	February 28, 2013*	December 31, 2019
Darlington	Unit 4	February 28, 2013*	December 31, 2019
Pickering A	Unit 1	June 30, 2010	December 31, 2021
Pickering A	Unit 2	Note 1	Note 1
Pickering A	Unit 3	Note 1	Note 1
Pickering A	Unit 4	June 30, 2010	December 31, 2021
Pickering B	Unit 5	June 30, 2008	September 30, 2014
Pickering B	Unit 6	June 30, 2008	September 30, 2014
Pickering B	Unit 7	June 30, 2008	September 30, 2014
Pickering B	Unit 8	June 30, 2008	September 30, 2014

*New license end date for Darlington supersedes the date referenced in Ex. A1-T6-S1, Appendix D in OPG's pre-filed evidence submission dated March 14, 2008. A new license for Darlington was issued by the CNSC in February 2008 for the period March 1, 2008 to February 28, 2013.

Note 1 – Pickering A Units 2 and 3 are in safe storage and their respective fixed asset values were written off in 2005.

End of life dates used for depreciation purposes for each of the units in OPG's prescribed nuclear facilities are based on the expected operating lives of the facilities. The end dates of the operating licenses issued by the Canadian Nuclear Safety Commission ("CNSC") are not a factor considered by OPG in establishing end of life dates for its prescribed nuclear facilities. The CNSC issues operating licenses on the basis of its assessment of: OPG's qualifications to operate the nuclear facilities, equipment fitness for service, and whether, in operating the nuclear facilities, OPG makes adequate provision for the protection of the environment, health and safety of persons and maintenance of national security pursuant to the *Nuclear Safety and Control Act*. Therefore, the CNSC does not issue licenses based on expected operating lives of nuclear facilities

Board Staff Interrogatory #47

Ref: Ex. F3-T2-S1, Appendix B and Ex. A2-T1-S1, Appendix A

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

Please explain how the extended useful lives for nuclear generation stations were established including details of the technical analysis for life limiting components with respect to each of the following changes shown in 2007 audited financial statements (page 45) and the Depreciation Review Committee Recommendations (Rate-Regulated Business) dated December 2007:

a) The service life of Pickering B nuclear generating station was extended to 2014 in 2006;
b) Effective January 1, 2008, the service life of Darlington nuclear generating station was extended from 2017 to 2019;
c) Effective January 1, 2008, the service life of Bruce A nuclear generating station was extended from 2030 to 2035; and
d) Effective January 1, 2008, the service life of Bruce B nuclear generating station was extended from 2012 to 2014.

Response

The overall approach for evaluating nuclear station end-of-life dates for depreciation purposes is described in L-1-45 and the Depreciation Review Committee ("DRC") Recommendations report for the regulated business dated December 2007 (Ex. F3-T2-S1, Section 2.0, Appendix B).

Pickering and Darlington Units
The end-of-life dates for the units at nuclear stations owned and operated by OPG are determined based on an assessment of the condition and expected remaining life of certain key components, referred to as the "life-limiting components", and expected operation of the units. The life limiting components for OPG's nuclear units are: steam generators, pressure tubes, feeders and reactor components. Engineering analyses of these four components and the expected operation of the units are prepared by nuclear engineering staff and are reviewed by nuclear senior management and the DRC in order to determine appropriate end-of-life dates for each station. Engineering analyses specifically indicate which of the four components is expected to reach the end of its life first and, therefore, should be viewed as the determining factor for the overall life of each unit. For both Pickering B and Darlington, engineering assessments (summarized below) concluded that pressure tubes are the life limiting component that would reach their end of life first.

The expected service life for pressure tubes has remained unchanged over a number of years, and is consistent with the design life of 210,000 effective full power hours ("EFPH") of operation, which represents operation of a unit at full power for 210,000 hours. The service life of the pressure tube is dependent on the amount of time it is in use under various operating conditions. It is not a calendar year measure. Projections of the end of service life, converted to calendar year terms, are updated on a regular basis based on operating conditions. These updates are based on actual operating history and forecasts for future station operation. When the pressure tube reaches the 210,000 EFPH design life is affected by: the duration of planned outages, extensions to planned outages, unplanned outages, and station deratings. The more frequently the pressure tubes operate in each calendar year, the earlier the design life in calendar year terms is reached. The extensions to the service life, in calendar year terms, reflect updates to projections of when the design life (210,000 EFPH) of the station's pressure tubes is reached.

In 2006, based on the review of the engineering analysis for Pickering B and expected operation of Pickering B units, it was determined that the life of the station should be extended to September 30, 2014. In 2007, based on the review of the analysis for Darlington and expected operation of Darlington units, DRC determined that the life of the station should be extended to December 31, 2019. (For clarity, OPG's policy is to use a single depreciation end-of-life date for all units associated with a particular nuclear station, which is typically based on an average of the estimated end-of-life dates for each of the units.)

A summary of the engineering assessment of the four life-limiting components for Pickering B and Darlington is provided below.

Pressure Tubes

Pickering B pressure tubes were designed for an operating life of 210,000 EFPH or 30 calendar years of operation at an average capacity factor of 80 percent. The capacity factor represents the maximum generation that a unit is able to produce when operated at full power. The design basis life was determined from conservative assumptions of pressure tube deformation and changes in mechanical properties due to deuterium ingress and irradiation. Current fitness-for-service assessments indicate that there is high confidence that Pickering B pressure tubes will reach the design end-of-life.

Pickering B pressure tubes are life limited principally by axial elongation due to irradiation relative to the available bearing travel allowance. (CANDU reactors are designed to accommodate the pressure tube growth through the use of bearings at each end to the reactor). The expected unit lifetime is based on the projected time for the fastest growing pressure tubes to reach the end of bearing travel.

Pressure tube to calandria tube contact is also limiting at Pickering B, as all units contain loose-fitting annulus spacers that were displaced, to varying degrees, from their installed locations. Hence, all units are susceptible to the pressure tube sagging into contact with its calandria tube, which enhances the possibility of hydride blister formation and growth.

Pressure tube to calandria tube contact is being managed by spacer location and repositioning programs. There is a potential for post-repositioning spacer movement, and this is being addressed to meet the pressure tube design life via probabilistic assessments and re-inspections to confirm spacer positions.

Darlington pressure tubes were also designed for an operating life of 210,000 EFPH, based on conservative assumptions of pressure tube deformation and changes in mechanical properties due to deuterium ingress and irradiation.

In addition to limitations due to the fastest growing pressure tubes, Darlington pressure tubes are limited by total hydrogen isotope concentration due to deuterium ingress, which affects the mechanical properties, specifically the fracture toughness of the irradiated pressure tube material. Darlington pressure tubes operate at a higher pressure and temperature than Pickering B pressure tubes, resulting in a higher rate of deuterium ingress. Specifically, deuterium ingress in the rolled joint region (where the pressure tube is mechanically coupled to the stainless steel end fitting) and the associated diffusion inboard of the rolled joints may be approaching the Canadian Standards Association's standard CAN/CSA N285.8 which limits total hydrogen content towards the end of life in some tubes.

Steam Generators

Steam generator end-of-life is defined as that point in time where existing deficiencies prevent the unit from being declared fit-for-service and where those deficiencies cannot be adequately corrected for technical or economic reasons. For Pickering B steam generators, under deposit pitting corrosion of the steam generator tubes is the main life limiting degradation mechanism.

Pitting degradation is managed through routine maintenance (high pressure water lancing) to remove deposits from the tubesheet region of the steam generators. Inspections of the steam generator tubes during each planned outage are undertaken to confirm the effectiveness of the maintenance activities and to remove any compromised tubes from service.

Thinning and erosion corrosion of steam generator tubes are also considered potential life limiting mechanisms for Pickering B steam generators, but the degradation associated with these mechanisms is shallow (less than 30 percent through wall) and the mechanism has been dormant for several years, with no new initiation or growth, as confirmed by on-going inspections of the steam generators.

The tubing material in the Darlington steam generators is considered more resistant to corrosion degradation. Some minor shallow pitting of the tubing (less than 10 percent through wall) has been observed in the Darlington units but this is not considered to be life limiting for the steam generators. The life cycle management strategy for tube pitting degradation in the Darlington steam generators is through on-going tube inspections and routine maintenance (high pressure water lancing) to remove deposits from the tubesheet region during unit planned outages.

The major degradation mode experienced in the Darlington steam generators has been fretting of the steam generator tubes at the U-bend supports. Tube fretting was first discovered in the Darlington steam generators in 1998 and was managed initially through extensive inspections and plugging of tubes with deeper frets. Due to the advanced nature of the fretting degradation, auxiliary anti-vibration bar supports were installed in all 16 Darlington steam generators between 2003 and 2005. Re-inspection of the steam generators after the anti-vibration bar installation has indicated little or no fret initiation or growth at the original U-bend supports.

With the degradation mechanisms currently present, steam generators at both Pickering B and Darlington meet all requirements for fitness-for-service over the nominal operating intervals. Both stations have steam generator life cycle management plans, with the unit end-of-life assumed to be equivalent to the pressure tubes end-of-life.

Therefore, in both Pickering B and Darlington, the steam generator life is an economic one, i.e., the point when the cost of steam generators maintenance and inspection can no longer be justified as the option that provides the maximum value to the station. Based on economic cost-benefit analysis, steam generators have a high probability of operating to the defined unit end-of-life dates as determined by pressure tube limitations.

Feeders

General experience with CANDU stations has identified five main degradation mechanisms for feeder piping:

- General flow accelerated corrosion (typically seen on tight radius bends)
- Local flow accelerated corrosion (typically seen near welds)
- Fretting with other components
- Cracking of welds
- Cracking of tight radius bends

To date, only thinning and fretting with other components have been observed at units owned and operated by OPG. The end of life for feeder piping can be defined as that point in time when the pipe can no longer be demonstrated to be fit-for-service due to wall thinning from flow accelerated corrosion or because of the development of a crack.

The end-of-life for a nuclear facility or individual unit can be defined as that point in time when the quantity of feeders requiring mitigating actions to remain fit-for-service can no longer be economically managed.

OPG inspects feeder piping for all known active and inactive degradation mechanisms. Formal assessments of the condition of OPG feeder piping are produced and routinely updated based on the latest inspection results. Feeder thinning is known to limit the life of a number of feeders, and fitness-for-service plans are produced for each station to outline specific mitigation requirements, which can include feeder replacement.

Currently, OPG's feeder condition assessments do not identify the need for sufficient mitigating action to justify the end-of-life of any unit owned and operated by OPG. Feeder piping degradation does not limit the life of units owned and operated by OPG as it is more economical to perform mandatory repairs/replacements than to shut down the unit permanently. If the cracking of feeder piping became an active degradation mechanism at a unit, this conclusion would have to be reassessed.

Reactor Components

The most significant degradation mechanisms for reactor components are:

- Ductility reduction due to irradiation
- Fatigue and fretting due to flow induced vibration
- Elongation and local deformation caused by irradiation

The reactor components that are affected by these degradation mechanisms are:

- Calandria vessel
- Calandria tubes
- Guide tubes
- Moderator inlet nozzles

No operational problems have been experienced in any Pickering B or Darlington reactor unit as a result of these degradation mechanisms. In addition, inspection plans have been prepared and engineering evaluations undertaken to demonstrate that affected components are fit for continued service till the end of the current operating life as defined by pressure tube elongation.

Bruce Generating Stations

OPG does not operate the nuclear units on lease to Bruce Power and does not have access to detailed technical data necessary to conduct an engineering analysis on the life-limiting components of Bruce units. Therefore, the extensions of Bruce A and Bruce B Generating Stations' end-of-life dates were not determined based on an engineering analysis such as the one discussed above for stations that OPG operates.

Sections 2.2.2 and 2.3.0, part (e) of the 2007 DRC report discuss the basis for the decision to extend the life of Bruce A Generating Station. Sections 2.2.1 and 2.3.0, part (d) of the 2007 DRC report discuss the basis for the decision to extend the life of Bruce B Generating Station

The Bruce A service life extension for depreciation purposes was based on information made publicly available by Bruce Power LP in August 2007, when it announced that Bruce A Unit 4 will be refurbished to last until 2036. The expected end-of-life date of 2036 for Bruce A Unit 4 resulted in a revised average end-of-life for all four Bruce A units of 2035 for depreciation purposes. (As noted previously, OPG uses a single depreciation end-of-life date for all units associated with a particular nuclear station.)

The Bruce B service life extension for depreciation purposes was based on the analysis of historical performance of Bruce B units to achieve their end-of-life limit based on pressure tubes. The historical information is consistent with the assumptions for the design life of pressure tubes of 210,000 EFPH used for Pickering A, Pickering B and Darlington stations.

In extending the service life of both Bruce A and Bruce B stations, OPG also considered the 2007 Integrated Power System Plan report that the Ontario Power Authority filed with the OEB in August 2007. OPG concluded that the life extensions of the Bruce stations for depreciation purposes were consistent with the assumptions made in the report with respect to operating lives of both Bruce A and Bruce B units.

Board Staff Interrogatory #48

Ref:

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

The net fixed assets (in service) of the nuclear and hydroelectric rate-regulated segments for 2007 were $4,030 M and $3,871 M respectively; however, their respective annual depreciation expenses for 2007 were $426 M and $68 M respectively. Please explain why the depreciation expenses for nuclear were over six times greater than that of hydroelectric although the net asset values of the segments were comparable.

Response

For the purposes of calculating depreciation expense for most of its in-service fixed assets, OPG applies the straight-line method based on estimated service lives of the assets. Nuclear assets have significantly shorter estimated service lives than those of the rate-regulated hydroelectric segment. As a result, the depreciation expense of the nuclear segment is significantly higher than that of the rate-regulated hydroelectric segment.

Board Staff Interrogatory #49

Ref:

Issue Number: 5.2
Issue: Are the proposed depreciation rates and resulting expense appropriate?

Interrogatory

Please provide a copy of any depreciation study, since April 1999, of the company's assets and associated amortization rates, and describe any associated changes made to amortization rates and the rationale.

Response

OPG declines to provide historical information prior to 2005 for the reasons given in L-12-6.

Depreciation studies conducted since 2005 are provided in Appendix A ("2006 Depreciation Review Committee Recommendations") and Appendix B ("2007 Depreciation Review Committee Recommendations") to Ex. F3-T2-S1. Associated changes to depreciation rates and rationale are described in Ex. F3-T2-S1 and its appendices.

Board Staff Interrogatory #50

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

The application notes that, when reviewing executive compensation, OPG looks at two comparator groups of: utilities (Canadian owned energy companies) and non-utilities (Canadian owned public & private large manufacturing & high tech firms).The objective is to position OPG's executive compensation at the 75th percentile against other utilities and the median or 50th percentile of comparable non-utility companies. The updated application now states "OPG has reviewed its philosophy in late 2007 and now also plans to conduct a comparison using the 50th percentile for the public and utility markets going forward." Is this comparison in addition to or in replacement of the objective outlined in the original application?

Response

The comparison cited in the updated written evidence dated March 14, 2008 at Ex. F3-T4-S1, pages 12 - 13 replaces the objective outlined in the original evidence dated November 30, 2007 at Ex. F3-T4-S1, pages 12 - 13.

Board Staff Interrogatory #51

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

The application notes that employees in nuclear operations who are authorized by the CNSC and are required to maintain their licenses as a requirement of their job, receive a license retention bonus of between 14% - 20% of base salary and that full bonus is pensionable. Are these employees also eligible to receive the "goal sharing" incentive payments for unionized staff?

Response

Yes, all unionized staff participate in the Goalsharing program and receive the same award as others in their business unit.

Board Staff Interrogatory #52

Ref: Ex. F3-T4-S1, page 8

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Chart 3 on page 8 shows "Average Employee Costs ($K) For Regulated Business – Year End 2006" for the nuclear operations. Please revise the table in the following manner:
a) Add a row (above "Base Salary") called "Total Wages" which aggregates Base Salary + Overtime + Incentives + Other;
b) Add a row (after "Benefits") that provides the average "Pension" amount; and
c) If possible, please also update all of the figures in the table for year end 2007.

Please provide the revised table in Excel.

Response

a) Please refer to the attached recast Chart 3 with 2006 data. OPG notes that the average amounts in the benefits category for regular employees in the Society and Management groups in the regulated hydroelectric function have been corrected to $4.7K and $7.3K, respectively, as discussed in Ex. L-6-009 part (e).

b) Please refer to the attached recast Chart 3 with 2006 data. OPG notes that the "Benefits" line in the chart refers to the cost of benefit coverage for employees while they are employed (footnote 4 to the chart). Therefore, OPG presents an average pension and other post employment benefits ("OPEB") amount in response to this question. OPEB costs are not captured in the "Benefits" line.

c) Please refer to the attached updated Chart 3 with 2007 data in the same format as requested for parts (a) and (b) above.

Ex. F3-T4-S1, Chart 3 (Recast)
Average Employee Costs ($K) For Regulated Business - Year End 2006

		PWU		Society		Management Group	
		Regular	Non-Regular[5]	Regular	Non-Regular[5]	Regular	Non-Regular[5]
Nuclear	**Total Average Wages**	**94.3**	**49.4**	**109.6**	**42.4**	**145.9**	**26.3**
	Base Salary[1]	72.2	32.7	90.6	36.5	117.6	25.8
	Overtime[1]	14.5	10.1	14.3	3.6	0.9	0.0
	Incentives[1,2]	1.5	0.0	2.4	0.0	18.9	0.0
	Other[1,3]	6.1	6.6	2.3	2.3	8.5	0.5
	Benefits[4]	**4.1**	**0.0**	**5.0**	**0.0**	**6.4**	**0.0**
	Pension/OPEB[6]	**22.7**	**0.0**	**27.6**	**0.0**	**35.9**	**0.0**
Regulated Hydro	**Total Average Wages**	**91.4**	**15.0**	**101.7**	**6.9**	**154.8**	**46.0**
	Base Salary[1]	77.7	13.9	92.9	6.9	122.6	45.1
	Overtime[1]	8.7	1.1	4.7	0.0	0.3	0.0
	Incentives[1,2]	1.2	0.0	2.4	0.0	21.1	0.0
	Other[1,3]	3.8	0.0	1.7	0.0	10.8	0.9
	Benefits[4]	**4.6**	**0.0**	**4.7**	**0.0**	**7.3**	**0.0**
	Pension/OPEB[6]	**24.4**	**0.0**	**25.8**	**0.0**	**40.1**	**0.0**
Corporate Support Functions	**Total Average Wages**	**63.9**	**21.8**	**96.1**	**58.4**	**130.8**	**66.7**
	Base Salary[1]	59.5	20.1	90.5	54.0	105.3	55.5
	Overtime[1]	1.6	0.8	2.3	0.9	0.1	0.0
	Incentives[1,2]	1.1	0.0	2.0	0.4	20.0	4.3
	Other[1,3]	1.7	0.9	1.3	3.1	5.4	6.9
	Benefits[4]	**4.2**	**0.0**	**5.7**	**0.0**	**6.2**	**0.0**
	Pension/OPEB[6]	**22.2**	**0.0**	**30.0**	**0.0**	**32.5**	**0.0**

[1] Based on 2006 year end payroll data for employees in their home-base positions at year end

[2] Includes Goalsharing and Authorization Bonuses for PWU; Goalsharing, Performance Recognition Plan and Authorization Bonuses for the Society, and Annual Incentive Plan and Leadership Allowances for Management Group

[3] Includes travel time, unused vacation days paid out, standby allowance and shift allowance

[4] Includes group life insurance and health and dental benefits coverage while employed

[5] Includes temporary employees for “peak” periods

[6] Represents the current service cost (CSC) component of total pension/OPEB costs. CSC is the only component of the pension/OPEB costs (discussed in section 7.3.1 Ex. F3-T4-S1) that relates solely to current employees. CSC represents the cost of the pension/OPEB benefit deemed to be accrued by current employees in the year.

Ex. F3-T4-S1, Chart 3 (Recast)
Average Employee Costs ($K) For Regulated Business - Year End 2007

		PWU		Society		Management Group	
		Regular	Non-Regular[5]	Regular	Non-Regular[5]	Regular	Non-Regular[5]
Nuclear	**Total Average Wages**	**100.6**	**54.3**	**112.9**	**88.5**	**147.8**	**33.5**
	Base Salary[1]	74.0	34.1	92.2	71.8	120.5	32.2
	Overtime[1]	18.3	13.3	15.7	12.9	0.7	0.0
	Incentives[1,2]	2.1	0.0	2.7	0.3	16.8	0.0
	Other[1,3]	6.2	6.9	2.3	3.5	9.8	1.3
	Benefits[4]	**4.2**	**0.0**	**5.1**	**0.0**	**6.9**	**0.0**
	Pension/OPEB[6]	**22.9**	**0.0**	**28.1**	**0.0**	**37.6**	**0.0**
Regulated Hydro	**Total Average Wages**	**92.7**	**25.9**	**102.1**	**14.7**	**156.7**	**0.0**
	Base Salary[1]	79.2	22.7	92.8	14.1	123.9	0.0
	Overtime[1]	8.4	2.6	4.7	0.0	0.0	0.0
	Incentives[1,2]	1.1	0.0	2.5	0.0	20.2	0.0
	Other[1,3]	4.0	0.6	2.1	0.6	12.6	0.0
	Benefits[4]	**4.2**	**0.0**	**4.7**	**0.0**	**6.8**	**0.0**
	Pension/OPEB[6]	**23.0**	**0.0**	**25.3**	**0.0**	**37.3**	**0.0**
Corporate Support Functions	**Total Average Wages**	**64.4**	**19.4**	**96.4**	**44.4**	**133.6**	**47.1**
	Base Salary[1]	60.2	18.3	90.6	41.6	109.6	41.0
	Overtime[1]	1.7	0.0	2.1	0.9	0.0	0.0
	Incentives[1,2]	1.1	0.0	2.4	0.1	18.7	4.0
	Other[1,3]	1.4	1.1	1.3	1.8	5.3	2.1
	Benefits[4]	**3.4**	**0.0**	**5.0**	**0.0**	**6.4**	**0.0**
	Pension/OPEB[6]	**19.1**	**0.0**	**28.1**	**0.0**	**36.3**	**0.0**

[1] Based on 2007 year end payroll data for employees in their home-base positions at year end

[2] Includes Goalsharing and Authorization Bonuses for PWU; Goalsharing, Performance Recognition Plan and Authorization Bonuses for the Society, and Annual Incentive Plan and Leadership Allowances for Management Group

[3] Includes travel time, unused vacation days paid out, standby allowance and shift allowance

[4] Includes group life insurance and health and dental benefits coverage while employed

[5] Includes temporary employees for “peak” periods

[6] Represents the current service cost (CSC) component of total pension/OPEB costs. CSC is the only component of the pension/OPEB costs (discussed in section 7.3.1 Ex. F3-T4-S1) that relates solely to current employees. CSC represents the cost of the pension/OPEB benefit deemed to be accrued by current employees in the year.

