Request IR-62:

With respect to NSPI(Multeese) IR-7(a),

a) What is the Planning Reserve Margin that NSPI is required to maintain?

b) Please provide a table showing for the years 2012 - 2022 forecast available firm capacity (including both NSPI resources and firm purchases), firm peak demand, and reserve margin in both MW and %.

Response IR-62:

(a) NS Power maintains a minimum planning reserve margin of 20 percent above forecasted firm peak demand in order to comply with Northeast Power Coordinating Council (NPCC) reliability criteria. Failure to comply with these requirements would jeopardize NS Power's ability to connect to other neighbouring jurisdictions.

(b) Please refer to the figures below for NS Power's existing firm capacity in 2012 and the loads and resources figure from NS Power's 2012 10 Year System Outlook, filed on June 29, 2012.[1]

2012 Firm Capacity	**MW**
Steam	1568.0
Combined Cycle	146.7
CT	189.0
Hydro	381.1
Pre-2001 IPP Renewables	25.8
Post-2001 IPP Renewables (assumed firm capacity*)	72.9
NSPI Owned Wind (assumed firm capacity*)	28.8
Total Existing Firm Capacity	**2412.0**

*Assumed capacity values for wind generation are being re-evaluated in the Renewables Integration Study presently underway.
Note: Independent Power Producer (IPP), Combustion Turbine (CT)

[1] NSPI 10 Year System Outlook, 2012-2021 Report, NSUARB-NSPI-P-194, June 29, 2012.

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Load and Resources Outlook for NSPI - Winter 2012/2013 to 2021/2022

(All values in MW except as noted)

		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
A	Firm Peak Load Forecast	2,006	2,024	2,040	2,056	2,081	2,102	2,131	2,158	2,183	2,203
B	DSM Firm	49	71	95	121	147	174	201	228	255	282
C	Firm Peak Less DSM (A - B)	1,958	1,953	1,945	1,935	1,933	1,928	1,930	1,930	1,928	1,921
D	Required Reserve (C x 20%)	392	391	389	387	387	386	386	386	386	384
E	Required Capacity (C + D)	2,349	2,344	2,334	2,322	2,320	2,314	2,316	2,316	2,313	2,305
F	Existing Resources	2412	2412	2412	2412	2412	2412	2412	2412	2412	2412
	Total Cumulative Additions:										
G	Thermal[1]	0	0	0	-120	-120	-273	-273	-273	-273	-273
H	Hydro [2]	0	0	0	0	0	4	4	4	4	4
I	Contracted Wind (Firm capacity)[3]	15	15	15	15	15	15	15	15	15	15
J	Biomass[4]	0	10	10	63	63	63	63	63	63	63
K	Community Feed-in-Tariff[5]	0	6	11	17	26	34	34	34	34	34
L	Maritime Link Import [6]	0	0	0	0	0	155	155	155	155	155
M	Total Firm Supply Resources (F + G + H + I + J + K + L)	2428	2443	2449	2388	2396	2411	2411	2411	2411	2411
	+ Surplus / - Deficit (M - E)	79	99	115	65	76	97	95	95	98	106
	Reserve Margin % (M/C -1)	24%	25%	26%	23%	24%	25%	25%	25%	25%	26%

Notes:

[1] Thermal includes Burnside #4 (winter capacity 33 MW) assumed to be returned to service in 2015. Also includes assumed retirement dates of solid fuel unit(s) for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial regulations.

[2] Amount shown as Hydro includes a small capacity addition to NS Power's existing generation fleet.

[3] Contracted Wind (Firm capacity) reflects the assumed firm capacity contribution based on a combined three-year average of actual capacity factor during peak hours and the annual forecasted value (as per a formula agreed on by NS Power and the Renewable Energy Industry Association of Nova Scotia and as employed in NS Power 2009 IRP Update modeling). These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

[4] Biomass includes the PH Biomass Project and a small IPP. The PH Biomass Project is currently registered for Energy Resource Interconnection Service (ERIS) but will be transitioned to firm capacity as a network resource through an application under the GIP coincident with the assumed retirement of a solid

fuel unit. The assumed retirement dates of solid fuel unit(s) are for planning purposes in order to comply with federal environmental regulations, and are subject to adjustment due to equivalency with provincial regulations.

