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Request IR-1:

Reference: DE, page 12. "We have updated this previous benchmarking to demonstrate to our customers that N.S. Power's operating expenses compare favourably to other Canadian utilities."

Please

(a) indicate when the update occurred,

(b) identify how many NSPI employees were involved directly in the update and state their positions with NSPI, and

(c) describe in detail how this benchmarking update was carried out.

Response IR-1:

(a) The update was completed in March 2011.

(b) The update was completed by the Director of Strategic Planning under the direction of the Executive Vice President of Sustainability.

(c) Appendix B, page 3 of the application describes the approach used in the benchmarking update.

REDACTED

Request IR-2:

Reference: DE, pages 30-31. Figure 2.5 shows that as at December 31, 2010, NSPI has an open percentage requirement of solid fuel of [redacted].

Please provide an update to figures 2.5 and 2.6 as of the date of the Application. Please also provide NSPI's most updated forecast of the amount of low sulphur coal (in tonnes) that is forecast to be consumed in 2012, as well as the 2011 carry-over inventory expected to be available in 2012, and the expected cost of that inventory on a $/MMBtu basis.

Response IR-2:

NSPI will file an updated forecast in the FAM and GRA processes, in accordance with the FAM schedule, by the end of August, 2011. This will provide the most up to date information to the UARB at the time of the hearing and aligns with established processes.

REDACTED

Request IR-3:

Reference: DE, page 34 and OE-01H. "Petroleum coke purchases are generally made on an as delivered basis with the supplier responsible for freight."

(a) Please provide a detailed explanation for the [redacted] in ocean freight for petroleum coke of $[redacted]CDN/MT as shown in OE-01H for the 2011 BCF, versus $[redacted]CDN/MT shown in OE-01H for the 2012 GRA.

(b) Is the $[redacted]CDN/MT a supplier freight price or an NSPI contracted freight price? If an NSPI contracted freight price, please explain the statement at page 34.

(c) Has NSPI considered negotiating to purchase petcoke ex freight and arrange its own freight? If not, why not?

Response IR-3:

(a) Please refer to Liberty IR-16.

(b) The $[redacted] CDN/MT is an NSPI contracted freight price. The open portion of petroleum coke is forecasted using the POA Appendix B without freight included. NSPI uses the contracted price for freight. As we enter into new contracts to close the open position, the petroleum coke contracts may include transportation costs.

(c) NSPI has purchased petroleum coke without freight included. The decision to purchase petroleum coke with or without freight included is dependent on many factors such as refinery policy, price, vessel availability and current NSPI freight contracts.

REDACTED

Request IR-4:

Reference: DE, page 35, Figure 2.9 and OE-01K. For the forecast of low sulphur coal, [redacted] were used in the development of the forecast.

Please identify the efforts, if any, undertaken by NSPI to obtain supplier bids within [redacted] of the start of the Fuel Forecast Development.

Response IR-4:

NSPI's efforts to solicit the market place are based upon inventory levels and portfolio requirements. Changes in relative forward gas and coal pricing during the fourth quarter of 2010 suggested that considerably more gas would be consumed in 2011 than had been anticipated in the 2011 BCF. The level of fuel switching between the two commodities was such that much of the low sulphur open position for 2011 would be displaced. NSPI elected to continue to monitor the gas market and projected coal inventories until the second quarter of 2010 before continuing to fill the 2011 open position. By doing so, NSPI would be increasing its ability to switch to lower priced gas in 2011 and it would be reducing the potential for inventory carryovers into 2012.

REDACTED

Request IR-5:

Reference: DE, page 40, OE-01A, and OE-01B. "We anticipate consuming 46,000 barrels of HFO in 2012 as support fuel at our coal fired plants, compared to 44,000 barrels in 2011 BCF."

OE-01B, Attachment 1, page 2 shows net generation of solid fuel at Lingan of [redacted] Gwh and HFO generation of [redacted] GWh in the 2011 BCF. For 2012 (as shown in OE-01A, Attachment 1, page 2), solid fuel generation at Lingan is forecast to be [redacted] GWh ([redacted]) but HFO generation is shown as [redacted] GWh, which is [redacted] GWh. Please explain in detail why HFO generation is forecast [redacted].

Response IR-5:

In the 2012 GRA, HFO is consumed at Lingan as an auxiliary fuel, which is forecast, according the FAM POA Appendix B, based on a simple average of usage over the last three years. The information below illustrates the methodology for the auxiliary fuel after the simple average is calculated.

	2011 BCF	**2012 GRA**
Total Lingan Consumption – All Fuels (GBtu)	44,607.5	45,041.9
Auxiliary Fuel, as a percent of total Lingan consumption	0.43%	0.56%
Total Auxiliary Fuel at Lingan (GBtu)	190.9	254.1
HFO as a percent of Total Auxiliary Fuel	72.16%	81.55%
Total HFO Consumption at Lingan (GBtu)	138.0	207.1

These figures are rounded.

NON-CONFIDENTIAL

Request IR-6:

Reference: DE, page 43 and OP-06, Attachment 1, page 1. "The total capacity from these pre-2001 contracts totals about 24 MW and provides approximately 170 GWh annually."

The energy in GWh in OP-06 for contract IPPs (pre-2001) is listed as 198 GWh, not 170 GWh. Please reconcile and explain the difference between these two numbers and indicate which is correct.

Response IR-6:

The forecasted generation from all pre-2001 IPPs is 170 GWh. The forecasted generation from all non-wind IPPs is 198 GWh**.**

NON-CONFIDENTIAL

Request IR-7:

Reference: DE, page 45, Tidal Energy.

Please identify all costs, if any, that have been included in the test year that are associated with tidal energy, other than the costs associated with the Annapolis tidal generating plant. If there are such costs, please itemize them in detail.

Response IR-7:

We understand the question to refer to fuel and purchased power costs. There are no other tidal energy costs included in the 2012 test year for fuel and purchased power forecast; however, employees in various other departments spend time working on matters relating to tidal energy and $300,000 is included in OM&G in 2012 for berthing fees for the in-stream tidal unit.

REDACTED

Request IR-8:

Reference: DE, page 47 and OE-12. "Through our purchase of forward foreign exchange contracts, we have 47% of our 2012 USD requirement at an average of 0.9960 and a forecast blended rate of 1.0089 on all fuel costs in this Application."

(a) OE-12, Attachment 1, shows [redacted] hedged at a rate of [redacted] of a total forecast requirement of [redacted]. This hedged amount is [redacted] not 47%. Please explain why there appears to be a discrepancy between OE-12, Attachment 1, and NSPI's comments on page 47.

(b) The unhedged U.S. dollar figure used to calculate NSPI's FX contracts for 2012 is shown as of December 31, 2010 at a rate of [redacted]. Please provide the most up-to-date forecasts from the various financial institutions if NSPI has more current forecasts from these financial institutions than those used in the Forecast Fuel Development.

Response IR-8:

(a) As part of our forecasting process, OE-12, Attachment 1 reflects the most updated information in order to start the GRA forecast process and is used as an exchange rate in preparing the application. For this purpose, the USD forecast used was [redacted].

Once the 2012 GRA forecast is completed, a new USD requirement is produced. This increased to [redacted]. The [redacted] hedged, is [redacted] percent of the new requirement.

REDACTED

(b) The unhedged 2012 average updated rate is $0.99 CAD to 1.00 USD.

As of June 17, 2011				
FX Forecasts	**Q1/12**	**Q2/12**	**Q3/12**	**Q4/12**
BMO (Jun 17)	0.95	0.96	0.97	0.97
BNS (Jun 1)	0.94	0.94	0.93	0.92
RBC (Jun 1)	0.97	1.00	1.02	1.02
CIBC (Jun 15)	1.02	1.00	0.98	0.97
TD (Jun 14)	1.00	0.98	0.97	0.95
Bank of America (Jun 1)	1.04	1.05	1.06	1.07
Average	0.99	0.99	0.99	0.98

NON-CONFIDENTIAL

Request IR-9:

Reference: DE, page 50. "NS Power will file an updated fuel standardized filing for this GRA Application no later than August 31."

Please confirm that for this update NSPI will re-run Strategist, and will also list any new contracts for committed volumes and/or fuel hedges that NSPI has entered into after the start date of the Fuel Forecast Development, and reflect the change in contracts committed, applicable hedges and updates of market fuel prices and the foreign exchange rate.

Response IR-9:

Confirmed.

REDACTED

Request IR-10:

Reference: DE, page 51. "NS Power is requesting that its portion of the Point Tupper Wind Farm's OM&G, financing and depreciation costs, now recovered through the FAM, be recovered through our non-fuel rate components effective for the 2012 test year."

(a) Please confirm that under its proposal, NSPI's actual portion of the Project Profits from the Point Tupper Wind Farm will continue to flow through to customers under the FAM.

(b) Please identify the level of OM&G, financing, and depreciation costs that NSPI proposes to include in this Application for the Point Tupper Wind Farm.

(c) Please provide NSPI's actual OM&G, financing, and depreciation costs by month since the commissioning of the Point Tupper Wind Farm.

Response IR-10:

(a) Effective January 1, 2012, the IPP cost and associated Eco Energy credits as well as NSPI's portion of the project revenue would flow through the FAM. The OM&G, financing and depreciation would be recovered through the non-fuel rate.

(b)

OM&G	[redacted]
Financing	$981,558
Depreciation	[redacted]

(c) Please refer to Confidential Attachment 1.

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Request IR-11:

Reference: DE, page 53. "The total depreciable plant balance used in the 2012 test year has increased by about $990 million over 2009 compliance, due to in-service additions filed through the ACE Program for 2010 and forecasted 2011 and 2012."

(a) Please provide a detailed and itemized breakdown of the increase of $990 million to the depreciable plant balance based on projects that have been approved by the Board versus does that have not yet been approved by the Board.

(b) For all depreciable plant not currently in-service which makes up a part of the $990 million increase, please provide the forecasted in-service dates.

Response IR-11:

(a-b) Please refer to Attachment 1 for a detailed list of the actual 2010 additions included. Please refer to Attachment 2 for the list of forecasted additions for 2011 and 2012. The forecasted projects and cost reflect items included as part of the Application which was prepared in advance of the 2011 ACE Plan. Project approval reflects initial work order application by the UARB only. Approvals are as of June 15, 2011.

2010 Actual Additions

Project #	CI	Project Title	Addition ($)	Approved
W107	36882-W107	Nuttby Mountain Wind Project Dev	109,845,132	Y
W111	39592-W111	PE Digby Wind Project	64,742,447	Y
W112	39084-W112	Point Tupper Wind Project	25,874,382	Y
P773	28413-P773	Work Management System Replacement	16,531,877	Y
H574	31244-H574	HYD Paradise Wood Stave Pipeline R	9,454,795	Y
S629	38834-S629	TRE5 - Turbine Upgrades - LP/IP/HP	5,922,846	Y
T602	29008-T602	Construct 139H Dartmouth Crossing S	4,659,794	Y
S428	34203-S428	LIN Unit #3 Mercury Abatement	4,507,211	Y
G147	38402-G147	CT U&U LM#4 Engine Refurbish	4,320,170	Y
T642	39763-T642	PE Digby Wind Farm Substation	4,316,122	Y
T645	39764-T645	PE Digby Wind Farm Trans. Line	4,040,597	Y
S615	38362-S615	TUC U&U #1 GEN ROTOR RESTORE	4,000,963	Y
S652	37609-S652	LIN - Unit #1 Rotor Rewind	3,822,850	Y
T623	37942-T623	Nuttby Mountain Wind Project Substa	2,970,718	Y
T592	29013-T592	82V Elmsdale Transformer Addition	2,923,227	Y
S430	34223-S430	POT Mercury Abatement Project	2,817,844	Y
S495	38382-S495	TUC U&U #3 Bus Duct Replacement	2,788,460	Y
S620	34062-S620	TRE5 - Condenser Upgrades	2,749,306	Y
S432	34242-S432	TRE Unit #6 Mercury Abatement	2,122,569	Y
S251	28487-S251	LIN Supplemental Water Supply	2,073,327	Y
S426	34182-S426	LIN Unit #1 Mercury Abatement	2,032,202	Y
T595	29012-T595	UPGRADE L6537	1,972,850	Y
S429	34222-S429	LIN Unit #4 Mercury Abatement	1,971,632	Y
S427	34202-S427	LIN Unit #2 Mercury Abatement	1,960,870	Y
H571	31203-H571	HYD Toms Lake Dam Safety Remedial W	1,958,723	Y
S431	34224-S431	TRE Unit#5 Mercury Abatement	1,863,276	Y
S657	38942-S657	TUC #3 GENERATOR ROTOR REWIND	1,808,682	Y
S651	38442-S651	LIN-U&U Unit#2 ESP Flow Modif	1,691,228	Y
S595	38943-S595	LIN1 - Boiler Refurbishment	1,664,581	Y
S505	36222-S505	TUC #2 U&U Generator Refurbishment	1,608,410	Y
P806	39188-P806	PE Transportation Vehicle Replace	1,597,303	Y
H555	33942-H555	U&U Coon Pond Pipeline Replacement	1,595,104	Y
H572	32442-H572	HYD Ridge Spillway Refurbishment	1,568,145	Y
T631	39167-T631	PE L7011 Deteriorated Replacements	1,558,806	Y
D249	35642-D249	2009 Recloser Additions	1,546,619	Y
T596	29010-T596	Install 138-25KV Transformer At 22C	1,530,566	Y
D173	31042-D173	Metro St Light & Service Work	1,509,505	Y
H530	28570-H530	HYD Hollow Bridge Generator Rewind	1,492,476	Y
D263	39175-D263	PE 2010 Recloser Additions	1,466,773	Y
D271	39176-D271	PE 2010 Dist. Cutout Replacements	1,380,956	Y
P740	28788-P740	3RD PARTY HIGH VOLUME CALL ANSWER S	1,336,627	Y
P807	39189-P807	PE Class 3 Light Work Vehicles	1,196,975	Y
P810	33642-P810	2009 Transportation Vehicle Replace	1,195,228	Y
D250	35882-D250	2009 Cutout Replacements	1,144,245	Y
S648	37743-S648	LIN1 - CW Large Bore Pipe Replaceme	1,097,709	Y
S641	34702-S641	LIN - Mill Component Replacement	1,093,725	Y
D317	38888-D317	50N-412 Targeted Replacements	1,041,181	Y
D266	39180-D266	PE 2010 Off Road to Roadside	1,004,972	Y
G151	28752-G151	LM6000 - Overhaul TUC #5 Engine	990,129	Y
S580	24509-S580	TUC - Replace Unit #3 Turbine Super	933,409	Y
S644	38851-S644	LIN - Coal Belt Sampler	925,571	Y
S649	39443-S649	LIN1-U&U Turbine Fastener Replace	921,671	Y
D318	33766-D318	11S-411 Targeted Replacements	894,074	Y
H563	14361-H563	HYD Soldiers Lake Dam Safe	892,759	Y
S621	34367-S621	POA - 2010 Refractory Program	792,217	Y
S522	24722-S522	LIN1-Turbine Supervisory Control Re	760,478	Y
P813	38900-P813	Opsym	758,682	Y
D172	31082-D172	East St. Light and Service Install	753,954	Y
P824	34748-P824	Upgrade Microsoft Office Pro	751,574	Y
S467	30967-S467	LIN3 Replace #4 HP Heater	745,854	Y
H568	36342-H568	U&U Tusket Tainter Gate	740,812	Y
D224	36183-D224	Reliability Replacements East	732,448	Y
S469	30970-S469	LIN3 Replace #6 HP Heater	714,078	Y
D239	33762-D239	73W-411 Device Replacements/ Reliab	669,609	Y
H521	10900-H521	HYD DEB # 10 - Generator Rewind	661,302	Y

2010 Actual Additions

Project #	CI	Project Title	Addition ($)	Approved
P787	35842-P787	Nuttby Mount. Wind Land Rights U&U	648,885	Y
H582	31225-H582	HYD Weymouth Falls # 1 Runner	642,173	Y
D222	36142-D222	Reliability Replacements - West	640,682	Y
S530	37563-S530	TRE6 - Bottom Ash System Refurbish	636,729	Y
S547	34504-S547	TRE6 - Waterwall Panel Replacement	632,420	Y
S413	28914-S413	LIN 2008 CW Pump Rebuild	628,180	Y
D319	38890-D319	57C-426 Targeted Replacements	626,309	Y
S625	38946-S625	LIN1 - Replace High Voltage Bushin	625,106	Y
S650	39603-S650	TRE6 - (PE) Boiler Superheater/Rehe	614,896	Y
S494	36482-S494	LIN4-U&U-3/4 Turbine Bearing Rep.	609,445	Y
S562	37542-S562	TRE - Unit 1-4 Roof Replacement	602,035	Y
S561	34690-S561	LIN - Boiler Feed Pump Rebuild	600,703	Y
S577	38843-S577	TRE5 - FD Fan Refurbishments	590,513	Y
T622	35862-T622	2009 Transmission Switching Improve	589,943	Y
T621	35202-T621	St. Croix to Avon - Reconductor 69	585,495	Y
S592	38728-S592	TRE5 - Hot End Air Heater Basket	584,265	Y
D282	39281-D282	2010 Central St Light & Serv. Work	577,934	Y
S480	33662-S480	LIN2 Replace High Voltage Bushings	566,649	Y
D301	38903-D301	Halifax UG Cable Replacement	547,951	Y
T624	37944-T624	Nuttby Mountain Wind Project Trans	544,105	Y
S408	32002-S408	TUC#1 Chimney Liner Restoration	543,088	Y
S662	39471-S662	TRE6 - (U&U) PA Damper Replacements	537,082	Y
S491	36282-S491	LIN3 - U&U- LTSH1 Bend Replacements	529,695	Y
D132	28494-D132	2007 Northeast Replace Arrestors	526,940	Y
T606	33464-T606	2009 Tx Line Insulator Replacement	525,579	Y
D171	31062-D171	West St. Light & Service Install	513,805	Y
P745	28395-P745	CIS CLEANUP & HARDWARE UPGRADE	512,841	Y
S531	37622-S531	TRE - Facilities Improvement	502,764	Y
D252	38682-D252	Dartmouth East New Feeder	496,677	Y
S445	32582-S445	POT Front Water Wall Panel Replacem	493,326	Y
S492	34442-S492	LIN1 - U&U Re-Heat Bend Replacement	492,890	Y
S552	37834-S552	TRE6 - Pulverizer Ductwork	488,027	Y
S264	28865-S264	POT-UNIT#2 LOW NOX COMBUSTION FIRIN	487,387	Y
S565	38582-S565	TRE6 - Airheater Refurbishment	485,531	Y
P820	37722-P820	PeopleSoft Upgrade	478,877	Y
P771	33602-P771	CIP Standards Implementation	458,903	Y
D199	29019-D199	Convert 12.5Kv Tie- Rockingham To S	456,266	Y
S398	30942-S398	LIN Floor Grating and Structural Up	452,641	Y
S500	38933-S500	TRE5 - P/E - Pulverizers Overhauls	433,600	Y
G145	35682-G145	CT LM#5 U&U Combustor Replace	424,203	Y
S440	31282-S440	LIN 1&2 Precip. Out Duct & Clad Res	423,192	Y
P799	33502-P799	FAC Environmental Site Assessment	422,903	Y
S579	38883-S579	TRE - DCMS Upgrade - Phase 2	419,061	Y
D288	39408-D288	2010 Padmount Replacement Program	417,809	Y
D216	35442-D216	Margaretsville Upgrade	416,479	Y
D280	39279-D280	2010 Reliability Replacmnts Central	414,384	Y
P812	38244-P812	Replace Microwave Radio Systems	410,003	Y
D238	33742-D238	22C-404 Device Replacements	408,850	Y
T641	38858-T641	L6002 Deteriorated Replacements	398,688	Y
S593	38729-S593	TRE5 - Replace Demin and Reserve	397,460	Y
S474	31544-S474	LIN2 Super Heater Hanger Replaceme	391,520	Y
T638	38860-T638	2010 Pole Retreatment	387,617	Y
D303	38885-D303	19C Canso Distribution Supply	381,876	Y
P825	39144-P825	U&U PowerPlant Version 10 Upgrade	380,575	Y
P823	39623-P823	LIN-U&U-CW Pump Refurbishment	378,757	Y
S566	38622-S566	TRE6 - Pulverizer Refurbishment	370,614	Y
H590	39082-H590	HYD - U&U Nictaux Headcover	367,811	Y
D237	33764-D237	103H-432 Device Replacements/ Relia	363,053	Y
D206	34982-D206	Padmount Replacement Program 2009	360,754	Y
D281	39280-D281	2010 Reliability Replacements East	359,502	Y
D302	38025-D302	131H-422 Targeted Replacements	357,111	Y
D278	39277-D278	Scotch Village Phase 1	341,847	Y
S529	36802-S529	LIN1 - ESP Outlet Duct Expansion J	323,782	Y
S420	30322-S420	TUC3 Replace Main Steam Stop Valv	320,937	Y
H588	36382-H588	U&U WRC Unit #1 Spherical Valve	320,672	Y

2010 Actual Additions

Project #	CI	Project Title	Addition ($)	Approved
S525	34502-S525	TRE - Asbestos Abatement 2010	317,102	Y
D243	37302-D243	Tupperville Plant Replacement	315,065	Y
S470	31162-S470	LIN2 Condenser Tube Plastocor Upgra	314,153	Y
D217	33463-D217	20H-306 Conversion 12 kV to 25 kV	311,102	Y
D254	33763-D254	58H-431 Device Replacements	308,226	Y
S345	29039-S345	LIN4 Fire Protection / Turbine Hall	306,611	Y
S537	38910-S537	LIN - Fall Protection	303,902	Y
D304	38886-D304	131H-423 Targeted Replacements	300,754	Y
S578	38846-S578	LIN1 - Fire Protection / Turbine	297,054	Y
S627	22954-S627	TRE5 - Bottom Ash / Boiler Seal Rep	294,996	Y
S422	30966-S422	LIN Eye Wash Station Enhancements	293,274	Y
S570	26025-S570	POT - ID Cladding Replacement	290,520	Y
S608	37643-S608	TRE5 - Reclaim Feeder Upgrades	289,537	Y
S551	37744-S551	LIN - CW Screen Refurbishment	288,242	Y
D240	33769-D240	4C-430 Device Replacements	285,102	Y
S473	25415-S473	LIN1&2 Stack Breech Duct	281,353	Y
S483	37004-S483	LIN4 - U&U- Water Wall Panel Repl.	264,309	Y
S524	34368-S524	POA - Screw Cooler Rotor Replaceme	263,339	N/A
D297	39495-D297	Queen Street Deteriorated Plant	260,519	Y
S612	30386-S612	POT - West CW pump refurbishment	255,004	Y
S635	38835-S635	TRE5 - Air Register Upgrades	254,966	Y
Projects Less than $250K			35,904,413	
Distribution Routines			38,764,073	
Transmission Plant Routines			7,482,032	
General Plant Routines			8,808,928	
		Total	$465,537,000	

2011-2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
10772	WRC- T2 Tunnel Adit Replacement	258,147	N
10796	TUC - U#3 BOILER FD PUMPS VARIABLE	1,305,268	N
10898	TUS - GENERATOR REWIND UNITS 1, 2	821,227	N
11554	WRC DAM SAFETY REMEDIAL WORKS	1,175,367	N
11610	STM- COON POND DAM SAFETY	1,798,475	N
11885	Insulator On Feeders 11S-411 And 11	279,431	N
11948	POT - REHEATER ORIFICING	439,993	N
12079	SHH - RUF 1&2 RUNNER REPLACEMENT	613,996	N
12206	GANNON RD.-INSTALL NEW 128-12.3 KV,	1,533,963	N
12212	HOPEWELL-138KV LINE TERMINAL TO TRA	512,972	N
12240	NIC - GENERATING UNIT # 2	4,029,115	N
12419	STM - TID PIPELINE REPLACEMENT	6,020,361	N
14371	HYD - AVO #2 PIPELINE REPLACE	4,733,409	N
14762	Cowie Hill Phase 2 U/g To O/h Conve	464,361	N
16003	LINGAN - REPLACE UNIT 1-2 DUPLEX AC	512,408	N
16415	BLR-MET GENERATOR REWIND	648,904	N
16416	BLR-HEG UNIT 2 GENERATOR REWIND	323,889	N
17368	MER-COF DAM SAFETY REMEDIAL WORKS	565,571	N
17579	STM-COON POND PIPELINE REPLACEMENT	3,328,014	N
17581	WEY - ELECTRICAL REFURBISHMENT	910,649	N
17830	HYD - STM Big Indian Lake Dam Safet	3,703,458	N
17939	Cowie Hill Phase 1 U/g To O/h Conve	395,104	N
18019	L6537 SWITCH REPLACEMENT & ADDT.	474,336	N
18174	MER-ULF GENERATOR REWIND	281,714	N
18175	MER-LLF RUNNER REPLACEMENT	634,653	N
18267	WIRELESS CDS	400,108	N
18448	TUC-CW SYSTEM BIOFOULING CONTROL	2,115,253	N
18469	TUC - UNIT 2 CONDENSER TUBE RESTORA	558,647	N
18907	GENERATOR REWIND ?	430,441	N
18991	LIN, ONLINE VIBRATION MONITORING EQ	660,952	N
20511	CT'S -Replace Halon Fire Protection	400,200	N
20512	CT'S - Re-insulate Vj Generator Rot	327,110	N
20673	LIN, REFURBISHMENT PROGRAM FOR FD/I	527,117	N
20718	TUC - UNIT 2 CHIMNEY LINER RESTORA	600,338	N
20741	TUC - UNIT 1 BOILER IMPROVEMENTS (1	3,720,299	N
20758	NIC - PIPELINE REPLACEMENT	1,351,382	N
21168	TRE5 - CONVERT COAL FEEDERS TO GRAV	579,913	N
21266	LIN, UNIT 1-2 2003 DIVISION WALL RE	296,159	N
23081	Extend New Feeder To Beaverbank Roa	302,821	N
23093	EMPLOYEE SELF-SERVICE TECHNOLOGY	387,289	N
23122	MER LLF RUNNER #4	553,648	N
23123	MER - LLF#3 RUNNER REPLACEMENT	300,000	N
23341	CDS COMPUTER DISPATCH SYSTEM UPGRAD	292,306	N
23602	STM - WRIGHTS LAKE DAM	889,678	N
24923	REPLACE BREAKERS 17V-503 AND 17V-40	277,589	N

2011-2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
25171	L5532 RE-INSULATION	634,810	N
25182	TUC - UNIT 2 LOW LOAD CAPABILITY IM	385,327	N
25385	LIN-REPLACE WASTEWATER FORCE MAIN	269,118	N
26472	TRE - 6A CW Pump Refurbishment	262,674	N
26904	GULCH WS PENSTOCK REPLACEMENT	639,374	N
27088	POA ST2 TRANSFORMER REPLACEMENT	475,421	N/A
27149	TUC - REPL. CONDENSATE POLISHERS &	1,475,468	N
27150	TUC - REPLACE UNIT #1 AIR HEATER	2,113,710	N
27507	RUTH FALLS BUTTERFLY VALVE REPLACEM	550,199	N
27850	LIN-ENGINEERING MODIFICATIONS FOR C	918,910	N
28063	87S-LINGAN - PROCURE SPARE FOR GT4	2,210,206	N
28079	88S-LINGAN - SWAP NODES L-7012 & GT	1,511,695	N
28080	88S-LINGAN - REPLACE BREAKER 714	2,760,679	N
28131	POT - BURNER CORNER TUBE NEST PHASE	399,243	N
28288	POT - TURBINE SUPERVISORY EQUIPMENT	843,210	N
28347	LIN- STACK PAINTING 0-300 FT LEVEL	330,047	N
28424	DEPOT & SUBSTATION SECURITY SYSTEM	706,791	N
28470	L5501 REBUILD	1,356,942	N
28641	ROSEWAY UNIT REFURBISHMENT	293,036	N
28674	TRENTON 6 DCS OPERATOR INTERFACE UP	437,322	N
28790	POA Ash Cell Capping Cell 3 Stage 1	326,533	N/A
28793	POA- PE- COAL CONVEYOR SUPPORT REF.	408,052	N/A
28849	TRE5 - CONDENSER PIPE REPLACEMENTS	406,293	N
28907	LIN-CW Organic Sea Debris Capture U	1,042,996	N
28921	LIN3-REPLACE STACK BREECH EXPANSION	283,000	N
30624	LIN HEAVY PARTS STORAGE	254,855	N
30909	LIN C/W INLET CANAL WALL SEALING	300,967	N
30911	LIN1- STACK BREACHING EXPAN	260,895	N
30924	LIN REPLACE CRUSHERs	261,232	N
31243	LIN-REPLACE BOILER HOUSE LOUVERS	311,061	N
31246	HYD Methals Intake Refurbishment	520,548	N
31442	LIN2-REPLACE HIGH VOLTAGE BUSHINGS	307,532	N
31545	LIN3-Replace Screens on Backpass	804,422	N
31583	LIN2 - L-1 BLADING REPLACEMENT	518,434	N
31602	LIN2-REFURBISH GENERATOR HYDROGEN	563,808	N
31729	POA SH3 TUBE BENDS REPLACEMENT	376,866	N/A
32304	AMI Hardware & Software Installatio	30,694,639	N
32522	LIN - CW TRENCH CTRL CABLE UPGRADE	297,570	N
33282	LIN Super Heater Header Vestibule	318,904	N
33504	Upgrade 69 kV Circuit - Pleasant St	993,896	N
33625	Mobile 138kV Circuit Switcher	268,685	N
34386	POA Cell 4 Stage 1 Residue Mangemen	2,549,001	N
34544	POT TURBINE MAJOR REBUILD	1,293,745	N
34565	HYD- ANNAPOLIS CONTROLS PLC	300,000	N
34703	Lin CW Pump Rebuild	485,000	N

2011-2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
35022	POA Front End Loader Replacement	802,653	N/A
36562	POA PE Turbine Cont. Sys Repl.	2,013,267	N/A
36565	POA ID Fan Motor Upgrade	503,317	N/A
36603	LIN2- DAS Upgrades	461,298	N
36862	HYD - Wreck Cove Unit # 1 Overhaul	6,779,725	N
36962	TUC East Tunnel Cable Re-routing	262,761	N
37611	LIN3 - AVR Replacement	1,574,495	N
37828	TRE - Fire Water Storage Bunker	401,327	N
38042	TRE6 - Steam Coil Airheater Upgrade	511,663	N
38043	TRE6 - Turbine Gland Replacement	402,653	N
38102	POT - Utilization of Heavy Biofuel	306,008	N
38242	TRE - Fire Water Storage Bunker	400,000	N
38603	TRE6 - LP Turbine Gland Replacement	400,000	N
38816	Kempt/Lakeside Protection Upgrades	567,495	N
38817	TRE6 - Primary Air Fan Shaft	333,449	N
38823	2012 Protection Upgrades	2,322,763	N
38824	2011 Protection Upgrades	3,349,299	N
38826	POT - DCS upgrade	725,025	N
38947	Co-Firing Biomass	10,000,231	N
39263	LIN U&U CW Pump Refurb	21,927,101	N
39264	FAC Space 2011	5,036,203	N/A
39265	Transmission Reliablity Replacement	9,225,033	N
39266	Transmission Reinforcements	7,487,020	N
39267	Transmission Replacements	6,441,338	N
39269	2011 Recloser Additions	1,379,482	N
39271	Dist. Reliability Replacements	2,661,552	N
39274	Distribution Replacements	1,902,033	N
39275	Halifax UG Cable Replacement	617,399	N
39276	Bedford 4 kV Conversion	1,617,199	N
39306	Radio & Communication Replacements	488,170	N
39502	TRE - Stack Coating	603,980	N
H517	HYD Gaspereau Dam Safety	2,131,001	Y
H602	HYD- Ruth Falls #3 Runner Replmt	414,557	Y
H611	HYD - BER-GUL - Electrical Refurbis	662,935	N
H601	HYD - STM-SAL #4 Runner	270,824	Y
S587	POT - Condenser Waterbox Replacemen	323,448	Y
S353	TUC 6 Waste Heat Recovery	557,435	Y
S692	POT - TURBINE ELECTRO HYDRAULIC GOV	581,502	N
S711	POT 2A Mill and Feeder Refurbishmen	416,666	N
S712	POT - ANALYTICAL PANEL AND ANALYZER	324,709	N
S795	TRE6 - Turbine Controls Power Suppl	336,179	N
P833	Right of Way Purchase Northern NS	4,446,277	Y
P772	FAC Space 2011	57,428,836	Y
S399	LIN PF Line Upgrades	276,090	Y
H574	HYD Paradise Wood Stave Pipeline R	11,020,417	Y

2011-2012 Additions

Project #	Project Title	Addition ($)	Approved (Y/N)
T674	Canaan Rd 43V to Tremont 51V Line	7,901,434	Y
T639	Spare Generator Transformer	4,371,274	Y
T670	Upgrade L-8002	1,926,888	Y
P789	Connectivity Upgrade	2,650,314	Y
S614	LIN1- ESP Gas Flow Modification	1,540,413	Y
P863	2010 Backup Control Centre	2,856,185	Y
T650	1H Water St Replace 138 kV GIS	8,368,588	Y
T675	51V Tremont Circuit Breaker & Bus	6,628,453	Y
S661	Port Hawkesbury Biomass Project	203,511,819	Y
D339	2011 Dist. Cutout Replacements	1,176,075	N
D370	2011 Distribution Feeder Ties	347,147	N
S792	POT Unit 2 Generator Major Refurbis	2,086,097	N
Projects Less than $250K		15,580,919	
Distribution Routines		41,853,703	
Transmission Routine		9,482,406	
General Plant Routines		7,918,398	
	Total	$602,354,079	

NON-CONFIDENTIAL

Request IR-12:

Reference: DE, page 59. "In the 2009 Rate Decision, the Board approved the amortization of DSM expenditures for 2008 and 2009 over six years starting in 2009."

(a) Please confirm that as part of the 2009 General Rate Application, the Board approved DSM expenditures of $12.9 million for 2008 and 2009.

(b) Please confirm that the actual DSM expenditures by NSPI in 2008 and 2009 were $11.85 million.

(c) Please provide a revised table that re-amortizes the remaining $5.4 million of actual DSM expenditures ($11.85 million - $6.45 million collected in 2009, 2010, and 2011) over the remaining three-year period.

Response IR-12:

(a) Confirmed. Please see the 2009 Rate Case Decision[1], page 39, line 106.

(b) NSPI invested $11.85 million in 2008 and 2009 on DSM expenditures.

[1] NSPI 2009 Rate Case, UARB Decision, NSUARB – NSPI – P – 888, November 5, 2008

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(c) See table below:

Year	Opening Balance ($M)	Adjustment [1] ($M)	Amortization ($M)	Ending Balance ($M)
2009	12.9	-	2.2	10.8
2010	10.8	-	2.2	8.6
2011	8.6	-	2.2	6.5
2012	6.5	(1.1)	1.8	3.6
2013	3.6	-	1.8	1.8
2014	1.8	-	1.8	-

Notes:

Represents adjustment of Board approved 2008 and 2009 expenditures to reflect actual expenditures. Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

REDACTED

Request IR-13:

Reference: OE-01P. [redacted]

(a) [redacted]

(b) [redacted]

(c) [redacted]

Response IR-13:

(a-c) A request for registration of the dispute under the International Centre for Settlement of Investment Disputes (ICSID) Additional Facility Rules was accepted by the Secretary-General of ICSID, and the parties are in the process of appointing the Tribunal. The arbitration will follow the usual arbitral steps of a procedural conference, the filing of formal claims and document disclosure, followed by a hearing. Each party will also have the opportunity to make procedural and other interim motions as the matter progresses. As a result, it is not possible at this time to ascertain the likely duration of the dispute. Given that this matter is in the early stages of an arbitration process, NSPI is not able to provide a damage estimate.

In 2012, the Power Production Division of NSPI forecasts [redacted] to deal with a range of legal issues related to fuel procurement and plant operations. Given the wide range of measures that may be required, individual actions are not individually budgeted.

REDACTED

Request IR-14:

Reference: FOR-01 and CS-01-CS-03.

(a) Please indicate the date that the FOR-01 and CS-01-CS-03 financial outlook documents were prepared.

(b) Please confirm that these statements show NSPI's 2011 forecast of net earnings applicable to common shares of [redacted] and a return on average common equity of [redacted]

(c) Please indicate whether in preparing these statements NSPI assumed the carry-over of any excess earnings from 2010 into 2011.

Response IR-14:

(a) The FOR-01 and CS-01-CS-03 documents were completed on April 13, 2011.

(b) Confirmed.

(c) [redacted]

Request IR-15:

Reference: DE, page 119 and SR-02, page 1.

Footnote 38 indicates the load forecast was completed in December 2010. However, the 2011 load forecast cover page indicates it was prepared in April 2011. Please reconcile these two dates and indicate when the load forecast report was prepared.

Response IR-15:

The 2011 load forecast modeling was completed in December 2010 to meet planning and scheduling deadlines.

The 2011 Load Forecast Report was written in March-April as a requirement for a 10 year energy and demand forecast under Section 3.3.1.2 of the Nova Scotia Wholesale Electricity Market Rules to be filed by April 30 each year.

REDACTED

Request IR-16:

Reference: DE, page 130. "Overall, we forecast delivery losses at 6.6% of the 2012 net in-province energy requirement."

(a) Please provide all supporting documentation and information NSPI has relied on to calculate the line losses of 6.6% for the 2012 load forecast.

(b) Please provide NSPI's actual line losses for the past five years, as a percent of total system requirements and total GWh.

(c) The Q1 2011 FAM report (at page 67) appears to show "Line and other Losses" as [redacted] for the month of February 2011, yet the actual year-to-date "Line and other Losses" are shown as [redacted] as at the end of March 2011. Please explain why this is the case.

Response IR-16:

(a) The forecast for losses are calculated using general assumptions of line losses based on the service voltage of customer groups and historical booked losses.

The annual sales for customer classes generally served from the lower voltage distribution system are grouped together and considered distribution sales.

The annual sales for the large industrial customer classes, mostly served from the more efficient high-voltage grid, are grouped together and considered transmission sales.

REDACTED

Losses for each group are calculated as an average of the historical percentages, with transmission losses estimated using data from the grid (SCADA system) and distribution losses calculated as total booked losses minus transmission losses.

REDACTED

The calculations are detailed in the table below.

Customer Class	**Sales**			
Residential	4,438			
Small General	242			
General Demand	2,648			
Large General	418			
Unmetered	120			
Small Industrial	265			
Medium Industrial	526			
Distribution Sales		8,658		GWh
Distribution Losses and Δ Unbilled (3-yr average = 5.6%)		487		
Distribution Requirement			9,145	GWh
Large Industrial		948		
Mersey Rate		189		
Mersey Additional Energy		180		
GR&LF		19		
Municipal		204		
ELII 2P-RTP		1,904		
Transmission Sales			3,444	GWh
Transmission Requirement (before transmission losses)			12,589	GWh
Transmission Losses (3-yr average = 2.89 %)			364	
In-Province Requirement			12,953	GWh
Distribution Losses			487	
Transmission Losses			364	
Losses within Municipal Utilities (est. 3.8% of sales)			8	
Total Losses			859	GWh
Losses as percentage of requirement			6.6%	
Adjustments for new DSM / LED	Δ Sales	-283		
	Δ Losses	-23		
		-306		
In-Province Requirement with adjustments			12,647	GWh
Total Losses with adjustments			836	GWh
Losses as percentage of in-province requirement			6.6%	

REDACTED

(b) The tables below shows the losses and percentages for in-province load as well as the total system load.

	2006	2007	2008	2009	2010
In-Province Requirement (GWh)	10,946	12,640	12,539	12,073	12,158
In-Province Losses (GWh)	825	834	790	786	708
Losses percent of In-Province	7.5%	6.6%	6.3%	6.5%	5.8%
Total Requirement (GWh)	11,352	12,699	12,563	12,092	12,164
Total Losses (GWh)	847	836	791	786	708
Losses percent of Total	7.5%	6.6%	6.3%	6.5%	5.8%

(c) Page 99 of the Q1 2011 FAM Report shows [redacted] MWh at the end of March 2011 not [redacted] MWh. "Line and other Losses" for the month of February 2011 was inadvertently shown as [redacted] MWh at page 67 and NSPI subsequently recognized that the actual amount for February is now reflected as [redacted] MWh for FAM reporting.

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Request IR-17:

Reference: SR-02, Attachment 1, page 6 of 55.

> **A review of NSPI's load forecasting methodology in 2008 recognized that load forecasting could be enhanced with better integration of DSM savings by adopting an end-use model framework. NSPI is currently reviewing methods of updating its load forecasting methodology to employ Statistically-Capital Adjusted N-Use (SAE) modeling.**

Please indicate whether NSPI's 2011 Load Forecast currently contains any SAE modeling. If not, please indicate when NSPI anticipates that SAE modeling will form part of its load forecasts.

Response IR-17:

The NSPI load forecast methodology has not yet been changed to include statistically adjusted end-use modeling (SAE). Some work remains to resolve and refine several data and model structure issues before the SAE methods can be integrated with the NSPI load forecast. NSPI is not certain when this work will be completed however the current SAE model is a useful tool for assessing the effects of numerous types of end-use scenarios and DSM programs.

NON-CONFIDENTIAL

Request IR-18:

Reference: DE, Section 8.0.

Please identify and explain any differences in methodology used in the 2011 load forecast versus the 2009 load forecast.

Response IR-18:

The 2011 load forecast was produced with the same methodology and procedures as the 2009 load forecast.

NON-CONFIDENTIAL

Request IR-19

Reference: DE, Figure 8.1, page 120.

(a) Please provide a similar chart showing the forecast accuracy of NSPI's system peak for the years 2005 to 2010.

(b) For the actual system peak for the years 2007 to 2010, please also indicate the actual load of the two Extra-Large Industrial customers at the time of the system peak, and the load for these customers included in the forecast of system peak.

(c) For each of the past five winters, ending with the winter of 2010/2011, please provide the coincident peak load on NSPI's system and the portion represented by non-firm load. Also provide the date and time and the lowest hourly temperature for that day.