Board Staff Interrogatory #53

Ref: Ex. F3-T4-S1, page 35

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Chart 9 (page 35) provides a range of OPG positions and compares them to the 75th percentile of market data which appears to be based on a study of the Power Services Industry in Canada by Towers Perrin. The application notes "while some positions are paid above market and some are below market, OPG is slightly above market on an overall basis". Of the 34 positions, OPG is lower for 5 positions and higher for 28 positions. It also appears 11 or about one-third of the positions are between 15% - 28% higher for OPG. Given the above, on what basis did OPG conclude that OPG is "slightly above market on an overall basis"? Please quantify the difference.

Response

In standard compensation practice the term "on market" refers to a value that is within plus or minus 10 percent of the median values. This practice reflects the fact that market pricing and comparisons are not exact sciences. In order to establish market competitiveness using a survey, there is a need to ensure that the job matching process achieves 80 percent accuracy, that the age of the various components of the data are equivalent, that outliers have been excluded from the analysis, and that no one company's information has skewed the overall data. Given that the above factors inherently contribute a level of imprecision to the survey results, the accuracy of market pricing comparisons is considered to be between -10 percent and +10 percent of the median value.

Based on this definition of "on market", OPG has two positions that are below market, 13 positions that are on market and 19 positions that are above market as per Ex. F3-T4-S1, Chart 9, page 35. Overall, the 19 positions that are above market are higher than the "on market" definition by slightly over 7 percent. On this basis OPG concluded that it is "slightly above market" as indicated in the evidence cited in the interrogatory.

Board Staff Interrogatory #54

Ref: Ex. F3-T4-S1, page 36

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Chart 10 shows a wage comparison between OPG and Bruce Power based on the last round of negotiations between the PWU and Bruce. The finding was: "OPG wages are generally lower -- on a weighted average basis, the differential between OPG and Bruce Power wages was 12.8% in 2006 and will grow to 13.3% in 2008". What are the results, on a similar weighted average basis, if the comparison is limited to nuclear employees in both companies?

Response

The job titles shown in Ex. F3-T4-S1, Chart 10, page 36 are strictly nuclear positions. Therefore, the comparison as shown is already limited to nuclear employees in both companies.

Board Staff Interrogatory #55

Ref: Ex. F3-T4-S1, page 18

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

In section 7.1, in discussing changes made to the pension promise, one change is that all new employees hired into manager positions or higher received the inclusion of incentive amounts in pensionable earnings. What percentage of the incentive amounts is included in pensionable earnings? Is there a standard practice for the recognition of incentives in pensionable earnings in other electricity generation companies in Canada?

Response

The amount of incentive awards that are included in pensionable earnings for new employees hired into management positions after July 1, 2001 is 100 percent of the incentive amounts up to the target level of the incentive. Target levels for incentives vary according to salary level (as shown in Ex. F3-T4-S1, Chart 4, page 14). OPG notes that employees on this version of the pension plan give up 50 percent of annual indexing in order to have the incentive amounts up to the target level form part of their pensionable earnings. Management employees hired before July 1, 2001 are generally part of the pension plan that provides for 100 percent indexing but their pensionable earnings include incentive awards only up to 5 percent of base salary.

According to a survey by Watson Wyatt in 2006 in Canada, bonuses were included in pensionable earnings by 59 percent of Energy, Resources and Utilities companies.

Board Staff Interrogatory #56

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

The evidence states the most recent actuarial valuation, filed and current to January 1/05, showed the pension fund to be in a deficit position, The next actuarial valuation was to be performed as of January 1/08. If the updated valuation is now completed, please provide a copy; if it is not completed, please advise when it will be available.

Response

The January 1, 2008 funding valuation has not yet been completed. It is currently expected to be available by the end of August 2008.

Board Staff Interrogatory #57

Ref: Ex. F3-T4-S1

Issue Number: 5.3
Issue: Are the 2008 and 2009 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

Interrogatory

Please explain the reasons for the changes in the evidence update related to the pension and OPEB cost assumptions including the inflation rate increase, and salary schedule escalation rate increase.

Response

Chart 5 of Ex. F3-T4-S1, page 24 in the original pre-filed evidence dated November 30, 2007 presented assumptions that were adopted as part of the 2007-2011 business plan for pension and OPEB costs for the period 2007 to 2009. This process took place in the latter half of 2006. Chart 5 in Ex. F3-T4-S1, page 24 in the updated evidence dated March 14, 2008 presents assumptions that were adopted as part of the 2008-2010 business plan for pension and OPEB costs for 2008 and 2009. This process took place in the latter half of 2007. In addition, the updated evidence presents the assumptions used in determining actual 2007 pension and OPEB costs. The reasons for the changes in assumptions between the original and updated evidence are outlined below.

The discount rates used to calculate pension and OPEB costs for a given year are based on the applicable bond rate at the end of the preceding year. This approach is consistent with GAAP. The discount rates of 5.0 percent for pension and OPEB costs (with the exception of 4.75 percent for long term disability benefits) used for the 2007 budget values in the original evidence were based on a forecast of the applicable bond rate as at December 31, 2006. This forecast was developed in the latter half of 2006 as the 2007 - 2011 business plan was finalized. Between the time the budgets were established during 2006 and December 31, 2006, the applicable bond rate changed. The actual bond rate as at December 31, 2006 was 5.25 percent for pension and OPEB costs (5.0 percent for long term disability benefits). This actual bond rate was used to calculate 2007 actual costs presented in the updated evidence.

The discount rates for 2008 and 2009 in the original evidence submission were based on a forecast of the applicable bond rates as at December 31, 2007 and December 31, 2008, respectively made during the 2007 - 2011 business planning process. The forecast of these bond rates at the above dates was updated as part of the 2008 - 2010 business planning process to reflect more recent trends in the bond rates.

The inflation rate assumption for the 2008 and 2009 pension and OPEB cost estimates was updated from 2.0 percent in the original evidence submission to 2.25 percent. The 2.25 percent inflation rate used in the 2008 - 2010 business plan took into consideration information regarding the Bank of Canada target inflation rate, the spread between yield rates on nominal and real bonds, and inflation experience.

The salary schedule escalation rate assumption of 3.0 percent for the 2008 and 2009 pension and OPEB cost estimate was updated to 3.25 percent to be consistent with the change in the assumption for the inflation rate discussed above.

The assumption of the rate of return on pension fund assets in 2007 was updated for the 2008 and 2009 pension cost estimate to reflect 2007 actual year-to-date return experience as well as an updated estimate of the return for the remainder of the 2007 year. The 2008 rate of return assumed for the 2009 pension cost estimate was updated in order to be consistent with the assumption of the expected long-term rate of return on OPG's pension fund assets.

Board Staff Interrogatory #58

Ref: Ex. F3-T1-S1

Issue Number: 5.4
Issue: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Interrogatory

The application states "Approximately 70 percent of OPG's total corporate function and centrally held costs are either directly assigned or allocated to regulated operations." Has the regulated allocation increased or decreased relative to the historic years? If the allocations have changed, please explain why. Please support your explanation by replicating Table 1 in the application (F3-T1-S1) and include two columns for each year showing the total $ amounts allocated to: (1) non-prescribed assets; and (2) prescribed assets.

Response

The table replicating Table 1 Ex. F3-T1-S1 is attached in the requested format. The table shows that the share (approximately 70%) of total corporate function and centrally held costs are either directly assigned or allocated to regulated operations during the historic (2005 - 2007) and forecast periods (2008 - 2009) has been stable. Percentages allocated to regulated operations per the attached tables are as follows: 2005 Actual – 67.7%, 2006 Actual – 70.0%, 2007 Actual – 71.3%, 2008 Plan – 69.6%, 2009 Plan – 68.9%.

In comparing the historic period to the forecast period, several categories of corporate costs did experience notable fluctuations in the percentage allocated to prescribed assets. These fluctuations are explained below.

- The percentage of Corporate Affairs costs allocated to regulated facilities increased relative to the historic period mainly due to activities associated with the OEB payment amounts hearing, water safety initiatives undertaken on behalf of the hydroelectric business, community engagement initiatives and initiatives related to community and sponsorship advertising.

- The percentage of Energy Markets costs allocated to regulated facilities increased relative to the historic period mainly due to the organizational transfer of the Sustainable Development (SD) group from Corporate Centre to Energy Markets in 2008 (A higher percentage of the SD group's costs is attributable to the regulated operations than that of the other activities of Energy Markets). The corresponding decrease in the amount of Corporate Centre costs allocated to regulated facilities following the transfer of the SD group has been offset by an increase in legal costs associated with the OEB payment amounts proceeding.

- The percentage of IESO Non-Energy Charges allocated to regulated facilities increased relative to the historic period mainly as a result of the addition of the Global Adjustment and OPG rebate. This change is discussed in L-1-60.

- The percentage of other centrally held costs allocated to regulated facilities generally decreased relative to the historic period. The decrease is due mainly to the lower ONFA guarantee fee in 2008 and 2009 and non-recurring nuclear environmental charges incurred in 2007. In general, OPG notes that the percentage of other centrally held costs allocated to regulated facilities is subject to greater variability year-over-year because on the non-recurring nature of certain costs charged to this category.

Please refer to Ex. F3-T1-S2 for additional detail relating to year-over-year fluctuations in corporate costs allocated to regulated operations.

Summary Schedule
Corporate Support Groups & Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2005 Actual				2006 Actual				2007 Actual				2008 Plan				2009 Plan			
		Prescribed Assets	Percent Allocated to Prescribed Assets	Non Prescribed Assets	Total	Prescribed Assets	Percent Allocated to Prescribed Assets	Non Prescribed Assets	Total	Prescribed Assets	Percent Allocated to Prescribed Assets	Non Prescribed Assets	Total	Prescribed Assets	Percent Allocated to Prescribed Assets	Non Prescribed Assets	Total	Prescribed Assets	Percent Allocated to Prescribed Assets	Non Prescribed Assets	Total
1	**Finance**	33.6	59.8%	22.6	56.2	36.6	64.2%	20.4	57.0	39.4	62.9%	23.2	62.6	43.6	65.0%	23.5	67.1	44.0	64.2%	24.5	68.5
2	**Corporate Affairs**	9.5	57.6%	7.0	16.5	12.2	73.1%	4.5	16.7	13.5	68.2%	6.3	19.8	24.0	77.4%	7.0	31.0	23.8	76.8%	7.2	31.0
3	**CIO**	104.5	69.9%	45.0	149.5	102.4	69.9%	44.0	146.4	118.1	70.2%	50.1	168.2	133.7	69.5%	58.6	192.3	132.3	69.5%	58.0	190.3
4	**Corporate Centre**[1]	13.8	67.6%	6.6	20.4	12.7	65.8%	6.6	19.3	13.9	66.2%	7.1	21.0	14.1	65.3%	7.5	21.6	13.9	64.4%	7.7	21.6
5	**Energy Markets**	4.2	18.2%	18.9	23.1	3.0	14.3%	18.0	21.0	4.1	19.9%	16.5	20.6	7.0	26.8%	19.1	26.1	6.9	25.9%	19.7	26.6
6	**Human Resources**	29.7	69.6%	13.0	42.7	32.8	71.8%	12.9	45.7	35.0	73.4%	12.7	47.7	35.0	71.6%	13.9	48.9	36.1	71.2%	14.6	50.7
7	**Real Estate**	37.4	79.2%	9.8	47.2	30.1	80.1%	7.5	37.6	34.5	81.8%	7.7	42.2	34.5	79.9%	8.7	43.2	34.2	79.7%	8.7	42.9
8	**Sub-Total**	$ 232.7	65.4%	$ 122.9	$ 355.6	$ 229.8	66.9%	$ 113.9	$ 343.7	$ 258.5	67.7%	$ 123.6	$ 382.1	$ 291.9	67.9%	$ 138.3	$ 430.2	$ 291.2	67.5%	$ 140.4	$ 431.6
	Centrally Held Costs:																				
9	**Pension/OPEB Related**	76.1	78.2%	21.2	97.3	165.6	79.3%	43.1	208.7	140.9	78.8%	37.9	178.8	116.6	78.8%	31.3	147.9	92.6	78.9%	24.8	117.4
10	**Insurance**	15.3	57.3%	11.4	26.7	15.0	56.4%	11.6	26.6	14.8	55.4%	11.9	26.7	14.9	56.2%	11.6	26.5	15.5	56.4%	12.0	27.5
11	**Performance Incentives**	25.8	76.8%	7.8	33.6	30.7	75.1%	10.2	40.9	31.1	76.2%	9.7	40.8	31.4	75.1%	10.4	41.8	32.0	74.9%	10.7	42.7
12	**IESO Non-Energy Charges**	15.3	59.1%	10.6	25.9	14.5	64.7%	7.9	22.4	13.2	64.4%	7.3	20.5	24.6	68.5%	11.3	35.9	24.6	69.9%	10.6	35.2
13	**Other**	18.6	66.4%	9.4	28.0	6.2	35.9%	11.0	17.2	26.3	84.6%	4.8	31.1	25.1	58.9%	17.5	42.6	21.1	56.0%	16.6	37.7
14	**Sub-Total**	$ 151.1	71.4%	$ 60.4	$ 211.5	$ 232.0	73.5%	$ 83.8	$ 315.8	$ 226.3	76.0%	$ 71.6	$ 297.9	$ 212.6	72.1%	$ 82.1	$ 294.7	$ 185.8	71.3%	$ 74.7	$ 260.5
15	**Total**	$ 383.8	67.7%	$ 183.3	$ 567.1	$ 461.8	70.0%	$ 197.7	$ 659.5	$ 484.8	71.3%	$ 195.2	$ 680.0	$ 504.5	69.6%	$ 220.4	$ 724.9	$ 477.0	68.9%	$ 215.1	$ 692.1

1 Corporate Centre includes Executive Office, Corporate Secretary, and Law.

Board Staff Interrogatory #59

Ref: Ex. F4-T1-S1 and Ex. F3-T1-S1, page 19

Issue Number: 5.4
Issue: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Interrogatory

The R.J. Rudden study (F4/T1/S1) notes, and expresses some reservations with the fact that, OPG's process relies on "judgments" made by departmental managers to support specific identification and time estimation for cost allocation purposes. Rudden also raised the following concern on page 19, "the completeness and understandability of the documentation varies considerably among the CSA groups and sometimes among departments within the groups." As a result, Rudden recommended (emphasis in original):

- "<u>Documentation of the OPG methodology should be improved.</u> OPG has documented significant portions of its cost allocation methodology. However, several areas should be improved. Improvement in these areas is typically required after initial adoption and implementation of a cost allocation methodology."; and
- "A template should be used to document specific identification and time estimation. Exhibit C has a proposed template."

The application states "OPG has not developed templates to document time estimates, as recommended by R.J. Rudden, but it is something we may consider in the future (F3/T1/S1/page 19)." Please explain why OPG has not adopted the Rudden recommendation?

Response

The R.J. Rudden study (Ex. F4-T1-S1) concluded on page 4 that OPG's "overall [cost allocation] approach is appropriate." With respect to the statement in the interrogatory that the study expresses some reservations with the fact that OPG's process relies on judgements made by department managers, OPG notes that page 18 of the study states: "The methodology relies on the judgements of departmental managers and Business Units to support specific identification and time estimation. These are the people in the best position to determine how resources are used." Furthermore, page 4 of the study concludes that "direct assignment of costs by specific identification and by estimation are based on sufficient information reasonably applied."

When direct assignment of costs is based on estimation of time, OPG's corporate support groups are required to provide documentation to support their estimates. OPG's approach permits individual groups to use different formats suitable to their needs to submit time estimates for cost allocation purposes. OPG is of the view that this is more conducive to ensuring the timeliness and accuracy of the information. Therefore, OPG has not developed standardized templates for documenting time estimates. OPG's current time estimate documentation meets the objective of ensuring an appropriate allocation of corporate costs.

Board Staff Interrogatory #60

Ref: Ex. F3-T1-S2, page 2

Issue Number: 5.4
Issue: Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

Interrogatory

OPG states on page 2 of F3-T1-S2 that the increase in the forecast of IESO non-energy charges in 2008 is mainly due to the "inclusion of a forecast of the Global Adjustment and the OPG Rebate, which were not included in the 2005 - 2007 budgets for centrally held costs and which are not presented as part of 2005 - 2007 actual costs". That increase is over $15M (from the 2007 budget year). Board staff understands that: (1) the Global Adjustment is a settlement undertaken by the IESO that takes OPG regulated payments into account (as opposed to an additional cost to OPG); and (2) the OPG Rebate results from a revenue cap placed on OPG's non-prescribed coal facilities. Please explain the $15M increase, and indicate whether any amounts related to the OPG Rebate have been allocated to OPG's regulated operations.

Response

The Global Adjustment is the difference between the total payments made to certain contracted or regulated generators/demand management projects, and any offsetting market revenues. Generators include OPG's regulated nuclear and hydroelectric facilities, non-utility generators under contract with the Ontario Electricity Financial Corporation and those under contract with the Ontario Power Authority. Conservation and demand management projects are those under contract with the Ontario Power Authority. The Global Adjustment is allocated to load customers in Ontario in proportion to their electricity consumption. From the perspective of a load customer, the Global Adjustment is a credit when market prices are high and a charge when market prices are low.

The OPG rebate is the payment made by OPG for non-prescribed generation revenues exceeding the revenue cap as described by Order In Council 1062. Like the Global Adjustment, the OPG rebate is allocated to load customers in Ontario in proportion to their electricity consumption. Unlike the Global Adjustment, the OPG rebate is, from a load customer perspective, only a credit (when market prices are high); when market prices are low, there is no charge to customers.

Some of OPG's electricity consumption is treated no differently from any other load customer in Ontario and is therefore allocated a share of the Global Adjustment and OPG rebate. In 2007, approximately 1.1 TWh was consumed by OPG's regulated facilities. Because the Global Adjustment and OPG rebate is allocated to Ontario loads in proportion to their consumption, OPG regulated facilities are allocated a portion of these charges and credits.

IESO non-energy charges are subject to great uncertainty and hence are very difficult to forecast. In the March 14, 2008 update, the forecast IESO non-energy charges were based on average actual expenditures between 2005 and 2007 (excluding Global Adjustment and OPG rebate) along with an explicit forecast of both the OPG rebate and Global Adjustment for 2008 and 2009. Table 1 below shows annual costs for IESO non-energy charges from F3-T1-S1 Table 1, line 12.

Table 1: Actual IESO non-energy charges

$ million	**2005**	**2006**	**2007**	**Average**
Actual cost[1]	25.9	22.4	20.5	22.9

The historical actual costs shown in Table 1 do not include OPG's Global Adjustment or OPG rebate charges and credits.

OPG's forecast of its net Global Adjustment / OPG rebate charges is $13 million for 2008 and $12.3 million for 2009. The Global Adjustment forecast was calculated by applying a regression equation that was constructed using 2005 to 2007 actual values of HOEP and Global Adjustment. The regression equation was then applied to OPG's forecast of market prices for the test period from the 2008-2010 Business Plan. The OPG rebate forecast was based on the 2008-2010 Business Plan.

The final values of $35.9 million and $35.2 million for 2008 and 2009 respectively are simply the sum of the average actual cost and the forecast OPG rebate and Global Adjustment. The results are shown in Table 2 below.

Table 2: 2008 and 2009 Plan IESO non-energy charges

$ million	**2008**	**2009**
Average cost 2005 to 2007	22.9	22.9
OPG rebate and Global Adjustment forecast	13.0	12.3
Total	**35.9**	**35.2**

Board Staff Interrogatory #61

Ref:

Issue Number: 5.5
Issue: Are the asset service fee amounts charged to the regulated hydroelectric and nuclear businesses appropriate?

Interrogatory

Please identify the primary drivers underlying the following trends:

a) Asset Service Fees charged to the nuclear business increasing by 73.5% ($10.8M) from 2005 to 2009; and

b) Asset Service Fees charged to the hydroelectric business rising by 75% ($0.9M) from 2005 to 2009.

Response

The increases in the asset service fees charged to both nuclear and regulated hydroelectric businesses occurred primarily in 2006 due to the following factors:

- OPG refined its methodology for computing asset service fees during 2006 to include certain Real Estate operating costs, such as the cost of utilities and facility maintenance, as a component of the fee. These costs were previously allocated to generation facilities through the cost allocation process.

