SCHOOL ENERGY COALITION

CROSS-EXAMINATION MATERIALS

OPG PANEL 4

SEC Interrogatory #024

Ref: Ex. F2-T4-S1, page 5
Ex. F2-T4-S1, Table 1

Issue Number: 6.3
Issue: Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

Interrogatory

a) Please provide a table showing for 2007 through 2012 the costs of the Outage Improvement Strategy, the number of planned outages, the expected outage costs and the expected outage costs without implementation of the Outage Improvement Strategy.

b) Please provide the cost-benefit analysis that was undertaken for this initiative.

Response

a) Please see the table below:

Outage OM&A - Nuclear ($M)

	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Outage Improvement Strategy OM&A Costs (includes training costs)	-	-	-	$2.1	$1.8	$1.9
Number of Planned Outages	6	3	7	9	4	4
Outage Costs	$208.8	$191.1	$246.8	$267.8	$210.1	$196.9
Net Savings from Outage Improvement Strategy (includes training costs)	-	-	-	$1.7	$5.9	$7.9
Expected Outage Costs without implementation of the Outage Improvement Strategy	-	-	-	$269.5	$216.0	$204.8

b) Attachment 1 contains the preliminary cost benefit analysis for the 2009 Outage Improvement Strategy Initiatives that was developed for the 2010 - 2014 Business Plan. Further refinements to this cost benefit analysis are anticipated. Consistent with ScottMadden's recommendation at Ex. F5-T1-S2, page 34 and discussed at Ex. L-14-016, OPG will be encouraging the functional/peer teams to refine and improve their initiatives throughout the remainder of the planning cycle and into implementation.

Attachment 4

Forecast for Major Unforeseen Events

This attachment describes the derivation and rationale for the 2.0 TWh forecast for major unforeseen events described in section 3.5.

On average from 2005 to 2008, OPG's actual nuclear production has been less than the approved business plan forecast by approximately 3.5 TWh. An analysis undertaken in 2009 revealed that these unplanned variances were largely the result of high forced loss rates due to major unforeseen events (2.05 TWh, on average) and forced extensions to planned outages (1.19 TWh, on average) (Table 1). Examples of major unforeseen events include losses due to feeder thinning (2005); the inter-station transfer bus issue (2007); the resin release issue (2007) and calandria tube deterioration (2008).

Table 1

Average TWh Variance to Business Plan, 2005 to 2008

Station	Planned Outage Variances	Forced Losses		Forced Extension to Planned Outages		Other Losses[1]	Total Average Variance
		Major Unforeseen Events	Balance	Major Unforeseen	Balance		
Pickering A	0.41	-1.18	-0.51	0.00	-0.27	0.04	-1.51
Pickering B	0.11	-0.87	-0.05	-0.09	-0.64	-0.17	-1.71
Darlington	-0.12	0.00	0.54	0.00	-0.28	-0.45	-0.30
Total Fleet	0.39	-2.05	-0.02	-0.09	-1.19	-0.57	-3.52

A forecast for major unforeseen events was not included in the nuclear generation forecast presented in EB-2007-0905. For the 2010 - 2014 Business Plan, a forecast of generation

[1] Other losses are comprised of grid losses, net lake losses and consumption (i.e. station operating and outage)

losses due to major unforeseen events has been included in the nuclear production forecast. This reflects OPG's recent actual experience as well as OPG's expectation that there will be future production losses due to these major unforeseen events. The average amount (2.0 TWh) incurred over the last 4 years is considered a realistic projection of the expected losses.

The adjustment to the nuclear production forecast of 2 TWh for major unforeseen events results in a more accurate and reasonable production forecast for OPG.

PRODUCTION FORECAST AND METHODOLOGY – NUCLEAR

1.0 PURPOSE

This evidence provides a description of the methodology used to forecast nuclear production, and presents the nuclear production forecast for 2011 - 2012.

2.0 OVERVIEW

OPG is seeking approval of a production forecast of 98.9 TWh for the 2011 - 2012 test period for the nuclear facilities, which is an improvement of 3.9 TWh over the actual production achieved during 2008 - 2009.

OPG operates its nuclear generating stations in compliance with all applicable regulations, requisite licences and approvals in a safe, efficient, and cost effective manner. OPG, in accordance with its Nuclear Safety Policy, conservatively implements unit shutdowns in all circumstances when, in OPG's assessment, the safe operation of the station could be at risk.