Response IR-19:

a) The table below shows the NSPI system peak forecast accuracy since 2005.

NSPI Peak Forecast Accuracy

Year	Forecast MW	Actual MW	Variance MW	Variance %	Weather-Adjusted Variance MW	Weather-Adjusted Variance %
2005	2,160	2,143	-17	-0.8	-56	-2.6
2006	2,176	2,085	-91	-4.2	35	1.6
2007	2,256	2,145	-112	-4.9	-93	-4.1
2008	2,212	2,192	-20	-0.9	0	0.0
2009	2,261	2,086	-175	-7.7	-154	-6.8
2010	2,147	2,114	-33	-1.5	16	0.7

NON-CONFIDENTIAL

b) The following table shows the coincident peak forecast for the two Extra-Large Industrial customers and the actual load at the time of the annual system peaks for 2007 to 2010.

Year	Bowater Forecast MW	Newpage Forecast MW	Bowater Actual MW	Newpage Actual MW
2007	84	200	96	200
2008	85	200	72	193
2009	87	200	6	180
2010	85	197	70	159

c) The table below shows the peak demand, the coincident non-firm demand and the hour of the peak for the past five winters. The lowest hourly temperature of the peak day is also included.

NSPI Winter Peak Load and Temperatures

Winter	Peak Load MW	Coincident Non-Firm MW	Time of Peak Hour Ending	Lowest Hourly Temperature °C
2006/2007	2,145	381	Jan 26, 2007 18:00	-15.5
2007/2008	2,192	352	Jan 21, 2008 19:00	-15.6
2008/2009	2,086	227	Jan 17, 2009 18:00	-17.8
2009/2010	2,114	295	Feb 02, 2010 19:00	-14.4
2010/2011	2,168	265	Jan 24, 2011 18:00	-17.1

NON-CONFIDENTIAL

Request IR-20

Please provide any and all runs that NSPI has made of the Strategist Model that are intended to calibrate the accuracy of the Strategist Model and its algorithms and logic.

Response IR-20:

The performance of Strategist's dispatch optimization modules was benchmarked against another dispatch optimization software, PROMOD IV, at the turn of the century. As a result of this benchmarking exercise, the decision was made to continue using Strategist and discontinue licensing the PROMOD IV software.

In 2008, as a part of the FAM approval process, the results from the actual 2007 system dispatch were compared with a Strategist dispatch optimization assuming the 2007 system parameters and actual fuel costs. The difference between the Strategist total fuel costs and the 2007 actual total fuel costs were less than 1 percent.

CONFIDENTIAL (Attachment Only)

Request IR-21

Reference: Appendix H, ELI 2P-RTP Revisions

(a) **Please provide in electronic format the hourly <u>actual</u> marginal energy costs as reported in NSPI's SRMC report, for calendar year 2010 and the first quarter of 2011. Each hour should show the marginal cost per MWh, and the fuel type (coal, gas, import, etc.).**

(b) **With respect to the response to part (a), for each hourly marginal cost in which the fuel type is an import, please provide the following information:**

(i) **Indicate whether the import was scheduled or non-scheduled.**

(ii) **Indicate how far in advance of delivery the import was scheduled.**

(iii) **Identify the nature of the imported power. For example, is the import part of a long-term purchase of 1 year or more, part of a short-term purchase of less than 1 year, a combination of long-term and short-term purchases, or a part of some other type of purchase?**

(iv) **Indicate whether the import was a block purchase, a load following purchase, or a combination of block and load following purchases.**

(v) **Indicate the schedule duration of the import (e.g. 16 hours, 24 hours, weekly, monthly, etc.)**

CONFIDENTIAL (Attachment Only)

Response IR-21:

(a) Please refer to Confidential Attachment 1, filed electronically.

(b) (i) All imports are scheduled.

(ii) For the purposes of power imports, "Real Time" refers to a contract for purchase that was concluded at least 90 minutes before the energy was scheduled to flow across the NS/NB inter tie. Energy cannot be scheduled on a shorter lead time. Day Ahead refers to purchase agreements concluded at least 16 hours before the energy was scheduled to flow. It is not possible to determine the precise time when import contracts were concluded.

For full details refer to Confidential Attachment 1, filed electronically.

(iii) No annual import contracts were entered into. At times, combinations of imported energy are scheduled.

(iv) All imports are block (strip) purchases, defined in MW and start and finish times.

(v) Please refer to Confidential Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-22

Reference: Appendix H, ELI 2P-RTP Revisions

Please describe how NSPI's marginal cost model accounts for imported power in its marginal energy cost algorithms. Include in your description a narrative describing the assumptions made with respect to the loads of ELI 2P-RTP customers.

Response IR-22:

For the purposes of setting 20-minute ahead marginal prices for the ELI 2P-RTP class, NSPI assumes that ELI 2P-RTP customers will be operating at their Customer Base Line (CBL). Once contracted, scheduled import energy cannot be curtailed or avoided by NSPI. This energy is "must take" energy and similar to "must run" power production units is excluded from the 20-minute ahead marginal cost for ELI 2P-RTP purposes.

CONFIDENTIAL (Attachment Only)

Request IR-23

Reference: Appendix H, ELI 2P-RTP Revisions

Please provide in electronic format the posted 20-minute-ahead estimated marginal cost used for purposes of the ELI 2P-RTP rate for calendar year 2010 and the first quarter of 2011.

Response IR-23:

Please refer to Confidential Attachment 1, filed electronically.

CONFIDENTIAL (Attachment Only)

Request IR-24

Reference: Appendix H, ELI 2P-RTP Revisions

(a) Please provide in electronic format the following hourly information for calendar year 2010:

(i) Generation by plant and unit.

(ii) Purchased power differentiating by imports, IPPs and wind purchases.

(iii) Export sales.

(b) Please explain what constitutes IPPs and what constitutes wind purchases.

Response IR-24:

(a) (i) Please refer to Confidential Attachment 1, filed electronically, tab 'Generation'

(ii) Please refer to Confidential Attachment 1, filed electronically, tab 'IPP, Wind, Imports'

(iv) Please refer to Confidential Attachment 1, filed electronically, tab 'Scheduled Exports'

(b) Wind purchases represent purchased power from IPP wind producers. IPP purchases represent purchases from all other IPP producers except wind, including hydro, biomass and biogas.

CONFIDENTIAL (Attachment Only)

Request IR-25

Reference: Appendix H, ELI 2P-RTP Revisions

Please provide in electronic format, for calendar year 2010, the hourly total load including exports at the generator.

Response IR-25:

Please refer to Confidential Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-26

Reference: Appendix H, ELI 2P-RTP Revisions

Please provide for the year 2010 in electronic format, the actual hourly load at the meter for the ELI 2P-RTP class.

Response IR-26:

Please refer to Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-27

Reference: In GRA Section DE-03, DE-04, on page 134, NSPI states:

> **Amortization of NS Power Demand Side Management expenditures incurred by NS Power in 2008 and 2009, as approved for recovery through rates in 2009 (based on a 6-year amortization schedule), continues to be included in the COSS.**

Please identify each line number of Exhibit 3 and Exhibit 6 of GRA Section SR-01, Attachment 1 which includes any of those DSM costs or amortizations, and the amount of those costs included in the Total Company column of each of those lines.

Response IR-27:

The DSM amortization-related rate base in SR-01 Attachment 1, Exhibit 3 is included under Deferred Charges – Other category and amounts to $4.3 million. The $4.3 million is calculated by averaging the 2011 amount ($5.4 million) and the 2012 amount ($3.2 million). The breakdown is:

- Demand Classification
    - Generation (line 18) - $926,107
    - Transmission < 138kV (line 36) - $48,092
    - Transmission > 69kV (line 11) - $157,429
    - Distribution (line 26) - $551,844

- Energy Classification
    - Generation (line 18) - $2,004,327
    - Transmission <138kV (line 36) - $77,017
    - Transmission > 69kV (line 11) - $252,116

- Customer Classification
    - Distribution (line 11) - $266,068
    - Retail (line 24) - $0

The DSM amortization costs in SR-01 Attachment 1, Exhibit 6, are included in the Corporate Taxes category and amount to $2.2 million. The breakdown would be as follows:

- Demand Classification
    - Generation (line 11) – $431,367
    - Transmission < 138kV (line 27) - $23,115
    - Transmission > 69kV (line 6) – $75,602
    - Distribution (line 17) - $267,500
    - Distribution (line 25) - $13,076

- Energy Classification
    - Generation (line 12) - $1,035,649
    - Transmission < 138kV (line 23) – $37,018
    - Transmission > 69kV (line 33 – $121,074

- Customer Classification
    - Distribution (line 6) - $145,599
    - Retail (line 26) - $0

In preparing this response, NSPI discovered that the classification of DSM rate base and costs among the three functional areas of generation, transmission and distribution is not consistent with the treatment of these costs in the 2009 GRA and DSM proceedings, whereby they were treated as generation-related only.

NON-CONFIDENTIAL

Request IR-28

Assuming that NSPI's Application is accepted exactly as filed, please quantify the base cost of fuel associated with each energy rate shown in Figure 10.9 (pages 156 and 157) of GRA Section DE-03, DE-04.

Response IR-28:

Please refer to Attachment 1.

Base Cost of Fuel Cost of Service Allocation of Fuel Expenses among Rate Classes

FOR THE YEAR ENDING DECEMBER 31, 2012

Line #	COLUMN	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
6	FORMULA								G x J (line 29)	G x K (line 29)	E x L (line 29)	K + L	J + K + I	G * O (line 29)	G X P (line 29)	E X Q (line 29)	P + Q	O + P + Q	I + N + S	G * U (line 29)	G * V (line 29)	G * W (line 29)	T + U + V + W	X x C	Y / Y (line 30)	Z x X (line 30)	AA / H
11		Cost Allocation Factors						Fuel-related Costs from COS																Fuel Costs used for FAM purposes			
12			3 CP Demands[2]		Energy Requirement[2]				Purchased Power Regular					Purchased Power Wind													
13										Fixed					Fixed												
14	Rate Class	R/C Ratios[1]	KW Demand	Relative Shares	KWh Energy	Relative Shares	kWhs Sales[2]	Fuel Costs before Purchased Power	Variable	Energy-related	Demand-related	Total	Total	Variable	Energy-related	Demand-related	Total	Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	Export Revenues	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
16	**Above-the-line and Classes**																										
17	Residential non ETS						4,154,583,973																				
18	Residential ETS						217,953,895																				
19	Residential Subtotal	99.1%	3,509,838	52.6%	4,811,851,826	39.6%	4,372,537,868	$182,348,122	$11,367,917	$6,361,616	$3,908,065	$10,269,681	$21,637,598	$12,794,405	$3,838,321	$2,187,090	$6,025,411	$18,819,816	$222,805,537	($380,301)	$0	$0	$222,425,236	$220,524,123	39.7%	$220,974,350	**5.054**
21	Small General	105.0%	155,518	2.3%	240,415,681	2.0%	219,487,473	$9,095,134	$567,978	$317,847	$173,163	$491,010	$1,058,988	$639,250	$191,775	$96,908	$288,683	$927,933	$11,082,055	($19,001)	$0	$0	$11,063,054	$11,616,207	2.1%	$11,639,923	**5.303**
22	General Demand	105.0%	1,373,015	20.6%	2,703,080,232	22.2%	2,534,007,171	$101,990,984	$6,385,980	$3,573,667	$1,528,798	$5,102,465	$11,488,446	$7,187,317	$2,156,195	$855,569	$3,011,764	$10,199,080	$123,678,510	($213,636)	$0	$0	$123,464,874	$129,638,118	23.3%	$129,902,790	**5.126**
23	Large General	100.6%	162,393	2.4%	420,469,138	3.5%	394,351,292	$15,820,580	$993,351	$555,891	$180,818	$736,709	$1,730,060	$1,118,000	$335,400	$101,192	$436,592	$1,554,593	$19,105,233	($33,231)	$0	$0	$19,072,001	$19,188,772	3.5%	$19,227,948	**4.876**
24	Small Industrial	100.6%	107,379	1.6%	278,013,116	2.3%	261,850,163	$10,460,365	$656,801	$367,553	$119,562	$487,116	$1,143,917	$739,219	$221,766	$66,911	$288,677	$1,027,896	$12,632,178	($21,973)	$0	$0	$12,610,206	$12,691,031	2.3%	$12,716,941	**4.857**
25	Medium Industrial	97.2%	209,410	3.1%	542,704,428	4.5%	512,943,913	$20,379,599	$1,282,130	$717,494	$233,169	$950,664	$2,232,794	$1,443,016	$432,905	$130,490	$563,395	$2,006,411	$24,618,804	($42,892)	$0	$0	$24,575,911	$23,896,149	4.3%	$23,944,936	**4.668**
26	Large Industrial	97.5%	323,310	4.8%	977,034,327	8.0%	932,644,237	$36,648,067	$2,308,227	$1,291,710	$359,992	$1,651,702	$3,959,929	$2,597,872	$779,361	$201,464	$980,826	$3,578,697	$44,186,693	($77,219)	$0	$0	$44,109,474	$43,019,728	7.7%	$43,107,558	**4.622**
27	ELI 2P-RTP (base rate)	95.0%	632,285	9.5%	1,851,329,712	15.2%	1,814,317,632	$69,516,867	$4,373,734	$2,447,592	$704,024	$3,151,616	$7,525,350	$4,922,567	$1,476,770	$393,996	$1,870,766	$6,793,333	$83,835,551	($146,318)	$0	$0	$83,689,232	$79,504,771	14.3%	$79,667,089	**4.391**
28	Municipal	97.9%	125,369	1.9%	207,083,043	1.7%	197,368,264	$7,826,530	$489,230	$273,779	$139,594	$413,372	$902,603	$550,621	$165,186	$78,121	$243,308	$793,928	$9,523,061	($16,367)	$0	$0	$9,506,694	$9,304,235	1.7%	$9,323,231	**4.724**
29	Unmetered	100.0%	72,739	1.1%	128,053,320	1.1%	115,739,970	$4,806,975	$302,524	$169,296	$80,992	$250,287	$552,811	$340,486	$102,146	$45,326	$147,471	$487,957	$5,847,743	($10,121)	$0	$0	$5,837,623	$5,837,623	1.1%	$5,849,541	5.054
30	ATL and FAM Subtotal / Average	100.0%	6,671,256	100.0%	12,160,034,820	100.0%	11,355,247,982	$458,893,225	$28,727,872	$16,076,445	$7,428,178	$23,504,623	$52,232,495	$32,332,752	$9,699,825	$4,157,068	$13,856,894	$46,189,645	$557,315,365	($961,058)	$0	$0	$556,354,307	$555,220,756	100.0%	$556,354,307	**4.900**
32	Puchased Power Allocation Factors.								**55.0%**	**68.4%**	**31.6%**	**45.0%**		**70.0%**	**70.0%**	**30.0%**	**30.0%**										
34	Additional Energy																										
36	Additional Energy Sections 2C and 2D	100.0%	-	0.0%	-	0.0%	-	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			$0			$0	
37	Subtotal		-		-		-	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0			$0			$0	
40	**Total subject to FAM adj. (Above-the-line & Additional Energy)**		**6,671,256**		**12,160,034,820**		**11,355,247,982**	**$458,893,225**	**$28,727,872**	**$16,076,445**	**$7,428,178**	**$23,504,623**	**$52,232,495**	**$32,332,752**	**$9,699,825**	**$4,157,068**	**$13,856,894**	**$46,189,645**	**$557,315,365**	**($961,058)**	**$0**	**$0**	**$556,354,307**			**$556,354,307**	**4.900**
42	**Below-the-line before Additional Energy**																										
44	Additional Energy billed under LF rate	100.0%	42,857	0.6%	183,598,531	1.5%	179,928,000	$10,276,948	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,276,948	$0			$10,276,948	NA	NA	$10,276,948	**5.712**
45	GRLF	100.0%	31,940		110,623,070		108,411,483	$6,176,300					$0					$0	$6,176,300	$0			$6,176,300			$6,176,300	**5.697**
46	Mersey Basic Block (Energy entitlements)	100.0%	85,714		192,855,600		189,000,000	$112,924					$0					$0	$112,924	$0			$112,924			$112,924	**0.060**
47	ELI 2P-RTP (debits & credits only)		-		-		-	$0					$0					$0	$0	$0			$0			$0	**N/A**
48	**Total Below-the-line before Additional Energy**		160,511		487,077,201		477,339,483	$16,566,171	$0	$0	$0	$0	$0	$0	$0	$0		$0	$16,566,171	$0			$16,566,171			$16,566,171	**3.471**
50	**In Province Total**		6,831,767		12,647,112,022		11,832,587,465	$475,459,396	$28,727,872	$16,076,445	$7,428,178	$23,504,623	$52,232,495	$32,332,752	$9,699,825	$4,157,068	$13,856,894	$46,189,645	$573,881,536	($961,058)	$0	$0	$572,920,478	$0	0	$572,920,478	**4.842**
52	Exports	100.0%	-		34,907,000		33,860,000																				
54	**Subtotal (BTL before AE & Exports)**		160,511		521,984,201		511,199,483																				
56	Grand Total		**6,831,767**		**12,682,019,022**		**11,866,447,465**	$475,459,396	$28,727,872	$16,076,445	$7,428,178		$52,232,495	$32,332,752	$9,699,825	$4,157,068		$46,189,645	**$573,881,536**	($961,058)	$0	$0	$572,920,478			**$572,920,478**	**4.828**

NON-CONFIDENTIAL

Request IR-29:

Reference: Page 11 of GRA Section DE-03, DE-04. "Renewable investments are also bringing tax reductions that are largely offsetting the costs of renewable projects in the early years."

Please quantify the amount of tax reductions or tax credits in 2012 that are attributable to renewable investments.

Response IR-29:

The estimated tax savings in 2012 that are attributable to renewable investments is $10.7 million.

NON-CONFIDENTIAL

Request IR-30:

Reference: Page 10, lines 9-10 of GRA Section DE-03, DE-04.

For the year 2010, please quantify or estimate the GWh of wind energy (purchased and/or NSPI-owned) that displaced solid fuel-fired energy.

Response IR-30:

NSPI has estimated 203 GWh of renewable energy displaced solid fuel energy based on the months that solid fuel units were on the margin.

NON-CONFIDENTIAL

Request IR-31:

Please explain the minimum length (duration) of time that NSPI must schedule uncontracted-for imported power, and how far in advance (of delivery) NSPI must schedule this power.

Response IR-31:

The minimum length (duration) of time that NSPI must schedule uncontracted-for imported power is 90 minutes.

NSPI must begin the process of making arrangements for uncontracted-for import power approximately 90 minutes prior to the beginning of the delivery hour in order to allow sufficient time to enter into the transaction with a counterparty, submit it, and receive approval from the system operator.

NON-CONFIDENTIAL

Request IR-32:

Reference: DE, Appendix I

Please provide the electronic spreadsheet used to develop GRA Section DE-03, DE-04, Appendix I.

Response IR-32:

Please refer to Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-33:

Please reconcile GRA Section FOR-01, Column 5 with the cost of service study (GRA Section SR-01) Exhibit 4, Column 1 for the following items:

(a) Interest expense ($150.4 million on line 27 of GRA Section FOR-01 with $121.5 million on line 40 of Exhibit 4)

(b) Income tax ($18.1 million on line 31 of GRA Section FOR-01 with $40.7 million on line 42 of Exhibit 4).

Response IR-33:

(a) The net interest expense of $121.5 million (SR-01, Exhibit 4, line 40) represents the difference between interest (FOR-01, line 27) and allowance for funds used during construction and FAM interest (FOR-01, line 23).

$150.4 million - $28.9 million = $121.5 million

(b) The total income tax of $40.7 million (SR-01, Exhibit 4, line 42) is comprised of corporate income tax of $18.1 million (FOR-01, line 31), provincial capital tax of $1.0 million (FOR-01, line 15), and regulatory amortization of $21.6 million (FOR-01, line 21).

$18.1 million + $1.0 million + $21.6 million = $40.7 million

NON-CONFIDENTIAL

Request IR-34:

GRA Section SR-01, Exhibit 2A, page 1, line 1, shows $242,745 classified as energy related. Please provide the following data for each item included in this amount.

(a) A description and purpose of the item.

(b) The generating unit in which the item is installed.

(c) The original cost of the item.

(d) The year that the item was installed.

(e) The estimated useful life of the item.

Response IR-34:

(a-e) Please refer to Attachment 1.

Breakdown of Steam Assets Classified Initially as Energy

Title/Description	Generating Unit	Original Cost	Install Year	Average Remaining Life
Lingan Precipitator Refit Program	Lingan - Common	$127,486	2007	21.5
Installation of a Wastewater Treatment Facility	Lingan - Common	$5,420,997	2003	21.5
Refurbish Light Oil Tanks and Lines	Lingan - Common	$178,300	2008	21.5
Ash Site Sealing and Capping	Lingan - Common	$990,203	2003	21.5
Ash Site North "A" Cell Development	Lingan - Common	$396,802	2009	21.5
Recoat Bunker C Tank	Lingan - Common	$332,967	2008	21.5
Reburbish Fly ash Handling	Lingan 1-2	$598,380	2005	8.4
Lingan Unit #2 Low Nox Combustion Firing System	Lingan 1-2	$3,751,102	2007	8.4
Lingan Unit #1 Low Nox Combustion Firing System	Lingan 1-2	$3,875,373	2009	8.4
Lingan Unit #1 Mercury Abatement	Lingan 1-2	$1,800,618	2010	8.4
Lingan Unit #2 Mercury Abatement	Lingan 1-2	$1,847,113	2010	8.4
Lingan Unit # 3 Low Nox Combustion Firing System	Lingan 3-4	$3,813,164	2006	21.2
Lingan Unit #3 Low Nox Combustion Firing System	Lingan 3-4	$4,181,455	2007	21.2
Lingan Unit #3 Mercury Abatement	Lingan 3-4	$4,459,213	2010	21.2
Lingan Unit #4 Mercury Abatement	Lingan 3-4	$1,754,567	2010	21.2
POA Ash Cell Capping Cell 3 Stage 1[1]	Point Aconi	N/A	2011	30.6
Stage 3 Residue Management Site	Point Aconi 1	$1,737,017	2007	30.6
POA Bag house Bag Replacement Pro	Point Aconi 1	$854,385	2009	30.6
Cell 3 Stage 3 Residue Management Site	Point Aconi 1	$2,598,775	2009	30.6
Point Aconi	Point Aconi 1	$75,000,000	1993	30.6
POT - Develop new ash cells[1]	Point Tupper	N/A	2011	N/A
POT - Utilization of Heavy Biofuel[1]	Point Tupper	N/A	2011	N/A
POT - Wastewater cell refurbishment[1]	Point Tupper	N/A	2011	N/A
Point Tupper Unit #1 Replacement of Opacity Monitors	Point Tupper 1	$68,850	2008	20.4
Point Tupper Unit #1 Mercury Abatement	Point Tupper 1	$2,461,060	2010	20.4
Point Tupper Unit #2 Low Nox Combustion Firing System	Point Tupper 2	$3,074,921	2009	21.3
Pt. Tupper Relocate Port Malcolm Rd	Point Tupper 2	$1,567,961	2009	21.3
Point Tupper Fuel Conversion	Point Tupper 2	$94,469,366	1987	21.3
Port Hawkesbury Biomass Project[1]	Steam General	N/A	2013	N/A
POT - Marine Terminal Dust Mitigati[1]	Strait Marine Terminal	N/A	2011	N/A

Breakdown of Steam Assets Classified Initially as Energy

Title/Description	Generating Unit	Original Cost	Install Year	Average Remaining Life
Tufts Cove Fuel Conversion[2]	Total Tufts Cove	$25,601,694	2000	N/A
TRE - CW Outlet Oil Boom[1]	Trenton	N/A	2012	N/A
TRE - Wastewater Treatment Plant Up[1]	Trenton	N/A	2011	N/A
Ash Lagoon Capping	Trenton - Common	$125,439	2007	29.7
Trenton Site Environ. Improvements	Trenton - Common	$121,586	2007	29.7
Ash Lagoon Covering	Trenton - Common	$100,163	2008	29.7
Trenton Ash Site Covering	Trenton - Common	$99,211	2009	29.7
TRE - Storm Drainage Improvements	Trenton - Common	$120,525	2010	29.7
Ash Site Covering Project	Trenton - Common	$113,372	2010	29.7
TRE - Ash Site Management	Trenton - Common	$124,720	2010	29.7
Continuous Emission Monitoring System Replacement	Trenton 5	$143,963	2005	21.2
Trenton Unit #5 Bag House Addition	Trenton 5	$29,051,521	2009	21.2
Trenton Unit #5 Mercury Abatement	Trenton 5	$1,588,705	2010	21.2
Trenton Unit #6 Low Nox Combustion Firing System	Trenton 6	$4,106,621	2008	29.7
Trenton Unit #6 Mercury Abatement	Trenton 6	$1,877,140	2010	29.7
Tufts Cove Oil Tank #4 Refburb/Upgrade	Tufts Cove - Common	$1,300,701	2002	21.5
Connect Plant to Municipal Sewer System at HRM Request	Tufts Cove - Common	$154,138	2007	21.5
Fuel Oil Storage Handling	Tufts Cove - Common	$94,010	2006	21.5
Yard Oil Piping Upgrade	Tufts Cove - Common	$88,716	2008	21.5
Replace HFO Tank Interface Liner	Tufts Cove - Common	$103,051	2008	21.5
TUC - Oil Tank Protective Coating	Tufts Cove - Common	$23,366	2010	21.5
Replace water Treatment Equipment	Tufts Cove - Common	$102,291	2010	21.5
Tufts Cove Unit #1 Electrostatic Precipitator	Tufts Cove 1	$9,225,531	2005	10.3
Tufts Cove No#2 Precipitator	Tufts Cove 2	$4,278,674	1998	10.3
Tufts Cove Unit #3 Electrostatic Precipitator	Tufts Cove 3	$11,430,258	2005	21.4

(1) Construction work in progress, unable to provide total cost or estimated life
(2) Not Applicable

NON-CONFIDENTIAL

Request IR-35:

Please provide all workpapers supporting the $115,618 of wind plant classified as energy related in GRA Section SR-01, Exhibit 2A, page 1, line 3.

Response IR-35:

Consistent with the currently used cost of service methodology, as approved by the UARB in its decision in the last Cost of Service and Rate Design Hearing[1] conducted in 1995, NSPI has repeatedly classified generation costs with environmental compliance and fuel conversion as energy related.

[1] NSPI 1995 Cost of Service and Rate Design, UARB Decision NSUARB – NSPI – 864, September 22, 1995 (page 23, paragraph 2)

NON-CONFIDENTIAL

Request IR-36:

For the $1,228,735 of demand-related steam plant shown on GRA Section SR-01, Exhibit 2A, page 1, line 1, please segregate that cost by unit.

Response IR-36:

NSPI does not have the requested information.

CONFIDENTIAL (Attachment Only)

Request IR-37:

GRA Sections FOR-01, FOR-02, FOR-03, FOR-04, FOR-05, FOR-06 and FOR-07 show 2009 compliance figures. For each of those schedules, please also provide the comparable figures for actual results in 2009 for each of those schedules.

Response IR-37:

Please refer to Partially Confidential Attachment 1 for schedules adjusted to include the actual results for 2009.

Nova Scotia Power Inc. **FOR-01**

Regulated Statement of Earnings
Years Ended December 31st
Millions of Dollars

2012 Financial Outlook

1		(1)	(2)	(3)	(4)	(5)	(6)
2		**Compliance Restated 2009**	**Actual 2009**	**Actual 2010**	**Forecast 2011**	**Present Rates 2012**	**Proposed Rates 2012**
3	**Revenue**						
4	Electric	$1,241.3	$1,188.1	$1,167.3	[redacted]	$1,279.2	$1,373.2
5	Other	14.7	15.3	15.9	[redacted]	15.5	15.9
6	Total	1,256.0	1,203.4	1,183.2	[redacted]	1,294.7	1,389.1
7					[redacted]		
8	**Cost of Operations**				[redacted]		
9	Fuel and purchased power	545.0	500.4	587.0	[redacted]	573.9	573.9
10	FAM Fuel Deferral	-	13.5	(102.7)	[redacted]	50.2	50.2
11	Cost of goods sold	1.5	1.7	1.4	[redacted]	1.5	1.5
12	Operating maintenance and general	216.7	207.1	229.5	[redacted]	248.5	248.5
13	Unmetered Settlement Agreement Adjustment	(1.0)	-	-	[redacted]	-	-
14	Grants in lieu of property taxes	34.8	34.9	35.4	[redacted]	36.4	36.4
15	Provincial capital tax	5.3	5.6	4.6	[redacted]	1.0	1.0
16	Depreciation	145.0	143.5	150.5	[redacted]	178.0	178.0
17	Total Cost of Operations	947.3	906.7	905.8	[redacted]	1,089.5	1,089.5
18					[redacted]		
19	**Earnings From Operations**	308.7	296.7	277.4	[redacted]	205.2	299.6
20					[redacted]		
21	Regulatory amortization	(18.3)	(27.2)	(36.9)	[redacted]	(21.6)	(21.6)
22	Other Income	-	0.4	0.8	[redacted]	-	-
23	Allowance for funds used during construction and FAM interest	7.6	6.4	20.9	[redacted]	28.9	28.9
24					[redacted]		
25	**Earnings Before Interest and Tax**	298.0	276.3	262.2	[redacted]	212.5	306.9
26					[redacted]		
27	Interest	119.9	111.4	138.7	[redacted]	151.5	150.4
28					[redacted]		
29	**Earnings Before Income Tax**	178.1	164.9	123.5	[redacted]	61.0	156.5
30					[redacted]		
31	Corporate income tax	64.4	43.8	(11.3)	[redacted]	(11.6)	18.1
32					[redacted]		
33	**Net Earnings Before Dividends**	113.7	121.1	134.9	[redacted]	72.6	138.4
34					[redacted]		
35	Preferred dividends	14.1	9.3	8.0	[redacted]	8.0	8.0
36					[redacted]		
37	**Net Earnings Applicable to Common Shares**	**$99.6**	**$111.8**	**126.8**	[redacted]	**$64.6**	**$130.4**
38							

39 **Notes:**
40 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.
41 2) Part VI.I tax reclassified from preferred dividends to corporate income tax.

Nova Scotia Power Inc. **FOR-02**

Regulated Balance Sheet
Years Ended December 31st
Millions of Dollars

2012 Financial Outlook

Line		Compliance Restated 2009	Actual 2009	Actual 2010	Forecast 2011	Present Rates 2012	Proposed Rates 2012
1		(1)	(2)	(3)	(4)	(5)	(6)
3	**Assets**						
4	Fixed assets (net)	$2,408.5	$2,423.7	$2,733.5	[redacted]	$3,000.5	$3,000.5
5	Construction work in progress	70.1	150.0	273.0	[redacted]	479.1	479.1
6		2,478.6	2,573.7	3,006.4	[redacted]	3,479.6	3,479.6
7					[redacted]		
8	**Current assets**				[redacted]		
9	Cash and Short-term Investments	-	0.3	0.3	[redacted]	-	-
10	Accounts receivable	207.6	189.7	192.5	[redacted]	231.2	231.2
12	Materials inventory	29.9	26.3	28.4	[redacted]	28.4	28.4
13	Fuel inventory	78.5	139.3	125.9	[redacted]	88.1	88.1
14	Prepaid expenses	5.9	7.0	6.1	[redacted]	6.4	6.4
15	Short-Term Derivatives - Hedging	9.8	19.4	24.7	[redacted]	24.7	24.7
16	Held for Trading Securities	61.3	8.9	6.3	[redacted]	6.3	6.3
17	Due from associated companies	0.8	61.8	70.9	[redacted]	1.1	1.1
18	Total Current Assets	393.8	452.7	455.1	[redacted]	386.3	386.3
19					[redacted]		
20	Long-Term Derivatives - Hedging	10.4	29.8	20.7	[redacted]	20.7	20.7
21	Held for Trading Securities	48.1	6.2	8.2	[redacted]	8.2	8.2
22	Future Income Taxes	-	(17.6)	(163.2)	[redacted]	(144.2)	(144.2)
23	Deferred Charges (Financial Instruments)	10.5	13.5	1.3	[redacted]	1.3	1.3
24	Deferred charges	218.1	325.6	511.6	[redacted]	342.7	342.71
25					[redacted]		
26	Contract Receivable	110.6	82.1	-	[redacted]	-	-
27					[redacted]		
28	**Total Assets**	**$3,270.1**	**$3,466.0**	**$3,840.1**	[redacted]	**$4,094.6**	**$4,094.6**
29					[redacted]		
30	**Equity and Liabilities**				[redacted]		
31					[redacted]		
32	**Shareholder's Equity**				[redacted]		
33	Common shares	$830.6	$934.7	$984.7	[redacted]	$984.7	$984.7
34	Preferred shares	260.0	135.0	135.0	[redacted]	135.0	135.0
35	Accumulated Other Comprehensive Gain/(Loss)	(48.4)	(44.0)	10.8	[redacted]	10.8	10.8
36	Retained earnings	244.8	246.8	273.6	[redacted]	407.7	402.7
37					[redacted]		
38	**Long term debt**	1,234.1	1,397.0	1,691.9	[redacted]	1,594.1	1,594.1
39					[redacted]		
40	Long-Term Derivatives - Hedging	33.1	20.0	9.4	[redacted]	9.4	9.4
41	Held for Trading Securities	1.7	1.3	1.8	[redacted]	1.8	1.8
42	Deferred credits (Financial Instruments)	108.5	15.1	14.3	[redacted]	14.3	14.3
43	Deferred credits	95.5	177.9	223.1	[redacted]	170.43	170.4
44					[redacted]		
45	**Current Liabilities**				[redacted]		
46	Current portion of long term debt	100.0	100.7	0.1	[redacted]	300.1	300.1
47	Bank indebtedness	197.7	199.5	290.0	[redacted]	290.0	282.2
48	Accounts payable	129.2	184.3	191.5	[redacted]	118.7	101.7
49	Dividends payable	3.2	1.7	1.7	[redacted]	1.7	1.7
50	Income taxes payable	1.9	1.2	(40.6)	[redacted]	3.7	33.5
51	Short-Term Derivatives - Hedging	43.8	53.0	2.2	[redacted]	2.2	2.2
52	Held for Trading Securities	9.3	12.2	20.8	[redacted]	20.8	20.8
53	Accrued interest	25.1	29.6	29.8	[redacted]	29.3	29.3
54	Total Current Liabilities	510.2	582.2	495.5	[redacted]	766.4	771.4
55					[redacted]		
56	**Total Liabilities and Equity**	**$3,270.1**	**$3,466.0**	**$3,840.1**	[redacted]	**$4,094.6**	**$4,094.6**

57

58 **Notes:**

59 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

Nova Scotia Power Inc. **FOR-03**

Regulated Statement of Retained Earnings
Years Ended December 31st
Millions of Dollars

2012 Financial Outlook

Line		(1)	(2)	(3)	(4)	(5)	(6)
2		**Compliance Restated 2009**	**Actual 2009**	**Actual 2010**	**Forecast 2011**	**Present Rates 2012**	**Proposed Rates 2012**
3	**Regulated Retained Earnings at Beginning of Year**	$224.3	$261.0	$246.8	[redacted]	$348.1	$348.1
4	Net earnings applicable to common shares	99.6	111.8	126.8		64.6	130.4
5		323.9	372.8	373.6		412.7	478.5
6							
7	Common dividends	(79.1)	(126.0)	(100.0)		(5.0)	(75.8)
8							
9	**Regulated Retained Earnings at End of Year**	**$244.8**	**$246.8**	**$273.6**		**$407.7**	**$402.7**

10
11 **Notes:**
12 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.
13 2) All dividends are paid to the extent required to maintain the capital structure approved for rate making.

Nova Scotia Power Inc. **FOR-04**

Regulated Statement of Cash Flows
Years Ended December 31st
Millions of Dollars

2012 Financial Outlook

		(1)	(2)	(3)	(4)	(5)	(6)
1							
3		**Compliance Restated 2009**	**Actual 2009**	**Actual 2010**	**Forecast 2011**	**Present Rates 2012**	**Proposed Rates 2012**
4							
5	**Operating Activities**						
6							
7	Net earnings applicable to common	$99.6	$111.8	$126.8	[redacted]	$64.6	$130.4
8	Non cash items:				[redacted]		
9	Depreciation	145.0	143.5	150.4	[redacted]	178.0	178.0
10	Regulatory amortization	18.3	27.2	36.9	[redacted]	21.6	21.6
11	Less AFUDC and FAM interest	(7.6)	(6.4)	(20.9	[redacted]	(28.9)	(28.9)
12	Deferred charges, net / Other	18.7	(9.2)	(54.8	[redacted]	45.4	45.4
13					[redacted]		
14	Cash flow from operations	274.0	266.9	238.4	[redacted]	280.7	346.5
15	Change in operating working capital	(33.8)	5.8	59.1	[redacted]	20.6	33.4
16					[redacted]		
17	**Net Cash From Operations**	240.2	272.7	297.5	[redacted]	301.3	380.0
18					[redacted]		
19	**Financing Activities**				[redacted]		
20					[redacted]		
21	Dividends paid on common shares	(79.1)	(126.0)	(100.0	[redacted]	(5.0)	(75.8)
22	Proceeds from (repayment of) long term debt	-	125.0	200.0	[redacted]	200.0	200.0
23	Proceeds from (repayment of) Preferred Shares	-	(125.0)	-	[redacted]	-	-
24	Proceeds from (repayment of) Common Shares	-		50.0	[redacted]	-	-
25	Increase in (repayment of) short term debt	34.6	123.8	90.6	[redacted]	(96.6)	(104.4)
26	Other	-	(1.6)	(7.6	[redacted]	(2.2)	(2.2)
27		-			[redacted]		
28	**Net Cash From Financing**	(44.5)	(3.8)	233.0	[redacted]	96.2	17.6
29					[redacted]		
30	**Investing Activities**				[redacted]		
31					[redacted]		
32	Property plant and equipment, net	(195.7)	(268.6)	(530.2	[redacted]	(397.5)	(397.6)
33	**Net Cash Used in Investing**	(195.7)	(268.6)	(530.2	[redacted]	(397.5)	(397.6)
34					[redacted]		
35	**Decrease in cash equivalents**	-	-	-	[redacted]	-	-
36					[redacted]		
37	Cash and cash equivalents:	-	0.3	0.3	[redacted]	0.0	(0.0)
38					[redacted]		
39	Cash and cash equivalents, beginning of year	-	-	-	[redacted]	-	-
40	Cash and cash equivalents, end of year	-	0.3	0.3	[redacted]	0.0	(0.0)
41							

42 **Notes:**
43 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.
44 2) All dividends are paid to the extent required to maintain the capital structure approved by the UARB.

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

FOR-05

2012 Financial Outlook

		(1)	(2)	(3)	(4)	(5)	(6)	(6)		(8)	(9)
1						Present Rates 2012			Proposed Rates 2012		
2		Compliance Restated 2009	Actual 2009	Actual 2010	Forecast 2011	Embedded Cost Rates	Proposed BA Component[2]	Total	Embedded Cost Rates	Proposed BA Component[2]	Total
3	**Residential**	**$542.8**	**$547.3**	**$531.0**	[redacted]	[redacted]	**$19.0**	**$583.2**	[redacted]	**$19.0**	**$625.7**
4											
5	**General**										
6	Small general	33.6	31.3	30.3	[redacted]	[redacted]	1.1	$30.5	[redacted]	1.1	$32.2
7	General	276.6	265.5	258.8	[redacted]	[redacted]	11.6	$284.8	[redacted]	11.6	$302.5
8	Large general	38.0	37.1	36.2	[redacted]	[redacted]	1.8	$37.8	[redacted]	1.8	$40.5
9	**Total General**	**348.2**	**333.9**	**325.3**	[redacted]	[redacted]	**14.5**	**353.1**	[redacted]	**14.5**	**375.2**
10											
11	**Industrial**										
12	Small industrial	26.1	25.9	25.7	[redacted]	[redacted]	1.1	$27.4	[redacted]	1.1	$29.4
13	Medium industrial	53.2	46.0	44.0	[redacted]	[redacted]	2.2	$47.1	[redacted]	2.2	$50.5
14	Large industrial	71.1	69.8	68.0	[redacted]	[redacted]	3.9	$74.3	[redacted]	3.9	$79.6
15	GRLF	1.1	0.6	1.2	[redacted]	[redacted]	-	$6.7	[redacted]	-	$6.7
16	Mersey Basic Block	9.4	7.9	8.5	[redacted]	[redacted]	-	$9.3	[redacted]	-	$9.3
17	Mersey Additional Energy	11.7	8.2	10.7	[redacted]	[redacted]	0.5	$11.7	[redacted]	0.5	$11.7
18	Extra large industrial 2P-RTP	130.3	105.4	111.3	[redacted]	[redacted]	7.5	$121.0	[redacted]	7.5	$137.0
19	**Total Industrial**	**302.9**	**263.8**	**269.4**	[redacted]	[redacted]	**15.3**	**297.6**	[redacted]	**15.3**	**324.3**
20											
21	**Other**										
22	Municipal	17.6	17.6	16.8	[redacted]	[redacted]	0.9	$18.5	[redacted]	0.9	$19.8
23	Unmetered before LED Capital-related Cost	25.2	24.6	24.3	[redacted]	[redacted]	0.5	$25.8	[redacted]	0.5	$25.9
24	LED Capital-related Costs				[redacted]	[redacted]	-	$0.0	[redacted]	-	$1.3
	Unmetered Total				[redacted]	[redacted]	0.5	$25.8	[redacted]	0.5	$27.2
25	**Total Other**	**42.8**	**42.2**	**41.1**	[redacted]	[redacted]	**1.4**	**44.3**	[redacted]	**1.4**	$47.0
26											
27	**Total In Province Electric Revenue**	**1,236.7**	**1,187.2**	**1,166.8**	[redacted]	[redacted]	**$50.2**	**$1,278.2**	[redacted]	**50.2**	**$1,372.3**
28											
29	**Exports**	**4.6**	**0.9**	**0.5**	[redacted]	[redacted]	**-**	**1.0**	[redacted]	**-**	$1.0
30											
31	**Total Electric Revenue**	**1,241.3**	**1,188.1**	**1,167.3**	[redacted]	[redacted]	**50.2**	**1,279.2**	[redacted]	**50.2**	**$1,373.2**
32											

33 **Notes:**

34 1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.