- OPG expanded the scope of the asset service fee concept in 2006 to all centrally held assets to achieve consistent treatment. Specifically, OPG included the Kipling Building Complex and Energy Markets assets in the scope of the asset service fee. Hence, costs related to these centrally held assets, such as depreciation, that were previously allocated to generation segments were essentially replaced by the service fee starting in 2006.

Board Staff Interrogatory #62

Ref: Ex. F2-T5-S1, page 2

Issue Number: 5.7
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

The application (F2/T5/S1/page 2) notes OPG's nuclear fuel supply chain is made up of the following stages:

a) The purchase of uranium concentrate;

b) The purchase of services for the conversion of uranium concentrate to uranium dioxide; and

c) The purchase of services for the manufacture of fuel bundles containing the uranium dioxide.

During the test years, what is the percentage breakdown for the three stages in terms of the total nuclear fuel cost?

Response

The requested information on the percentage breakdown for the components of OPG's nuclear supply chain costs is commercially sensitive because it could be used to derive approximate unit prices for uranium conversion and manufacturing services. The release of this information could prejudice the commercial position of OPG and, potentially, third parties.

Pursuant to the OEB Rules of Practice and Procedure and Practice Direction on Confidential Filings, OPG will provide the requested information to the Board along with a request for the confidential treatment of this information. Should the Board agree that the information should be afforded confidential treatment, OPG proposes that it can only be made available to any party that completes the Declaration and Undertaking set out at Appendix D of the Practice Direction and complies with any other related instructions ordered by the Board.

Board Staff Interrogatory #63

Ref:

Issue Number: 5.7
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

At the end of section 2.5.2, it states "OPG has recently implemented a revised spot market procurement process to facilitate potential future spot market purchasing." Please explain how the revised spot market procurement process facilitates future spot market purchases?

Response

OPG's governance for purchasing requires that for expected purchases over $5M, a cross-functional sourcing team, which includes members from the requisitioner, law, finance, supply chain, and others as necessary, is to be convened which provides the appropriate reviews, controls and purchasing due diligence.

When uranium spot market prices are increasing rapidly, seller's validity periods (i.e., the time allowed to the buyer to accept or reject the seller's offer) are short relative to the time frames that are typically in place during times of market stability. The former purchasing governance put at risk the ability to complete uranium spot market purchases within such short validity periods.

The spot market uranium process facilitates future spot market purchases in the following ways:

- Allows individual transactions for the purchase of up to 300,000 pounds of uranium for delivery within 6 months, without recourse to a cross-functional sourcing team.
- Utilizes pre-approved standard contracts.
- Delegates credit limits to facilitate prompt approval of transactions with counterparties which have not been previously utilized by OPG.
- Monitors credit exposures.
- Utilizes existing independent departments (originally set up to provide support for non-uranium energy market transactions) to provide contract administration, transaction management support, and verification, which also provides the appropriate separation of duties, which would otherwise have been provided through the cross-functional sourcing team.
- Allows transactions to be completed within one week.

The uranium spot market process is modeled on existing processes in use by OPG for energy transactions such as coal, natural gas, and electricity.

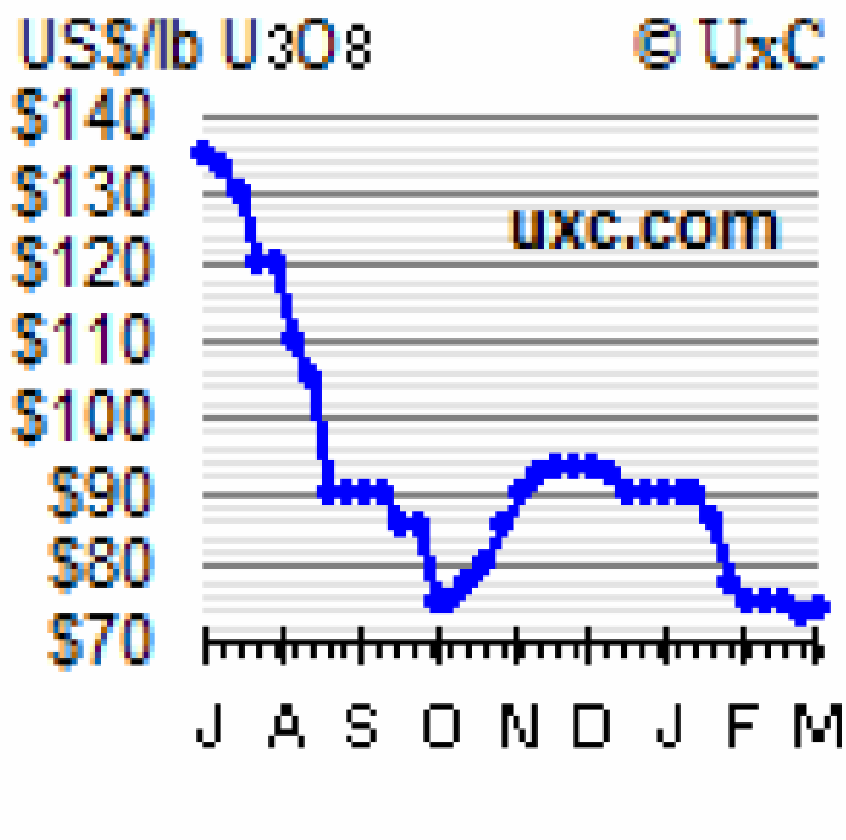
Board Staff Interrogatory #64

Ref:

Issue Number: 5.7
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

Above Figure 1.0 it states, "Spot market prices increased to an all time peak of US $136 per pound (US $354 per kgU) in 2007 before declining to around US $90 per pound (US $234 per kgU), as shown in the following Figure 1.0 based on the Ux Consulting Company's U308 weekly spot price, and this has impacted OPG's market priced and indexed contracts". Based on a more recent U308 weekly spot price as at March 3, 2008 from Ux Consulting, the decline appears to have continued down to around $70 (please see accompanying chart). How has this decline to between $70 and $90 during the past seven months impacted OPG's market priced and indexed contracts?



Response

A decline (or increase) in market price does not impact existing indexed contracts since pricing under an indexed contract is based on a base price which escalates in accordance with changes in published economic indicators, not changes in market prices. (See response to L-1-66 for example pricing provisions). The phrase "spot market prices increased … and this has impacted OPG's … indexed contracts." refers to the impact of market conditions on the base prices of new indexed contracts relative to the base prices that would have been available prior to the spot price run-up. Base prices increased at the same time as spot market prices.

To the extent that OPG had deliveries under market price related contracts over the seven month period, the price of those deliveries would be at, or near, the published price indicators just prior to the time of delivery and would therefore reflect the decline during the past seven months.

Board Staff Interrogatory #65

Ref:

Issue Number: 5.7
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

The updated evidence shows that nuclear fuel costs for 2008 and 2009 were revised to $162.4 M and $204.2 M respectively. The revised costs compared to the 2007 actual of $113 M represent increases of $49.4 M (47%) for 2008 and $91.2 M (81%) for 2009.

a) Please provide a detailed calculation including the forecasted uranium prices and other assumptions showing how the nuclear fuel costs for 2008 and 2009 were derived. If independent sources were used to derive the forecast, please provide copies of the information provided by the independent sources.

b) In light of the significant increases in nuclear fuel costs from 2007 to 2008 and 2009, does OPG intend to change how it manages the risk associated with uranium prices? If so, what does OPG intend to do and when will it implement this change? If no change is planned, please explain why.

Response

a) The detailed calculation showing how nuclear fuel costs were derived relies upon commercially sensitive information. The release of this information could harm OPG and third parties.

OPG uses information from an independent source to derive forecast uranium prices. The information provided by this source is confidential and proprietary to the source. OPG has no concerns with disclosing the information requested in the interrogatory to those parties that sign a declaration and undertaking in accordance with section 6.1 of the Board's Practice Direction on Confidential Filings. However, OPG cannot release the information unless and until it receives prior written consent from the source of the information. To this end, OPG has issued a request to the source of the information. Upon receiving consent from the source, OPG intends to provide the information to the Board along with a request for the confidential treatment of this information. If the Board agrees, OPG proposes that it be made available to any party that completes the Declaration and Undertaking set out at Appendix D of the Practice Direction.

b) OPG manages the risks associated with uranium prices by maintaining a portfolio of uranium supply arrangements which contain diverse pricing mechanisms. As described in Ex. F2-T5-S1, page 6, Chart 2, OPG's current uranium supply contracts provide pricing which is market-related at the time of delivery, or which has base prices that escalate to the time of delivery by formula or published indexes (known as "base price escalated" pricing). This mix of pricing terms moderates the impact of uranium market price volatility. Also, OPG enters the market for new contracts on a regular basis, which has the effect of dollar cost averaging the prices paid over time.

The diversified portfolio of uranium supply arrangements also mitigates the impact of any individual source supply disruption.

In 2003, OPG recognized the potential for market supply shortfalls and significant price increases and accelerated its program to increase its forward contract coverage. Between 2003 and 2007 OPG negotiated eight new uranium supply contracts which now provide physical coverage and price diversity for a portion of expected requirements through 2017. The physical coverage is 100 percent of requirements in 2008 and 2009 and declines to about 15 percent for 2016 and 2017

In 2007, OPG revised its process for making uranium purchases in the spot market to expedite the approvals to make spot market purchases in times of price weakness. The benefits of this revised process are further discussed in L-1-63.

OPG is currently developing a framework to manage uranium market price risk, including determination of the optimal mix of market related and base price escalated pricing provisions in its portfolio of supply arrangements. This work is expected to be complete by the end of July 2008.

OPG is also currently observing the development of the financial futures market for uranium but has not made any decisions at this time concerning participation in such market. OPG has not included any assumptions on the use of such a market in its rate submission.

Board Staff Interrogatory #66

Ref:

Issue Number: 5.7
Issue: Is the forecast of nuclear fuel costs appropriate?

Interrogatory

The application states that OPG has entered into two types of contracts. One is an indexed contract and is described as follows: "indexed pricing include base prices, set at the time of contract signing, but which escalate to the time of delivery by formula or by published indexes". This description appears to suggest they are only indexed if the market price escalates. If OPG entered into such a contract when the uranium price peaked, does it mean OPG would pay about $140 (i.e., not indexed to follow the subsequent decline in the market price to about $70) but if the market price had doubled the indexing provision would require OPG to pay about $280? If so, what benefits does indexing contracts provide?

Response

The term "published indexes" as used by OPG refers to independently published economic indices, such as the Canadian Consumer Price Index or the US Gross Domestic Product Implicit Price Deflator ("GDPIPD"). They are specifically not indicators of uranium market prices.

A hypothetical example of pricing provision in a contract with indexed pricing is:

Price (at time of delivery) = Base Price x Escalation Factor

Where:

Base Price = US $45.00 per pound U3O8

$$\text{Escalation Factor} = \frac{\text{GDPIPD (delivery)}}{\text{GDPIPD (base)}}$$

GDPIPD (delivery) = U.S. Gross Domestic Product Implicit Price Deflator, as determined quarterly and reported by the Bureau of Economic Analysis of the United States Department of Commerce in the publication "Survey of Current Business" for the quarter immediately prior to the quarter of delivery.

GDPIPD (base) = U.S. Gross Domestic Product Implicit Price Deflator, as determined quarterly and reported by the Bureau of Economic Analysis of the

United States Department of Commerce in the publication "Survey of Current Business" for the first quarter of 2006.

The price paid by OPG under a contract with indexed pricing, commonly referred to as "Base Price Escalated", would be unaffected by changes in the uranium price.

The benefit of contracts with Base Price Escalated pricing terms are:

- Better cost certainty for OPG than contracts with market related pricing since the published economic indexes are generally less volatile than market prices.
- Protection against significant increases in market price.

Board Staff Interrogatory #67

Ref: Ex. G1-T1-S1, pages 13 - 15

Issue Number: 6.1
Issue: Are the proposals for the treatment of revenues from Segregated Mode of Operation, water transactions and congestion Management Settlement Credits appropriate?

Interrogatory

The Application proposes not to include payments from the IESO to OPG for congestion management settlement credits in revenues to offset the revenue requirement. This differs from the proposed treatments for Segregated Mode of Operation and water transactions. The argument advanced in favour of this approach is that the IESO payments compensate OPG for costs incurred in not providing energy as dispatched.

a) What costs are incurred?

b) If the “costs” are foregone revenues, in what sense are these “opportunity costs” in the sense of standard economic theory (as opposed to rents)?

c) Why in the cases of Segregated Mode of Operation and water transactions does OPG propose to treat revenues for the non-use of facilities for Ontario load as appropriate to offset the revenue requirement but not those of congestion credits?

Response

a) Hydroelectric energy is typically offered to the market in a fashion that will result in the most efficient production of electricity given the prevailing hydroelectric conditions. Constrained operation typically results in less efficient production of electricity than would have otherwise occurred. Given the limited storage at Beck, it is also possible that prolonged constrained off operation will result in the spilling of water. The cost associated with CMSCs is therefore the lost energy production due to reduced efficiency and possible spill.

b) Constrained on operation can include opportunity costs when water which could have been stored for future periods and is valued above the current energy price is constrained on by the IESO due to system requirements.

The costs associated with constrained off operation relate to the inefficient operation detailed in part a).

c) CMSCs should not be used to offset the revenue requirement because the lost energy production from the inefficient use of the hydroelectric facilities from constrained operation is not forecast by OPG nor recoverable through the water condition variance account. Ontario consumers have benefited from constrained operation as the constrained off energy has been economically scheduled in the IESO's price setting calculation and has therefore lowered the energy clearing price.

In contrast, Segregated Mode of Operation and Water Transactions are actions OPG undertakes to provide a potential economic benefit to ratepayers in Ontario (see Ex. G1-T1-S1, page 6, lines 13 – 20) and a potential commercial benefit to OPG.Thus these actions merit different revenue treatment. Although the net revenues associated with SMO and WT activities are not used to offset the revenue requirement (See Ex. G1-T1-S1, page 7, lines 16 - 17 and page 11, lines 10 -12), OPG proposes to share any incremental net revenues realized with ratepayers. CMSCs on the other hand are payments from the IESO for energy that has been dispatched to meet system requirements. In these instances, OPG has either lost revenue from constrained off production or lost the opportunity to earn higher revenues in the future from constrained on production (these losses are not recovered - once they are gone, they are gone for good).

Board Staff Interrogatory #68

Ref: Ex. G1-T1-S1, pages 5 - 13

Issue Number: 6.1
Issue: Are the proposals for the treatment of revenues from Segregated Mode of Operation, water transactions and congestion Management Settlement Credits appropriate?

Interrogatory

The Application proposes that Segregated Mode of Operation and water transactions revenues be subject to a revenue-sharing formula. Given that the costs of operation are the same whether or not the generating units are dedicated to Ontario load, what is the rationale for offsetting only 50% of the extra revenues rather than 100% of the "extra" revenues?

Response

As indicated in the Ex. G1-T1-S1, pages 8 and 9, the costs and risks of operating in Segregated Mode of Operation (SMO) are not the same as operating solely in Ontario. OPG is subject to incremental costs when engaged in SMO such as transmission export fees, transmission charges in other control areas, transmission losses between generator and delivery point and loss of production during switching operations. OPG is also exposed to risks including market price forecasting, the IESO preventing, recalling or curtailing the transaction, curtailments by other independent system operators, equipment failure and counterparty credit risk. Further, SMO transactions are executed by OPG's non-regulated business which incurs additional costs which include arranging, conducting and settling these transactions, IT systems, control and governance functions and market memberships. The proposed revenue sharing formula takes these factors into account while providing an incentive to encourage these transactions which benefit Ontario as discussed in Ex. G1-T1-S1, page 6.

Water transactions are executed with the goal of maximizing energy production from the total water available for generation. The majority of these transactions are related to operating conditions; namely maintenance, ice conditions or spill conditions, water which NYPA or OPG cannot utilize for energy production with a majority of these transactions being transfers to NYPA. Revenues received by OPG for water transactions, like SMO transactions, are incremental to what could be obtained from the Ontario market. Water transactions, like SMO transactions, have increased costs, namely an accommodation charge (i.e. Water transaction net revenues are gross revenues less accommodation charges and GRC). As with SMO transactions, the 50:50 sharing proposal for water transfers provides an incentive to OPG and benefits to Ontario consumers.

Board Staff Interrogatory #69

Ref: Ex. G1-T1-S1, Table 1

Issue Number: 6.2
Issue: Are the forecasts of ancillary services revenues appropriate?

Interrogatory

Please provide a detailed listing of the ancillary service revenues, by service.

Response

Below is a table providing a detailed listing of ancillary service revenues for OPG Nuclear and Regulated Hydroelectric resources.

Actual M$		Operating Reserve	Black Start	Reactive Support and Voltage Control	Automatic Generation Control	Total
2005 Apr-Dec	Nuclear	0.1	-	2.7	-	2.8
	Reg HE	2.0	0.3	2.1	19.6	24.0
2006	Nuclear	0.3	-	2.8	-	3.1
	Reg HE	2.0	0.4	1.5	40.2	44.1
2007	Nuclear	0.0	-	2.8	-	2.8
	Reg HE	1.6	0.4	1.2	32.3	35.6
Forecast M$						
2008	Nuclear	-	-	3.0	-	3.0
	Reg HE	1.1	0.4	2.0	28.9	32.4
2009	Nuclear	-	-	3.1	-	3.1
	Reg HE	1.2	0.4	2.1	29.4	33.1

Board Staff Interrogatory #70

Ref: Ex. G2-T2-S1, Table 3 and 4

Issue Number: 6.5
Issue: Are OPG's forecasts of costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease, accurate?

Interrogatory

Section 6.(2) 5 limits the review of either revenues or costs related to the "lease of the Bruce Nuclear Generating Stations" to the "most recently audited financial statements that were approved by the Board of Directors of OPGI before the effective date of [the first order]". Note 18 to the 2007 statements states: "For 2004 through 2008", minimum payments under the lease are $190M annually"; that recorded revenues for 2007 and 2006 were $253M and $251M, respectively and that the net book value of the assets leased to Bruce as of Dec 31/07 was $1,201M. No figures are provided for OPG's costs in note 18; however, the Application does provide some costs related to the lease (ExG2T2S1 tables 3 & 4). Are the revenues and costs provided in the Application and related to the Bruce lease taken from most recently audited financial statements? If not, what is the source of those figures?

Response

Section 6.(2)5 of O. Reg 53/05 requires the OEB, in making its first order, to accept OPG's revenues associated with the Bruce lease and costs associated with the Bruce nuclear generating stations as reported in OPG's most recently audited financial statements. The regulation does not limit the review of all costs associated with the Bruce stations. Section 6(2)9 requires the OEB to ensure OPG recovers all costs it incurs with respect to the Bruce stations.

OPG's audited financial statements are prepared for financial reporting purposes based on generally accepted accounting principles and are not prepared for regulatory purposes. While the audited financial statements do not explicitly report each cost and revenue that is provided in Ex. G2-T2-S1, all of these costs and revenues are embedded in various line items in the statements with the exception of interest, capital tax, and return on rate base.

The historical revenue and costs (years 2005, 2006 and 2007) associated with the Bruce lease presented in the Application are derived from the information in the respective audited financial statements. Bruce lease revenue for 2006 and 2007 per Ex. G2-T2-S1, Table 1 is reported as part of the nuclear segment's revenue in Note 18 to the financial statements. Depreciation expense for 2006 and 2007 per Ex. G2-T2-S1, Table 3 are reported as part of the nuclear segment's depreciation and amortization in Note 18 to the 2007 financial statements. Property taxes per Ex. G2-T2-S1, Table 3 are reported in Note 18 to the financial statements in the nuclear segment's property and capital taxes.

The 2005 amounts for the above items are reported in Note 19 to the 2005 financial statements. Revenues and costs associated with the Bruce lease for the test years are the forecasts of these items in OPG's 2008 - 2010 Business Plan.

Interest, capital tax, and return on rate base as presented in Exhibit G are determined using regulatory constructs, and therefore are not presented in the audited financial statements or OPG's Business Plan.

Board Staff Interrogatory #71

Ref: Ex. G2-T2-S1, Table 3 and 4

Issue Number: 6.5
Issue: Are OPG's forecasts of costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease, accurate?

Interrogatory

Section 6 (2) 10 provides that the net revenues earned with respect to any lease of the Bruce Nuclear Generating Stations (if any) are to be deducted from the prescribed payments. Note 18 provides only part of the revenues that must be accepted for 2008 and only one part of the cost determination (net assets). Please list all of the costs and revenues related to the lease of the Bruce Nuclear Generating Stations and indicate where they may be found in the 2007 audited financial statements.

Response

The revenues related to the Bruce lease are discussed in Section 3.0 of Ex. G2-T2-S1 and the costs related to the Bruce Generating Stations are discussed in Section 4.0 of this exhibit. These revenues and costs are also presented in Ex. G2-T2-S1, Tables 1 – 5.

Note 18 to the 2007 Audited Financial Statements includes all revenues associated with the Bruce lease and most costs associated with the Bruce Generating Stations. The revenues are included as part of Nuclear revenue in Note 18. As explained in the response to interrogatory Ex. L-1-070, the audited financial statements are prepared for financial reporting purposes using generally accepted accounting principles, and therefore only include depreciation expense, property tax, and used fuel management storage expense. The costs associated with the Bruce Generating Stations that are calculated using regulatory principles (interest, capital tax, and return) are not equal to the amounts recorded in the financial statements.

