NON-CONFIDENTIAL

Request IR-94:

Referring to Schedule RB-01, Attachment 1, Pages 3 and 4, please provide documentation supporting the forecasted plant additions in 2011 and 2012.

Response IR-94:

Please refer to NPB IR-11 Attachment 2.

NON-CONFIDENTIAL

Request IR-95:

Referring to Schedule RB-01, Attachment 1, Page 4, please provide a complete description of the forecasted additions to steam and hydro generation plant in 2012. The response should identify any large (over $10 million) projects included in the forecast and the present status of any such projects.

Response IR-95:

Please refer to NPB IR-11 Attachment 2.

Request IR-96:

Please provide a comparison of actual to budgeted plant expenditures for each month in 2011 to date.

Response IR-96:

Please refer to the table below for plant expenditures.

Month	Actual ($)	Budget ($)
January	14,073,141	26,381,230
February	20,139,911	24,191,132
March	20,805,106	30,879,687
April	24,582,389	26,398,449
May	22,847,403	38,651,829

NON-CONFIDENTIAL

Request IR-97:

Please provide the actual balance of plant in service and accumulated depreciation by function as of the latest date available.

Response IR-97:

Please refer to Attachment 1.

CA-IR-097 Attachment 1
Summary of Plant in Service
As of May 31, 2011

Func Class Id	Plant in Service (in '000s)	Accumulated Depreciation (in '000s)
Distribution Plant - D	1,216,012	671,341
Gas Turbine Generation Plant - G	33,078	25,011
LM6000	83,454	18,796
General Plant - P	355,323	193,529
Hydro Generation Plant - H	426,036	151,023
Steam Generation Plant - S	1,977,612	853,194
Transmission Plant - T	656,497	335,440
Wind Generation Plant - W	220,747	7,222
Total	**4,968,760**	**2,255,556**

NON-CONFIDENTIAL

Request IR-98:

Referring to DE-03&04, page 54, with regard to the 2011-12 projects identified as "Tufts Cove 6 Combined cycle," "NewPage Biomass Project," and "Additional wind turbines," please provide the dollar amounts of forecasted capital spending and additions to plant in service in each year 2011 and 2012 for each project.

Response IR-98:

Please refer to the table below.

	Tufts Cove 6 Combined Cycle ($)	**Port Hawkesbury Biomass Project ($)**	**Additional Wind Turbines ($)**
2011 Forecasted Spend	557,435	65,425,204	30,030,156
2011 Forecasted Additions	557,435	-	-
2012 Forecasted Spend	-	51,776,691	30,195,123
2012 Forecasted Additions	-	-	-

NON-CONFIDENTIAL

Request IR-99:

Please show how the forecasted 2012 allowance for funds used during construction ("AFUDC") income was developed based on the construction work in progress ("CWIP") included in the 2012 test year rate base. The response should show the calculation of AFUDC on the 2012 CWIP balances, and to the extent that any balances of CWIP do not accrue AFUDC should explain why not.

Response IR-99:

AFUDC included in the 2012 forecasted capital spending is calculated within NSPI's asset management accounting system according to NSPI's Accounting Policy 6420 Allowance for Funds Used During Construction. Please refer to Attachment 1 for the details of this policy.

Attachment 2 provides a list of all projects included in the 2012 capital spend forecast and the associated AFUDC as well as an explanation for any projects that do not require AFUDC.

PROPERTY, PLANT AND EQUIPMENT

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION - 6240

NOVA SCOTIA POWER
An Emera Company

GENERAL

01 The cost-of-capital invested in construction work in progress is included in an allowance for funds used during construction[1] ("AFUDC") as an addition to the cost of property constructed using a weighted average cost-of-capital. This will be charged to operations through depreciation over the service life of the related assets and recovered through future revenues.

02 The AFUDC includes a designated cost of equity funds, to be capitalized as part of the acquisition of the related asset. That cost shall be capitalized under those circumstances only if its subsequent inclusion in allowable costs for rate-making purposes is probable.[2]

03 The cost to acquire or construct a capital asset over time should include the cost of financing that asset until it is placed in service. By including AFUDC in the cost of the capital asset, the associated financing costs will be more equitably recovered from customers, through depreciation, over the service life of the asset,

POLICY

04 Allowance for funds used during construction should be capitalized at the effective cost-of-capital rate, compounded semi-annually, except in the following circumstances:

a. Projects that will be under construction for less than a predetermined time;
b. Projects delayed for more than one year due to extraordinary circumstances; and
c. Projects with an economic value or future benefits that will be exceeded by such capitalization.

PROCEDURES

05 **Criteria for Application**

AFUDC is applied to all capital work orders with the following exceptions:

a. work orders with a construction period less than two months (*e.g.* routine work orders);
b. work orders used to purchase assets that are in-service immediately upon delivery (*e.g.* office furniture, tools, vehicles, computer hardware, etc.);
c. work orders for the purchase of land or land rights that will be held for future use;
d. work orders with customer contributions equal to 100% of construction costs and receivable as costs are incurred;
e. work orders that are deferred for more than one year; and
f. retirement work orders.

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1 FASB ASC 980-360-20

2 FASB ASC 980-360-25-1

06 **Basis for Application**

The application base for AFUDC includes the cumulative total of all direct and indirect charges to work orders, but excludes all AFUDC related to spending subsequent to January 1 or July 1, whichever is the latest. This exclusion effectively results in semi-annual compounding of AFUDC.

07 **Timing of Application**

AFUDC application begins in the month in which a work order receives charges and continues until the month the work order becomes operational plant. On most work orders, AFUDC is applied at the full rate to cumulative charges to the end of the current month. In the case of major capital work orders, the actual start date and the operational date will be taken into consideration when applying AFUDC.

08 **Calculation of AFUDC Rate**

The rate used to capitalize AFUDC is the Company's ***weighted average cost of capital before tax***. The rate is calculated annually, in advance, by dividing the forecasted annual interest expense, preferred dividends and net earnings applicable to common shareholders by the forecasted average debt and equity. The annual AFUDC rate is then divided by twelve to arrive at the monthly rate.

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CA IR-099 Attachment 2
2012 Capital Spend Forecast - AFUDC Project Details

Project #	Project	AFUDC Amount	Reason for No AFUDC
10898	TUS - GENERATOR REWIND UNITS 1, 2	20,987	
11610	STM- COON POND DAM SAFETY	27,150	
11948	POT - REHEATER ORIFICING	6,932	
12041	WRC - LOWER TURBINE RING UNIT 2	2,493	
12079	SHH - RUF 1&2 RUNNER REPLACEMENT	19,121	
12419	STM - TID PIPELINE REPLACEMENT	199,691	
16416	BLR-HEG UNIT 2 GENERATOR REWIND	4,393	
17581	WEY - ELECTRICAL REFURBISHMENT	10,528	
17617	BLR-BLACK RIVER LAKE GATE REFURBISH	1,209	
17660	BLR - DEAN CHAPTER SPILLWAY REBUILD	2,636	
18168	SIS PIPELINE REPLACEMENT	1,974	
20511	CT'S -Replace Halon Fire Protection	12,985	
20571	WEY-POWERHOUSE & TAILRACE REFURBISH	18	
20575	HEG#1-RUNNER REPLACEMENT	6,038	
20741	TUC - UNIT 1 BOILER IMPROVEMENTS (1	3,854	
20758	NIC - PIPELINE REPLACEMENT	18,999	
21168	TRE5 - CONVERT COAL FEEDERS TO GRAV	10,614	
22423	TRE - 5-1 CW PUMP REFURBISHMENT	4,061	
22426	TRE - 5-2 Air Heater Outlet Expansi	1,437	
22427	TRE5 - PARALLEL SLIDE VALVE REFURBI	3,538	
22431	TRE6 - DEPAC UPGRADES (2ND FIELD)	2,923	
22663	TRE6 - LUBE OIL COOLER UPGRADES	2,930	
23122	MER LLF RUNNER #4	3,607	
23341	CDS COMPUTER DISPATCH SYSTEM UPGRAD	6,575	
23602	STM - WRIGHTS LAKE DAM	24,008	
24627	TRE6 - PULVERIZER PF LINE ELBOWS RE	2,262	
25182	TUC - UNIT 2 LOW LOAD CAPABILITY IM	5,247	
26121	POT - WWTP CELL REFURBISHMENT	2,623	
26904	GULCH WS PENSTOCK REPLACEMENT	10,794	
27119	POT - UPGRADE AND REPAIRS TO THE CW	9,030	
27149	TUC - REPL. CONDENSATE POLISHERS &	11,927	
27150	TUC - REPLACE UNIT #1 AIR HEATER	13,445	
27312	REPLACEMENT OF RAGGED LAKE ECC HEAT	-	Operational prior to 2012
28131	POT - BURNER CORNER TUBE NEST PHASE	6,516	
28278	DONAHUE LAKE DAM SPILLWAY	3,952	
28288	POT - TURBINE SUPERVISORY EQUIPMENT	36,943	
28306	TRE5 - FLOW ELEMENT REPLACEMENT	4,534	
28424	DEPOT & SUBSTATION SECURITY SYSTEM	1,771	
28445	PRE. ENG. - PTMT DUST MITIGATION PR	3,378	
28641	ROSEWAY UNIT REFURBISHMENT	6,742	
28674	TRE6 HMI Upgrades	6,462	
28694	TRE5 - Pulverizer PA Damper Drive	2,212	
28697	TRE6 - STACK LIGHTING SYSTEM UPGRAD	2,771	
28792	POA Coal Cracker Refurbishment Proj	281	
28794	POA TRUCK SCALE REPLACEMENT PROJECT	2,248	
28819	TRE6 - PRECIP INSULATOR MODIFICATIO	5,797	
28849	TRE5 - CONDENSER PIPE REPLACEMENTS	2,968	
28907	LIN-CW Organic Sea Debris Capture U	50,748	
29065	CT'S -Replace Halon Fire Protection	20,987	
29066	CT'S Replace Halon Fire Protection	9,295	
30044	POT - Ash cell capping Cell C	-	Operational prior to 2012
30122	POT - Mercury CEM	1,972	
30142	POT - Iso-kinetic samplers	949	
30829	TRE5 Sootblower Upgrade	4,290	
30843	TRE SAFETY VALVE DRAIN REPLACEMENT	2,386	

CA IR-099 Attachment 2
2012 Capital Spend Forecast - AFUDC Project Details

Project #	Project	AFUDC Amount	Reason for No AFUDC
30862	TRE5 - Boiler Thermoprobe Upgrade	8,230	
31583	LIN2 - L-1 BLADING REPLACEMENT	115,337	
31724	POA LIMESTONE CRACKER REFURBISHMENT	1,017	
31729	POA SH3 TUBE BENDS REPLACEMENT	1,845	
31730	POA WELLFIELD PUMP REBUILD PROJECT	264	
32304	AMI Hardware & Software Installatio	532,782	
33142	CT-U&U #4 Restoration And Upgrade	-	Operational prior to 2012
33562	FAC Land Registration Act	39,704	
34382	POA Vacuum Pump Rebuild	808	
34385	POA Leco Sulphur Analyzer Replaceme	1,377	
34505	TRE-6B Vacuum Pump Overhall	2,424	
34522	TRE6 SEQUENCE OF EVENTS RECORDER	1,156	
34565	HYD- ANNAPOLIS CONTROLS PLC	-	Operational prior to 2012
35022	POA Front End Loader Replacement	2,623	
36565	POA ID Fan Motor Upgrade	3,279	
36584	POA Condensate Extraction Pump	-	Operational prior to 2012
36862	HYD - Wreck Cove Unit # 1 Overhaul	133,591	
36865	HYD - ANN Exciter Replacement	3,786	
36866	ANN Generator Protection Relays	1,239	
36867	ANN Servomotor	1,377	
37562	TRE5 - Bunker C Pump Replacement	4,218	
37607	LIN - DCS Equipment Upgrades	13,653	
37824	TRE5 - Common Water Pipe Upgrade	6,173	
37827	TRE6 - Replacement of BAS	-	Operational prior to 2012
37831	TRE5 - Polisher Valve Replacements	629	
38042	TRE6 - Steam Coil Airheater Upgrade	11,531	
38043	TRE6 - Turbine Gland Replacement	2,623	
38163	TRE6 - Pulverizer Refurbishment	984	
38242	TRE - Fire Water Storage Bunker	-	Operational prior to 2012
38603	TRE6 - LP Turbine Gland Replacement	-	Operational prior to 2012
38726	TRE - Anion/Cation Resin	-	Operational prior to 2012
38730	TRE - Transformer Compound Sprinker	-	Operational prior to 2012
38817	TRE6 - Primary Air Fan Shaft	2,496	
38823	2012 Protection Upgrades	37,091	
38827	TRE6 - Changing Air Supply to Slip	547	
38828	TRE5 - Seal Oil Piping Upgrades	3,124	
38829	TRE5 - Belt Scale Upgrade	483	
38868	HYD Marshall Falls Hydro Station	417,653	
38944	LIN - Unit 2 Rotor Rewind	41,524	
38945	LIN2 #8 Nozzle Replacement	22,081	
38947	Co-Firing Biomass	246,501	
39265	Transmission Reliablity Replacement	257,452	
39266	Transmission Reinforcements	1,530,359	
39267	Transmission Replacements	184,291	
39271	Dist. Reliability Replacements	222,521	
39274	Distribution Replacements	39,240	
39275	Halifax UG Cable Replacement	16,258	
39306	Radio & Communication Replacements	5,448	
39502	TRE - Stack Coating	3,926	
39932	TRE - Ash Site Phase 2 Development	240,665	
39934	TRE5 - Conveyor System Upgrades	6,104	
39951	TRE5 - Coal Bunkerette Replacement	2,627	
39956	TRE5 - Precip Static Transfer Switc	1,861	
39957	TRE - PLC Network Upgrades	1,768	
39958	TRE6 - Coal Handling MCC A/C Upgrad	1,194	