2) Please note that this is the proposed BA Componentof the FAM rider. This will be decided in a separate venue later this fall.

Nova Scotia Power Inc. **FOR-06**

Gwh Production and Sales

Years Ended December 31st

2012 Financial Outlook

1		(1)	(2)	(3)	(4)	(5)	(6)
2		**Compliance Restated 2009**	**Actual 2009**	**Actual 2010**	**Forecast 2011**	**Present Rates 2012**	**Proposed Rates 2012**
3	**Residential**	**4,185.7**	**4,227.8**	**4,147.2**	[redacted]	**4,372.5**	**4,372.5**
4							
5	**General**						
6	Small general	255.1	236.2	232.2		219.5	219.5
7	General	2,561.9	2,454.4	2,440.2		2,534.0	2,534.0
8	Large general	426.4	416.7	416.1		394.4	394.4
9	**Total General**	**3,243.4**	**3,107.3**	**3,088.5**		**3,147.8**	**3,147.8**
10							
11	**Industrial**						
12	Small industrial	252.4	251.6	254.2		261.9	261.9
13	Medium industrial	580.2	497.8	490.7		512.9	512.9
14	Large industrial	964.8	900.6	929.0		932.6	932.6
15	GRLF	11.1	6.3	20.4		108.4	108.4
16	Mersey Basic Block	189.0	169.6	189.0		189.0	189.0
17	Mersey Additional Energy	178.9	121.6	167.2		179.9	179.9
18	Extra large industrial 2P-RTP	2,098.3	1,694.8	1,857.1		1,814.3	1,814.3
19	**Total Industrial**	**4,274.7**	**3,642.3**	**3,907.6**		**3,999.1**	**3,999.1**
20							
21	**Other**						
22	Municipal	198.4	198.1	193.2		197.4	197.4
23	Unmetered	115.6	112.0	112.8		115.7	115.7
24	**Total Other**	**314.0**	**310.1**	**306.0**		**313.1**	**313.1**
25							
26	**Total In Province Electric Sales**	**12,017.8**	**11,287.5**	**11,449.3**		**11,832.6**	**11,832.6**
27							
28	**Export**	**38.9**	**18.1**	**5.8**		**33.9**	**33.9**
29							
30	**Total Electric Sales**	**12,056.7**	**11,305.6**	**11,455.1**		**11,866.4**	**11,866.4**
31							
32	**Losses**						
33	In-province sales	899.1	785.9	708.3		814.5	814.5
34	Exports	1.2	0.2	0.1		1.0	1.0
35	**Total Losses**	**900.3**	**786.1**	**708.4**		**815.6**	**815.6**
36							
37	**Total System Requirements**	**12,957.0**	**12,091.7**	**12,163.5**		**12,682.0**	**12,682.0**
38							
39	**Net System Requirements**	**12,916.9**	**12,073.4**	**12,157.6**		**12,647.1**	**12,647.1**

40

41 **Notes:**

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

Nova Scotia Power Inc. **FOR-07**

Details of Fuel and Purchased Power
Years Ended December 31st
Millions of Dollars

2012 Financial Outlook

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1								
2		Compliance Restated 2009	Actual 2009	Actual 2010	2011 Base Reset	Forecast 2011	Present Rates 2012	Proposed Rates 2012
3	**Fuel By Type**							
4	Solid Fuel	$320.7	$293.2	$326.9	$351.0	[redacted]	$372.1	$372.1
5	Natural gas	132.5	136.4	167.8	73.7	[redacted]	87.5	87.5
6	Bunker C	45.7	(5.3)	(3.8)	2.8	[redacted]	4.1	4.1
7	Furnace	2.1	2.2	2.6	2.3	[redacted]	2.8	2.8
8	Diesel	22.4	3.2	1.9	1.9	[redacted]	3.2	3.2
9	Additives - Mercury	3.7	0.5	7.6	10.0	[redacted]	0.3	0.3
10	Additives	-	5.0	3.8	3.5	[redacted]	3.5	3.5
11	2009 Settlement Agreement Adjustment	(14.5)	-	-	-	[redacted]	-	-
12	**Total Fuel For Generation**	**512.6**	**435.0**	**506.8**	**445.2**	[redacted]	**473.5**	**473.5**
13						[redacted]		
14	**Purchased Power**					[redacted]		
15	Imports	5.9	37.4	33.1	24.7	[redacted]	33.4	33.4
16	Independent power producers	34.2	15.1	16.4	14.8	[redacted]	18.9	18.9
17	Wind purchases	-	9.4	27.7	42.7	[redacted]	46.2	46.2
18	**Total Purchased Power**	**40.1**	**61.9**	**77.2**	**82.2**	[redacted]	**98.5**	**98.5**
19						[redacted]		
20	**Fuel and Purchased Power**	**552.7**	**496.9**	**584.0**	**527.4**	[redacted]	**572.0**	**572.0**
21						[redacted]		
22	**Fuel For Resale**					[redacted]		
23	Costs	53.0	44.5	7.9	21.7	[redacted]	34.6	34.6
24	Recoveries	(65.8)	(42.6)	(8.2)	(20.7)	[redacted]	(33.8)	(33.8)
25	**Net Cost (Benefit)**	**(12.8)**	**1.9**	**(0.3)**	**1.1**	[redacted]	**0.8**	**0.8**
26						[redacted]		
27	**Exports**	**4.1**	**0.9**	**0.3**	**8.4**	[redacted]	**0.7**	**0.7**
28	**Water Royalties**	**1.0**	**0.9**	**0.9**	**0.9**	[redacted]	**0.9**	**0.9**
29	**Market To Market on HFO and Natural Gas**	**-**	**(0.2)**	**2**	**-**	[redacted]	**(0.5)**	**(0.5)**
30	**Total Fuel and Purchased Power**	**$545.0**	**$500.4**	**$587.0**	**$537.8**	[redacted]	**$573.9**	**$573.9**
31						[redacted]		
32	**Total System Requirements (GWH)**	**12,957.0**	**12,091.7**	**12,163.5**	**12,574.4**	[redacted]	**12,682.0**	**12,682.0**
33						[redacted]		
34	**Total Fuel Cost / MWH**	**$42.06**	**$41.38**	**$48.26**	**$42.77**	[redacted]	**$45.26**	**$45.26**
35								
36	**Notes:**							
37	1) Figures presented reflect whole numbers which may cause $0.1M in rounding differences on some line items.							

NON-CONFIDENTIAL

Request IR-38:

Using mid-year equity (defined as [beginning-year equity + end-of-year equity]/2), please provide the actual ROE earned by NSPI for each of the years 2002 through 2010. Please provide the numerator and denominator for each of those percentages.

Response IR-38:

NSPI calculates ROE based on an established methodology using a five quarter average equity. Attachment 1 provides NSPI's ROE and average common equity for the years 2002 through 2010.

Nova Scotia Power Inc.
Historical Return on Equity
Years Ended December 31st
Millions of Dollars

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Average common equity	$1,029.1	$1,101.8	$1,104.9	$1,085.6	$1,121.2	$1,123.6	$1,128.2	$1,220.0	$1,263.5
Regulated Earnings	$106.0	$115.3	$110.8	$94.7	$107.3	$103.0	$109.6	$111.8	$121.3
Return on equity	**10.3%**	**10.5%**	**10.0%**	**8.7%**	**9.6%**	**9.2%**	**9.7%**	**9.2%**	**9.6%**

NON-CONFIDENTIAL

Request IR-39:

Reference: GRA Section DE-03, DE-04, Appendix H.

NSPI is proposing certain changes in the ELI 2P-RTP rate. Had these proposed revisions been in effect for the years 2009 and 2010, please quantify the before-tax revenue increase NSPI would have realized. Please provide all supporting calculations for these estimates.

Response IR-39:

In preparing the proposals for changes to the 2P-RTP Tariff, NSPI did not undertake an analysis of how the changes might have affected historical results. The changes are proposed to apply on a go forward basis. Therefore, the requested analysis is not available.

CONFIDENTIAL (Attachment only)

Request IR-40:

Reference: GRA Section DE-03, DE-04, Appendix H.

Please provide all assumptions and workpapers/calculations used to develop the table shown on the top of page 5 of 26. If an Excel spreadsheet or model was used please provide that spreadsheet with all formulae intact.

Response IR-40:

Please refer to Confidential Attachment 1, filed electronically.

The table illustrates the effect of the current billing provisions concerning CBL setting and administration, on the under-recovery of fixed costs. For the sake of simplicity and to be conservative, the impact of billing adjustments associated with billing a portion of Bowater's ELI 2P-RTP CBL energy under the Additional Energy rate was not included. The calculations assume that all of Bowater's CBL energy was billed at the ELI 2P-RTP rate (as opposed to a small portion being billed under the lower Large Industrial Interruptible rate). As a result, the non-fuel related revenue and contribution to fixed costs are slightly overstated (i.e. conservative).

Upon further review it has been determined that the 2009 CBL actual amount provided in the table was not adjusted to reflect the July 2009 shut-down and the amount actually billed. As a result the amount of the CBL energy used in the 2009 calculation was overstated in 2009 by 16 GWh and the reported under recovered fixed costs was understated by $0.4 million. The revised table is presented below.

CONFIDENTIAL (Attachment only)

1

	2009 Compliance Filing		Actual		Unrecovered Fixed Costs	
Year	CBL Energy (GWhs)	Non-Fuel related revenues before customer charges (millions of $'s)	CBL Energy (GWhs)	Non-Fuel related revenues before customer charges (millions of $'s)	Amount (in millions of $'s)	%
2009	2,098.3	$46.9	1,857.5	$41.5	($5.4)	-11%
2010	2,098.3	$46.9	1,947.3	$43.5	($3.4)	-7%
Total	4,196.5	$93.8	3,804.8	$85.0	($8.8)	-9%
2011 FCST	2,098.3	$46.9	1,898.7	$42.4	($4.5)	-10%

NON-CONFIDENTIAL

Request IR-41:

Reference: GRA Section DE-03, DE-04, Appendix H.

Please confirm that the figures shown in the section of the table marked "Actual" relate to the CBL energy charged to those customers in the years 2009 and 2010 at the Standard Energy Charge. If this is not what they represent please provide for each of the years 2009 and 2010 the actual energy that was charged to these customers under the Standard Energy Charge.

Response IR-41:

Please refer to NPB IR-40.

NON-CONFIDENTIAL

Request IR-42:

Please provide the actual total metered energy taken under the ELI 2P-RTP tariff, inclusive of load increases and net of load decreases from the CBL, for each of the years 2009 and 2010.

Response IR-42:

The total actual metered energy taken under the ELI 2P-RTP tariff during 2009 and 2010 was 1,741 GWh and 1,873 GWh, respectively. This energy includes the Mersey Agreement energy taken above 42 MW, which was billed as Mersey Additional Energy. Please refer to NPB IR-53 for actual energy taken after the Mersey adjustments.

NON-CONFIDENTIAL

Request IR-43:

Please provide the net credits (debits less credits) paid (or credited) to the ELI 2P-RTP customers in 2009 and 2010 for their deviations from the CBL in each of those two years.

Response IR-43:

The net credits (credits – incremental charges) paid to customers during 2009 were $7,204,739. The net credits paid during 2010 were $4,724,654.

NON-CONFIDENTIAL

Request IR-44:

Reference: GRA Section SR-01, Attachment 1.

For each amount in the Total Expense column (Column 1) of Exhibit 4, lines 1, 2 and 3, please provide the dollar amount of the total that would be subject to true-up under the FAM.

Response IR-44:

Please refer to NPB IR-28.

Of the $475.5 million fuel component (SR-01 Attachment 1, Exhibit 4, line 1), $458.9 million would be subject to a true-up under the Fuel Adjustment Mechanism. The total purchased power amount, regular of $52.2 million and wind of $46.2 million (SR-01 Attachment 1, Exhibit 4, lines 2 and 3), would be subject to true-up under the Fuel Adjustment Mechanism

NON-CONFIDENTIAL

Request IR-45:

Reference: GRA Section SR-01, Attachment 1.

Please provide all workpapers supporting the split of the purchased power regular costs between line 2 (fixed) and line 3 (variable) of Exhibit 5.

Response IR-45:

Consistent with the approach taken in previous Cost of Service Studies, NSPI has assigned a 55/45 split between variable and fixed purchased power regular costs. Please refer to Attachment 1 for a more detailed explanation.

NON-CONFIDENTIAL

Request IR-147:

With respect to SR-01, Attachment 1, page 32, please explain how the Purchased Power expenses (both regular and wind) are classified between fixed (lines 3 and 5) and variable (lines 4 and 6). Are the fixed charges based on a constant per month or based on the capacity or some other method?

Response IR-147:

Lines 3 and 4, "Purchased Power – Regular" costs are assigned using the proportions of 45 percent fixed and 55 percent variable. These proportions are estimates based on the typical type of product bundles that are available when entering into purchased power contracts; that is, firm/non-firm, or capacity-only, or proportions thereof.

Lines 5 and 6, "Purchased Power – Wind" costs are assigned using the assumption of 30 percent fixed and 70 percent variable.

NON-CONFIDENTIAL

Request IR-46:

Reference: GRA Section SR-01, Attachment 1.

Please provide all workpapers supporting the split of purchased power wind costs between line 4 (fixed) and line 5 (variable) of Exhibit 5.

Response IR-46:

Consistent with the approach taken in previous Cost of Service Studies, NSPI has assigned a 70/30 split between variable and fixed purchased power wind costs. Please refer to NPB IR-45 Attachment 1.

Request IR-47:

Please provide all documentation and substantiation for the customer costs or any other directly assigned costs to the ELI 2P-RTP class.

Response IR-47:

Costs that are directly assigned to ELI 2P-RTP are illustrated in SR-01 Attachment 1, Exhibit 6 in the following lines:

Page 1 of 4

- Line 17: ELI 2P-RTP Demand Adjustment
- Line 19: ELI 2P-RTP Priority Demand Adjustment[1]

[1] NSPI 2006 Hearing to Establish a Rate to Replace Nova Scotia Power Incorporated's Extra Large Industrial Interruptible Rate, UARB Decision, NSUARB-NSPI-P-883, September 28, 2006

NON-CONFIDENTIAL

Request IR-48:

On page 7 of Appendix H of GRA Section DE-03, DE-04, NSPI states that the customer may request that NSPI set an operational CBL that would be distinct from the nominal CBL.

(a) Is the customer required to nominate an operational CBL?

(b) Can NSPI unilaterally request or establish an operational CBL?

Response IR-48:

(a) Yes, the customer is required to inform NSPI of anticipated changes in its consumption and nominate an appropriate operational CBL. This requirement aligns with the treatment of modifications of existing CBL in the Special Conditions Section of the current ELI 2P-RTP.

(b) No, NSPI may not unilaterally request or establish an operational CBL. The CBL is initially set on a prospective basis on an energy requirement and duration estimated by the customer. Should a significant reduction in energy usage be observed, NSPI will request information from the customer and work towards the setting of an appropriate operational CBL. Similar to the current provision NSPI and or the customer may approach the UARB if no agreement can be reached.

NON-CONFIDENTIAL

Request IR-49:

On page 7 of Appendix H of GRA Section DE-03, DE-04, NSPI proposes to set lower and upper bounds to the pricing credit in reference to the operational CBL at 90% and 110% of the Standard Energy Charge, respectively. Please explain how these lower and upper bounds were derived.

Response IR-49:

Under the proposed changes to the Extra Large Industrial Two Part Real Time Pricing (ELI 2P-RTP) Tariff, an Operational Customer Baseline (CBL) can be established to accommodate load shifting needs of customers during periods of reduced power consumption arising from factors beyond the customer's control. Shifted energy from the Operational CBL is proposed to be priced in the same manner as the shifted energy during regular operations.

The CBL Base Cost Rate will remain unchanged during the period. In recognition of the avoided cost savings, associated with the reduced CBL energy, NSPI is proposing to credit the customer at a fixed price set in advance of the operational CBL event. (Please refer to NPB IR-51 for details). The recovered fuel costs under the Standard Energy charge (SEC) and credit paid out to ELI 2P-RTP customers form FAM inputs as fuel cost recoveries and fuel costs, respectively.

In view of the significant potential impact that the reductions in consumption may have on the ELI 2P-RTP customers and FAM customers, NSPI has proposed the 110% and 90% SEC-based band around the avoided unit costs for the reduced CBL energy. The 110% upper bound to the pricing credit is intended to strike a balance in marginal cost savings on ELI 2P-RTP and the FAM customers.

NON-CONFIDENTIAL

From 2009 to 2011, a high cost range above $100/MWh has been experienced. At the approximate median of $150/MWh of that high cost range, the 110% bound distributes the savings associated with the avoided costs equally between ELI 2P-RTP and FAM customers in terms of their effect on the marginal cost of power of these customers. For symmetry, the 90% lower bound has also been proposed.

Please refer to Attachment 1, filed electronically for calculations in support of the 110% bound.

NON-CONFIDENTIAL

Request IR-50:

On page 8 of Appendix H of GRA Section DE-03, DE-04, NSPI proposes that the credit floor should be lowered to a credit equivalent to the fuel contribution portion of the Standard Energy Charge. Please quantify this limit at proposed rates and provide all supporting calculations.

Response IR-50:

Under the proposed rates this limit is 4.391 cents per kWh. Please refer to NPB IR-28 for supporting calculations.

NON-CONFIDENTIAL

Request IR-51:

In the redlined tariff of the ELI 2P-RTP rate, Appendix H of GRA Section DE-03, DE-04, at page 15, NSPI is proposing to insert new language that references the "forecast average unit avoided cost associated with this load reduction." Please explain how the forecasted average unit avoided cost will be estimated or projected.

Response IR-51:

NSPI is proposing to use the Strategist™ Model to forecast the average unit avoided costs associated with the temporary reduction in customer's load. For the purpose of each forecast two strategist runs will be done: one under the assumption that system load is not affected by customer load reduction; and the other based on reduced system load. The difference in total system costs from these two runs will represent the avoided fuel costs associated with the reduced customer load. The unit avoided cost, as used for the credit pricing purposes of the CBL load representing the difference between the nominal and operational CBL energies, will be capped at 110 percent of Standard Energy Charge and floored at 90 percent of the Standard Energy Charge.

Request IR-52:

On page 6 of Appendix H of GRA Section DE-03, DE-04, NSPI states that it has reviewed the practices and real-time pricing tariffs of other jurisdictions, especially those of Georgia Power. Please provide all tariffs and practices of real-time pricing rates in other jurisdictions that NSPI has reviewed.

Response IR-52:

Documentation and analyses of real-time pricing rates in other jurisdictions that NSPI has reviewed are provided as follows:

Analyses and Investigation		
Reference	**Document Titled**	**Link**
1	Real-Time Pricing Hour Ahead with Adjustable CBL Schedule: "RTP-HAA-4" – Georgia Power	http://www.georgiapower.com/pricing/pdf/6.50_RTP-HAA-4.pdf
2	Real Time Pricing Supplemental Tariff	www.energy.ca.gov/papers/2001-07-27_ATTACHEMENT_A.DOC
3	Schedule 1823 – Transmission Service – Stepped Rate – BC Hydro	www.bchydro.com/.../transmission_service_rate_3yr_summary_report.Par.0001.File.transmission_service_rate_3yr_summary_report.pdf
4	Real Time Pricing Program – Duke Energy Ohio	www.duke-energy.com/pdfs/DE-OH-RTP.pdf
5	British Columbia Hydro and Power Authority Transmission Service Rates Customer Baseline Load	www.bcuc.com/ApplicationView.aspx?ApplicationId=116
7	A Survey of Utility Experience with Real Time Pricing – Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-54238)	eetd.lbl.gov/ea/emp/reports/54238.pdf
8	Two Part – Time of Use: Schedule TPP – Kansas City Power & Light Company	www.kcpl.com/about/MORates/Sched20.pdf
9	Schedule HP (NC) Hourly Pricing for Incremental Load – Duke Energy Carolinas, LLC	www.duke-energy.com/pdfs/NCScheduleHP.pdf

10	Real-Time Pricing and Related Successful Products – Christensen Associates	sedc-coalition.eu/wp.../OSheasy-Real-Time-Pricing-December-2001.ppt
11	Primer on Demand-Side Management: With an emphasis on price-responsive programs – Charles River Associates	siteresources.worldbank.org/.../PrimeronDemand-SideManagement.pdf
12	Basics of rate design – pricing principles and self selecting two-part tariffs - Sanford V. Berg, Public Utility Research Center, University of Florida, United States	www.regulationbodyofknowledge.org/documents/159.pdf
13	Rate RTP: Real Time Pricing Program – Duke Energy Kentucky, Inc.	http://www.scribd.com/doc/47951156/Duke-Energy-Kentucky-Inc-Rate-RTP-Experimental-Real-Time-Pricing-Program

NON-CONFIDENTIAL

Request IR-53:

Please reconcile the 1,695 GWh and 1,857 GWh for the ELI 2P-RTP rate actual sales for the years 2009 and 2010, respectively, shown in Table A3:Energy Sales by Rate Class of GRA Section SR-02, Attachment 1, page 46, with the 1,873.5 GWh and 1,947.3 GWh actual sales for this rate shown in the table appearing at the top of page 5 of Appendix H of GRA Section DE-03, DE-04.

Response IR-53:

The figures shown in Table A3: Energy Sales by Rate Class of GRA Section SR-02, Attachment 1, represent energy actually used and billed as ELI 2P-RTP energy after the Mersey Agreement volume taken above 42 MW has been adjusted and billed as Mersey Additional Energy.

The figures shown on page 5 of Appendix H of GRA Section DE-03, DE-04 refer to energy defined by the CBL levels in those years, not energy actually used.

REDACTED

Request IR-54:

Reference: OE-1A, Attachment 1, pages 1, 3 and 11 to 26

Please reconcile the individual plant fuel costs by classification (Solid Fuel, Natural Gas, Bunker C, Furnace and Diesel) from pages 11 – 26 with the fuel costs by classification on page 1 and on page 3. Explain the details, calculations and assumptions used in deriving any differences between the totals by fuel classification for all generating plants and the amounts included in the summaries on pages 1 and 3.

For example, a comparison of the sum of individual plant costs of each fuel on pages 11 – 26 with the summaries on pages 1 and 3 gives the following results: [redacted].

Response IR-54:

The reconciling items are fuel for exports, solid fuel adjustments, and natural gas pipeline imbalance charges. Solid fuel adjustments include solid fuel handling, targeted in-furnace injection, contract volume adjustments, provincial emissions fee and a railcar lease.

Please refer to Confidential Attachment 1 for reconciliation.

REDACTED

Request IR-55:

Reference: OE-1A, Attachment 1, pages 1, 3, 11, 14, 16, 18, 22, 23, 24 and 26 of 26

Please reconcile the total costs of individual plant Adjustments and Pipeline Costs from pages 11 – 26 with the costs included on the summary pages 1 and 3.

For example, [redacted].

Response IR-55:

Please refer to Confidential Attachment 1.

REDACTED

Request IR-56:

Reference: OE-1A, Attachment 1, pages 23 and 25

Natural Gas generation includes [redacted]. Please provide detailed calculations by derivative contract supporting these costs. This data should detail by contract the quantity contracted, the date each contract was signed, the date it becomes due, the fixed or floating price negotiated, the price assumed to be paid for the physical quantity of fuel at the due date and the resulting hedge cost.

Response IR-56:

Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-57:

Reference: OE-1A, Attachment 1, pages 23 and 25

Do hedge costs included in fuel costs for Tufts Cove and LM 6000 include costs of any quantities of Natural Gas that are assumed to be Fuel for Resale? If not, where do those hedge costs related to Sales for Resale Fuel appear in the filing? Please describe and give calculations for allocating hedge costs between Natural Gas and HFO used for generation and Fuel for Resale.

Response IR-57:

No. Hedges are tracked separately for burn or resale. There are no resale hedges included in this application.

REDACTED

Request IR-58:

Reference: OE-1A, Attachment 1, pages 1 and 3

Please provide the quantity, sourcing and pricing assumptions for Fuel for Resale costs and recoveries and justify why the forecast includes [redacted]

Response IR-58:

Please refer to Liberty IR-14.

NON-CONFIDENTIAL

Request IR-59:

Reference: OP-01 Attachment 1, pages 28 - 32. "Changeover to United States Generally Accepted Accounting Principles"

Please provide a description and detailed calculations of 2012 rate case costs and reductions in costs related to this changeover, allocating the additional costs and recoveries between new costs for 2012 and retroactive adjustments for prior year costs or reductions in costs.

Response IR-59:

There are three specific items related to the adoption of US GAAP that affect 2012 OM&G costs relative to 2009C:

- Reduction in 2012 OM&G consulting costs related to 2011 Accounting Standards conversion project of approximately $0.7 million.
- The treatment of pension. Please refer to Liberty IR-80 for additional details
- The treatment of income taxes has been prepared in accordance with US GAAP

The 2012 test year financial statements are prepared in accordance with Canadian GAAP only, with the exception of pension expense and income taxes, as complete conversion details were not available when the 2012 test year was prepared. The resultant differences largely reflect reclassifications between accounts and have no effect on the proposed 2012 revenue requirement.

REDACTED

Request IR-60:

Reference: OE-1A, Attachment 1, pages 11, 14, 16, 18 and 22 of 26

Please describe whether NSPI has considered the possibility of using natural gas in place of Bunker C and/or furnace oil as supplemental or flame stabilization fuel and provide any relevant studies or reports NSPI has conducted or commissioned in this regard.

Response IR-60:

NSPI is currently in the process of evaluating the potential for using natural gas as a supplemental fuel at [redacted]. The study work is in the preliminary stages and should be completed by the end of September 2011.

Aside from [redacted], discussed in IR-111, no other existing sites are currently under consideration for natural gas fuelling.

These facilities are being reviewed [redacted].

NON-CONFIDENTIAL

Request IR-61:

In reference to page 9 of NSPI's Application, NSPI identified that the $14.6 million increase it is seeking in this case is attributable to operating and sustaining their workforce. Please provide a breakdown of the $14.6 million into wage increases, new positions and succession planning.

Response IR-61:

Please refer to response to Liberty IR-27.

NON-CONFIDENTIAL

Request IR-62:

Please provide a listing of the severe weather events which have affected NSPI's reliability for the last decade. Please provide the non-internal labour costs incurred that are associated with each severe weather event. In the response, please provide the number of customers who were without service as a result of the severe weather event. Also provide the average amount of time the customers were without service.

Response IR-62:

Please see Attachment 1 for a listing of severe weather events that had a significant impact on NSPI's reliability, including associated customer outage information. NSPI is invoiced all-inclusive rates, usually on a per hour basis, for storm response by contractors. These are commercial rates that include pricing related not only to labour, but also to vehicles, tools, overhead costs and profits. As a result, we are unable to provide the non-internal labour costs that resulted from these storm events.

Major Event Days - 2000 to 2011 (June)

The following are dates which had sufficient customer-hours of interruption to exceed the 2.5 Beta thresholds as defined in standard IEEE 1366-2003 entiled "Guide for Electric Power Distribution Reliability Indices".

CI = Customer Interruptions
CH = Customer Hours of Interruption
CAIDI = Customer Average Interruption Duration Index (Hours)

Start Date	End Date	CI	CH	CAIDI	Description
2000-12-18	2000-12-18	88,414	226,402	2.56	Wind Storm
2002-01-25	2002-01-25	83,297	198,848	2.39	Winter Storm
2002-11-07	2002-11-07	83,683	442,178	5.28	Winter Storm
2003-09-28	2003-10-04	451,489	13,974,720	30.95	Hurricane Juan
2004-02-19	2004-02-20	72,865	573,869	7.88	"White Juan"
2004-11-13	2004-11-15	367,707	5,195,679	14.13	Ice Storm
2004-12-27	2004-12-27	74,222	486,041	6.55	Winter Storm
2005-03-09	2005-03-09	149,447	814,191	5.45	Winter Storm
2005-11-22	2005-11-22	126,303	594,498	4.71	Wind & Rain Storm
2005-12-09	2005-12-10	242,228	1,336,312	5.52	Wet Snow & Wind Storm
2006-12-04	2006-12-05	45,527	325,149	7.14	Wet Snow Storm
2007-11-03	2007-11-04	359,600	3,617,114	10.06	Tropical Storm Noel
2008-11-19	2008-11-20	55,439	210,076	3.79	Wet Snow & Wind Storm
2008-12-22	2008-12-24	428,394	2,418,764	5.65	"Christmas Storms of '08"
2009-01-01	2009-01-02	27,875	210,592	7.55	"New Years" Storm
2009-03-02	2009-03-03	73,263	469,890	6.41	Amherst Area Ice Storm
2010-02-26	2010-02-27	107,527	262,064	2.44	Winter Storm
2010-09-04	2010-09-05	390,441	3,528,671	9.04	Hurricane Earl
2010-12-06	2010-12-07	69,153	190,707	2.76	Wind Storm
2010-12-13	2010-12-14	185,628	1,770,329	9.54	Wind Storm - Annapolis Valley
2010-12-27	2010-12-28	98,556	351,159	3.56	Winter Storm
2011-06-01	2011-06-02	90,590	500,360	5.52	Lightning Storm

Note 1: Customer interruptions could include customers interrupted more than once during the same event.

NON-CONFIDENTIAL

Request IR-63:

In reference to page 62 of NSPI's Application, please provide a breakdown of the $12.5 million OM&G increase related to the Digby, Nuttby and Point Tupper wind projects. Please identify labour and other operating expenses and increases separately.

Response IR-63:

The $12.5 million is comprised of $3.4 million for vegetation management, $3.7 million for storm response, and $5.4 million for the Digby, Nuttby, and Point Tupper renewable project operating costs, as reflected in Figure 5.1 on page 63 of NSPI's application.

Provided in the table below is a breakdown of the $5.4 million OM&G for the Digby, Nuttby, and Point Tupper wind projects.

	Nuttby Wind Project ($M)	**Digby Wind Project ($M)**	**Point Tupper Wind Project ($M)**	**Total ($M)**
Labour	0.2	0.1	-	0.3
Other Non-Labour	0.8	0.8	0.4	2.0
Materials	0.1	0.1	-	0.1
Contracts	1.3	1.3	0.4	3.0
Total	**2.4**	**2.3**	**0.7**	**5.4**

NON-CONFIDENTIAL

Request IR-64:

Please provide all salary surveys NSPI has participated in to determine that among competing companies, NSPI stands at the 50th percentile for non union salaries (page 63 of the Application).

Response IR-64:

Please refer to Liberty-IR-37.

NON-CONFIDENTIAL

Request IR-65:

Please provide the material presented to the Board consultants to review the operating and maintenance practices for transmission and distribution (page 66 of the Application).

Response IR-65:

Materials provided to the Board consultants were provided in the context of their review of NSPI's operating and maintenance practices for transmission and distribution as part of the UARB's proceeding in the matter of a Public Review of the Power Outages resulting from the storm of November 13, and 14, 2004. This proceeding included Information Requests, and Evidence by Intervenors and Board Counsel consultants. The UARB issued a decision in this matter on August 5, 2005.[1]

[1] NSPI Public Review of the Power Outages resulting from the storm of November 13 and 14, 2004, UARB Decision, NSUARB-NSPI-P-401.32, August 5, 2005

NON-CONFIDENTIAL

Request IR-66:

Please provide the analysis of NSPI's vegetation management practices and spending levels presented to the Board's consultant. If any of the practices or spending levels have subsequently changed, please identify and provide an explanation for the changes (page 66 of the Application).

Response IR-66:

Nova Scotia Power filed its Distribution System Vegetation Management Report on September 29, 2006. This report was reviewed by the Board Counsel consultant, The Liberty Consulting Group, as a part of proceeding P-401.32 (and has been re-filed in subsequent GRAs, most recently in answer to 2009 GRA IRs).

The increase to distribution vegetation management spending proposed in the 2006 report was $3.6 million. The Board's decision in that matter read, in part:

> The Board is certainly prepared to approve this important and necessary program should NSPI wish to proceed on the basis that ongoing annual costs associated with this project would be included in future rate applications. The matter will be explored further in the upcoming rate hearing.[1]

As part of the 2009 GRA, Nova Scotia Power submitted its updated 5-Year Vegetation Management Plan 2009-2013 (2009 GRA NSPI (UARB) IR-5 Attachment 3). In the GRA, NSPI proposed to increase spending on vegetation management by $7.0 million from that approved by the Board in prior rate filings. The increase consisted of $3.6 million for distribution system spending and $3.4 million for storm hardening of the transmission and distribution systems.

[1] UARB correspondence to Nova Scotia Power, December 15, 2006, P-401.32.

NON-CONFIDENTIAL

The 2009 Settlement Agreement which was approved by the Board included $3.6 million of the proposed spending increase. NSPI's 2012 Application seeks approval for the additional $3.4 million in transmission and distribution system storm hardening.

NSPI's vegetation management practices are continuously refined to respond to changing vegetation conditions. An example of this is the framework developed by NSPI and HRM following the 2009 GRA and described in the Memorandum of Understanding between the parties. Please refer to Attachment 1.

Nova Scotia Power Incorporated
Vegetation Management Program

Memorandum of Understanding

Between

Halifax Regional Municipality

And

Nova Scotia Power Incorporated

APPROVED
AS TO FORM
Municipal Solicitor

June 24, 2010

Nova Scotia Power Incorporated Vegetation Management Program

Memorandum of Understanding
between
Halifax Regional Municipality
and
Nova Scotia Power Incorporated

June 24, 2010

This Memorandum of Understanding ("MOU") between Halifax Regional Municipality ("HRM") and Nova Scotia Power Incorporated ("NSPI"), dated as of the 24th day of June, 2010 ("Effective Date") sets forth the mutual understandings of the parties with respect to NSPI vegetation management practice within the HRM Urban Core, as described herein.

1.0 Objective

1.1. The purpose of the MOU is to set the foundation for a cyclical vegetation management program ("Vegetation Management Program") to be implemented by NSPI for the area of HRM outlined in Schedule A, attached hereto, and also known as the "HRM serviced area" ("Urban Core"), including the establishment of mutually agreed clearances that provide for safe and reliable operation of NSPI's distribution system and which also promotes the tree health and canopy objectives of HRM.

2.0 General Matters

2.1 NSPI's Vegetation Management Program in the HRM Urban Core will be implemented in collaboration with HRM. It is anticipated that throughout the term of the MOU, NSPI vegetation management practices in the HRM will be refined, based on experience of NSPI and input of HRM.

2.2 This MOU shall come into force and effect as of the Effective Date and shall remain in force and effect until December 31, 2013 unless extended by mutual agreement in writing by the parties.

2.3 This MOU may be terminated by either party, with or without cause, upon ten (10) days written notice.

Nova Scotia Power Incorporated Vegetation Management Program

Memorandum of Understanding
between
Halifax Regional Municipality
and
Nova Scotia Power Incorporated

June 24, 2010

2.4 Notwithstanding the wording used in this MOU, the parties acknowledge and agree that neither the MOU taken as a whole, nor any of its parts taken separately, are, or have ever been, intended to be legally binding or to impose legal obligations on any of the parties. For greater certainty, the parties confirm that this MOU shall have no legal effect.

2.5 Neither this MOU nor any right of the parties under this MOU, may be transferred or assigned, either directly or indirectly, by any party without the written consent of the other party.

2.6 This MOU may only be amended or modified with the written consent of each of party.

2.7 Each party shall bear its own costs and expenses unless otherwise provided for in this MOU or mutually arranged and agreed to in writing. Neither party is authorized or empowered to obligate the other party to incur any costs or expenses on behalf of the other party.

2.8 The following persons are designated as the principal contacts for the purposes of this MOU:

(a) For HRM:

John Simmons
Urban Forrester, Real Property Planning
Halifax Regional Municipality
e-mail: simmonj@halifax.ca
Phone: 902-490-6833
Fax: 902-490-6233

(b) For NSPI:

Paul Casey
Directory of Reliability and Control Center Operations
Nova Scotia Power Incorporated
Email: Paul.casey@nspower.ca
Phone: 902-428-7721
Fax: 902-428-7799

2.9 This MOU may be executed by the parties in separate counterparts, each of which so executed shall be deemed to be an original. Such counterparts together shall constitute one and the same instrument and, notwithstanding the date of execution, shall be deemed to bear the effective date set forth above. Signatures delivered by facsimile will be deemed for all purposes to be original counterparts of this MOU and each party undertakes, on request of the other, to provide the other with an original (bearing original signatures) as soon as reasonably practicable.

3.0 Overall Standards and Specifications

3.1 The standard ANSI 300 for trimming and pruning and the International Society of Arboriculture, Atlantic Code of Practice (Provincial Guideline) shall provide the fundamental criteria for all vegetation management activities to be undertaken by NSPI.

3.2 The standard CSA 23.33 shall be adhered to by both NSPI and HRM for determining the frequency of cyclical work and developing vegetation management prescriptions.

3.3 NSPI and HRM will work together to achieve a balance between the requirements for frequent cyclical trimming on planted street trees and the opportunities for developing sustainable rights-of-way requiring a much lower frequency of management intervention.

3.4 NSPI and HRM agree that planting under utility lines is a function of creating the urban forest, and shall work in concert to ensure the maximum benefits provided by trees. These guidelines set out in the MOU will direct new plantings ensuring that trees are planted in such a way as to prevent future conflict with the power line.

3.5 A list of acceptable compatible trees for planting on power line rights-of-way shall be developed by the HRM in consultation with NSPI.

3.6 Upon request from NSPI, HRM shall provide to NSPI the results of HRM's annual planting program where locations may impact on NSPI's power line rights-of-way in order to assist NSPI in determining future mitigation plans.

4.0 Vegetation Management Zones

4.1 The Urban Core will be subdivided into the following vegetation management zones:

1. Planted Street Tree Rights-of-Way
2. Natural Vegetation and Large-Lot Developing Rights-of-Way

4.2 Vegetation management practices to apply in each of the vegetation management zones are set out below.

5.0 Planted Street Tree Rights-of-Way

5.1 "Planted Street Tree Rights-of-Way" are in areas where the HRM have planted trees as an integral part of developing and contributing to the HRM's urban forest. Depending on the tree type and tree condition, a cycle which best suits the development of any species shall be determined collaboratively by HRM and NSPI.

5.2 The Vegetation Management Program shall ensure all trees are maintained in such a way that prevents trees from growing toward utility lines, balancing the competing objectives for safe and reliable operation of the power system and realizing a healthy urban canopy for HRM.

5.3 Trimming and pruning cycles shall be directed on a street by street basis and be determined by tree conformity. Tree conformity is a descriptor used to characterize a tree's growth response after cyclical maintenance. A tree of conformity responds well to directional trimming and pruning and alters future growth to those limbs growing away from the power line. A tree of non-conformity, irrespective of directional trimming and pruning, continues to grow branches in close proximity to the power lines

5.4 ***Management Tactics***

5.4.1 Trees of conformity which have developed stable limbs and stems at a safe distance from utility lines shall be managed through trimming and pruning every 5 to 7 years. All growth in close proximity to utility wires shall be removed to a safe distance or to the distance previously considered acceptable.

5.4.2 Non-conforming trees shall be managed through trimming and pruning every 3 to 5 years to develop growth away and at a safe distance from all utility wires with the overall objective of developing the tree to be conforming.

5.4.3 After three cycles of attempting, without success, to manage a non-conforming tree into a state of conformity, HRM and NSPI shall meet to identify opportunities for more effective means for maintaining safe clearances that include, but are not limited to: a) heavier pruning, b) tree removal / replacement or c) revision to NSPI physical plant.

5.4.4 Tree maintenance shall be completed to prevent expected growth from encroachment, and encourage branch growth away from all utility lines.

5.4.5 Early intervention trimming on trees that are not in close proximity to utility lines shall be completed in such a way as to ensure trees develop to conformity. This level of maintenance may also require more frequent cycles coupled with non-aggressive maintenance. Stem and limb growth will be directed away from the centre of the pole line as much as possible to prevent growth from more frequent pruning while ensuring that the tree develops in a healthy manner.

5.4.6 Maintenance shall, where justified, be conducted to prepare for upgrades to existing construction. Where upgrades to an existing NSPI pole line are necessary, NSPI will consider redesign, relocation, or reconfiguration of the facilities in such a way as to minimize impacts to present vegetation. Agreement to a modified pruning regime will be required prior to any change.

5.4.7 All tree growth must accommodate power line sway.

5.4.8 Branches and limbs growing above and over top of the utility lines shall be assessed to determine whether or not they are a threat to falling on utility lines under storm conditions. Upon assessment, all large diameter growth or growth over 10 centimetres slated for removal shall be subject to the approval of HRM.

5.5 ***Management Options***

5.5.1 Management options are: cyclical pruning and trimming and tree removal.

5.5.2 All cut brush shall be disposed of by slashing or chipping on site or be chipped and hauled away.

6.0 Natural Vegetation and Large-Lot Developing Rights-of-Way

6.1 "Natural Vegetation and Large Lot Developing Rights-of-Way" are in areas where native, natural tree and shrub growth occurs and where the presence and growth of trees is not actively being managed by the HRM. Areas are defined on a span by span basis on sections of streets, roads, routes or highways.

6.2 The management of these areas will be community-level based. The frequency shall be determined by the anticipated growth of the vegetation, and the cycle is likely to be in excess of 5 to 7 years. Compatible vegetation, such as shrubs, shall be encouraged, while all non-compatible growth will be either trimmed or removed to facilitate the development of a sustainable right-of-way.

6.3 ***Management Tactics***

6.3.1 Roadside vegetation shall be managed in such a way as to encourage the development of street trees that upon maturity will satisfy aspects of the HRM urban forest plan. Tolerant to moderately tolerant deciduous species shall be selected for street trees whenever the opportunity exists. Naturally occurring trees left to develop as street trees shall be managed similar to the early intervention of planted street trees to ensure conformity. As a preference, trees left to develop as street trees shall be located on the side of the right-of-way closest to the road.