Board Staff Interrogatory #72

Ref:

Issue Number: 7.1

Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

The Ontario Nuclear Funds Agreement Reference Plan ("the Reference Plan") defines OPG's obligations for nuclear waste management and decommissioning. Please provide a comprehensive executive summary from the most recent reference plan that explains how OPG's obligations were determined.

Response

The Ontario Nuclear Funds Agreement ("ONFA") Reference Plan is summarized in Ex. H1-T1-S1. As noted in Ex. H1-T1-S1, this reference plan was formally approved by the Province in December 2006.

Within the reference plan OPG's obligations are included for the following programs:

- Used fuel interim storage
- Low and intermediate level waste interim storage
- Used fuel long term management
- Low and intermediate level waste long term management
- Station decommissioning

Cost estimates for interim storage for used fuel, as well as for low and intermediate level waste, are prepared internally at OPG based on costs for existing storage programs. Cost estimates for long term management have been prepared by a number of external engineering consultants as part of development of plans for long term management of these wastes as identified in Ex. H1-T1-S1. Cost estimates for station decommissioning were prepared by TLG Services also as referenced in Ex. H1-T1-S1.

To arrive at the present value of the obligations, the cost estimates are escalated to the time of expenditure consistent with program timing included within the reference plan assumptions and then discounted to arrive at the present value of these obligations.

Board Staff Interrogatory #73

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Is the Bruce facility included in the Reference Plan? Are nuclear waste management costs either explicitly, or implicitly, included in the Bruce lease agreement? Does Bruce Nuclear assume any liabilities or pay any costs, directly or indirectly, for nuclear waste management?

Response

The ONFA Reference Plan includes all OPG owned nuclear facilities, including Bruce A and Bruce B Generating Stations.

The respective responsibilities of OPG and Bruce Power for any liability or costs associated with nuclear waste management are described in Ex. G2-T2-S1 pages 3 and 4, section 2.0 paragraphs 2 and 3.

Board Staff Interrogatory #74

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Does OPG make provision for its liability on decommissioning fund performance on an ongoing basis? If yes, how does it do so and what are the expected costs in the test period?

Response

No, OPG does not make any provision for its liability on decommissioning fund performance.

Board Staff Interrogatory #75

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

On page 21 of the OPG's Stakeholder Consultation summary report, it states, "Under the Ontario Nuclear Funds Agreement between OPG and the Province, OPG is required to make funding payments of approximately $450 million/year. These payments are not included in the revenue requirement. The revenue requirement is based on accrual accounting." Do these funds arise from the return on the fund? If not, how is OPG planning to provide the funding for this obligation?

Response

OPG's liabilities for decommissioning and nuclear waste management are satisfied by the funds created according to the Ontario Nuclear Funds Agreement ("ONFA"). The annual contributions OPG makes to the funds together with the return on the funds provides the necessary financing for the liabilities.

The means of funding OPG's contributions to the ONFA funds is provided through a number of components of the revenue requirement. Ex. H1-T1-S2, describes the revenue requirement treatment of OPG's liabilities for decommissioning its nuclear stations (including the Bruce Generating Stations) and nuclear used fuel and low and intermediate level waste management (collectively, the "Nuclear Liabilities").

Board Staff Interrogatory #76

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

The application says it is likely that OPG will cease to pay a provincial guarantee fee for the decommissioning fund when the update is complete. Does the application exclude the guarantee fee in the test period?

Response

As stated in Ex. H1-T1-S1 page 6, it is projected that decommissioning and used fuel funds accumulated in accordance with the Ontario Nuclear Funds Agreement will be sufficient to meet the CNSC financial guarantee requirement beyond 2010. It is expected that the need for the provincial guarantee will be eliminated at that time. Therefore, the provincial guarantee fee remains included in the proposed revenue requirement in the test period, which ends on December 31, 2009.

The forecast amounts of the provincial guarantee fee for the years 2008 and 2009 are $4.0M annually, as presented on Ex. F3-T1-S1 Table 12 line 6.

Board Staff Interrogatory #77

Ref:

Issue Number: 7.1

Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Please provide an explanation of how the Bruce Extraordinary Payment affects OPG's revenue requirements? Does the Bruce Extraordinary Payment increase the tax loss carry forward position of OPG?

Response

The Bruce Extraordinary Payment of $334M represents a one-time contribution to the nuclear segregated funds to satisfy OPG's funding requirements under the terms of the Ontario Nuclear Funds Agreement. For revenue requirement purposes, the Payment is treated in the same way as regular contributions to the segregated funds. Contributions to the segregated funds affect OPG's revenue requirement only by virtue of reducing regulatory taxable income as they are deductible for income tax purposes under the *Electricity Act, 1998* (as discussed in section 4.0 of Ex. F3-T2-S1).

The Bruce Extraordinary Payment increased OPG's cumulative regulatory tax losses available at the end of 2007 by $334M. This difference can be seen when comparing the updated pre-filed evidence submission dated March 14, 2008 to the original submission dated November 30, 2007. The original submission included a forecast of this Payment in the amount of $341M to be made in the first quarter of 2008. Therefore, OPG's cumulative regulatory tax loss carry forward position at the end of 2008 and 2009 remained essentially unaffected by the shift in the timing of the Payment.

Board Staff Interrogatory #78

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Withdrawals from the Ontario Nuclear Fund for eligible expenditures must be approved by the Province. Does OPG anticipate withdrawing funds from the fund during the test period? Is OPG required to reimburse the fund for withdrawals and expenditures prior to plant decommissioning?

Response

Expenditures eligible for withdrawal from the segregated funds include ongoing costs for long term programs associated with waste management and station decommissioning. As such, there will be withdrawals from the Ontario Nuclear Funds during the test period. These ongoing costs form part of the current approved Reference Plan and the associated segregated fund contributions. No reimbursement of withdrawals is required as the funds have been built up to include these expenditures.

Board Staff Interrogatory #79

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Please explain why OPG's proposed method of cost recovery for obligations to decommission nuclear plants is based on the useful lives of the nuclear stations rather than when the stations are actually decommissioned.

Response

By recovering these costs over the useful life of the Nuclear Stations the cost recovery period matches the period during which the Nuclear Stations provide benefit through electricity generation.

Board Staff Interrogatory #80

Ref:

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Please provide a breakdown by year for nuclear fixed assets decommissioning and nuclear waste management costs and the associated depreciation expenses for 2006 and 2007, which were capitalized and forecasted for 2008 and 2009. Please show how the amounts were calculated.

Response

OPG capitalized an amount of $1,386M on December 31, 2006 related to its nuclear decommissioning and nuclear waste management obligations, including the Bruce Nuclear Generating Stations, as a result of the update to the ONFA reference plan approved by the Province of Ontario in December 2006 (as discussed in Ex. H1-T1-S1). OPG did not capitalize any amounts in 2007 and does not forecast to capitalize any amounts in 2008 or 2009. The depreciation expense associated with the $1,386M amount capitalized in 2006 was $Nil in 2006 and $57M in 2007, and is forecast to be $57M in each of 2008 and 2009. OPG notes that the depreciation for 2007 has been deferred in the Nuclear Liability Deferral Account (as discussed in Ex. J1-T1-S1).

The amount of $1,386M was calculated as follows:

In accordance with the approved 2006 ONFA reference plan, the cost estimate for future costs from 2007 onwards for OPG's nuclear station decommissioning and nuclear waste management obligations is $24.0B in 2007 constant dollars. The cost estimate based on the previously approved ONFA reference plan is $20.5B in 2007 constant dollars. In accordance with the Canadian Institute of Chartered Accountants Handbook Section 3110, Asset Retirement Obligations, a credit adjusted risk-free rate of 4.6 percent was used to discount the incremental cash flow to arrive at $1,386M in present value terms.

Depreciation expense related to the amount of $1,386M capitalized on December 31, 2006 has been calculated on a straight line basis using the asset balances and station service lives shown below.

2007 ($M)	Total
Amount capitalized on December 31, 2006	**1,386.5**
Depreciation expense	**56.5**
Closing balance	**1,330.0**

2008 ($M)	Total
Opening balance	**1,330.0**
Depreciation expense	**57.3**
Closing balance	**1,272.7**

2009 ($M)	Total
Opening balance	**1,272.7**
Depreciation expense	**57.3**
Closing balance	**1,215.4**

The end of station service lives used to calculate depreciation for accounting purposes are as follows:

2007	Pickering A	Pickering B	Darlington	Bruce A	Bruce B
End of life dates used for depreciation purposes	2021	September 2014	2017	2030	2012

2008 & 2009	Pickering A	Pickering B	Darlington	Bruce A	Bruce B
End of life dates used for depreciation purposes	2021	September 2014	2019*	2035*	2014*

*Remaining estimated service lives for Darlington, Bruce A and Bruce B nuclear stations have been extended effective January 1, 2008. Refer to Ex. F3-T2-S1 for details.

Board Staff Interrogatory #81

Ref: Ex. H

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Please provide the accretion expense amounts for nuclear fixed assets decommissioning and nuclear waste management amounts forecasted for 2008 and 2009. Please show how the amounts were calculated.

Response

Accretion expense is the increase in the book value of the Nuclear Liabilities due to the passage of time. Accretion expense is calculated by multiplying the recorded book value amounts of the liabilities for nuclear fixed assets decommissioning and nuclear waste management (Nuclear Liabilities) by the credit-adjusted risk-free rate. The credit-adjusted risk free rate is the rate of interest on monetary assets that are essentially risk free of default risk, adjusted for the effect of an entity's credit standing. The discount rate used to calculate the present value of the Nuclear Liabilities was 5.75 percent for liabilities established prior to December 31, 2006. The increase in cost estimates related to the 2006 Approved Reference Plan, which was booked on December 31, 2006, was discounted at 4.6 percent.

The accretion expense for the Nuclear Liabilities forecasted for 2008 and 2009 of $603.2M and $626.M, respectively, are calculated as follows:

(In million $)	2008	2009
Nuclear Liabilities accreted at 5.75%	9,331.2	9,690.4
Accretion rate	5.75%	5.75%
Accretion expense	536.5	556.7
Nuclear Liabilities accreted at 4.6%	1,449.8	1,516.4
Accretion rate	4.60%	4.60%
Accretion expense	66.7	69.8
Total accretion expense	603.2	626.5

Board Staff Interrogatory #82

Ref: Ex. H

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

In other jurisdictions are there alternative mechanisms available and used for the regulatory recovery of nuclear fixed assets decommissioning and/or nuclear waste management costs in other jurisdictions? If so, please outline what these are and how they are applied.

Response

OPG has not undertaken an extensive review of the mechanisms used in other jurisdictions for the regulatory recovery of nuclear fixed assets decommissioning and/or nuclear waste management costs. However, our understanding of alternative regulatory treatment/recovery mechanisms used in other jurisdictions is presented below.

New Brunswick Power and Hydro Quebec are the only utilities in Canada, besides OPG, that own nuclear generating assets. In the case of New Brunswick Power, the annual expense amounts related to nuclear liabilities (depreciation and accretion charges, etc.) are recovered through a power purchase agreement with the distribution company. In the case of Hydro Quebec, it is not clear to OPG how nuclear liabilities expenses are recovered.

In the US, utilities with nuclear generation recover decommissioning costs as part of depreciation expense (depreciation and accretion charges net of any decommissioning fund earnings). The liability for used fuel lies with the US federal government, to whom utilities pay a per kWh charge for assuming the disposal obligation.

In terms of the accounting treatment of nuclear fixed asset removal and nuclear waste management costs, the approach appears to be uniform across North America (per Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3110, Asset Retirement Obligations, and United States Financial Accounting Standards Board ("FASB") Statement 143, Accounting for Asset retirement Obligations). Under this treatment, which is also described in Ex. H1-T1-S2, utilities are required to estimate the fair value of their asset retirement obligations like nuclear fixed assets decommissioning and/or nuclear waste management costs, record them as a liability and capitalize any associated asset retirement costs.

Board Staff Interrogatory #83

Ref: Ex. H

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

For 2008 and 2009, please provide a schedule that projects the beginning and ending aggregate recorded amount of the asset retirement obligations showing separately the changes attributable to:

a) liabilities incurred in the current period;

b) liabilities settled in the current period;

c) accretion expense;

d) revisions in estimated cash flows; and

e) any other change factors.

Response

1) For items a) to c) above.

	2008	**2009**
Accrued nuclear fixed asset removal and nuclear waste management liability ($M)		
Opening balance of liability	10,781.0	11,206.8
Liabilities incurred for management of used fuel and L&IL Waste	48.0	39.0
Less – liabilities settled during the year	(225.4)	(193.4)
Accretion expense	603.2	626.5
Ending balance of liability	**11,206.8**	**11,678.9**

2) For items d) and e) above

No revisions in estimated cash flows or other change factors are anticipated in 2008/2009.

Board Staff Interrogatory #84

Ref: Ex. H

Issue Number: 7.1
Issue: The proposed rate base includes the estimated net book value of OPG's nuclear fixed assets, which in turn includes amounts related to OPG's obligations to decommission the nuclear plants and manage nuclear waste. Do the amounts fall within the parameters of O. Reg 53/05? The proposed revenue requirement includes depreciation of those nuclear fixed asset costs and a return on rate base. Is this method of recovering nuclear fixed asset removal and nuclear waste management costs appropriate? Or should alternative recovery mechanisms be considered?

Interrogatory

Please provide the key assumptions on which the carrying amount of the asset retirement obligations are based and any changes forecasted, including:

a) The total undiscounted amount of the estimated cash flows required to settle the obligations or a range of amounts when there is uncertainty as to the amount required;

b) The expected timing of payment of the cash flows required to settle the obligations, or a range when there is uncertainty as to the timing of settlement;

c) The credit-adjusted risk-free rate or rates at which the estimated cash flows have been discounted; and

d) Changes in these assumptions that have been made over the period 2006-2009 with rationale for changes.

Response

a) The total undiscounted amount of the estimated cash flows required to settle the obligations was estimated to be approximately $24.0 billion in 2007 dollars, based on the 2006 ONFA ("Ontario Nuclear Funds Agreement") Reference Plan.

b) The 2006 Approved ONFA Reference Plan includes cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shutdown and to 2065 for placement of used fuel into the long-term disposal repository followed by extended monitoring. End of station shutdown dates may change as decisions on life extension are made.

c) The discount rate used to calculate the present value of the liabilities was 5.75 percent for liabilities established prior to December 31, 2006. The increase in cost estimates for OPG's liability for nuclear waste management and decommissioning based on the 2006 Approved ONFA Reference Plan were discounted at a rate of 4.6 percent.

d) OPG updated its estimates for its liabilities for nuclear waste management and decommissioning in 2006. These estimates were approved by the Province in December 2006, which resulted in an update to the ONFA Reference Plan. The change to the recorded book value of the asset retirement obligation was made on December 31, 2006. Major changes that were incorporated in the ONFA Reference Plan were discussed on page 45 of the OPG Annual Report 2006 under Appendix A of Ex. A2-T1-S1.

Board Staff Interrogatory #85

Ref: Ex. I1-T1-S1, Section 4.4, pages 7 - 8

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

What are the reasons OPG proposes a different incentive pricing mechanism for the Beck PGS?

Response

OPG is not proposing a different incentive pricing mechanism for the Beck PGS. OPG proposes one incentive pricing mechanism that covers all of OPG's regulated hydroelectric facilities, including the Beck complex. The reasons why the Beck PGS cannot be considered separately are identified in Section 3.1 in Ex. I1-T1-S1.

Board Staff Interrogatory #86

Ref: Ex. I1-T1-S1, Section 4.0, pages 5 - 8

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

The current incentive mechanism, i.e., prescribed hydroelectric asset output above 1900 MW per hour receives HOEP, was invoked more than 50% of the time.

a) What is the revenue generated by this incentive on an annual basis since its inception?

b) Without this mechanism, how would OPG have operated its hydraulic assets differently? What are the projected differences in production levels for 2005, 2006 and 2007?

c) What are the historical net revenue differences for 2005, 2006 and 2007 arising because of different production levels between the incentive and no incentive scenarios?

Response

a) The annual revenues generated by OPG's prescribed hydroelectric assets and reported in OPG's audited Financial Statements (page 28 of OPG's 2007 MD&A and page 31 of OPG's 2005 Annual Report (both contained in Ex. A2-T1-S1 Appendix A), for production above 1900MW are as follows:

i.	2005 (Apr1-Dec31)	$210M
ii.	2006	$169M
iii.	2007	$158M

b) In a scenario where the 1900 MWh in any hour threshold is eliminated and OPG receives the regulated rate of $33/MWh for all of the output from the regulated hydroelectric facilities, economically rational operation would result in OPG operating its assets with a flat production profile to maximize total energy output, instead of time-shifting water. In particular, the PGS cycle (i.e., the pump/generate cycle which is used at the Beck PGS to time-shift production to periods of peak demand) results in a net loss of energy for a fixed volume of water. It is only economic if cycling losses are off-set by an off-peak to on-peak price differential. A fixed rate of $33 /MWh (with no incentive mechanism) would result in significantly less cycling of the Beck PGS for economic purposes. The facilities would be operated to maximize revenue by maximizing production per unit of water at the entire Beck complex. With no incentive mechanism, OPG would not engage in any super-peaking operations, as described in Exhibit I1-T1-S1, page 16, lines 21-29.

It is difficult to estimate the difference in historical production levels in the absence of the incentive mechanism. A change of this type would have necessitated a re-evaluation of OPG's existing offer strategy, potentially resulting in changes. The market response to those changes cannot be quantified accurately.

c) For the reasons indicated above, the corresponding changes in revenue cannot be quantified accurately.

Board Staff Interrogatory #87

Ref: Ex. I1-T1-S1, Section 5.2, pages 11 - 17

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

OPG proposes a new incentive mechanism based on its actual average hourly net energy production over the month instead of a fixed energy amount (1900 MW/hour). OPG claims that a mechanism based on actual monthly production will increase efficiency, will place more financial risk on OPG to meet hourly production volumes and will increase OPG's incentive to time shift its production. Please explain how this proposed mechanism will cause OPG to operate its hydraulic prescribed assets optimally? How would this proposed incentive mechanism affect OPG's operation of its non-prescribed assets?

Response

In general terms, the incentive mechanism encourages peaking operation of the regulated hydroelectric facilities as indicated in Ex. I1-T1-S1, Section 3.0. Further, to improve market efficiency in Ontario, the hydroelectric incentive mechanism should encourage regulated hydroelectric generation to respond to market signals in all hours – hence the change suggested from the interim period mechanism. It is within this context (i.e., peaking operation in conjunction with market signals) that OPG considers "optimal" operation.

If the regulated hydroelectric facilities are operated at the monthly average energy production for the whole month, no incentive payment will be realized by OPG. As shown in Ex. I1-T1-S1, page 11, lines 4 - 12, the second term of the equation will be zero, indicating no incentive payment. The second term of the equation is the incentive portion of the payment mechanism and incentives can be realized by responding to market signals. However, responding to market signals has corresponding risks and rewards. The second term can result in either positive or negative revenues to OPG. The risks consist of forecasting risk (e.g., volume risk, price risk) and the rewards are realized due to price spreads between the off-peak and on-peak prices.

On-peak and off-peak prices used in decisions to shift hydroelectric generation are forecasted prices that are subject to price uncertainty. The volume transferred from the on-peak to off-peak hours is also subject to production efficiency losses (i.e., less MW from the same amount of water flow) and further risks corresponding to unit incapability or system restrictions occurring during the on-peak period.

The incentive mechanism as proposed, will therefore encourage peaking operation of the regulated facilities while responding to market signals, thereby resulting in “optimal” operation.

The proposed incentive mechanism does not directly affect OPG’s operation of its non-prescribed assets. The replacement of any shortfall in production can be from any resource offering generation or bidding load into the IESO administered market, including OPG’s non-prescribed assets.

Board Staff Interrogatory #88

Ref: Ex. I1-T1-S1, Section 5.2, pages 11-17

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

OPG states that it is likely to earn a net premium of $12 million from this revised incentive system, with an estimated range of $5 million to $19 million. Did OPG consider a revenue-sharing mechanism that would preserve an incentive for OPG and also benefit consumers directly by reducing revenue requirement? If not, why not?

Response

Yes, OPG did consider a revenue-sharing mechanism but this approach was not proposed because it would work to lower overall consumer benefits as explained below.

The net premium of $12 million is a function of the daily differential between on-peak and off-peak prices. OPG requires a minimum price-differential in order for the time-shifting of the regulated hydroelectric production to be economically viable because of the energy losses and variable costs associated with this activity. Reducing the value of the incentive to OPG by introducing a revenue-sharing mechanism will increase the required price-differential. This, in turn, will reduce the number of occasions that time-shifting of the regulated hydroelectric production will occur, and thus reduce the much larger benefits to consumers that arise from a reduction in Hourly Ontario Energy Price during peak-periods as is explained in L-1-91.

Board Staff Interrogatory #89

Ref: Ex. I1-T1-S1, Section 5.2, pages 11 - 17

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

How would the "notional purchase" volume be established and enforced? Would this require a specified hourly output level from the prescribed assets and a contractual obligation on OPG to make that level of supply available to the market? Why would OPG be "notionally obligated" to purchase from the market at market prices? Alternatively, could OPG increase production from its own fossil fueled plants (or other OPG generation) to make up the shortfall?