CA IR-099 Attachment 2
2012 Capital Spend Forecast - AFUDC Project Details

Project #	Project	AFUDC Amount	Reason for No AFUDC
39964	CT TUC 4&5 Engine Control Improvem	1,703	
40253	POT - Ash contacted water managemen	-	Operational prior to 2012
40277	1H-415 Targeted Replacements	138	
40310	Circuit Switcher Additions	2,212	
40311	50MVA Mobile Substation Transformer	10,494	
40320	LED Street Light Conversion	467,176	
40330	LIN2 HT Fastener Replacement	39,342	
40363	LIN3 HVB Refurbishment	22,584	
40365	MS Sharepoint Platform Upgrade	41,351	
40371	LIN Training Facilities	4,276	
40403	Work & Asset Management	428,661	
40542	CT Fall Protections	2,171	
40553	Wind Farm #2	1,247,103	
40555	Baghouse #1	1,296,193	
40557	Baghouse #2	1,296,193	
40558	Baghouse #3	278,519	
40563	2012 RTU Replacement Program	13,434	
40565	Hydro Refurbishments	747,058	
40643	CIS	106,178	
40645	Design Studio (FPS)	2,182	
40646	GIS Functionality Enhancements	49,347	
40647	Service Hub (CDS)	2,722	
40648	Field Mobility System	54,920	
40649	PeopleSpft (Human Resource Mgt)	8,201	
40650	PowerPlant (Capital Mgt)	4,544	
40651	Fuelworx (Fuel Management)	3,277	
40652	Nucleus	9,120	
40653	Millenium/Kanteh	1,454	
40655	LIN 2012 Mill Refurbishment	31,592	
40656	BFP Refurbishment	20,887	
40657	LIN CW Pump Refurbishment	4,974	
10626-S001-301	LIN - Routine Capital Program	-	Routine
11648-P016-301	LIN - Plant Tools	-	Routine
14841-T016-630	PROTECTION MODIFICATIONS AND REPLAC	-	Routine
14973-T018-820	PRIMARY EQUIPMENT SPARES	-	Routine
16073-P010-615	SCADA IMPROVEMENTS ROUTINE	-	Routine
16192-P009-630	MOBILE TRANFORMER & TRACK ROUTINE	-	Routine
16365-P025-635	MOBILE RADIO ROUTINE	-	Routine
16550-P028-635	TELECOMMUNICATION SYSTEMS REPLACE A	-	Routine
16551-P027-635	TELECOMMUNICATION RADIO AND FIBRE O	-	Routine
20945-P006-863	REPLACEMENT AND ADDITIONAL WORK VEH	-	Routine
22410-S654	TRE - 5-1 CONDENSATE EXTRACTION PUM	-	Operational prior to 2012
23115-T001-820	PROVINCIAL TRANSMISSION LINE REPLAC	-	Routine
23118-T011-820	PROVINCIAL - PLANNED TRANS LINE REP	-	Routine
23120-T003-820	PROVINCIAL-TRANS SUBSTATION PRIMARY	-	Routine
23121-T004-820	PROVINCIAL- SUBSTATION ADDITIONS &	-	Routine
23127-D010-840	D010 Provincially Widening	-	Routine
23135-D006-800	D006 Regulatory Replacements - Prov	-	Routine
23136-D007-800	D007 Contractual Replacemens (Joint	-	Routine
23137-D055-800	D055 - Planned Replacement Of Distr	-	Routine
23158-D005-800	D005 Unplanned Replace Deteriorated	-	Routine
23361-D008-800	D008 Provincial Storm	-	Routine
23511-D018-800	Primary Equipment Spares - Distribu	-	Routine
25667-P040-351	DCMS Equipment Replacement Routine	-	Routine
26716-D004-800	New Customer Upgrades	-	Routine

CA IR-099 Attachment 2
2012 Capital Spend Forecast - AFUDC Project Details

Project #	Project	AFUDC Amount	Reason for No AFUDC
26757-P002-800	PROVINCIAL LINE TOOLS & EQUIPMENT R	-	Routine
27116-S761	POT - LAB UPGRADES	-	Operational prior to 2012
27855-S004-351	POT-ROOFING ROUTINE	-	Routine
28430-P041-032	FAC - Land Acquisition Routine	-	Routine
28466-P030-032	FAC - Lower Water Street	-	Routine
28553-S697	POT SSC COOLING WATER LINE REPL	-	Operational prior to 2012
28645-S795	TRE6 - Turbine Controls Power Suppl	8,851	
29009-P833	Right of Way Purchase Northern NS	19,830	
29038-D051-800	System Performance Improvement Rout	-	Routine
29807-H541	HYD - PE Tusket Falls Main Dam	-	Operational prior to 2012
30283-S665	POT - Tupper Vessel Access	13,301	
30954-S613	LIN3-ESP Gas Flow Modification	20,826	
31202-H557	HYD - Gate Refurbishment	-	Part of Routine H006 - Gate Refurbishment
31204-H564	HYD - Donahoe Lake Dam Safety	17,126	
33624-T639	Spare Generator Transformer	48,966	
33863-S005-301	LIN-Heat Rate Routine	-	Routine
34182-S426	LIN Unit #1 Mercury Abatement	-	Operational prior to 2012
34202-S427	LIN Unit #2 Mercury Abatement	-	Operational prior to 2012
34203-S428	LIN Unit #3 Mercury Abatement	-	Operational prior to 2012
34222-S429	LIN Unit #4 Mercury Abatement	-	Operational prior to 2012
34223-S430	POT Mercury Abatement Project	-	Operational prior to 2012
34224-S431	TRE Unit#5 Mercury Abatement	-	Operational prior to 2012
34242-S432	TRE Unit #6 Mercury Abatement	-	Operational prior to 2012
36882-W107	Nuttby Mountain Wind Project Dev	-	Operational prior to 2012
37662-S609	TRE - CW Outlet Oil Boom	816	
37702-H576	HYD- PE WRC Overhaul	8,731	
38243-P814	Telecommunications Spares	-	Routine
38896-P815	FAC Environment Site Assess Routine	-	Routine
38897-P816	FAC Enviro Property Remed Routine	-	Routine
39029-S661	Port Hawkesbury Biomass Project	13,900,681	
39323-W115	Digby Wind Project	-	Operational prior to 2012
39566-S679	LIN2-LSB Replacement	119,658	
39643-D309	West River Station Reliability	-	Operational prior to 2012
39766-D061-800	New Customers - Residential	-	Routine
39770-D062-800	New Customers - Commercial	-	Routine
39933-S793	TRE - Siding Replacement	19,593	
40103-P834	U&U Load Control Demo	131,953	
40231-T688	2011 Protection Upgrades LAK	17,199	
40321-T687	Canaan Rd to Prospect Rd Tx Line	73,429	
40342-S768	POT - Refurbish Unit 2 precipitator	-	Operational prior to 2012
		25,406,061	

NON-CONFIDENTIAL

Request IR-100:

Please provide the forecasted balance of CWIP as of the end of each month in 2012.

Response IR-100:

Please refer to Attachment 1.

CA IR-100 Attachment 1				
CWIP Continuity (in $000's)				
	CWIP Opening Balance	2012 Forecasted Spending	2012 Forecasted Additions	CWIP Ending Balance
January-12	322,062	24,898	(3,416)	343,544
February-12	343,544	27,290	(9,358)	361,475
March-12	361,475	32,274	(6,909)	386,840
April-12	386,840	38,153	(5,452)	419,540
May-12	419,540	37,888	(10,431)	446,997
June-12	446,997	40,736	(7,375)	480,358
July-12	480,358	39,368	(7,593)	512,133
August-12	512,133	38,934	(13,097)	537,971
September-12	537,971	40,431	(16,422)	561,980
October-12	561,980	36,824	(31,301)	567,503
November-12	567,503	32,936	(50,045)	550,394
December-12	550,394	33,229	(104,514)	479,110
		422,961	(265,914)	

NON-CONFIDENTIAL

Request IR-101:

With regard to the forecasted balance of CWIP as of December, 31 2012, please provide the balance of CWIP for each forecasted addition to generating capacity. The response should provide the CWIP balance associated with each project, expected total cost of the project when complete, and the expected date that the project will be complete and go into service.

Response IR-101:

Please refer to the table below.

Project	CWIP Balance December 31, 2012 ($M)	Estimated Project Total ($M)	Estimated In-service date
Additional Wind	60.2	120.0	December 2013
Port Hawkesbury Biomass	117.2	207.8	February 2013

*Note: Project estimates do not include related transmission investments.

NON-CONFIDENTIAL

Request IR-102:

Referring to Schedule RB-02, please explain why the FAM Deferral is included in rate base, as the Company accrues interest on FAM over and under-recoveries.

Response IR-102:

The FAM Deferral is included in rate base because it is a regulatory deferred asset. Please refer to the Rate Base Accounting Policy in Attachment 1. The corresponding interest recovery related to the FAM Deferral is incorporated with the 2012 revenue requirement. Average rate base for purposes of determining the revenue requirement is calculated as a simple average of year-end balances whereas the FAM interest is calculated with monthly balances and compounded semi-annually as approved by the UARB.

The treatment of the FAM Deferral is consistent with the rate base methodology used for construction work in progress (CWIP). NSPI includes CWIP in rate base and incorporates the associated allowance for funds used during construction (AFUDC) recovery amounts in the overall revenue requirement calculations.

GENERAL INFORMATION
RATE BASE - 1520

DEFINITION

01 Rate base is comprised of the net value of certain assets upon which Nova Scotia Power Inc. ("NSPI") can earn a specified rate of return. The rate base and rate of return are approved by the Nova Scotia Utility and Review Board ("UARB") in compliance with the Public Utilities Act.

02 The rate base and the allowed rate of return are periodically reviewed by the UARB.

POLICIES

03 The components of rate base should include:

a. Cost (gross historical cost less capital contributions) less accumulated depreciation of used and useful plant in service;

b. Construction Work-in-Progress;

c. Allowance for materials and supplies;

d. Allowance for working capital;

e. Deferred charges and credits;

f. Contract receivable resulting from the settlement between NSPI and its natural gas supplier.

04 The excess of the purchase price paid for an acquired company over the amount to be included in rates as approved by the UARB should be excluded from rate base.

05 Assets held for future use should be excluded from rate base unless UARB approval has been obtained.

NON-CONFIDENTIAL

Request IR-103:

Please reconcile the total of expenses in 2012 on Schedule OE-02 - OE-09, Attachment 1, to the total regulated OM&G in 2012 on DE-03-DE-04, Appendix C, Page 2.

Response IR-103:

The expenses on Schedule OE-02 – OE-09 Attachment 1 contain the specific OM&G expenses identified by the UARB in the standard filing requirements. DE-03-DE-04, Appendix C, Page 2, contains all OM&G expenses. Appendix C includes all cost recoveries, corporate support transfers and administrative overhead credits not included in OE-02 – OE-09. Maintenance & Repair Expenses in OE-02 – OE-09, line 8, includes a labour component that is also included in the Salaries & Benefits amount shown on line 4. Billing & Collection Expense, line 9, also includes a labour component that is also included in the Salaries & Benefits amount shown on line 4.

Please refer to Attachment 1 for a breakdown of each category.

NOVA SCOTIA POWER INC.
OPERATING, MAINTENANCE AND GENERAL EXPENSES
(in Thousands of $)

		2012	DE-03 - DE-04 Appendix C Reference
Salaries & Benefits (net of pension expense)			
Corporate Groups	$	19,616	'Total Labour' Page 3, 5, 7, 9, 11, 13, 16, and 18
Technical & Construction Services		8,955	'Total Labour' Page 20
Sustainability		754	'Total Labour' Page 23
Power Production		55,117	'Total Labour' Pages 25, 27, 30, 32 and 34
Customer Operations		38,572	'Total Labour' Pages 36, 38, 40, and 43
Customer Service		17,517	'Total Labour' Page 45
Corporate Adjustments, net		3,247	'Total Labour' Page 48
	$	143,778	
Pension Charged to Labour		(6,100)	'Total Labour' Page 11
50% Mgmt Incentive/RSU/DSU		5,100	'Total Labour' Page 48
TOTAL	**$**	**142,778**	
Insurance Costs			
Corporate Secretary and General Counsel	$	5,400	Acount 043-Insurance, Page 5
Hydro & Wind Energy		123	Acount 043-Insurance, Page 32
	$	**5,523**	
Membership Dues & Professional Assoication Charges			
Corporate Groups	$	311	Account 029-Membership Dues, Page 3, 5, 7, 9, 11, 13, 16, and 18
Technical & Construction Services		99	Account 029-Membership Dues, Page 20
Sustainability		14	Account 029-Membership Dues, Page 23
Power Production		163	Account 029-Membership Dues, Pages 25, 27, 30, 32 and 34
Customer Operations		396	Account 029-Membership Dues, Pages 36, 38, 40, and 43
Customer Service		99	Account 029-Membership Dues, Page 45
	$	**1,082**	
Contracts			
Corporate Groups	$	7,156	Account 013-Contracts, Page 3, 5, 7, 9, 11, 13, 16, and 18
Technical & Construction Services		530	Account 013-Contracts, Page 20
Sustainability		-	Account 013-Contracts, Page 23
Power Production		16,485	Account 013-Contracts, Pages 25, 27, 30, 32 and 34
Customer Operations		21,748	Account 013-Contracts, Pages 36, 38, 40, and 43
Customer Service		1,542	Account 013-Contracts, Page 45
	$	**47,461**	
Maintenance & Repair Expenses			
Thermal Plants	$	32,297	'All Accounts', Page 27
Combustion Turbines		989	'All Accounts', Page 30
Hydro & Wind Energy		9,243	'All Accounts', Page 32
Energy, Fuels and Risk Management		-	n/a
Total Power Production	$	42,529	
Regional Operations	$	13,447	'All Accounts', Page 36
Control Center		-	'All Accounts', Page 38
Reliability and Workforce Management and Resource Allocation		15,905	'All Accounts', Page 40
Administration (incl Storm)		11,430	'All Accounts', Page 43
Total Customer Operations	$	40,782	
TOTAL	**$**	**83,311**	

NOVA SCOTIA POWER INC.
OPERATING, MAINTENANCE AND GENERAL EXPENSES
(in Thousands of $)

		2012	DE-03 - DE-04 Appendix C Reference
Billing & Collection Expense			
Customer Service	$	32,459	'Total', Page 45
Relative share of Total Customer Service		x 23%	Based on two year average (2010 actuals and 2011 Forecast)
	$	**7,475**	
Regulatory Expenses			
Regulatory Affairs	**$**	**5,859**	'Total', Page 18
Pension Expense			
Corporate Groups	$	5,350	Account 042-Employee Benefits, Page 3, 5, 7, 9, 11, 13, 16, and 18
Technical & Construction Services		2,506	Account 042-Employee Benefits, Page 20
Sustainability		216	Account 042-Employee Benefits, Page 23
Power Production		13,632	Account 042-Employee Benefits, Page 25
Customer Operations		8,910	Account 042-Employee Benefits, Page 43
Customer Service		4,087	Account 042-Employee Benefits, Page 45
	$	34,700	
Post Retirement Benefits Charged to Corporate Groups		(76)	Account 042-Employee Benefits, Page 11
Pension Plans	$	34,624	
Other Post Retirement Benefits		6,176	'Total Labour' plus Account 042-Employee Benefits, Page 11
	$	**40,800**	

NON-CONFIDENTIAL

Request IR-104:

Referring to Schedule OE-02 - OE-09, Attachment 1, please provide an analysis of Salaries & Benefits of $142.8 million in 2012. The response should itemize the salaries and each benefit included in the total and should show the salaries and benefits included in the forecast of OM&G in 2012.

Response IR-104:

Please refer to CA IR-103 Attachment 1 for salaries by group. Please refer to Liberty IR-108(a) for a list of benefits.

NON-CONFIDENTIAL

Request IR-105:

Please provide the total full time equivalent employees assumed in the forecast of 2012 OM&G expenses.

Response IR-105:

NSPI does not prepare labour forecasts based upon full time equivalent employees. Please refer to Liberty IR-121(a-b) for an explanation of considerations given when forecasting future labour costs. Please refer to Liberty IR-110 Attachment 1 for a list of additions and reductions of positions between 2009 Compliance and 2012 Forecast.

NON-CONFIDENTIAL

Request IR-106:

Please provide the actual full time equivalent employees for each month from December 2008 until the most recent month available.

Response IR-106:

The table below lists the actual full time equivalent employees from December 2008 to April 2011. The count includes all active regular and term employees as of the dates provided.