6.3.2 Rights-of-way, which have been developing over an extended period of time under the influence of the adjoining land owner, shall be managed to the extent possible in accordance with their expectations unless otherwise directed by the HRM.

6.3.3 Although the abutting land owner does not own the right-of-way, their use or management expectation is respected by NSPI. Abutting property owners are contacted and notified of vegetation management plans.

6.3.4 Trees developing as a multiple-stem clump or as sprouts shall be identified for possible thinning, as opposed to complete removal, to encourage one or two stems to develop to maturity as a single-trunk specimen.

6.3.5 All tree growth must accommodate power line sway.

6.3.6 Shade intolerant species, sometimes referred to as "pioneer species", such as Populus sp. Betula sp. at either the sapling or pole development stage, that are not anticipated to develop to a compatible state of maturity below a utility line, shall be removed.

6.3.7 Widening of the vegetative management area on HRM right-of-way requires specific approval from the HRM.

6.3.8 In cases where adjoining lands to the right-of-way are not developed and development is not anticipated and the natural vegetation is providing "green space," all trees within the full extent of the right-of-way are eligible to be cut and fully removed, in agreement with HRM.

6.3.9 Trees located within two metres of a utility pole or structure with electrical lines attached shall be removed.

6.3.10 A selected number of softwood or coniferous trees, shall be left as conforming trees when the overall tree composition and density is low for a span and the height of the softwood tree is beneath the height of existing communication cables.

6.3.11 Where there are limited opportunities to develop street trees on cross-country rights-of-way or rights-of-way located in industrial areas, compatible vegetation such as shrub growth and low growing trees shall be encouraged for the provision of a stable plant community.

6.4 *Management Options*

6.4.1 Management options include: trimming, selective ground cutting, selective herbicide application (stump treatment only) and mowing and less frequently, planting.

6.4.2 All cut brush shall be disposed of by slashing or chipping on site or be chipped and hauled away.

7.0 Permits

7.1 The primary goal of this MOU is to allow HRM and NSPI to develop a working relationship of mutual trust and respect for achieving a well executed cyclical vegetation management program which recognizes the values of the urban forest, and the provision of safe reliable power to HRM. In reaching this goal, it is the intent of both HRM and NSPI to move to an efficient process of approval, notification and audit.

7.2 HRM will issue a "Streets and Services" permit to NSPI to cover defined cyclical vegetation management activities planned for the municipal right-of-way. The permit application shall identify:

- Street locations including side and limits
- Schedule of activities
- Name of authorized vegetation management contractor

T-600 By-law approvals will be included in the approved Street and Services Permit.

7.3 HRM shall be notified in advance of all activities in the HRM right-of-way that need to be scheduled to accommodate the cyclical vegetation management program. A two week work schedule shall be provided five working days prior to initiation of the planned work. Any changes to the scheduled activities shall be provided to HRM prior to work being undertaken.

7.4 The HRM shall make every effort to issue the Streets and Services Permit within 30 days of submission of the application by NSPI.

Nova Scotia Power Incorporated Vegetation Management Program

Memorandum of Understanding
between
Halifax Regional Municipality
and
Nova Scotia Power Incorporated

June 24, 2010

IN WITNESS THEREOF, the parties have duly executed this Memorandum of Understanding effective as of the date set forth above.

HALIFAX REGIONAL MUNCIPALITY

Per:

Name: ~~Dan English~~ Wayne Anstey
Title: A/Chief Administrative Officer

Witness

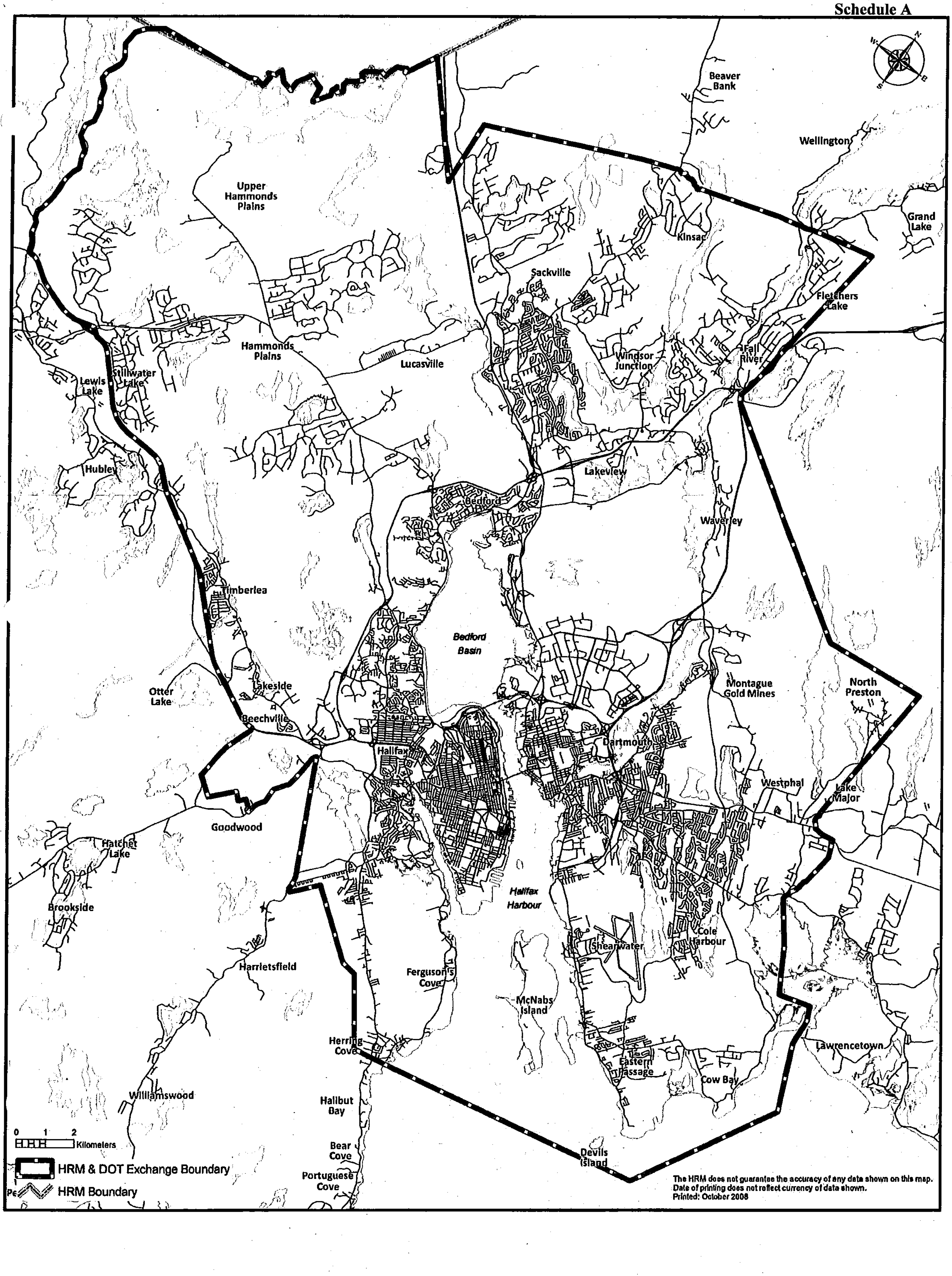
NOVA SCOTIA POWER INCORPORATED

Per:

Name: Alan Richardson
Title: VP Integrated Customer Service

Witness

Schedule A



Beaver Bank
Wellington
Upper Hammonds Plains
Grand Lake
Kinsac
Sackville
Fletchers Lake
Hammonds Plains
Lucasville
Windsor Junction
Fall River
Lewis Lake
Stillwater Lake
Hubley
Lakeview
Bedford
Waverley
Timberlea
Bedford Basin
Otter Lake
Lakeside
Montague Gold Mines
North Preston
Beechville
Dartmouth
Halifax
Westphal
Lake Major
Goodwood
Hatchet Lake
Brookside
Halifax Harbour
Shearwater
Cole Harbour
Harrietsfield
Ferguson's Cove
McNabs Island
Herring Cove
Lawrencetown
Eastern Passage
Cow Bay
Williamswood
Halibut Bay
Bear Cove
Portuguese Cove
Devils Island
0 1 2
Kilometers
HRM & DOT Exchange Boundary
HRM Boundary
The HRM does not guarantee the accuracy of any data shown on this map.
Date of printing does not reflect currency of data shown.
Printed: October 2008

NON-CONFIDENTIAL

Request IR-67:

On page 67 of the Application NSPI identifies five conditions that would raise OM&G. Please provide a quantification of each condition or its impact to OM&G. Of the increase identified, please separate out labour costs from other OM&G increases.

Response IR-67:

The five conditions identified on page 67 of the Application provided metrics related to the 2012 test year over 2002. For the purposes of this Application, a detailed analysis has not been conducted comparing the 2012 test year over 2002. Please refer to Section 5.4 of the Application (pages 72-91) for quantification of changes in operating costs for each group from 2009C to the 2012 test year forecast.

NON-CONFIDENTIAL

Request IR-68:

Please identify the other utilities and/or other companies which NSPI believes it competes with for employees (page 68 of the Application).

Response IR-68:

NS Power competes for employees with other regulated and deregulated electric utilities in Canada and the United States, as well as companies in other related industries (power producers, manufacturing, professional services firms, consulting) in Atlantic Canada. The market for employees with skills required by NS Power is an open labour market. We do not attempt to maintain a list of these companies.

NON-CONFIDENTIAL

Request IR-69:

Please identify the number of employees by year, since 2008, who have left NSPI citing wages/salaries as the main reason for leaving NSPI.

Response IR-69:

NS Power does not track this information.

NON-CONFIDENTIAL

Request IR-70:

Please provide the average tenure of employees at NSPI. Please provide this information on a union and non-union basis.

Response IR-70:

Average tenure (years of service) for non-union employees is 12.2 years.

Average tenure (years of service) for union employees is 13.2 years.

NON-CONFIDENTIAL

Request IR-71:

(a) Please indicate whether NSPI restated its 2009 Compliance numbers to account for the development of a Sustainability Group. If yes, please provide the purpose of the Sustainability Group including a list of members in the group.

(b) Please identify the costs of the group by years since its formation, breaking out the costs between labour and non-labour.

Response IR-71:

(a) NSPI restated its 2009 Compliance numbers to account for the development of the Sustainability Group. Please refer to Liberty IR-50 for additional details.

(b) Please refer to Appendix C pages 23-24 of the Application

Request IR-72:

Please reconcile the cost increase of $18.3 million identified on page 73 of the Application to the $12.5 million identified on page 62 of the Application for the costs associated with the Point Tupper, Nuttby Mountain, and Digby wind projects.

Response IR-72:

Lines 21-22 of page 73 of the Application indicate that $5.4 million of the $18.3 million increase in OM&G for Power Production is for the Point Tupper, Nuttby Mountain and Digby wind projects.

As detailed in the response to NPB IR-63, the $12.5 million consists of the following three initiatives: $3.4 million for vegetation management, $3.7 million for storm management, and $5.4 million for renewable project operating costs.

In figure 5.5 on page 74 of the Application there is a listing of the cost categories that comprise the total $18.3 million increase in Power Production OM&G where the $5.4 million is listed for the operating costs of the three new wind projects.

Request IR-73:

Reference: Liberty IR-53

Please provide a copy of the work and asset management strategy. How will this strategy differ from the goal of the Sustainability Group?

Response IR-73:

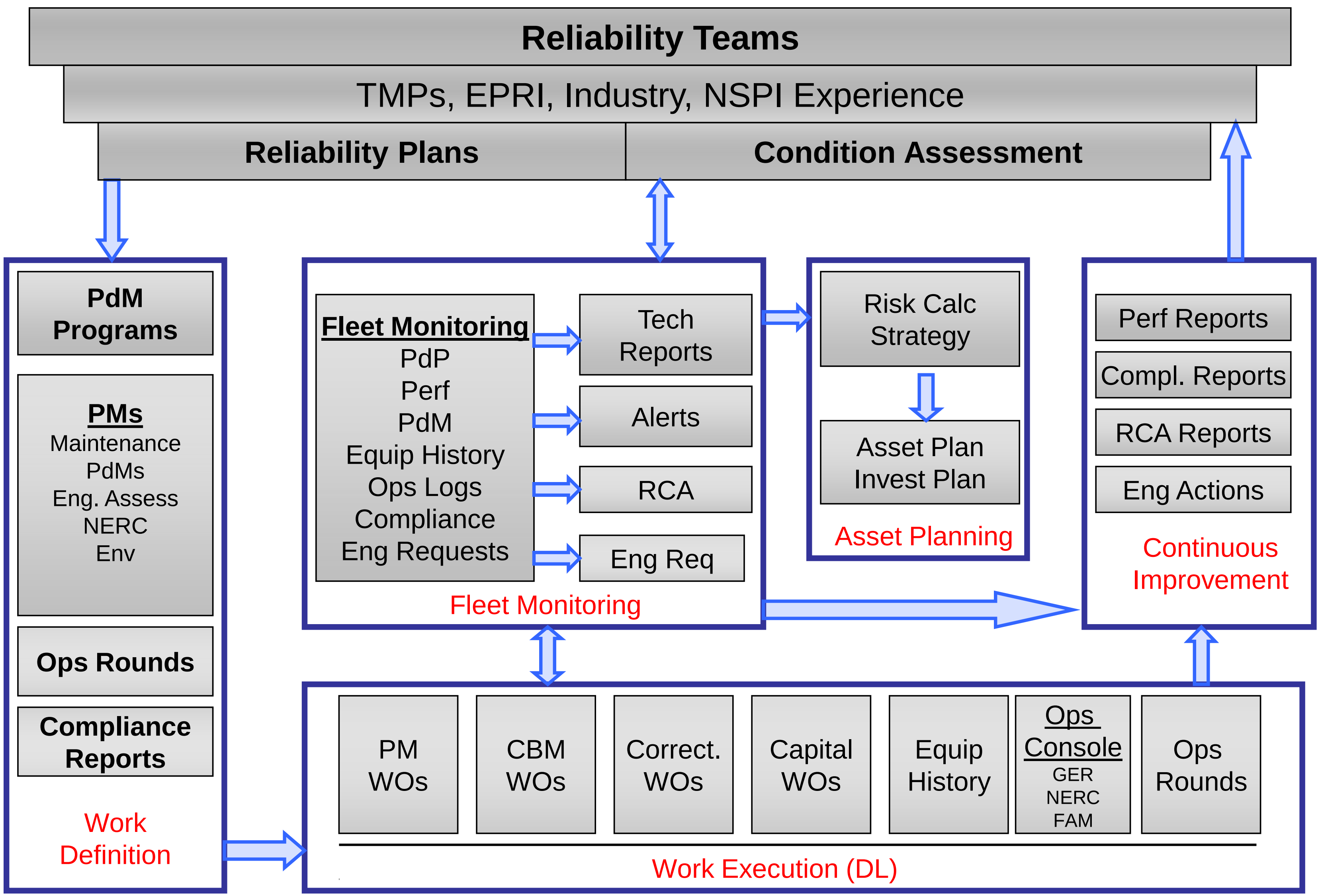
Please refer to Attachment 1.

This strategy differs from the goal of the Sustainability Group in that the asset management group is responsible for developing, deploying and supporting work management processes, equipment reliability programs, and monitoring equipment condition. It further measures equipment maintenance and equipment performance. The Sustainability Group is responsible for renewables development activities and other items as detailed in Liberty IR-50.

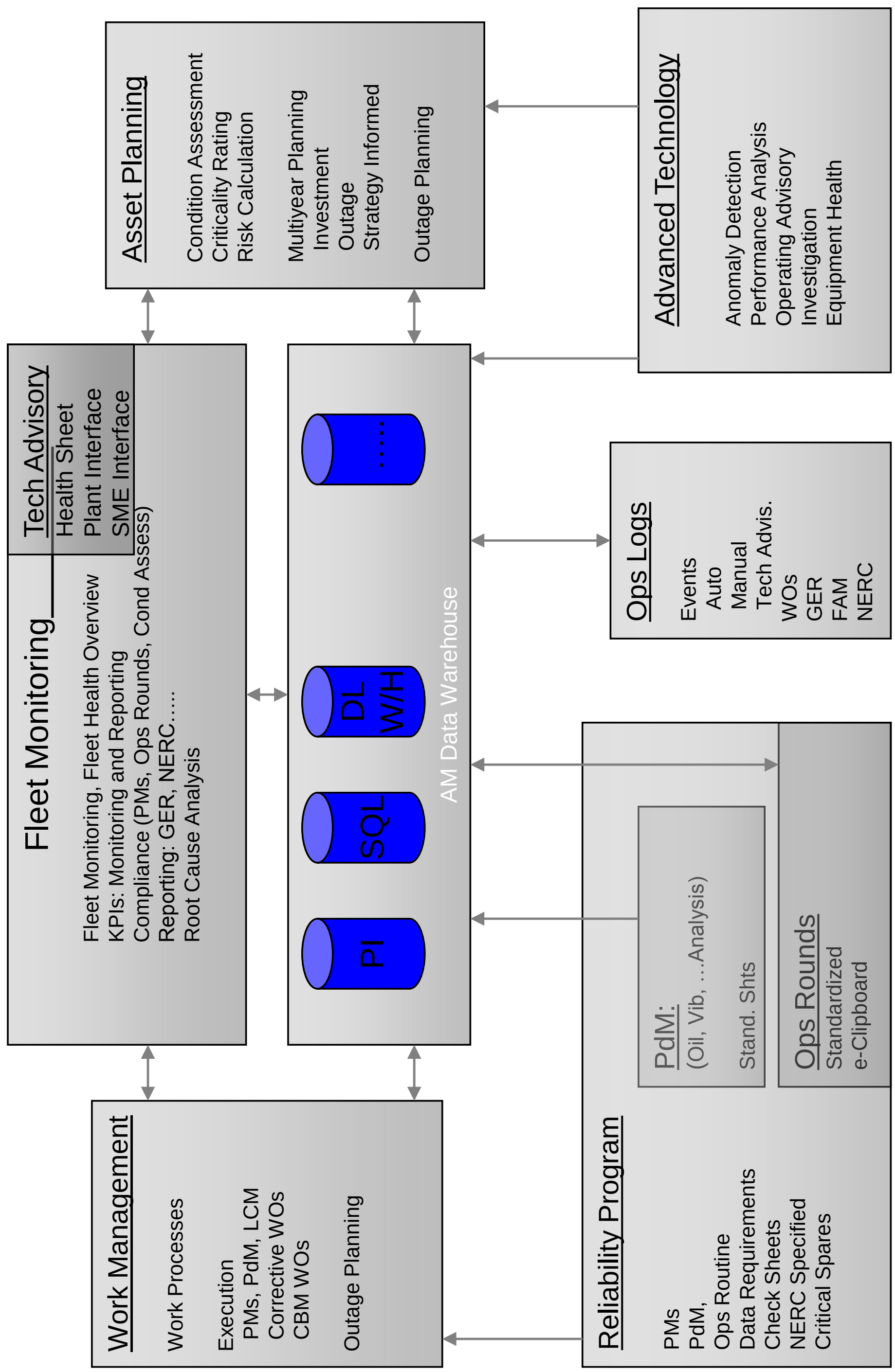
Generation Asset Management

Overview: Oct 2010

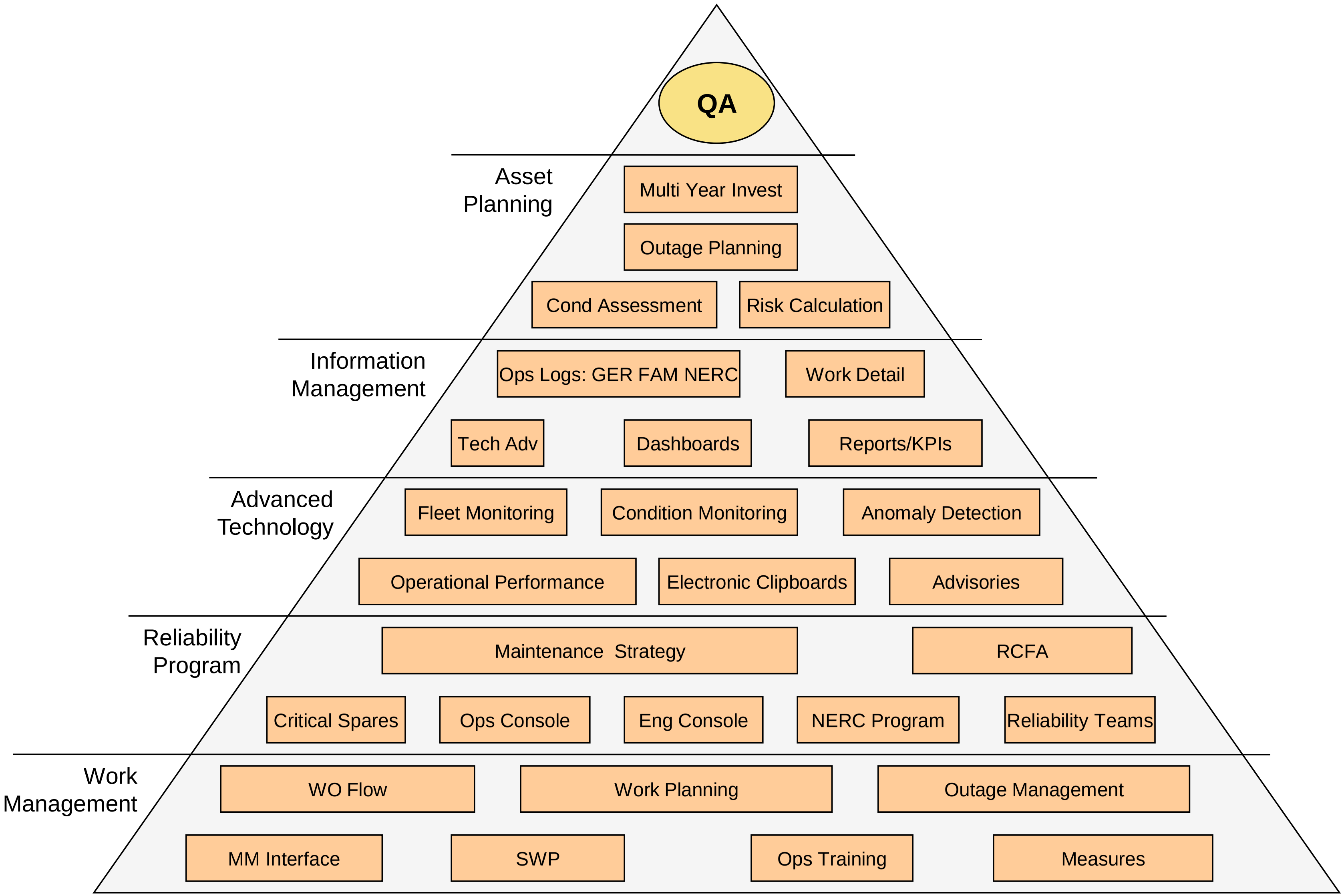
Asset Management Overview



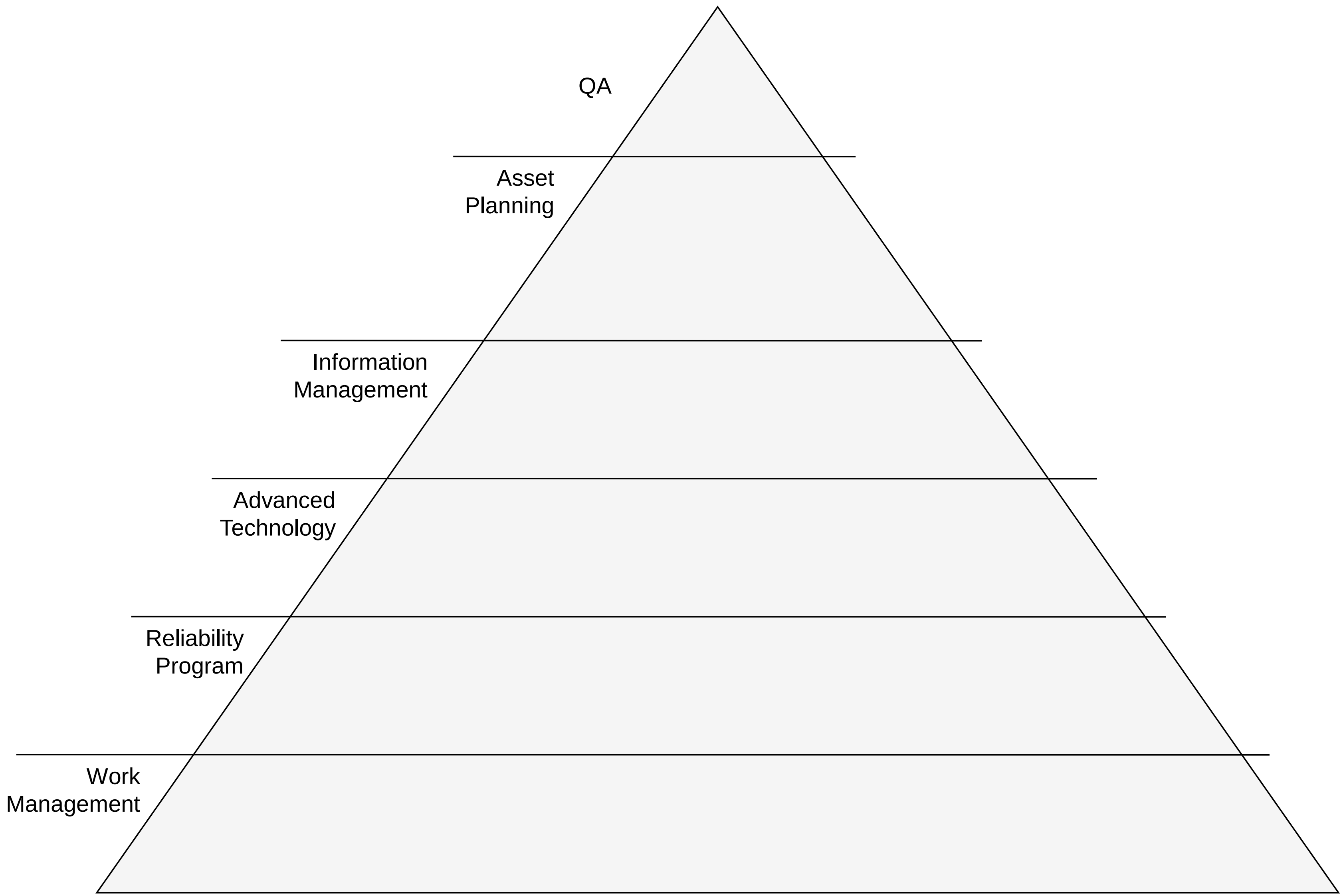
Asset Management: Info Flow



Asset Management: Elements

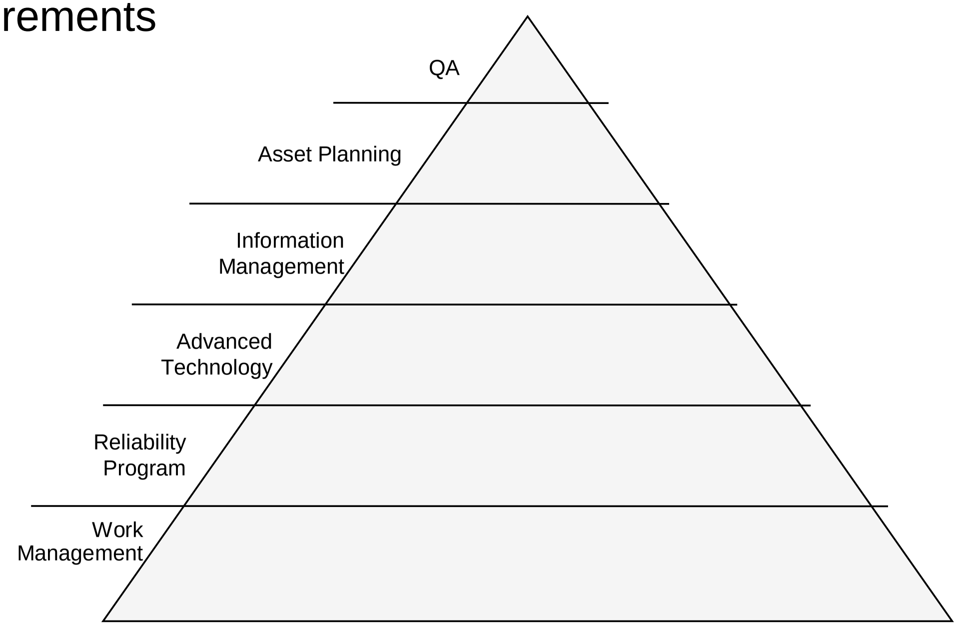


Generation Asset Management: Layered Approach

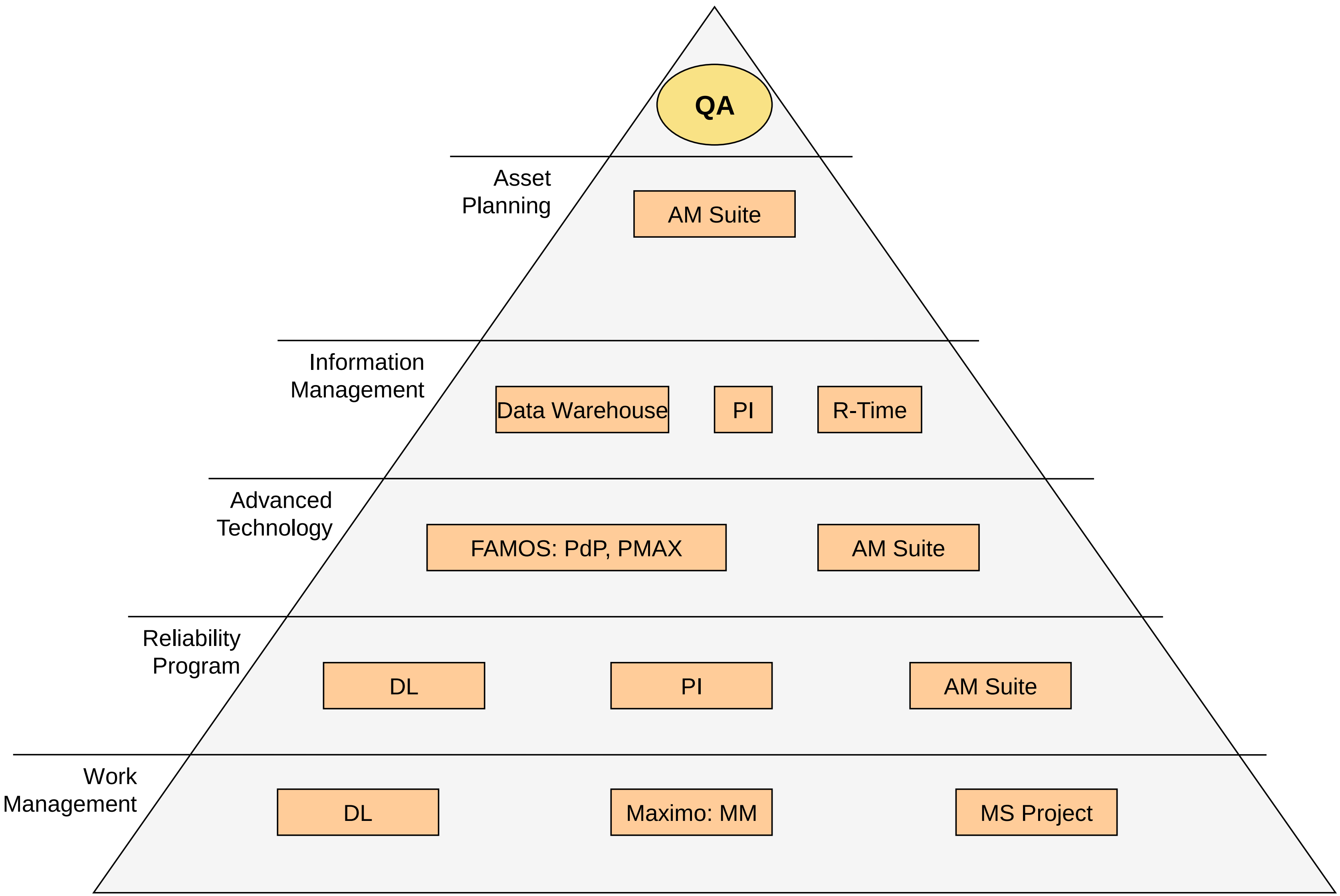


Asset Management: Layered Approach

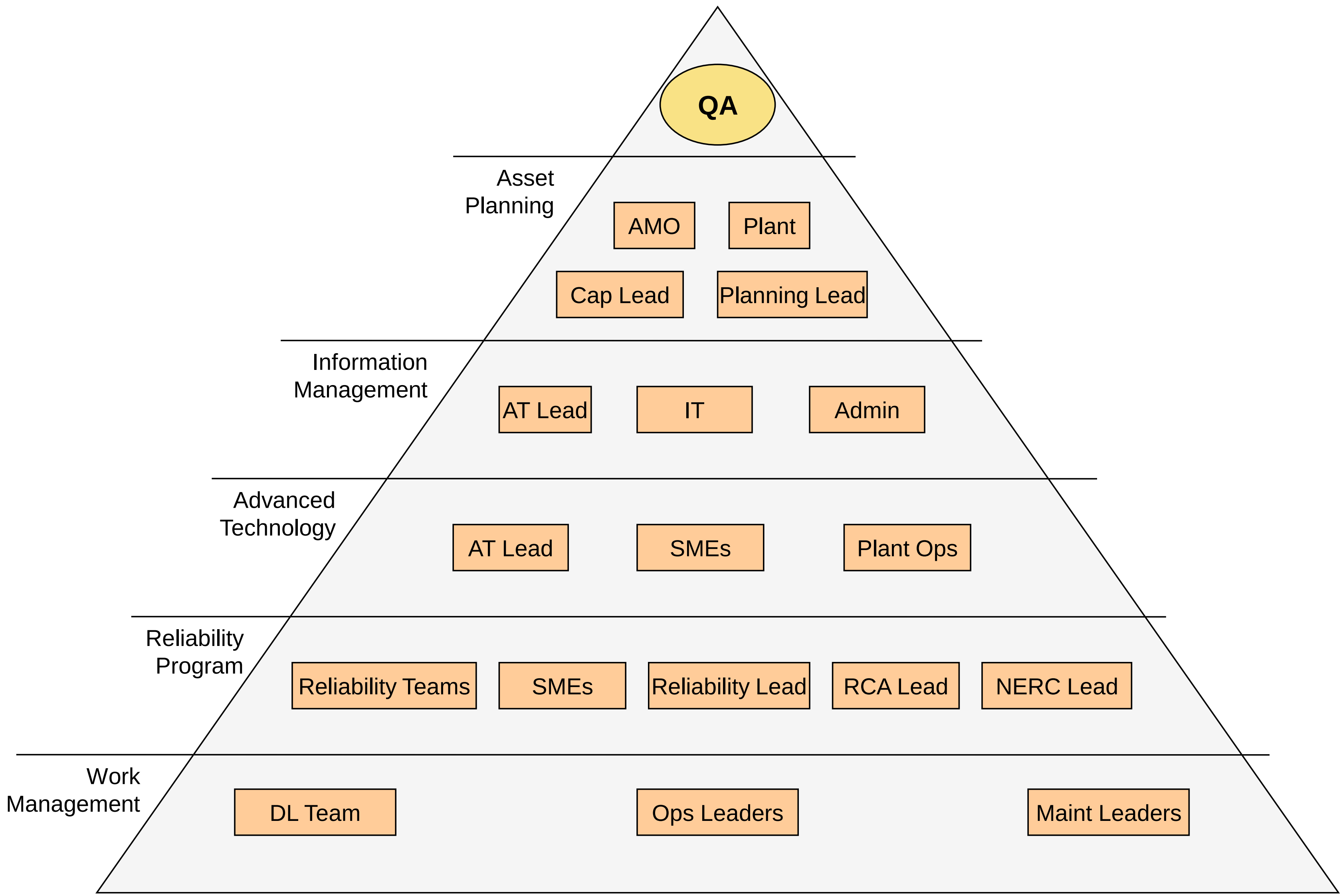
- 6 Layers of Activity
- Independently Adding Value
- Value magnified as they are integrated into AM Model
- Each layer "turning on" independently and in small steps
  - Minimum Organization Churn or Interruption
- Low Risk Approach
  - Staged Monetary Commitments
  - Controlled Resource Requirements
  - No single "Turn On Date"
  - Employing learning
- Max employee participation
  - Buy In
  - Knowledge Capture



Generation Asset Management: Tools

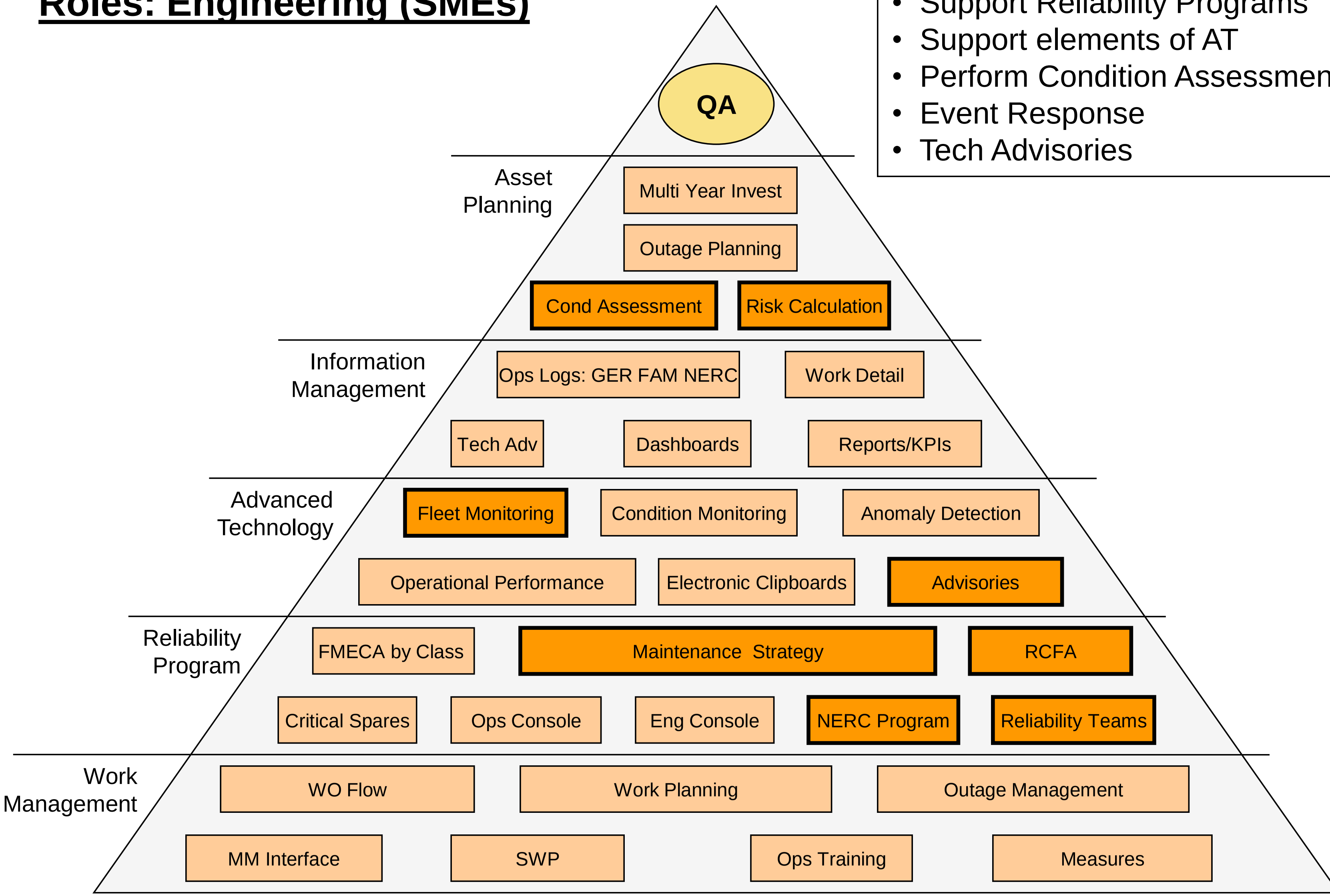


Generation Asset Management: Key Roles



Generation Asset Management Roles: Engineering (SMEs)