Response

Notional Purchase Volume:
Section 5.1 and 5.2 of Ex. I1-T1-S1 describes the notional volume that OPG "purchases" at market prices. These notional volumes are calculated at the end of each month as the volume difference between the after-the-fact, average monthly net-energy (using all production data from the regulated hydroelectric facilities) and the actual net-energy (from these same facilities, excluding SMO) supplied during each 5 minute interval in the IESO market. These volume differences are multiplied by the corresponding Market Clearing Price (MCP) for that 5 minute interval and aggregated, with the net amount being settled financially with the IESO on a monthly basis.

Contractual Obligation:
There is no need for a contractual obligation. Payment and enforcement will be through standard settlement practices with the IESO per the Board's decision in this proceeding.

Purchase at Market Prices:
Time-shifting production involves storing a certain volume of water in a lower-priced time period for release at a later, higher-priced time period. Under the proposed incentive mechanism this is interpreted as a purchase and subsequent sale of energy at IESO market clearing prices. As indicated in Ex. I1-T1-S1, page 10, lines 1 - 8, OPG is financially obligated to supply the after-the-fact, average monthly hourly volume in all hours of the month. Should production from its regulated hydroelectric facilities be below this amount then OPG's payment from the IESO will be reduced by the production shortfall multiplied by the market price.

<u>Shortfall:</u>

The reduction in production during low price periods can be made up from any resource offering into the IESO-administered market, including OPG's fossil fueled plants. Similarly, during periods where OPG's regulated hydroelectric facilities produce more than the hourly quantity, the incremental production may displace other resources.

Board Staff Interrogatory #90

Ref: Ex. I1-T1-S1, Section 5.2, pages 11 - 17

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

Has OPG commissioned any studies or analysis of this incentive mechanism by outside experts or OPG staff? If so, please provide copies of the studies or analysis.

Response

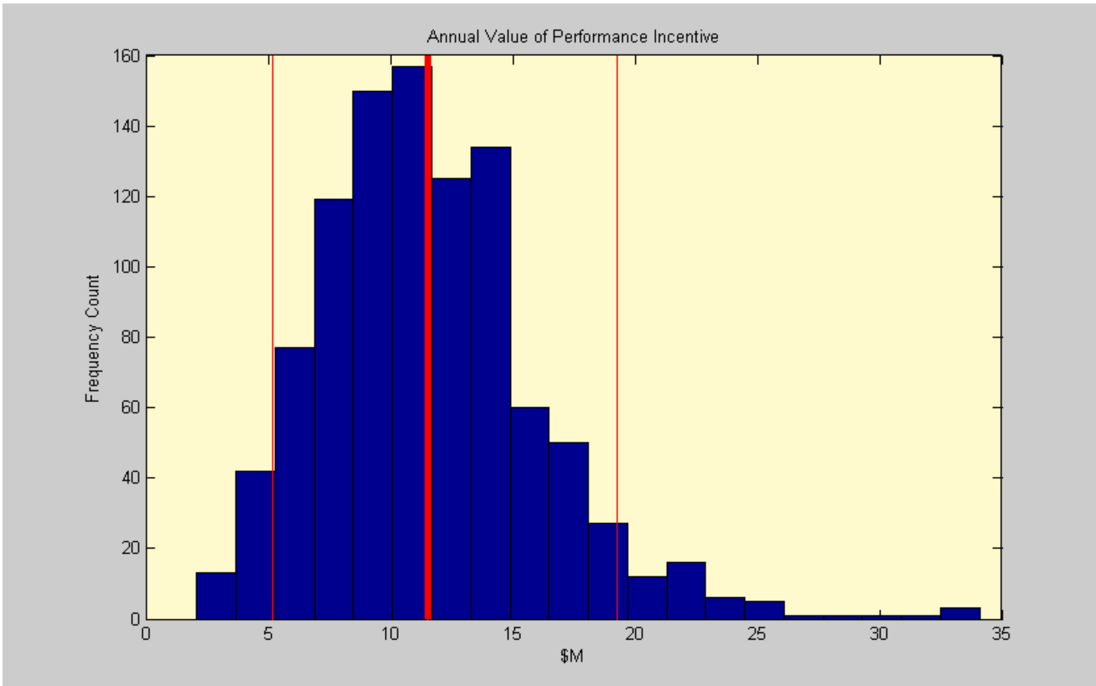
OPG did not commission any studies or analysis by outside experts.

Analysis was conducted by OPG staff, using multiple market simulations based on statistical forecasts of production and market prices, as described in Section 5.4 of Ex. I1-T1-S1, to arrive at forecasts of the expected annual value of the proposed incentive mechanism. Although the proposed performance incentive will be calculated using the 5 minute intervals in the IESO-market, the simulations and subsequent analysis were performed on an hourly granularity, as 5 minute data was not available.

A summary of three key areas in the analysis is provided below for 2009:
- Calculation of the expected value of the hydroelectric incentive payment
- Distribution of forecasted market clearing prices
- Variability of regulated hydroelectric production.

Each of these areas is considered below.

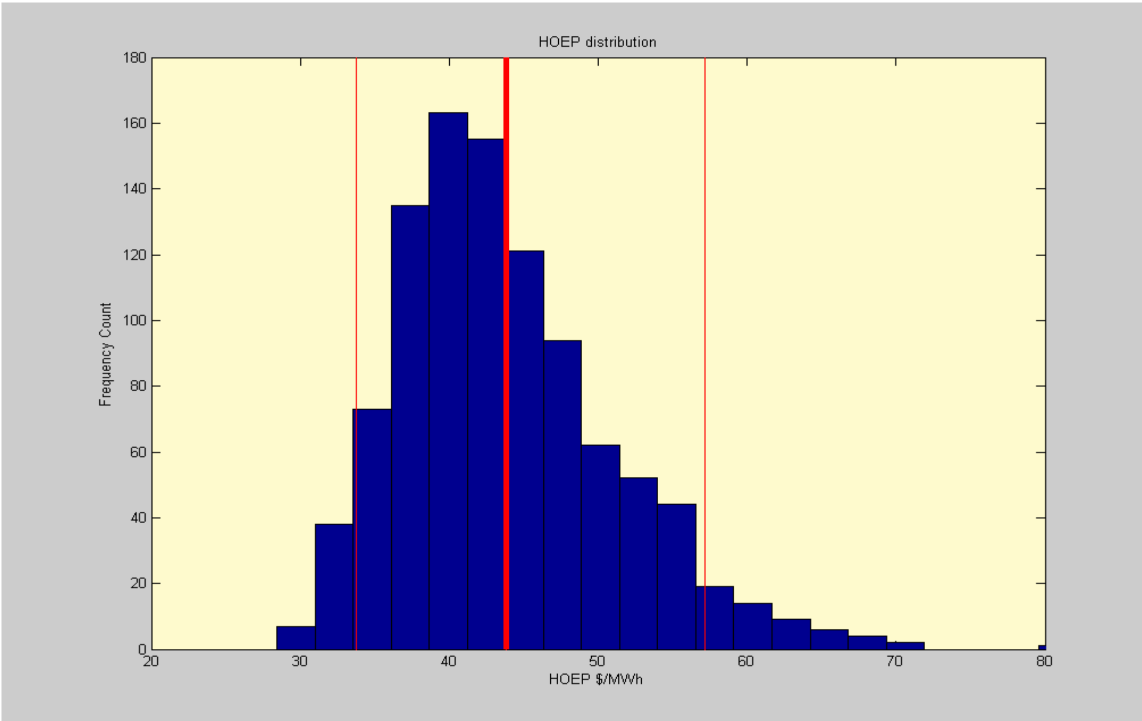
Annual value of the hydroelectric incentive payment:
The distribution of the expected annual value of the performance incentive for 2009, using 1,000 market simulations is depicted below in blue as a histogram. The distribution has a mean of \$11.6M, with a 90% confidence interval from \$5.2M to \$19.3M, as shown in Ex. I1-T1-S1, page 16, lines 1 - 3. The thick red line is placed at the mean, while the thin red lines are placed at the 5^{th} and 95^{th} percentile.



Section 5.2 of Ex. I1-T1-S1 describes the hydroelectric incentive payment and how it is calculated monthly as a function of the hourly market clearing prices and the hourly regulated hydroelectric production, relative to the actual, average hourly production for that month. Although it is impractical to provide all the hourly values for price and production for all the 1,000 market simulations that were used, OPG can provide high level characteristics of price and production.

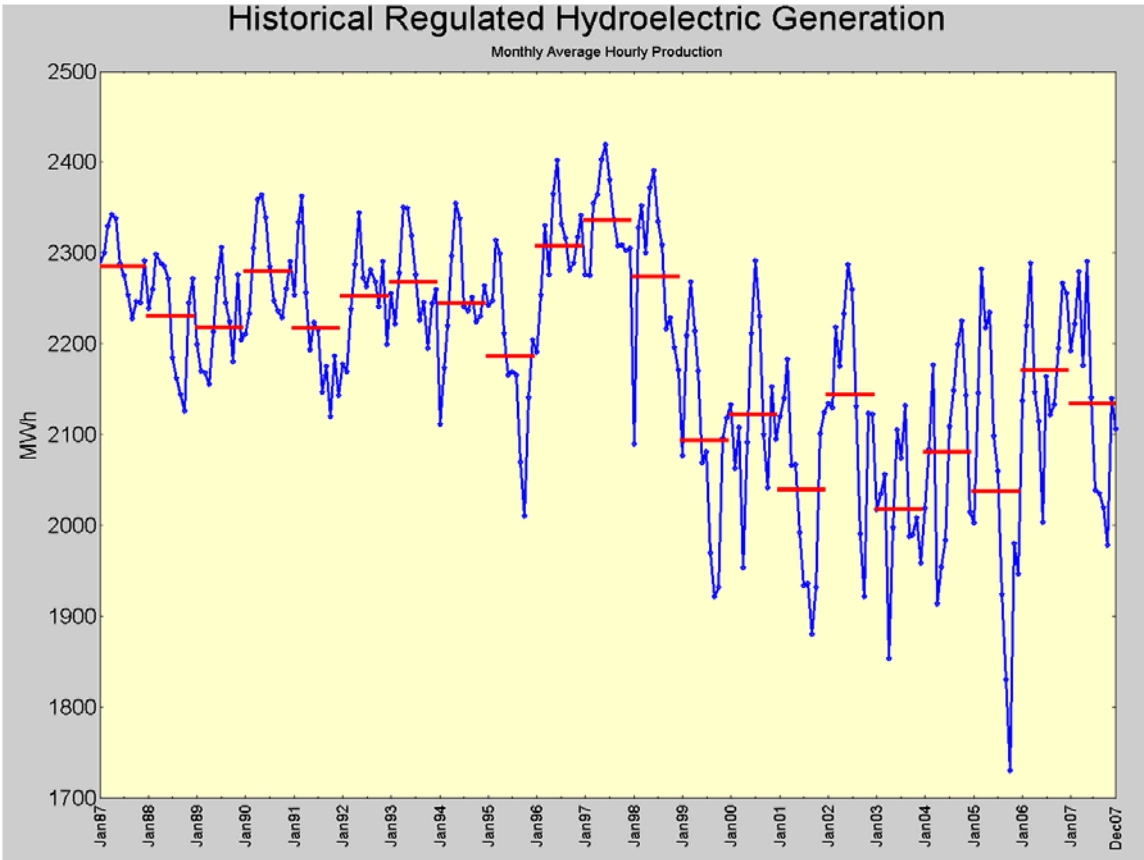
This expected value is less than the actual 2005, 2006 and 2007 value of the current incentive mechanism. The value of the current incentive mechanism was $121.6M, $46.1M and $50.8M for 2005, 2006 and 2007 respectively (values are calculated Ex. C1-T2-S1 Table 1 Line No. 4 minus Line No. 5).

<u>Market clearing price:</u>
The distribution of the forecast annual HOEP over the 1,000 market simulations that were used is depicted below in blue as a histogram. The distribution has a mean of $43.8/MWh, with a 90 percent confidence interval from $33.8/MWh to $57.2/MWh, as shown in Ex. I1-T1-S1, page 16, lines 4 - 6. The thick red line is placed at the mean, while the thin red lines are placed at the 5th and 95th percentile.



Variability of Regulated Hydroelectric Production:

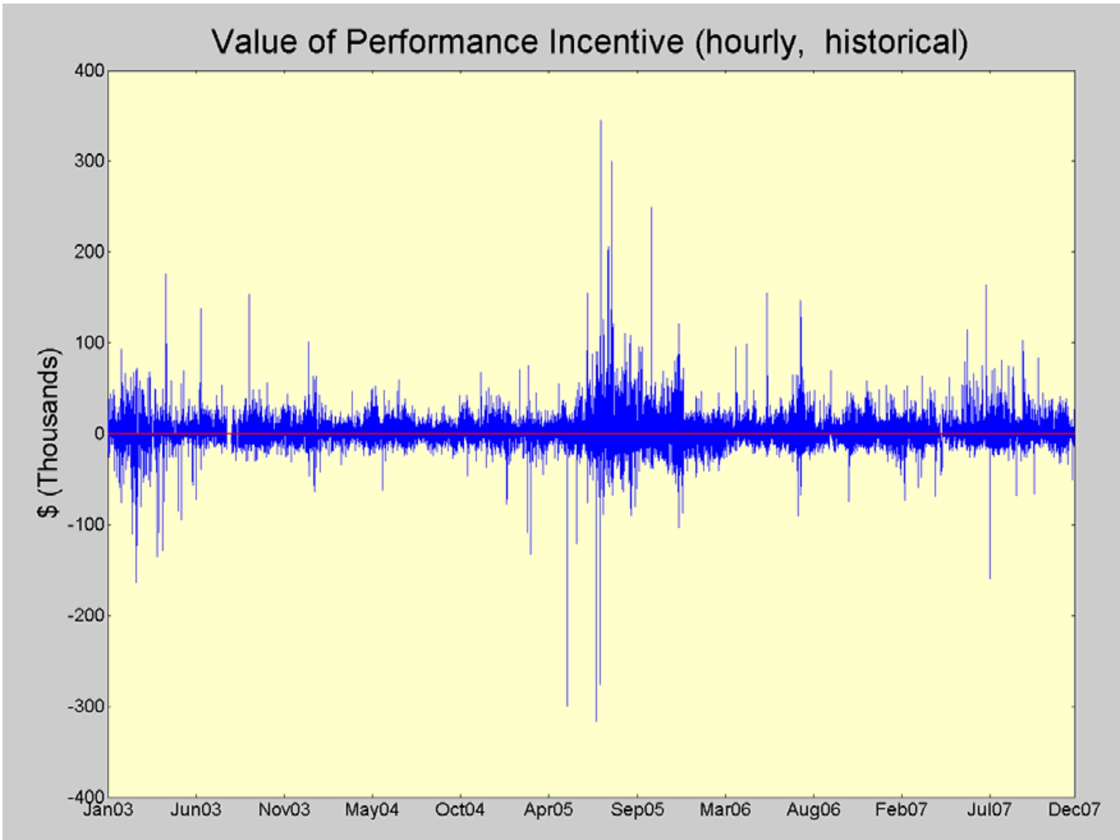
For the regulated hydroelectric production the last twenty years of hourly production were used as historical scenarios to reflect the range of hydrological conditions. A condensed view, showing the average hourly production for each month during that period, is given by the blue line in the graph below, with the annual averages as red lines.



The use of historical data in the market simulations allows OPG to assess the risk associated with under production due to water conditions (within the context of the variance accounts) as discussed in Ex. J1-T1-S1, Section 3.1.1. OPG is still exposed to production and price risk as discussed in Ex. I1-T1-S1, Section 5.3.

The production data analysis in conjunction with the market price analysis were used in the statistical modeling (i.e., the multiple market simulations) to arrive at a mean value associated with the proposed incentive mechanism.

<u>Risk Profile:</u>
To further illustrate the financial risks associated with hydroelectric production, using the historical values for production and HOEP, OPG calculated what the hourly value of the performance incentive would have been, since market opening. As illustrated below and described in Ex. I1-T1-S1, Section 5.3, on an hourly basis OPG is exposed to price volatility, resulting in potentially large negative values of the performance incentive.


Value of Performance Incentive (hourly, historical)
$ (Thousands)
400
300
200
100
0
-100
-200
-300
-400
Jan03
Jun03
Nov03
May04
Oct04
Apr05
Sep05
Mar06
Aug06
Feb07
Jul07
Dec07

Board Staff Interrogatory #91

Ref: Ex. I1-T1-S1, page 17, lines 6-12

Issue Number: 8.1
Issue: Are OPG's suggested changes to the hydroelectric incentive payment system appropriate?

Interrogatory

OPG claims that the proposed incentive mechanism will result in consumer benefits with an estimated annual value of between $80 million and $270 million, an incentive payment of $12 million in 2009 to OPG and unspecified market benefits from additional supply during peak demand periods. How did OPG calculate these specific benefits?

Response

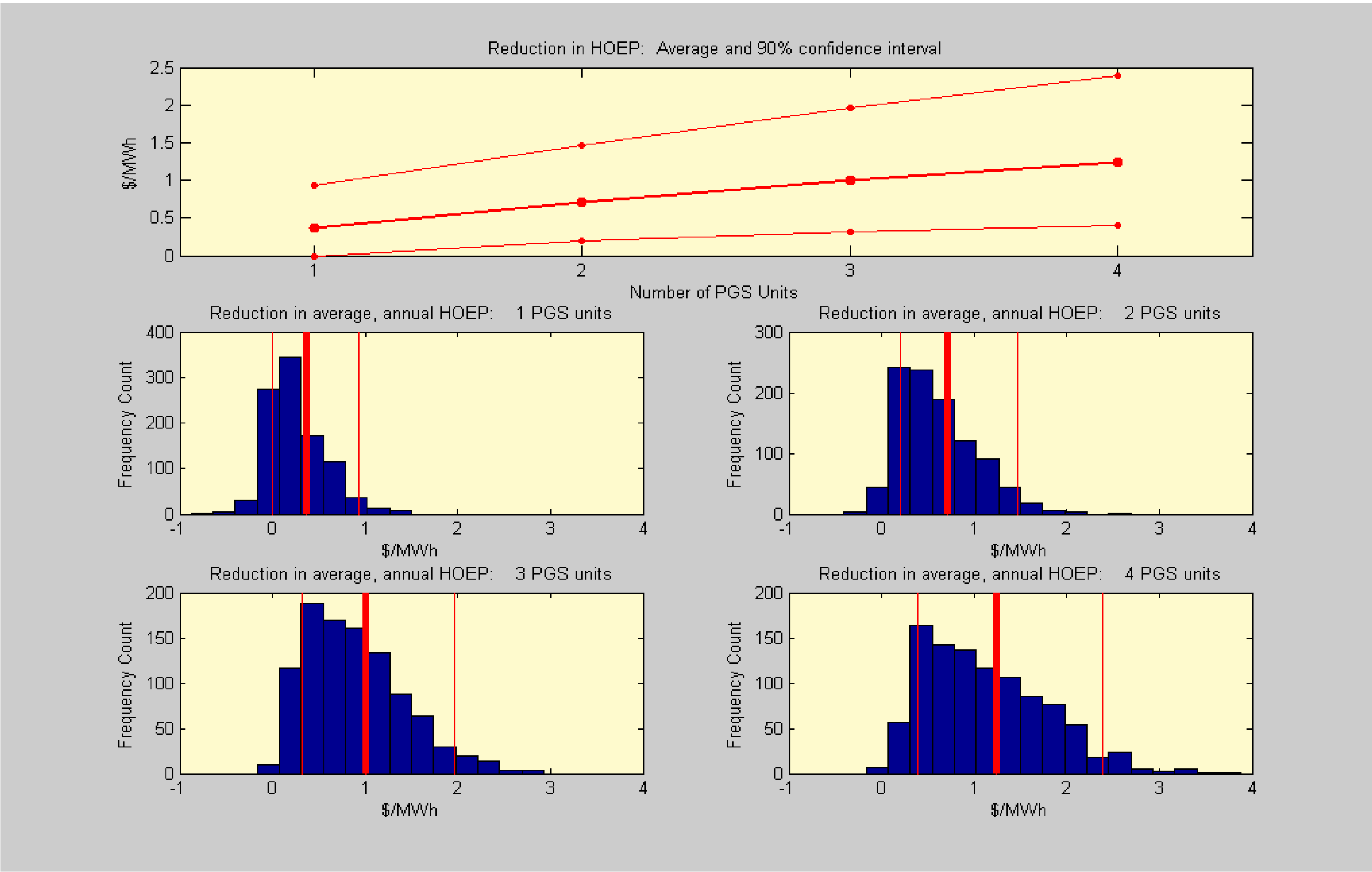
As described in Section 5.4 of Ex. I1-T1-S1, OPG used multiple market simulations based on statistical forecasts of production and market prices to determine a distribution for the annual value of the hydroelectric performance incentive, and the benefits to consumers. For the calculation of the value of the incentive mechanism, please refer to L-1-90.

The distributions of the reduction in Hourly Ontario Energy Price ("HOEP") and the consumer benefits, as summarized in Chart 1 on page 15 of Ex. I1-T1-S1, are depicted in greater detail in the attached graphs.

The value of the annual consumer benefit was estimated as follows. First, a baseline was established by running the market simulations with none of the PGS units operating. After this, exactly the same market simulation was run, but now with 1, 2, 3, and 4 PGS units operating. From this, the reduction in HOEP and the consumer benefits were derived as a differential from the baseline.

Reduction in HOEP:
The top panel in the first graph shows the average reduction in HOEP, as a function of the number of Beck PGS units that are employed. For example, with one PGS unit, the average reduction in HOEP is 0.4$/MWh, with a 90% confidence interval of 0$/MWh to 0.9$/MWh. For four PGS units the average reduction in HOEP increases to 1.2$/MWh, with a 90% confidence interval of 0.4$/MWh to 2.4$/MWh.

