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Request IR-22:

Please provide any additional materials or explanations that NSPI has received from Hatch or the Nova Scotia Department of Energy regarding the results of 2008 Nova Scotia Wind Integration Study, performed by Hatch for the Nova Scotia Department of Energy (the Hatch report).

Response IR-22:

Nova Scotia Power has not received additional materials or explanations from Hatch or the Nova Scotia Department of Energy regarding the results of the 2008 Nova Scotia Wind Integration Study.

Request IR-23:

Please describe NSPI's efforts to resolve the issues related to wind integration raised in the Hatch report.

Response IR-23:

As Nova Scotia Power has been increasing its renewable generation portfolio to meet RES requirements, it actively monitors the effects of increasing amounts of intermittent generation resources (wind) on the bulk power system. Monitoring and analysis includes the use of specific weather forecasts and the correlation to actual site output. The expectation is that by late 2011 corollary data of weather and wind production can be used to further optimize system generation dispatch. Until the end of 2010, there was not sufficient wind penetration with locational diversity to commence the analytical work to assess the operational effects such as regulation and load following.

Nova Scotia Power will initiate a supplier selection process for a consultant to commence studies of the wind generation, as recommend by the Hatch Report shortly, and to conduct an assessment of the impacts in wind on the system. The scope of the work includes development of recommendations to support load following and backup requirements.

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Request IR-24:

Please provide all studies or reports commissioned by NSPI to follow up on or improve on the results in the 2008 Hatch report.

Response IR-24:

Please refer to CA IR-23 and CA IR-25.

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Request IR-25:

Please provide all studies, memos, RFPs, reports or analyses related to NSPI's efforts to resolve each of the following issues raised by or related to the 2008 Hatch report:

(a) NSPI's existing 10-minute load-following capacity, including any variation by load level, such as on- or off-peak (Hatch Table 7-1).

(b) NSPI's existing regulation capacity (Hatch Table 7-3).

(c) The "more detailed impact studies…required to fully understand the cost and technical implications related to possible transmission upgrades and new operational demands on existing infrastructure" related to the meeting the 2013 RES requirement (Hatch Report, page x)

(d) "The total cost impacts" of increasing "the number of starts and stops of the large thermal units" and "all components of the delivery system [experiencing] greater load variations," that "are not well understood at this time." (Hatch Report, page x and page 8-4)

(e) The "further study and experience…needed to verify" that "increases in renewable production and decreases in CO2 emissions may be achievable with little impact on production costs" (Hatch Report, page x)

(f) "More detailed studies of the high voltage transmission system (referred to as dynamic stability studies) are needed; these studies should be done in advance of the estimated 520 MW of new wind power capacity for 2013 to identify any possible transmission upgrades necessary." (Hatch Report, page xi)

(g) "Actual production patterns of the operating wind power plants." (Hatch Report, page xi)

(h) "A wind power forecasting pilot project." (Hatch Report, page xi)

(i) "Additional information on the time patterns of wind power generation." (Hatch Report, page xi)

(j) "Technical/economic studies to investigate viability of investment in NSPI's major thermal power units to allow better adaptation to more frequent stops/starts and output fluctuation." (Hatch Report, page xi)

(k) "It would be desirable to select a different year [than 2005] as the calculation base [for zonal 1-minute load profiles], compare the results from the two different bases and examine the differential impacts of wind power integration." (Hatch report, p. 8-5)

(l) "It is recommended to carry out sensitivity analysis to different levels of wind power forecasting error." (Hatch report, p. 8-5)

(m) "It is recommended to carry out short circuit and stability analysis, identify the dynamic impact of wind power integration on system operation and address the potential problems." (Hatch report, p. 8-5)

(n) "The transmission analysis has identified a need to construct one 345 kV transmission line running from the Canso Strait bus to the Metro bus if significant additional amounts of wind power capacity would be developed in the Canso Strait and Sydney zones. The estimated costs of the new circuit are some $262.2 million. It is suggested to investigate further the possibility of wind power developments in

the two zones, compare the costs/benefits of development of wind power plants in the two zones or other zones, and study the associated overall benefits of the new line to the system." (Hatch report, p. 8-5)

(o) "It is recommended to carry out a detailed cost estimate of the new line and investigate its costs/benefits further if these suggested analyses show favourable outcomes." (Hatch report, p. 8-5)

(p) "It is recommended to carry out sensitivity dispatch analysis to the wind power generation pattern by shifting the entire pattern by 6, 12 and 18 hours." (Hatch report, p. 8-5)

(q) "NSPI should carry out technical/economic studies to investigate if any investments on [steam turbine driven generating] units are desirable to meet the operational challenges or improve their operational capability. (Hatch report, p. 8-6)

Response IR-25:

(a) NSPI retains sufficient 10-minute operating reserve at all times for response to contingency losses on the power system as dictated by NPCC Criteria and other agreements.

(b) NSPI carries a minimum of 36 MW of spinning reserve.

(c) The approved Generation Interconnection Process (GIP) includes a study process for each generation application received by the System Operator. These projects are listed in the Generation Interconnection Queue found on the Open Access System Information System (OASIS) on Nova Scotia Power's web site. There are more potential projects listed on the Generation Interconnection Queue than what is required to meet the 2013

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RES requirement. System Impact Studies are performed on these projects at the customer's request and are confidential to the customer requesting the study. Numerous System Impact Studies have been performed that identify the technical requirements and transmission upgrades associated with each project.

Transmission upgrades are very dependent on the transmission interconnection location of the generation source, the type of interconnection service requested, and the sequence in which these interconnections are installed. Until formal Power Purchase Agreements and Generation Interconnection Agreements are in place, it is difficult to determine which projects will proceed to construction and what the total associated transmission requirements will be.

In the 2009 Integrated Resource Plan (IRP) Update, a number of potential generation scenarios were reviewed to identify transmission requirements. The results of these scenario reviews were included in the 2009 IRP Update. In addition, NSPI's 10 Year Outlook Report provides a discussion on transmission implications for potential generation scenarios.

Nova Scotia Power will initiate a supplier selection process for a consultant to commence studies of the wind generation, as recommend by the Hatch Report shortly, and to conduct an assessment of the impacts in wind on the system. Please refer to CA IR-23.

NSPI is also part of Power Shift Atlantic, which includes a group of Maritimes utilities studying load control in conjunction with additional renewable energy sources (wind). NSPI filed a capital work order application for this project on October 4, 2010 which was approved by the UARB on November 23, 2010. Please refer to Capital Work Order Application 40103 (P-510 – Matter No. M03589).

This project studies whether shifting patterns in energy consumption through load control can enable utilities to more effectively integrate renewable energy such as wind, and is therefore aligned with the results of the IRP.