Section 3.0 provides a description of the nuclear production planning process which produces an integrated nuclear outage and generation plan ("Integrated Plan"). Section 4.0 presents the nuclear production forecast trend for 2007 - 2012 and describes the key factors impacting each year's production forecast.

During the test period, OPG forecasts improved production performance across its entire nuclear fleet, as a result of a reduction in the number of planned outage days and improvements in forced loss rate ("FLR") at Pickering A and B.

3.0 NUCLEAR PRODUCTION PLANNING PROCESS

3.1 Integrated Nuclear Outage and Generation Plan

Through the nuclear production planning process, OPG seeks to establish accurate and reliable annual production forecasts for its individual nuclear units and an aggregated forecast for each station. Nuclear facilities are designed as base load generators; meaning generator output is not intended to vary with market demand. Therefore, the annual nuclear production forecast is equal to the sum of the generating units' capacity multiplied by the number of hours in a year, less the number of hours for planned outages or forced production losses (i.e., unplanned outages and derates). As such, the production planning process is focused on establishing annual planned outage schedules, in accordance with established outage scheduling guidelines, and on estimating forced production losses.

OPG is a member of the World Association of Nuclear Operators ("WANO") and uses WANO performance indicators to plan, track and assess the performance of its nuclear units. For the purpose of this evidence, forced production losses and planned outages are defined as per WANO (see Attachment 1). Phase 1 of the ScottMadden Report (see Ex. F5-T1-S1) provides additional background on standard industry benchmarks used to plan and track nuclear generation performance.

The objectives of the production planning process are to:

- Provide a key input into the annual OPG business planning process.
- Ensure availability and optimal deployment of the internal and external resources needed to execute the inspection, modification, and maintenance programs.
- Provide long-term operational plans to allow coordination of nuclear outages across OPG so that reactor outages are planned to occur in periods that have minimal impact on the Ontario electrical grid.
- Comply with the IESO Market Rules by providing information on OPG's nuclear production, capacity, and reliability assumptions.

The nuclear production planning process generates an annual Integrated Plan, with the following deliverables:

- A five-year planned outage schedule for all stations that includes unit outage start dates, end dates, and durations.
- A summary of major elements comprising the scope of work that will be executed during each outage, with a higher level of specificity for scope elements occurring in outages during the first two years of the Integrated Plan.

- Operational reliability performance targets such as unit capability factor and the level of targeted forced production losses represented by the forced loss rate ("FLR"). The process for setting these performance targets is discussed at Ex. F2-T1-S1.
- Outage resource requirements and cost estimates for inclusion in the outage OM&A budget. Further discussion of the outage OM&A forecast can be found at Ex. F2-T4-S1.
- Five-year generation forecasts in terawatt-hours ("TWh") for individual nuclear units and an aggregated forecast for each station.

3.2 Generation Planning Methodology

The outage and generation planning process mandates three formal planning and review sessions over a 12-month period, culminating in a final Integrated Plan. The process reflects the dynamic nature of outage planning and ensures that all regulatory, operational or maintenance issues that have arisen since the prior period are incorporated into the plan, including:

- "Lessons learned" from recent OPG outages, internal operating experience, emergent discovery work, or short-term updates to life cycle management programs.
- Operating experience from others in the nuclear industry.
- Unanticipated regulatory orders/decisions/requirements (e.g., Canadian Nuclear Safety Commission, ("CNSC") Technical Standards and Safety Authority), or a failure to obtain regulatory concurrence for plans, such that OPG must undertake unanticipated work activities.

The timing of the three planning and review sessions is as follows:

- In the late fall, the then current five-year Integrated Plan is reviewed and material updates, if any, to the outage schedule are identified.
- In the spring, the first draft of the new Integrated Plan is produced and any material updates to the current outage schedule are identified.
- In the summer, the final Integrated Plan is produced. It is incorporated into the OPG Nuclear business plan which is approved by the Chief Nuclear Officer ("CNO") and then

submitted as part of OPG's business planning process (see Ex. A2-T2-S1 for a discussion of the corporate business planning process).