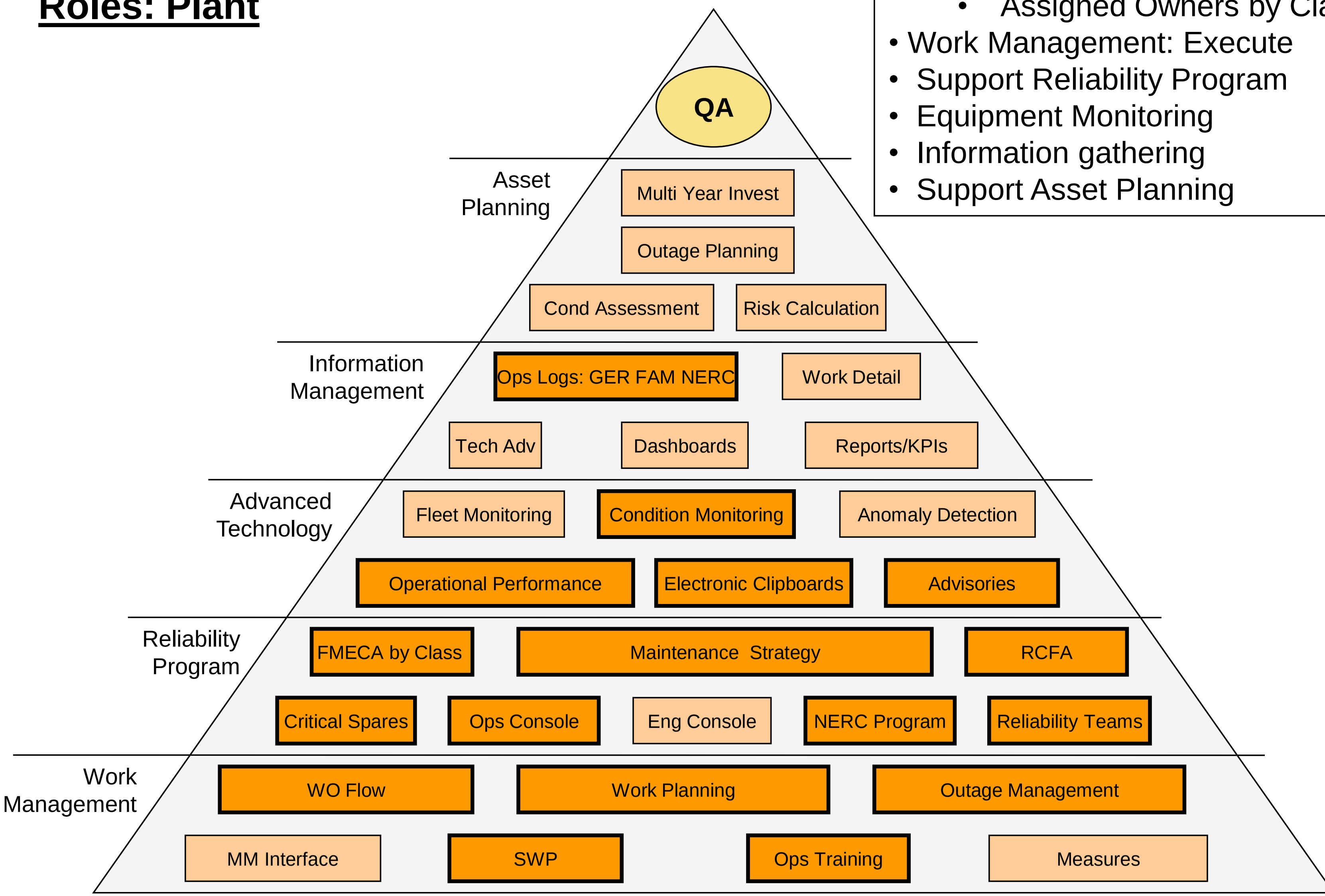
Engineering Key Roles:
- SMEs
- Support Reliability Programs
- Support elements of AT
- Perform Condition Assessments
- Event Response
- Tech Advisories



Key Roles: SMEs

- SMEs assigned as experts to Asset Classes
- Develop and Maintain TMPs
- Participate on Reliability Teams
  - Provide Asset Expertise
- Stay abreast of Industry knowledge and experience
  - Reflect in TMPs
  - Provide Technical advisories
- Maintain awareness of and relevant codes and regulations
  - Reflect in TMPs
  - Provide Technical Advisories
- Participate in RCAs
- Event Response. Support Plants during equipment issues.
- Outage Support
- Condition Assessment: Provide annual condition assessments
- Interface with Fleet Monitoring to produce Tech Reports

Generation Asset Management Roles: Plant



Plant: Key Roles:
- Asset Owners
    - Assigned Owners by Class
- Work Management: Execute
- Support Reliability Program
- Equipment Monitoring
- Information gathering
- Support Asset Planning

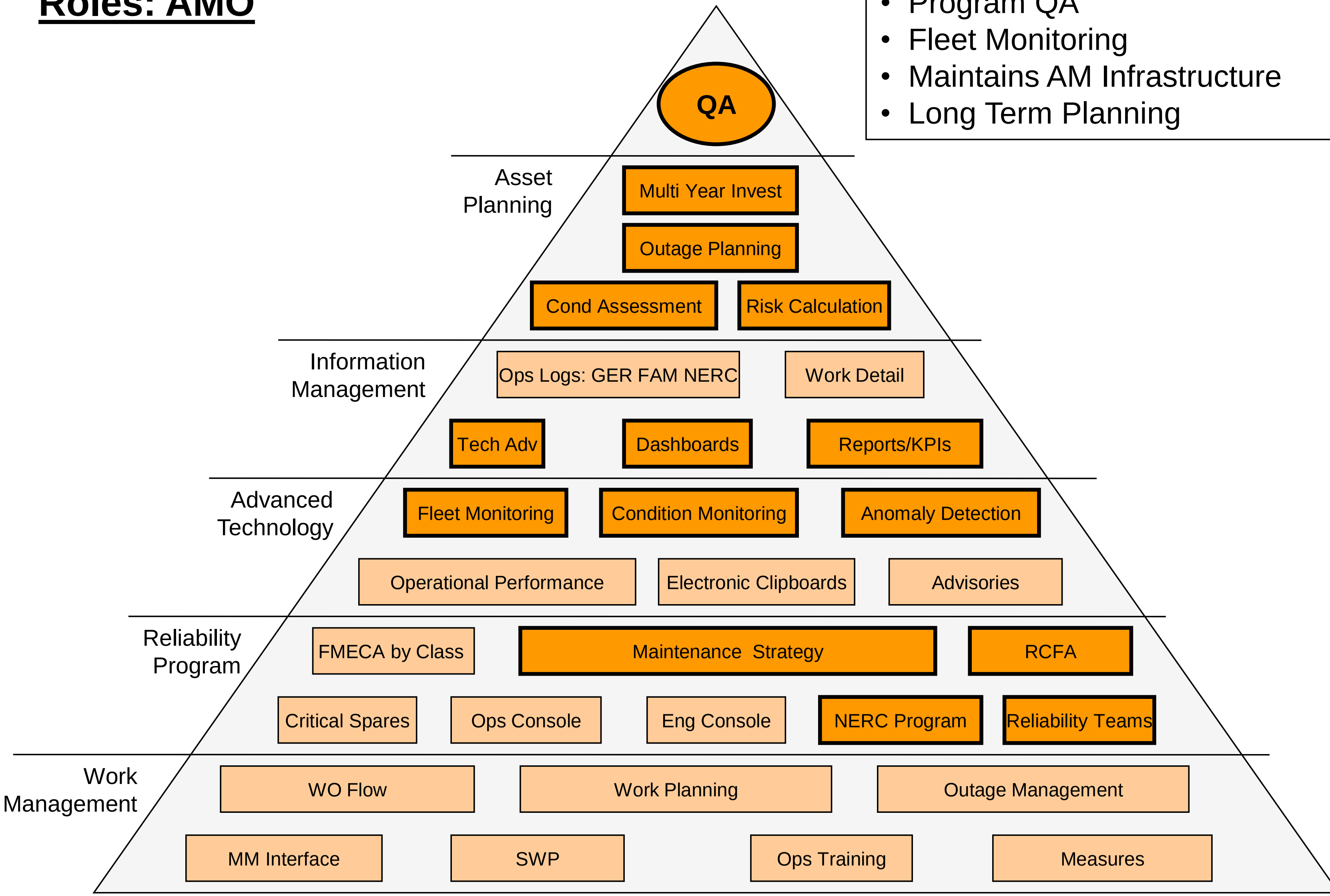
Key Roles: Plant

- Asset Owners
  - Assign ownership of key assets to Plant Tech Personnel
  - Participate on Reliability Teams
  - Ensure Reliability programs are executed
- Lead event response
- Participate with AMO in outage planning
- Lead Outage Execution
- Execute Capital Program
- Provide membership to DL Team
- Provide membership to Reliability Teams
- Interface with Fleet Monitoring regarding equipment health
- Execute Work Mangement Process and Planning process

Generation Asset Management Roles: AMO

AMO: Key Roles:

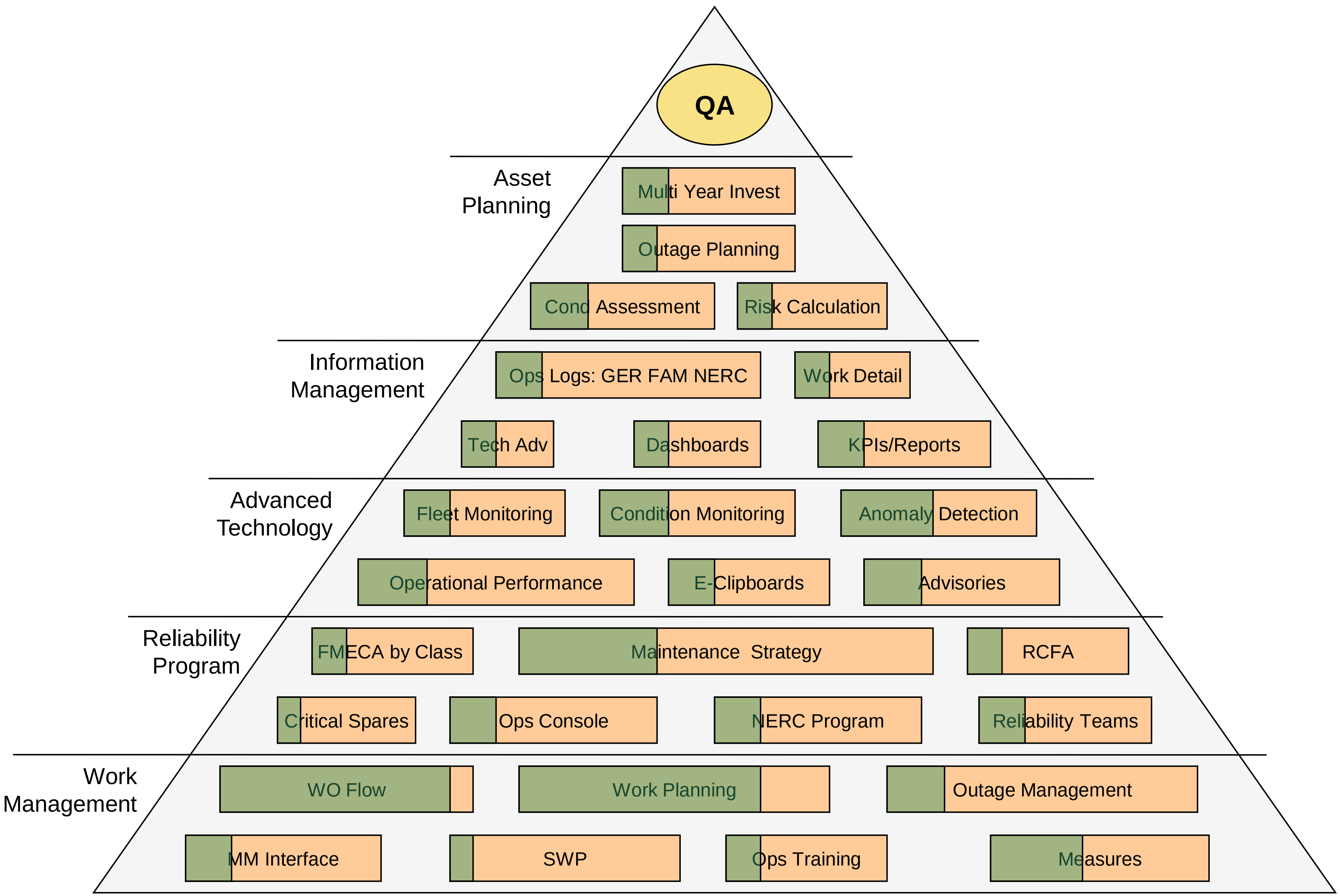
- Program Owners (Incl Relaibility)
- Program QA
- Fleet Monitoring
- Maintains AM Infrastructure
- Long Term Planning



Key Roles: AMO

- Program Owners
  - Maintains Reliability and Planning Processes
  - Ensures DL and Reliability Teams are functioning as per charter
- Program QA
  - Work Management
  - Reliability programs
- Manages RCFA Program
- Manages NERC Program
- Adminsters actions in Engineering Console
  - RCA
  - TAs
  - Eng Requests
- Provides Fleet Monitoring
  - PdP, Performance, PdM
  - Tech Reports
  - Supports RCAs
- Maintains AM Infrastructure
  - PI, PEMs, FAMOS, DL, AM Tools, PdMInterface, e-clipboards,
  - Interfaces with IT
- Long Term Planning
  - Produces 5 year Plans
  - Interfaces with Gen Planning

Generation Asset Management: Elements and Status



Asset Management: Near Term Deliverables

- Work Management
  - Hydro to DL
  - Weekly Planning Process and Support Tools fully operational
  - Outage Planning Process defined
- Reliability Program
  - Reliability Plans represented in DL for:
    - UPS, Gen O/P, Gen, Fire, Turbine*, Hg, CTs, NERC-GEN, NERC-CIPS
  - NERC Reliability Program
  - RCFA Program
  - AM System: Vendor selected.
  - Turb/Gen: Detailed 3rd party assessment initiated
  - Engineering Console Complete
- Advanced Technology
  - Lingan PdP and Performance Monitoring deployed
  - Fleet Turbine PdP deployed
- Information Management
  - E-clipboards demostrated in service: CTs, Hydro
  - Fleet Monitoring function defined and utilized: Lingan
- Asset Planning: Influence Multiyear Investment Plan

Asset Management: 2011 Targets

- Work Management
  - % improvement in: Plan/Unplanned , CM/CBM
  - Outage Planning Process in service
- Reliability Program
  - Reliability Plans :
    - Major Asset Classes concluded
    - Maintenance Strategy managed:
  - PdM program defined for Fleet and integrated
  - Ops Rounds: Standardized, Electronic, integrated
- Advanced Technology
  - Fleet PdP and Performance Monitoring 75% complete
- Information Management
  - E-clipboards: Widespread Use (Ops and Maintenance)
  - Fleet Monitoring fully manned and operational
- Asset Planning:
  - Condition Assessment and Risk Calculation driving long term planning

NON-CONFIDENTIAL

Request IR-74:

Reference: DE, pages 80-81

Please provide the storm operating expense for the August 29th tropical storm "Denny."

Response IR-74:

The total OM&G cost for tropical storm "Danny" was $549,492.

NON-CONFIDENTIAL

Request IR-75:

In reference to Table 5.11 on page 81, please provide a listing of each storm event which comprised the total storm operating expense listed for each year. Does NSPI have a standard which determines if a storm is a major storm versus other storms? If so, please provide a description of the standard.

Response IR-75:

Please refer to NPB IR-5 Attachment 1 for a listing of the storm events and costs.

NSPI uses the IEEE standard 1366-2003, entitled "A Guide for Electric Power Distribution Reliability Indices" to categorize storms for reliability indices purposes. NSPI expenses costs associated with larger outage events to our storm accounts, generally those defined as Level 2, 3 or 4 in our Emergency Service Restoration Plan.

Nova Scotia Power Storm Costs

Storm Events[1]

2006			
01 Jan - 12 Dec	Other Storm Events	**$**	**3,686,039**

2007			
11 Nov	Hurricane Noel	$	6,338,856
01 Jan - 12 Dec	Other Storm Events		5,381,267
Total 2007		**$**	**11,720,123**

2008			
09 Sep	Hurricane Kyle	$	1,833,947
12 Dec	Christmas Storm		3,158,940
01 Jan - 12 Dec	Other Storm Events		2,777,215
Total 2008		**$**	**7,770,102**

2009			
01 Jan	snow, wind	$	1,161,676
01 Jan	snow, freezing rain		11,192
01 Jan	wind		28,439
02 Feb	wind,snow,ice		36,357
02 Feb	snow		401,044
02 Feb	wind,snow		269,699
03 Mar	ice, snow		1,412,334
07 Jul	lightning		256,110
08 Aug	Hurricane Bill		1,923,457
08 Aug	T.S. Danny		549,492
11 Nov	snow, wind		441,162
12 Dec	wind, rain		20,153
12 Dec	snow		769,372
12 Dec	snow, wind		289,054
12 Dec	wind		106,974
12 Dec	snow		43,694
Total 2009		**$**	**7,720,210**

2010			
01 Jan	snow, freezing rain	$	566,145
01 Jan	wind, rain		279,267
01 Jan	wind		46,029
02 Feb	wind, rain		467,714
03 Mar	wind, rain		747,391
05 May	wind,rain		305,038
08 Aug	lightning		67,788
08 Aug	lightning		134,476
09 Sep	Hurricane Earl		6,401,298
09 Sep	wind, rain		45,894
11 Nov	wind, rain		969,052
12 Dec	wind & snow, Level 3		2,689,129
12 Dec	wind,snow		1,375,440
Total 2010		**$**	**14,094,661**

[1] Storm events were not all tracked separately prior to 2009

NON-CONFIDENTIAL

Request IR-76:

Is it NSPI's position that currently rates recover $5.0 million annually for storm response costs, and thus a $3.7 million increase is requested to achieve the five-year average of $8.7 million? If not, please reconcile the statement on page 81 (lines 7-11) of the Application.

Response IR-76:

Please refer to Liberty IR-58.

NON-CONFIDENTIAL

Request IR-77:

Does NSPI have a defined vegetation management trim cycle whereby all circuits are trimmed within a specified time interval? If yes, please provide the trim interval for the circuits. If no, please provide the basis for trimming circuits.

Response IR-77:

No. NSPI's approach to vegetation management is to optimize existing funding by scheduling and prioritizing work for reliability improvement and outage prevention. NSPI's goal is to create sustainable rights of way; developing stable, compatible plant communities that do not require frequent maintenance.

NON-CONFIDENTIAL

Request IR-78:

Does NSPI believe that removing off right-of-way hazard trees would impact the costs of storm restoration expense? If yes, has NSPI developed any estimates of the cost savings?

Response IR-78:

Please refer to Liberty IR-59 and Liberty IR-60.

CONFIDENTIAL (Attachment Only)

Request IR-79:

Reference: Page 113.

> **It consists primarily of coal and oil inventory, thermal plant inventory and of transformers and conductor to support the transmission and distribution system.**

Please provide a breakdown of the materials and supplies inventory being requested by NSPI in this case. Provide monthly totals if that was the basis for the requested inventory levels. If another method was used, please provide support.

Response IR-79:

Please refer to Partially Confidential Attachment 1 for the breakdown of the allowance for materials and supplies inventory.

Nova Scotia Power Inc.
Allowance for materials & Supplies
Years Ended December 31st
Thousands of Dollars

	January	February	March	April	May	June	July	August	September	October	November	December	Average
2011 Solid Fuel Inventory	[redacted]												
2012 Solid Fuel Inventory	51,292	44,972	43,683	41,437	48,771	65,441	62,488	62,854	66,826	69,516	71,697	63,841	57,735
Average Solid Fuel Inventory	75,575	71,290	60,556	49,815	49,329	77,240	71,044	77,883	83,596	80,079	79,174	64,991	70,048
2011 Liquid Fuel Inventory	[redacted]												
2012 Liquid Fuel Inventory	26,119	25,883	25,683	25,529	25,426	25,289	25,131	24,972	24,864	24,706	24,523	24,287	25,201
Average Liquid Fuel Inventory	25,997	25,824	25,673	25,552	25,457	25,351	25,229	25,103	25,004	24,874	24,732	24,560	25,280
Average Fuel Inventory	101,572	97,114	86,229	75,368	74,786	102,591	96,274	102,986	108,600	104,953	103,906	89,551	95,327
2011 Materials Inventory	[redacted]												
2012 Materials inventory	26,912	26,131	26,653	27,506	27,784	27,787	28,062	29,252	28,600	28,615	28,193	28,350	27,820
Average Materials Inventory	26,817	26,426	26,687	27,114	27,253	27,254	27,392	27,987	27,661	27,668	27,457	27,536	27,271
Allowance for Materials & Supplies	128,389	123,540	112,916	102,481	102,038	129,845	123,666	130,973	136,260	132,622	131,364	117,087	122,598

NON-CONFIDENTIAL

Request IR-80:

In reference to Figure 7.2 please provide copies of the excerpts from the UARB which allowed recovery of these deferred charges or credits. Also, please provide a detailed description of each deferred account and the circumstances why it was established.

Response IR-80:

Defeasance & Finance Charges:

Please refer to Attachment 1 for a copy of the relevant excerpt from the UARB's decision from the 1993 Rate Decision[1].

Defeasance: Upon privatization in 1992, NSPI became responsible for managing a portfolio of defeasance securities held in trust. The excess of the cost of defeasance investments over the face value of the related debt is deferred on the balance sheet and amortized over the life of the defeased debt as permitted by the UARB.

Financing issue costs: Included in financing issue costs are unamortized debt financing costs, discounts and premiums which are amortized over the term of the related debt.

Section 21 and Q1 2005 taxes:

NSPI's 2007 GRA applied for approval of the recovery of the deferral of the Section 21 taxes and Q1 2005 taxes in customer rates. NSPI and stakeholders entered into a settlement agreement with respect to the 2007 GRA. Please refer to Attachment 2 for a copy of the Minutes of Settlement. Paragraph 8 confirms that the parties agreed to no changes from NSPI's Application

[1] NSPI 1993 Rate Case, UARB Decision, NSUARB-NSPI-P-863, March 24, 1993, pages 24-25.

for rate base, return on rate base, return on equity, OM&G, regulatory amortization and income taxes. The UARB's decision of February 5, 2007[2] approved this settlement.

NSPI has a regulatory asset related to pre-2003 income taxes that have been paid, but not yet recovered from customers. This circumstance arose when NSPI claimed capital cost allowance deductions in its corporate income tax returns that were ultimately disallowed by a decision of the Supreme Court of Canada. In its February 2007 decision, the UARB approved recovery of this regulatory asset over eight years, commencing April 1, 2007.

Prepaid Pension Asset:

Please refer to Attachment 3 for a copy of UARB-approved, NSPI Accounting Policy 2400.

Fuel Adjustment Mechanism:

Please refer to Attachment 4 for a copy of the relevant excerpt from the UARB's decision approving the FAM[3]. Please also refer to Attachment 5 for a copy of the UARB-approved NSPI Accounting Policy 5110.

Asset Retirement Obligations:

Please refer to Attachment 6 for a copy of UARB-approved NSPI Accounting Policy 6320.

Asset retirement obligations ("ARO") are recognized when incurred and represent the fair value, using the Company's credit-adjusted risk-free rate, of the Company's estimated future cash flows necessary to discharge legal obligations related to reclamation of land at the Company's thermal, hydro and combustion turbine sites, and disposal of polychlorinated biphenyls ("PCBs") in its

[2] 2007 Rate Case, UARB Decision, NSUARB-NSPI-P-886, February 5, 2007.
[3] 2009 Rate Case Decision, NSUARB-NSPI-P-888, November 5, 2008, paragraphs 126-136.

transmission and distribution equipment. Estimated future cash flows are based on the Company's completed depreciation studies, prior experience, estimated useful lives, governmental regulatory requirements and the costs of activities such as demolition, restoration and remedial work based on present-day methods and technologies. Actual results may differ from these estimates.

Future Income Taxes:

Paragraph 5 of NSPI Accounting Policy 5110 (Attachment 5) states:

> Future income tax is recorded on the FAM Regulatory Asset (Liability) balance resulting in a future income asset or liability. The income tax expense (recovery) is recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

Please also refer to Attachment 7, UARB-approved NSPI Accounting Policy 5900. Paragraph 5 states:

> The Company will recognize a deferred regulatory asset (liability) related to FAM. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM regulatory asset (liability) is expected to reverse.

Please also refer to Attachment 8 which discusses Future Income Taxes treatment under FAM.

Other:

The three main accounts in this category are Vegetation Management, DSM and Renewable Energy Deposits.

Please refer to Attachment 9 for a copy of the excerpt from the UARB decision approving the DSM deferral[4]. Please refer to Attachment 10 for a copy of the UARB decision approving the vegetation management deferral[5].

The UARB agreed to allow NSPI to defer up to $12.8 million of demand side management expenditures for the period January 1, 2008, through December 31, 2009, to be recovered in rates over six years commencing January 1, 2009.

The UARB agreed to allow NSPI to defer up to $2.0 million of vegetation management spending in 2008 to be recovered in rates in a future period. The investment in vegetation management spending was part of a specific initiative to improve the reliability of service provided to customers.

Renewable Energy deposits accounts relate to study deposits received from interconnection customers as part of the Generator Interconnection Procedures and deposits related to contractual obligations.

[4] 2009 Rate Case Decision, NSUARB-NSPI-P-888, November 5, 2008, paragraph 107.
[5] UARB correspondence to NSPI, March 12, 2008; P-401.32.

Productivity Improvement

In a January, 1992 news release issued by Nova Scotia Power Corporation announcing its privatization, Mr. Comeau is stated to have said that "He believes privatization will encourage the company to achieve further efficiencies and better cost control, ultimately leading to lower rates than otherwise would have been the case".

The Board expects the Company to proceed aggressively with its cost control efforts. The Company will be expected to present tangible evidence at its next rate hearing that real success is being achieved in controlling expenses and improving productivity. The Board will expect the Company to achieve these improvements without detrimentally affecting customer service.

Capital Structure

The Board views a range of 8%-10% for preferred share capital and a range of 33%-35% for common share capital to be appropriate.

Debt Defeasance

The Board accepts the argument that the debt defeasance expense is one which was imposed on the Company by the government. It is a legitimate expense in lieu of the Provincial Government guarantee. The net expense, if any, to be recovered from rates, will not impose an undue burden on its customers.

The Board retained R. A. Radchuck, F.C.A., of Peat Marwick Thorne to review the proposals and calculations of NSPI with respect to debt defeasance. He concluded that the net cost of defeasance will be more than offset, over the life of the program, by reductions in interest expense, and that, therefore, "it is possible, at this time, to assume that the net cost of defeasance over the full term of the debt (with the exception of future issues) would be minimal".

The Board will allow NSPI to recover the imposed cost of defeasance through customers' rates. The increase in book value of the debt, the issue cost of the new debt and the acquisition cost of the defeasance assets are to be written off on a specific issue basis over the term of the new debt issues.

Deferral of Point Aconi Costs

In view of the Company's forecast of changes in the yearly revenue requirement, the Board accepts the proposed plan for deferring the recognition of certain costs of the Point Aconi generating station.

Return on Common Equity

In reviewing the evidence presented by Ms. McLeod, the Board has several concerns. The criteria used in selecting companies for the **comparable earnings** test appear to favour consistently good performers. In order for the necessary calculations to be made, the companies selected could not have negative earnings. Although the market-to-book ratio of the sample is very high and shows earnings well in excess of the cost of capital, no downward adjustment was made.

These factors bring into question her conclusion that "the returns earned by the sample of 16 unregulated corporations can be viewed generally as the returns that an investor in NSPI would otherwise have available from an investment of comparable risk", because the investor would need to know in advance how to exclude companies that might show a loss.

A further concern with her **comparable earnings** methodology is that actual performance was used for the years 1982-1991 and projected returns for 1992 and 1993. The Board considers it inappropriate to include projections when performing comparable earnings analysis. The probable error

2006 NOVA SCOTIA UTILITY AND REVIEW BOARD P-886

IN THE MATTER OF: *The Public Utilities Act*, R.S.N.S. 1989, c.380 as amended

- and -

IN THE MATTER OF: An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations

MINUTES OF SETTLEMENT

WHEREAS the Applicant, Nova Scotia Power Inc. ("NSPI"), the undersigned Intervenors (Avon Valley et al, the Consumer Advocate, the Halifax Regional Municipality, and the Municipal Electric Utilities Co-operative of Nova Scotia), and the staff of the Nova Scotia Utility and Review Board, have reached agreement on the matters in issue in this Application;

AND WHEREAS this Agreement is subject to review and approval by the Nova Scotia Utility and Review Board;

THE UNDERSIGNED PARTIES ("the parties") HEREBY AGREE and respectfully request the Utility and Review Board ("UARB") to approve:

1. NSPI's 2007 test year revenue requirement is set at $1,159.5 million, with new rates effective April 1, 2007.

2. NSPI's 2007 forecasted fuel expense is set at $470 million, with the natural gas margin set at $47 million. In the event NSPI's actual natural gas margin does not achieve a level of $47 million, NSPI may defer for later recovery in rates any difference, down to $39 million, for a maximum deferral of $8 million.

3. The third year of the phase in of depreciation rates is deferred for recovery in the next general rate application.

4. All parties agree in principle that the UARB should adopt a Fuel Adjustment Mechanism ("FAM"). The parties request the UARB to establish a process that commences as soon as possible to establish a FAM. The parties will work constructively on the content or elements of a FAM. A FAM hearing will begin no later than July 15, 2007.

5. NSPI shall file with the UARB and the parties (subject to the usual undertakings regarding confidentiality), on or before October 31, 2007, an updated forecast for fuel and purchased power and other significant projected cost changes for 2008.

Any of the parties may ask the UARB to consider whether there should be a proceeding to adjust rates for 2008.

6. Excess earnings by NSPI, if any, in 2007 and 2008 will be applied to the S21 unamortized balance.

7. NSPI's request for a deferral of first quarter 2007 fuel costs is withdrawn.

8. There are no further changes to NSPI's Application including: rate base and return on rate base, return on equity, OM&G, regulatory amortizations and income taxes.

9. NSPI's request for a true-up for the 2P-RTP is deferred to the December 1 annual review of the ELI 2P-RTP rate.

10. The UARB directive from the 2006 Rate Case regarding the study of NSPI's OM&G is not deemed to be completed by this Agreement.

11. The Revenue to Cost ratio methodology as described by Dr. Stutz at pages 15 and 16 of his December 20, 2006 Evidence will be adopted, except for modifications to incorporate a change to the unmetered rate class, for which the combined C3 weighting factor will be .82 for billing services and call centres.

12. Subject to paragraph 4, above, this agreement does not preclude NSPI or any of the parties from taking any positions in future regulatory proceedings.

AGREED, and signed by legal Counsel or other authorized representative, THIS 21st DAY OF JANUARY, 2007.

Nova Scotia Power Inc.

Per: Rene Gallant

Avon Valley et al

Per: Robert G. Grant, Q.C.

Consumer Advocate

Per: John Merrick, Q.C.

Halifax Regional Municipality

Per: Martin C. Ward, Q.C.

Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

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Municipal Electric Utilities Co-operative Of Nova Scotia

Per: Don Regan

UARB Staff

Per: Bruce Outhouse, Q.C.

GENERAL ACCOUNTING

EMPLOYEE FUTURE BENEFITS - 2400

GENERAL

01 The Company maintains contributory defined-benefit and defined-contribution pension plans that cover substantially all employees, and plans providing non-pension benefits for its retirees.

02 The defined-benefit pension plans are based on the years of service and average salary at the time the employee terminates employment and provide annual post-retirement indexing equal to the change in the Consumer Price Index up to a maximum increase of 6% per year.

03 Other retirement benefit plans include: unfunded pension arrangements, unfunded long service award and contributory health care plan.

04 The measurement date for the assets and obligations of each benefit plan is December 31.

POLICIES

05 Pension obligations and obligations associated with non-pension post-retirement benefits such as health benefits to retirees and retirement awards, are actuarially determined using the projected benefit method prorated on service and management's best assumptions. The projected benefit obligation is valued based on market interest rates at the valuation date.

06 Adjustments to the projected benefit obligation arising from plan amendments are amortized on a straight-line basis over the expected average remaining service period (“ARSP”) of active employees.

07 Pension fund asset values are calculated using market values at year-end. The expected return on pension assets is determined based on market-related values. The market-related values are determined in a rational and systematic manner so as to recognize asset gains and losses over a five-year period.

08 For any given year, when Nova Scotia Power Inc’s (“NSPI”’s) net actuarial gain (loss), less the actuarial gain (loss) not yet included in the market-related value of plan assets, exceeds 10% of the greater of the projected benefit obligation and the market-related value of the plan assets, an amount equal to the excess divided by the ARSP is amortized on a straight-line basis.

09 On January 1, 2011, NSPI adopted the US accounting standard on employee future benefits retrospectively with restatement.

10 Plan surpluses are recognized as assets and plan deficits are recognized as liabilities on the balance sheet. The difference between plan surplus (deficits) and accrued benefit assets (liabilities) is recognized in accumulated other comprehensive income.

PROCEDURES

11 Actuarial valuations are performed annually for all plans.

12 Pension expense, as determined in the annual actuarial valuation, is charged to both operating departments and corporate adjustments.

13 Pension funding for pre-funded plans are paid as determined in an annual actuarial valuation.

14 Pension plan assets are invested by fund managers. Monthly statements are provided by the trustee showing asset market values, investment income, pension benefits, refunds of contributions and plan expenses.

15 A Statement of Net Assets and a Statement of Changes in Net Assets for all pension plans are prepared quarterly. These statements show pension asset market values, contributions receivable, accounts payable, investment income, changes in market values, contributions received, pension benefits paid, refunds of contributions and plan expenses.

16 For the defined benefit pension plan, employee contributions for current service are matched by NSPI through the payroll system and remitted to the trustee for investment by fund managers. Additional employer contributions for current service and/or past service, where required, are also remitted to the trustee for investment by the fund managers.

17 For the defined contribution pension plan, employee and employer contributions are remitted to a pension plan administrator and invested according to instructions provided by the employee.

18 For the defined benefit pension plan, administrative expenses are paid by NSPI and reimbursed from the pension fund through requests to the trustee.

10.4 Submissions - Board Consultants

[123] Both Dr. Stutz and Mr. Antonuk indicated in their testimony at the hearing that they are satisfied the FAM is ready to be implemented.

[124] Dr. Stutz concluded in his Statement:

> Sections 1 to 8 of the Agreement deal with the Fuel Adjustment Mechanism (FAM). I agree that the FAM is substantially complete. The arrangements to finalize it provided in the Agreement are reasonable and appropriate. I know of no "unsettled issue" likely to prevent the FAM from coming into operation on January 1, 2009.
>
> [Stutz Statement, Exhibit N-75]

[125] In his testimony, Mr. Antonuk of Liberty indicated that it is appropriate to implement the FAM at this point and that three remaining issues can be resolved prior to its implementation:

> Yes. We believe that that is appropriate and it's difficult to see the settlement operating without the adoption of a FAM based on the way it's structured, and I think its structure clearly contemplates that. For our part, we're optimistic that while there remain issues to be resolved with respect to the FAM that those can and should, and I hope will, be resolved by the parties amicably. In the event they're not, I think they're the kinds of issues that are clearly amenable to prompt and effective resolution by the Board in any event. And those issues are three. One is the use of the API-4 index for performing the forecast of solid fuels. We're in agreement with the NSPI proposal to use that forecast but want that forecast use to be revisited in approximately a year. I believe we actually have agreement on that at the present time but it's not yet committed to writing. The second issue is that we are still working on language that addresses the degree to which there will or won't be consultation by the fuel auditor prior to the commencement of the fuel audits called for by the FAM, and the third is the method to be used for estimating import power sales, and on those latter two discussions -- or issues, discussions have been active among the FAM collaborative participants and I expect those discussions to continue and hopefully to be resolved in the immediate future.
>
> [Transcript, September 18, 2008, pp. 130-131]

10.5 Findings

[126] The implementation of the FAM received full support from the signatories to the Agreement, effective January 1, 2009. In clause 3 of the Agreement, the parties undertake to finalize the FAM documentation and NSPI agrees to file, for Board approval,

a final Tariff and Plan of Administration no later than October 15, 2008. Those documents have been filed and are under review by the Board. The Base Cost of Fuel is proposed to be set at $545 million in 2009 rates.

[127] Further, the Board observes that implementation of the FAM was not opposed by the formal intervenors who did not sign the Agreement.

[128] In their testimony at the hearing, Dr. Stutz and Mr. Antonuk, the Board's consultants, agreed that it was appropriate to implement the FAM at this point. While a few points remain outstanding, they are confident that any such items can be resolved prior to the proposed implementation date.

[129] In this regard, the Board observes that the development of the FAM has followed an extensive collaborative process between NSPI and its stakeholders. The Board's consultants were also involved throughout the entire process. All parties involved in this consultative exercise expressed their general satisfaction with the preliminary Plan of Administration filed with the Board in June 2008.

[130] In its Rate Decision dated February 5, 2007, and in its Decision dated December 10, 2007 giving conditional approval to the FAM, the Board identified at least four prerequisites prior to the implementation of a FAM:

> ...
>
> 1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
>
> 2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
>
> 3. disclosure and transparency with respect to the administration of the FAM;
>
> 4. a meaningful audit process under the administration of the Board.
>
> [Board Decision, P-887, December 10, 2007, para. 45]

[131] Based upon its review of the evidence and the submissions of the parties, the Board is satisfied that these prerequisites have been fulfilled. The consultative process has also addressed other issues.

[132] The Board is mindful of the concerns of NSPI's customers with respect to the implementation of a FAM. While some may contend that a FAM could result in reduced transparency and less oversight, the reality is quite the opposite. Any future adjustments to the Base Cost of Fuel will occur in an even more transparent manner than is presently the case. Under the FAM, the fuel forecasting process will be subjected to more periodic review by the Board and intervenors.

[133] The Board refers to its previous comments on these points:

> [76] The Board views a FAM as a tool which can actually provide a closer and more timely oversight of NSPI's fuel costs than is presently the case. As noted elsewhere in this decision, under a FAM, assessments as to the reasonableness of fuel expenses and NSPI's performance in obtaining fuel at the lowest price reasonably possible, will be carried out by the Board, as well as Intervenors, on an ongoing and more frequent basis than in the past. In the last ten years, this form of fuel costs examination has occurred four times—always in conjunction with general rate applications. Under a FAM, fuel costs will be determined on an annual basis, following the reporting, analysis and stakeholder involvement in the FAM process throughout the preceding year, which forms the basis for any adjustment.
>
> [77] Customers should also understand that, under a FAM, the rate they pay to NSPI will not go up and down every time the cost of fuel fluctuates. In other words, a FAM will not operate in the same manner as they experience at the gas pumps, where prices can change every week.
>
> [78] Even under the proposed January 1, 2009 implementation date of the FAM, the earliest time a fuel adjustment change to rates could possibly occur would be January 1, 2010. Also, it could only occur then if the previous year's fuel costs passed all the reporting, auditing, and review tests designed to ensure that the cost to be passed on to ratepayers is as low as reasonably possible—a result which, in the Board's opinion, improves its ability to protect the public interest.
>
> [Board Decision, P-887, December 10, 2007, paras. 76-78]

[134] The Board also observes that the implementation of the FAM is accompanied by a 0.2% reduction in the return on equity that can be earned by NSPI (i.e., the target

ROE will decrease from 9.55% to 9.35%). The lower return on equity results in a reduced revenue requirement to be recovered in customers' rates.

[135] Finally, there is a further benefit of a FAM for customers. The implementation of the FAM will allow NSPI to recover its prudently incurred fuel costs. This, in turn, will lower NSPI's business risk profile and foster the improved financial health of the utility over the long term, which could possibly lead to an improved outlook from bond-rating agencies and cause them to upgrade their rating for NSPI. Ultimately, this could benefit ratepayers by reducing NSPI's debt and interest charges, possibly lessening the pressure for rate increases in the future. An improved rating could also positively impact NSPI's ability to procure fuel commodities and to access capital markets for upcoming infrastructure projects.

[136] Taking into account all of the foregoing, the Board approves the FAM, on the basis of the provisions contained in the Agreement. The FAM shall take effect on January 1, 2009, conditional on the final approval of the Tariff and Plan of Administration.

11.0 WRITTEN AND ORAL SUBMISSIONS FROM THE PUBLIC

[137] In the advertised Notice of Public Hearing concerning NSPI's rate application, the public was advised that they could file submissions with the Board outlining their views regarding NSPI's application. In response to this notification, the Board received thirty-one written submissions from the public, plus six individuals made presentations at the evening session on September 17, 2008.

COST OF OPERATIONS

FUEL ADJUSTMENT MECHANISM - 5110

BACKGROUND

01 The Nova Scotia Utility and Review Board ("UARB") approved the implementation of a Fuel Adjustment Mechanism ("FAM") in the 2009 General Rate Decision effective January 1, 2009.

DEFINITION

02 The FAM includes the difference between actual fuel costs and amounts recovered from customers in the current period and in the two preceding years. The following are the components of the FAM:

a) Base Fuel Costs - Customer rates are set to recover the base amount of fuel costs. The differences between NSPI's actual fuel costs and the fuel costs recovered through the base fuel cost (i.e. what is charged and recovered from consumers) accumulate each month in the FAM as a Regulatory Asset (if NSPI under recovers actual fuel costs) or as a Regulatory Liability (if NSPI over-recovers actual fuel costs). The fuel base rate is reset every two years through a formal regulatory process or during a general rate application.

b) Actual Adjustment ("AA") – The AA results from dividing the previous year's FAM Regulatory Asset (Liability) balance by the current year's sales forecast. The AA is used in determining the current year's electricity rates. As amounts are recovered (rebated) from (to) customers in the current year, the remaining balance of the AA amount decreases.

c) Balance Adjustment("BA") - The BA is the residual amount of the AA related to subsequent years that was not fully recovered through the AA, which is based on sales forecasts. The BA rate is established similar to the AA rate using the cumulative remaining FAM Regulatory Asset (Liability) balance divided by forecasted sales for the period. Any residual BA balance at the end of a period is applied to the subsequent year and used in the determination of future BA rates.

d) Incentive (discentive) - On the accumulated FAM amount under or over-recovered in any given year, before interest, an amount of 10% of the amount less the difference between the incentive threshold and the base fuel costs, to a maximum of five million dollars will be calculated and will reduce (increase) the FAM Regulatory Asset (Liability) balance and fuel adjustment on the Statement of Earnings.

POLICIES

03 Differences between actual fuel costs and amounts recovered from customers accumulate in the FAM Regulatory Asset (Liability) included in "Other Assets" or "Other Liabilities" on the Balance Sheet and subsequently become an adjustment (either an addition or deduction) to the subsequent year's electricity rates.

04 Interest is earned at the current year's weighted average cost of capital ("WACC") compounded semi annually on the accumulated FAM Regulatory Asset (Liability) balance. NSPI earns the interest on a

Regulatory Asset and the customer earns the interest on a Regulatory Liability. The interest accumulates in the FAM Regulatory Asset (Liability) account.

05 Future income tax is recorded on the FAM Regulatory Asset (Liability) balance resulting in a future income asset or liability. The income tax expense (recovery) is recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

06 The incentive (discentive) is determined at the end of each year. Each quarter an accrual is recorded based on forecasted sales and fuel expenses for the remainder of the year.