[5] The Community Feed-in-Tariff represents distribution-connected renewable energy projects as outlined in the Province's Renewable Electricity Plan in April 2010. The projects are assumed to be phased-in over 5 years starting in 2014. The value in the table is the assumed firm capacity value of intermittent generation for small-scale projects. For long-term planning purposes the firm capacity value is based on an assumed 34 percent capacity factor as estimated by the provincial government. For short-term assessments (e.g. 18-month Load and Capacity Assessment) the assumed capacity factor may be less. These assumed capacity values are being re-evaluated in the Renewables Integration Study presently underway.

[6] Maritime Link Import is RES compliant hydro energy assumed to be from the Muskrat Falls project in Newfoundland and Labrador and will largely achieve the incremental requirements of the 2020 RES target of 40 percent renewable energy. This firm capacity import and the forecast retirement of a solid fuel unit are assumed to coincide.

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Request IR-63:

Further to NSPI (Liberty) IR-39 which derives the $110 million, NSPI (Multeese) IR-18(d) which indicates that NSPI is not seeking protection against ROE less than 9.1%, and NSPI (Liberty) IR-44(b) which suggests that FAM adjustments do not contribute to the $110 million, please identify all factors that could lead to a deferral greater than $110 million at the end of 2014.

Response IR-63:

Liberty IR-39 asked for an illustrative example of how the rate stabilization plan, specifically item 3, page 29 of the Application, would work if approved as applied for and the deferral amount matched the Section 21 Tax deferral in rates. In response, NS Power provided a deferral amount that illustrated the 3 percent increase requested in the Rate Stabilization Plan and which, after possible changes to the revenue requirement resulting from the regulatory process, could be amortized within the confines of the Section 21 Tax deferral already included in rates.

The current forecasted amount of the Fixed Cost deferral, after interest, as indicated in Appendix P, Attachment 2, page 4, column S, "grand total" line of the Application is $124.4 million. The following factors could lead to an increase in the Fixed Cost deferral amount during the Rate Stabilization two year period;

- A reduction from forecast in the amount of fixed cost recovery received from NewPage and Bowater
- Changes to the Rate Stabilization Plan as filed

A FAM payable or receivable could be possible in addition to the Fixed Cost deferral discussed above if fuel costs come in higher or lower than what is approved in the Application.

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Request IR-64:

With respect to the Excel version of NSPI(Liberty) IR-39 Attachment 1, please provide the derivation of the numbers in cells B6, B7, B10, B11, B16, B25, B26, B34 and B35.

Response IR-64:

The derivation of cells B6 and B7 have been provided in CA IR-9 Attachment 1 page 2.

Please refer to Confidential Attachment 1 for the derivation of cells B10 and B11.

Cell B16 is the interest on the total estimated fixed cost recovery for one month using NS Power's 2012 estimated weighted average cost of capital of 7.97 percent. The derivation is:

B17 * 7.97 / 12

Cells B25 and B26 are one twelfth of the 2013 estimated deferred amount of revenue requirement of $27.2 million due to the Rate Stabilization Plan and associated interest as calculated above, respectively.

($27.2 / 12 + B24 * (44.199)) * 0.0797 / 12

Cells B34 and B35 are one twelfth of the 2014 estimated deferred amount of revenue requirement of $26.7 million due to the Rate Stabilization Plan and associated interest as calculated above, respectively.

($26.7 / 12 + B33 * (76.178)) * 0.0797 / 12

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Request IR-65:

With respect to NSPI (Multeese) IR- 19(b), which discusses separate tracking of fuel and non-fuel cost recovery by customer class,

a) Does the tracking of non-fuel cost recovery include consideration of differences between forecast and actual customer class load?

b) If the answer to a) is affirmative, please provide two sample calculations of the residential sector contribution to non-fuel cost recovery, the first assuming class load to be the load on which this Application is predicated, and the second assuming the actual class load is 1% lower than expected.

c) If the answer to a) is affirmative, please discuss how this approach changes the risk to NSPI as compared to traditional rate setting where rates are set based on forecasted revenue requirements and billing determinants, and NSPI accepts the risk (including both upside and downside) of changes in load.

Response IR-65:

(a) No.

(b-c) Not applicable.