Date	FTEs
2008.12.31 Dec 2008	1695
2009.01.31 Jan 2009	1697
2009.02.28 Feb 2009	1690
2009.03.31 Mar 2009	1710
2009.04.30 Apr 2009	1727
2009.05.31 May 2009	1752
2009.06.30 Jun 2009	1827
2009.07.31 Jul 2009	1889
2009.08.31 Aug 2009	1906
2009.09.30 Sep 2009	1870
2009.10.31 Oct 2009	1914
2009.11.30 Nov 2009	1917
2009.12.31 Dec 2009	1858
2010.01.31 Jan 2010	1832
2010.02.28 Feb 2010	1840
2010.03.31 Mar 2010	1888
2010.04.30 Apr 2010	1963
2010.05.31 May 2010	2028
2010.06.30 Jun 2010	2052
2010.07.31 Jul 2010	2038
2010.08.31 Aug 2010	2019
2010.09.30 Sep 2010	1999
2010.10.31 Oct 2010	1980
2010.11.30 Nov 2010	1975
2010.12.31 Dec 2010	1927
2011.01.31 Jan 2011	1885
2011.02.28 Feb 2011	1895
2011.03.31 Mar 2011	1892
2011.04.30 Apr 2011	1915

NON-CONFIDENTIAL

Request IR-107:

Please provide the wage rate increases assumed in forecasting the 2012 salaries expense. The response should show the assumed wage rate increases for each employee classification.

Response IR-107:

Please refer to Liberty IR-109(a).

REDACTED

Request IR-108:

Please provide actual wage rate increases in each year 2008 – 2010 and 2011 to date. The response should show the actual wage rate increases for each employee classification.

Response IR-108:

Please refer to Attachment 1 for union wage rate increases for each year 2008 – 2011.

The table below provides the average salary increase (percentage) by job family for 2008 – 2010.

Wage increases for 2011 will not be processed until mid-September.

Average of Increase	**Year**		
Job Family	**2008 (%)**	**2009 (%)**	**2010 (%)**
Accountant	[redacted]		
Accounts Payable			
Administrative and Support Positions			
Audit			
Communication			
Cost/Financial Analyst			
Customer Care			
Customer Care Reps			
Director			
Engineering (P.Eng)			
Engineering Support			
Environment			
Field Operations			
Finance & Accounting			
Fuels & Energy			
Human Resources			
IT Related			
Legal & Regulatory			
Manager			

REDACTED

Average of Increase	Year		
Job Family	**2008 (%)**	**2009 (%)**	**2010 (%)**
Planner	[redacted]	[redacted]	[redacted]
Procurement	[redacted]	[redacted]	[redacted]
Project Lead	[redacted]	[redacted]	[redacted]
Real Estate	[redacted]	[redacted]	[redacted]
Supervisor	[redacted]	[redacted]	[redacted]
Technologist, GIS, CADD	[redacted]	[redacted]	[redacted]
Grand Total	[redacted]	[redacted]	[redacted]

JOB CLASSIFICATION	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2010 10-01 $1.00	Wage Rate 2011 03-04 4%	Wage Rate 2012 Remains the same as 2011 *(Pending Negotiations
Leading Powerline Technician (Shift)	33.90	35.26	36.31	37.76	37.76
Powerline Technician (Shift)	32.30	33.59	34.59	35.97	35.97
Leading Powerline Technician	32.37	33.66	34.71	36.10	36.10
Powerline Technician	30.83	32.06	33.06	34.38	34.38
Powerline Tech Shift Spare	32.30	33.59	34.59	35.97	35.97
Tech Powerline Trainee 1st6mos (55%)	16.96	17.63	18.18	18.91	18.91
Tech Powerline Trainee 2nd6mos(60%)	18.50	19.24	19.84	20.63	20.63
Tech Powerline App 3rd 6mos (65%)	20.04	20.84	21.49	22.35	22.35
Tech Powerline App 4th 6mos (70%)	21.58	22.44	23.14	24.07	24.07
Tech Powerline App 5th 6 Mos (80%)	24.66	25.65	26.45	27.50	27.50
Tech Powerline App 6th 6 Mos (85%)	26.21	27.25	28.10	29.22	29.22
Tech Powerline App 7th 6mos (90%)	27.75	28.85	29.75	30.94	30.94
Tech Powerline App 8th 6mos (95%)	29.29	30.46	31.41	32.66	32.66
Electrician Leading	31.77	33.04	34.09	35.46	35.46
Electrician (Shift)	30.26	31.47	32.47	33.77	33.77
Leading Electrician	31.77	33.04	34.09	35.46	35.46
Electrician	30.26	31.47	32.47	33.77	33.77
Electrician Helper (80%)	24.21	25.18	25.98	27.02	27.02
Electrician Apprentice 1st 6mo (55%)	16.64	17.31	17.86	18.57	18.57
Electrician Apprentice 2nd 6mo (60%)	18.16	18.88	19.48	20.26	20.26
Electrician Apprentice 3rd 6mo (65%)	19.67	20.46	21.11	21.95	21.95
Electrician Apprentice 4th 6mo (70%)	21.18	22.03	22.73	23.64	23.64
Electrician Apprentice 5th 6mo (80%)	24.21	25.18	25.98	27.02	27.02
Electrician Apprentice 6th 6mo (85%)	25.72	26.75	27.60	28.71	28.71
Electrician Apprentice 7th 6mo (90%)	27.23	28.32	29.22	30.39	30.39
Electrician Apprentice 8th 6mo (95%)	28.75	29.90	30.85	32.08	32.08
Electrician(Shift)App 1st 6mos (55%)	16.64	17.31	17.86	18.57	18.57
Electrician(Shift)App 2nd 6mos (60%)	18.16	18.88	19.48	20.26	20.26
Electrician(Shift)App 3rd 6mos (65%)	19.67	20.46	21.11	21.95	21.95
Electrician(Shift)App 4th 6mos (70%)	21.18	22.03	22.73	23.64	23.64
Electrician(Shift)App 5th 6mos (80%)	24.21	25.18	25.98	27.02	27.02
Electrician(Shift)App 6th 6mos (85%)	25.72	26.75	27.60	28.71	28.71
Electrician(Shift)App 7th 6mos (90%)	27.23	28.32	29.22	30.39	30.39
Electrician(Shift)App 8th 6mos (95%)	28.75	29.90	30.85	32.08	32.08
Quality Technician	33.23	34.56	35.56	36.98	36.98
Leading Electrical Technician	33.29	34.62	35.67	37.10	37.10
Electrical Technician	31.70	32.97	33.97	35.33	35.33
Electrical Tech App 5th 6 Mos (80%)	25.36	26.38	27.18	28.26	28.26
Electrical Tech App 6th 6 Mos (85%)	26.95	28.03	28.88	30.03	30.03
Electrical Tech App 7th 6 Mos (90%)	28.53	29.67	30.57	31.80	31.80
Electrical Tech App 8th 6 Mos (95%)	30.12	31.32	32.27	33.56	33.56

JOB CLASSIFICATION	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2010 10-01 $1.00	Wage Rate 2011 03-04 4%	Wage Rate 2012 Remains the same as 2011 *(Pending Negotiations
System Operator- Transmission	41.05	42.69	43.69	45.44	45.44
System Operator- Energy	38.82	40.37	41.37	43.03	43.03
System Operator- Hydro	37.95	39.47	40.47	42.09	42.09
System Operator- Distribution	37.24	38.73	39.73	41.32	41.32
SYS OPERATOR-TRAN APP 1ST 6MOS	22.58	23.48	24.03	24.99	24.99
SYS OPERATOR-TRAN APP 2ND 6MOS	24.63	25.61	26.21	27.26	27.26
SYS OPERATOR-TRAN APP 3RD 6MOS	26.68	27.75	28.40	29.54	29.54
SYS OPERATOR-TRAN APP 4TH 6MOS	28.74	29.88	30.58	31.81	31.81
SYS OPERATOR-TRAN APP 5TH 6MOS	32.84	34.15	34.95	36.35	36.35
SYS OPERATOR-TRAN APP 6TH 6MOS	34.89	36.29	37.14	38.62	38.62
SYS OPERATOR-TRAN APP 7TH 6MOS	36.95	38.42	39.32	40.90	40.90
SYS OPERATOR-TRAN APP 8TH 6MOS	39.00	40.56	41.51	43.17	43.17
SYS OPERATOR-HYDRO APP 1ST 6MOS	20.87	21.71	22.26	23.15	23.15
SYS OPERATOR-HYDRO APP 2ND 6MOS	22.77	23.68	24.28	25.25	25.25
SYS OPERATOR-HYDRO APP 3RD 6MOS	24.67	25.66	26.31	27.36	27.36
SYS OPERATOR-HYDRO APP 4TH 6MOS	26.57	27.63	28.33	29.46	29.46
SYS OPERATOR-HYDRO APP 5TH 6MOS	30.36	31.58	32.38	33.67	33.67
SYS OPERATOR-HYDRO APP 6TH 6MOS	32.26	33.55	34.40	35.78	35.78
SYS OPERATOR-HYDRO APP 7TH 6MOS	34.16	35.52	36.42	37.88	37.88
SYS OPERATOR-HYDRO APP 8TH 6MOS	36.05	37.50	38.45	39.99	39.99
SYS OPERATOR-ENERGY APP 1ST 6MOS	21.35	22.20	22.75	23.67	23.67
SYS OPERATOR-ENERGY APP 2ND 6MOS	23.29	24.22	24.82	25.82	25.82
SYS OPERATOR-ENERGY APP 3RD 6MOS	25.23	26.24	26.89	27.97	27.97
SYS OPERATOR-ENERGY APP 4TH 6MOS	27.17	28.26	28.96	30.12	30.12
SYS OPERATOR-ENERGY APP 5TH 6MOS	31.06	32.30	33.10	34.42	34.42
SYS OPERATOR-ENERGY APP 6TH 6MOS	33.00	34.31	35.16	36.58	36.58
SYS OPERATOR-ENERGY APP 7TH 6MOS	34.94	36.33	37.23	38.73	38.73
SYS OPERATOR-ENERGY APP 8TH 6MOS	36.88	38.35	39.30	40.88	40.88
SYS OPERATOR-DIST APP 1ST 6MOS	20.48	21.30	21.85	22.73	22.73
SYS OPERATOR-DIST APP 2ND 6MOS	22.34	23.24	23.84	24.79	24.79
SYS OPERATOR-DIST APP 3RD 6MOS	24.21	25.17	25.82	26.86	26.86
SYS OPERATOR-DIST APP 4TH 6MOS	26.07	27.11	27.81	28.92	28.92
SYS OPERATOR-DIST APP 5TH 6MOS	29.79	30.98	31.78	33.06	33.06
SYS OPERATOR-DIST APP 6TH 6MOS	31.65	32.92	33.77	35.12	35.12
SYS OPERATOR-DIST APP 7TH 6MOS	33.52	34.86	35.76	37.19	37.19
SYS OPERATOR-DIST APP 8TH 6MOS	35.38	36.79	37.74	39.25	39.25
Leading Meterperson	31.77	33.04	34.09	35.46	35.46
Meterperson	30.26	31.47	32.47	33.77	33.77
Leading Garage Mechanic	31.77	33.04	34.09	35.46	35.46
Garage Mechanic	30.26	31.47	32.47	33.77	33.77
Garage Mechanic Helper (80%)	24.21	25.18	25.98	27.02	27.02

JOB CLASSIFICATION	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2010 10-01 $1.00	Wage Rate 2011 03-04 4%	Wage Rate 2012 Remains the same as 2011 *(Pending Negotiations
Garage Mechanic App. 1st 6mos (55%)	16.64	17.31	17.86	18.57	18.57
Garage Mechanic App. 2nd 6mos (60%)	18.16	18.88	19.48	20.26	20.26
Garage Mechanic App. 3rd 6mos (65%)	19.67	20.46	21.11	21.95	21.95
Garage Mechanic App. 4th 6mos (70%)	21.18	22.03	22.73	23.64	23.64
Garage Mechanic App. 5th 6mos (80%)	24.21	25.18	25.98	27.02	27.02
Garage Mechanic App. 6th 6mos (85%)	25.72	26.75	27.60	28.71	28.71
Garage Mechanic App. 7th 6mos (90%)	27.23	28.32	29.22	30.39	30.39
Garage Mechanic App. 8th 6mos (95%)	28.75	29.90	30.85	32.08	32.08
Wiring Inspector	31.68	32.95	33.95	35.31	35.31
Cust. Serv. Field Rep	24.26	25.23	25.23	26.24	26.24
Csfr Learner (1st Yr - 85%)	20.62	21.45	21.45	22.30	22.30
Meter Reader	14.85	15.44	15.44	16.06	16.06
Meter Reader II		20.51	20.51	21.33	21.33
CUSTOMER PLANNER	24.28	25.25	25.25	26.26	26.26
OPERATIONS PLANNER	26.99	28.07	28.07	29.19	29.19
FORESTRY COORDINATOR	26.79	27.86	27.86	28.97	28.97
REGIONAL PLANNER	32.37	33.66	34.71	36.10	36.10
PLANNING & SUPPORT ADMINISTRAT				29.19	29.19
REGIONAL PLANNER APP 5TH 6 MOS			27.77	28.88	28.88
REGIONAL PLANNER 6TH SIX MONTH			29.50	30.68	30.68
REGIONAL PLANNER 7TH SIX MONTH			31.24	32.49	32.49
REGIONAL PLANNER 8TH SIX MONTH			32.97	34.29	34.29
GIS DATA COLLECTOR				12.98	12.98
Leading Power Engineer*	34.70	36.09	37.14	38.63	38.63
Power Engineer*	33.05	34.37	35.37	36.79	36.79
Auxiliary Power Engineer	33.05	34.37	35.37	36.79	36.79
Auxiliary Power Engineer 2nd (96%)	31.73	33.00	33.96	35.32	35.32
Auxiliary Power Engineer 3rd (93%)	30.74	31.96	32.89	34.21	34.21
Power Engineer App.1st 6mos*(50%)	16.53	17.19	17.69	18.40	18.40
Power Engineer App.2nd 6mos*(55%)	18.18	18.90	19.45	20.24	20.24
Power Engineer App.3rd 6mos*(60%)	19.83	20.62	21.22	22.07	22.07
Power Engineer App.4th 6mos*(65%)	21.48	22.34	22.99	23.91	23.91
Power Engineer App.5th 6mos*(75%)	24.79	25.78	26.53	27.59	27.59
Power Engineer App.6th 6mos*(80%)	26.44	27.50	28.30	29.43	29.43
Power Engineer App.7th 6mos*(85%)	28.09	29.22	30.07	31.27	31.27
Power Engineer App.8th 6mos*(90%)	29.75	30.93	31.83	33.11	33.11
Operator Learner (4th Class)	19.11	19.88	19.88	20.67	20.67
Operator Learner 3rd Class (75%)	24.79	25.78	26.53	27.59	27.59
Aux. Power Engineer App.1st 6mos*(50%)	16.53	17.19	17.69	18.40	18.40
Aux. Power Engineer App.2nd 6mos*(55%)	18.18	18.90	19.45	20.24	20.24