(d) The effects of cycling NSPI's large Steam Units are being considered in concert with "Unit Age", "Unit Operating History" and anticipated "End of Life". These factors, and the resulting Maintenance and Investment Plans will be managed within NSPI's broader thinking on Asset Management. The Asset Management philosophy and Project (Please refer to Liberty IR-53 and NPB IR-73) will include:

- Methods, tools and processes to gain comprehensive assessment of equipment health.
- Overlaying anticipated Strategic Purpose for each Steam Unit
- Design of suitable Maintenance Strategies for Asset Classes with consideration for per unit Strategic Purpose
- Design of Investment Plans with consideration for each unit's Strategic Purpose.

For select Units and select Asset Classes, special analysis will need to be conducted to gather sufficient detail of "Present State" and project equipment performance based on new operating modes (cycling).

(e) It was generally believed by NSPI that the Hatch study may have lacked sufficient system stability assessments and that the time resolution of the Hatch study was not fine enough to allow this production cost impact to be insinuated. NSPI's wind integrations study will seek to improve the assessment of impacts on production costs.

(f) Please refer to part (c).

(g) NSPI is conducting a wind integration study. Please refer to CA IR-23. It will address various issues raised by the Hatch Report where appropriate.

(h) NSPI has developed a wind forecasting model and is in the process of calibrating it based on the observed deltas between actual and forecast values.

(i) NSPI is evaluating time patterns of wind generation.

(j) Please refer to part (d).

(k) NSPI's wind study will evaluate a different year than 2005.

(l) NSPI's wind study will evaluate this.

(m) Please refer to part (c).

(n) In the 2009 Integrated Resource Plan (IRP) Update a number of potential generation scenarios were reviewed to identify transmission requirements, including additional wind in the Cape Breton area. The results of these scenario reviews were included in the 2009 IRP Update. The selected projects to meet the RES requirements to date have required significantly less transmission upgrade than those identified for new wind capacity generation east of the Canso Strait.

(o) Please refer to part (n).

(p) NSPI is conducting a wind integration study. Please refer to CA IR-23. It will address various issues raised by the Hatch Report where appropriate.

(q) Please refer to part (d).

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Request IR-26:

Please provide the tables in SR-01 Attachment 1 in their original spreadsheet form, with all formulae live and all supporting spreadsheets.

Response IR-26:

Please refer to Multeese IR-1 Attachment 1.

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Request IR-27:

Please explain why NSPI believes that demand-related generation is driven only by loads in December, January and February.

Response IR-27:

Demand-related generation costs are driven primarily by the system peak demand. Historically, all of the NSPI's system peaks occurred in one of these three winter months.

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Request IR-28:

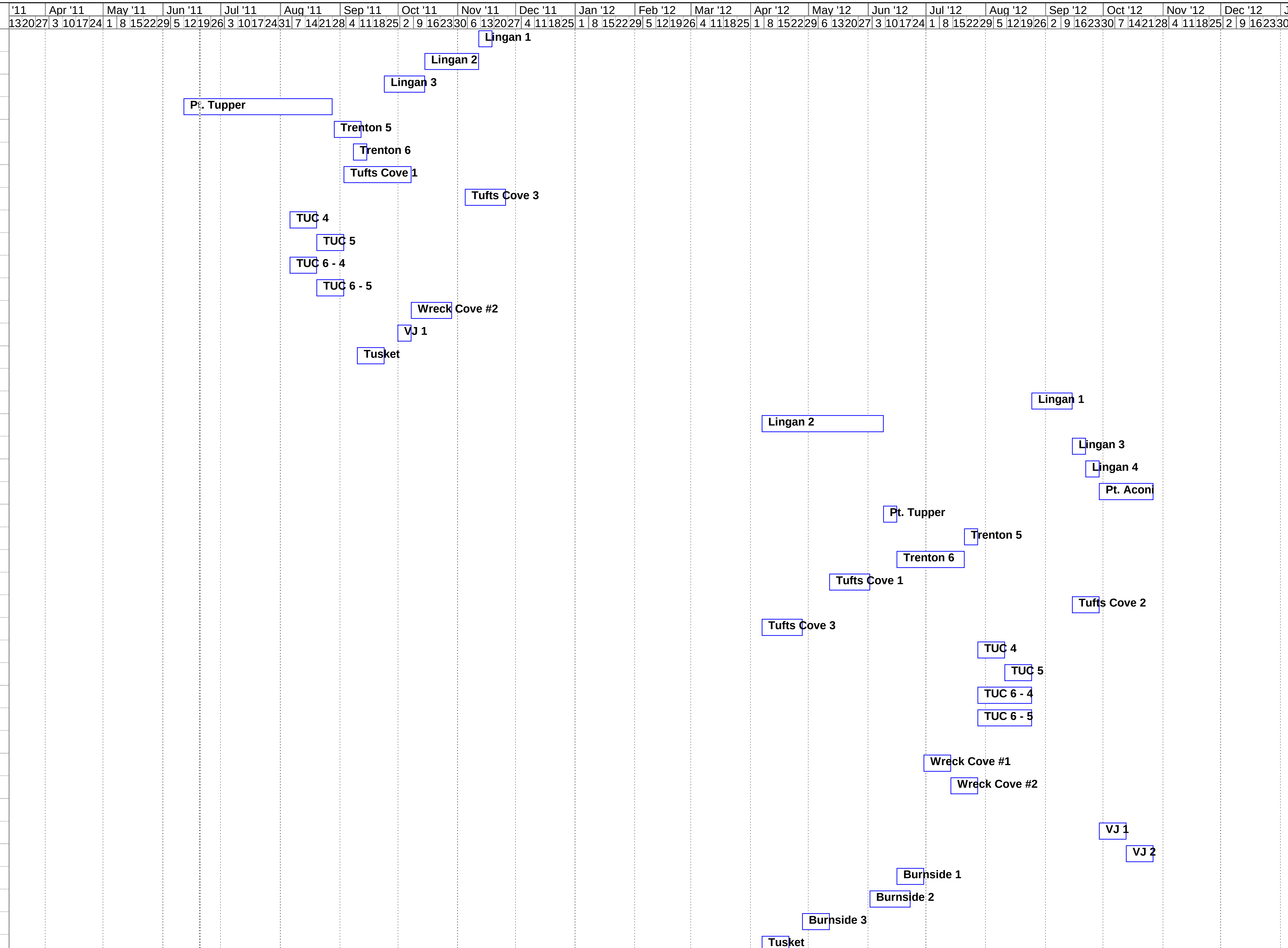
Please provide NSPI's current schedule for generation maintenance by week for July 2011 through December 2012.

Response IR-28:

Please refer to Attachment 1.