As noted by ScottMadden (see Ex. F5-T1-S2 page 16), the gap-based business planning process introduced in 2009 as part of the Phase 2 Nuclear Benchmarking Initiative was overlaid on the nuclear planning process already underway. The final Integrated Plan generated in the summer of 2009 and used in the 2010 - 2014 nuclear business plan therefore reflects the combination of the "bottom-up" analysis from the draft Integrated Plan prepared in the spring and the performance targets (i.e., forced loss rate and unit capacity factor) generated during the gap-based, top down, target setting process. Further discussion of the process by which target setting impacted the development of the final Integrated Plan can be found in section 3.2.1.2.

In addition to the three formal planning and review sessions, non-routine meetings are also convened when developments in program assumptions or outage schedules need to be addressed. On limited occasions, significant developments may necessitate updates to the current outage schedule, if they impact the immediate two year outage planning horizon.

The final Integrated Plan and all non-routine updates are approved by the CNO.

At each stage of the planning process, material updates are communicated to the IESO. Planned outages must be registered with and "time-stamped" by the IESO. OPG files its nuclear outage schedule in order to secure an early "time-stamp" date for its outages, which determines their standing in the IESO's outage queue. All outages in the queue are subject to final approval by the IESO, which can deny this approval at any time up to the start of the outage.

The following describes in greater detail the stages in the preparation of the final Integrated Plan:

3.2.1 Integrated Plan Development

In the fall of each year, each station submits an initial outage outlook for the five-year period commencing in January of the next calendar year. For example, the generation plans reviewed during 2009 covered the 2010 – 2014 timeframe. The initial outage outlook will reflect any regulatory, operational or maintenance issues that have arisen since the finalization of the prior Integrated Plan. Often outage durations are amended to reflect analysis of data obtained from recent outages experienced at OPG or other nuclear stations.

Outages during the first two years of the five year planning cycle are subject to the most extensive review and planning.

At the end of this stage, OPG Nuclear has identified:

- An updated, five-year planned outage schedule for each unit in the nuclear fleet, with the addition of a fifth year, as described below.
- Forced production loss and Unit Capability Factor ("UCF") targets, as described below.
- Generation targets and the underlying rationale for the changes from the prior Integrated Plan.

3.2.1.1 Planned Outage Schedule

Planned outage scope and duration are primarily determined by the station's life cycle plan (as discussed below). This plan identifies the inspections and maintenance necessary to ensure the continued safe, reliable, long-term operation of the plant and compliance with regulatory requirements. With regard to the scope of regulatory requirements, the nuclear industry stands apart from other regulated industries and other forms of electrical generation due to the complex nature of its technology, the criticality of safety in its operations and nuclear regulations. Consequently, the key drivers associated with OPG's nuclear operations (i.e., safety, complexity, training, material standards, work environment, non-standard fleet, aging technology, evolving regulatory standards, and achievements in technology) that are outlined in the base OM&A exhibit (Ex. F2-T2-S1) are equally applicable to outage scope, duration, and cost.

The outage scheduling guidelines considered during the planning process are:

- Eliminate/minimize overlap of planned outages.
- Minimize the scheduling of planned outages during peak seasonal periods.
- Ensure outage changes impact minimally on planned production targets.
- Proactively minimize the probability of inter-site work and schedule conflicts related to shared resources and tooling (e.g., inspection maintenance services campaigns and feeder replacement projects; optimize use of roving maintenance crews).
- Ensure standard intervals are applied between planned outages at each unit.

Outages involve many OPG divisions and individuals working together, and as such they require high levels of coordination. Outages require focus, expertise, and a level of detail that exceeds major construction projects. They require careful preparation and the safe execution of a well-developed plan that accounts for nuclear, radiological, and industrial safety, as well as, the efficient achievement of production goals and cost controls.

Outages consist of a combination of “routine” inspection and maintenance activities and “non-routine” activities specific to a particular outage. They involve thousands of work tasks, representing many person-hours of labour, sequenced in the optimal order to ensure safe and effective execution. As an example of the complexity of outage planning, Attachment 3 includes a Level 1 schedule for the Pickering B Unit 6 2009 planned outage.

Examples of routine activities would be preventive maintenance programs, feeder inspections and water lancing of steam generators, to maintain performance and reliability. Non-routine activities include corrective and elective maintenance programs and could include upgrades, replacements or modifications to the equipment or plant configuration that can only be done when the unit is shut down, such as single fuel channel replacement or low level drain state.