07 The balance accumulated in the FAM Regulatory Asset (Liability) includes the incentive (disincentive) component of the FAM and any interest.

08 The revenue related to the fuel under or over recovery in the current year is not billed and collected until subsequent years. Revenue is therefore recognized when the FAM is billed or refunded to customers.

09 Customer rates to recover (refund) the FAM Regulatory Asset (Liability) balance are approved by the UARB. A regulatory filing which includes 10 months of actual results and two months of forecast data is filed in November of each year for rates effective January 1st of the subsequent year. Differences in forecast amounts for the two months are recovered through the BA.

PROCEDURES

10 The FAM Regulatory Asset (Liability) is recorded on the balance sheet with Other Assets (Liabilities). The interest and incentive is accumulated to the FAM Regulatory Asset (Liability). The effect of income tax is recorded on the balance sheet as a Future Income Tax Asset or Liability.

11 The FAM is recorded on the income statement as an addition or deduction to expenses referred to as Fuel Adjustment. The Fuel Adjustment reflects the net amount of over or under-recoveries from the current year's base fuel costs, including the incentive, the recognition of AA amounts from the prior year and the recognition of BA amounts from two years ago.

12 Revenues associated with the recovery (rebate) of FAM fuel costs are reported as electric revenues. The interest associated with the FAM Regulatory Asset (Liability) is recorded as interest income or interest expense.

PROPERTY, PLANT AND EQUIPMENT

ASSET RETIREMENTOBLIGATIONS (ARO) - 6320

DEFINITION

01 An asset retirement obligation is an obligation associated with the retirement of a tangible long-lived asset that an entity 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.[1]

GENERAL

02 The present value of this estimated future expenditure is recognized as a liability with an equivalent amount added to the carrying amount of the associated fixed asset consistent with *FASB ASC 410-20.*

03 The Nova Scotia Utility and Review Board ("UARB") provided a depreciation order effective January 1, 2004 approving the amount of future expenditures associated with the removal of long-lived assets. Any difference between the amount approved by the UARB as depreciation expense and the amount that is calculated under GAAP is recognized as a regulated asset.

POLICY

04 A liability for an asset retirement obligation should be recognized when a reasonable estimate of fair value can be made.[2]

05 Upon initial recognition, the carrying amount of the related long-lived asset will be increased by the same amount as the asset retirement liability. Subsequently, asset retirement costs will be allocated to expense using a systematic and rational method over the useful life of the asset.[3]

06 After initial recognition, period-to-period changes in the liability should be recognized in the liability for the asset retirement obligation resulting from passage of time and revisions to either the timing or the amount of the original estimate.[4]

[1] FASB ASC 410-20-15-2
[2] FASB ASC 410-20-25-4
[3] FASB ASC 410-20-35-2
[4] FASB ASC 410-20-35-3

INCOME TAXES - 5900

POLICY

01 Income tax expense should be categorized as current or deferred income tax expense as appropriate.

02 The Company uses the applicable enacted tax rate when measuring current and deferred income tax expense.

03 The Company follows the flow-through method of accounting for investment tax credits ("ITC's"). ITC's are recorded in the year earned as a reduction to income tax expense to the extent that realization of such benefit is more likely than not.

04 The Company recognizes deferred income tax assets (liabilities) as appropriate. To the extent deferred income taxes are expected to be recovered from or returned to customers in future rates, the Company will recognize a deferred regulatory asset (liability)[1]

05 The Company will recognize a deferred regulatory asset (liability) related to FAM. Deferred income tax expense (benefit) and a corresponding deferred income tax (liability) asset related to the FAM will be recognized based on the enacted income tax rate(s) for the period(s) when the FAM regulatory asset (liability) is expected to reverse.

FEDERAL INCOME TAXES

06 The Company is subject to federal income tax at prescribed rates applied to taxable income.

PROVINCIAL INCOME TAXES

07 The Company is subject to provincial income tax at prescribed rates applied to taxable income.

TAX ON LARGE CORPORATIONS

08 The Company is subject to a provincial capital tax ("PCT") at prescribed rates applied to taxable capital.

PART VI.1 TAX

09 The Company is subject to Part VI.1 tax at a prescribed rate applied to preferred share dividends paid. The Company receives a tax deduction equal to a prescribed multiple of the Part VI.1 tax.

1 FASB ASC 980-740-25-2

PROCEDURES

10 A monthly income tax provision is recorded by multiplying the Company's effective combined federal and provincial income tax rate forecasted for the year (calculated without inclusion of the forecasted FAM adjustment) by the net earnings before tax for the period. The monthly income tax provision with respect to FAM is based on the actual FAM adjustment for the period multiplied by the enacted tax rate.

11 The Company prepares an estimate of its taxable capital using a forecasted year-end balance sheet. The taxable capital forecast is then multiplied by the enacted tax rate to determine the PCT expense for the year. The PCT estimate is prorated based upon days to determine the amount to accrue each month.

12 The net Part VI.1 tax is calculated using enacted rates and recorded as an additional cost (recovery) of the preferred share dividend. It is reclassified to current income tax expense for external reporting purposes. The monthly Part VI.1 tax expense is based on the amount of preferred dividends declared in the month. The monthly Part VI.1 tax deduction is based on the annual forecasted Part VI.1 deduction prorated based upon the total preferred dividends declared in a month.

13 The Company currently follows the policy of claiming sufficient capital cost allowance and cumulative eligible capital (the tax system's equivalent of depreciation and amortization), to minimize taxable income.

14 Federal and provincial income taxes are included in general ledger account 086 - Income Tax Expense and Provincial Capital Tax is included in account 067. The net Part V1.1 tax is included in general ledger account 786 – Tax on Preferred Dividends.

NOVA SCOTIA POWER
An Emera Company

March 23, 2009

Nancy McNeil
Clerk of the Board
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box1692, Unit "M"
Halifax, NS B3J 3S3

Dear Ms. McNeil,

Effective January1, 2009, NSPI implemented the fuel adjustment mechanism (FAM) that was approved by the UARB in the 2009 Rate decision. Attached is a description of how NSPI will be accounting for the mechanism. NSPI requested Grant Thornton to review the proposed accounting treatment related to the FAM and they concluded the following:

> we wish to confirm we are in agreement with the conclusions and positions taken by management and that the proposed accounting treatment is appropriate under Canadian generally accepted accounting principles.

Attached is a description of the accounting treatment for the FAM and a letter from Grant Thornton confirming NSPI's position.

We respectfully submit the FAM accounting description for information.

I would be pleased to have our accounting personnel and advisors meet with the Board, or its designates, at the Board's convenience if the Board would consider this helpful.

For more information, please do not hesitate to contact the undersigned.

Regards,

G Blunden.

Greg Blunden, CA
Vice President Finance & Treasurer
Nova Scotia Power Inc.

Attach.

cc: Rene Gallant
Claudette Porter
Eric Ferguson

Fuel Adjustment Mechanism Overview

The purpose of this document is to provide an overview of the approved Fuel Adjustment Mechanism as well as, management's position on the associated accounting and financial reporting implications.

Background

The Nova Scotia Utility and Review Board approved the implementation of a Fuel Adjustment Mechanism (FAM) in the 2009 General Rate Decision effective January 1, 2009. The FAM is being established to mitigate the effects of volatile fuel costs on the electricity rates paid by the customers of Nova Scotia Power Incorporated (NSPI). The FAM design protects the financial integrity of the Company and delivers timely price signals to customers to promote efficient use of electricity. Differences between actual fuel costs and amounts recovered from customers will accumulate in the FAM deferral account and subsequently become an adjustment (either an addition or deduction) to the following year's electricity rates.

Components of the FAM

- Base Fuel Cost

  In the implementation year, 2009, the difference between NSPI's actual fuel costs and the fuel costs recovered through the base fuel cost (i.e. what is charged and recovered from consumers) will accumulate each month in the FAM as a regulatory asset (if NSPI under-recovers actual fuel costs) or as a regulatory liability (if NSPI over-recovers actual fuel costs). In each month of under-recovery, the 'FAM Regulatory Asset' will be debited and an account called 'Amortization of Fuel Expense' is credited. This will effectively increase assets and decrease expenses (therefore increase equity). The opposite occurs in the case of over-recovery. For 2009, the base fuel cost is set at $545 million ($42.41 per MWh). Customer rates are set to recover this base amount of fuel cost.

  Revenue associated with the deferred balance is not considered earned at this point due to it not meeting the three general criteria as outlined in CICA Handbook Section 3400 Revenue. The earnings process must be complete, measurability is reasonably assured, and collectability is reasonably assured. "Performance should be regarded as having been achieved when reasonable assurance exists regarding the measurement of the consideration that will be derived from rendering the service or performing the long-term contract" (CICA HB 3400.08). In particular, it is the lack of measurability that prevents revenue related to the fuel under or over recovery from being recognized in 2009 as it will not be billed and collected until 2010.

- Interest

  As the FAM regulatory asset or liability accumulates, interest is earned at the current year's weighted average cost of capital (WACC) based on the principles applied in calculating the Allowance for Funds Used During Construction (AFUDC), by either NSPI (in the case of a regulatory asset) or the customer (in the case of a regulatory liability). The interest will accumulate in the FAM regulatory asset or liability account. In the case of under-recovery, the 'FAM Regulatory Asset' is debited and AFUDC is credited. The opposite entry occurs in the case of over-recovery.

- Incentive

  There is an incentive portion of the FAM to encourage NSPI to effectively manage fuel costs. On the accumulated FAM amount under or over-recovered in any given year, before interest, an amount of 10% of the amount less the difference between the incentive threshold and the base fuel costs, to a maximum of five million dollars will be calculated and will reduce the regulatory asset or liability and amortization of fuel expense. The incentive is determined at the end of each year. For reporting purposes, an accrual will be reviewed on a quarterly basis and reassessed based on forecasted sales and fuel expenses for the remainder of the year. For 2009, the incentive threshold is calculated using a base fuel cost amount of $590 million ($45.95 per MWh)

  For example: For 2009, in the case of an under-recovery (regulatory asset) of $60 million, 10% of the under-recovered amount ($60 million) less the difference between the incentive threshold of $590 million and base fuel cost of $545 million (i.e.($60-$45)x10% or $1.5 million) would be credited to the 'FAM Regulatory Asset' and debited to 'Amortization of Fuel Expense'.

- Income taxes

  As a regulated entity, historically NSPI followed the taxes payable method of accounting for its income tax. Beginning in 2009 the Company is required to record future income taxes in accordance with CICA 3465 Income Taxes.

  Currently, the reported income tax expense is based on the current income tax paid. For purposes of reporting the FAM, NSPI will record the future income tax impact by recognizing either a future income asset or liability. The income tax expense (recovery) will be recorded based on NSPI's applicable statutory income tax rates for the period expected to apply when the 'FAM Regulatory Asset (Liability)' reverses.

  Recovering the FAM on a net of tax basis is aligned with the regulatory revenue principles in determining customer rates for the FAM adjustment. The FAM mechanism for setting customer rates and ultimately determining NSPI's revenues reflects a recovery (refund) of fuel costs and associated interest carrying costs excluding any tax effects. This is unique as the rate setting mechanism for recovering other deferred regulatory assets typically includes a full general rate application which inherently reflects the associated tax effects. It is anticipated that if NSPI did not record an income tax provision associated with the FAM, NSPI's effective tax rate would be volatile and would be in contradiction to the fundamental design of the FAM.

NSPI's income tax accounting policy will be amended to incorporate the addition of the FAM. This will include a specific paragraph reference to the income tax treatment. A draft of the amended income tax policy is included as an attachment.

At year end, the under or over-recovered amount, with interest and incentive adjustment net of income taxes will be the total FAM deferral amount for 2009 recorded on NSPI financial statements. For purposes of establishing customer rates to recover (refund) the balance before taxes, a regulatory filing including 10 months of actual results and two months of forecast data will be processed in November of each year for rates effective January 1st of the subsequent year. Differences in forecast amounts for the two months will be recovered through the 'Balance Adjustment'.

2010 Rate ($/Kwh) = Base Rate ($/Kwh) +/- [2009 FAM Amount ($) / 2010 Sales Forecast (Kwh)]

- Actual Adjustment

The result of dividing the 2009 FAM balance by the 2010 sales forecast is called 'Actual Adjustment', or AA. This is the adjustment used to determine the 2010 electrical rate. As amounts are recovered from customers in 2010, the balance of the AA amount decreases. Revenue is now considered earned and is recorded. The associated expense deferred from 2009 can now be amortized in 2010. The 'FAM Regulatory Asset' is credited and the 'Amortization of Fuel Expense' is debited. Revenues are credited as earned and accounts receivable/cash are debited.

Throughout 2010 while recovering the AA amount related to 2009, the regulatory asset or liability accounts will continue to accumulate due to the variance between 2010's actual fuel costs and the amounts recovered through the fuel base rate. The fuel base rate itself is reset every two years through a formal regulatory process.

- Balance Adjustment

It is inevitable that estimates will not equal actual sales and fuel costs. Therefore the AA from one year (i.e. 2009) will not be fully recovered in the following year (i.e. 2010) as it is based on forecasted 2010 sales. The 'Balance Adjustment', or BA, for 2010 is the residual amount of the AA related to 2009 (and any subsequent years) that was not fully recovered in 2010. The BA becomes another adjustment that will only first affect electricity rates in 2011. The BA rate is established similar to the AA rate using the cumulative asset (liability) divided by forecasted sales for the period. Any residual BA balance at the end of a period is simply applied to the subsequent year and used in the determination of future BA rates. In this way, all actual fuel costs are recovered from customers.

2011 Rate ($/Kwh) = [Base Rate] +/- [2010 "AA"] +/- [2009 "BA"]

Effect of FAM on Financial Statements

The 'FAM Regulatory Asset (Liability)' will be recorded on the balance sheet with deferred charges (credits). The interest, incentive, and effects of income tax will be accumulated to the asset or liability. Disclosure in the financial statement notes with deferred charges (credits) will include separate recognition of the 'FAM Regulatory Asset (Liability)'.

The income statement in the first year (2009) will show an addition or deduction to expenses on a line called 'Amortization of Fuel Expense' based on the over or under-recovered amounts net of the incentive portion. Beginning in 2010, the 'Amortization of Fuel Expense' will reflect the net amount of over or under-recoveries from 2010 base fuel costs and the credit or debit recognition of 'Actual Adjustment' amounts from 2009.

Revenues associated with the recovery of FAM fuel costs will be reported as electric revenues. The interest associated with the 'FAM Regulatory Asset (Liability)' will be recorded as AFUDC. The income tax provision recorded will be reported as part of income taxes on the statement of earnings.

The Statement of Cash Flow will include an additional line to remove the deferral, as this transaction does not affect cash flow until the following year with the receipt of associated revenues.

Journal Entry Summary

To illustrate the financial effects of the FAM accounting, a summary of journal entries follows:

2009:

1) Assuming actual fuel costs of $600 million (Under-recovery of $600-545=$55 million):

   Dt: FAM Regulatory Asset $55 million

   Ct: Amortization of Fuel Expense $55 million

2) Record incentive portion of FAM ($55-(590-545)) x 10% = $1 million):

   Dt: Amortization of Fuel Expense $1 million

   Ct: FAM Regulatory Asset $1 million

3) Recognize interest amounts of $2 million:

   Dt: FAM Regulatory Asset $2 million

   Ct: AFUDC $2 million

4) Record income tax provision for FAM deferral amounts assuming an applicable statutory tax rate of 35% ($55-1+2) x 35%:

   Dt: Income tax expense $19.6 million

   Ct: Future income tax liability $19.6 million

2010:

1) Record revenue recognition of 'Actual Adjustment' FAM amounts:

   Dt: Cash (Accounts Receivable) $56 million

   Ct: Electric Revenues $56 million

   Dt: Amortization of Fuel Expense $56 million

   Ct: FAM Regulatory Asset $56 million

   Dt: Future income tax liability $19.6 million

   Ct: Income tax expense $19.6 million

Financial Reporting Disclosure

The specific disclosure within the financial statements related to the FAM includes:

Deferred Charges and Credits

Fuel Adjustment Mechanism

The Nova Scotia Utility and Review Board approved the implementation of a Fuel Adjustment Mechanism (FAM) in the 2009 General Rate Decision effective January 1, 2009. The FAM is being established to mitigate the effects of volatile fuel costs on the electricity rates paid by the customers of NSPI. The FAM design protects the financial integrity of the Company and delivers timely price signals to customers to promote efficient use of electricity. Differences between actual fuel costs and amounts recovered from customers will accumulate in the FAM regulatory asset (liability) and subsequently become an adjustment (either an addition or deduction) to the following year's electricity rates. The FAM asset (liability) bears AFUDC. The FAM is also subject to an incentive portion with NSPI retaining or absorbing 10% of the under or over-recovered amount less the difference between the incentive threshold and the base fuel cost to a maximum of $5 million. The FAM regulatory asset (liability) is recorded before taxes. The Company has also recognized a future income tax liability (asset) based on NSPI's applicable statutory income tax. The FAM is recognized by NSPI as a regulatory asset or liability based on the expectation that successive rates will be adjusted to provide recovery from, or refund to, customers in the following period. In the absence of FAM regulatory approval, fuel costs would be expensed as incurred and net earnings for 2009 would be $XX million lower (2008 - nil).

Conclusions

The proposed accounting and financial reporting of the FAM is aligned with the regulatory framework and basic principles of the FAM. The reporting and disclosure provides transparency and the appropriate level of detail.

The financial reporting implications with the FAM have been incorporated into the analysis and research work related to the implementation of International Financial Reporting Standards. These findings will be integrated with future accounting and financial reporting policies.

Grant Thornton

January 30, 2009

Ms. Claudette Porter, CA
Controller
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Dear Ms. Porter:

Re: Proposed accounting for fuel adjustment mechanism in fiscal 2009

We recently received your request to review the proposed accounting treatment related to the Fuel Adjustment Mechanism of Nova Scotia Power Inc. ("the Company") which is effective beginning in fiscal 2009. You have asked us to confirm the appropriateness of the proposed accounting treatment under Canadian generally accepted accounting principles ("GAAP").

Based on our review of the proposed accounting treatment of the Fuel Adjustment Mechanism, attached as Appendix A, we wish to confirm we are in agreement with the conclusions and positions taken by management and that the proposed accounting treatment is appropriate under Canadian generally accepted accounting principles.

If you have any questions, please contact us.

Yours sincerely,
Grant Thornton LLP

Grant Thornton LLP

G. Hutchings, CA
Partner

[Exhibit N-1(a), p. 85]

[105] NSPI's application proposed to recover the 2008 and 2009 Demand Side Management (DSM) costs as follows:

> With the DSM investment as outlined in the DSM Settlement Agreement of $3.1 million for 2008 and $9.8 million for 2009, the total forecast expenditure over the 2008-2009 period is $12.9 million. NSPI is requesting recovery of this $12.9 million in equal increments over 2009, 2010 and 2011. NSPI proposes that $4.3 million be incorporated into the 2009 test year revenue requirement to reflect DSM costs. The recovery is further discussed in Section 5 of this Application.
>
> [Exhibit N-1(a), p. 86]

[106] The Agreement proposes that the amortization period for the 2008 and 2009 DSM costs be increased from three years to six years[10]. The net effect of this change is the reduction of the revenue requirement by $2.1 million in 2009[11].

8.2 Findings

[107] The Board has considered the amortization of the 2008 and 2009 DSM program costs over six years as proposed in the Agreement. Based on the size of rate increases proposed in the application, the Board agrees that it is reasonable to amortize these expenditures over a longer period than the three years proposed in the Application. The Board approves the amortization of DSM expenditures for 2008 and 2009 in the amount of $12.9 million over six years starting in 2009.

---

[10] Exhibit –69, para. 11

[11] Exhibit N-72

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March 12, 2008

By email: rene.gallant@emera.com

Mr. Rene Gallant
General Manager & Regulatory Counsel
Nova Scotia Power Inc.
PO Box 910, Scotia Square
Halifax, Nova Scotia B3J 2W5

Dear Mr. Gallant:

Power Outage Review Decision - Distribution System Vegetation Management - P-401.32

This letter is further to NSPI's correspondence of February 15, 2008, in response to a request from the Board dated December 18, 2007, for an update from NSPI with respect to its plans to address the above-noted outstanding matter.

As you are aware, the adequacy of NSPI's Distribution System Vegetation Management activities is a concern dating back to the power outage review decision issued by the Board on August 5, 2005, following a public hearing process conducted in a number of communities across the Province in April and May of 2005. This review was at the request of then Premier John Hamm and resulted from extensive and lengthy outages, affecting in excess of 160,000 customers, during and after a major storm in November of 2004.

The Board's decision determined that a review of this issue should be conducted. In a report dated November 29, 2005. Liberty Consulting Group found that:

- All circuits, including those recently maintained, require attention to vegetation management. The overall condition of the power system with regard to vegetation control is poor.

- NSPI does not have an effective and formal full circuit vegetation management program.

- NSPI's procedures and practices are weak in tracking work order completion, maintaining transmission line right-of-way buffer strips, evaluating reliability projects, and classifying outage data for reliability reporting.

- NSPI did not consistently performed [sic] corrective maintenance over the 2002-2004 period.

- The reliability statistics of circuits 70W-321, 77V-401, 78W-301, 15N-421, 113H-432, and 62N-414 rank poorly when compared to regional statistics, even when storms and transmission-caused outages are excluded. NSPI should investigate the causes of this performance and identify corrective actions.

The Board further commented on this issue in correspondence related to a final cost work order request by NSPI dated December 18, 2007:

> You may recall that in correspondence dated December 15, 2006 to Dan Muldoon, General Manager of Customer Operations, NSPI; the Board noted that while it would approve a requested expenditure of $3.6 million for a Distribution System Vegetation Management program, in view of its long-standing concerns that absent such action the reliability of service to NSPI customers would continue to decline, it also noted that:
>
> > . . .
> >
> > NSPI states that its request for Board approval of this project is on the basis that the expenditure of $3.6 million can be recovered in customer rates. However, in view of the fact that NSPI's October 10, 2006 general rate application does not include this cost in its test year revenue requirement, approval of this project, on the basis set out by NSPI, would result in a corresponding increase to the 2007 test year revenue requirement. This was clearly a foreseeable expenditure which NSPI could have provided for in its filing. As NSPI is aware, the issue concerning revisions to the revenue requirement filed by NSPI in its rate application has been raised by a number of intervenors in the upcoming rate hearing and was one of the matters heard by the Board at the preliminary hearing on December 7, 2006. In the Board's direction to the parties, issued on December 8, 2006, the reference to the revenue requirement states:
> >
> > > <u>Confirmation of Revenue Request</u>
> > >
> > > NSPI confirmed that the revenue request being applied for was the revenue request filed with its evidence of October 10, 2006. It has not been amended and will not be amended by NSPI.
> >
> > The Board is certainly prepared to approve this important and necessary program should NSPI wish to proceed on the basis that ongoing annual costs associated with this project would be included in future rate applications. The matter will be explored further in the upcoming rate hearing.
>
> As you are aware, the Board's February 2, 2007 decision on NSPI's rate application confirmed its approval of the Settlement Agreement ("SA") which, in part, provided for a revenue requirement of $1,159.5 million. In view of the SA, "further exploration of this issue" did not occur at the 2007 rate hearing.

In its update on this issue, NSPI is now requesting approval for a $2 million increase in vegetation management spending, with recovery of same deferred, stating that:

> . . .

> ... NSPI plans to increase expenditure on vegetation management during 2008. The Company will spend an additional $2 million on vegetation management on the distribution system. NSPI also hereby respectfully requests UARB approval for deferred recovery of these additional costs.
>
> NSPI knows reliable electric service is important to our customers. Increased investment in vegetation management, based on a sound plan, is a key part of meeting customer expectations. The Company will work with the Board and stakeholders to develop support for the program and the remaining additional required funding over the long term. In light of the interest in reliability and the vegetation management program generally in prior proceedings, the Company is providing a copy of this correspondence and attachments to stakeholders for information.
>
> [NSPI, Correspondence to Board, dated February 15, 2008]

In view of the long-standing concerns of the Board and the public in this matter, and the fact that, as NSPI acknowledged in its September 29, 2006 response to Liberty's report, vegetation encroachment on the system is the single largest cause of electric service interruption, the Board finds that this spending increase is required in order to improve the reliability of service provided to customers. Accordingly, the Board approves the additional $2 million spending in 2008 on the basis that it is both appropriate and justifiable. The Board also approves the proposed deferral of this expenditure, including the recovery period, subject to review at the next rate hearing.

Yours truly,

Nancy McNeil

Nancy McNeil
Regulatory Affairs Officer/Clerk

c.c. Eric Ferguson
Bruce Outhouse, Q.C.
John Merrick, Q.C. - Consumer Advocate
George Cooper, Q.C. - New Page/Bowater
Robert Grant, Q.C. - Avon Valley et al
Don Regan - MEUNSC
Mary Ellen Donovan - HRM
Robert Patzelt, Q.C. - CME
Brendan Haley - Ecology Action Centre
Claire McNeil - Affordable Energy Coalition
Mark Reiksts - Province of Nova Scotia

NON-CONFIDENTIAL

Request IR-81:

Does NSPI believe it could seek deferral accounting treatment for recovery of an extraordinary storm event? Please describe in detail.

Response IR-81:

In theory, the circumstance anticipated in this question could arise and the UARB has jurisdiction to approve such a request. NS Power has not made such a request in the past, nor as part of this Application.

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Request IR-82:

Please provide NSPI's actual electricity sales for 2005-2010 consistent with 2012 GRA DE-03 – DE-04.

Response IR-82:

Year	Total Electric Sales
2005	11,645 GWh
2006	10,527 GWh
2007	11,864 GWh
2008	11,772 GWh
2009	11,306 GWh
2010	11,455 GWh

NON-CONFIDENTIAL

Request IR-83:

In reference to Appendix C, page 2 of 49, please provide 2007-2009 actual results in the same format.

Response IR-83:

Please refer to Attachment 1.

NOVA SCOTIA POWER INC.
REGULATED OPERATING, MAINTENANCE AND GENERAL EXPENSES
FOR THE YEARS 2007 THROUGH 2009

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Executive Management	1,224	1,891	1,218
Corporate Office of Secretary and General Counsel	5,638	5,551	5,564
Corporate Finance	3,128	4,361	5,313
Investor Relations, Communications and Public Affairs	1,093	2,483	2,521
Corporate Human Resources (including Safety)	2,450	3,843	4,651
Facilities and Procurement	8,830	9,212	9,534
Information Technology	7,783	8,236	8,510
Regulatory Affairs	4,487	5,169	4,269
TOTAL CORPORATE GROUPS	**34,633**	**40,746**	**41,580**
TECHNICAL & CONSTRUCTION SERVICES	-	**-**	**9,221**
SUSTAINABILITY			**1,141**
Renewable Planning	4,928	5,505	-
Head Office	12,032	12,934	9,466
Thermal Plants	55,838	60,882	60,751
Combustion Turbines	1,109	1,158	1,194
Hydro & Wind Energy	7,259	8,567	8,526
Energy, Fuels and Risk Management	2,819	3,149	4,010
TOTAL POWER PRODUCTION	**83,985**	**92,195**	**83,947**
Regional Operations	13,777	14,426	16,255
Control Center	5,711	5,881	6,320
Reliability, Workforce Management and Resource Allocation	21,308	22,657	26,677
Administration (incl Storm)	26,017	14,111	13,273
TOTAL CUSTOMER OPERATIONS	**66,813**	**57,075**	**62,525**
CUSTOMER SERVICE	**28,428**	**27,690**	**29,650**
Pension Expense	5,386	(550)	(584)
Corporate Adjustments	(17,340)	(17,865)	(20,490)
TOTAL CORPORATE ADJUSTMENTS	**(11,954)**	**(18,415)**	**(21,074)**
TOTAL REGULATED OM&G	**201,905**	**199,291**	**206,990**

NON-CONFIDENTIAL

Request IR-84:

In reference to Appendix C, please provide the 2007, 2008 and 2009 actual amounts for the following pages consistent with the reported 2010 actual figures:

(a) Executive Management – page 83

(b) Corporate Secretary – page 5

(c) Corporate Finance – page 7

(d) Investor Relations, Communications and Public Affairs – page 9

(e) Human Resources – page 11

(f) Facilities and Procurement – page 13

(g) Information Technology – page 16

(h) Regulatory Affairs – page 18

(i) Technical and Construction Service – page 20

(j) Sustainability – page 23

(k) Power Production Head Office – page 25

(l) Thermal Plants –page 27

(m) **Combustion Turbines – page 30**

(n) **Hydro & Wind Energy – page 32**

(o) **Energy, Fuels, and Risk Management – page 34**

(p) **Regional Operations – page 36**

(q) **Control Center – page 38**

(r) **Reliability and Workforce Management and Resource Allocation – page 40**

(s) **Customer Operations – Administration – page 43**

(t) **Customer Service – page 45**

(u) **Corporate Adjustments – page 48**

Response IR-84:

(a-u) Please refer to Attachment 1.

Executive Management

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	**589**	**947**	**683**
010 Office Supplies	10	16	10
011 Travel Expense	38	247	62
013 Contracts	13	8	7
014 Overtime Meals	1	2	
015 Frt, Post & Delivery	-	-	1
021 Telephones	6	28	13
028 Consulting	344	18	-
029 Membership Dues	132	79	178
032 Subscrpt/Info.Software	1	1	-
037 Ext. Legal & Audit		14	-
041 Meals & Entertainment	42	59	189
042 Employee Benefits	16	194	37
056 Training & Development	5	13	2
066 Other Goods & Services	27	265	36
Total Non-Labour	**635**	**944**	**535**
Total	**1,224**	**1,891**	**1,218**

Corporate Office of Secretary and General Counsel

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***1,064***	***896***	***958***
010 Office Supplies	11	9	15
011 Travel Expense	28	35	43
012 Materials	15	(2)	-
013 Contracts	4	7	3
015 Frt, Post & Delivery	8	12	16
021 Telephones	11	12	14
027 Corporate Filing Fees	86	82	84
029 Membership Dues	15	23	23
032 Subscrpt/Info.Software	13	22	19
033 Rental/Mtnce equipment/software	4	-	-
034 Appl. Software	2	1	1
035 Comp.Hrdwr & Op.Sftwr	-	-	-
036 Directors' Fees & Exp	393	616	541
037 Ext. Legal & Audit	301	375	203
038 Annual Shareholder Meeting	235	188	249
041 Meals & Entertainment	18	24	26
042 Employee Benefits	-	211	96
043 Insurance	3,694	3,560	3,677
052 Non Reg.Cost Recovery	(13)	-	-
056 Training & Development	5	10	23
057 Corp. Support Transfe	(249)	(563)	(404)
066 Other Goods & Services	(7)	33	(23)
Total Non-Labour	***4,574***	***4,655***	***4,606***
Total	***5,638***	***5,551***	***5,564***

Corporate Finance

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***3,056***	***3,479***	***3,891***
010 Office Supplies	55	43	49
011 Travel Expense	46	81	95
012 Materials	-	-	2
013 Contracts	466	461	375
015 Frt, Post & Delivery	2	1	1
021 Telephones	24	26	27
028 Consulting	209	875	2,485
029 Membership Dues	23	26	22
032 Subscrpt/Info.Software	42	59	49
033 Rental/Mtnce equipment/software	18	21	19
034 Appl. Software	3	5	3
035 Comp.Hrdwr & Op.Sftwr	1	1	47
037 Ext. Legal & Audit	249	215	228
040 Advertising	1	1	-
041 Meals & Entertainment	26	30	42
042 Employee Benefits	-	764	328
050 Rent	7	-	-
051 Gen.Cost Recovery	(202)	(217)	(183)
052 Non Reg.Cost Recovery	-	-	-
056 Training & Development	49	58	52
057 Corp. Support Transfe	(968)	(1,577)	(2,282)
059 HR Costs			31
066 Other Goods & Services	21	9	32
Total Non-Labour	***72***	***882***	***1,422***
Total	***3,128***	***4,361***	***5,313***

Investor Relations, Communications & Public Affairs

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Total Labour	***546***	***529***	***740***
010 Office Supplies	2	5	9
011 Travel Expense	40	39	57
012 Materials	4	10	3
013 Contracts	36	132	316
014 Overtime Meals	-	2	(1)
015 Frt, Post & Delivery	-	72	2
021 Telephones	10	12	13
028 Consulting	396	992	854
029 Membership Dues	8	-	6
032 Subscrpt/Info.Software	3	3	6
034 Appl. Software	-	1	3
035 Comp.Hrdwr & Op.Sftwr	1	1	23
040 Advertising	15	502	320
041 Meals & Entertainment	29	44	39
042 Employee Benefits	-	126	59
052 Non Reg.Cost Recovery	(18)	-	-
056 Training & Development	3	3	43
066 Other Goods & Services	18	10	29
Total Non-Labour	***547***	***1,954***	***1,781***
Total	***1,093***	***2,483***	***2,521***

Human Resources

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Total Labour	***1,560***	***2,077***	***2,244***
010 Office Supplies	14	29	45
011 Travel Expense	176	170	235
012 Materials	89	114	366
013 Contracts	525	540	891
021 Telephones	22	34	28
028 Consulting	132	282	208
029 Membership Dues	5	5	15
032 Subscrpt/Info.Software	1	14	(5)
033 Rental/Mtnce equipment/software	42	64	29
035 Comp.Hrdwr & Op.Sftwr	-	-	3
037 Ext. Legal & Audit	-	59	161
041 Meals & Entertainment	45	78	87
042 Employee Benefits	155	552	290
045 Pensioner Benefits	-	100	96
052 Non Reg.Cost Recovery	-	(23)	(9)
056 Training & Development	20	32	347
057 Corp. Support Transfe	(265)	(215)	(281)
059 Severance Costs	-		6
066 Other Goods & Services	(71)	(61)	(104)
190 Misc revenue/recoveries (OM&G)	-	(8)	(1)
Total Non-Labour	***890***	***1,766***	***2,407***
Total	***2,450***	***3,843***	***4,651***

Facilities and Procurement

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***3,438***	***3,636***	***3,605***
010 Office Supplies	681	9	12
011 Travel Expense	69	87	92
012 Materials	96	93	128
013 Contracts	1,312	1,494	1,562
015 Frt, Post & Delivery	212	139	152
019 Water	39	38	49
021 Telephones	49	40	38
028 Consulting	18	2	11
029 Membership Dues	3	5	1
032 Subscrpt/Info.Software	-	2	1
033 Rental/Mtnce equipment/software	2	-	1
034 Appl. Software	-	-	1
035 Comp.Hrdwr & Op.Sftwr	2	-	3
041 Meals & Entertainment	16	19	31
042 Employee Benefits	-	787	320
044 Energy Use (Non-Elect	81	160	89
046 Energy Use	371	331	358
050 Rent	3,911	3,930	4,094
051 Gen.Cost Recovery	(2,256)	(2,597)	(2,080)
052 Non Reg.Cost Recovery	(783)	(761)	(726)
056 Training & Development	33	63	44
058 Personal Equipment	5	5	5
061 Write-offs	15	(124)	(70)
062 Recoveries	(48)	(49)	(58)
066 Other Goods & Services	14	4	39
083 Short-term interest	997	995	1,042
091 Tax Assessment	881	937	771
190 Misc revenue/recoveries	(328)	(33)	19
Total Non-Labour	***5,392***	***5,576***	***5,929***
Total	***8,830***	***9,212***	***9,534***

Information Technology

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***2,151***	***2,172***	***2,267***
010 Office Supplies	11	(2)	5
011 Travel Expense	20	30	40
012 Materials	1	2	17
013 Contracts	2,601	3,051	3,069
015 Frt, Post & Delivery	-	1	1
021 Telephones	(8)	(15)	(5)
023 Data Communication Circuits	1,369	1,381	1,381
028 Consulting	64	225	337
029 Membership Dues	1	1	1
033 Rental/Mtnce equipment/software	1,432	1,418	1,662
034 Appl. Software	2	3	16
035 Comp.Hrdwr & Op.Sftwr	2	1	1
041 Meals & Entertainment	19	12	22
042 Employee Benefits	607	447	179
051 Gen.Cost Recovery	-	(1)	4
052 Non Reg.Cost Recovery	(518)	(533)	(532)
056 Training & Development	22	32	54
066 Other Goods & Services	7	11	(9)
Total Non-Labour	***5,632***	***6,064***	***6,243***
Total	***7,783***	***8,236***	***8,510***

Regulatory Affairs

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***949***	***1,191***	***1,249***
010 Office Supplies	8	30	6
011 Travel Expense	21	13	27
012 Materials	8	7	9
013 Contracts	6	-	5
015 Frt, Post & Delivery	3	4	1
021 Telephones	11	12	11
028 Consulting	2,068	2,073	1,436
029 Membership Dues	6	8	9
032 Subscrpt/Info.Software	8	4	8
034 Appl. Software	11	12	8
035 Comp.Hrdwr & Op.Sftwr			13
037 Ext. Legal & Audit	1,245	1,413	1,274
040 Advertising	24	37	23
041 Meals & Entertainment	42	38	35
042 Employee Benefits	-	248	92
056 Training & Development	28	27	28
066 Other Goods & Services	49	52	35
Total Non-Labour	***3,538***	***3,978***	***3,020***
Total	***4,487***	***5,169***	***4,269***

Technical & Construction Services

(in Thousands of $)

	2009 Actual
Total Labour	*6,666*
010 Office Supplies	34
011 Travel Expense	426
012 Materials	176
013 Contracts	597
015 Frt, Post & Delivery	10
016 Tools & Equipment	8
021 Telephones	110
028 Consulting	258
029 Membership Dues	109
031 Fleet Fuel	15
032 Subscrpt/Info.Software	8
033 Rental/Mtnce equipment/software	160
034 Appl. Software	39
035 Comp.Hrdwr & Op.Sftwr	9
041 Meals & Entertainment	143
042 Employee Benefits	602
050 Rent	11
052 Non Reg.Cost Recovery	(238)
056 Training & Development	50
057 Corp. Support Transfe	(62)
058 Personal Equipment	12
066 Other Goods & Services	106
190 Misc revenue/recoveries (OM&G)	(28)
Total Non-Labour	*2,555*
Total	*9,221*

Note: There are no actual costs for Technical and Construction Services prior to 2009.

Sustainability (1)

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***3,728***	***3,225***	***469***
010 Office Supplies	22	24	9
011 Travel Expense	213	245	58
012 Materials	136	189	2
013 Contracts	53	199	-
015 Frt, Post & Delivery	9	9	-
016 Tools & Equipment	1	-	-
021 Telephones	80	59	8
028 Consulting	249	224	399
029 Membership Dues	162	166	10
031 Fleet Fuel	22	19	-
032 Subscrpt/Info.Software	9	6	9
033 Rental/Mtnce equipment/software	62	50	-
034 Appl. Software	12	7	1
035 Comp.Hrdwr & Op.Sftwr	2	2	1
037 Ext. Legal & Audit	196	258	83
041 Meals & Entertainment	58	75	10
042 Employee Benefits	-	784	41
050 Rent	6	18	-
052 Non Reg.Cost Recovery	-	(16)	(11)
056 Training & Development	36	24	4
057 Corp. Support Transfe	(93)	(97)	-
058 Personal Equipment	4	3	-
061 Write-offs	6	-	
066 Other Goods & Services	(45)	36	48
190 Misc revenue/recoveries (OM&G)		(4)	
Total Non-Labour	***1,200***	***2,280***	***672***
Total	***4,928***	***5,505***	***1,141***

(1) Costs for 2007-2008 are from the Renewable Planning Department. In 2009, the Renewable Planning department was reorganized in to Sustainability and Technical and Construction Services.