Thermal Maintenance Schedule
(June, 2011 to December, 2012)

ID	Task Name	Duration	Start	Finish
1	Lingan 1	1 ewk	Sat 11/12/11	Sat 11/19/11
2	Lingan 2	4 ewks	Sat 10/15/11	Sat 11/12/11
3	Lingan 3	3 ewks	Sat 9/24/11	Sat 10/15/11
4	Pt. Tupper	11 ewks	Sat 6/11/11	Sat 8/27/11
5	Trenton 5	2 ewks	Sun 8/28/11	Sun 9/11/11
6	Trenton 6	1 ewk	Thu 9/8/11	Thu 9/15/11
7	Tufts Cove 1	5 ewks	Sat 9/3/11	Sat 10/8/11
8	Tufts Cove 3	3 ewks	Sat 11/5/11	Sat 11/26/11
9	TUC 4	2 ewks	Sat 8/6/11	Sat 8/20/11
10	TUC 5	2 ewks	Sat 8/20/11	Sat 9/3/11
11	TUC 6 - 4	2 ewks	Sat 8/6/11	Sat 8/20/11
12	TUC 6 - 5	2 ewks	Sat 8/20/11	Sat 9/3/11
13	Wreck Cove #2	3 ewks	Sat 10/8/11	Sat 10/29/11
14	VJ 1	1 ewk	Sat 10/1/11	Sat 10/8/11
15	Tusket	2 ewks	Sat 9/10/11	Sat 9/24/11
16				
17	Lingan 1	3 ewks	Sat 8/25/12	Sat 9/15/12
18	Lingan 2	9 ewks	Sat 4/7/12	Sat 6/9/12
19	Lingan 3	1 ewk	Sat 9/15/12	Sat 9/22/12
20	Lingan 4	1 ewk	Sat 9/22/12	Sat 9/29/12
21	Pt. Aconi	4 ewks	Sat 9/29/12	Sat 10/27/12
22	Pt. Tupper	1 ewk	Sat 6/9/12	Sat 6/16/12
23	Trenton 5	1 ewk	Sat 7/21/12	Sat 7/28/12
24	Trenton 6	5 ewks	Sat 6/16/12	Sat 7/21/12
25	Tufts Cove 1	3 ewks	Sat 5/12/12	Sat 6/2/12
26	Tufts Cove 2	2 ewks	Sat 9/15/12	Sat 9/29/12
27	Tufts Cove 3	3 ewks	Sat 4/7/12	Sat 4/28/12
28	TUC 4	2 ewks	Sat 7/28/12	Sat 8/11/12
29	TUC 5	2 ewks	Sat 8/11/12	Sat 8/25/12
30	TUC 6 - 4	4 ewks	Sat 7/28/12	Sat 8/25/12
31	TUC 6 - 5	4 ewks	Sat 7/28/12	Sat 8/25/12
32				
33	Wreck Cove #1	2 ewks	Sat 6/30/12	Sat 7/14/12
34	Wreck Cove #2	2 ewks	Sat 7/14/12	Sat 7/28/12
35				
36	VJ 1	2 ewks	Sat 9/29/12	Sat 10/13/12
37	VJ 2	2 ewks	Sat 10/13/12	Sat 10/27/12
38	Burnside 1	2 ewks	Sat 6/16/12	Sat 6/30/12
39	Burnside 2	3 ewks	Sat 6/2/12	Sat 6/23/12
40	Burnside 3	2 ewks	Sat 4/28/12	Sat 5/12/12
41	Tusket	2 ewks	Sat 4/7/12	Sat 4/21/12



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Request IR-29:

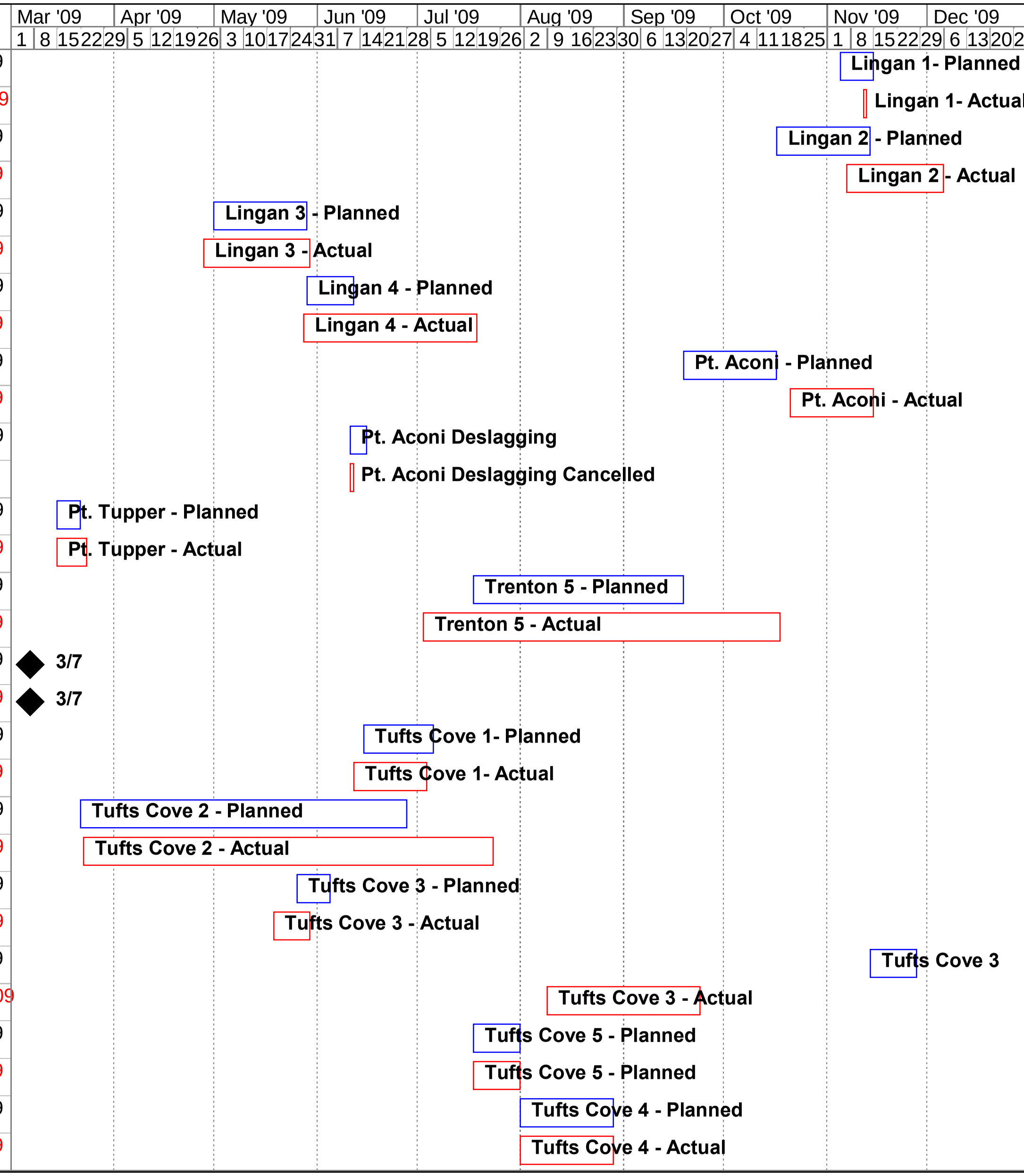
Please provide NSPI's actual planned generation outages by week for January 2009 through June 2011.