Even though OPG Nuclear is transitioning to standard baseline outage templates as discussed in Attachment 2, any outage will have unique aspects based on its specific scope. Approximately 60 per cent of the work activities in an outage typically relate to routine preventative maintenance and inspection activities while the remaining 40 per cent relate to work activities for non-routine upgrades and modifications. Within this split, the planned outage scope would primarily consist of pre-defined work activities and related work tasks. However, approximately 15 per cent of planned outage scope is contingency work activities that are anticipated to arise from discovery work during the routine inspection and preventive maintenance activities. These contingency activities are carefully selected based on risk assessments and historical experience. This approach allows OPG to proactively plan for, and be in a position to quickly respond to, such discovery work as it is identified over the course of the outage. Including contingency work activities within the planned outage scope minimizes the potential disruption to the outage schedule due to critical path and bulk work delays, as well as improving the accuracy of the Integrated Plan.

In addition, in order to avoid a significant disruption to the outage schedule, OPG may postpone completion of non-critical, non-safety related discovery work until after the outage. A decision to postpone work can lead to reduced production reliability during the post-outage period and require that future planned outages include the deferred items. By providing for a prudent level of contingency work activity in the planned outage scope, OPG balances the risk of outage extension due to discovery work against post-outage production reliability (i.e., the risk of more and longer force outages which impacts FLR).

Though outage duration is determined by the critical path of outage inspections and maintenance, it is also impacted by CANDU design (i.e., fuel is not offloaded during the outage) and the availability of the mandatory minimum equipment required for protection of the reactor fuel. Historically, the bulk of the outage critical path duration has been fuel channel and steam generator work. Recently, feeder piping inspections and maintenance are emerging as an additional critical path driver on some units. Pickering B Continued Operations, as discussed at Ex. F2-T2-S3, will result in additional planned outage days in 2010 - 2012 due to the need to perform additional Spacer Location and Relocation (“SLAR”) work as well as other work activities.

The following steps outline the process that yields each station's planned outage schedule:

- Each station identifies the inspection and maintenance activities required to comply with the aging and life cycle management programs and to ensure the safe and reliable operation of the facilities for the duration of their planned lives. The aging and life cycle management programs outline specific objectives for the major plant components (e.g., fuel channels, steam generators, feeders). The programs detail the frequency and nature of inspections, and the recurring preventive maintenance work required to ensure fitness for service and to maintain the reliability and safety of the plant. While outages will always include routine inspections and maintenance activities, the equipment affected will vary from one outage to the next, in accordance with the schedule specified in the aging and life cycle management programs. The variation in the scope of outages comes from corrective maintenance, projects and other non-routine activities. These variations are required to respond to issues specific to a station or to a unit(s) within a station, as units do not necessarily age according to the same pattern or at the same rate. The critical path of an outage can be impacted by these variations.
- OPG's nuclear operating licenses issued by the Canadian Nuclear Safety Commission ("CNSC") (further described in Ex. A1-T6-S1) require that a number of tests and maintenance activities be performed at specified intervals to ensure continued safety. In some instances, the requirement necessitates the shut down of all the units within the station because the test or the work involves a common safety system or component (e.g., vacuum building outage at Darlington in 2009 and in Pickering in 2010). The stations develop high level planned outage schedules with the input of several organizations, including Engineering, Inspection Maintenance and Commercial Services ("IM&CS"), and Projects and Modifications. To accommodate constraints around inter-site sharing of certain resources and tooling, this input is a significant factor in determining both the scheduled outage dates and the sequencing of major critical path activities. It helps ensure effective deployment of inspection and maintenance resources between the units on outage, particularly in those instances where overlapping, multi-site outages occur. For example, IM&CS staff will review the outage schedule to ensure that the planned activities can be completed with the available resources and external commitments. This review is critical due to the limited availability of highly specialized

nuclear tooling and personnel. Efforts are also made to schedule outages at different sites sequentially to facilitate the sharing of operations and maintenance resources. As well, the planned outage schedule is reviewed to identify and resolve potential conflicts between stations over the use of shared specialty resources such as project crews, contract staff, and major component spares such as turbine spindles or feeder replacement tooling. At this stage, the outage OM&A costs are estimated based on several factors including historical experience, projected contractors' costs, parts and projected equipment costs, and staffing requirements. Further discussion about outage OM&A costs can be found at Ex. F2-T4-S1. Station staff prepare resource, duration, and cost estimates at a detailed level for the outages. This allows the stations to prioritize work activities and examine the economic justification for necessary but non-essential activities, relative to other competing needs. The outage schedules involve development of detailed logic diagrams that identify the start and end dates for individual activities within each outage. The critical path for upcoming outages is also determined at this stage of the planning.