JOB CLASSIFICATION	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2010 10-01 $1.00	Wage Rate 2011 03-04 4%	Wage Rate 2012 Remains the same as 2011 *(Pending Negotiations
Aux. Power Engineer App.3rd 6mos*(60%)	19.83	20.62	21.22	22.07	22.07
Aux. Power Engineer App.4th 6mos*(65%)	21.48	22.34	22.99	23.91	23.91
Aux. Power Engineer App.5th 6mos*(75%)	24.79	25.78	26.53	27.59	27.59
Aux. Power Engineer App.6th 6mos*(80%)	26.44	27.50	28.30	29.43	29.43
Aux. Power Engineer App.7th 6mos*(85%)	28.09	29.22	30.07	31.27	31.27
Aux. Power Engineer App.8th 6mos*(90%)	29.75	30.93	31.83	33.11	33.11
Leading Gas Turbine Attendant Opr.	31.77	33.04	34.09	35.46	35.46
Gas Turbine Attendant Operator	30.26	31.47	32.47	33.77	33.77
Gas Turbine Attendant App.1ST 6mos (55%)	16.64	17.31	17.86	18.57	18.57
Gas Turbine Attendant App.2NDT 6mos (60%)	18.16	18.82	19.48	20.26	20.26
Gas Turbine Attendant App 3RD 6mos (65%)	19.67	20.46	21.11	21.95	21.95
Gas Turbine Attendant App.4TH 6mos (70%)	21.18	22.03	22.73	23.64	23.64
Gas Turbine Attendant App.5TH 6mos (80%)	24.21	25.18	25.98	27.02	27.02
Gas Turbine Attendant App.6TH 6mos (85%)	25.72	26.75	27.60	28.71	28.71
Gas Turbine Attendant App.7TH 6mos (90%)	27.23	28.32	29.22	30.39	30.39
Gas Turbine Attendant App.8TH6MOS (95%)	28.75	29.90	30.85	32.08	32.08
Leading Maintenance Person	32.37	33.66	34.71	36.10	36.10
Leading Maintenance Person (Shift)	32.37	33.66	34.71	36.10	36.10
Maintenance Person (Certified)	30.83	32.06	33.06	34.38	34.38
Maintenance Person (Certified) (Shift)	30.83	32.06	33.06	34.38	34.38
Maintenance Person Helper (80%)	24.66	25.65	26.45	27.50	27.50
Maintenance Pers. App 1st 6mos(55%)	16.96	17.63	18.18	18.91	18.91
Maintenance Pers. App 2nd 6mos(60%)	18.50	19.24	19.84	20.63	20.63
Maintenance Pers. App.3rd 6mos(65%)	20.04	20.84	21.49	22.35	22.35
Maintenance Pers. App.4th 6mos(70%)	21.58	22.44	23.14	24.07	24.07
Maintenance Pers. App.5th 6mos(80%)	24.66	25.65	26.45	27.50	27.50
Maintenance Pers. App.6th 6mos(85%)	26.21	27.25	28.10	29.22	29.22
Maintenance Pers. App.7th 6mos(90%)	27.75	28.85	29.75	30.94	30.94
Maintenance Pers. App.8th 6mos(95%)	29.29	30.46	31.41	32.66	32.66
Maint Pers(Shift) App 1st 6mos (55%)	16.96	17.63	18.18	18.91	18.91
Maint Pers(Shift) App 2nd 6mos (60%)	18.50	19.24	19.84	20.63	20.63
Maint Pers(Shift) App 3rd 6mos (65%)	20.04	20.84	21.49	22.35	22.35
Maint Pers(Shift) App 4th 6mos (70%)	21.58	22.44	23.14	24.07	24.07
Maint Pers(Shift) App 5th 6mos (80%)	24.66	25.65	26.45	27.50	27.50
Maint Pers(Shift) App 6th 6mos (85%)	26.21	27.25	28.10	29.22	29.22
Maint Pers(Shift) App 7th 6mos (90%)	27.75	28.85	29.75	30.94	30.94
Maint Pers(Shift) App 8th 6mos (95%)	29.29	30.46	31.41	32.66	32.66
Leading Carpenter	30.15	31.35	31.35	32.60	32.60
Carpenter	28.71	29.86	29.86	31.05	31.05
Leading Power Plant Technician II	34.87	36.27	37.32	38.81	38.81
Power Plant Technician II	33.21	34.54	35.54	36.96	36.96

JOB CLASSIFICATION	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2010 10-01 $1.00	Wage Rate 2011 03-04 4%	Wage Rate 2012 Remains the same as 2011 *(Pending Negotiations
Power Plant Technician II (Shift)	33.21	34.54	35.54	36.96	36.96
Leading Power Plant Technician I	33.29	34.62	35.67	37.10	37.10
Power Plant Technician I	31.70	32.97	33.97	35.33	35.33
Power Plant Technician I (Shift)	31.70	32.97	33.97	35.33	35.33
Power Plant Tech. I App. 5th 6mos (80%)	25.36	26.38	27.18	28.26	28.26
Power Plant Tech. I App. 6th 6mos (85%)	26.95	28.03	28.88	30.03	30.03
Power Plant Tech. I App. 7th 6mos (90%)	28.53	29.67	30.57	31.80	31.80
Power Plant Tech. I App. 8th 6mos (95%)	30.12	31.32	32.27	33.56	33.56
Power Plant Tech I (Shift) App 5th 6mos (80%)	25.36	26.38	27.18	28.26	28.26
Power Plant Tech I (Shift) App 6th 6mos (85%)	26.95	28.03	28.88	30.03	30.03
Power Plant Tech I (Shift) App 7th 6mos (90%)	28.53	29.67	30.57	31.80	31.80
Power Plant Tech I (Shift) App 8th 6mos (95%)	30.12	31.32	32.27	33.56	33.56
Leading Painter	30.15	31.35	31.35	32.60	32.60
Painter	28.71	29.86	29.86	31.05	31.05
Painter Helper (80%)	22.97	23.89	23.89	24.84	24.84
Leading Meter Tester	30.15	31.35	31.35	32.60	32.60
Meter Tester	28.71	29.86	29.86	31.05	31.05
Meter Tester Helper (80%)	22.97	23.89	23.89	24.84	24.84
Leading Protective Equip. Tester	30.15	31.35	31.35	32.60	32.60
Protective Equipment Tester	28.71	29.86	29.86	31.05	31.05
Fuels Analyst	23.89	24.85	24.85	25.84	25.84
Fuels Analyst Learner 2nd Yr (80%)	19.11	19.88	19.88	20.67	20.67
Fuels Analyst Learner 1st Yr (65%)	15.53	16.15	16.15	16.80	16.80
Leading Storekeeper	25.83	26.86	26.86	27.93	27.93
Storekeeper	24.60	25.58	25.58	26.60	26.60
Storekeeper Learner 2nd Yr (90%)	22.14	23.02	23.02	23.94	23.94
Storekeeper Learner 1st Yr. (80%)	19.68	20.46	20.46	21.28	21.28
Storekeeper Helper (77%)	18.94	19.70	19.70	20.48	20.48
Leading Utilityworker	25.09	26.09	26.09	27.13	27.13
Utilityworker I	23.89	24.85	24.85	25.84	25.84
Utilityworker II (80% Of I)	19.11	19.88	19.88	20.67	20.67
Utilityworker III (62% Of I)	14.81	15.41	15.41	16.02	16.02
*Leading Utilityworker (Shift)	25.09	26.09	26.09	27.13	27.13
*Utilityworker I (Shift)	23.89	24.85	24.85	25.84	25.84
*Utilityworker II (Shift) (80%)	19.11	19.88	19.88	20.67	20.67
*Utilityworker III (Shift) (62%)	14.81	15.41	15.41	16.02	16.02
Leading Utilityworker Oil Filter Operator	27.26	28.35	28.35	29.48	29.48
Utilityworker Oil Filter Operator	25.96	27.00	27.00	28.08	28.08

JOB CLASSIFICATION	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2010 10-01 $1.00	Wage Rate 2011 03-04 4%	Wage Rate 2012 Remains the same as 2011 *(Pending Negotiations
Utilityworker Oil Filter Learner 2nd Yr (90%)	23.37	24.30	24.30	25.27	25.27
Utilityworker Oil Fil Leaner 1st Yr (80%)	20.77	21.60	21.60	22.46	22.46
Leading Utility Operator	27.35	28.44	28.44	29.58	29.58
Utility Operator	26.05	27.09	27.09	28.17	28.17
Utility Operator Lrnr. 1st Yr. (85%)	22.14	23.03	23.03	23.95	23.95
Ldg. Groundhand Equip.Operator	25.83	26.86	26.86	27.93	27.93
Groundhand Equipment Operator	24.60	25.58	25.58	26.60	26.60
Groundhand Equip Op Leaner 1st Yr (89%)	21.89	22.77	22.77	23.68	23.68
Janitor Leading	14.81	15.39	15.39	16.01	16.01
Janitor	14.10	14.66	14.66	15.25	15.25

ARTICLE 9 - WAGE RATES - TERM EMPLOYEES

JOB CLASSIFICATION

WAGE RATES - TERM EMPLOYEES	Wage Rate 2007 07-27 2.5%	Wage Rate 2008 12-26 3.5%	Wage Rate 2010 03-05 4%	Wage Rate 2011 03-04 4%
WELDER - UNCERTIFIED	20.23	20.94	21.78	22.65
HEAVY EQUIPMENT OPERATOR	23.23	24.04	25.00	26.00
LEADING INSTRUMENT (SURVEY)	22.91	23.71	24.66	25.65
INSTRUMENT (SURVEY)	21.82	22.58	23.48	24.42
SURVEY ASSISTANT	14.31	14.81	15.40	16.02
POWER SAW OPERATOR (WITH SAW)	16.29	16.86	17.53	18.23
POWER SAW OPERATOR	14.31	14.81	15.40	16.02
TRACTOR OPERATOR	14.99	15.51	16.13	16.78
COMPRESSOR,DRILLER, MIXER OPR	15.19	15.72	16.35	17.00
CEMENT FINISHER	14.63	15.14	15.75	16.38
CONCRETE INSPECTOR	14.72	15.24	15.85	16.48
JACK HAMMER, PUMP, AIR TOOL OPR	14.24	14.74	15.33	15.94
UTILITYWORKER (HYDRO) (80% OF I)	18.47	19.11	19.88	20.67
UTILITYWORKER LEARNER (HYDRO) (70%)	16.16	16.72	17.40	18.09
PROTECTIVE EQUIP.TESTER HELPER (78%)	21.64	22.39	23.29	24.22

NON-CONFIDENTIAL

Request IR-109:

Please provide the price escalation rates assumed in forecasting 2012 OM&G. The responses should provide the price escalation rates assumed for 2011 and 2012, the sources of the assumed rates, and the expenses to which the rates were applied.

Response IR-109:

Please refer to Liberty IR-128.

NON-CONFIDENTIAL

Request IR-110:

Please provide the incentive compensation expense included in 2012 test year OM&G expenses.

Response IR-110:

Please refer to Liberty IR-130(g).

NON-CONFIDENTIAL

Request IR-111:

Please provide the incentive compensation expense incurred in each year 2008 – 2010.

Response IR-111:

Incentive compensation expense incurred in 2008 was $4,819,005, expense incurred in 2009 was $5,355,073 and expense incurred in 2010 was $6,263,236. Only 50 percent of incentive costs are included in regulated OM&G costs, as approved by the UARB. The amounts above reflect 100 percent of the amounts.

NON-CONFIDENTIAL

Request IR-112:

Please describe the Company's incentive compensation program. The response should explain the achievement goals of the program and the portion of the compensation related to each achievement goal and the test year incentive compensation expense for each employee category identified in the response.

Response IR-112:

Please refer to Liberty IR-130.

NON-CONFIDENTIAL

Request IR-113:

Referring to DE-03 – DE-04, page 62, please provide all workpapers supporting Figure 5.1.

Response IR-113:

Please refer to response to Liberty IR-38.

NON-CONFIDENTIAL

Request IR-114:

Referring to DE-03 – DE-04, page 69, lines 12-13, please provide workpapers supporting the $5.0 million related to succession planning initiatives.

Response IR-114:

The following table details the succession planning costs by major operating area with references to the Application:

OM&G Group	$M	Reference
Power Production	$ 1.5	Figure 5.5, page 74
Customer Operations	1.2	Figure 5.9, page 79
Technical & Construction Services	0.9	Figure 5.16, page 86
Corporate Support	1.4	Figure 5.20, Page 89
Total	**$ 5.0**	

Please also refer to Liberty IR-110 Attachment 1, filed electronically, for work papers further supporting the cost allocations by major operating group.

NON-CONFIDENTIAL

Request IR-115:

Referring to DE-03 – DE-04, page 69, lines 12-13, please provide the increase in expenses from January 2010 to date for planning initiatives such as the addition of power engineers and apprentices.

Response IR-115:

Please refer to Liberty IR-110 Attachment 1, filed electronically; details include dates when positions have been filled.

NON-CONFIDENTIAL

Request IR-116:

Referring to DE-03 – DE-04, page 69, lines 9-13, union and non-union wage increases are indicated as having resulted in an increase in OM&G expenses of $12.3 million from 2009 to 2012, with an additional $5.0 million increase attributable to succession and workforce planning initiatives. On DE-03 – DE-04, page 63 the total increase in "Labour-related" OM&G from 2009 to 2012 is shown as $9.1 million. Please reconcile the amounts on page 69 to the amount on page 63.

Response IR-116:

Please refer to Liberty IR-139 Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-117:

Referring to DE-03 – DE-04, page 69, lines 24-26, please provide the complete actuarial study supporting the forecasted 2012 pension expense of $40.8 million.

Response IR-117:

Please refer to Liberty IR-80.

NON-CONFIDENTIAL

Request IR-118:

Referring to DE-03 – DE-04, pages 70-72, please provide workpapers supporting the changes to the pension cost associated with each factor.

Response IR-118:

Please refer to Attachment 1. Please refer to Liberty IR-81 Attachment 1 for the 2009C components and the Application, RB-02 – RB-16, Attachment 2 for the 2012 components.

CA IR-118 Attachment 1

NSPI Pension Expense Reconciliation from 2009C to 2012

All figures in millions	**Submitted 2009C**	**Submitted 2012**	**2012 at 7.25% Asset Return Assumption**	**2012 at 5.75% Discount Rate Assumption**	**Commentary**
CURRENT SERVICE COST	13.8	16.0	16.0	15.0	
INTEREST ON ACCRUED BENEFITS	48.7	54.0	54.0	54.6	
EXPECTED RETURN ON ASSETS	-47.9	-52.0	-53.9	-52.0	
STRAIGHT LINE AMORTIZATION OF:					
- Transitional Obligation (Asset)	2.3	0.0	0.0	0.0	**Reduction of $2.3 million due to change to US GAAP**
- Past Service Costs	0.2	0.2	0.2	0.2	
- Actuarial Losses / (Gains)	12.3	22.6	22.6	19.5	**Increase of $7.2 million from 2009C (12.3M) to 2012 at 5.75% discount rate (19.5M). This is the increase in pension expense due to actuarial gain/losses (since discount rate is same)**
Total Pension Expense	29.3	40.8	38.9	37.3	
Asset Return Assumption	7.25%	7.00%	7.25%	7.00%	
Discount Rate	5.75%	5.50%	5.50%	5.75%	
Commentary (Relative to 2012C):			**Change of $1.9 million**	**Change of $3.5 million**	

NON-CONFIDENTIAL

Request IR-119:

Please provide an analysis of labour costs, pension costs, and other benefits costs, showing the total amount of 2012 forecasted cost and the net amount of each cost included in OM&G after Administrative Overhead credits. The response should include all supporting workpapers and calculations.

Response IR-119:

Please refer to Attachment 1.