Power Production Head Office

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Total Labour	***396***	***585***	***683***
010 Office Supplies	6	4	6
011 Travel Expense	29	69	133
012 Materials	(2)	5	2
013 Contracts	160	18	159
021 Telephones	4	14	11
028 Consulting	109	234	122
029 Membership Dues	4	78	107
032 Subscrpt/Info.Software	8	10	85
035 Comp.Hrdwr & Op.Sftwr	-	-	1
037 Ext. Legal & Audit	1,061	3,523	4,421
041 Meals & Entertainment	17	9	22
042 Employee Benefits	10,156	8,389	3,628
056 Training & Development	(1)	1	1
066 Other Goods & Services	85	(5)	85
Total Non-Labour	***11,636***	***12,349***	***8,783***
Total	***12,032***	***12,934***	***9,466***

Thermal Plants

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***35,903***	***38,222***	***37,712***
010 Office Supplies	80	69	83
011 Travel Expense	170	157	242
012 Materials	7,761	7,716	7,643
013 Contracts	9,440	11,963	11,992
014 Overtime Meals	125	129	144
015 Frt, Post & Delivery	117	132	110
016 Tools & Equipment	257	210	289
017 Chemicals	518	518	775
018 Gases	220	281	275
019 Water	747	839	986
021 Telephones	128	133	144
028 Consulting	81	64	171
029 Membership Dues	15	21	42
030 Lubricants	159	203	229
031 Fleet Fuel	253	453	25
033 Rental/Mtnce equipment/software	110	122	197
034 Appl. Software	11	9	7
035 Comp.Hrdwr & Op.Sftwr	9	12	13
041 Meals & Entertainment	133	150	195
050 Rent	39	37	41
051 Gen.Cost Recovery	(48)	(64)	(13)
055 Warranty & Service Contracts	12	13	10
056 Training & Development	129	110	180
058 Personal Equipment	257	300	268
065 By-product Sales	(734)	(844)	(845)
066 Other Goods & Services	149	103	54
189 Steam Sales	(197)	(167)	(218)
190 Misc revenue/recoveries	(6)	(9)	-
Total Non-Labour	***19,935***	***22,660***	***23,039***
Total	***55,838***	***60,882***	***60,751***

Combustion Turbines

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***631***	***680***	***731***
010 Office Supplies	4	3	3
011 Travel Expense	15	24	24
012 Materials	134	87	134
013 Contracts	268	314	237
014 Overtime Meals	2	1	2
015 Frt, Post & Delivery	11	4	11
016 Tools & Equipment	4	1	3
019 Water	-	-	1
021 Telephones	9	8	9
030 Lubricants	28	26	28
033 Rental/Mtnce equipment/software	1	-	-
041 Meals & Entertainment	4	6	7
056 Training & Development	-	1	1
058 Personal Equipment	(2)	2	2
066 Other Goods & Services	-	1	1
Total Non Labour	***478***	***478***	***463***
Total	***1,109***	***1,158***	***1,194***

Hydro & Wind Energy

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Total Labour	***4,816***	***4,978***	***5,116***
010 Office Supplies	28	26	23
011 Travel Expense	101	143	174
012 Materials	444	405	524
013 Contracts	782	1,191	1,612
014 Overtime Meals	12	11	11
015 Frt, Post & Delivery	5	5	17
016 Tools & Equipment	25	30	26
021 Telephones	73	74	79
028 Consulting	568	1,250	456
029 Membership Dues	4	3	16
030 Lubricants	25	16	33
031 Fleet Fuel	185	221	177
033 Rental/Mtnce equipment/software	37	30	20
034 Appl. Software	(3)	2	2
035 Comp.Hrdwr & Op.Sftwr	4	(1)	4
041 Meals & Entertainment	64	68	94
042 Employee Benefits	2	2	-
056 Training & Development	14	25	34
058 Personal Equipment	34	41	53
066 Other Goods & Services	39	58	55
083 Short-term interest	1	-	-
190 Misc revenue/recoveries	(1)	(11)	-
Total Non-Labour	***2,443***	***3,589***	***3,410***
Total	***7,259***	***8,567***	***8,526***

Energy, Fuels and Risk Management

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***2,110***	***2,054***	***2,420***
010 Office Supplies	6	5	6
011 Travel Expense	82	64	65
012 Materials	5	-	79
013 Contracts	182	261	639
015 Frt, Post & Delivery	2	2	1
016 Tools & Equipment	-	10	15
021 Telephones	22	60	25
028 Consulting	220	368	316
029 Membership Dues	68	62	6
032 Subscrpt/Info.Software	41	193	345
033 Rental/Mtnce equipment/software	1	-	-
034 Appl. Software	2	-	14
035 Comp.Hrdwr & Op.Sftwr	3	-	1
037 Ext. Legal & Audit	17	-	4
041 Meals & Entertainment	22	13	22
052 Non Reg.Cost Recovery	(7)	-	-
056 Training & Development	37	32	42
066 Other Goods & Services	6	25	10
Total Non-Labour	***709***	***1,095***	***1,590***
Total	***2,819***	***3,149***	***4,010***

Regional Operations

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***11,452***	***11,876***	***12,875***
010 Office Supplies	52	55	52
011 Travel Expense	121	147	114
012 Materials	691	662	1,435
013 Contracts	781	1,014	1,070
014 Overtime Meals	36	39	47
015 Frt, Post & Delivery	12	13	11
016 Tools & Equipment	196	216	211
019 Water	3	1	3
020 Royalties/Easements/Appraisals	78	67	50
021 Telephones	451	466	444
028 Consulting	1	2	-
029 Membership Dues	4	2	3
034 Appl. Software	1	-	1
035 Comp.Hrdwr & Op.Sftwr	4	4	2
040 Advertising	1	1	2
041 Meals & Entertainment	103	101	109
042 Employee Benefits	93	91	75
056 Training & Development	37	28	15
058 Personal Equipment	244	261	433
059 HR Costs	56	-	-
061 Write-offs	7	-	-
066 Other Goods & Services	199	314	245
083 Short-term interest	-	-	-
190 Misc revenue/recoveries	(846)	(934)	(942)
Total Non-Labour	***2,325***	***2,550***	***3,380***
Total	***13,777***	***14,426***	***16,255***

Control Center

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***4,231***	***4,291***	***4,789***
010 Office Supplies	7	9	9
011 Travel Expense	54	59	68
012 Materials	41	47	43
013 Contracts	215	298	306
014 Overtime Meals	1	3	3
015 Frt, Post & Delivery	4	5	6
016 Tools & Equipment	2	1	-
020 Royalties/Easements/Appraisals	32	44	43
021 Telephones	100	73	77
023 Data Communication Circuits	363	470	340
028 Consulting	45	(22)	3
029 Membership Dues	227	269	355
032 Subscrpt/Info.Software	-	-	1
033 Rental/Mtnce equipment/software	257	145	52
034 Appl. Software	2	(1)	1
035 Comp.Hrdwr & Op.Sftwr	2	-	1
041 Meals & Entertainment	26	20	22
050 Rent	99	102	113
055 Warranty & Service Contracts	98	65	183
056 Training & Development	34	17	62
058 Personal Equipment	2	-	2
066 Other Goods & Services	12	6	6
190 Misc revenue/recoveries	(143)	(20)	(165)
Total Non Labour	***1,480***	***1,590***	***1,531***
Total	***5,711***	***5,881***	***6,320***

Reliability, Workforce Management and Resource Allocation

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Total Labour	***12,727***	***14,074***	***11,870***
010 Office Supplies	37	30	38
011 Travel Expense	422	406	265
012 Materials	1,500	1,492	1,487
013 Contracts	11,930	12,603	17,891
014 Overtime Meals	20	22	30
015 Frt, Post & Delivery	9	9	7
016 Tools & Equipment	69	62	53
020 Royalties/Easements/Appraisals	27	28	27
021 Telephones	195	208	246
025 Leasing	34	25	13
028 Consulting	57	77	75
029 Membership Dues	16	17	36
031 Fleet Fuel	282	2	2
032 Subscrpt/Info.Software	1	-	-
033 Rental/Mtnce equipment/software	24	22	22
034 Appl. Software	3	11	3
035 Comp.Hrdwr & Op.Sftwr	25	4	1
041 Meals & Entertainment	184	157	132
042 Employee Benefits	31	28	28
050 Rent	2	1	-
052 Non Reg.Cost Recovery	-	(7)	-
056 Training & Development	60	87	33
058 Personal Equipment	163	145	155
066 Other Goods & Services	(319)	(344)	(389)
190 Misc revenue/recoveries	(6,191)	(6,502)	(5,348)
Total Non-Labour	***8,581***	***8,583***	***14,807***
Total	***21,308***	***22,657***	***26,677***

Customer Operations - Administration (including Storm & Safety)

(in Thousands of $)

	2007 Actual	*2008 Actual*	*2009 Actual*
Total Labour	***5,654***	***4,540***	***3,707***
010 Office Supplies	7	7	7
011 Travel Expense	371	221	266
012 Materials	296	243	137
013 Contracts	6,856	3,682	4,216
014 Overtime Meals	68	43	75
020 Royalties/Easements/Appraisals	11	-	-
021 Telephones	29	19	15
028 Consulting	73	305	183
029 Membership Dues	114	(8)	2
031 Fleet Fuel	2,143	2,946	2,326
034 Appl. Software	43	-	-
041 Meals & Entertainment	270	163	203
042 Employee Benefits	9,783	6,295	2,347
052 Non Reg.Cost Recovery	(4)	-	-
056 Training & Development	8	-	-
058 Personal Equipment	22	7	8
066 Other Goods & Services	527	(2,030)	(98)
190 Misc revenue/recoveries (OM&G)	(254)	(2,322)	(121)
Total Non-Labour	***20,363***	***9,571***	***9,566***
Total	***26,017***	***14,111***	***13,273***

Customer Service

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***14,781***	***15,254***	***16,126***
010 Office Supplies	50	53	69
011 Travel Expense	157	133	221
012 Materials	258	325	462
013 Contracts	686	636	1,397
014 Overtime Meals	5	6	7
015 Frt, Post & Delivery	1,960	1,978	2,076
016 Tools & Equipment	3	2	3
017 Chemicals	7	9	6
021 Telephones	431	389	442
025 Leasing	28	17	22
028 Consulting	293	212	1,021
029 Membership Dues	65	79	93
031 Fleet Fuel	532	556	438
033 Rental/Mtnce equipment/software	775	787	969
034 Appl. Software	1	3	23
035 Comp.Hrdwr & Op.Sftwr	2	1	88
040 Advertising	320	289	415
041 Meals & Entertainment	84	97	124
042 Employee Benefits	3,846	2,884	1,187
051 Gen.Cost Recovery	-	-	(1)
055 Warranty & Service Contracts	1	3	4
056 Training & Development	21	46	120
058 Personal Equipment	65	48	74
059 HR Costs	50	159	44
060 Commissions	248	251	203
061 Write-offs	5,466	5,330	6,154
062 Recoveries	(1,363)	(1,550)	(1,680)
064 Customer Recovery	11	13	26
066 Other Goods & Services	12	29	7
083 Short-term interest	(110)	(100)	(128)
190 Misc revenue/recoveries	(257)	(249)	(362)
Total Non-Labour	***13,647***	***12,436***	***13,524***
Total	***28,428***	***27,690***	***29,650***

Corporate Adjustments

(in Thousands of $)

	2007 Actual	2008 Actual	2009 Actual
Total Labour	***3,067***	***3,218***	***4,003***
028 Consulting	(12)	-	-
036 Directors' Fees & Exp	-	11	47
042 Employee Benefits	5,386	(550)	(584)
051 Gen.Cost Recovery	5	-	-
057 Corp. Support Transfe	(973)	(860)	(976)
061 Write-offs	950	2,245	781
066 Other Goods & Services	237	249	334
083 Short-term interest	(1,007)	(1,011)	(1,054)
091 Tax Assessment	(64)	3	(126)
092 Vehicle Allocated Costs	(3,966)	(5,002)	(4,807)
095 Admin. Overheads	(15,577)	(16,718)	(18,692)
Total Non-Labour	***(15,021)***	***(21,633)***	***(25,077)***
Total	***(11,954)***	***(18,415)***	***(21,074)***

NON-CONFIDENTIAL

Request IR-85:

In reference to Appendix E, please provide actuals for 2007, 2008 and 2009 in the same format as actual 2010.

Response IR-85:

Please refer to NPB IR-83.

NON-CONFIDENTIAL

Request IR-86:

Reference: DE, page 112

Please provide the details for the 2009 allowance for working capital, Settlement Agreement Adjustment of $(40.9) million.

Response IR-86:

As part of the 2009 General Rate Application Settlement Agreement, parties to the Agreement requested that NSPI identify revenue reductions. The adjustment of $40.9 million to the forecasted 2009 CWC was an arbitrary amount used to reduce the average cash working capital rate base to arrive at the specific revenue requirement. Please refer to Attachment 1.

NOVA SCOTIA
POWER
An Emera Company

September 17, 2008

Nancy McNeil
Clerk of the Board
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
P.O. Box 1692, Unit "M"
Halifax, NS B3J 3S3

Re: NSPI General Rate Application P-888

Dear Ms. McNeil:

The 2009 General Rate Application Settlement Agreement describes certain fuel and non-fuel reductions from the originally requested revenue requirement increase of $132.5 million (above the line revenue). The total reduction in above the line revenue from the original Application is $28.3 million, which is comprised of $14.5 million of fuel costs and $13.8 million of non-fuel costs.

In addition to certain specified reductions, parties to the Agreement requested that NSPI identify revenue reductions in other OM&G and rate base items in the amount of $6 million (paragraph 11). NSPI was given discretion to determine which components of filed costs would be changed in order to identify the $6 million in reductions, as long as the changes were actual reductions and not deferrals. NSPI has allocated these adjustments by reducing the increases proposed for Net Bad Debt, Insurance costs, Taxes, and the reduction of average Cash Working Capital (CWC) rate base.

Similar to the assumed amount for fuel, NSPI anticipates that these costs may be experienced in 2009 despite these changed assumptions for the purpose of achieving the agreed revenue requirement. The Company will be required to continue to carefully manage all of its costs in order to achieve its 2009 results.

The following provides a listing of the changed assumptions that NSPI has determined would comprise the $28.3 million reduction in revenue requirement. These amounts are estimates and will be used in future financial reporting as required.

N. McNeil
September 17, 2008
Page 2 of 2

Original GRA	$132.5M
Fuel	($14.5M) = Assumed reduction to achieve $545M in base rates
OMG	($4.8M) = Vegetation ($3.4M), Net bad debt ($1.0M), Insurance ($0.4M)
DSM	($2.1M) = amortization moves from 3 years to 6 years
Taxes	($3.3M) = includes tax effect of DSM amortization change
Rate base	($0.8M) = decrease of average rate base by $8M to remove fuel deferral
Rate base	($3.0M) = Reduction of average CWC rate base by $37.1M
Rate base	$0.2M = Increase of average DSM unamortized rate by $1.1M
Total	($28.3M)
Rev Increase	$104.2M = Settlement agreement

Yours truly,

Rene Gallant

Cc: Terry Dalgleish, Q.C.
Anne Marie Curtis
Bruce Outhouse, Q.C.
All Intervenors

2009 General Rate Application Settlement Agreement

Whereas Nova Scotia Power Inc (NSPI) filed an Application for a General Rate Increase with the Nova Scotia Utility and Review Board (UARB) on May 27, 2008, proposing an increase in revenue requirement of $132.5 million and seeking an average rate increase of 11.9% effective January 1, 2009 (the "Application");

And whereas NSPI, New Page Port Hawkesbury Ltd. and Bowater Mersey Paper Company Ltd. (NPB), the Avon group (Avon), the Consumer Advocate (CA), the Municipal Electric Utilities of Nova Scotia Cooperative (MEUNSC) and the Department of Energy (DOE) have worked together with staff and consultants to the UARB to develop and implement a Fuel Adjustment Mechanism (FAM) for NSPI;

And whereas the Parties to this Agreement agree that the FAM will be ready to operate effective January 1, 2009 and NSPI will be ready for the FAM;

And whereas NSPI is forecasting revenue requirement increases in the 2009 test year consisting primarily of fuel expenses and other costs, which have been disclosed in the Application and examined during the course of the Application pre-hearing discovery processes;

And whereas the Parties desire to resolve the Application, and to continue to work collaboratively to accomplish objectives that will benefit customers over the long term;

The signatories to this agreement hereby agree:

FAM and Fuel Related Items:

1. The FAM, including supporting documentation, is substantially complete, and there are no remaining issues that would cause any of the Parties to object to the operation of the FAM on January 1, 2009.

2. The Parties request that the UARB approve the FAM to commence on January 1, 2009, as an outcome of this General Rate Application and in lieu of the formal schedule for approval previously established by the UARB in its December 10, 2007 Decision.

3. The Parties will finalize the FAM documentation and NSPI will file a final proposed Tariff and Plan of Administration no later than October 15, 2008 for UARB approval. Any matters regarding the FAM documentation which remain outstanding between the Parties will be determined by the UARB, and Parties other than NSPI, including UARB consultants, shall file any comments on outstanding issues with the UARB by October 22, 2008. Other aspects of FAM

implementation, as directed by the UARB in its December 10, 2007 Decision, will continue throughout 2008.

4. The Parties agree that the Base Cost of Fuel in rates will increase by $75 million and will be set in the amount of $545 million, (and adjusted for the FAM per Schedule 2, Appendix A of the FAM Plan of Administration to calculate the average cost per MWh, of $42.41 per MWh, and for each customer class), and that NSPI will recover the Base Cost of Fuel from customers in 2009 rates that are effective January 1, 2009.

5. NSPI has advised the Parties, each of whom hereby specifically acknowledges, that NSPI forecasts fuel costs in 2009 to increase by approximately $82 million above the amount requested to be incorporated into rates in NSPI's Application as filed. The actual amount of the fuel adjustment for 2010 will be determined per the FAM process, and Parties will retain their rights to investigate and litigate these fuel amounts in a hearing before the UARB as part of the FAM process.

6. The Parties agree that recovery of up to $8 Million of the 2008 natural gas sales margin deferral (subject to a reduction of this deferral amount in the event NSPI would otherwise earn in excess of 9.8% ROE in 2008), as approved by the UARB on July 23, 2007, will be recovered in the first FAM adjustment, including carrying charges from January 1, 2009, and shall not be a rate base item.

7. The Parties agree that for the purposes of calculating the FAM incentive, the Base Cost of Fuel in rates will be assumed to be re-set at $590 million (as adjusted per Schedule 2, Appendix A of the FAM Plan of Administration to calculate an average cost per MWh, of $45.95 per MWh, and for each customer class) until the Base Cost of Fuel is again actually re-set, either pursuant to the FAM or during a future General Rate Application.

8. The Parties acknowledge and advise the UARB that an outcome of delayed recovery of a portion of NSPI's forecasted increased 2009 fuel costs described in paragraph 5 above is that the first FAM adjustment will most likely result in an increased recovery from customers beginning on January 1, 2010.

<u>Other Costs and Items:</u>

9. Beginning on January 1, 2009, the revenue for rate setting purposes for each customer class shall be as set out in Schedule 1 attached. The increase in revenue requirement will be $104.2 million, comprised of the $75 million noted in paragraph 4 and the $29.2 million noted in paragraph 10.

10. NSPI has advised the Parties and the UARB of non-fuel cost increases in the 2009 test year. The Parties agree to an increase in revenue requirement of $29.2 million to recover non-fuel cost increases and which increase is in addition to the fuel cost recovery provided above in paragraph 4.

11. The non-fuel increase incorporates reductions in NSPI's forecasted 2009 revenue requirement, compared to the Application, in the non-fuel related areas of the Application, including a reduction of $3.4 million in Vegetation Management costs, extension of the amortization period for Demand Side Management costs to six years to reduce revenue requirement by $3.6 million, removal of the 2008 fuel deferral from rate base as noted above in paragraph 6, and other OM&G and rate base reductions in the total amount of $6.0 million. This increase incorporates the ROE reduction requested in the Application. NSPI's proposed rates and proof of revenue for 2009 shall be as set out in Schedule 1 attached.

12. The revenue requirement increase will be allocated proportionately to each customer class, on an "across the board" basis, with revenue from each customer class increasing by the same percentage as other customer classes in order to recover in total the increased revenue requirement.

    a. This is a one time allocation approach and does not create any precedent for future cases, including the adjustments noted below in sub-paragraphs b) and c).

    b. Subsequent to such allocation, the Unmetered class rate and revenue will be reduced to the point where the Unmetered class revenue to cost ratio would be 1.00. This reduction in revenue will not be recovered from other customers.

    c. A further adjustment will be made so that the group of Large Industrial Class customers who receive the Interruptible credit will see the same average rate increase as other classes. This will be accomplished by applying a temporary equalization adjustment. The adjustment will be cost neutral to other classes and will not affect the interruptible credit value.

13. The Parties also acknowledge that their agreement to the non-fuel average revenue increase should not be construed as an acceptance by any of the Parties of any allocation or amortization of future DSM or other costs to such Parties, and that the average increase in this Agreement shall not be adjusted on account of any future DSM or other decision by the UARB. In particular, the Parties may take any position on DSM cost recovery and allocation in respect of post-2009 DSM programs and costs.

14. Unless revised by the terms of this Agreement, all other aspects of NSPI's Application are adopted for the purposes of this Agreement only, and this Agreement does not preclude NSPI or any of the other Parties from taking any positions in future regulatory proceedings or otherwise.

15. NSPI will provide a Cost of Service Study in electronic form to Parties, subject to appropriate confidentiality undertakings and on condition that the model not be used for commercial purposes. Such information shall likewise be available in electronic form for subsequent proceedings.

All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated ____________________ Per: René Gallant		[...other parties as may wish to support the Agreement]
Avon Group Robert G. Grant Per: ROBERT G. GRANT		Consumer Advocate ____________________ Per:
Municipal Electric Utilities of Nova Scotia Cooperative ____________________ Per:		New Page/Bowater Mersey ____________________ Per:
Canadian Manufacturers and Exporters Association ____________________ Per:		Halifax Regional Municipality ____________________ Per:

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All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated ________________ Per: René Gallant		[...other parties as may wish to support the Agreement]
Avon Group ________________ Per:		Consumer Advocate ________________ Per:
Municipal Electric Utilities of Nova Scotia Cooperative ________________ Per:		New Page/Bowater Mersey ________________ Per:
Canadian Manufacturers and Exporters Association ________________ Per:		Halifax Regional Municipality ________________ Per:

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All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated Per: René Gallant		[...other parties as may wish to support the Agreement]
Avon Group Per:		Consumer Advocate Per:
Municipal Electric Utilities of Nova Scotia Cooperative Per:		New Page/Bowater Mersey Per:
Canadian Manufacturers and Exporters Association Per: Robert G.H. Patzelt, Q.C.		Halifax Regional Municipality Per:

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All of which is hereby agreed this day of September, 2008:

Nova Scotia Power Incorporated ____________________ Per:	[...other parties as may wish to support the Agreement]
Avon Group ____________________ Per:	Consumer Advocate ____________________ Per:
Municipal Electric Utilities of Nova Scotia Cooperative ____________________ Per:	New Page/Bowater Mersey ____________________ Per:
Canadian Manufacturers and Exporters Association ____________________ Per:	Halifax Regional Municipality ____________________ Per:
Quettta Inc. John McReynolds Per: Prez	

Post-it® Fax Note 7671	Date 15 Sep 08	# of pages ▶ 1
To Rene Gallant	From McReynolds	
Co./Dept.	Co. Quitta Inc.	
Phone #	Phone # 902/492-0283	
Fax # 428-6542	Fax #	

Received Time Sep. 15. 2008 4:13PM No. 0224

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All of which is hereby agreed this day of September, 2008:

Nova Scotia Power Incorporated ________________ Per:		[...other parties as may wish to support the Agreement]
Avon Group ________________ Per:		Consumer Advocate and Small Business Advocate ________________ Per: JOHN MERRICK
Municipal Electric Utilities of Nova Scotia Cooperative ________________ Per:		New Page/Bowater Mersey ________________ Per:
Canadian Manufacturers and Exporters Association ________________ Per:		Halifax Regional Municipality ________________ Per:
Quettta Inc. ________________ Per:		

15. NSPI will provide a Cost of Service Study in electronic form to Parties, subject to appropriate confidentiality undertakings and on condition that the model not be used for commercial purposes. Such information shall likewise be available in electronic form for subsequent proceedings.

All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated Per: René Gallant		[...other parties as may wish to support the Agreement]
Avon Group Per:		Consumer Advocate Per:
Municipal Electric Utilities of Nova Scotia Cooperative Per:		New Page/Bowater Mersey Per: George T. H. Cooper
Canadian Manufacturers and Exporters Association Per:		Halifax Regional Municipality Per:

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All of which is hereby agreed this 15th day of September, 2008:

Nova Scotia Power Incorporated ________________ Per: René Gallant		[...other parties as may wish to support the Agreement]
Avon Group ________________ Per:		Consumer Advocate ________________ Per:
Municipal Electric Utilities of Nova Scotia Cooperative ________________ Per:		New Page/Bowater Mersey ________________ Per:
Canadian Manufacturers and Exporters Association ________________ Per:		Halifax Regional Municipality ________________ Per: Martin C Ward, Q.C.

2009 General Rate Application
Settlement Agreement
Schedule 1

Schedule 1 (page 1)	**Current Revenue**	**Proposed Revenue**	**Revenue Increase**	**% Revenue Increase**	**R/C Ratios**
ABOVE-THE-LINE CLASSES					
Residential	**$496.3**	**$542.8**	**$46.5**	**9.4%**	**98.9%**
Commercial					
Small General	$30.7	$33.6	$2.9	9.4%	102.3%
General Demand	$252.8	$276.6	$23.7	9.4%	107.2%
Large General	$34.8	$38.0	$3.3	9.4%	98.7%
Total Commercial	**$318.3**	**$348.2**	**$29.8**	**9.4%**	**105.7%**
Industrial					
Small Industrial	$23.9	$26.1	$2.2	9.4%	102.0%
Medium Industrial	$48.6	$53.2	$4.6	9.4%	100.8%
Large Industrial	$65.0	$71.1	$6.1	9.4%	97.5%
ELI 2P-RTP	$119.2	$130.3	$11.2	9.4%	91.0%
Total Industrial	**$256.6**	**$280.6**	**$24.1**	**9.4%**	**95.3%**
Other					
Municipal	$16.1	$17.6	$1.5	9.4%	99.8%
Unmetered	$24.0	$25.2	$1.2	5.0%	100.0%
Total Other	**$40.1**	**$42.8**	**$2.7**	**6.8%**	**99.9%**
Total Above-the-line classes	**$1,111.3**	**$1,214.5**	**$103.2**	**9.3%**	**99.9%**
Below-the-line	**$21.2**	**$22.1**	**$0.9**	**4.5%**	
Exports	**$4.6**	**$4.6**	**$0.0**	**0.0%**	
Miscellaneous	**$14.2**	**$14.7**	**$0.4**	**2.9%**	
Total Revenue	**$1,151.3**	**$1,255.8**	**$104.5**	**9.1%**	

2009 General Rate Application
Settlement Agreement
Schedule 1

Schedule 1 (page 2)

	GRA 2009						SETTLEMENT					VARIANCES					
ABOVE-THE-LINE CLASSES	Current Revenue	Costs	R/C Ratio	Proposed Revenue	Revenue Increase	% Revenue Increase	Costs	R/C Ratio	Proposed Revenue	Revenue Increase	% Revenue Increase	Costs	% Costs	Proposed Revenue	% Proposed Revenue	Revenue Increase	Revenue Increase
Residential	**$496.3**	**$561.8**	**99.0%**	**$556.2**	**$59.9**	**12.07%**	**$548.8**	**98.9%**	**$542.8**	**$46.5**	**9.38%**	**($13.0)**	**-2.3%**	**($13.4)**	**-2.4%**	**($13.4)**	**-22.3%**
Commercial																	
Small General	$30.7	$33.6	102.5%	$34.4	$3.7	12.07%	$32.8	102.3%	$33.6	$2.9	9.38%	($0.7)	-2.2%	($0.8)	-2.4%	($0.8)	-22.3%
General Demand	$252.8	$263.9	105.0%	$277.1	$24.3	9.60%	$258.0	107.2%	$276.6	$23.7	9.38%	($5.9)	-2.2%	($0.6)	-0.2%	($0.6)	-2.3%
Large General	$34.8	$39.4	98.9%	$39.0	$4.2	12.07%	$38.5	98.7%	$38.0	$3.3	9.38%	($0.9)	-2.2%	($0.9)	-2.4%	($0.9)	-22.3%
Total Commercial	**$318.3**	**$336.9**	**104.0%**	**$350.5**	**$32.2**	**10.11%**	**$329.4**	**105.7%**	**$348.2**	**$29.8**	**9.38%**	**($7.5)**	**-2.2%**	**($2.3)**	**-0.7%**	**($2.3)**	**-7.2%**
Industrial																	
Small Industrial	$23.9	$26.2	102.2%	$26.7	$2.9	12.07%	$25.6	102.0%	$26.1	$2.2	9.38%	($0.6)	-2.2%	($0.6)	-2.4%	($0.6)	-22.3%
Medium Industrial	$48.6	$53.9	101.0%	$54.5	$5.9	12.07%	$52.7	100.8%	$53.2	$4.6	9.38%	($1.2)	-2.2%	($1.3)	-2.4%	($1.3)	-22.3%
Large Industrial	$65.0	$74.7	97.5%	$72.8	$7.8	12.07%	$72.8	97.5%	$71.1	$6.1	9.38%	($1.8)	-2.4%	($1.7)	-2.4%	($1.7)	-22.3%
ELI 2P-RTP	$119.2	$147.0	95.1%	$139.8	$20.6	17.31%	$143.2	91.0%	$130.3	$11.2	9.38%	($3.7)	-2.5%	($9.4)	-6.8%	($9.4)	-45.8%
Total Industrial	**$256.6**	**$301.7**	**97.4%**	**$293.8**	**$37.2**	**14.50%**	**$294.4**	**95.3%**	**$280.6**	**$24.1**	**9.38%**	**($7.3)**	**-2.4%**	**($13.1)**	**-4.5%**	**($13.1)**	**-35.3%**
Other																	
Municipal	$16.1	$18.0	100.1%	$18.0	$1.9	12.07%	$17.6	99.8%	$17.6	$1.5	9.38%	($0.4)	-2.2%	($0.4)	-2.4%	($0.4)	-22.3%
Unmetered	$24.0	$25.5	100.0%	$25.5	$1.5	6.43%	$25.2	100.0%	$25.2	$1.2	5.00%	($0.3)	-1.3%	($0.3)	-1.3%	($0.3)	-22.2%
Total Other	**$40.1**	**$43.6**	**100.0%**	**$43.6**	**$3.5**	**8.70%**	**$42.8**	**99.9%**	**$42.8**	**$2.7**	**6.76%**	**($0.7)**	**-1.7%**	**($0.8)**	**-1.8%**	**($0.8)**	**-22.3%**
Total Above-the-line classes	**$1,111.3**	**$1,244.1**	**100.0%**	**$1,244.1**	**$132.8**	**11.9%**	**$1,215.5**	**99.9%**	**$1,214.5**	**$103.2**	**9.28%**	**($28.6)**	**-2.3%**	**($29.6)**	**-2.4%**	**($29.6)**	**-22.3%**
Below-the-line	**$21.2**			**$22.4**	**$1.2**	**5.86%**			**$22.1**	**$0.9**	**4.45%**	$0.0		($0.3)	-1.3%	($0.3)	-24.1%
Exports	**$4.6**			**$4.6**	**$0.0**	**0.00%**			**$4.6**	**$0.0**	**0.00%**	$0.0		$0.0	0.0%	$0.0	0.0%
Miscellaneous	**$14.2**			**$14.8**	**$0.5**	**3.62%**			**$14.7**	**$0.4**	**2.86%**	$0.0		($0.1)	-0.7%	($0.1)	-21.0%
Total Revenue	**$1,151.3**			**$1,285.8**	**$134.5**	**11.68%**			**$1,255.8**	**$104.5**	**9.08%**	**$0.0**		**($30.0)**	**-2.3%**	**($30.0)**	**-22.3%**

Schedule 1 page 3

Current Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			PRESENT RATES FORECAST 2009
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue	
Residential Sector																		
Non-ETS	4,028.9	$ 0.10670	$ 429.9		$ -	$ -	-	$ -	$ -	4,028.9	$ 429.9	-	$ -	$ -	5.0	$ 10.83	$ 54.0	$ 483.9
ETS	9.8	$ 0.15320	$ 1.5	33.6	$ 0.10670	$ 3.6	113.5	$ 0.05335	$ 6.1	156.8	$ 11.1	-	$ -	$ -	0.1	$ 18.82	$ 1.3	$ 12.4
Total	**4,038.7**		**$ 431.4**	**33.6**		**$ 3.6**	**113.5**		**$ 6.1**	**4,185.7**	**$ 441.0**	**-**		**$ -**	**5.1**		**$ 55.3**	**$ 496.3**
Commercial Sector																		
Small General	43.9	$ 0.11810	$ 5.2	211.3	$ 0.10390	$ 22.0	-		$ -	255.1	$ 27.1	-	$ -	$ -	0.3	$ 12.65	$ 3.6	$ 30.7
General Demand	1,385.6	$ 0.08780	$ 121.7	$ 1,176.4	$ 0.06200	$ 72.9	-		$ -	2,561.9	$ 194.6	7.1	$ 8.260	$ 58.3	-	$ -	$ -	$ 252.8
Large General																		
Without Trans. Own.	240.2	$ 0.05980	$ 14.4							240.2	$ 14.4	0.5	$ 10.060	$ 5.4				$ 19.7
With Trans. Own.	186.2	$ 0.05980	$ 11.1							186.2	$ 11.1	0.4	$ 9.740	$ 3.9				$ 15.1
Sub-total	426.4		$ 25.5							426.4	$ 25.5	0.9		$ 9.3				$ 34.8
Total	**1,855.8**		**$ 152.3**	**1,387.6**		**$ 94.9**				**3,243.4**	**$ 247.2**	**8.0**		**$ 67.5**	**0.3**		**$ 3.6**	**$ 318.3**
Industrial Sector																		
Small Industrial	171.5	$ 0.07670	$ 13.2	81.0	$ 0.05850	$ 4.7				252.4	$ 17.9	1.0	$ 5.890	$ 6.0				$ 23.9
Medium Industrial	580.2	$ 0.05460	$ 31.7							580.2	$ 31.7	1.8	$ 9.480	$ 16.9				$ 48.6
Large Industrial Firm																		
Without Trans. Own.	89.0	$ 0.05470	$ 4.9							89.0	$ 4.9	0.2	$ 9.110	$ 1.7				$ 6.6
With Trans. Own.	69.3	$ 0.05470	$ 3.8							69.3	$ 3.8	0.1	$ 8.790	$ 0.8				$ 4.6
Sub-total	158.3		$ 8.7							158.3	$ 8.7	0.3		$ 2.5				$ 11.2
Large Industrial Interr.																		
Without Trans. Own.	186.6	$ 0.05470	$ 10.2							186.6	$ 10.2	0.5	5.6800	$ 3.0				$ 13.2
With Trans. Own.	619.8	$ 0.05470	$ 33.9							619.8	$ 33.9	1.2	5.3600	$ 6.7				$ 40.6
Sub-total	806.5		$ 44.1							806.5	$ 44.1	1.8		$ 9.7				$ 53.8
Total Large Industrial	**964.8**		**$ 52.8**						$ 1.0	**964.8**	**$ 52.8**	**2.1**		**$ 12.2**				**$ 65.0**
ELI 2P-RTP	2,098.3	$ 0.05655	$ 118.7							2,098.3	$ 118.7				0.0	$ 20,700.00	$ 0.5	$ 119.2
Total Industrial	**3,814.7**		**$ 216.3**	**80.98**		**$ 4.7**				**3,895.6**	**$ 221.0**	**4.9**		**$ 35.1**	**0.0**		**$ 0.5**	**$ 256.6**
Other																		
Municipal																		
Without Trans. Own.	124.5	$ 0.05630	$ 7.0							124.5	$ 7.0	0.3	$ 9.380	$ 3.2				$ 10.2
With Trans. Own.	73.9	$ 0.05630	$ 4.2							73.9	$ 4.2	0.2	$ 9.060	$ 1.7				$ 5.9
Sub-total	198.4		$ 11.2							198.4	$ 11.2	0.5		$ 4.9				$ 16.1
Unmetered	115.6	$ 0.20750	$ 24.0							115.6	$ 24.0							$ 24.0
Total	**314.0**		**$ 35.2**							**314.0**	**$ 35.2**	**0.5**		**$ 4.9**				**$ 40.1**
Total Above-the-line	**10,023.2**		**$ 835.1**	**1,502.15**		**$ 103.2**	**113.49**		**$ 6.1**	**11,638.9**	**$ 944.4**	**13.4**		**$ 107.6**	**5.3**		**$ 59.3**	**$ 1,111.3**
Below-the-line Classes																		
GRLF and Mersey Contract	379.0	$ 0.05586	$ 21.2							379.0	$ 21.2							$ 21.2
Total	**379.0**		**$ 21.2**							**379.0**	**$ 21.2**							**$ 21.2**
Total In-Province	**10,402.2**		**$ 856.3**	**1,502.1**		**$ 103.2**	**113.5**		**$ 6.1**	**12,017.9**	**$ 965.6**	**13.4**		**$ 107.6**	**5.3**		**$ 59.3**	**$ 1,132.5**
Exports	**38.9**	**$ 0.11774**	**$ 4.6**							**38.9**	**$ 4.6**							**$ 4.6**
Total Electric Revenue	**10,441.1**		**$ 860.9**	**1,502.1**		**$ 103.2**	**113.5**		**$ 6.1**	**12,056.7**	**$ 970.1**	**13.4**		**$ 107.6**	**5.3**		**$ 59.3**	**$ 1,137.0**

Schedule 1 page 4

Proposed Tariffs	First KWh Block			Second KWh Block			Third KWh Block			Total KWHs		Demand			Base Charge			PROPOSED RATES FORECAST 2009	% Increase
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue	GWS or GVAS	Charge per KW or KVA	Revenue	Billmonths (in millions)	Base Charge	Revenue		
Residential Sector																			
Domestic Service	4,028.9	$ 0.11796	$ 475.3							4,028.9	$ 475.3				5.0	$ 10.83	$ 54.0	$ 529.2	
Domestic Service Time of Day	9.8	$ 0.15320	$ 1.5	33.6	$ 0.11796	$ 4.0	113.5	$ 0.06028	$ 6.8	156.8	$ 12.3				0.1	$ 18.82	$ 1.3	$ 13.6	
Total	**4,038.7**		**$ 476.7**	**33.6**		**$ 4.0**	**113.5**		**$ 6.8**	**4,185.7**	**$ 487.5**				**5.1**		**$ 55.3**	**$ 542.8**	9.38%
Commercial Sector																			
Small General	43.9	$ 0.13066	$ 5.7	211.3	$ 0.11495	$ 24.3				255.1	$ 30.0				0.3	$ 12.65	$ 3.6	$ 33.6	9.38%
General	1,385.6	$ 0.09603	$ 133.1	$ 1,176.4	$ 0.06781	$ 79.8				2,561.9	$ 212.8	7.1	$ 9.034	$ 63.7				$ 276.5	9.38%
Large General																			
Without Trans. Own.	240.2	$ 0.06539	$ 15.7							240.2	$ 15.7	0.5	$ 11.000	$ 5.9				$ 21.6	
With Trans. Own.	186.2	$ 0.06539	$ 12.2							186.2	$ 12.2	0.4	$ 10.680	$ 4.3				$ 16.5	
Sub-total	426.4		$ 27.9							426.4	$ 27.9	0.9		$ 10.2				$ 38.0	9.38%
Total	**1,855.8**		**$ 166.7**	**1,387.6**		**$ 104.1**				**3,243.4**	**$ 270.7**	**8.0**		**$ 73.9**	**0.3**		**$ 3.6**	**$ 348.2**	
Industrial Sector																			
Small Industrial	171.5	$ 0.08389	$ 14.4	81.0	$ 0.06399	$ 5.2				252.4	$ 19.6	1.0	$ 6.442	$ 6.5				$ 26.1	9.38%
Medium Industrial	580.2	$ 0.05972	$ 34.6							580.2	$ 34.6	1.8	$ 10.369	$ 18.5				$ 53.2	9.38%
Large Industrial Firm																			
Without Trans. Own.	89.0	$ 0.05993	$ 5.3							89.0	$ 5.3	0.2	$ 9.897	$ 1.9				$ 7.2	
With Trans. Own.	69.3	$ 0.05993	$ 4.2							69.3	$ 4.2	0.1	$ 9.577	$ 0.9				$ 5.0	
Sub-total	158.3		$ 9.5							158.3	$ 9.5	0.3		$ 2.7				$ 12.2	9.38%
Large Industrial Interruptible																			
Without Trans. Own.	186.6	$ 0.05922	$ 11.1							186.6	$ 11.1	0.5	6.4670	$ 3.4				$ 14.5	
With Trans. Own.	619.8	$ 0.05922	$ 36.7							619.8	$ 36.7	1.2	6.1470	$ 7.7				$ 44.4	
Sub-total	806.5		$ 47.8							806.5	$ 47.8	1.8		$ 11.1				$ 58.8	9.38%
Total Large Industrial	**964.8**		**$ 57.3**							**964.8**	**$ 57.3**	**2.1**		**$ 13.8**				$ 71.0	9.38%
Extra Large Industrial Interruptible	2,098.3	$ 0.06187	$ 129.8							2,098.3	$ 129.8				0.0	$ 20,700.00	$ 0.5	$ 130.3	9.38%
Total Industrial	**3,814.7**		**$ 236.1**	**80.98**		**$ 5.2**				**3,895.6**	**$ 241.3**	**4.9**		**$ 38.9**	**0.0**		**$ 0.5**	**$ 280.6**	9.38%
Other																			
Municipal																			
Without Trans. Own.	124.5	$ 0.06156	$ 7.7							124.5	$ 7.7	0.3	$ 10.256	$ 3.5				$ 11.2	
With Trans. Own.	73.9	$ 0.06156	$ 4.5							73.9	$ 4.5	0.2	$ 9.936	$ 1.9				$ 6.4	
Sub-total	198.4		$ 12.2							198.4	$ 12.2	0.5		$ 5.4				$ 17.6	9.38%
Unmetered	115.6	$ 0.21788	$ 25.2							115.6	$ 25.2							$ 25.2	5.00%
Total	**314.0**		**$ 37.4**							**314.0**	**$ 37.4**	**0.5**		**$ 5.4**				$ 42.8	
Total Above-the-line	**10,023.2**		**$ 916.9**	**1,502.15**		**$ 113.2**	**113.49**		**$ 6.8**	**11,638.9**	**$ 1,037.0**	**13.4**		**$ 118.1**	**5.3**		**$ 59.3**	**$ 1,214.4**	9.28%
Below-the-line Classes																			
GRLF and Mersey Contract	379.0	$ 0.05834	$ 22.1							379.0	$ 22.1							$ 22.1	
Total	**379.0**		**$ 22.1**							**379.0**	**$ 22.1**							$ 22.1	
Total In-Province	**10,402.2**		**$ 939.0**	**1,502.1**		**$ 113.2**	**113.5**		**$ 6.8**	**12,017.9**	**$ 1,059.1**	**13.4**		**$ 118.1**	**5.3**		**$ 59.3**	**$ 1,236.5**	
Exports	**38.9**	**$ 0.11774**	**$ 4.6**							**38.9**	**$ 4.6**							**$ 4.6**	
Total Electric Revenue	**10,441.1**		**$ 943.6**	**1,502.1**		**$ 113.2**	**113.5**		**$ 6.8**	**12,056.7**	**$ 1,063.7**	**13.4**		**$ 118.1**	**5.3**		**$ 59.3**	**$ 1,241.1**	

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Request IR-87:

Reference: NSPI GRA Section DE-03 – DE-04

Please provide complete copies of all correspondence between NSPI and Standard & Poor's, Dominion Bond Rating Service, Moody's Investors Service or other credit rating agencies issued over the last five years.

Response IR-87:

Correspondence between Nova Scotia Power and rating agencies is made in the form of presentations and reports.