Response IR-29:

Please refer to Attachment 1, 2 and 3.

2009 Thermal Maintenance Schedule
(as of May 11th , 2009

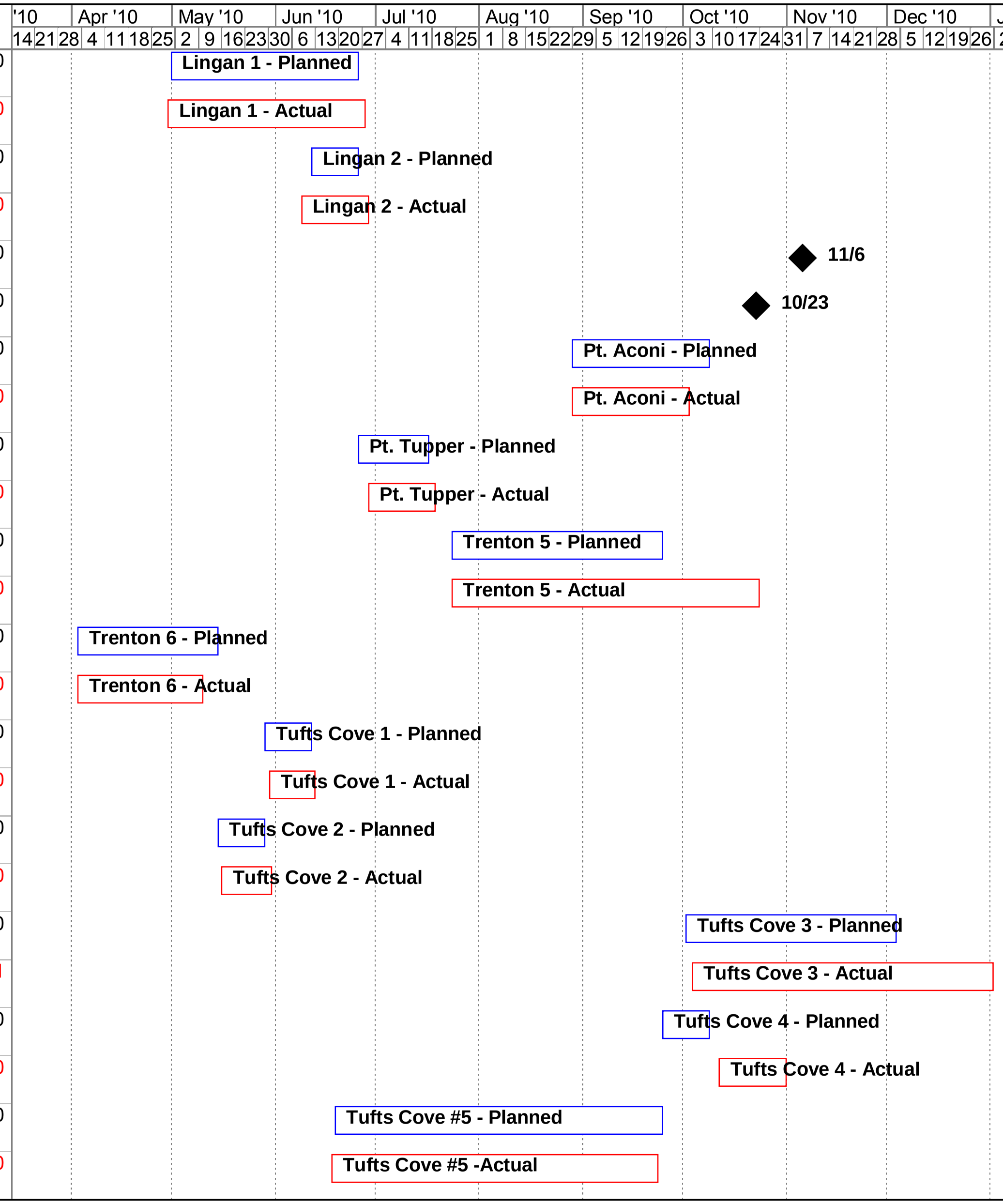
ID	Task Name	Duration	Start	Finish
1	Lingan 1- Planned	10 days	Thu 11/5/09	Sat 11/14/09
2	Lingan 1- Actual Cancelled	0 days	Thu 11/12/09	Thu 11/12/09
3	Lingan 2 - Planned	4 wks	Sat 10/17/09	Sat 11/14/09
4	Lingan 2 - Actual	29 days	Sat 11/7/09	Sat 12/5/09
5	Lingan 3 - Planned	4 wks	Fri 5/1/09	Fri 5/29/09
6	Lingan 3 - Actual	32 days	Tue 4/28/09	Fri 5/29/09
7	Lingan 4 - Planned	14 days	Fri 5/29/09	Thu 6/11/09
8	Lingan 4 - Actual	52 days	Thu 5/28/09	Sat 7/18/09
9	Pt. Aconi - Planned	4 wks	Sat 9/19/09	Sat 10/17/09
10	Pt. Aconi - Actual	25 days	Wed 10/21/09	Sat 11/14/09
11	Pt. Aconi Deslagging	5 days	Thu 6/11/09	Mon 6/15/09
12	Pt. Aconi Cancelled	0 days	Thu 6/11/09	Thu 6/11/09
13	Pt. Tupper - Planned	1 wk	Sun 3/15/09	Sun 3/22/09
14	Pt. Tupper - Actual	9 days	Sun 3/15/09	Mon 3/23/09
15	Trenton 5 - Planned	9 wks	Sat 7/18/09	Sat 9/19/09
16	Trenton 5 - Actual	107 days	Fri 7/3/09	Sat 10/17/09
17	Trenton 6 - Planned	0 wks	Sat 3/7/09	Sat 3/7/09
18	Trenton 6 - Actuall	0 wks	Sat 3/7/09	Sat 3/7/09
19	Tufts Cove 1- Planned	3 wks	Mon 6/15/09	Mon 7/6/09
20	Tufts Cove 1- Actual	3.05 wks	Fri 6/12/09	Fri 7/3/09
21	Tufts Cove 2 - Planned	14 wks	Sun 3/22/09	Sun 6/28/09
22	Tufts Cove 2 - Actual	17.48 wks	Mon 3/23/09	Thu 7/23/09
23	Tufts Cove 3 - Planned	10 days	Tue 5/26/09	Thu 6/4/09
24	Tufts Cove 3 - Actual	11 days	Tue 5/19/09	Fri 5/29/09
25	Tufts Cove 3 (MSV)	2 wks	Sat 11/14/09	Sat 11/28/09
26	Tufts Cove 3 - Actual	46 days	Sun 8/9/09	Wed 9/23/09
27	Tufts Cove 5 - Planned	2 wks	Sat 7/18/09	Sat 8/1/09
28	Tufts Cove 5 - Planned	2 wks	Sat 7/18/09	Sat 8/1/09
29	Tufts Cove 4 - Planned	4 wks	Sat 8/1/09	Sat 8/29/09
30	Tufts Cove 4 - Actual	4 wks	Sat 8/1/09	Sat 8/29/09