NOVA SCOTIA POWER INC.
REGULATED OPERATING, MAINTENANCE AND GENERAL EXPENSES
(in Thousands of $)

	2012 Costs	DE-03 - DE-04 Appendix C Reference
Labour		
Corporate Groups	$ 19,616	Page 3, 5, 7, 9, 11, 13, 16, and 18
Technical & Construction Services	8,955	Page 20
Sustainability	754	Page 23
Power Production	55,117	Pages 25, 27, 30, 32 and 34
Customer Operations	38,572	Pages 36, 38, 40, and 43
Customer Service	17,517	Page 45
Corporate Adjustments	3,247	Page 48
Total Labour Costs	$ 143,778	
Pension Charged to Labour	(6,100)	Page 11
Administrative Overheads	(22,991)	Page 48, account 095
Labour, net of AO & Pension	**$ 114,687**	
Pension		
Corporate Groups	$ 5,350	Page 3, 5, 7, 9, 11, 13, 16, and 18, account 042
Technical & Construction Services	2,506	Page 20, account 042
Sustainability	215	Page 23, account 042
Power Production	13,631	Pages 25, 27, 30, 32 and 34, account 042
Customer Operations	8,910	Pages 36, 38, 40, and 43, account 042
Customer Service	4,087	Page 45, account 042
Total Employee Benefits	$ 34,700	
Pension Charged to Labour	6,100	Page 11, labour account
Total Pension Costs	**$ 40,800**	
Other Benefits		
Incentive Compensation	$ 2,750	Page 48, labour account
Total Other Benefits	**$ 2,750**	

Notes:
1) Figures presented reflect whole numbers which may cause rounding differences on some line items.

NON-CONFIDENTIAL

Request IR-120:

Referring to DE-03 – DE-04, page 74, please provide all workpapers supporting Figure 5.5.

Response IR-120:

Please refer to Appendix C, pages 25-35 of the Direct Evidence, for working papers to support Figure 5.5, as well as Liberty IR-110.

NON-CONFIDENTIAL

Request IR-121:

Referring to DE-03 – DE-04, page 79, please provide all workpapers supporting Figure 5.9.

Response IR-121:

Please refer to the Application, DE-03 – DE-04 Appendix C, pages 36 to 44 inclusive, for a full listing of expenses by account, including variance explanations detailing the specific changes in each area. Please also refer to Liberty IR-58, Liberty IR-59 and Liberty IR-60.

NON-CONFIDENTIAL

Request IR-122:

Referring to DE-03 – DE-04, page 81, lines 9 -12, it states that $8.7 million is included in the 2012 revenue requirement, which is an increase of $3.7 million in 2012 for the storm response program. The chart in Figure 5.11 shows that the storm cost in 2009 was $7.7 million. An increase of $3.7 million to the $7.7 million in 2009 implies a total of $11.4 million. Please reconcile this amount to the $8.7 of storm response expense that the Company states is included in the 2012 test year expenses.

Response IR-122:

Please refer to Liberty IR-58 for a detailed explanation of the costs included in the 2012 rate Application. The $3.7 million increase is relative to the 2009 compliance year costs currently included in NSPI's rates, which are $5.0 million. The 2009 actual storm OM&G expenses were $7.7 million, which exceeded the amount included in rates by $2.7 million.

NON-CONFIDENTIAL

Request IR-123:

Referring to DE-03 – DE-04, page 81, Figure 5.11, please provide the same information for the years 2001 – 2005.

Response IR-123:

Please refer to NPB IR-124 for a list of storm costs by year. NSPI did not specifically track individual storm costs prior to 2006.

REDACTED

Request IR-124:

Please provide the actual vegetation management expense in each year 2007 – 2010 and in 2011 to date.

Response IR-124:

The actual vegetation management program expense for the requested periods can be seen in the table below.

2007 ($M)	**2008 ($M)**	**2009 ($M)**	**2010 ($M)**	**2011 May YTD ($M)**
6.5	9.2*	12.7**	10.3	[redacted]

* Includes $2 million which was deferred for future recovery

** Includes additional vegetation management advanced from future years

NON-CONFIDENTIAL

Request IR-125:

Referring to DE-03 – DE-04, page 85, please provide all workpapers supporting Figure 5.14.

Response IR-125:

Please refer to Appendix C, pages 45 - 47 and OR-05 of the 2012 Application.

NON-CONFIDENTIAL

Request IR-126:

Referring to DE-03 – DE-04, page 86, please provide all workpapers supporting Figure 5.16.

Response IR-126:

Please refer to Appendix C, page 20 of the Application, Liberty IR-104 Attachment 1, and Liberty IR-110 Attachment 1.

NON-CONFIDENTIAL

Request IR-127:

Referring to DE-03 – DE-04, page 89, please provide all workpapers supporting Figure 5.20.

Response IR-127:

For the supporting details for Figure 5.20, please refer to the Application, DE-03 – DE-04, Appendix C, pages 3-18.

- Union and non-union labour, plus Other labour increases represent the total labour variance plus Corporate Support Transfer Variance, pages 3-18.

- Corporate Support Transfers were extracted pages 3-18, consisting of account '057 Corp Support Transfers'.

- Pension details extracted from pages 3-18, account '042 Employee Benefits'.

- Insurance details extracted from page 5, account '043 Insurance'

- Lower Water Street OM&G related savings extracted from page 13, consisting of accounts: 013, 046, 050, 051, 061, and 091.

- Other figures reflect the total for each group extracted from pages 3-18, net of other categories identified in table above.

Please also refer to Liberty IR-104 Attachment 1.

NON-CONFIDENTIAL

Request IR-128:

Referring to DE-03 – DE-04, page 91, please provide all workpapers supporting Figure 5.22.

Response IR-128:

Please refer to Liberty IR-104 Attachment 1.

NON-CONFIDENTIAL

Request IR-129:

Referring to DE-03 – DE-04, page 91, please describe how the applied overheads credit is calculated and how the applied overheads credit in 2012 is forecasted.

Response IR-129:

Please refer to Liberty IR-49.

NON-CONFIDENTIAL

Request IR-130:

Please provide workpapers showing the application of the 2012 depreciation rates to the 2012 depreciable plant in service, to develop the forecasted 2012 test year depreciation expense.

Response IR-130:

Depreciation expense for the 2012 test year is calculated within NSPI's asset management accounting system according to NSPI's Accounting Policy 5300 Depreciation and Amortization Expense. Please refer to Attachment 1 for the details of this policy.

Attachment 2 provides the 2012 depreciation expense by function and by depreciation group as calculated.

COST OF OPERATIONS

DEPRECIATION AND AMORTIZATION EXPENSE - 5300

POLICIES

01 The cost of property, plant and equipment and intangibles should be depreciated or amortized over the useful life of the assets.[1]

02 Net salvage values should be amortized over the useful lives of the assets to which they relate and either charged to depreciation expense (when negative) or credited to depreciation expense (when positive).

03 Depreciation and amortization expense should be provided on a straight-line basis.

04 Where Nova Scotia Power Inc. ("NSPI") has a legal obligation associated with the retirement of a tangible long-lived asset that NSPI is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel[2], NSPI will include a portion of this Asset Retirement Obligation ("ARO") in Depreciation Expense, Please refer to NSPI's Accounting Policy and Procedures Manual Section 6320 for Asset Retirement Obligations.

PROCEDURES

05 The life estimations and policies, including AROs and other significant assumptions are periodically reviewed and the results filed with the Nova Scotia Utility and Review Board ("UARB") for its approval.

06 The depreciation or amortization base consists of the original cost of assets in service, including AROs, but excludes the following assets which are not depreciated or amortized:

a. land and land acquisition costs - these costs are excluded since land generally appreciates in value over time with the recovery of invested capital occurring at the time of disposal; and

b. fully-depreciated and amortized assets - these are assets which have been fully depreciated or amortized but have not been retired from service.

07 In most cases, depreciation and amortization begins in the month an asset is placed in service and ceases on the first of the month in which it is retired. The exceptions are large projects, such as thermal plants, that are depreciated on the specific day the asset goes into service and depreciation is stopped when it is retired as these have a significant financial impact on the Company.

08 Depreciation and amortization rates, including net salvage allowances, are approved by the UARB based on periodic depreciation studies and/or settlement agreements filed with the UARB.

[1] FASB ASC 360-10-35-3
[2] FASB ASC 410-20-15-2

09 The remaining life is forecasted through the use of mortality statistics that determine the best fit ***Iowa Curve*** which gives the expected retirement characteristics. This technique is applied to all mass plant accounts. Production plant assets remaining life is derived using engineering studies.

10 Depreciation and amortization rates are filed annually with the Annual Capital Expenditures Plan to the UARB.

2012 Depreciation Expense

Function	Forecast Depreciation Group	Depreciation Rate	Depreciation Expense
Distribution Plant - D	001 Land - Dist. Plant	0.00%	-
Distribution Plant - D	002 Land Rights - Dist. Plant	1.56%	340,158
Distribution Plant - D	003 Bldg.,Struct.Grnd. - Dist. Plan	5.31%	68,714
Distribution Plant - D	004 Misc.Equipment - Dist. Plant	12.49%	111,135
Distribution Plant - D	007 Environmental - Dist. Plant	12.49%	34,278
Distribution Plant - D	008 Site Restoration Asset - Dist.	0.00%	-
Distribution Plant - D	035 Wood Poles - Dist. Plant	3.79%	18,351,509
Distribution Plant - D	036 Other Poles - Dist. Plant	3.79%	-
Distribution Plant - D	037 Steel Towers - Dist. Plant	3.79%	19,634
Distribution Plant - D	038 Insulators - Dist. Plant	3.79%	150,757
Distribution Plant - D	039 O/H Cond. - Dist. Plant	3.33%	6,357,512
Distribution Plant - D	040 O/H Cond.Devices - Dist. Plant	3.33%	869,924
Distribution Plant - D	041 O/H Line Transf. - Dist. Plant	4.09%	11,739,044
Distribution Plant - D	042 O/H Ln.Transf.Dev. - Dist. Plan	4.09%	78,210
Distribution Plant - D	043 Substn Dev. - Dist. Plant	1.28%	41,008
Distribution Plant - D	044 Substn.Transf. - Dist. Plant	1.28%	927,359
Distribution Plant - D	045 U/G Conduit - Dist. Plant	1.51%	107,517
Distribution Plant - D	046 U/G Conductor - Dist. Plant	3.17%	1,306,644
Distribution Plant - D	047 U/G Conductor Devices - Dist. P	3.17%	100,330
Distribution Plant - D	048 U/G Line Transf. - Dist. Plant	4.09%	551,810
Distribution Plant - D	049 U/G Line Transf.Device - Dist.	4.09%	24,338
Distribution Plant - D	050 Street Lights - Dist. Plant	5.33%	2,872,281
Distribution Plant - D	051 Meters - Dist. Plant	6.87%	3,308,751
Distribution Plant - D	052 Services - Dist. Plant	5.33%	6,463,425
Distribution Plant - D	054 Remote Monitoring - Dist. Plant	10.32%	31,890
Distribution Plant - D	064 Sup. Control and DA - Dist. Pla	9.68%	88,434
Distribution Plant - D	Cap. Contr. - Dist. Plant	3.89%	(3,994,500)
Distribution Plant - D	Salvage Allow. - Dist. Plant	0.00%	-
Distribution Plant - D Total			**49,950,161**
Gas Turbine Generation Plant - G	001 Land Burnside C/T	0.00%	-
Gas Turbine Generation Plant - G	001 Land Tusket C/T	0.00%	-
Gas Turbine Generation Plant - G	008 ARO Burnside C/T	0.00%	-
Gas Turbine Generation Plant - G	008 ARO Tusket C/T	0.00%	-
Gas Turbine Generation Plant - G	008 ARO Victoria Junction C/T	0.00%	-
Gas Turbine Generation Plant - G	Burnside C/T	2.40%	500,756
Gas Turbine Generation Plant - G	LM 6000 TC #4	2.55%	1,194,208
Gas Turbine Generation Plant - G	LM 6000 TC #5	2.77%	911,934
Gas Turbine Generation Plant - G	Tusket C/T	6.42%	350,833
Gas Turbine Generation Plant - G	Victoria Junction C/T	3.17%	240,909
Gas Turbine Generation Plant - G Total			**3,198,640**
General Plant - P	001 Land - General Plant	0.00%	-
General Plant - P	002 Land Rights - General Plant	1.93%	71,674
General Plant - P	003 Bldg.,Struct.Grnd. - General Pl	2.85%	3,556,959
General Plant - P	004 Misc.Equipment - General Plant	5.02%	1,311,317
General Plant - P	007 Environmental - General Plant	5.02%	223,567
General Plant - P	026 Rds,Trls.Brdgs. - General Plant	2.58%	12,993
General Plant - P	054 Remote Monitoring - General Pla	10.27%	94,956
General Plant - P	055 Teleprotection - General Plant	4.38%	4,600
General Plant - P	056 Comm. Ent. Cables&Prot - Genera	4.38%	28,776
General Plant - P	057 Leased Comm. Facilitie - Genera	4.38%	259
General Plant - P	059 Multiplex - General Plant	4.38%	129,175
General Plant - P	060 Broadband Radio - General Plant	4.38%	647,608
General Plant - P	061 Switched Telecomm. Sys - Genera	4.38%	295,683
General Plant - P	062 Fibre Optics - General Plant	4.38%	62,805
General Plant - P	063 Mobile Radio Infrastru - Genera	4.38%	960,445
General Plant - P	064 Sup. Control and DA - General P	1.33%	192,500
General Plant - P	065 Transp.Vehicles - General Plant	9.55%	2,398,940
General Plant - P	066 Work Vehicles - General Plant	9.55%	1,928,005
General Plant - P	067 Office Equipment - General Plan	9.26%	82,681
General Plant - P	068 Office Furn.-General - General	9.26%	1,192,278
General Plant - P	069 Office Furn.-Modular - General	9.26%	121,913
General Plant - P	070 Shop Equipment - General Plant	0.00%	-
General Plant - P	071 Leasehold Improv. Scotia Square	0.00%	-
General Plant - P	071 Leasehold Improvements -General	0.00%	-
General Plant - P	072 Computer Equipment - General Pl	20.00%	15,845,144