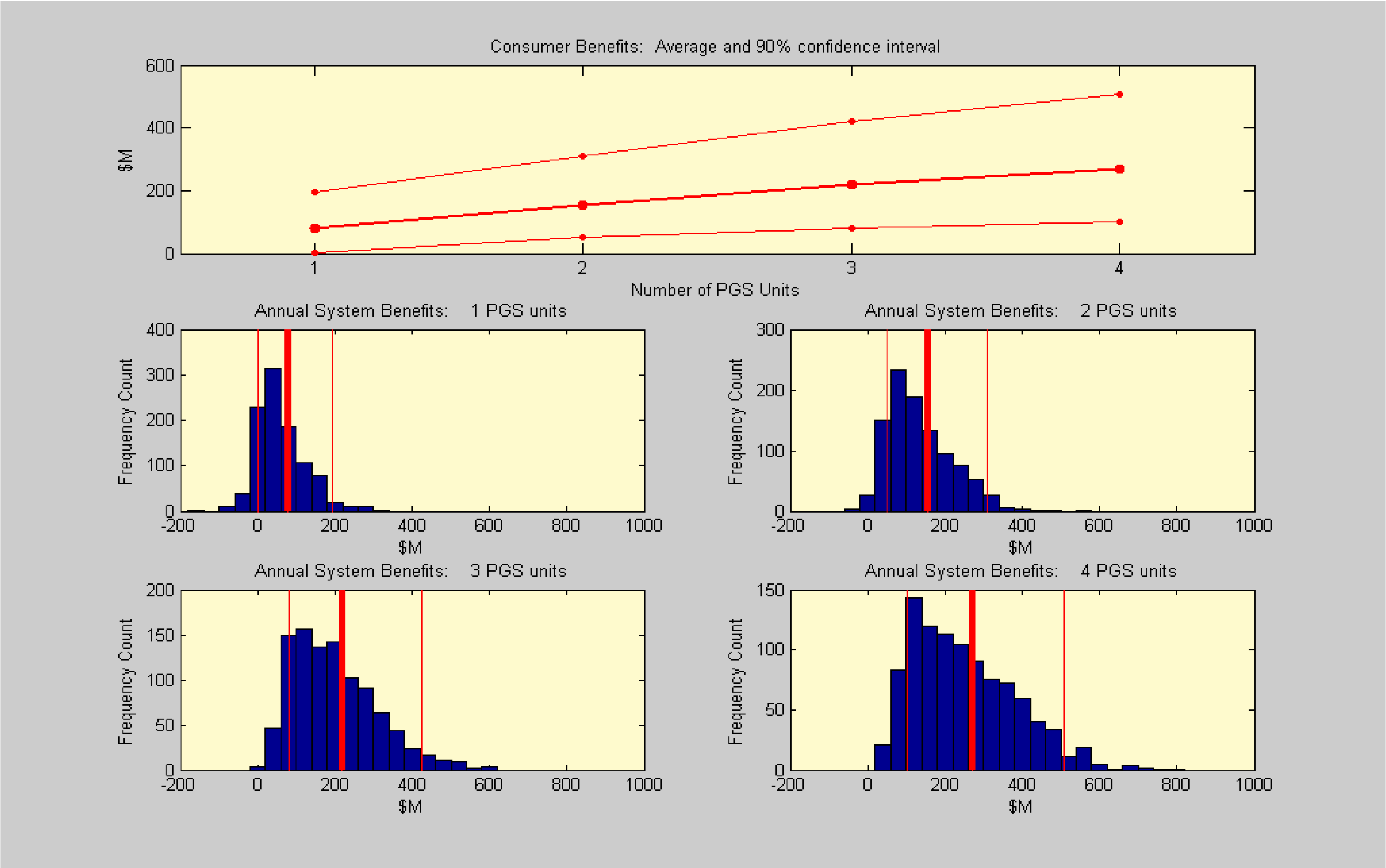
The lower four panels show the distribution of the average reduction in HOEP achieved by running 1, 2, 3 or 4 PGS units. In each of those panels the thick red vertical line is placed at the average and the thin red vertical lines are placed at the 5th and 95th percentiles.


Reduction in HOEP: Average and 90% confidence interval
$/MWh
Number of PGS Units
Reduction in average, annual HOEP: 1 PGS units
Reduction in average, annual HOEP: 2 PGS units
Reduction in average, annual HOEP: 3 PGS units
Reduction in average, annual HOEP: 4 PGS units
Frequency Count
$/MWh

<u>Consumer Benefits:</u>

The top panel in the second graph shows the benefit to consumers, by having primary demand satisfied at a lower HOEP, as a function of the number of Beck PGS units that are employed. For example, with one PGS unit, the average benefit to the consumer is 80M$, with a 90% confidence interval of 1M$ to 190M$. For four PGS units the average benefit to the consumer increases to 270M$, with a 90% confidence interval of 100M$ to 510M$.

The lower four panels show the distribution of the benefit to consumers achieved by running 1, 2, 3 or 4 PGS units. In each of those panels the thick red vertical line is placed at the average and the thin red vertical lines are placed at the 5^{th} and 95^{th} percentile.


Consumer Benefits: Average and 90% confidence interval
$M
Number of PGS Units
Annual System Benefits: 1 PGS units
Annual System Benefits: 2 PGS units
Annual System Benefits: 3 PGS units
Annual System Benefits: 4 PGS units
Frequency Count
$M

Board Staff Interrogatory #92

Ref: Ex. I1-T2-S1, Section 3.0, pages 1 - 2, Sections 3.2 and 3.3, pages 7 - 8

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

OPG's rationale for a fixed (25%) - variable (75%) payment structure for the nuclear assets has three components: nuclear generation has a high proportion of fixed costs; generators in Ontario and other jurisdictions have fixed payments as part of their compensation; and the OEB has approved fixed-variable rate structures for other entities with a high proportion of fixed costs. Typically, fixed payments are awarded through a competitive process for capacity. Ontario's OPA-based supply contracts were competitively awarded and have a fixed payment "top-up" mechanism based on a total revenue requirement – but generators are required to operate to receive payments and can be "deemed to have run" to calculate their revenue requirement.

Given that it is not subject to any competitive procurement for capacity, why has OPG proposed a payment structure that includes a fixed payment for its nuclear units that is payable even when they do not operate?

Response

As explained in the evidence at Ex. I1-T2-S1, pages 7 - 9, the primary rationale for this proposal is the premise that the design of payments amounts should reflect, at least to some extent, the underlying cost structure, and the majority of OPG's nuclear-related costs are fixed in nature.

This proposal is further supported by the fact that:

- Generators in Ontario and other jurisdictions receive payments to cover some of their fixed costs,
- The OEB has previously approved rate structures that include both fixed and variable components.

OPG believes that its proposal for a 25% fixed component provides a reasonable degree of consistency with the underlying cost structure while still providing OPG with a strong production incentive in the form of a high variable component based on energy production.

Board Staff Interrogatory #93

Ref: Ex. I1-T2-S1, Section 3.0, pages 1 - 2, Sections 3.2 and 3.3, pages 7 - 8

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

Other regulated entities with a high proportion of fixed costs, e.g., electricity transmission and distribution networks and natural gas pipelines, do not have the level of outage risk of OPG's nuclear plants. Given that outage levels exceed OPG's own target levels, what is the rationale for ratepayers assuming any of OPG's nuclear outage risk?

Response

OPG's requested payment amounts allow OPG the opportunity to recover prudently incurred costs and a fair return on invested capital that reflects the risks faced by OPG. Nuclear outages represent a significant risk to OPG's earnings as evidenced by the experience in 2007 when nuclear production was 5.7 TWh below forecast.

While the proposal for a fixed payment equivalent to 25 percent of the nuclear revenue requirement helps mitigate the risk to OPG's revenues, it is also intended to provide a better matching to OPG's costs which are over 90 percent fixed and to better align OPG's payments with those of other generators that have alternative methods for fixed cost recovery.

With respect to examples cited (i.e., electricity transmission and distribution utilities and natural gas pipelines), it is OPG's understanding that the primary rationale for providing them with a fixed component in their rate structures is cost causality rather than risk mitigation.

Board Staff Interrogatory #94

Ref: Ex. I1-T2-S1, Section 3.0, pages 1-2, Sections 3.2 and 3.3, pages 7-8

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

All of the examples in the application appear to be "wires" or "pipeline" businesses where some proportion of fixed charges are the norm. Please provide some examples of specific regulated generators in North America that receive a fixed charge. Of those, please identify the generators that get paid a fixed amount whether they are available or not to run (i.e., during an outage).

Response

OPG has not done a comprehensive investigation of North American utilities for information on fixed charges for generation. In many instances, where generation is regulated, it is regulated as part of a larger integrated electrical utility which includes transmission and distribution assets. It is therefore difficult in those instances to separate out the generation portion of any fixed charges for the integrated utility. However, OPG does have a few examples of generation receiving fixed charges to cover a portion of its costs. These are provided below.

Within Ontario, OPG's Lennox facility is covered by an RMR agreement that is reviewed and approved by the OEB so it is analogous to a regulated generator. This agreement provides for fixed monthly payments to OPG that are initially set based on a forecast of fixed and variable operating costs less expected revenues earned by the facility. These monthly payments are then subject to true-up mechanisms designed to ensure that OPG recovers its actual fixed and variable costs less actual realized revenues. The Lennox RMR agreement includes rewards and penalties for exceeding or failing to meet performance targets when the facility is required to operate. The potential penalty, however, is capped at $2 million, an amount which is substantially less than the payments for fixed cost recovery.

Similar types of RMR agreements exist, for example, in ISO New England. While the facilities in New England each have their own agreements, reflecting individual plant and operator circumstances, they are based on the standard form agreement included within the ISO New England tariff. The standard form agreement includes monthly Fixed-Cost Charge payments which would typically include all the costs of owning and operating a facility, including a return on capital. The monthly Fixed-Cost Charge is reduced by revenues from energy and energy-related sales from the plant. The New England standard form agreement includes penalties if the generator is not able to comply with dispatch instructions (i.e., is not able to generate when called upon to do so), which are limited to the fixed cost payment in any month.

Board Staff Interrogatory #95

Ref: Ex. I1-T2-S1, page 5, lines 7-14

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

OPG cites a Market Surveillance Panel Report and an IESO report on operating reserve to support the assertion that Ontario market prices are often too low to allow generators to earn sufficient revenues. Given that OPG's prescribed assets receive payment amounts that are independent of market price levels, how are the conditions cited in these reports relevant to OPG?

Response

The reference in the evidence is cited to make the point that both the Market Surveillance Panel ("MSP") and the IESO acknowledge that if generators are not able to earn sufficient revenues to cover their costs, there will be a negative impact on generation investment. In this regard, OPG's regulated assets are no different than the generators cited by the MSP.

In Ontario, the shortfall in energy-related payments has resulted in contracts from the OPA that provide for a degree of fixed cost recovery. In other markets, it has resulted in the creation of capacity markets to provide a degree of fixed cost recovery for generators.

Board Staff Interrogatory #96

Ref: Ex. I1-T2-S1, Section 3.1, pages 2 - 5

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

OPG argues that the current energy-only payment structure does not reflect cost causality and results in higher financing costs because fixed costs are recovered through a mechanism that is based on variable energy usage. Does OPG have analysis that documents this claim of higher financing costs because of energy-only payments? Are there specific examples where OPG has incurred higher financing costs as a result of the current system of energy-only payments?

Response

OPG's evidence states that collection of fixed costs through a rate based on variable energy usage can cause a mismatch between revenues and costs, contributing to volatility in earnings and net income. While OPG cannot provide specific examples of higher financing costs that it has incurred as a result of the current, all energy, payment design, the degree of volatility in earnings will directionally affect OPG's credit-worthiness as assessed by the rating agencies and therefore its ultimate cost of financing.

In it latest review of OPG, Standard & Poor's indicates a positive outlook for OPG (Ex. A2-T3-S1). However, it also highlights the risk arising from potential volatility in nuclear revenues, indicating that "the outlook could also be revised to stable or negative as a result of a sustained period of significantly lower-than-expected electricity production due to operational or technological challenges at the company's nuclear facilities…" (Ex. A2-T3-S1, Attachment B, page 4).

Board Staff Interrogatory #97

Ref: Ex. I1-T2-S1, Section 3.1, pages 2-5

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

As base load plants, nuclear facilities do not vary from their projected output or energy sales except when they are offline because of unscheduled outages. Revenue variability from the nuclear plants is the result of these outages and not demand fluctuations. How will OPG's proposed fixed payment help to reduce unscheduled outages?

Response

The proposed fixed payment will neither help nor hinder the reduction of unscheduled outages. A payment design that provides for 75% of the revenue requirement to be recovered through an energy rate is an enormous incentive to avoid unscheduled outages.

The proposal to recover 25% of the revenue requirement via a fixed monthly payment is intended to better align OPG's payment amounts with OPG's costs, which are largely fixed, to mitigate to some degree the volatility of nuclear earnings, and to better align the payment amount design with the payment streams of other Ontario utilities and contract generators.

Board Staff Interrogatory #98

Ref: Ex. I1-T2-S1, Section 3.1, page 9, lines 1 - 4

Issue Number: 8.2
Issue: Is the fixed payment of 25% of revenue requirement an appropriate design for the nuclear facilities?

Interrogatory

OPG accepts that a variable payment structure is essential to provide incentives to maximize production from OPG's nuclear plant. As a starting position, OPG proposes the 25% fixed payment be reviewed for effectiveness in future periods. How does a 75% revenue requirement recovery through energy charges increase incentives for OPG to maximize production compared to payments based on a 100% energy charge?

Response

A 75% recovery through energy charges does not increase incentives for OPG to maximize production compared to a 100% energy charge. However, OPG believes that it has sufficient incentive to maximize production with a payment amount design that provides for 75% recovery through an energy charge while still providing a degree of risk mitigation against potentially volatile earnings.

Board Staff Interrogatory #99

Ref: Ex. J

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

In its evidence concerning the regulated hydroelectric and ancillary services variance account, OPG states that it has established and recorded a segregated mode and water transactions net revenue variance account. "Segregated mode" refers to the segregation by Saunders G.S. of some of its generation units from the Ontario grid and their reconnection to the Hydro Quebec grid to facilitate exports. Water transactions refer to water or equivalent energy transfers between OPG and the New York Power Authority made pursuant to treaty obligations for water sharing and hydraulic management. These additional accounts are not required by section 5(1) and result in credits for consumers.

a) For the purposes of receiving the regulated price, does OPG reduce total production volumes from the hydroelectric facilities by the segregated mode and water transactions volumes?

b) Segregated mode and water transactions appear to be analogous to an export sale. How does OPG account for export sales revenue and energy volumes from prescribed asset production, both hydro-electric and nuclear?

c) OPG states the following with respect to the segregated mode of operations revenue sharing proposal:
"The proposed sharing mechanism recognizes that OPG is using prescribed assets to earn this revenue so it would only be fair to share a portion of the net revenues from SMO transactions"

Please detail all revenues derived from these assets, including export revenues.

Response

a) No, as indicated in Ex. G1-T1-S1, page 7, forecasting SMO transactions is difficult as they are a response to market-based signals. Likewise, for water transactions, Ex. G1-T1-S1, pages 10 and 11 outlines that NYPA and OPG coordinate certain operations to maximize energy production from the total water available under the treaties and that forecasting such transaction volumes and revenues is difficult.

The production volume used in calculating the revenue requirements and proposed hydroelectric payments amounts is the total production from the regulated facilities based on the forecast water conditions, irrespective of the type of transaction associated with those facilities.

b) Segregated mode operations and water transfers are different than exports. Segregated mode operation is the physical connection of a specific generating facility to a neighbouring control area. Exports are not tied to any specific source of supply. Rather, they are purchases from the Ontario Market that are conveyed to or through a transmission system interconnected with the IESO controlled grid. The actual supply for the export comes from a common pool of supply that includes both imports and all Ontario generation in the market during the period of the export. OPG does not forecast or attribute export sales revenues and energy volumes from the prescribed assets or any other OPG generation facility.

Water transactions are also facility specific. Their goal is to maximize energy production from the total water available for generation. The majority of these transactions are related to operating conditions; namely maintenance, ice conditions or spill conditions, water which NYPA or OPG cannot utilize for energy production.

c) Revenues derived from these assets are provided in Ex. G1-T1-S1, Table 1 and Ex. G1-T1-S 2, Table 1.

Board Staff Interrogatory #100

Ref: Ex. J1-T1-S1, Section 3.1.1; pages 3 - 6

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

Section 5(1) specifies that the forecast information is the basis for deviations of actual production from the hydroelectric production forecast based on changes in water conditions. Energy volumes in Table 3 (J1.Tl.Sl. Table 3) do not match those in the Production Forecast information (El .TI .S2.Table 1). Did OPG use a revised forecast for determining these deviations? If so, please produce the revised forecast and advise why it was used instead of the original forecast?

Response

OPG did not use a revised forecast. As per J1-T1-S1, page 3, line 15 and continued on line 16, OPG used the production as forecast for the interim rate period. The Table 3 reference production was then calculated as the forecast production excluding the Decew Falls Generating Stations. The following chart reconciles Table 3 with the production as originally forecast.

MWh	**2005**	**2006**	**2007**
Forecast Information[1]	17,956,293	18,390,009	18,722,387
less Jan - March 05	4,526,912		
less Decew[2]	830,448	1,035,506	1,108,052
Reference Plan Production Table 3 line 1	12,598,933	17,354,503	17,614,335

[1] from "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" as posted on the OEB website.

[2] As identified in Ex. J1-T1-S1, Section 3.1, there are a number of natural variables which affect water availability, and over which, OPG has no control. The IVA – Hydroelectric Water Conditions Sub-account reflects the differences between forecast and actual water conditions due to these variables. However, flow to the DeCew plants is diverted from Lake Erie, through the Welland Canal, and is not subject to these natural variables. Unless extremely low levels are forecast for Lake Erie, the general expectation is that the water for Decew is only limited by outages and other non-natural variables such as rowing events. For the period 2005 through 2007, it was not expected that there would be any extended periods where natural conditions would impact the

flow to DeCew. Consequently the revenue and GRC cost variances attributed to DeCew were considered to be zero.

Board Staff Interrogatory #101

Ref: Ex. J1-T1-S1, Section 4.4.2, page 17, lines 2 - 9

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

In the transmission outages and restrictions sub-account, OPG calculates the value of lost production on the basis of an hourly capability factor for the affected units. Is this an actual capability factor or a theoretical 100% factor?

Response

The calculation is based on a theoretical 100 percent factor equivalent to the maximum design rating for each of the units.

Board Staff Interrogatory #102

Ref: Ex. J1-T1-S1, Section 4.4.2, page 17, lines 2 - 9

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

For the Nuclear transmission outages which occurred at Darlington:

a) Why is the value of the one-day outage on Dec. 12, 2005 greater than the two-day outages of April25/26, 2006 and June 17/18, 2006?

b) Why are there no Congestion Management Settlement Credits payments for the 2006 outages?

Response

a) The value of the one day outage on December 12, 2005 is greater than the value of the two outages in April and June 2006 because all four of the Darlington units were impacted in the December outage, compared to only one unit in both the April and June outage.

b) OPG received Congestion Management Settlement Credits (CMSC) for the April and June outages. They amounted to less than $33k in each instance. Since the evidence presents dollars to the nearest hundred thousand, they rounded to $0.0M.

Board Staff Interrogatory #103

Ref: Ex. J1-1-1, Section 3.2, pages 5 - 6

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

Under what circumstances might the IESO refuse an OPG request for segregated mode of operation?

Response

The IESO Market Rules, Appendix 7.7, provide the rules pertaining to Segregated Mode of Operation (SMO).

The IESO may deny a request for SMO if the IESO feels that SMO would threaten the reliability of the IESO-controlled grid. The IESO may also revoke or terminate a previously granted approval for SMO at any time if it is the IESO's opinion that SMO would threaten the reliability of a local area which forms part of the IESO-controlled grid or the security of the integrated power system. The IESO may also refuse SMO for specific revenue metering issues.

In addition to actions by the IESO, these transactions can also be curtailed due to switching restrictions, transmission outages or limitations (inside and outside Ontario) and market transactions from Quebec into Ontario.

Board Staff Interrogatory #104

Ref: Ex. J1-1-1, Section 3.2, pages 5 - 6

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

Does OPG ever engage in segregated mode of operation transactions when market prices in neighbouring markets are below $33/MWh? If yes, then on average how much energy is sold annually at prices under $33/MWh?

Response

Yes, however, these conditions generally occur when Ontario and surrounding markets are in low load periods, such as during times when excess baseload generation (EBG) must be managed (e.g., to prevent the risk of poisoning out a nuclear unit or the spilling of water). However, in these situations while the prices in neighbouring markets may be below $33/MWh, the SMO selling price is usually greater than HOEP in Ontario. On occasions when OPG would sell below HOEP, again, it is generally for EBG reasons.

On average, during 2005 - 2007, OPG sold approximately120,000 MWh annually, or about 10% of the total annual SMO energy volume, at market prices less than $33/MWh.

Board Staff Interrogatory #105

Ref: Ex. J1-1-1, Section 3.2, pages 5 - 6

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

How does OPG assess and evaluate a segregated mode of operation request? What criteria does OPG use to determine if it will engage in these transactions?