2010 Thermal Maintenance Schedule
(Sept 9th, 2010)

Revision 2010 - 0

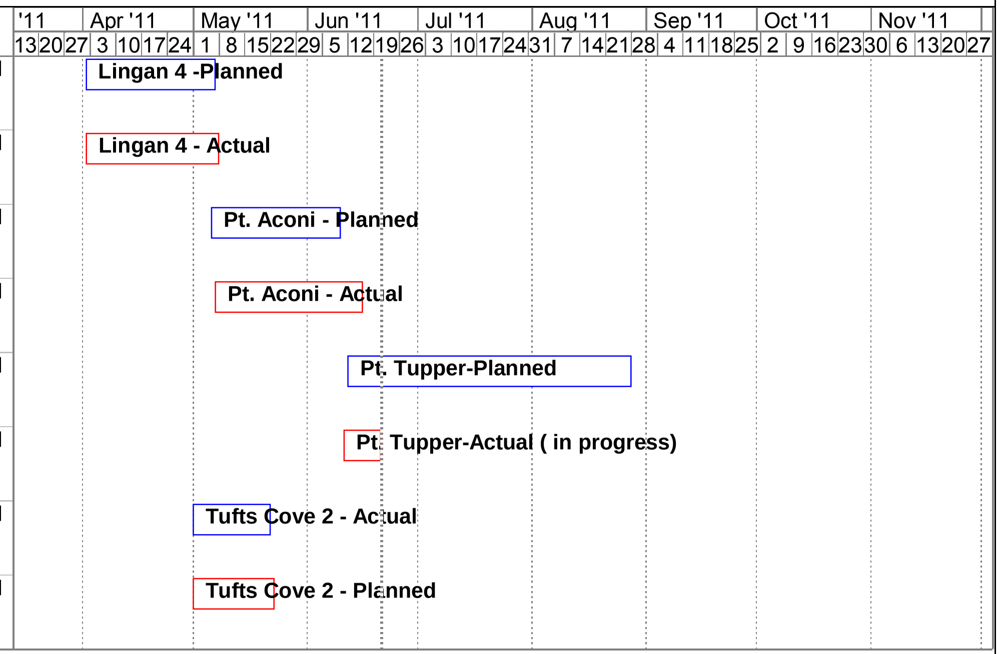
ID	Task Name	Duration	Start	Finish
1	Lingan 1 - Planned	8 wks	Sat 5/1/10	Sat 6/26/10
2	Lingan 1 - Actual	8.4 wks	Thu 4/29/10	Sun 6/27/10
3	Lingan 2 - Planned	2 wks	Sat 6/12/10	Sat 6/26/10
4	Lingan 2 - Actual	2.8 wks	Wed 6/9/10	Mon 6/28/10
5	Lingan 3	0 wks	Sat 11/6/10	Sat 11/6/10
6	Lingan 4	0 wks	Sat 10/23/10	Sat 10/23/10
7	Pt. Aconi - Planned	5.8 wks	Sun 8/29/10	Fri 10/8/10
8	Pt. Aconi - Actual	5 wks	Sun 8/29/10	Sun 10/3/10
9	Pt. Tupper - Planned	3 wks	Sat 6/26/10	Sat 7/17/10
10	Pt. Tupper - Actual	2.8 wks	Tue 6/29/10	Sun 7/18/10
11	Trenton 5 - Planned	9 wks	Sat 7/24/10	Sat 9/25/10
12	Trenton 5 - Actual	13.1 wks	Sat 7/24/10	Sun 10/24/10
13	Trenton 6 - Planned	6 wks	Sat 4/3/10	Sat 5/15/10
14	Trenton 6 - Actual	5.3 wks	Sat 4/3/10	Mon 5/10/10
15	Tufts Cove 1 - Planned	2 wks	Sat 5/29/10	Sat 6/12/10
16	Tufts Cove 1 - Actual	1.9 wks	Sun 5/30/10	Sat 6/12/10
17	Tufts Cove 2 - Planned	2 wks	Sat 5/15/10	Sat 5/29/10
18	Tufts Cove 2 - Actual	2.1 wks	Sun 5/16/10	Sun 5/30/10
19	Tufts Cove 3 - Planned	9 wks	Sat 10/2/10	Sat 12/4/10
20	Tufts Cove 3 - Actual	12.8 wks	Mon 10/4/10	Sat 1/1/11
21	Tufts Cove 4 - Planned	2 wks	Sat 9/25/10	Sat 10/9/10
22	Tufts Cove 4 - Actual	2.8 wks	Tue 10/12/10	Sun 10/31/10
23	Tufts Cove #5 - Planned	14 wks	Sat 6/19/10	Sat 9/25/10
24	Tufts Cove #5 -Actual	13.9 wks	Fri 6/18/10	Thu 9/23/10



Revision 2010-02

2011 Thermal Maintenance Schedule
(April 11th, 2011)

ID	Task Name	Duration	Start	Finish
1	Lingan 4 -Planned	5 wks	Sat 4/2/11	Sat 5/7/11
2	Lingan 4 - Actual	36 days	Sat 4/2/11	Sat 5/7/11
3	Pt. Aconi - Planned	5 wks	Fri 5/6/11	Fri 6/10/11
4	Pt. Aconi - Actual	40 days	Sat 5/7/11	Wed 6/15/11
5	Pt. Tupper-Planned	11 wks	Sat 6/11/11	Sat 8/27/11
6	Pt. Tupper-Actual (in progress)	10 days	Sat 6/11/11	Mon 6/20/11
7	Tufts Cove 2 - Actual	3 wks	Sun 5/1/11	Sun 5/22/11
8	Tufts Cove 2 - Planned	22 days	Sun 5/1/11	Sun 5/22/11



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Request IR-30:

Please explain why "'wind assets are assigned 30% to 3CP demand and the remaining plant to energy." (SR-01 Attachment 1 Page 8)

Response IR-30:

Consistent with the approach taken in previous Cost of Service Studies, NSPI has re-classified 30 percent of its initially determined demand-related portion of wind asset rate base into demand- and energy-related components.