2012 Depreciation Expense

Function	Forecast Depreciation Group	Depreciation Rate	Depreciation Expense
General Plant - P	073 Laboratory - General Plant	0.00%	-
General Plant - P	074 Stores - General Plant	14.97%	70,794
General Plant - P	076 Mine Equipment - General Plant	2.92%	58,676
General Plant - P	078 Comp. Appl. Software - General	10.00%	3,324,867
General Plant - P	080 Purchase Differance - General P	0.00%	-
General Plant - P	081 Non-Utility Property - General	0.00%	-
General Plant - P	Cap. Contr. - General Plant	8.16%	(173,376)
General Plant - P	Salvage Allow. - General Plant	0.00%	-
General Plant - P Total			**32,443,236**
Hydro Generation Plant - H	001 Land Annapolis Tidal Power	0.00%	-
Hydro Generation Plant - H	001 Land Avon Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Bear River Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Black River Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Dickie Brook Hydro	0.00%	-
Hydro Generation Plant - H	001 Land Fall River Hydro	0.00%	-
Hydro Generation Plant - H	001 Land Harmony Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Lequille Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Mersey Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Roseway & Harmony Hydro	0.00%	-
Hydro Generation Plant - H	001 Land Sheet Harbour Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land St.Margaret's Hydro System	0.00%	-
Hydro Generation Plant - H	001 Land Tusket Hydro	0.00%	-
Hydro Generation Plant - H	001 Land Wreck Cove Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Annapolis Tidal Power	0.00%	-
Hydro Generation Plant - H	008 ARO Avon Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Bear River Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Black River Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Dickie Brook Hydro	0.00%	-
Hydro Generation Plant - H	008 ARO Fall River Hydro	0.00%	-
Hydro Generation Plant - H	008 ARO Harmony Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Lequille Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Roseway & Harmony Hydro	0.00%	-
Hydro Generation Plant - H	008 ARO Sheet Harbour Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO St.Margaret's Hydro System	0.00%	-
Hydro Generation Plant - H	008 ARO Tusket Hydro	0.00%	-
Hydro Generation Plant - H	008 ARO Wreck Cove Hydro System	0.00%	-
Hydro Generation Plant - H	Annapolis Tidal Power	2.32%	861,361
Hydro Generation Plant - H	Avon Hydro System	3.02%	554,037
Hydro Generation Plant - H	Bear River Hydro System	1.80%	694,564
Hydro Generation Plant - H	Black River Hydro System	2.04%	888,077
Hydro Generation Plant - H	Cap. Contr. - Bear River Hydro Syst	1.80%	(25,532)
Hydro Generation Plant - H	Cap. Contr. - Fall River Hydro	1.82%	(7,932)
Hydro Generation Plant - H	Cap. Contr. - Sheet Harbour Hydro S	3.38%	-
Hydro Generation Plant - H	Cap. Contr. - Wreck Cove Hydro Syst	1.67%	(10,020)
Hydro Generation Plant - H	Dickie Brook Hydro	3.16%	249,040
Hydro Generation Plant - H	Fall River Hydro	1.82%	40,075
Hydro Generation Plant - H	Harmony Hydro System	4.55%	225,853
Hydro Generation Plant - H	Hydro Production Administration	2.10%	190,618
Hydro Generation Plant - H	Lequille Hydro System	2.33%	458,520
Hydro Generation Plant - H	Mersey Heavy Maintenance	0.00%	-
Hydro Generation Plant - H	Mersey Hydro System	0.00%	808,185
Hydro Generation Plant - H	Milton Heavy Maintenance	2.10%	610
Hydro Generation Plant - H	Roseway & Harmony Hydro	2.29%	54,600
Hydro Generation Plant - H	Sheet Harbour Hydro System	3.38%	866,401
Hydro Generation Plant - H	St.Margaret's Hydro System	2.85%	613,309
Hydro Generation Plant - H	Tusket Hydro	2.64%	309,597
Hydro Generation Plant - H	White Rock Heavy Maintenance	2.10%	1,105
Hydro Generation Plant - H	Wreck Cove Hydro System	1.67%	2,766,002
Hydro Generation Plant - H Total			**9,538,471**
Steam Generation Plant - S	001 Land Accounting	0.00%	-
Steam Generation Plant - S	001 Land Glace Bay Admin./Capital	0.00%	-
Steam Generation Plant - S	001 Land Lingan Admin./Common Capit	0.00%	-
Steam Generation Plant - S	001 Land Maccan Capital	0.00%	-
Steam Generation Plant - S	001 Land Power Prod. Controller	0.00%	-
Steam Generation Plant - S	001 Land Pt.Aconi Admin./Capital	0.00%	-

2012 Depreciation Expense

Function	Forecast Depreciation Group	Depreciation Rate	Depreciation Expense
Steam Generation Plant - S	001 Land Pt.Tupper Admin./Capital	0.00%	-
Steam Generation Plant - S	001 Land Trenton Admin./Common Capi	0.00%	-
Steam Generation Plant - S	001 Land Tufts Cove Admin./Common C	0.00%	-
Steam Generation Plant - S	001 Land Water Street Capital	0.00%	-
Steam Generation Plant - S	008 ARO Lingan Admin./Common Capita	0.00%	-
Steam Generation Plant - S	008 ARO Pt.Aconi Admin./Capital	0.00%	-
Steam Generation Plant - S	008 ARO Pt.Tupper Admin./Capital	0.00%	-
Steam Generation Plant - S	008 ARO Trenton Admin./Common Capit	0.00%	-
Steam Generation Plant - S	008 ARO Tufts Cove Admin./Common Ca	0.00%	-
Steam Generation Plant - S	Cap. Contr. - Glace Bay Admin./Capi	0.00%	-
Steam Generation Plant - S	Cap. Contr. - Lingan 1&2 Prod. Unit	4.12%	-
Steam Generation Plant - S	Cap. Contr. - Lingan Admin./Common	4.48%	(147,795)
Steam Generation Plant - S	Cap. Contr. - Trenton Admin./Common	0.47%	-
Steam Generation Plant - S	Glace Bay Admin./Capital	0.00%	-
Steam Generation Plant - S	Lingan 1&2 Prod. Unit	4.12%	8,661,388
Steam Generation Plant - S	Lingan 3&4 Prod.Unit	2.28%	5,829,173
Steam Generation Plant - S	Lingan Admin./Common Capital	4.48%	5,600,921
Steam Generation Plant - S	Power Prod. Controller	2.82%	167,552
Steam Generation Plant - S	Pt. Tupper Unit #1	3.97%	1,268,724
Steam Generation Plant - S	Pt.Aconi Admin./Capital	2.27%	11,849,104
Steam Generation Plant - S	Pt.Tupper Admin./Capital	2.82%	4,229,807
Steam Generation Plant - S	Straight Marine Terminal	4.06%	1,354,359
Steam Generation Plant - S	TC Unit 1 Capital	4.24%	1,665,654
Steam Generation Plant - S	TC Unit 2 Capital	3.68%	1,241,076
Steam Generation Plant - S	TC Unit 3 Capital	2.33%	1,531,866
Steam Generation Plant - S	TC Unit 6 Capital	2.55%	2,251,499
Steam Generation Plant - S	Trenton Admin./Common Capital	0.47%	121,673
Steam Generation Plant - S	Trenton Unit 5 Capital	3.10%	3,980,277
Steam Generation Plant - S	Trenton unit 6 Capital	2.34%	6,244,456
Steam Generation Plant - S	Tufts Cove Admin./Common Capital	3.44%	2,393,510
Steam Generation Plant - S	Water Street Capital	0.00%	-
Steam Generation Plant - S Total			**58,243,245**
Transmission Plant - T	001 Land - Trans. Plant	0.00%	-
Transmission Plant - T	002 Land Rights - Trans. Plant	1.26%	655,674
Transmission Plant - T	003 Bldg.,Struct.Grnd. - Trans. Pla	2.14%	451,450
Transmission Plant - T	004 Misc.Equipment - Trans. Plant	2.14%	21,795
Transmission Plant - T	007 Environmental - Trans. Plant	2.14%	37,201
Transmission Plant - T	008 Site Restoration Asset - Trans.	0.00%	-
Transmission Plant - T	022 Elec Contr.Equip. - Trans. Plan	2.14%	225,343
Transmission Plant - T	023 Power Equip.-Station S - Trans.	2.14%	22,400
Transmission Plant - T	026 Rds,Trls.Brdgs. - Trans. Plant	1.74%	2,910
Transmission Plant - T	035 Wood Poles - Trans. Plant	4.32%	5,185,623
Transmission Plant - T	036 Other Poles - Trans. Plant	4.32%	1,458
Transmission Plant - T	037 Steel Towers - Trans. Plant	1.26%	938,656
Transmission Plant - T	038 Insulators - Trans. Plant	4.32%	683,295
Transmission Plant - T	039 O/H Cond. - Trans. Plant	1.96%	1,865,944
Transmission Plant - T	040 O/H Cond.Devices - Trans. Plant	1.96%	44,470
Transmission Plant - T	043 Substn Dev. - Trans. Plant	2.14%	2,707,100
Transmission Plant - T	044 Substn.Transf. - Trans. Plant	2.14%	4,212,051
Transmission Plant - T	045 U/G Conduit - Trans. Plant	1.53%	19,761
Transmission Plant - T	046 U/G Conductor - Trans. Plant	2.61%	8,009
Transmission Plant - T	047 U/G Conductor Devices - Trans.	2.61%	38
Transmission Plant - T	060 Broadband Radio - Trans. Plant	2.14%	4,899
Transmission Plant - T	061 Switched Telecomm. Sys - Trans.	2.14%	62,313
Transmission Plant - T	062 Fibre Optics - Trans. Plant	2.14%	3,727
Transmission Plant - T	064 Sup. Control and DA - Trans. Pl	2.14%	18,420
Transmission Plant - T	Cap. Contr. - Trans. Plant	2.35%	(774,483)
Transmission Plant - T	Salvage Allow. - Trans. Plant	0.00%	-

2012 Depreciation Expense

Function	Forecast Depreciation Group	Depreciation Rate	Depreciation Expense
Transmission Plant - T Total			**16,398,054**
Wind Generation Plant - W	001 Land Wind Turbine	0.00%	-
Wind Generation Plant - W	Cap. Contr. - Wind Turbine	5.52%	(50,710)
Wind Generation Plant - W	Digby Wind Farm	4.00%	2,601,935
Wind Generation Plant - W	Grand Etang Wind Turbine	5.52%	158,488
Wind Generation Plant - W	Nuttby Mountain Wind	4.00%	4,470,479
Wind Generation Plant - W	Pt. Tupper Wind Farm	4.00%	1,037,270
Wind Generation Plant - W	Renewable Energy	4.00%	-
Wind Generation Plant - W	Wind Turbine	5.52%	5,752
Wind Generation Plant - W Total			**8,223,215**
Grand Total			**177,995,022**

NON-CONFIDENTIAL

Request IR-131:

Referring to FOR-1, Attachment 1, please provide documentation supporting the forecasted grants in lieu of property taxes in 2012.

Response IR-131:

Please refer to Attachment 1.

CA IR-131 Attachment 1
Nova Scotia Power Inc.
Estimated 2012 Expense for Grants in Lieu of Taxes / Property Taxes

In accordance with Financial Measures (2003) Act, NSPI is required to make two payments annually, one on January 31 and on June 1 in the amount of $15,500,000. In June 2004 and each payment thereafter, the payment must be increased by the average annual CPI for Canada for the previous calendar year. (Based on the Legislation Changes - Received May 27, 2003)

June 1, 2003	15,500,000
January 31, 2004	15,500,000
2003 CPI (used for June 2004 & Jan 2005 payments)	2.80%
June 1, 2004	15,934,000
January 31, 2005	15,934,000
2004 CPI (used for June 2005 & Jan 2006 payments)	1.90%
June 1 2005 payment	16,236,746
January 2006 payment	16,236,746
2005 CPI (used for June 2006 & Jan 2007 payments)	2.20%
June 1 2006 payment	16,593,954
January 31, 2007 payment	16,593,954
2006 CPI (used for June 2007 & Jan 2008 payments)	2.00%
June 1, 2007 payment	16,925,834
January 31, 2008 payment	16,925,834
2007 CPI (used for June 2008 & Jan 2009 payments)	2.20%
June 1, 2008 payment	17,298,202
January 31, 2009 payment	17,298,202
2008 CPI (used for June 2009 & Jan 2010 payments)	2.30%
June 1, 2009 payment	17,696,060
January 31, 2010 payment	17,696,060
2009 CPI (used for June 2010 & Jan 2011 payments)	0.30%
June 1, 2010 payment	17,749,149
January 31, 2011 payment	17,749,148
2010 CPI (used for June 2011 & Jan 2012 payments)	1.80%
June 1, 2011 payment	18,068,632
January 31, 2012 expected payment	18,068,632
2011 Estimated CPI (used for June 2012 & Jan 2013 payments)	2.20%
June 1, 2012 expected payment	18,466,142
January 31, 2012 expected payment	18,466,142

Estimated expense for:	**2012**
Based on Current Legislation:	
January - March	4,517,158
(based on amount paid on June 1, 2011)	
January - December	18,068,632
(based on amount to be paid on January 31, 2012)	
April - December (June 2012 expected payment)	13,849,607
Estimated Expense for 2012	**36,435,397**

Breakdown by Month for 2012:	June 1, 2011 Payment	Jan 31, 2012 Payment	June 1, 2012 Payment	**Total**
January	1,505,719	1,505,719		**3,011,439**
February	1,505,719	1,505,719		**3,011,439**
March	1,505,719	1,505,719		**3,011,439**
April		1,505,719	1,538,845	**3,044,565**
May		1,505,719	1,538,845	**3,044,565**
June		1,505,719	1,538,845	**3,044,565**
July		1,505,719	1,538,845	**3,044,565**
August		1,505,719	1,538,845	**3,044,565**
September		1,505,719	1,538,845	**3,044,565**
October		1,505,719	1,538,845	**3,044,565**
November		1,505,719	1,538,845	**3,044,565**
December		1,505,719	1,538,845	**3,044,565**
	4,517,158	18,068,632	13,849,607	**36,435,397**
Check	4,517,158	18,068,632	13,849,607	36,435,397

NON-CONFIDENTIAL

Request IR-132:

Referring to Schedule OE-10-OE-11, Attachment 1, please explain the addition to taxable income on line 8 for accounting amortization of financing costs, and provide supporting calculations for this item for 2012.

Response IR-132:

The addition to net income before tax on line 8 includes accounting amortization of issue costs for long term debt. This includes amortization of commissions paid, discounts or premiums on issuance and other related issue costs. The addition also includes accounting amortization of costs related to defeasing the provincially guaranteed debt of Nova Scotia Power Corporation, which was required subsequent to privatization.

Please refer to Attachment 1 for further details.

CA IR-132 Attachment 1

Accounting Amortization of Financing Costs
Millions of Dollars

	Present/Proposed Rates 2012	
Amort costs - existing 1-250	$	0.4
Amort costs - defeasance 1-252		11.9
Amort costs - new issues 1-251		1.5
Total	$	13.8

NON-CONFIDENTIAL

Request IR-133:

Referring to Schedule OE-10-OE-11, Attachment 1, please explain the deduction to taxable income on line 17 for financing cost deductions, and provide supporting calculations for this item for 2012.

Response IR-133:

The deduction to net income before tax on line 17 includes tax amortization of costs related to defeasing the provincially guaranteed debt of Nova Scotia Power Corporation, which was required subsequent to privatization. The deduction also includes tax amortization of issue costs with respect to long term debt.

Please refer to Attachment 1 for further details.

CA IR-133 Attachment 1

Tax Amortization of Financing Costs
Millions of Dollars

	Present/Proposed Rates 2012	
Defeasance - ITA 18(9.1)	$	8.4
Long term debt - ITA 20(1)(e)		1.4
Total	$	9.8

NON-CONFIDENTIAL

Request IR-134:

Referring to Schedule OE-10-OE-11, Attachment 1, please itemize the deduction to taxable income on line 21 for "Other", and provide supporting calculations for this item for 2012.

Response IR-134:

Please refer to Attachment 1.

Deduction to Net Income Before Tax - Other

Millions of Dollars

	Present/Proposed Rates 2012 ($M)
Expenditures capitalized for accounting	72.0
Capital lease payments	0.2
Total	72.2

NON-CONFIDENTIAL

Request IR-135:

Referring to Schedule OE-10-OE-11, Attachment 1, please provide workpapers supporting the forecasted 2012 CCA. The response should also reconcile the plant additions reflected in the CCA to the plant additions in 2012 on RB-01, Attachment 1, Page 4 and should explain how the forecasted plant additions in 2012 on RB-01, Attachment 1, Page 4 were assigned to CCA Rate % classifications.

Response IR-135:

Please refer to Attachment 1.