- Each station's planned outage schedule includes an allowance for uncertainty in the outage duration related to potential discovery work. The allowance for uncertainty reflects a station level assessment of past outages, known and unknown technological risks specific to the outage, the number of inspections that may result in discovery work and resource capability and availability.

3.2.1.2 Forced Production Losses and Unit Capability Targets

All generating units face the risk of unscheduled equipment problems that may require unplanned shutdowns or a derating of the generating unit. Accordingly, the stations develop forced loss rate ("FLR") targets that reflect the risk of such forced production losses for all units in the station.

In 2010, FLR targets were developed by station management with input from the Outage and Strategic Planning Departments, Engineering, and Nuclear Finance. FLR targets are based on the plants' recent performance, any known improvements or deterioration in plant material condition, past and future investment in reducing corrective and elective maintenance backlogs to improve reliability and other performance improvement initiatives, as well as known risks.

As part of the Phase 2 Nuclear Benchmarking initiative (Ex. F2-T1-S1), OPG introduced a change to its production forecast methodology related to the use of gap-based target setting to establish top-down, station FLR and Unit Capability Factor targets. The targets were initially set for the fifth year (2014) of the Nuclear business plan. The stations then reviewed their bottom-up FLR and Unit Capability Factor ("UCF") targets for the prior years (2010 - 2013) for reasonableness and consistency with the 2014 operational targets.

3.3 Initial Draft Integrated Plan

Using each station's initial planned outage schedule and the FLR and UCF target assumptions, Nuclear Finance prepares a draft five-year Integrated Plan. The draft Integrated Plan includes monthly and annual generation targets (TWh), planned outage days, and corresponding generation performance indicators at the unit, station and fleet level, for each of the five years of the Integrated Plan.

Included in the draft Integrated Plan is a fleet-level uncertainty adjustment. The fleet level adjustment recognizes the potential for events that are not predictable from a station level perspective. These events could impact the duration of a planned outage resulting in forced extensions of planned outages. The fleet level adjustment is intended to address planned outage risks including those that could emerge from fleet aging issues, or the complexity in fleet level activities (e.g., traveling crews and IM&CS) in support of outages. The fleet level adjustment is implemented by applying adjustments to the planned outage duration for each station's planned outage schedule. The combined fleet level uncertainty adjustment directly applied to the station production targets is 0.3 TWh in 2011 and 0.35 TWh in 2012.

3.4 Final Integrated Plan Approval

The Integrated Plan is finalized after the CNO reviews the station's nuclear generation targets, planned station outage schedules, and generation performance indicators included in the draft Integrated Plan. This review identifies revisions to the generation plan to reflect the latest generation-related information from across Nuclear or any changes in the overall nuclear program direction. The final Integrated Plan is incorporated into OPG's overall business planning process. Once approved through the OPG business planning process, the Integrated Plan will not change until the completion of the subsequent business planning cycle.

3.5 Forecast for Major Unforeseen Events

On average from 2005 - 2008, OPG's actual nuclear production has been less than the approved nuclear business plan forecast by approximately 3.5 TWh. An analysis of these production shortfalls revealed that they were largely the result of Nuclear's experience with forced outages and forced extensions to planned outages due to major unforeseen events. Accordingly, OPG has adjusted its production forecast methodology in the 2010 - 2014 Business Plan to include a 2.0 TWh per year allowance for major unforeseen events on the expectation that these types of events will occur in the future. (see Attachment 4 for analysis).

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The Nuclear business unit strives to maximize nuclear production while ensuring safe and reliable operations. In order to incent and challenge the nuclear organization, OPG has established a stretch performance target that is 2.0 TWh higher than the 2010 - 2014 Business Plan production forecast. The performance of OPG Nuclear's management will be assessed in part against its ability to achieve this stretch target (including payouts under the Annual Incentive Plan).