Response

As indicated in Ex. G1, T1-S 1, page 6, Segregated Mode of Operation (SMO) is conducted when OPG identifies economic opportunities in neighbouring markets. These opportunities are typically arranged in advance with counterparties or other market operators such as the NYISO or NE-ISO. The economic drivers are forecast market prices in Ontario and surrounding markets. In short, when the basis or spread between Ontario and the receiving market exceeds the costs, then the transaction would be economic. Additional criteria, which benefit Ontario, are excess baseload generation management and the minimization of spill.

Board Staff Interrogatory #106

Ref: Ex. J1-1-1, Section 3.2, pages 5-6

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

OPG states that it will share "net revenues" from segregated mode of operation transactions. Does OPG net out segregated mode of operation related costs from total hydraulic production costs?

Response

No. The incremental costs associated with Segregated Mode of Operation (SMO) transactions are deducted from the revenues associated with SMO transactions to arrive at the “net revenues” that are shared.

Board Staff Interrogatory #107

Ref: Ex. J1-1-1, Section 3.2, pages 5 - 6

Issue Number: 9.3
Issue: Were the revenues recorded in the forecast variance account earned or foregone; were the costs prudently incurred; and were the revenues and costs accurately recorded as required by section 6(2)1?

Interrogatory

How often is OPG unable to fulfill a segregated mode of operation commitment? What penalties are associated with non-fulfillment?

Response

OPG does not maintain specific statistics on how often it is unable to fulfill a SMO transaction.

Once OPG commits to a Segregated Mode of Operation (SMO) transaction, OPG has exposure to the following risks:

(a) IESO refuses or recalls SMO in accordance with the Market Rules

(b) Switch problems prevent segregation

(c) Interruptions due to other authorities such as the New York Independent System Operator or New England - Independent System Operator

(d) Water conditions

(e) Operational restrictions at Saunders

OPG typically incorporates terms within SMO contracts that protect it from these risks through negotiations with the buyer. However, inclusion of these terms may come at a cost; either through a lower selling price, refusal to accept terms, or lost sales opportunities due to a purchaser's previous curtailment experience. Should OPG fail to fulfill its obligations for reasons not identified in the contract, then OPG would be subject to liquidated damages (i.e. replacement costs) for the volume not delivered.

Board Staff Interrogatory #108

Ref: Ex. J1-T1-S1 and Ex. A2-T1-S1, Appendix A

Issue Number: 9.4
Issue: Are all of the non-capital costs recorded in deferral account established under section 5(4) incurred after January 1, 2005, and associated with either the planned return to service of all of the units at the Pickering A Nuclear Generating Station or units the board of directors of OPG determined should be placed in safe storage?

Interrogatory

Are any OM&A costs in the Pickering deferral account also included in the total OM&A costs for nuclear?

Response

No.

Board Staff Interrogatory #109

Ref: Ex. J1-T1-S1 and Ex. A2-T1-S1, Appendix A

Issue Number: 9.4
Issue: Are all of the non-capital costs recorded in deferral account established under section 5(4) incurred after January 1, 2005, and associated with either the planned return to service of all of the units at the Pickering A Nuclear Generating Station or units the board of directors of OPG determined should be placed in safe storage?

Interrogatory

The 2007 audited financial statement (page 42) states that the net balance in the account as of December 31, 2007 was $183 M (net of accumulated amortization of $125 M). It also states OPG commenced the amortization of the deferral account when Unit 1 of the Pickering A nuclear generating station was returned to service in November 2005. The amortization of $96 M was charged to depreciation and amortization expense in 2007 (2006 – $25 M). In addition, the evidence at J1/T1/S1 indicates that the amortization method used ensures that the opening balance of the account at the end of 2007 excludes costs that were already recovered through interim payments.

a) Section 6 (2) 3 requires amortization of the deferral account balance using the straight line method. How is OPG's proposal to use units-of-production method consistent with the section requirements?

b) The section also requires the Board to ensure recovery "over a period not to exceed 15 years." Notwithstanding OPG's decision to begin amortization of the balance in 2005, please confirm that the 15-year period referred to in the regulation begins at the effective date of the Board's first order under section 78.1 of the Act.

c) Please identify the amount collected and explain how it was collected by the "recovery through interim payments."

d) What were the cost differences, by year, of the costs identified on a "unit of production basis" versus the actual cost recovery through interim payments?

Response

OPG assumes that this interrogatory is referring to page 22 of OPG's 2007 Annual Report rather than page 42.

Exhibit J1-T1-S1, Table 5 and Ex. J1-T2-S1, Table 3 show the PARTS balance remaining at December 31, 2007 as $183.8 M whereas the presentation in the annual report is rounded to $183 M.

a) Section 6(2)3 of the regulation specifies that the balance in the PARTS deferral account should be recovered on a straight line basis over a period not to exceed 15 years. The regulation establishes the requirements for establishing payment amounts. OPG has utilized a straight line method for calculating the rate rider for the test period. As explained in the evidence, OPG used the units of production method to record the recovery of the PARTS deferral account balance during the interim period to ensure that the PARTS account balance accurately reflected the amounts actually recovered through the interim period. This accounting methodology supports the regulatory process as it ensures that only actual costs are recovered as per section 6(2)3.

b) Section 6(2)3 states that in making an order, the Board shall authorize recovery of the balance recorded in the (PARTS) deferral account over a period not to exceed 15 years. OPG has interpreted this to mean that the maximum recovery period is 15 years. OPG is of the view that the recovery period for the PARTS deferral account starts in 2005 because the interim payment amounts, which include an amount for the recovery of the PARTS balance, began at that time. However, OPG acknowledges that the regulation could be interpreted to mean that the recovery period begins with the effective date of the Board's first order in 2008.

c) The amount collected during the interim rate period ending December 31, 2007 is $124.3 M as per Ex. J1-T1-S1, Table 6. For an explanation of how it was collected see response in part a) above and Section 4.1.2 in Ex. J1-T1-S1.

d) There are no differences between the costs calculated on a "units of production basis" and the actual costs recovered through interim payments. The total recovery during the interim rate period is $124.3 M and the yearly recovery is presented in Ex. J1-T1-S1, Table 6.

Board Staff Interrogatory #110

Ref: Ex. J1-T1-S1, page 12

Issue Number: 9.5
Issue: Are the revenue requirement impacts of any change in OPG's nuclear decommissioning liability, arising from an approved reference plan approved after April 1, 2005, accurately recorded in the nuclear liability deferral account established under subsection 5.1(1), as required by section 6(2)7?

Interrogatory

The account includes amounts recorded for interest at six percent on the account's monthly balances, as well as interest at six percent on the debt component of the return on rate base. This appears to be a double counting of interest. Please explain. If it is a double counting, please submit a corrected account.

Response

There is no double counting. The increased asset values of $1,386M at December 31, 2006 associated with the change in OPG's nuclear decommissioning liabilities would have been reflected in OPG's 2007 revenue requirement if OPG were able to adjust its payment amounts to reflect the increase in OPG's assets. O. Reg. 53/05 recognizes this by providing that OPG reflect the return on rate base that it would otherwise have recovered in increased payment amounts during 2007. The six percent interest cost reflects the deferral of the recovery from 2007 to a future period.

Board Staff Interrogatory #111

Ref: Ex. J1-T3-S1, Section 3.1, page 3, lines 9 - 15

Issue Number: 9.7
Issue: What deferral and variance accounts, other than those mandated by Reg. 53/05, should be established for 2008 and 2009?

Interrogatory

OPG proposes to change the carrying costs for the Pickering Deferral Account from an annual rate of 6% (section 5 (5)) to the weighted average cost of capital approved by the Board. Please explain the impact of this proposed change on the projected annual revenue requirement on an annual basis and on a NPV basis accumulated over the projected life of the account?

Response

The impact of applying six percent interest rate versus the proposed weighted average cost of capital ("WACC") is detailed in following table ($M). This analysis assumes that the current cost of service revenue requirement approach continues over the projected life of the account.

Year	6%	WACC[1]	difference
	a	b	b-a
2008	37.4	37.4	0.0
2009	14.2	14.5	0.3
2010	15.1	15.8	0.7
2011	16.0	17.3	1.3
2012	17.1	18.9	1.8
2013	18.2	20.6	2.4
2014	19.3	22.5	3.2
2015	20.6	24.7	4.1
2016	22.0	27.0	5.0
2017	23.6	29.8	6.2
2018	25.4	33.0	7.6
2019	27.7	37.4	9.7
Total	256.6	298.9	42.3
NPV[2]	155.6	176.0	20.4

[1] WACC rates, as per Ex. C. 2008 is 8.48 percent; 2009 is 8.56 percent (assumed 2009 rate for 2010 - 2019)

[2] NPV calculated using a discount rate of 8.56 percent (long term WACC)

Board Staff Interrogatory #112

Ref: Ex. J1-T3-S1, Section 3.1; page 3, lines 9 - 15

Issue Number: 9.7
Issue: What deferral and variance accounts, other than those mandated by Reg. 53/05, should be established for 2008 and 2009?

Interrogatory

OPG proposes (J1/T3/S1 pages 1-2) that the interest rate applicable to all deferral and variance account balances (with the exception of the Pickering A Return to Service Deferral Account OPG for which it proposes to use the weighted average cost of capital) shall be the forecast interest rate applied to OPG's other long-term debt provision. On November 28, 2006, the Board approved a methodology to prescribe an interest rate for the deferral and variance accounts of natural gas and electricity rate-regulated companies (EB-2006-0117). The prescribed interest rate, which is updated quarterly, is equal to the three-month bankers' acceptance rate, as published on the Bank of Canada's website, plus a fixed spread of 25 basis points, effective May 1, 2006 for electricity LDCs.

Effective on the date of the Board's first payment order for OPG, will the company adopt the implementation the Board-prescribed interest rate for existing deferral/variance created by O. Reg. 53/05 (or amended regulations) and any new account(s) approved by the Board? If not, please explain why not?

Response

OPG has proposed interest rates for its deferral/variance accounts that are more reflective of the costs that it will face than the generic interest rate adopted for electricity and gas distribution companies.

OPG's proposal to use a forecast long-term debt rate eliminates forecast bias, keeps OPG whole, is consistent with the longer recovery cycle associated with a test period in excess of one year, and is the easiest for OPG to administer. For deferral/variance accounts that reflect activity that is fundamentally capital in nature, the appropriate carrying charge, in OPG's view, is the weighted average cost of capital in the approved capital structure.

OPG is mindful of the regulatory burden directly associated with regulating the large number of LDCs in the province and the benefits associated with not having to approve a utility-specific capital structure for each LDC. As a result, OPG supported the position in EB-2006-0117 that generic solutions should apply where appropriate, but it believes that a generic solution is not appropriate in this application.

In the current application, OPG's capital structure, capital costs and embedded capital costs are subject to Board review. Unlike many of the LDC's that are regulated on an historic test year, OPG uses a forecast test year. Therefore, the interest rates and return on capital information that OPG proposes to use to determine the carrying charges for deferral and variance accounts will be scrutinized in the course of this review. In OPG's case, there is no regulatory efficiency gained by substituting generic proxy data for utility specific cost forecasts.

Board Staff Interrogatory #113

Ref: Ex. J, Section 3.1; page 3, lines 9 - 15

Issue Number: 9.7
Issue: What deferral and variance accounts, other than those mandated by Reg. 53/05, should be established for 2008 and 2009?

Interrogatory

On November 28, 2006, the Board approved a methodology to prescribe an interest rate for construction work in progress (CWIP) for natural gas and electricity rate-regulated companies (EB-2006-0117). The prescribed interest rate for CWIP is equal to the DEX Mid Term Corporate Bond Index Yield.

Effective on the date of the Board's first payment order for OPG, will the company adopt implementation of the Board-prescribed interest rate for CWIP? If not, please explain why not?

Response

OPG does not believe that the generic CWIP methodology is appropriate for its projects. A better approach would be to use a rate that more accurately reflects the costs that OPG will face. Many of OPG's current and potential future projects will involve large capital expenditures over many years making them more akin to rate base than to the shorter-term projects covered by the generic methodology.

An explanation of why OPG believes the use of its specific interest rate forecast is superior to a generic approach are discussed in L-1-112.

Board Staff Interrogatory #114

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

For income taxes purposes, are capital cost allowance deductions claimed on the fixed asset decommissioning and nuclear waste management provisions? If yes, please provide a breakdown of amounts capitalized and the related depreciation expenses and CCA for 2006, 2007 and forecasted for 2008 and 2009.

Response

No. OPG is not able to claim capital cost allowance deductions on its fixed asset decommissioning and nuclear waste management provisions because regulations pursuant to the *Electricity Act, 1998* do not permit the inclusion of these fixed assets in the undepreciated capital cost ("UCC") of OPG's assets for income tax purposes.

Board Staff Interrogatory #115

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

OPG's application (K1-T1-S2 and K1-T1-S3-Table 1) indicates that the proposed revenue requirement for the 21-month period ended December 31, 2009 has been reduced by $228 million through application of "certain tax losses accumulated over the interim period." At the February 6, 2008 hearing on the issues list, OPG's counsel stated the following in respect of tax losses:

… there actually are not corporate tax losses anymore. They were actually used. But what we have done is, because we understood that the regulated assets were to be treated on a stand-alone basis, we have notionally preserved those tax loss carry-forwards that were attributable to the regulated business, and even though they "corporately" actually don't exist anymore, we are giving the customers of [sic] the benefits of those tax loss carry forwards. [Transcript, February 6, 2008, pp. 38 and 39]

a) Please confirm that OPG does not currently have any tax loss carry forwards that can be applied to reduce PILs payments required in 2008 and later years.

b) If OPG, as the corporate entity that pays PILs, does not have any tax loss carry forwards, does that mean that any tax losses incurred by the prescribed assets in 2005 through 2007 have been used to reduce PILs payments that otherwise would have been made by OPG in those years? If that is correct, how can the benefits of those losses be used twice – once to reduce corporate PILs payments in 2005 through 2007, and again to reduce PILs payments in respect of earnings from the prescribed assets in 2008 and 2009?

Response

a) As at December 31, 2007, OPG, as a corporate entity, has no tax loss carry forwards that can be applied to reduce PILs payments required in 2008 or later years.

b) OPG's prescribed and non-prescribed assets are in the same corporate entity. Therefore, any actual tax losses incurred by the prescribed assets in 2005 through 2007 would automatically offset any actual taxable income generated by the non-prescribed assets and, accordingly, would reduce PILs payments by OPG as a whole. There are no actual corporate tax losses available to reduce PILs payments by OPG, as a single corporate entity, in 2008 or later years. However, as stated by OPG's counsel at the hearing on February 6, 2008 and as noted in Section 4.0, Ex. F3-T2-S1, for the purposes of this Application OPG has calculated regulatory tax losses that have been generated by the prescribed assets on a stand-alone basis since April 1, 2005. These losses are used to reduce OPG's regulatory taxes as part of the proposed revenue requirement calculation for the benefit of the ratepayers through lower payment amounts in 2008 and 2009. The application of these losses to reduce OPG's revenue requirement for the test period has no direct impact on the actual amount of PILs payments that will be required in 2008 and later years by OPG as a corporate entity.

Board Staff Interrogatory #116

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

Starting April 1, 2005, OPG began accounting for income taxes (PILs) related to the prescribed assets using the taxes payable method, rather than the liability method that is required to be used by most commercial companies. Per Note 11 (page 36) of OPG's 2007 financial statements, it appears that had the company followed the liability method of accounting, its December 31, 2007 balance sheet would have included an additional future tax liability of $436 million (the difference between a $205 million liability as shown in the financial statements and a $641 million liability that would have been booked had the liability method been adopted).

a) Given that OPG's prescribed assets were not subject to regulation by the OEB in 2005, 2006, and 2007, please explain the rationale for following the taxes payable method in those years.

b) The unrecorded future income liability of $436 million referred to in the preamble to this question presumably will turn into a real PILs liability in future periods as the temporary differences between book and tax deductions start to reverse. Is OPG proposing that those taxes be included in future payment amounts for the prescribed assets approved by the Board? If so, please explain why is it appropriate for electricity consumers in future periods to pay for a tax liability that OPG chose not to recognize in 2005, 2006, and 2007?

Response

a) Although OPG's prescribed assets were not regulated by the OEB during 2005, 2006 and 2007, OPG considers that they were regulated assets under the terms of O. Reg. 53/05.

In the information provided to the Province for its use in setting the payment amounts during 2005, 2006 and 2007, OPG used the taxes payable method and therefore did not include future income tax expense in the submission. This approach was consistent with the treatment that OPG expected the OEB to adopt when the Board assumed authority to regulate OPG in 2008. The use of the taxes payable method was endorsed by CIBC World Markets, the advisors hired by the Province to assist it with setting the interim payment amounts.

OPG notes that the use of the taxes payable method is consistent with established OEB regulatory principles for regulated gas utilities as well as the guidance set out in the OEB's Electricity Distributors Rate Handbook.

Accordingly, OPG is of the view that upon becoming subject to regulation by the OEB, future income taxes not recovered through payment amounts established by O. Reg. 53/05 will be recovered through payment amounts established by the OEB (once these future income taxes translate into PILs through reversal of temporary differences).

In addition, OPG notes that the Canadian Institute of Chartered Accountants ("CICA") Handbook ("HB") Section 3465, Income Taxes, paragraph 102 states that: "A rate-regulated enterprise need not recognize future income taxes in accordance with this Section to the extent that future income taxes are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers…"

In accordance with the above paragraph, OPG elected to follow, for financial reporting purposes, the taxes payable method for its regulated operations effective April 1, 2005 and therefore has not recognized future income taxes during 2005, 2006 and 2007 to the extent that such future taxes are expected to be included in future regulated prices.

OPG made this election because OPG became a rate-regulated enterprise on April 1, 2005 as defined by Canadian Generally Accepted Accounting Principles ("GAAP") in CICA HB Section 1100, Generally Accepted Accounting Principles, paragraph 36.

b) Yes, OPG is proposing that these taxes be recovered in future payment amounts set by the Board. OPG's proposal is consistent with OEB practice as well as the application of the intergenerational equity principle in the OEB Electricity Distributors Rate Handbook that requires recovery of income taxes in the period they are actually incurred rather than when they are recognized as a future income tax expense for accounting purposes. As noted above, OPG did not include future income taxes in the information provided to the Province for the determination of payment amounts under O. Reg. 53/05. Therefore, OPG should be entitled to the recovery of the actual PILs related to these future income taxes that were not recovered during the period from April 1, 2005 to the effective date of the OEB's first order.

OPG's proposal is also consistent with OPG's view that ratepayers are entitled to the benefit of regulatory income tax losses generated by the regulated operations since April 1, 2005, as discussed in Ex. F3-T2-S1. The amount of the regulatory tax losses generated during the period from April 1, 2005 to December 31, 2007 is $990.2M (Table 9, Ex. F3-T2-S1), which translates into an approximate benefit to consumers of $312M (at the tax rate of 31.50 percent, which is in effect for 2008). OPG also notes that the entire benefit of these tax losses is being credited to consumers over the current 21-month test period (Ex. K1-T1-S2), whereas the temporary differences cited in the interrogatory will likely reverse over a significantly longer period of time.

Board Staff Interrogatory #117

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

Ref: F3/T2/S1/Table 8

Please provide a copy of the actual 2006 T2 and CT 23 tax returns and supporting schedules for Ontario Power Generation Inc. From the 2006 tax returns, provide the following information:

a) Please identify any non-rate regulated corporate activities within OPG.

b) Please provide an Excel spreadsheet that shows OPG's 2006 tax return data from the T2 federal Sch1 allocated between regulated and non-regulated business segments. The first section should show the total OPG tax return data and then the split between regulated and non-regulated (please see schedule below).

c) Please provide a schedule for the calculation of Ontario 2006 CT 23 taxable income and income tax PILs allocated between regulated and non-regulated as described above for the T2 return (please see schedule below).

d) Please allocate the federal T2 Sch8 (Undepreciated Capital Cost and Capital Cost Allowance) amounts between regulated and non-regulated for each column, and for each tax class shown on the Sch8.

e) Please provide an Excel spreadsheet that allocates the Ontario capital tax as filed in the 2006 CT 23 return between regulated and non-regulated.

f) Please provide an analysis for the 2006 Cumulative Eligible Capital (CEC) and the deductions claimed.

No.	**Per tax return**	**Non-Rate Regulated**	**Rate Regulated**

Response

As explained further below, OPG declines to provide the requested tax returns because it does not consider them to be relevant to the determination of payment amounts for the test period and the returns themselves are currently the subject of amendment. OPG does not believe that reviewing the requested information in hearing context would be a good use of the Board's time given the complexity of the information. If the Board was to determine that the information is relevant, then OPG would request that the information be treated as confidential.

A review of the income tax returns would not be very helpful to the setting of payment amounts for the regulated assets because these returns are prepared on a corporate basis that does not distinguish between regulated and unregulated operations. The work to allocate the data in the returns between regulated and unregulated businesses would be involved and would produce a result that would still require a complex reconciliation to make it comparable to the stand-alone tax information filed in the Application. Secondly, OPG files a number of T2 and CT23 tax returns because it is comprised of several legal entities (not established on the basis of whether they form part of regulated or unregulated operations). This additional complexity would further diminish the usefulness of the information.