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Request IR-31:

Please provide NSPI's estimate of the amount of installed wind capacity needed to provide supply reliability equivalent to one MW of gas-turbine capacity.

Response IR-31:

Discussions are taking place with the System Operator concerning the potential to assign a capacity value to wind generation based on the wind forecast. However, given that there are days with virtually no wind generation and that wind is non-dispatchable, there is no direct equivalency between installed wind capacity and MWs of gas-turbine capacity. Nova Scotia Power is in the process of selecting a consultant to assess the impacts of wind generation on the system. The Study will determine the amount of fast-acting generation that will be required for load following and back-up of wind generation.

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Request IR-32:

Please list all the "Environmental and fuel conversion assets in the rate base [that are] are extracted up front and classified 100% as energy-related."

(a) Do these costs include the conversion of Point Tupper from oil to coal in 1987?

(b) Do these costs include the conversion of Tufts Cove to gas?

(c) Do these costs include the conversion of the Point Tupper, Lingan, Point Aconi, and Trenton to burn different grades of coal?

Response IR-32:

(a-c) Yes. Please refer to Attachment 1 for the list of the Environmental and fuel conversion assets in the rate base that are extracted up front and classified 100 percent as energy related.

Environmental and Fuel Conversion Assets				
Title/Description	Generating Unit	Original Cost of the Item ($)	In service date	Average Remaining Life
2008 Pcb Equipment Inventory	Total Distribution Plant	$12,066.56	2009	N/A
Ash Lagoon Capping	Trenton - Common	$125,438.68	2007	29.7
Ash Lagoon Covering	Trenton - Common	$100,162.92	2008	29.7
Ash Site North "A" Cell Development	Lingan - Common	$396,802.30	2009	21.5
Ash Site Sealing and Capping	Lingan - Common	$990,203.25	2003	21.5
Bear River Oil Protection	Bear River	$60,364.23	2009	43.3
Cell 3 Stage 3 Residue Management Site	Point Aconi 1	$2,598,775.18	2009	30.6
Connect Plant to Municipal Sewer System at HRM Request	Tufts Cove - Common	$154,138.30	2007	21.5
Continuous Emission Monitoring System Replacement	Trenton 5	$143,962.63	2005	29.7
CT'S -Replace Halon Fire Protection	Victoria Junction	N/A	2012	N/A
Digby Wind Project	Wind General	N/A	2012	N/A
Disposal of PCB Transformers	Line Transformers	$75,693.27	2009	16.4
Eastern Valley Oil Protection	Black River	$75,665.55	2008	45
EP&M Mercury Measurement Instrumentation	Total General Plant	$252,962.17	2010	N/A
FAC Enviro Property Remed Routine	General Plant	N/A	2017	N/A
FAC Environment Site Assess Routine	General Plant	N/A	2016	N/A
FAC Environmental Property Remediation Routine	Total General Plant	$81,957.20	2010	N/A
FAC Environmental Site Assessment	Total General Plant	$422,919.57	2010	N/A
Fire Suppression - Replace Halon Gas System	Total General Plant	$346,847.56	2009	N/A
Fuel Oil Storage Handling	Tufts Cove - Common	$94,010.15	2006	21.5
GS Upgrade of Ambient Air Shelters	Total General Plant	$126,967.12	2010	N/A
Harmony Intake	Harmony	$84,958.08	2006	21.2
HYD Oil Relaease Risk Assessment	Hydro General	N/A	2012	N/A
Installation of a Wastewater Treatment Facility	Lingan - Common	$5,420,997.33	2003	21.5
In-Stream Tidal Generation	Annapolis Tidal	$4,573,089.13	2009	34.5
Lingan Precipitator Refit Program	Lingan - Common	$127,486.35	2007	21.5
Lingan Unit # 3 Low Nox Combustion Firing System	Lingan 3-4	$3,813,164.19	2006	21.2
Lingan Unit #1 Low Nox Combustion Firing System	Lingan 1-2	$3,875,372.97	2009	8.4
Lingan Unit #1 Mercury Abatement	Lingan 1-2	$1,800,618.17	2010	8.4
Lingan Unit #2 Low Nox Combustion Firing System	Lingan 1-2	$3,751,101.84	2007	8.4
Lingan Unit #2 Mercury Abatement	Lingan 1-2	$1,847,112.87	2010	8.4
Lingan Unit #3 Low Nox Combustion Firing System	Lingan 3-4	$4,181,454.76	2007	21.2
Lingan Unit #3 Mercury Abatement	Lingan 3-4	$4,459,213.27	2010	21.2
Lingan Unit #4 Mercury Abatement	Lingan 3-4	$1,754,566.56	2010	21.2
Little River Lake Dam Refurbishment	Black River	$290,246.93	2006	45

Title/Description	Generating Unit	Original Cost of the Item ($)	In service date	Average Remaining Life
Nictaux Lube & Oil Governor Update	Lequille System	$39,929.16	2009	33.6
Nuttby Mountain Wind Project Development	Wind Turbines	$110,050,218.00	2010	18.5
Padmount Replacement Program	Total Distribution Plant	$398,607.31	2010	N/A
PCB Equipment Removal/Destruction	Total Distribution Plant	$36,013.19	2010	N/A
PCB Management at Sensitive Sites	Total Distribution Plant	$294,139.13	2004	N/A
Pipeline Life Extension	Lequille System	$69,074.70	2003	33.6
Pipeline Rupture Detection	Bear River	$41,501.55	2009	43.3
Pipeline Rupture Detection	Lequille System	$123,812.50	2004	33.6
POA Ash Cell Capping Cell 3 Stage 1	Point Aconi Generating Station	N/A	2011	N/A
POA Bag house Bag Replacement Pro	Point Aconi 1	$854,385.19	2009	30.6
Point Aconi	Point Aconi 1	$75,000,000.00	1993	30.6
Point Tupper Fuel Conversion	Point Tupper 2	$94,469,366.00	1987	21.3
Point Tupper Unit #1 Mercury Abatement	Point Tupper 1	$2,461,060.04	2010	20.4
Point Tupper Unit #1 Replacement of Opacity Monitors	Point Tupper 1	$68,849.55	2008	20.4
Point Tupper Unit #2 Low Nox Combustion Firing System	Point Tupper 2	$3,074,920.62	2009	21.3
Point Tupper Wind Project	Wind Turbines	$18,730,503.00	2010	18.5
Port Hawkesbury Biomass Project	Steam General	N/A	2013	N/A
POT - Develop new ash cells	Point Tupper Generating Station	N/A	2012	N/A
POT - Marine Terminal Dust Mitigati	Strait Marine Terminal	N/A	2011	N/A
POT - Utilization of Heavy Biofuel	Point Tupper Generating Station	N/A	2011	N/A
POT - Wastewater cell refurbishment	Point Tupper Generating Station	N/A	2011	N/A
POT Ash Cell Capping Cell B	Point Tupper Generating Station	N/A	2013	N/A
Pt. Tupper Relocate Port Malcolm Rd	Point Tupper 2	$1,567,961.15	2009	21.3
Reburbish Fly ash Handling	Lingan 1-2	$598,380.44	2005	8.4
Recoat Bunker C Tank	Lingan - Common	$332,966.56	2008	21.5
Refurbish Light Oil Tanks and Lines	Lingan - Common	$178,299.88	2008	21.5
Removal of External Street Light Ballasts (contain PCB's)	Total Distribution Plant	$32,152.13	2006	N/A
Replace Deteriorated Padmount Transformers	Line Transformers	$54,373.98	2007	16.4
Replace Deteriorated Padmount Transformers	Line Transformers	$257,513.00	2008	16.4
Replace Deteriorated Padmount Transformers	Line Transformers	$28,633.27	2008	16.4
Replace Deteriorated Padmount Transformers	Line Transformers	$116,557.60	2006	16.4
Replace HFO Tank Interface Liner	Tufts Cove - Common	$103,050.60	2008	21.5
Replace water Treatment Equipment	Tufts Cove - Common	$102,291.11	2010	21.5
Replacement of Deteriorated Padmount Transformers	Line Transformers	$573,925.73	2005	16.4
Roseway Dyke Repair	Roseway	$58,705.62	2010	38
Rusty Transformers	Line Transformers	$48,741.00	2007	16.4