4.0 OPG NUCLEAR PRODUCTION FORECAST TREND

The expected trend in nuclear production starting from 2007 is for production to decline over the period 2008 - 2010 followed by an increase in 2011 and a further increase in 2012. This data is provided in Ex. E2-T1-S1 Table 1.

The major factors influencing the trend in production over 2007 - 2012 are:

- An expectation of improved performance at the Pickering units. The performance improvements at Pickering B during 2009 reflect the impact of various initiatives that have been undertaken since 2004. Improvements at Pickering A are expected by the end of the test period as a result of the Pickering A Equipment Reliability program. In addition, both stations will be positively impacted by new programs arising from the 2009 Nuclear Benchmarking initiative, designed to improve outage performance as discussed below in Attachment 1.
- A vacuum building outage at Darlington in 2009 which required all four Darlington units to be shut down for approximately four weeks.
- A vacuum building outage at Pickering in 2010 that will require all four Pickering B units and the two Pickering A units to be shut down for approximately four weeks.
- Extended scope and duration of planned outages at Pickering B over the period 2010 - 2012 as a result of the Pickering B Continued Operations initiative. There are 167 additional planned outage days in the test period for Continued Operations corresponding to a reduction of 1.9 TWh in the production forecast in the test period.
- An improvement in the forecast FLR at Pickering A starting in late 2009 reflecting recent CNSC concurrence with OPG's shutdown system trip setpoint methodology resulting in the elimination of the three per cent derate that was imposed in 2007.

The Nuclear production forecast for the 2011 - 2012 period does not include a specific provision for reduced production due to surplus baseload generation. OPG was not subject to material reductions in nuclear generation due to surplus baseload generation situations in 2008 or 2009 and is currently not anticipating a significant impact on its nuclear facilities during the test period.

Numbers may not add due to rounding.

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Exhibit E2
Tab 1
Schedule 2
Table 1c

Table 1c
Comparison of Production Forecast - Nuclear

Line No.	Prescribed Facility	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington NGS							
1	**TWh**	26.0	1.8	27.8	1.1	28.9	0.1	29.0
2	**Unit Capability Factor (%)**	85.9	4.4	90.3	3.6	93.9	0.2	94.1
3	**PO Days**	170.3	(51.5)	118.8	(50.5)	68.3	(2.8)	65.5
4	**FEPO Days**	11.9	(11.9)	0.0	0.0	0.0	0.0	0.0
5	**FLR (%)**	1.6	0.1	1.7	(0.2)	1.5	0.0	1.5
6	**FLR Days Equivalent**	20.9	1.6	22.5	(1.6)	20.9	0.1	21.0
	Pickering A NGS							
7	**TWh**	5.7	0.9	6.6	0.8	7.4	0.3	7.7
8	**Unit Capability Factor (%)**	64.2	9.5	73.7	8.9	82.6	2.7	85.3
9	**PO Days**	74.0	71.0	145.0	(63.0)	82.0	(7.0)	75.0
10	**FEPO Days**	32.5	(32.5)	0.0	0.0	0.0	0.0	0.0
11	**FLR (%)**	24.6	(16.6)	8.0	(1.0)	7.0	(2.0)	5.0
12	**FLR Days Equivalent**	152.6	(105.8)	46.8	(1.4)	45.4	(12.5)	32.9
	Pickering B NGS							
13	**TWh**	15.1	(1.4)	13.7	0.9	14.6	0.7	15.3
14	**Unit Capability Factor (%)**	84.0	(7.9)	76.1	4.9	81.0	3.7	84.7
15	**PO Days**	125.5	165.5	291.0	(69.0)	222.0	(50.0)	172.0
16	**FEPO Days**	27.7	(27.7)	0.0	0.0	0.0	0.0	0.0
17	**FLR (%)**	5.8	(0.8)	5.0	(0.5)	4.5	(0.5)	4.0
18	**FLR Days Equivalent**	75.9	(17.4)	58.5	(2.8)	55.7	(4.0)	51.7
	Totals							
19	**Unit Capability Factor (%)**	82.0	1.3	83.3	4.8	88.1	1.7	89.8
20	**PO Days**	369.8	185.0	554.8	(182.5)	372.3	(59.8)	312.5
21	**FEPO Days**	72.1	(72.1)	0.0	0.0	0.0	0.0	0.0
22	**FLR (%)**	6.4	(2.9)	3.5	(0.3)	3.2	(0.4)	2.8
23	**FLR Days Equivalent**	249.4	(121.6)	127.8	(5.8)	122.0	(16.4)	105.6
24	**Total TWh**	46.8	1.4	48.2	2.7	50.9	1.1	52.0
25	**Forecast for Major Unforeseen Events**	0.0	(2.0)	(2.0)	0.0	(2.0)	0.0	(2.0)
26	**Total TWh**	46.8	(0.6)	46.2	2.7	48.9	1.1	50.0