The requested information is not needed because OPG has already provided the relevant tax information, including a detailed computation of regulatory taxable income/loss for 2005 - 2009 for its regulated operations on a stand-alone basis specifically for the purposes of establishing payment amounts, as shown in Ex. F3-T2-S1, Tables 7 and 8. OPG has also provided evidence on the significant tax adjustments to regulatory earnings before tax presented in these tables (e.g., depreciation, pension and OPEB/SPP accrual, contributions to nuclear segregated funds), including audited consolidated financial statements appended in Appendix A of Ex. A2-T1-S1. In addition, support for the CCA deduction for regulatory tax purposes is provided in part (d) below. In order to support the amount of regulatory earnings before tax used in the computation of regulatory taxable income/loss, OPG also provides a reconciliation of regulatory earnings before tax for 2005 - 2007 to earnings for the regulated operations per OPG's annual audited consolidated financial statements in Table 1, Ex. C1-T2-S1.

Further, as discussed in Section 4.0 of Ex. F3-T2-S1, OPG is undergoing a tax audit for the 1999 taxation year by the Provincial Tax Auditors (the "auditors"). A number of issues identified by the auditors are now expected to be resolved and this will result in the amendment of OPG's tax returns for all years back to 1999. Therefore, the review of OPG's T2 and CT23 tax returns as currently filed would not be useful. The expected audit adjustments have already been incorporated in the calculation of regulatory income taxes for the purposes of this Application. OPG also notes that the remaining uncertainty surrounding the 1999 tax audit and the audits of future years is one of the reasons underlying OPG's proposal for the Changes in Taxation Rate or Rules Variance Account (Ex. J1-T3-S1).

Unregulated operations represent a significant portion of OPG's total operations and financial results. Therefore, OPG is concerned that the financial information for the company as a whole found in its T2 and CT23 tax returns and supporting schedules should remain confidential, if they are found to be relevant. OPG is particularly concerned in this regard because OPG's unregulated operations operate in a single line of business (i.e., not as a portfolio of different lines of business) and they operate in the same line of business as OPG's regulated operations.

(a) A discussion of non-rate regulated corporate activities within OPG is provided at Ex. A1-T4-S1 and in the OPG Annual Reports provided at Ex. A2-T1-S1.

(b) Please refer to the discussion above.

(c) Please refer to the discussion above.

(d) Please refer to the discussion above. OPG's CCA deduction is presented in Ex. F3-T2-S1, Table 8. Attached is a schedule that details the UCC balances and CCA claims, by CCA class, for each of the years 2005 - 2009 (refer to Appendix A to this response).

(e) OPG has calculated Ontario capital taxes using a regulatory approach for the purposes of the calculating the revenue requirement (refer to Ex. F3-T2-S1, Tables 2 and 5 and Ex. G2-T2-S1, Table 4). The calculation is based on capital tax rates applied to the rate base in excess of the general capital tax deduction, as noted in Section 5.0 of Ex. F3-T2-S1. The amount of capital tax calculated per actual CT23 returns is done on a different basis and is therefore not relevant to the determination of OPG's payment amounts.

(f) The calculations of regulatory taxable income/loss for 2005 - 2009 for OPG's regulatory operations provided in Ex. F3-T2-S1, Tables 7 and 8 do not include any deductions related to CEC. Therefore, the analysis requested is not relevant to the determination of OPG's payment amounts for its regulated operations.

APPENDIX A

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations (2005)

Class	Undepreciated capital cost at beginning of year	Cost of Acquisitions	Net Adjustments	Proceeds of dispositions	50% rule	Reduced undepreciated capital cost	CCA rate	Recapture/ Terminal loss	Capital cost allowance	Undepreciated capital cost at end of year
1	1,059,412,477	235,581,914	-	11,260,548	112,160,683	1,171,573,160	4%	-	46,862,926	1,236,870,917
2	1,944,010,195	-	-	-	-	1,944,010,195	6%	-	116,640,612	1,827,369,584
3	1,212,718	-	-	1,212,718	-	-	5%	-	-	-
8	345,199,432	73,575,446	-	610,530	36,482,458	381,681,890	20%	-	76,336,378	341,827,970
10	63,327,098	24,811,645	-	20,836,970	11,670,769	55,631,004	30%	-	16,689,301	50,612,472
12	3,187,565	1,835,974	-	-	917,987	4,105,552	100%	-	4,105,552	917,987
17	386,541,028	234,441,392	-	13,736	117,213,828	503,754,856	8%	-	40,300,388	580,668,295
42	576,268	-	-	-	-	576,268	12%	-	69,152	507,115
45	3,684,090	8,395,838	-	-	4,197,919	7,882,009	45%	-	3,546,904	8,533,024
	3,807,150,871	578,642,209	-	33,934,502	282,643,644	4,069,214,934		-	304,551,214	4,047,307,363
						CCA adjustment			12,000,000	*
									316,551,214	

* Represents the difference between CCA claim estimated for evidence filing on March 14, 2008 and CCA claim after finalization of tax audit adjustments

APPENDIX A

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations (2006)

Class	Undepreciated capital cost at beginning of year	Cost of Acquisitions	Net Adjustments	Proceeds of dispositions	50% rule	Reduced undepreciated capital cost	CCA rate	Recapture/ Terminal loss	Capital cost allowance	Undepreciated capital cost at end of year
1	1,236,870,917	66,173,401	1,928,966	-	33,086,701	1,271,886,583	4%	-	50,875,463	1,254,097,820
2	1,827,369,584	-	-	74,401	-	1,827,295,183	6%	-	109,637,711	1,717,657,472
3	-	-	-	133,968	-	(133,968)	5%	-	(6,698)	(127,270)
8	341,827,970	54,668,739	(1,779,289)	1,873,230	26,398,053	366,446,137	20%	-	73,289,227	319,554,963
10	50,612,472	4,911,628	1,950,279	155,586	2,394,253	54,924,540	30%	-	16,477,362	40,841,431
12	917,987	255,703	-	-	127,852	1,045,839	100%	-	1,045,839	127,852
17	580,668,295	13,865,367	(1,928,966)	576,096	7,132,966	584,895,635	8%	-	46,791,651	545,236,950
38	-	70,418,223	-	-	35,209,112	35,209,112	30%	-	10,562,733	59,855,490
42	507,115	-	-	-	-	507,115	12%	-	60,854	446,262
45	8,533,024	1,950,831	(170,990)	-	975,416	9,337,449	45%	-	4,201,852	6,111,013
	4,047,307,363	212,243,892	-	2,813,281	105,324,350	4,151,413,624		-	312,935,994	3,943,801,980
						CCA adjustment			5,000,000 *	
									317,935,994	

* Represents the difference between CCA claim estimated for evidence filing on March 14, 2008 and CCA claim after finalization of tax audit adjustments

APPENDIX A

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations (2007)

Class	Undepreciated capital cost at beginning of year	Cost of Acquisitions	Net Adjustments	Proceeds of dispositions	50% rule	Reduced undepreciated capital cost	CCA rate	Recapture/ Terminal loss	Capital cost allowance	Undepreciated capital cost at end of year
1	1,254,097,820	134,706,834	98,914	3,599	36,851,618	1,352,048,352	4%	-	54,081,934	1,334,818,035
1.1	-	906,624	-	-	453,312	453,312	6%	-	27,199	879,425
2	1,717,657,472	-	-	34,530	-	1,717,622,942	6%	-	103,057,376	1,614,565,565
3	(127,270)	-	-	-	-	(127,270)	5%	-	(6,363)	(120,906)
8	319,554,963	23,877,828	(126,570)	755,656	11,561,086	330,989,479	20%	-	66,197,896	276,352,669
10	40,841,431	3,436,439	275,807	106,450	1,664,995	42,782,232	30%	-	12,834,670	31,612,557
12	127,852	12,479,362	-	-	6,239,681	6,367,533	100%	-	6,367,533	6,239,681
17	545,236,950	110,941,671	-	14,845	55,463,413	600,700,363	8%	-	48,056,029	608,107,747
38	59,855,490	-	-	-	-	59,855,490	30%	-	17,956,647	41,898,843
42	446,262	-	-	-	-	446,262	12%	-	53,551	392,710
45	6,111,013	324,299	4,795	-	162,150	6,277,957	45%	-	2,825,081	3,615,026
45.1	-	1,274,247	-	-	637,124	637,124	55%		350,418	923,829
	3,943,801,980	287,947,304	252,946	915,080	113,033,377	4,118,053,773		-	311,801,970	3,919,285,181
						CCA adjustment			4,000,000 *	
									315,801,970	

* Represents the difference between CCA claim estimated for evidence filing on March 14, 2008 and CCA claim after finalization of tax audit adjustments

APPENDIX A

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations (2008)

Class	Undepreciated capital cost at beginning of year	Cost of Acquisitions	Net Adjustments	Proceeds of dispositions	50% rule	Reduced undepreciated capital cost	CCA rate	Recapture/ Terminal loss	Capital cost allowance	Undepreciated capital cost at end of year
1	1,334,818,035	186,098,000			93,049,000	1,427,867,035	4%	-	57,114,681	1,463,801,354
1-rolling start	-	129,000,000				129,000,000	4%	-	5,160,000	123,840,000
1.1	879,425	-	-	-	-	879,425	6%	-	52,766	826,660
2	1,614,565,565	-			-	1,614,565,565	6%	-	96,873,934	1,517,691,631
3	(120,906)	-			-	(120,906)	5%	-	(6,045)	(114,861)
8	276,352,669	44,568,000			22,284,000	298,636,669	20%	-	59,727,334	261,193,335
10	31,612,557	17,862,000			8,931,000	40,543,557	30%	-	12,163,067	37,311,490
12	6,239,681	9,388,000			4,694,000	10,933,681	100%	-	10,933,681	4,694,000
17	608,107,747	60,084,000			30,042,000	638,149,747	8%	-	51,051,980	617,139,767
38	41,898,843				-	41,898,843	30%	-	12,569,653	29,329,190
42	392,710				-	392,710	12%	-	47,125	345,585
45	3,615,026	14,000,000			7,000,000	10,615,026	45%	-	4,776,762	12,838,264
45.1	923,829	-	-	-	-	923,829	55%		508,106	415,723
	3,919,285,181	461,000,000	-	-	166,000,000	4,214,285,181		-	310,973,043	4,069,312,138
						CCA adjustment			- *	
									310,973,043	

* Represents the difference between CCA claim estimated for evidence filing on March 14, 2008 and CCA claim after finalization of tax audit adjustments

APPENDIX A

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations (2009)

Class	Undepreciated capital cost at beginning of year	Cost of Acquisitions	Net Adjustments	Proceeds of dispositions	50% rule	Reduced undepreciated capital cost	CCA rate	Recapture/ Terminal loss	Capital cost allowance	Undepreciated capital cost at end of year
1	1,463,801,354	141,367,000			70,683,500	1,534,484,854	4%	-	61,379,394	1,543,788,960
1-rolling start	123,840,000	61,000,000				184,840,000	4%	-	7,393,600	177,446,400
1.1	826,660	-	-	-	-	826,660	6%	-	49,600	777,060
2	1,517,691,631	-			-	1,517,691,631	6%	-	91,061,498	1,426,630,133
3	(114,861)	-			-	(114,861)	5%	-	(5,743)	(109,118)
8	261,193,335	46,152,000			23,076,000	284,269,335	20%	-	56,853,867	250,491,468
10	37,311,490	13,983,000			6,991,500	44,302,990	30%	-	13,290,897	38,003,593
12	4,694,000	15,642,000			7,821,000	12,515,000	100%	-	12,515,000	7,821,000
17	617,139,767	62,856,000			31,428,000	648,567,767	8%	-	51,885,421	628,110,346
38	29,329,190	-			-	29,329,190	30%	-	8,798,757	20,530,433
42	345,585	-			-	345,585	12%	-	41,470	304,115
45	12,838,264	14,000,000			7,000,000	19,838,264	45%	-	8,927,219	17,911,045
45.1	415,723	-	-	-	-	415,723	55%		228,648	187,075
	4,069,312,138	355,000,000	-	-	147,000,000	4,277,312,138		-	312,419,628	4,111,892,510
						CCA adjustment			2,000,000 *	
									314,419,628	

* Represents the difference between CCA claim estimated for evidence filing on March 14, 2008 and CCA claim after finalization of tax audit adjustments

Board Staff Interrogatory #118

Ref: Ex. K

Issue Number: 10.1
Issue: Are regulatory income and capital taxes appropriately determined in accordance with regulatory and tax legislation requirements?

Interrogatory

Ref: F3/T2/S1/Table 8

Please provide a tax forecast for 2007, 2008 and 2009 for the rate-regulated business segments using the 2006 tax information (T2, S1 and S8, etc.) as the format and starting point. Note that the federal income tax rate was reduced for 2008 and 2009 from the rates shown at F3/T2/S1/Table 7.

Response

For the reasons cited in L-1-117, OPG declines to provide the requested tax forecasts. If this information was required to be provided, OPG would request that the information be treated as confidential since the corporate data reflected in OPG's tax returns is considered to be commercially sensitive.

OPG has provided in its evidence a detailed computation of regulatory taxable income/loss for 2007 - 2009 for its regulated operations on a stand-alone basis specifically for the purposes of establishing payment amounts. This can be found at Ex. F3-T2-S1, Table 7. Evidence is also provided with respect to the significant tax adjustments to regulatory earnings before tax presented in these tables (e.g., depreciation, pension and OPEB/SPP accrual, contributions to nuclear segregated funds). In addition, support for the CCA regulatory tax deduction for 2007 - 2009 is provided in interrogatory L-1-117 (d). Finally, OPG provides a reconciliation of regulatory earnings before tax for 2007 to earnings for the regulated operations per OPG's annual audited consolidated financial statements in Table 1, Ex. C1-T2-S1.

OPG's updated pre-filed evidence dated March 14, 2008 (Ex. F3-T2-S1, Table 7) incorporates the reduced federal income tax rates of 31.50 percent and 31.00 percent for 2008 and 2009, respectively, based on the federal "Economic Statement" presented on October 30, 2007 and substantially enacted on December 13, 2007 when Bill C-28 passed the third reading in the House of Commons.

Board Staff Interrogatory #119

Ref: Ex. K1-T1-S2, page 1, lines 7-23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

OPG proposes to use its accumulated income tax losses to mitigate the increase in payment amounts by reducing the revenue requirements. OPG's application applies these tax losses so that there is a consistent payment amount increase across the two generation technologies.

a) Could these tax losses be applied differently to reduce one revenue requirement proportionally more than the other? Has OPG investigated alternative allocations?

b) If these tax losses were allocated to the two revenue requirements in a different manner would there be substantial differences in the mitigation impacts?

Response

a) The tax losses could be applied differently. OPG applied the tax losses to equalize the percentage rate increase for each technology. OPG has not investigated any alternative allocations.

b) Whether or not there would be substantial difference in mitigation impacts would depend on the manner in which the tax losses were allocated between the two technologies. The mitigation of the combined revenue requirement would still be the same, although the payment amounts for the two technologies would be different than those set out in OPG's application.

Board Staff Interrogatory #120

Ref: Ex. K1-T1-S2, page 1, lines 7 - 23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

In the reconciliation of financial to regulatory accounting income for 2006, please explain why Incentive Revenue at Market Price and Interest Expense on Regulatory Assets were deducted in the determination of regulatory earnings before taxes. (C1/T2/S1/Table 1)

Response

Accounting revenue and EBIT for the prescribed hydroelectric facilities includes revenue at market price for production above 1900MWh in any hour. OPG's current payment amount of $33/MWh was calculated as the total forecast cost of regulated hydroelectric operations (including a return on equity) divided by total production. OPG's regulatory earnings before taxes is determined on the same basis. Therefore the incentive revenue is removed from accounting EBIT and replaced with the revenue for the equivalent amount of production at current payment amounts.

Accounting EBIT is a before - interest income. In order to calculate regulatory ROE, which is an after-interest quantity, it is necessary to remove interest associated with the regulatory assets. This is done using the same capital structure used in the determination of the interim payment amounts.

Board Staff Interrogatory #121

Ref: Ex. K1-T1-S2, page 1, lines 7-23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

Please provide a non-capital loss carry-forward continuity schedule for income tax purposes on company-wide basis, allocated to the prescribed assets showing the origination of losses by year and their application to other years' taxable income. (F3/T2/S/Table 9)

Response

OPG has provided a continuity schedule of regulatory tax loss carry-forwards for the period 2005 to 2009 for its regulated operations for the purposes of establishing payment amounts in Table 9 Ex. F3-T2-S1.

There were no actual tax losses generated by the unregulated operations during 2005-2007, as noted in the response to interrogatory L-1-122. In addition, as noted in the response to interrogatory L-1-115(a), OPG does not have any actual tax loss carry-forward amounts available at the end of 2007 on a company-wide basis. OPG also does not expect to incur actual tax losses during the test period on a company-wide basis.

Information related to tax losses, if any, incurred by OPG prior to 2005 is not relevant for the determination of payment amounts for OPG's regulated operations.

Board Staff Interrogatory #122

Ref: Ex. K1-T1-S2, page 1, lines 7 - 23

Issue Number: 10.2
Issue: Is the proposed treatment of OPG's loss carry forwards for the regulated business appropriate?

Interrogatory

Are losses arising from the non-regulated business segments in prior years being proposed to reduce/eliminate regulatory taxable income of the regulated business segments in 2008 and 2009? If so, provide the breakdown of these amounts being applied and the rationale for this treatment.

Response

There were no tax losses generated by the non-regulated business segments during 2005-2007.

Board Staff Interrogatory #123

Ref: Ex. K1-T1-S1, page 1, lines 16-30

Issue Number: 10.3
Issue: Are OPG's methods for removing Q1 2008 costs, revenues and production appropriate?

Interrogatory

To adjust for the first quarter of 2008, OPG pro-rates costs, revenue and production based on causal factors and not a straight line 25%. OPG's discussion of these causal factors does not include any statistical or trend analysis. Please provide the supporting analysis for this allocation.

Response

OPG prepared an analysis of historical budget and actual costs for 2005 and 2006 for nuclear and corporate groups to assess differences from a "straight line" 25% allocation. The analysis indicated that the actual patterns could vary significantly from a 25% allocation.

The referenced analysis, shown in Attachment 1, identifies the split between Q1 and Q2 - Q4 expenditures, by major OM&A category, for budget and actual expenditures in 2005 and 2006. It confirmed that while base expenditures are relatively linear, project and outage expenditures can vary considerably. Regulated hydro was excluded from the analysis given that outage and project expenditures play a much smaller role in the variability relative to nuclear expenditures.

As a result, OPG elected to implement a more rigorous approach to estimating the Q1 expenditures. For OM&A expenditures for nuclear, regulated hydro and allocated corporate, monthly budget values were used, which captured the variation in proposed outage and project expenditures, and resulted in 24% of annual expenditures being attributed to Q1.

Attachment 2 provides details on the basis of the allocation to Q1 of each revenue requirement component used in the updated evidence. Although regulated hydro was excluded from the original analysis as shown in Attachment 1, the same allocation approach was applied to regulated hydro to ensure a consistent approach across all groups.

Attachment 1

OM&A Trending ($M)

	2005 Actual					2005 Budget				
	Jan - Mar		Apr - Dec		Total	Jan - Mar		Apr - Dec		Total
Nuclear										
Base	237	*24%*	738	*76%*	975	247	*25%*	725	*75%*	972
Planned Outage	61	*28%*	159	*72%*	220	54	*24%*	173	*76%*	227
Projects	26	*17%*	130	*83%*	156	39	*25%*	116	*75%*	154
Contingency	0		0		0	14	*25%*	41	*75%*	55
Total	**324**	***24%***	**1,027**	***76%***	**1,351**	**354**	***25%***	**1,055**	***75%***	**1,409**
Corporate Support groups	**98**	***25%***	**288**	***75%***	**386**	**107**	***25%***	**322**	***75%***	**429**

	2006 Actual					2006 Budget				
	Jan - Mar		Apr - Dec		Total	Jan - Mar		Apr - Dec		Total
Nuclear										
Base	260	*25%*	792	*75%*	1,051	256	*24%*	807	*76%*	1,063
Planned Outage	50	*19%*	216	*81%*	266	59	*24%*	185	*76%*	244
Projects	27	*19%*	115	*81%*	142	35	*24%*	112	*76%*	147
Contingency	0		0		0	7	*19%*	32	*81%*	39
Total	**337**	***23%***	**1,122**	***77%***	**1,459**	**357**	***24%***	**1,137**	***76%***	**1,494**
Corporate Support groups	**97**	***25%***	**287**	***75%***	**384**	**106**	***25%***	**319**	***75%***	**425**

Attachment 2

Cost/Revenue Element	Primary Driver(s) of Attribution	Changes Compared to a simple 25% split
Ancillary Revenues	25% of annual	None
Bruce Lease Revenues	25% of annual	None
Nuclear OM&A base	Nuclear monthly budget	23% of costs in Q1
Nuclear OM&A outage	Nuclear monthly budget	28% of costs in Q1
Nuclear OM&A project	Nuclear monthly budget	22% of costs in Q1
		24% weighted average
Hydro OM&A base	Hydro monthly budget	23% of costs in Q1
Hydro OM&A project	Hydro monthly budget	16% of costs in Q1
		22% weighted average
Nuclear Fuel	Monthly Energy Plan	23% of fuel costs in Q1 - reflects forecast generation for Q1
Hydro GRC	Monthly Energy Plan & Graduated Rates (See Ex F1-T4-S1)	21% of GRC costs in Q1 - reflects forecast generation for Q1 and graduated rates of the property tax component charge of GRC
Depreciation & Amortization	25% of i/s depreciation + i/s additions by quarter	Depreciation grows throughout the year, therefore Q1<25% of annual
Property Tax	25% of annual	None
Financing Return on Equity Capital Tax	Rate base	Rate base declines (slightly) during 2008 due to depreciation; therefore Q1>25% of annual