Title/Description	Generating Unit	Original Cost of the Item ($)	In service date	Average Remaining Life
Ruth Falls Canal Fish Lovre Improvements	Sheet Harbor	$405,953.17	2006	25.5
Spherical Valve Replacement	Wreck Cove System	$263,006.64	2009	41.8
Stage 3 Residue Management Site	Point Aconi 1	$1,737,016.93	2007	30.6
Sydney Replace Deteriorated Padmount Transformers	Line Transformers	$137,000.00	2006	16.4
TRE - Ash Site Management	Trenton - Common	$124,720.10	2010	29.7
TRE - CW Outlet Oil Boom	Trenton Generating Station	N/A	2012	N/A
TRE - Storm Drainage Improvements	Trenton - Common	$120,524.75	2010	29.7
TRE - Wastewater Treatment Plant Up	Trenton Generating Station	N/A	2011	N/A
Trenton Ash Site Covering	Trenton - Common	$99,210.85	2009	29.7
Trenton Ash Site Covering Project	Total Trenton	$113,372.43	2010	N/A
Trenton Site Environ. Improvements	Trenton - Common	$121,586.35	2007	29.7
Trenton Unit #5 Bag House Addition	Trenton 5	$29,051,521.15	2009	29.7
Trenton Unit #5 Mercury Abatement	Trenton 5	$1,588,705.12	2010	29.7
Trenton Unit #6 Low Nox Combustion Firing System	Trenton 6	$4,106,621.42	2008	29.7
Trenton Unit #6 Mercury Abatement	Trenton 6	$1,877,140.40	2010	29.7
TUC - Oil Tank Protective Coating	Tufts Cove - Common	$23,365.65	2010	21.5
Tufts Cove Fuel Conversion	Total Tufts Cove	$25,601,694.00	2000	N/A
Tufts Cove No#2 Precipitator	Tufts Cove 2	$4,278,674.00	1998	10.3
Tufts Cove Oil Tank #4 Refburb/Upgrade	Tufts Cove - Common	$1,300,701.30	2002	21.5
Tufts Cove Unit #1 Electrostatic Precipitator	Tufts Cove 1	$9,225,531.00	2005	10.3
Tufts Cove Unit #3 Electrostatic Precipitator	Tufts Cove 3	$11,430,257.74	2005	21.4
Vault Oil Containment	Total Distribution Plant	$209,748.00	2007	N/A
Vault Oil Containment	Total Distribution Plant	$121,051.34	2005	N/A
West Replace Deteriorated Padmounts	Total Distribution Plant	$148,535.00	2006	N/A
Weymouth Falls Oil Containment	Bear River	$175,006.99	2005	43.3
White Rock Bar Rack Refurbishment	Black River	$44,827.44	2006	45
Wolfville Site Remediation	Total General Plant	$213,526.01	2007	N/A
Yard Oil Piping Upgrade	Tufts Cove - Common	$88,715.57	2008	21.5

NON-CONFIDENTIAL

Request IR-33:

Please explain how NSPI proposes to classify and allocate the costs of the Tufts Cove heat-recovery unit.

Response IR-33:

The Tufts Cove heat-recovery unit will be classified and allocated in the same manner as other steam plant assets in the cost of service model.

NON-CONFIDENTIAL

Request IR-34:

In Exhibit 2B, pages 1–2, please provide full documentation of the "Initial R/B Classification" for each generation and transmission function.

Response IR-34:

Please refer to CA IR-45 and its Attachment 1 (pages 2 and 3).

CONFIDENTIAL (Attachment Only)

Request IR-35:

Please provide a map of NSPI's transmission system, identifying each substation.

Response IR-35:

A high level system map is provided in Confidential Attachment 1. Detailed maps of NSPI's transmission system are not distributed due to system security reasons, but are available for viewing at NSPI offices.

CONFIDENTIAL (Attachment Only)

Request IR-36:

Please provide a list of NSPI substations, including for each:

(a) Station name.

(b) Number of transformers.

(c) MVA of transformers.

(d) High-side and low-side nominal voltages.

(e) 2010/11 peak load on the substation.

(f) Time and date of the 2010/11 peak load on the substation.

(g) Load, date and time of the monthly peak on the substation, for each month from June 2009 to May 2011.

Response IR-36:

(a-f) Please refer to Confidential Attachment 1.

(g) The Company does not normally record the data as requested. We are unable to compile such information within the time prescribed to respond to this request.

NON-CONFIDENTIAL

Request IR-37:

Please indicate which distribution substation is a dedicated substation, as listed in Exhibit 3B, and which class it serves.

Response IR-37:

NSPI does not have the detail requested.

NON-CONFIDENTIAL

Request IR-38:

Please explain the distinction between "bulk power" and "general" distribution substations in Exhibit 3B.

Response IR-38:

For the COSS purposes the rate base associated with the distribution substations has been split among the four categories named: "Distribution Bulk Power", "Distribution Dedicated Bulk Power", "Distribution General" and "Distribution Dedicated General" using the same proration approach since the last COSS hearing was held in 1995.

The approved methodology has been applied consistently in all NSPI filings since this Decision.

NON-CONFIDENTIAL

Request IR-39:

Please explain whether any Large Industrial, ELI 2P-RTP, or Municipal customers are served from substations that also serve other classes, and if so, explain how that consideration is reflected in Exhibit 3B.

Response IR-39:

Please refer to CA IR-45.