2012 CCA Schedule ($M)

Class	Rate	Opening Balance	Additions	Available for CCA	CCA	Closing Balance
1	4%	1,063.6	1.7	1,064.5	42.6	1,022.7
1	6%	56.7	-	56.7	3.4	53.3
2	6%	526.2	-	526.2	31.6	494.7
3	5%	8.8	-	8.8	0.4	8.3
8	20%	18.1	2.0	19.1	3.8	16.3
10	30%	23.7	1.0	24.2	7.3	17.4
12	100%	0.4	(0.2)	0.3	0.3	(0.1)
17	8%	409.6	97.2	458.2	36.7	470.1
45	45%	0.3	-	0.3	0.1	0.2
50	55%	-	7.5	3.8	2.1	5.5
47	8%	231.0	48.2	255.1	20.4	258.7
42	12%	0.1	-	0.1	0.0	0.1
43.2	50%	65.2	(1.3)	64.6	32.3	31.6
41	25%	0.1	-	0.1	0.0	0.1
43.1	30%	0.0	-	0.0	0.0	0.0
	SubTotal	2,404.0	**156.1**	2,482.0	181.0	2,379.0
Cumulative Eligible Capital	7%	48.7	2.6	51.2	3.6	47.7
	Total	2,452.7	158.6	2,533.3	184.6	2,426.7

Less:	
Tax shield on non-regulated assets	(0.9)
2012 CCA under present/proposed rates	**$ 183.7**

Reconciliation of Accounting Additions to Income Tax Additions ($M)

Accounting additions per RB-01	**264.9**
Adjustments:	
Non-regulated assets	5.1
Eligible capital expenditure	(2.0)
Cost of removal	8.1
Salvage	(0.4)
Land	(3.4)
Expenditures capitalized for accounting	(72.0)
Capitalized overhead	(18.8)
Interest capitalized for accounting	(25.4)
Income Tax Additions	**156.1**

CONFIDENTIAL (Attachment Only)

Request IR-136:

Referring to Schedule OE-10-OE-11, Attachment 1, please provide calculations supporting each item on lines 32-35 and lines 37-39 for each of the years shown.

Response IR-136:

Please refer to Partially Confidential Attachment 1 for details supporting items on lines 32-35.

Please refer to Partially Confidential Attachment 2 for details supporting lines 37 and 38.

Please refer to Partially Confidential Attachment 3 for details supporting line 39.

Corporate income tax calculations
Lines 32 - 35 of Partially Confidential 2012 GRA OE-10 - OE-11 Attachment 1 Page 1 of 1
Millions of Dollars

		Compliance Restated 2009	Actual 2010	Forecast 2011	Present Rates 2012	Proposed Rates 2012
Line 30 - Income for tax expense calculations		$ 185.1	$ (102.7)	[redacted]	$ 11.8	$ 107.3
Federal corporate income tax rate		x 19%	x 22.12%		x 15%	x 15%
Line 32 - Federal income tax		$ 35.1	$ (22.7)		$ 1.8	$ 16.1
Line 30 - Income for tax expense calculations		$ 185.1	$ (102.7)		$ 11.8	$ 107.3
Provincial corporate income tax rate		x 16%	x 16%		x 16%	x 16%
Line 33 - Provincial income tax		$ 29.6	$ (16.4)		$ 1.9	$ 17.2
Preferred dividends accrued in year		$ 14.1	$ 8.0		$ 8.0	$ 8.0
Part VI.1 tax rate		x 40%	x 40%		x 40%	x 40%
	A	$ 5.6	$ 3.2		$ 3.2	$ 3.2
Gross Part VI.1 tax		$ 5.6	$ 3.2		$ 3.2	$ 3.2
Deduction factor per ITA 110(1)(k)		x 3			x 9/4	x 9/4
Combined corporate income tax rate		x 35%	x 38.12%		x 31%	x 31%
	B	$ 5.9	$ 3.7		$ 2.2	$ 2.2
Line 34 - Part VI.1	**A-B**	$ (0.3)	$ (0.5)		$ 1.0	$ 1.0
Preferred dividends accrued in 2006 - 2006 statute barred in 2011						
Preferred dividends accrued in 2007 - 2007 statute barred in 2012					$ 14.1	$ 14.1
Part VI.1 tax rate					x 40%	x 40%
Deduction factor per ITA 110(1)(k)					x 3	x 3
Combined corporate income tax rate					x 38.12%	x 38.12%
Part VI.1 tax benefit received			C		$ 6.4	$ 6.4
Preferred dividends accrued in 2006 - 2006 statute barred in 2011						
Preferred dividends accrued in 2007 - 2007 statute barred in 2012					$ 14.1	$ 14.1
Part VI.1 tax rate					x 40%	x 40%
Deduction factor per ITA 110(1)(k)					x 9/4	x 9/4
Combined corporate income tax rate					x 38.12%	x 38.12%
Part VI.1 tax benefit recorded under US GAAP			D		$ 4.8	$ 4.8
Line 35 - Reversal of Part VI.1 tax liability (statute barred)			**D-C**		$ (1.6)	$ (1.6)

Notes:
1) Figures presented reflect whole numbers which may cause rounding differences on some line items.
2) 2010 rate equals the 2007 statutory rate due to loss carryback to 2007
3) 2011 rate equals the 2008 statutory rate due to loss carryback to 2008
4) Deduction factor per ITA 110(1)(k) is the substantively enacted rate for 2009 and 2010, as required by Canadian Generally Accepted Accounting Principals
5) Deduction factor per ITA 110(1)(k) is the enacted rate for 2011 and 2012, as required by United States Generally Accepted Accounting Principals

Corporate income tax adjustments

Line 37 of Partially Confidential 2012 GRA OE-10 - OE-11 Attachment 1 Page 1 of 1
Millions of Dollars

	Compliance Restated 2009	Actual 2010	Forecast 2011	Present Rates 2012	Proposed Rates 2012
2008 SR&ED benefit assessed in 2010	$ -	$ (0.4)	[redacted]	$ -	$ -
2009 T2 true-up	-	(0.3)		-	-
Rounding	-	(0.1)		(0.1)	-
Line 37 - Adjustments for tax returns and other	$ -	$ (0.8)		$ (0.1)	$ -

Line 38 of Partially Confidential 2012 GRA OE-10 - OE-11 Attachment 1 Page 1 of 1
Millions of Dollars

	Compliance Restated 2009	Actual 2010	Forecast 2011	Present Rates 2012	Proposed Rates 2012
Change in estimate of prior year tax benefits					
Expenditures capitalized for accounting	$	$ (4.1)	[redacted]	$ -	$ -
Capitalized overhead	-	(0.6)		-	-
Line 38 - Adjustments for tax returns and other	$ -	$ (4.7)		$ -	$ -

Corporate income tax adjustments
Line 39 of Partially Confidential 2012 GRA OE-10 - OE-11 Attachment 1 Page 1 of 1
Millions of Dollars

FAM future income tax ("FIT")	Compliance Restated 2009	Actual 2010	Forecast 2011	Present/Proposed Rates 2012
	n/a		[redacted]	
FAM Fuel Deferral (including Interest)		$ 9.8		$ -
2010 Tax Rate		34.0%		34.0%
FAM FIT		$ 3.3		$ -
FAM Fuel Deferral (including Interest)		$ 31.1		$ (46.7)
2011 Tax Rate		32.5%		31.0%
FAM FIT		$ 10.1		$ (14.5)
FAM Fuel Deferral (including Interest)		$ 65.7		$ -
2012 onward Tax Rate		31.0%		31.0%
FAM FIT		$ 20.4		$ -
Line 39 - FAM future income tax		$ 33.8		$ (14.5)

Notes:

1) Figures presented reflect whole numbers which may cause rounding differences on some line items.

CONFIDENTIAL (Attachment Only)

Request IR-137:

Referring to FOR-1, Attachment 1, please provide the AFUDC income and the FAM interest on Line 23 for each year separately.

Response IR-137:

Please refer to Partially Confidential Attachment 1.

Nova Scotia Power Inc.
Years Ended December 31st
Millions of Dollars

	Compliance Restated 2009	Actual 2010	Forecast 2011	Present Rates 2012	Proposed Rates 2012
Allowance for funds used during construction	$ 7.6	$ 17.2	[redacted]	$ 25.4	$ 25.4
DSM Cost Recovery Rider	-	(0.1)		-	-
FAM interest	-	3.8		3.5	3.5
Total AFUDC, DSM Cost Recovery, and FAM Interest	$ 7.6	$ 20.9		$ 28.9	$ 28.9

NON-CONFIDENTIAL

Request IR-138:

Referring to DE-03 – DE-04, page 56, lines 8-9, please provide documentation supporting the tax recovery of $5.5 million from Manufacturing and Processing tax credits from 1999-2002.

Response IR-138:

NSPI's Canada Revenue Agency Notice of Reassessments with respect to its taxation years ended December 31, 1999, to December 31, 2002, are attached as supporting documentation. Please refer to Attachment 1.

NSPI received a total refund of $8.1 million. Attachment 2 summarizes the allocation of the refund for accounting purposes and the composition of the $5.5 million recovery credited against the Section 21 regulatory asset.

Canada Revenue Agency | Agence du revenu du Canada
St. John's NL A1B 3Z1

NOVA SCOTIA POWER INCORPORATED
C/O CORPORATE TAX SERVICES
PO BOX 910 STN CENTRAL
HALIFAX NS B3J 2W5

Date of mailing	December 10, 2009
Business Number	11931 4938 RC0001
Tax year-end	December 31, 1999

0000153

CORPORATION NOTICE OF REASSESSMENT

RESULTS

This notice explains the results of our reassessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Reassessment : $ 882,807.85 Cr

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency | Agence du revenu du Canada

St. John's NL A1B 3Z1

Date of mailing	December 10, 2009
Business Number	11931 4938 RC0001
Tax year-end	December 31, 2000

0000149

NOVA SCOTIA POWER INCORPORATED
C/O CORPORATE TAX SERVICES
PO BOX 910 STN CENTRAL
HALIFAX NS B3J 2W5

CORPORATION NOTICE OF REASSESSMENT

RESULTS

This notice explains the results of our reassessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Reassessment : $ 2,504,528.13 Cr

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency   Agence du revenu du Canada

St. John's NL A1B 3Z1

Date of mailing	December 10, 2009
Business Number	11931 4938 RC0001
Tax year-end	December 31, 2001

NOVA SCOTIA POWER INCORPORATED
C/O CORPORATE TAX SERVICES
PO BOX 910 STN CENTRAL
HALIFAX NS B3J 2W5

0000143

CORPORATION NOTICE OF REASSESSMENT

RESULTS

This notice explains the results of our reassessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Reassessment : $ 2,006,496.83 Cr

Please refer to the Summary and Explanation for additional information.

Canada Revenue Agency   Agence du revenu du Canada

St. John's NL A1B 3Z1

Date of mailing	December 10, 2009
Business Number	11931 4938 RC0001
Tax year-end	December 31, 2002

0000139

NOVA SCOTIA POWER INCORPORATED
C/O CORPORATE TAX SERVICES
PO BOX 910 STN CENTRAL
HALIFAX NS B3J 2W5

CORPORATION NOTICE OF REASSESSMENT

RESULTS

This notice explains the results of our reassessment of the "T2 Corporation Income Tax Return" for the tax year indicated above. It also explains any changes we may have made to the return.

Result of this Reassessment :	$	2,731,114.60	Cr
Result of reassessment for reporting period ending December 31, 2001 :	$	2,006,496.83	Cr
Amount refunded:	$	4,737,611.43	
Prior balance:	$	0.00	
		================	
Total balance:	$	0.00	

We will deposit your refund of $4,737,611.43 into your account at the financial institution you have indicated.

Please refer to the Summary and Explanation for additional information.

CRA Refund analysis

Taxation year	Part 1 tax refund re: M&P tax credits	2001 SR&ED refund - non Section 21	Arrears Interest	Post 2002 arrears interest	Refund interest	Instalment Interest	Instalment Penalty	Post 2002 instalment Penalty	Total	
Dec 31/99	$ 492,654	$ -	$ 126,004	$ -	$ 264,150	$ -	$ -	$ -	$ 882,808	Refunded
Dec 31/00	1,505,761	-	212,220	-	748,914	27,370	10,264	-	$ 2,504,529	Refunded
Dec 31/01	1,043,010	172,927	98,677	-	598,834	67,671	25,377	-	$ 2,006,496	Refunded
Dec 31/02	1,840,507	(8,360)		22,021	806,150	51,488	-	19,308	$ 2,731,114	Refunded
	$ 4,881,932	$ 164,567	$ 436,901	$ 22,021	$ 2,418,048	$ 146,529	$ 35,641	$ 19,308	$ 8,124,947	
	A		**B**			**C**	**D**			

Summary:

Offset against Section 21 regulatory asset

Part 1 income tax	$ 4,881,932	**A**
Arrrears interest	436,901	**B**
Instalment interest	146,529	**C**
Instalment penalty	35,641	**D**
	$ 5,501,003	

NON-CONFIDENTIAL

Request IR-139:

Referring to DE-03 – DE-04, page 56, lines 8-9, was there any tax recovery from Manufacturing and Processing tax credits for years subsequent to 2002? If the response is affirmative, please provide the amounts applicable to each year subsequent to 2002 (or if not available by year, the aggregate amount for the years subsequent to 2002.)

Response IR-139:

NSPI received a $1.3 million tax recovery with respect to Manufacturing and Processing tax credits for its taxation year ended December 31, 2003. There were no tax recoveries with respect to Manufacturing and Processing tax credits subsequent to 2003.

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Request IR-140:

Referring to DE-03 – DE-04, page 56, lines 9-10, please provide workpapers supporting the reduction to the Section 21 regulatory asset. The response should show the amount of the reduction and the effect on the annual amortization, if any.

Response IR-140:

The $5.5 million tax recovery was applied to the Section 21 regulatory balance; this did not affect the 2009 annual amortization of $14.1 million. Please refer to CA IR-138 Attachment 2 for work papers.

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Request IR-141:

Referring to DE-03 – DE-04, page 57, Figure 4.2, please explain the difference between

(a) the 2010 and 2011 amortization of $13.5 million and $14.8 million, respectively and

(b) the $15.2 million and $16.3 million for 2010 and 2011 respectively in the amortization schedule in the 2009 GRA.

The response should include all supporting workpapers and calculations.

Response IR-141:

(a-b) Each year, the levelized revenue requirement schedule is updated to reflect the year end balances for Section 21 tax regulatory asset. The difference between the amortization schedule provided in the 2009 GRA and amortization amounts listed in part (a), is the amortization schedule for the revised 2010 and 2011 amortization amounts account for adjustments made to the Section 21 tax regulatory asset balance as detailed in DE-03 – DE-04 page 57 Figure 4.2 of the Application, thereby reducing the annual amortization, tax effect and carrying cost.

Please refer to Attachment 1 for detailed work papers showing the calculations for the annual amortizations shown in part (a). NSPI included the discretionary amortization expense of $10 million to the opening 2010 Section 21 balance of $75.2 million for purposes of calculating the levelized revenue requirement.