Please refer to the Application, OP-12 for copies of presentations made by Nova Scotia Power to Bond Rating Agencies and Investors in the last year, as well as for copies of Bond Rating Reports and Reports from Equity Analysts made since the last rate filing.

CONFIDENTIAL (Attachment Only)

Request IR-88:

Reference: NSPI GRA Section DE-03 – DE-04

Please provide a complete copy of any Canadian utility industry report issued by Standard & Poor's, Dominion Bond Rating Service, Moody's Investors Service or other credit rating agencies outlining credit rating metrics for Canadian utility companies issued over the last two years.

Response IR-88:

Please refer to Confidential Attachment 1 for copies of Canadian utility industry reports issued by Standards & Poor's over the last two years. NSPI has access to the Standards & Poor's reports through a paid subscription service. NSPI does not subscribe to reports for Canadian utility companies issued by Dominion Bond Rating Service and Moody's Investors Service.

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Request IR-89:

Reference: NSPI GRA Section DE-03 – DE-04, Page 99

Please provide all workpapers, on electronic spreadsheet with all formulas intact, used to develop the Funds From Operations to Debt metric and Funds From Operations to Interest metric, with and without rate relief, and the five-year average actual metrics cited in the GRA.

Response IR-89:

Please refer to Attachment 1, filed electronically. In preparing this response, NSPI noticed the ratios included on page 99 of the Application were based on the financial forecast before the depreciation settlement and were not updated for the final 2012 forecast as filed in the Application. Revised final calculations of these ratios have also been provided in Attachment 1.

Please refer to Attachment 2, filed electronically for the calculation of the 2010 metrics included in the five-year average.

Please refer to the Application OP-12 Attachment 3, page 12-22 for 2006 through 2009 metrics.

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Request IR-90:

Reference: NSPI GRA Section DE-03 – DE-04, Page 103

Preamble: NSPI indicated that on April 1, 2009, it retired $125 million of preferred shares. It states that at that time it was cheaper to refinance those by issuing debt than it was to issue additional preferred shares.

Please provide a complete copy of the study used by NSPI to determine if it was more appropriate to refinance preferred shares with debt, rather than to issue additional preferred stock.

Response IR-90:

In early 2009, the preferred share market in Canada continued to be a challenge for issuers with higher than normal interest rates and minimal market demand from retail and institutional investors. NSPI's Series C Preferred Shares were traditional perpetual preferred shares. This type of preferred share was no longer being bought nor offered to investors due to its fixed coupon and the challenges in the capital markets. Investment demand for preferred shares at the time was strictly limited to the new rate reset preferred share for five year terms.

NSPI did not complete a study regarding the re-financing of the Series C Preferred Shares. The optimal approach was to refinance the perpetual preferred shares with debt based on the following factors:

- Interest rates on debt were lower than the rate reset preferred shares available. Perpetual preferred shares were not being sold to investors at the time.

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- Rate reset preferred shares were treated as 50 percent equity whereas the retired perpetual preferred shares were treated as 100 percent equity by the DBRS rating agency.

- NSPI's common equity had increased to offset any bond rating metrics related to the retirement of the existing perpetual preferred shares.

- The tax consequences of debt relative to preferred shares provides savings in costs as the interest expense associated with debt is a tax deductible expense. Preferred share dividends are not tax deductible. The deduction associated with the Part VI.I tax on preferred share dividends does not offset the benefit of the tax deductibility of interest expense on debt.

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Request IR-91:

Reference: NSPI GRA Section DE-03 – DE-04, Page 103

Referring to preferred shares refinanced on April 1, 2009, please state how the credit rating agencies viewed the preferred shares. That is, were they given equity, debt or combination treatment in the calculation of credit metrics? Please provide copies of all corroborating evidence supporting the answer to this question.

Response IR-91:

As at December 31, 2009, NSPI had 5.4 million, 5.9 percent Series D preferred shares outstanding.

The last annual report issued by S&P with regard to these preferred shares was issued on Dec 30, 2010, and evaluated the preferred share balance as at December 31, 2009. S&P treats 50 percent of the preferred shares as debt and 50 percent as equity in calculating credit metrics. At the end of 2009 a total of $135 million of preferred shares were outstanding; therefore $67.5 million was treated as debt and $67.5 million was treated as equity. The adjustment is outlined on page 9 of Confidential Attachment 1.

The last annual report issued by DBRS with regard to these preferred shares was issued on Nov 25, 2010, and evaluated the preferred share balance as at December 31, 2009. DBRS calculates NSPI's debt to equity ratios using two methods. The first method is in accordance with the DBRS standard methodology which treats the preferred shares as 100 percent equity. The second method is in accordance with DBRS's interpretation of the UARB decision on NSPI's capital structure that 100 percent of the preferred shares are treated as debt. The UARB adjusted methodology is noted on page 8 of Confidential Attachment 2.

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Request IR-92:

Reference: NSPI GRA Section DE-03 – DE-04, Page 103

Please provide copies of reports from credit rating agencies or equity analysts, that support the GRA's contention that the 40% common equity ratio maximum is viewed as a risk-increasing aspect of the regulatory process for NSPI. Please also provide Emera's current common equity ratio.

Response IR-92:

On Page 103 of the GRA it states that the maximum 40% equity ratio challenges NSPI's credit rating. Credit metrics (e.g., debt/capital ratios, interest coverage ratios, and debt coverage ratios) are a function of the capital structure. Credit metrics, in turn, are a key element of the credit rating. The establishment of a maximum equity ratio limits the credit metrics that NSPI can achieve, and consequently limits the credit rating that is achievable.

Equity analyst reports do not comment on NSPI's credit rating. S&P's December 2010 debt rating report for NSPI (filed as OP-12-Attachment 3) indicated that the Company's capital structure is a function of regulatory constraints. S&P categorizes NSPI's financial risk (which includes its capital structure, ROE and resulting credit metrics) as "Significant". This represents higher financial risk than the "Intermediate" financial risk category assigned to the three Canadian electric utility utilities with whom S&P compared NSPI (CU Inc., Maritime Electric and FortisAlberta) in that report. NSPI's S&P credit rating of BBB+ is lower than the Canadian utility average of A-, as shown on Ms. McShane's Schedule 3 Appendix F of the Application. NSPI's DBRS credit rating of A(low) is lower than the Canadian utility average of A, also shown on Ms. McShane's Schedule 3. Please refer to CA-IR-07 for Emera's common equity.

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Request IR-93:

Reference: NSPI GRA Section DE-03 – DE-04, Page 103, Item #4

Preamble: NSPI identifies four risk factors that impact NSPI.

Please provide a detailed comparison of these risk factors to other Canadian transmission and distribution and integrated utilities, and explain whether or not NSPI's exposure to these risk factors is different compared to other Canadian utilities.

Response IR-93:

The following response has been provided by Kathy McShane:

The relevant point of departure for any relative risk assessment regarding the four risk factors that were identified at page 103 of the Application is other Canadian investor-owned electric utilities and electric utilities that are government-owned but whose returns (ROEs and capital structures) are set by the regulator according to principles consistent with those applied to investor-owned utilities. Canadian investor-owned electric utilities include AltaLink, ATCO Electric, FortisAlberta, FortisBC, Maritime Electric and Newfoundland Power. Government-owned electric utilities whose returns are set according to the same principles as investor-owned utilities are ENMAX Power, EPCOR Distribution & Transmission Inc., the Ontario electricity distributors (most of which are owned by Ontario municipalities) and Hydro One Networks Inc.'s electricity transmission operations.

<u>Risks Related to RES Goals and Potential Penalties</u>

With respect to the risk identified as "Nova Scotia RES goals and potential penalties plus federal GHG targets and impact on our thermal units", this is a risk that relates to generation facilities. Of the utilities identified above, only FortisBC, Maritime Electric and Newfoundland Power operate generation facilities. The other utilities are either transmission or distribution only utilities. Of the three utilities with generation facilities, only one, FortisBC, is a truly integrated electric utility (i.e., one which generates a material portion of the power it transmits and delivers). Its generation facilities are all hydroelectric. Consequently FortisBC does not face this risk factor. Newfoundland Power owns two small thermal generating facilities, but these account for a very small proportion of the power that it delivers, as Newfoundland Power obtains over 90 percent of its power from Newfoundland and Labrador Hydro. Maritime Electric owns two thermal generating stations, but it mainly sources its power supply from other off-island utilities. The primary functions of Maritime Electric's own thermal generation are for peaking and for supply security in case off-island supply is not available. Neither Newfoundland Power nor Maritime Electric face any material risk associated with renewable energy supply goals and penalties or federal GHG targets. This is a risk that is unique to NSPI.

Risks Related to FAM Deferrals

Regarding FAM deferrals, none of the Alberta utilities listed above produce, purchase or sell electricity, so they have no purchased power costs or fuel costs that would be exposed to deferral of recovery. The Ontario utilities purchase power from the Ontario wholesale market. Commodity cost rates for the purchased power are set province-wide by the Ontario Energy Board on the basis of forecasts and differences between the forecast and actual commodity rates accrue in deferral accounts and are either recovered from or returned to customers through subsequent commodity rates. While there may be some risk that recovery of differences between actual and forecast commodity costs could be deferred, since the commodity costs are the same for all distributors, a decision to do so would likely be imposed province-wide. Moreover, in contrast to NSPI, the Ontario utilities do not bear the responsibility for the acquisition of or the price paid for power.

As regards Newfoundland Power, as noted above, it acquires over 90 percent of its power from Newfoundland and Labrador Hydro. Differences between forecast and actual power costs, which relate largely to the amount and cost of power produced by Newfoundland and Labrador Hydro's one major thermal plant (which accounts for less than one-quarter of its regulated generation; the remainder is hydroelectric), are flowed through to customers through its Rate Stabilization Account over the subsequent 12 months. Though deferral of recovery of differences between actual and forecast power costs is possible, the amounts that accrue in Newfoundland Power's RSA are typically quite small in relation to its total purchased power costs. With respect to FortisBC, the company produces approximately 45 percent of its energy requirements with company-owned hydroelectric generating plants. Approximately 95 percent of its energy requirements and 80 percent of its peak capacity requirements are met either with owned generation or long-term contracts for power from hydroelectric plants.

The specifics of FortisBC's contracts eliminate any exposure to water flow risk. For the remaining energy and peak capacity requirements, FortisBC is allowed to recover all prudently forecast and actual purchased power costs from customers. Given the small amount of power produced or purchased that is not generated by hydroelectric facilities, the risk of deferral of recovery of differences between actual and forecast purchased power costs is minimal. As regards Maritime Electric, the utility has experienced material deferred recovery of actual purchased power costs, as discussed in McShane evidence at pages 42-43 of Appendix F. Overall, the risk is higher for NSPI than for any other of the Canadian electric utilities with the exception of Maritime Electric.

Risks Related to Increased Capital Program

With respect to the risk associated with the increased capital program and risk of recovery of capital in a timely manner, as noted at page 43 of McShane's evidence, the requirements for approval of projects and inclusion of those projects in rate base is materially the same across jurisdictions. There are some differences in relative scale of capital expenditures. Neither Newfoundland Power nor Maritime Electric is facing large capital programs. However most of the other utilities listed above are, including FortisBC, the Alberta utilities and the Ontario utilities. There is no indication in the debt rating reports of any of these utilities that timely inclusion of completed projects in rate base is a concern. In the case of the Alberta transmission utilities, where there are large multi-year projects direct assigned by the Alberta Electricity System Operator, decisions of the regulator have indicated a willingness to provide additional regulatory support as required to maintain credit metrics throughout the large capital build period. This support includes an increase in the allowed common equity ratio, inclusion of construction work in progress in rate base (with a cash return thereon), and the ability to recover future income taxes in rates on a current basis.

<u>Risks Related to Extreme Weather Events</u>

Of all of the Canadian electric utilities listed above rated by DBRS, NSPI is the only one whose risk related to extreme weather events has merited comment by DBRS.

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Request IR-94:

Reference: NSPI GRA Section DE-03 – DE-04, Page 105

Please provide all support for the projection of Commercial Paper interest rate of 2.5% to 4.0%. Please also identify the short-term Commercial Paper rate over the last two years.

Response IR-94:

Please refer to Confidential Attachment 1.

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Request IR-95:

Reference: NSPI GRA Section DE-03 – DE-04, Appendix F, Kathleen C. McShane's Expert Opinion on Capital Structure and Return on Equity

On an electronic spreadsheet with all formulas intact, please provide all analyses, schedules or investigation conducted by NSPI witness Kathleen C. McShane to support her evidence in this proceeding.

Response IR-95:

In addition to the documents referenced or filed in response to CA IRs 8-16, 19 and 21, additional documentation and analyses are provided as follows:
(Hardcopy documents are available for viewing at NSPI Offices.)

Analyses and Investigation		
Attachment	**Document Attached**	**Format**
1	Canada Bonds Outstanding 1996 2010	electronic
2	Canadian Betas Monthly Weekly Comparison	electronic
3	Chart 2 IFIC Quarterly Equity and Bond Net Sales	electronic
4 Confidential	Chart 3 DEX and 30 Year Spread	electronic
5	Chart 4 State Street Investor Confidence Index	electronic
6 Confidential	Conf Brd Provincial Outlook Canada Nova Scotia	hardcopy
7 Confidential	Conf Brd Winter Outlook 2011 NS Table	hardcopy
8	Difference in Financial Risk 40 vs 50 Equity Ratio	electronic
9	Internation Investment Position US portion Cdn direct investment	electronic
10	Intl Transactions Bond Purchases December 2010	electronic
11	MVX Data	electronic
12	Nortel Market Weights Monthly	electronic
13	NSPI FortisBC Generated Power Percent	electronic
14	Prices TSX and Capped Income Trust Index	electronic

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15	S&P PE Ratios 1926 to 2010	electronic
16	S&P Sector Breakdown S&P 500 Jan 5 2011	hardcopy
17	Stats Canada Canadas International Investment Position 3Q 2010	hardcopy
18	Table 8 10 Year Average Canadian Market Returns	electronic
19	Table 9 Sorted Canadian Risk Premiums	electronic
20	Tables 13 and 14 TSX Utilities Regressions	electronic
21	Trusteed Pension Funds Mkt Value 2010 Q2	electronic
22 Confidential	TSX Review December 2010 20 largest companies	hardcopy
23 Confidential	TSX Review December 2010 Sector Breakdown	hardcopy
24	Value Line Enbridge	hardcopy
25	Value Line TransCanada	hardcopy
Schedule 2		
26 Confidential	RRA extract Rate Case Decisions Jan to December 2010	hardcopy
27 Confidential	Schedule 2 page 2 US Allowed ROE	electronic
Schedule 4		
28	Canadian Capital Structures Electric Pipelines	electronic
	Schedule 5	
29	Capital Structures Cdn utilities Trailing 4 Quarters	electronic
30	Capital Structures US Sample Trailing 4 Quarters	electronic
Schedule 7		
31	Historic Equity Market Risk Premiums US Canada	electronic
Schedules 8, 9 and 10		
32	Schedules 8 9 and 10	electronic
Schedule 11		
33	Schedule 11 Cdn Utility Betas Rsqr	electronic
Schedule 12		
34 Confidential	S&P Issuer Ranking US Gas	hardcopy
35 Confidential	S&P Issuer Ranking US Electric	hardcopy
36	Schedule 12 2007 to 2009 Average Earned Returns	electronic
37	Schedule 12 VL	electronic
38	Schedule 12 Weekly Betas vs NYSE ending December 2010	electronic
39	EEI Backup	hardcopy
40	EIA Restructuring Status September 2010	hardcopy
41 Confidential	RRA State Regulatory	hardcopy

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42	Sample Selection	electronic
	Schedule 13	
43 Confidential	Blue Chip	hardcopy
44	DCF RP	electronic
45 Confidential	Three Stage Model	electronic
	Schedule 14	
46 Confidential	App ROE Regressions	electronic
47 Confidential	RRA 1995-1998	hardcopy
48 Confidential	RRA 1998-2004	hardcopy
49 Confidential	RRA 2004-2010	hardcopy
	Schedule 15	
50 Confidential	Mergent Gas Distribution Index 1985 2001	hardcopy
51 Confidential	Moody Electric Index F Confidential 1998-2001	hardcopy
52 Confidential	S&P Electric Index 1947-1973	hardcopy
53 Confidential	S&P Electric Index 1974-98	hardcopy
54 Confidential	S&P Gas Index 1947 1984	hardcopy
55	S&P Moodys Electric Index 1947 2001	electronic
56	S&P Moodys Electric Index 2002 onwards	electronic
57	S&P Moodys Gas Index 1947 1984	electronic
58	S&P Moodys Gas Index 1985 2001	electronic
59	S&P Moodys Gas Index 2002 onwards	electronic
60	Schedule 15 Utility Returns US and Canada	electronic
	Schedules 16 - 20	
61	Canadian Utilities Sample Daily Prices Oct-Dec 2010	electronic
62	Canadian Utilities Sample Dividends	electronic
63	Canadian Utilities Three state DCF	electronic
64 Confidential	Consensus Forecast Oct 2010	hardcopy
65	Electric Utilities Sample Daily Prices Oct-Dec 2010	electronic
66	Electric Utilities Sample Dividends	electronic
67	US Electric Utilities Three stage DCF	electronic
68	Value Line Sustainable Growth	electronic
69	Value Line Sheets	hardcopy
Electronic Version of the Schedules		
70	McShane Schedules	electronic

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Request IR-96:

Reference: NSPI GRA Section DE-03 – DE-04, Appendix F, Kathleen C. McShane's Expert Opinion on Capital Structure and Return on Equity

Please provide copies of all rate orders for Canadian utility companies setting authorized returns on equity reviewed by Ms. McShane or NSPI in supporting their determination of a fair and just return on equity in this proceeding.

Response IR-96:

The following requested rate orders are available for viewing at NSPI offices:

Attachment	Document Attached
1	AUC Decision 2009-216 2009 GCOC
2	BCUC G-35-94 ROE1994 Generic Decision
3	BCUC Terasen Utilities 2009 ROE Capital Structure
4	IAT Report 8-25-99 Rev of 7-9-99 Proceeding 990277
5	Manitoba PUB Order 49-95 Centra Gas
6	NEB Multi-Pipeline RH-2-94 Review Decision 2009
7	NEB Reasons for Decision RH-2-94
8	Newfoundland Labrador PU 16 (1998-1999)
9	Newfoundland Labrador PU 43 (2009)
10	Northwestern 1929
11	OEB 1997 EBRO 495 Consumers Gas
12	OEB Report of the Board Cost of Capital 20091211
13	PEI Order-UE10-03-MECL Rate App CTC
14	REGIE Gaz Metro D-99-11
15	REGIE Gaz Metro D-2009-156
16	TQM Reasons for Decision RH-1-2008
17	NSPI Order P-888(2) – January 2010
18	NSPI NSUARB-NSPI-P-886 February 2007
19	NSPI-P-881 March 2005
20	NSPI biomass project 2010
21	NSPI Decision NSUARB P- 888 November 2008
22	NSPI FAM conditional approval December 2007

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Request IR-97:

Reference: NSPI GRA Section DE-03 – DE-04, Appendix F, Kathleen C. McShane's Expert Opinion on Capital Structure and Return on Equity

Please provide complete copies of all materials cited in support of assertions and positions taken by Ms. McShane in this proceeding.

Response IR-97:

The following requested materials are available for viewing at NSPI offices:

Attachment	Document Attached
1	Bank of Cda Financial System Review December 2004
2	Bank of Cda Financial System Review December 2005
3	Bank of Cda Financial System Review June 2006
4	Bank of Cda Financial System Review December 2006
5	Bank of Cda Financial System Review December 2007
6	Bank of Cda Financial System Review December 2010
7	Bank of Cda Financial System Review June 2007
8	BMO Taylor 2007 ROE Assessment December 2006
9	Bonbright *et al* Principles of Public Utility Rates-- pg 317
10	CEPA -- Perspective on Canadian Gas Pipeline ROEs 2008
11	CGA – Natural Gas Utility Return Determination in Canada 2008
12	CIBC World Markets Time to Lighten Up 12-3-01
13 Confidential	Consensus Economic March 2011
14 Confidential	Consensus Economics December 2004
15	FCC Docket 92-133 1995
16	Foreign Affairs Canada State of Trade 2010
17	IFIC Assets by Class December 2010 (excel format)
18	IMF Global Financial Stability Report Oct 2010
19	Monetary policy report -- July 2007
20	Monetary policy report -- October 2005
21	Monetary Policy Report January 2011
22	NEB Hydrocarbon Transportation 2007
23	NEB HydrocarbonTransportation2006
24	Stats Can International Transactions in Securities December 2010

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Request IR-98:

Reference: NSPI GRA Section DE-03 – DE-04, Appendix F, Kathleen C. McShane's Expert Opinion on Capital Structure and Return on Equity

Please provide complete copies of all reference materials used to develop Ms. McShane's discounted cash flow studies, risk premium studies and selection of comparable risk utility groups.

Response IR-98:

The requested reference materials used to develop the discounted cash flow studies and the selection of comparable risk utility groups are filed in response to NPB IR-95 with the relevant schedules. The reference materials for the risk premium studies as they relate to the schedules are filed in response to NPB IR-95; the following additional references materials is available for viewing at NSPI offices:

Attachment	Document Attached
1 Confidential	Blue Chip Financial Forecast December 1 2010
2 Confidential	Blue Chip Financial Forecast February 1 2011
3	Brealey *et al* Principles of Corporate Finance 2006 page 151
4	Bruner *et al* Best Practices in Estimating the Cost of Capital
5	Burgess Fried PIAC Foreign Property
6	Canada Dept Finance Canada Economic Action Plan 3 2011
7	Carrick Your Bottom Line RTGAM.20050223
8	Chen Roll Ross Economic Forces and the Stock Market 1986
9	Dimson Marsh Staunton Triumph of the Optimists p. 182
10	Fama French CAPM Theory and Evidence 2004
11	Harrington Modern Portfolio Theory pp 188-189
12	Harris Marston Estimating Shareholder Risk Premia
13	Hockin Paving the Way
14	Ibbotson 1998 Yearbook pages 157-159

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15	Ibbotson 2010 Valuation Arithmetic Average
16	IFIC Year 2002 Review
17	Malkiel Random Walk 2003 pages 240 241
18	Oliver IDA Speech 2002
19	PIAC Foreign Property Rule Nov 2002
20	Ross Is Beta Useful

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Request IR-99:

Reference: DE, Section 5.3 Pension Costs, pages 69-72

Please provide:

(a) **The last two actuarial reports filed with the Superintendent of Pensions in accordance with the requirements in the Pension Benefits Regulations ("PBR") in respect of each pension plan for which NSPI has contribution obligations (the "NSPI RPPs");**

(b) **Any unfiled actuarial report, whether a current draft or finalized, prepared in respect of the NSPI RPPs and any supplementary, executive, and discretionary pension arrangements for which NSPI has contribution obligations or current or future liability (the "NSPI SERPS") for any period ending in 2008, 2009, 2010, or 2011 (the "Applicable Years");**

(c) **Any extrapolation or other actuarial funding estimate for any NSPI RPP or the NSPI SERPS that predicts, anticipates, or analyses contribution requirements and liabilities under the PBR or otherwise and prepared in respect of the Applicable Years;**

(d) **Any documentation related to efforts by NSPI to obtain solvency relief under the PBR in respect of any of the NSPI RPPs, including analysis by actuarial consultants or others of the benefits of obtaining such relief, any communications to employees or employee groups and trade unions in respect of such relief, any internal documents in respect of solvency relief, any filings or communications with the Superintendent of Pensions in respect of such relief, and any other documentation in respect of all NSPI RPPs;**

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(e) **Any documentation relating to the investments of the NSPI RPPs and NSPI SERPS or any master trust in which the NSPI RPPs were invested in respect of the Applicable Years provided by the actuarial consultant, asset consultant or investment advisor, or internal staff in respect of the NSPI RPPs, including the investment returns earned in each of those years, asset allocation in each of those years, analysis showing the performance of NSPI RPPs or NSPI SERPS relative to a universe of other pension plans, and reports by any asset consultant, investment advisor or internal staff;**

(f) **The Statement of Investment Policies and Procedures as required under the PBR and any amendments thereto in respect of each NSPI RPP in force in the Applicable Years and any similar document in respect of the NSPI SERPS;**

(g) **The annual information return filed under the PBR in respect of each NSPI RPP in respect of the Applicable Years;**

(h) **Any other communications between NSPI or its agents and the Superintendent of Pensions in respect of the NSPI RPPs during the Applicable Years;**

(i) **Copies of the plan text and each amendment for each NSPI RPP and NSPI SERP in force in respect of the Applicable Years;**

(j) **Current Collective agreements in respect of any trade unions which represent employees which participate in any of the NSPI RPPs;**

(k) **Copies of any governance policy adopted by the Board of Directors of NSPI (the “Board”) in respect of the NSPI RPPs;**

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(l) **Any documentation respecting consideration by NSPI to enter into defined contribution pension plans either for existing employees or new employees, including any internal analysis, advice from outside consultants, communications with trade unions or employees, or other documentation during the Applicable Years, inclusive;**

(m) **Any documentation respecting consideration by NSPI to change employee contribution levels to any of the NSPI RPPs or NSPI SERPS, including any internal analysis, advice from outside consultants, communications with trade unions or employees, or other documentation during the Applicable Years;**

(n) **Any documentation respecting consideration by NSPI to change benefit levels for any of the NSPI RPPs or NSPI SERPS, including any internal analysis, advice from outside consultants, communications with trade unions or employees, or other documentation during the Applicable Years;**

(o) **Copies of agreements, contracts, plan texts, booklets or any other documents that establish a legal obligation by NSPI to provide post employment benefits, excluding benefits provided by the NSPI RPPs or the NSPI SERPS (the "NSPI OPEB");**

(p) **Any documentation respecting consideration by NSPI to change the NSPI OPEB, including any internal analysis, advice from outside consultants, communications with trade unions or employees, or other documentation during the Applicable Years; and**

(q) **For the Applicable Years, Relevant Minutes of the Board, any Board committee or committee of NSPI management to which the Board has delegated responsibility for the sponsorship or administration of the NSPI RPPs, NSPI SERPS or NSPI OPEB.**

In this Information Request, "Relevant Minutes" means minutes that relate to the NSPI RPPs, NSPI SERPS, or NSPI OPEB).

Response IR-99:

(a) Please refer to Attachment 1, available for viewing at NSPI offices, for the two most recent actuarial reports for NSPI's registered pension plans, as at December 31, 2008 and December 31, 2009, filed with the Superintendent of Pensions for each of the NSPI Employees Pension Plan and NSPI Acquired Companies Pension Plan.

(b) Since privatization, NSPI has filed annual valuation reports with the Superintendent of Pensions in respect of the NSPI RPPs. A draft report in respect of the December 31, 2010 valuation has not yet been prepared.

Please refer to part (c) (i), (x), (xi), (xiii), and (xiv) for the accounting reports and management presentations for information related to the NSPI SERPs.

(c) Please refer to the following Attachments:

(i) Confidential Attachment 2 for presentations made by Morneau Shepell (formerly Morneau Sobeco) in 2008, 2009 and 2010 to NSPI's Pension Committee.

(ii) Confidential Attachment 3 for a presentation made by Morneau Shepell to the Union Executive in 2010.

(iii) Confidential Attachment 4 for a letter dated August 3, 2010 to Towers Watson regarding information requested for an asset liability study.

(iv) Confidential Attachment 5 for a letter dated July 27, 2009 with projections for 2009 and 2010.

(v) Confidential Attachment 6 for a memo dated January 8, 2009 with contribution projections from 2007 to 2025 under the existing and proposed pension legislation.

(vi) Confidential Attachment 7 for a memo dated November 13, 2008 regarding the impact of proposed pension legislation changes.

(vii) Confidential Attachment 8 for a memo dated November 12, 2008 regarding projected 2009 contributions.

(viii) Liberty IR-81 Attachment 1 for a letter dated February 19, 2008 which includes projected contributions for 2009 for each plan in Appendix B.

(ix) Confidential Attachment 9 for a draft letter dated November 30, 2007 which includes projected contributions from 2009 to 2012 in Appendix B.

(x) Attachment 10 for the December 31, 2007 Accounting Valuation Report. Please refer to Appendix D for the projected contributions for 2008 for each plan.

(xi) Attachment 11 for the December 31, 2008 accounting valuation report. Please refer to Appendix D for the projected contributions for 2009 for each plan.

(xii) Attachment 12 for the December 31, 2007 actuarial valuation report for each of the NSPI RPPs.

(xiii) Liberty IR-81 Attachment 2 for the December 31, 2009 accounting valuation report. Please refer to Appendix D for the projected contributions for 2010 for each plan.

(xiv) Liberty IR-80 Attachment 1 for the December 31, 2010 accounting valuation report. Please refer to Appendix D for the projected contribution for 2011 for each plan.

(xv) Liberty IR-85 Attachment 1 for a letter dated March 11, 2010 for the projected contribution for 2011 for each plan included in Appendix B.

(xvi) Please refer to part (a).

(xvii) Please refer to the Application, RB-02—RB-16, Attachment 2 for a letter dated January 31, 2011 for analysis prepared during 2011 but in respect of 2012 to 2016 included in Appendix B.

(d) NSPI was advised of the potential for solvency relief as permitted by pension legislation but deemed that it was not worthwhile to pursue it for the following reasons:

(i) The trade union represents approximately 50 percent of the active members and could veto the request;

(ii) The ability to take solvency relief only applies to the first actuarial report filed after December 30, 2008. As NSPI files annual valuations, the December 31, 2008 valuation report showed that the Employees plan did not have solvency funding requirements and the Acquired Companies Plan only had a total of $43,000 in solvency funding requirements, and so the solvency relief would not have had a material impact; and

(iii) Solvency relief only delays contributions requirements, it does not necessarily eliminate contribution requirements.

NSPI made submissions to the pension review panel to object to potential proposed changes to funding rules which would have significantly increased NSPI's funding requirements.

NSPI has not pursued solvency relief otherwise.

(e) Please refer to Confidential Attachment 13, available for viewing at NSPI offices, Confidential Attachment 14 and part (c) (xii) and (xvi) for Investment Analytics Reports, internal presentations and information included in actuarial reports related to investments.

(f) Please refer to Confidential Attachment 15 for the Statement of Investment Policies and Procedures.

(g) Please refer to Attachment 16 for the December 31, 2008, 2009 and 2010 Annual Information Returns.

(h) NSPI's communication to the Pension Superintendent during the Applicable Years relate primarily to the following:

(i) filing of valuation reports; and

(ii) providing requested information on plan amendments and additional information on annual information returns

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The Pension Superintendent's communication with NSPI during the Applicable Period has been primarily related to administrative issues related to the above.

(i) Please refer to Attachment 17 for a consolidated version of the NSPI Employees Plan text up to and including Amendment 12. Please refer to Confidential Attachment 18 for a draft of amendment 13 which has not been filed with the Superintendent.

Please refer to Attachment 19 for a consolidated version of the NSPI Acquired Companies Plan text up to and including Amendment 7. Please refer Confidential Attachment 20 for draft amendment 8 which has not been filed with the Superintendent.

Please refer to Confidential Attachment 21 for a copy of the plan text for NSPI SERP.

(j) Please refer to Liberty IR-24 Attachment 2.

(k) Please refer to Confidential Attachments 22 and 23.

(l) NSPI provided a one-time option in 2001 for non-union members to switch from defined benefit to defined contribution for future service. All NSPI non-union employees hired after 2000 have the option to join either the defined benefit or defined contribution provision of the registered pension plan.

While it was intended that the defined contribution provision would also be available to union members, the union executive has indicted that they do not wish to allow union members to join the defined contribution provision of the Plan. NSPI respects this position since the pension plan terms are negotiated as part of the collective bargaining process.

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During June of 2010, NSPI management prepared an internal analysis of pension and benefits including a comparison of defined benefit versus defined contribution pension plans. Please refer to Confidential Attachment 24. NSPI has modified the presentation to remove personal information.

(m) Please refer to Confidential Attachment 24, Appendices A-2, C, E and F. There has been internal discussion related to this matter, but no additional formal documentation.

(n) Please refer Confidential Attachment 24, Appendices A to F.

(o) Please refer to Confidential Attachment 25 for documentation related to post employment benefits. Union employees have the choice between the NSPI and Emera benefit plans.

(p) NSPI reviewed the pension plan and group benefits plan in 2010 as part of a total compensation review, however this review did not include consideration by NSPI to change the NSPI OPEB. Please refer to Confidential Attachment 24.

(q) NSPI will provide Board minutes and Board committee minutes to the UARB upon request. Please refer to Confidential Attachment 26 for copies of the Management Pension Committee Minutes. Please note that privileged references or references to non-NSPI matters, have been removed as shown by the blacked out portions of the text.

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Request IR-100:

Reference: Binder SF0065, Tab "Recommendation"

Please provide the calculation that supports the [redacted]

Response IR-100:

API4 Cal 11 (November 24, 2010) minus basis differential of [redacted]: FOB [redacted]

Delivered price converted to Canadian dollars: [redacted]

Fully Evaluated Price [redacted]

Price per MMBtu = [redacted]

[redacted]

Delivered price, converted to Canadian dollars: [redacted]

Fully Evaluated Price [redacted]

Price per mmbtu = [redacted]

Total MMBtus supplied by [redacted]

Cost benefit of supplying these MMBtus with [redacted]: [redacted]

[redacted] in Binder SF0065 Tab "Recommendation".

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Request IR-101:

Reference: OE-01H and Liberty IR-77

(a) Please provide the full calculation and assumptions for the forecast ocean freight costs on a $/MT basis as provided in OE-01H.

(b) Please summarize all steps taken by NSPI to reduce its freight costs given current market conditions. In particular, please indicate whether NSPI has considered [redacted].

(c) Please provide an update with respect to any current negotiations for ocean freight in 2012 and indicate how the result of these negotiations is expected to compare with the estimates included in the BCF forecast.

Response IR-101:

(a) Lingan and Point Aconi are fed from the International Pier. Trenton #5, Trenton #6, and Point Tupper are fed from Point Tupper Marine Terminal (PTMT). Please refer to Confidential Attachment 1 for the ocean freight prices broken down for each terminal.

(b) In August 2010, NSPI declared [redacted]

(c) NSPI is monitoring market freight prices which are estimated to continue to [redacted]. NSPI will review 2012 freight requirements in Q3 2011 in preparation for the 2012 [redacted]. As PTMT is the only discharge port that can accept bulker vessels, before going out to

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market, NSPI will review open freight tonnage requirements for 2012, current freight contracts, freight contract [redacted], discharge port capacity, as well as the flexibility option between Sydney International Pier (INP) and PTMT in regards to the belted self-unloader vessels.

REDACTED

Request IR-102:

Reference: Liberty IR-74.

[redacted].

(a) Please summarize the status of the steps taken in 2011 to [redacted] and identify the potential options and savings as compared [redacted].

(b) Please indicate whether it remains NSPI's intention to [redacted].

Response IR-102:

(a) Mid-sulphur coal from a single test cargo that was sourced [redacted] was tested at the Point Aconi plant in Q1 2011**.** A second source of mid-sulphur coal from [redacted] was also tested and this testing will continue following Point Aconi's maintenance shutdown in Q3 2011. The tests indicate that the Point Aconi plant is able to consume blends of mid-sulphur coal [redacted]. The timing and magnitude of longer, sustained tests on these fuels will be subject to price proposals that are being sought for mid-sulphur coal and petroleum coke supply for 2012. Potential options and savings compared to the consumption of petroleum coke are based on the price difference between mid-sulphur coal and petroleum coke in 2012, and unit performance parameters related to coal chemistry such as total percent sulphur in the blend. In the GRA 2012 Forecast, the forecasting methodology, [redacted]

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[redacted]. In contrast, the latest PACE index published for Q1 2011, [redacted]. The March 31 2011 [redacted]. These values represent a price spread between mid-sulphur [redacted] coal and petroleum coke of [redacted]. As discussed, further testing will be required to confirm the quantity of mid-sulphur coal that can be consumed over the long-term at Point Aconi.

(b) It is NSPI's intention to continue testing mid-sulphur coal at Point Aconi to establish longer-term effects on reliability. The quantity of mid-sulphur coal that would be purchased to continue this testing will be dependent on the price differential between petroleum coke and mid-sulphur coal received through RFP for 2012 supply. Mid-sulphur coal purchased will displace petroleum coke open position, [redacted].

REDACTED

Request IR-103:

Reference: Binder SF0068, “External Recommendation”, February 2011, page 8

Has NSPI taken up (or is it NSPI’s intention to take up) the EVA recommendation that it [redacted]?

Response IR-103:

Natural gas pricing has resulted in [redacted]. The 2012 open position for all commodities has thus [redacted]. Of the individual commodities left to purchase for 2012, the open position for low sulphur coal [redacted]. To conserve the overall open position, NSPI will purchase commodity by commodity beginning with [redacted]. NSPI’s intention is to return to the market late in the second quarter or early third quarter to evaluate [redacted]. NSPI’s further intention is to return to the market during the third quarter to evaluate proposals for [redacted].

REDACTED

Request IR-104:

Reference: OE-01K

Please provide the weekly forward price strips [redacted] for low sulphur coal for the months October 2010 to June 2011.

Response IR-104:

NSPI has proprietary access to [redacted] information for the months October 2010 to June 2011 and can make this data available for scheduled viewing upon request.

REDACTED

Request IR-105:

Reference: Binder GE0019, [redacted]

[redacted]

Response IR-105:

The Import Power Scheduling Services Contract, [redacted], found in Binder GE0019 contains a [redacted] for day-ahead imports and a [redacted] for real-time and day-ahead exports, compared to the previous contract.

Day-Ahead imports from [redacted] percent of total imports in 2010. Applying the [redacted] of the 484,000 MWh of forecasted imports in 2012 yields [redacted].

Exports to [redacted] of total exports in 2010. Applying the [redacted] 35,000 MWh of forecasted exports in 2012 yields [redacted]

REDACTED

Request IR-106:

Reference: NG0013, [redacted]

(a) [redacted]

(b) [redacted]

(c) [redacted]

Response IR-106:

(a) Please refer to Binder NG0013, Tab called "Evaluation", page 4 (available for viewing at NS Power offices).

(b) [redacted]

(c) Yes.

REDACTED

Request IR-107:

Reference: Binder GE0028, Import Power Price Strips

Please explain and provide the basis for the following assumptions:

(a) [redacted]**;**

(b) **"System Losses" of 3.3%; and**

(c) **Transmission charge of $6.07 (on peak) and $2.88 (off peak).**

Response IR-107:

The referenced information is contained within binder GE0022.

(a) Please refer to Liberty IR-94.

(b) "System Losses" refer to total amount of electric energy loss in an electric system between the generation source and points of delivery. The transmission system average loss factor is established by the New Brunswick System Operator (NBSO) in the Open Access Transmission Tariff, and is currently 3.3 percent. This information can be found in Section 15.7 page 35 of the Open Access Transmission Tariff on the NB System Operator (NBSO) website:

http://www.nbso.ca/Public/en/docs-EN/Tariff/TARIFF%20(April%201%202011).pdf

(c) The tariff fee charged by NBSO to use their transmission lines during on-peak hours is $6.07/MWh. The tariff fee charged by NBSO to use their transmission lines in off-peak

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hours is $2.88/MWh. Refer to schedule 8 sections 5 and 6 on the NB System Operator website noted above.

REDACTED

Request IR-108:

Reference: Binder GE0028, Adjustments. [redacted].

(a) **Please confirm that the current 2012 BCF forecast assumes** [redacted].

(b) **Please provide a breakdown for the last two years (by month if possible) of the percentage of NSPI import purchases in both on-peak and off-peak periods.**

Response IR-108:

(a) Confirmed.

(b) Please refer to Liberty IR-96, Attachment 1.

REDACTED

Request IR-109:

Reference: Binder GE0024, [redacted]

[redacted]

(a) Please indicate what follow-up efforts NSPI undertook with [redacted]

(b) Has NSPI given consideration to purchasing import power on a basis other than [redacted]

(c) Has NSPI given consideration to purchasing more or less than 100 MW of firm import on a larger than daily basis term power as part of its RFP?

(d) Did NSPI give any consideration to conducting an RFP for import power in [redacted]

Response IR-109:

(a) Although firm transmission was available [redacted], there was no firm transmission available [redacted] so there was no opportunity in this period [redacted].

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(b) NSPI has recently submitted an RFP to the market for the summer months of 2011 (July and Aug) as a package. We will also evaluate the coming months to decide if [redacted] opportunities exist.

(c) NSPI has purchased both more than and less than 100MWh [redacted]. In [redacted], NSPI completed [redacted] transactions that totaled [redacted]. In [redacted], NSPI completed [redacted]. On a forward basis, we will entertain and evaluate offers both below and in excess of the 100MWh RFP ask. Market and generation fleet conditions will dictate the amount of MWhs requested through the RFP process.

(d) Yes, however, there was no firm transmission available [redacted] for the months [redacted]

REDACTED

Request IR-110:

Reference: Confidential Data Room Solid Fuel Procurement

Please identify the number of times that NSPI solicited the market for solid fuel in the years 2006, 2007, 2008, 2009 and 2010. Please also identify the number of times in each year in which NSPI chose not to procure solid fuel as the result of its solicitation.

Response IR-110:

The response to this request is confidential.

NON-CONFIDENTIAL

Request IR-111:

Reference: DE, page 39. "As the graph indicates, natural gas prices are expected to remain below HFO prices throughout 2012."

(a) **Considering current levels of natural gas pricing, please indicate what efforts NSPI has taken to evaluate the use of natural gas at Burnside units. Please provide all information and analysis carried out by NSPI in the last two years.**

(b) **Please indicate if NSPI has carried out any evaluations regarding the potential use of natural gas at any of its other plants. If so, please provide all information carried out by NSPI in the last two years.**

Response IR-111:

(a) NSPI is in the process of conducting a detailed lifecycle assessment for the entire liquid-fueled combustion turbine fleet, including Burnside. The report is expected to be completed by Q3. The results of this work will help determine the future investment plans for these units including the potential to carry out a fuel conversion to natural gas.

(b) Please refer to NPB IR-60.