Numbers may not add due to rounding.

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Exhibit F2
Tab 4
Schedule 1
Table 1

Table 1
Outage OM&A - Nuclear ($M)

Line No.	Division	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Nuclear Stations						
1	Darlington NGS	97.1	83.2	109.8	106.7	64.2	59.0
2	Pickering A NGS	42.1	25.0	64.1	68.6	52.0	52.4
3	Pickering B NGS	69.6	82.9	70.2	90.5	81.1	74.9
4	Pickering B Continued Operations	0.0	0.0	2.8	1.9	13.0	10.6
5	**Total Stations**	208.8	191.1	246.8	267.8	210.2	196.9
	Nuclear Support Divisions						
6	Engineering	1.6	1.2	1.1	1.1	1.1	1.1
7	Projects & Modifications	2.6	1.8	2.9	3.1	1.5	1.1
8	Facilities Management	0.0	0.1	0.2	0.3	0.1	0.1
9	Programs & Training	1.0	0.6	1.0	0.8	0.5	0.5
10	Supply Chain	1.6	1.3	2.8	1.6	1.4	1.4
11	Performance Imprvmnt & Oversight	0.0	0.0	0.0	0.0	0.0	0.0
12	Inspection & Mtce Services[1]	0.0	0.0	0.0	0.0	0.0	0.0
13	Commercial Services	0.0	0.0	0.0	0.0	0.0	0.0
14	Nuclear Level Common	0.0	0.0	0.0	10.0	0.0	0.0
15	**Total Support**	6.8	5.0	8.0	16.8	4.6	4.2
16	**Total**	215.6	196.1	254.8	284.6	214.8	201.1

Notes:
1 Station costs include Inspection & Maintenance Services outage support.

ONTARIO POWER GENERATION

Generation Plan

		2010	2011	2012	2013	2014	Delta
TWh	2010-2014 OPG Submission	46.2	48.9	50.0	48.1	49.3	
	Additional Site performance target	2	2	2	2	2	
	2010-2014 Nuclear Submission	48.1	50.9	52.0	50.1	51.3	
	2009-2013 Nuclear BP	48.6	52.1	52.8	50.2	0.0	
	Variance	***-0.5***	***-1.3***	***-0.7***	***-0.2***	***N/A***	***-2.6***
	Variance to 2009-14 Nuclear BP	***-0.2***	***0.1***	***-0.1***	***0.7***		***0.5***
	Variance - Continued Ops Impact	***-0.3***	***-1.3***	***-0.7***	***-0.9***		***-3.2***
Planned Outage	2010-2014 Nuclear Submission	554.8	372.3	312.5	400.2	364.8	
	2009-2013 Nuclear BP	513.8	267.3	249.5	373.2		
	Variance	***41.0***	***105.0***	***63.0***	***27.0***	***N/A***	***236.0***
	Variance to 2009-14 Nuclear BP	***13.0***	***-6.0***	***7.0***	***-44.0***		***-30.0***
	Variance - Continued Ops Impact	***28.0***	***111.0***	***56.0***	***71.0***		***266.0***
Forced Loss Rate	2010-2014 Nuclear Submission	3.5%	3.2%	2.8%	2.8%	2.5%	
	2009-2013 Nuclear BP	3.6%	3.2%	2.8%	2.8%		*(average)*
	Variance	***0.0%***	***0.0%***	***0.0%***	***0.0%***	***N/A***	***0.0%***
	Variance to 2009-14 Nuclear BP	***0.0%***	***0.0%***	***0.0%***	***0.0%***		***0.0%***
	Variance - Continued Ops Impact	***0.0%***	***0.0%***	***0.0%***	***0.0%***		***0.0%***