CA IR-141 Attachment 1

Nova Scotia Power Inc.													
Sec 21 Deferral - Amortization Schedule													
Thousands of dollars													
2010 (1)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Opening balance	85,218	84,123	83,022	81,915	80,803	79,684	78,560	77,429	76,292	75,149	74,000	72,845	85,218
Amortization	(1,095)	(1,101)	(1,107)	(1,113)	(1,119)	(1,125)	(1,131)	(1,137)	(1,143)	(1,149)	(1,155)	(1,161)	(13,534)
Closing balance	84,123	83,022	81,915	80,803	79,684	78,560	77,429	76,292	75,149	74,000	72,845	71,684	71,684
Weighted average cost of capital	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%
Plus: Common equity tax cost	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%	1.81%
Plus: Provincial capital tax	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax adjusted weighted average													
cost of capital	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%	9.77%
Amortization cost	1,095	1,101	1,107	1,113	1,119	1,125	1,131	1,137	1,143	1,149	1,155	1,161	13,534
Tax	564	567	570	573	576	579	582	586	589	592	595	598	6,972
Carrying cost	694	685	676	667	658	649	640	630	621	612	602	593	7,727
Net Revenue requirement	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	28,233
2011 (2)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Opening balance	71,684	70,485	69,279	68,067	66,849	65,624	64,392	63,153	61,908	60,656	59,397	58,132	71,684
Amortization	(1,199)	(1,205)	(1,212)	(1,219)	(1,225)	(1,232)	(1,239)	(1,245)	(1,252)	(1,259)	(1,266)	(1,272)	(14,825)
Closing balance	70,485	69,279	68,067	66,849	65,624	64,392	63,153	61,908	60,656	59,397	58,132	56,859	56,859
Weighted average cost of capital	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%	7.96%
Plus: Common equity tax cost	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%	1.69%
Plus: Provincial capital tax	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Tax adjusted weighted average													
cost of capital	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%	9.65%
Amortization cost	1,199	1,205	1,212	1,219	1,225	1,232	1,239	1,245	1,252	1,259	1,266	1,272	14,825
Tax	577	580	584	587	590	593	596	600	603	606	609	613	7,138
Carrying cost	577	567	557	547	538	528	518	508	498	488	478	468	6,270
Net Revenue requirement	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	2,353	28,233

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Request IR-142:

Referring to DE-03 – DE-04, page 57, Figure 4.2, please explain why the amortization decreases from $14.1 million in 2009 to $13.5 million in 2010, although the intent of the levelization method is to have the amortization increase from year to year.

Response IR-142:

The decrease in amortization for 2010 is a result of updating the opening 2010 Section 21 tax regulatory asset balance to reflect 2009 actuals. The reduced 2010 regulatory asset opening balance resulted in decreased total future carrying costs, subsequently reducing the annual amortization.

Please refer to CA IR-141.

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Request IR-143:

Referring to DE-03 – DE-04, page 57, Figure 4.2, please explain how the discretionary amortization in each year was determined. The response should include all supporting workpapers and calculations.

Response IR-143:

The 2009 Return on Equity settlement allows NSPI to recognize additional amortization amounts in current periods, and reduce amounts in future periods. Please refer to page 56 of the Application, lines 19-27, for details on the discretionary amortization amounts taken. Amounts were determined by NSPI Management discretion including consideration of future customer rate requirements.

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Request IR-144:

Referring to DE-03 – DE-04, page 57, please provide workpapers supporting Figure 4.3. The response should be provided in Excel format, with formulas intact.

Response IR-144:

Please refer to Attachment 1, filed electronically.

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Request IR-145:

Please provide a copy of the confidential version of Appendix B to the currently approved Plan of Administration.

Response IR-145:

Please refer to Confidential Attachment 1.

Request IR-146:

Reference GRA Exhibits DE-03 and -04, p. 16. With respect to the Company's proposal to recover Point Tupper depreciation, financing, and OM&G costs through the "fixed rate component" of base rates:

(a) Please clarify what is meant by the reference to the "fixed rate component" of base rates. Is this intended to refer to rate components other than the Base Cost of Fuel?

(b) Please fill in the cost information in the following table regarding the Company's share of Point Tupper expenses and revenues.

	2010 Actual	**2011 BCF**	**2012 Forecast**
Fuel Expense (100% PPA)			
Project OM&G (49%)			
NSPI Internal OM&G			
Depreciation			
Finance Cost			
Sales Revenue (49%)			
EcoEnergy Revenue (49%)			

(c) Please specify which of the expense and revenue categories listed in the above table that the Company proposes to recover through the "fixed rate component" of base rates. For each expense or revenue category proposed for recovery in this fashion, please provide the rationale for recovering such item outside of the Fuel Adjustment Mechanism.

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(d) With regard to the Company's forecast for 2012 for Point Tupper finance cost (as indicated in the above table), please indicate whether and to what extent the forecast of finance cost will change as a result of the Company's proposal. Please show all calculations relied on to estimate the change in forecasted finance cost for 2012 as a result of the Company's proposal.

Response IR-146:

(a) Per the Board's December 21, 2010, approval of the accounting methodology applied to Point Tupper Wind, the cost of OM&G, financing and depreciation associated with NSPI's investment in Point Tupper Wind is included as a FAM expense and recovered from customers in accordance with the Board approved FAM processes. NSPI's current Application represents a change in accounting treatment for Point Tupper Wind financing costs from a fuel (i.e. FAM) expense to a non-fuel (i.e. fixed rate component or non-FAM) expense, which is the traditional manner to recover these types of costs.

(b) For 2010 actuals, please refer to Confidential Attachment 1.

	2011 BCF ($M)	**2012 Forecast ($M)**
Fuel Expense (100% PPA)	**2.8**	**5.6**
Project OM&G (49%)	**-**	**0.7**
NSPI Internal OM&G	**-**	**-**
Depreciation	**-**	**1.0**
Finance Cost	**-**	**1.0**
Sales Revenue (49%)	**1.4**	**2.7**
EcoEnergy Revenue (49%)	**(0.1)**	**(0.3)**

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(c) Please refer to Multeese IR-17.

(d) The proposed change will have no effect on the actual cost of financing the Point Tupper Wind Farm investment.

Request IR-147:

Reference GRA Exhibits DE-03 and -04, p. 18.

(a) Please provide copies of all input data files for the preliminary Strategist run relied on to forecast a fuel cost of $573.9 million for the 2012 test year.

(b) Please provide complete documentation of all adjustments made to the following Strategist inputs pursuant to Appendix B of the Plan of Administration:

(i) Heat Rate

(ii) Unit Maximum Capacities

(iii) Deration Factor

(iv) De-rated Adjusted Forced Outage Rate

(c) Please provide complete documentation of the estimation of hourly generation for 2012 from each of the Company's wind facilities.

(d) Please provide complete documentation of the derivation of price and volume inputs for each of the IPP contracts with wind facilities.

(e) Please provide copies of all output reports from the runs (preliminary and final) of Strategist, the Coal Model, and the Financial Model relied on to forecast a fuel cost of $573.9 million for the 2012 test year.

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Response IR-147:

(a-b) Input data files used in Strategist are included in the confidential FAM Data Room binder GE0022, 2012 GRA Source Information, available for viewing at NSPI offices.

(c) Forecast annual generation of each wind project is derived from the most recent three-year average of actual generation. A historical monthly profile is then applied to the annual forecast to determine generation by month. Subsequently, an hourly wind shape is applied to the monthly forecasts in Strategist to determine hourly requirements. The annual and monthly data are included in the binder referenced in part (a), Overall Information tab, IPP Production Forecast sheets. The hourly wind shape is attached in Confidential Attachment 1. Strategist uses one representative week per month.

(d) Please refer to the confidential FAM Data Room binder GE0022, Overall Information tab, available for viewing at NSPI offices.

(e) Fuel forecast output reports are included in the confidential FAM Data Room binder GE0022, 2012 GRA Source Information, available for viewing at NSPI offices.

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Request IR-148:

Reference GRA Exhibits DE-03 and -04, p. 18.

(a) Please confirm that the forecast of fuel cost for the 2012 test year was derived using the currently approved low sulphur fuel forecasting methodology, as opposed to the methodology proposed in the May 20, 2011 letter from NSPI to the Board.

(b) Has the Company estimated the impact on its forecast of fuel cost for the 2012 test year from adoption of the proposed methodology? If so, please provide this estimate.

Response IR-148:

(a) Confirmed.

(b) No, NSPI has not estimated the impact of the new methodology on the 2012 GRA. The Board approved this methodology on June 29th, 2011 and NSPI will use it when the Fuel and Purchased Power Forecast is updated in accordance with the FAM schedule (and simultaneously filed in the GRA proceeding).

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Request IR-149:

Reference GRA Exhibits DE-03 and -04, p. 18.

(a) Please provide the provincial emissions limits effective in 2012 for mercury, nitrogen oxides, sulphur dioxide, and carbon dioxide.

(b) Please provide the Company's forecast of emissions in the 2012 test year of mercury, nitrogen oxides, sulphur dioxide, and carbon dioxide.

Response IR-149:

(a) Please refer to the table below.

Emission	Provincial Limit for 2012
Mercury	100 kg
Nitrogen Oxides	21,365 Tonnes
Sulphur Dioxide	72,500 Tonnes
Carbon Dioxide	18.5 million Tonnes in total for 2012 and 2013

(b) The forecast emissions for 2012 are 100 kg of Mercury; 17,500 Tonnes of nitrogen oxides; 71,000 Tonnes of sulphur dioxide; and 9.3 million Tonnes of carbon dioxide.

Emissions forecasts will be updated as part of the FAM schedule.

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Request IR-150:

Reference GRA Exhibits DE-03 and -04, p. 26. With respect to the statement that the "Tufts Cove units were historically on the margin":

(a) Please provide the percentage of on-peak hours that Tufts Cove units were on the margin in 2009 and 2010.

(b) Please provide the Company's forecast for the percentage of on-peak hours that Tufts Cove units are expected to be on the margin in 2011 and 2012.

(c) Please provide the percentage of off-peak hours that Tufts Cove units were on the margin in 2009 and 2010.

(d) Please provide the Company's forecast for the percentage of off-peak hours that Tufts Cove units are expected to be on the margin in 2011 and 2012.

Response IR-150:

(a) The Tufts Cove Units were on the margin during on-peak hours 17 percent of the time in 2009 and 23 percent of the time in 2010.

(b) Tufts Cove total percentage of hours on the margin was forecast to be 17 percent in 2011 and 34 percent in 2012. These values were derived from the strategist runs for the 2011 BCF and the 2012 GRA. Strategist is not able to produce hourly profiles for the year and so is not able to distinguish between on-peak and off-peak hours. Strategist calculates the time on margin by reducing load by a fixed amount across all hours through the year and then comparing the output to the initial run to determine which units were serving the margin. Historical on-peak and off-peak hours are separately tracked on an hour-by-hour basis and therefore the historical values and the forecast values are not directly comparable.

(c) The Tufts Cove Units were on the margin during off-peak hours 23 percent of the time in 2009 and 32 percent of the time in 2010

(d) Please refer to part (b) above.

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Request IR-151:

Reference GRA Exhibits DE-03 and -04, p. 36.

(a) **Please provide a complete description of current plans for testing alternate fuels at Point Aconi. As part of this description, please indicate the alternate fuels being considered, the timetable for commencing and completing testing of alternate fuels, and the target date for switching Point Aconi away from petcoke.**

(b) **Please provide copies of all studies of the potential for, and costs associated with, fuel switching at Point Aconi.**

Response IR-151:

(a-b) Please refer to NPB IR-102 and Liberty IR-74.

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Request IR-152:

Reference GRA Exhibits DE-03 and -04, p. 38.

(a) Please provide all input assumptions, including forward market prices and basis adjustments, relied on to derive the forecast for 2012 of the average cost of natural gas consumed at Tufts Cove.

(b) Please show all calculations relied on to derive from input assumptions the forecast for 2012 of the average cost of natural gas consumed at Tufts Cove.

(c) Please provide all workpapers, including all electronic spreadsheets (with cell formulas intact), relied on to derive the forecast for 2012 of the average cost of natural gas consumed at Tufts Cove.

Response IR-152:

(a) Input assumptions are included in the confidential FAM Data Room binder GE0022, 2012 GRA Source Information available for viewing at NSPI offices. (Please refer to Overall Information tab, Forward Prices sheet and Financial Model tab, Tufts Cove sheet.)

(b) Calculations are included in the data room binder GE0022, Financial Model tab, Tufts Cove and Natural Gas Derivatives sheets.

(c) Please refer to FAM Data Room binder GE0022, available for viewing at NSPI offices. The average cost of natural gas at Tufts Cove is not calculated separately from the rest of the Total Fuel and Purchased Power forecast. The cost is derived based on forward market prices with basis adjustments, contract adjustments including tolls and retainage

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fees, hedges in place at the time of the forecast, all converted into Canadian dollars using the foreign exchange rate calculated as at December 31, 2010. Operational information such as heat rate and derating-adjusted forced outage rate (DAFOR) are also used in arriving at a consumed price.

Request IR-153:

Reference GRA Exhibit OE-01A, Attachment 1, p. 1.

(a) **Please provide complete documentation of the derivation of the monthly forecast of import costs.**

(b) **Please provide the derivation of the monthly estimates of the import volumes and import prices underlying the forecast of import costs, including all historical data and adjustments used in the derivation of monthly import volumes and prices. Please show how the derivation of the monthly estimates for import volumes and prices is in accordance with the methodology established in Appendix B to the Plan of Administration.**

Response IR-153:

(a-b) Please refer to the FAM confidential data room binder GE0022, available for viewing at NSPI offices. (Overall Information tab, Import Power Load Assumptions and Import Power Forward Prices sheets.)

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Request IR-154:

Reference GRA Exhibit OE-01A, Attachment 1, p. 7.

(a) **Please provide complete documentation of the derivation of the monthly values for the following forecasted items, including all historical data and adjustments used to derive monthly values. For each forecasted item, please show how the derivation of the monthly value is in accordance with the methodology established in Appendix B to the Plan of Administration.**

(i) **Generation for exports.**

(ii) **Losses on generation for exports.**

(iii) **Sales revenue.**

(iv) **Cost of sales by unit.**

(v) **Net margin on exports.**

(vi) **Net margin per MWh.**

(b) **Please provide versions of this report for actual monthly results in 2009, 2010, and 2011 year-to-date.**

(c) **Please provide versions of this report for actual monthly results in 2009, 2010, and 2011 year-to-date with all results reported separately for on-peak and off-peak hours.**

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(d) Please provide copies of all memoranda or reports by NSPI employees or consultants retained by NSPI regarding opportunities for either on-peak or off-peak export sales in 2012, forecasts of market prices for exports, estimates of net margins on export sales, or strategies for maximizing export margins in 2012.

Response IR-154:

(a) Input data files used to calculate export volumes, prices, and revenue are included in the Confidential FAM data room binder GE0022, 2012 GRA Source Information, Overall Information tab, Export Generation and Export Sales Margin sheets and Financial Model tab, Export Sales Revenue and Costs sheet, available for viewing at NSPI offices.

(b) Please refer to Confidential Attachment 1.

(c) Please refer to Confidential Attachment 2.

(d) No such memoranda or reports exist.

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Request IR-155:

GRA Exhibit OE-01A, Attachment 1, p. 10.

(a) Please indicate whether the monthly forecasts of generation for Tufts Cove 2 and 3 include the assumed generation for export sales. If not, please provide the additional monthly generation from these units assumed for the purposes of forecasting export sales. Please reconcile these monthly values with those provided on page 7 of GRA Exhibit OE-01A, Attachment 1.

Response IR-155:

(a) Monthly forecasts of generation at the individual units include generation for exports. As such, the export amounts on page 7 of GRA Exhibit OE-01A, Attachment 1 are included in the unit totals.

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Request IR-156:

Reference GRA Exhibit OE-01B, Attachment 1, p. 7.

(a) Please provide complete documentation of the derivation of the monthly values for the following forecasted items, including all historical data and adjustments used to derive monthly values. For each forecasted item, please show how the derivation of the monthly value is in accordance with the methodology established in Appendix B to the Plan of Administration.

(i) Generation for exports.

(ii) Losses on generation for exports.

(iii) Sales revenue.

(iv) Cost of sales by unit.

(v) Net margin on exports.

(vi) Net margin per MWh.

Response IR-156:

(a) Please refer to FAM confidential data room binder GE-0013, 2011 BCF Source Information available for viewing at NSPI offices. (Overall Information tab, Export Generation and Export Sales Margin sheets and Financial Model tab, Export Sales Revenue and Costs sheet)