- Reduction of 30 planned outage days contributes to a plan-over-plan generation increase (excluding continued operations) of 0.5 TWh.
- Investment in Continued Operations requires an additional 266 planned outage days resulting in a 3.2 TWh loss, but translates into a long-term benefit to base load generation for Ontario in the next decade.
- 2010 - additional planned outage days are required for replacing vacuum building risers; 2012 - additional days are required at Pickering B for feeder replacements; all additional days are mitigated by reduced scope required under Life Cycle Management Plans and weld overlay implementation at Darlington in 2012.

SEC Interrogatory #030

Ref: Ex. F2-T1-S1, Attachment 1

Issue Number: 6.5
Issue: Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

Interrogatory

a) Please provide an explanation as to why the Darlington GS FLR targets for 2011 and 2012 were chosen at 63 per cent above the achieved 2008 rate.

b) What would be the incremental revenue (at the proposed rates) if it were assumed Darlington GS had an FLR rate remain unchanged from that achieved in 2008 (i.e. .93).

Response

a) The Interrogatory refers to Ex. F2-T1-S1, Attachment 1 that shows a 2-year rolling average Force Loss Rate ("FLR") of 0.93 per cent for Darlington Generating Station in 2008. As shown in Ex. E2-T1-S2, Table 1c, Darlington's FLR targets for 2011 and 2012 are 1.50 per cent in each year. These are one year targets and not rolling averages.

The chart below shows actual yearly FLRs from 2005 – 2009 for Darlington Generating Station.

Year	FLR (%)
2005	1.3
2006	3.2
2007	1.1
2008	0.7
2009	1.6
5 Yr Average	**1.6**

Darlington Generating Station was able to achieve very impressive FLR performance in 2008. However, as the chart indicates, that performance has not been consistently achieved over the past five years.

Darlington 2011 and 2012 FLR targets were based on projected improvements in plant health and human performance factors which is expected to result in Darlington's FLR continuing to be better than CANDU median performance. The 2011 and 2012 FLR targets reflect these multi-year improvement plans and expected performance in these areas.

b) Incremental revenue for 2011 and 2012 would be approximately $10.3M per year based on a 0.17 TWh per year increase in generation resulting from an FLR of 0.93 per cent versus the 1.5 per cent FLR target.

CME Interrogatory #025

Ref: Ex. E1-T1-S1, and E1-T1-S2

Issue Number: 5.2
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

The evidence indicates that the Nuclear production forecast for 2011 is about 1.0 TWh below the forecast of 49.9 TWh approved by the Board for 2009. How much lower would the 24-month test period revenue deficiency be if the production forecast for the test period was greater by 1 TWh?

Response

Table 4 below provides a recalculation of the nuclear revenue deficiency under the scenario where forecast 2011 generation is 1 TWh higher. The impact is a reduction in the deficiency of $50M.

Summary of Revenue Deficiency
Test Period January 1, 2011 to December 31, 2012

Line No.	Description	Nuclear 2011	Nuclear 2012	Nuclear Total
		(d)	(e)	(f)
1	**Forecast Production (TWh)**[1]	49.9	50.0	99.9
2	**Prescribed Payment Amount ($/MWh)**[2]	52.98	52.98	N/A
3	**Indicated Production Revenue ($M)** (line 1 x line 2)	2,644.9	2,648.9	5,293.8
4	**Revenue Requirement ($M)**[3]	2,680.5	2,796.5	5,476.9
5	**Revenue Requirement Deficiency ($M)** (line 4 - line 3)	35.6	147.5	183.1
6	**Revenue Requirement Deficiency in current proposal ($M)**[4]	85.6	147.5	233.1
	Change from Rate Proposal (line 5 - line 6)	(50.0)	0.0	(50.0)

Notes:
1 Ex. E2-T1-S1 Table 1.
2 From EB-2007-0905 Payment Amounts Order.
3 Ex. I1-T1-S1 Table 1 (line 24). 2011 figure adjusted upward approximately $3M to account for additional fuel required.
4 Ex. I1-T1-S1 Table 4, line 5.