Yes, there are large industrial and municipal customers who are served from substations that also serve other classes. This is currently not reflected in Exhibit 3B, as NSPI has not attempted to change the basis of this schedule in this proceeding. NSPI has not proposed revisions to the Cost of Service Study, other than in respect of the LED streetlight initiative.

NON-CONFIDENTIAL

Request IR-40:

For each non-dedicated distribution substation,

(a) **Please indicate whether the substation serves exclusively one class, and if so, which class.**

(b) **If the substation serves more than one class, please provide NSPI's estimate of the mix of class load on that substation.**

Response IR-40:

(a-b) NSPI does not normally record the data as requested. We are unable to compile such information within the time prescribed to respond to this request. Please refer to CA IR-45.

NON-CONFIDENTIAL

Request IR-41:

Please list the transmission facilities that are required primarily to connect one or more generator to the transmission system, and the cost of those facilities.

Response IR-41:

The transmission facilities required to connect a generator to the transmission system vary with the location, voltage, and the configuration of the transmission system where the interconnection occurs. Interconnection costs can vary significantly for each generator connection.

NON-CONFIDENTIAL

Request IR-42:

Please provide any available information regarding the transmission facilities that are required primarily to transfer power from generation in the eastern portion of the province to load in the Halifax area, and the cost of those facilities.

Response IR-42:

The transmission facilities required to transfer power from generation sources in the eastern part of the province to the Halifax area vary with the geographic location, size (MW), and type of interconnection service requested by the generator.

East to west flows on the Nova Scotia system are currently limited by transmission transfer levels and availability of special protection systems. For additional firm capacity (non-curtailable) to increase east to west energy flows, significant investments in the bulk transmission system are required. Various scenarios of potential generation developments are outlined in the 10 Year System Outlook Report.

CONFIDENTIAL (Attachment Only)

Request IR-43:

For each of the "other gas turbines" (Tusket, Burnside, and Victoria Junction), please provide the monthly energy generation and monthly peak load on the plant, for each month from June 2009 to May 2011.

Response IR-43:

Please refer to Confidential Attachment 1. Each generating unit uses electrical energy to maintain itself in a state of readiness for operation. This is referred to as Station Service and would include energy for heating, cooling, control systems, and lighting. The negative values in the attachment reflect months with little or no generation and where station service was greater than the generation from the unit to serve customers and system load requirements.

NON-CONFIDENTIAL

Request IR-44:

Please provide the basis of the "76.6%/23.4% ratio" used to initially segregate transmission plant between > 69 kV and < 138 kV voltage (SR-01 Attachment 1 Page 8).

Response IR-44:

The use of the "76.6%/23.4% ratio" in the Cost of Service Study stems from the UARB Decision (NSPI-867) from December 22, 1995[1] in the matter of An Application by Nova Scotia Power Incorporated for approval of an Industrial Expansion Rate. The approved methodology has been applied consistently in NSPI filings since this Decision. Also, please refer to CA IR-45.

[1] NSPI 1995 Industrial Expansion Rate Case, UARB Decision, NSUARB – NSPI – 867, December 22, 1995.

NON-CONFIDENTIAL

Request IR-45:

Please provide the basis of the assumption that 30% of poles carry only primary lines, including all supporting data and analyses. (Exhibit 3B)

Response IR-45:

The Cost of Service Study is based on the methodology approved by the UARB in its Decision of September 22, 1995[1] in the matter of a Generic Hearing respecting Cost of Service and Rate Design for Nova Scotia Power Inc. The approved methodology has been applied consistently in NSPI filings since this Decision. NSPI has not attempted to retrieve and repeat the basis of this principle in this proceeding, which does not propose substantial revisions to the Cost of Service Study, other than in respect of the LED streetlights initiative.

Please refer to Attachments 1[2] and 2[3] for additional information concerning the allocation factors used in the Cost of Service Study submitted as evidence in the 1993 Hearing.

The 30 percent factor is discussed in Attachment 1, page 6 and Attachment 2, page 2.

[1] NSPI 1995 Cost of Service and Rate Design, UARB Decision NSUARB – NSPI – 864, September 22, 1995
[2] NSPI Hearing Relating to Cost of Service and Rate Design, NSUARB – NSPI – Direct Evidence (A.E. Dominie), February 15, 1993.
[3] NSPI Hearing Relating to Cost of Service and Rate Design, NSUARB – NSPI – Direct Evidence (A.E. Dominie), February 15, 1993.

ATTACHMENT 1

COST OF SERVICE PROCEDURES

1. Overview

The overall objective of a cost of service analysis is to identify any inter-class inequities which may be present with regards to over or under contribution to total allocated costs. This determination is based on a comparison of each class' revenue/cost ratio.

The first step in preparing a Cost of Service Study, once the test period is established, is to accumulate the financial and operating information pertaining to that period. In this case, the test period is the 12 months from January 1, 1993 to December 31, 1993. The data accumulated includes estimates for test period plant in service, reserve for depreciation, revenues, operating expenses, kilowatt hours sold, demand data and customer counts. After the data is reviewed, the study proceeds.

A Cost of Service Study consists of an allocation of all revenue requirement costs relative to the furnishing of electric utility service by the Company. This includes the appropriate assignment of operating and maintenance expenses, grants in lieu of taxes, depreciation and responsibility for interest and income taxes incurred on those elements of the electric utility plant in service necessary in whole or in part to provide electric service to the various classifications of utility customers, as well as any profit or loss incurred by the utility.

Where possible, costs are assigned directly to classes of service based upon details derived from the books and records of the Company or by special analyses and studies.

COST OF SERVICE PROCEDURES

Costs not directly assigned are analyzed by functional responsibility in groupings of accounts, such as production, transmission and distribution, and allocated to the various classes of service on the basis of the respective demands, energy use, number of customers, and/or revenue associated with the functional responsibility appropriate for each class of service. In general, the demand component of cost embraces those items which are incurred in order to obtain and maintain the ability to deliver electric energy to customers as called for by them, and are associated with meeting the maximum demands placed on the system. The energy use components of costs are those items which vary with the annual volume of energy supplied to the various classes of service provided by the Company. The customer components of cost are those items that vary with the number of customers served, and revenue related costs are those items which vary with the dollars of revenue received.

It is well established that large demands for electric energy require the use of large production units and transmission line facilities to meet these demands. Plant investment increases as such units and facilities are enlarged to meet these demands. Consequently, these costs are allocated in relationship to system maximum demand responsibility as measured by the allocation methodology. The distribution facilities are allocated on non-coincident demand to recognize diversity at that level. Class non-coincident demands are the demands which are imposed on the distribution system and, in general, are substantially larger than coincident demands. Consequently, the cost of service elements which increase with plant size and capacity are demand costs.

An example of energy costs which vary with the volume of electricity generated and supplied would be fuel costs. These costs increase as the quantity of fuel required to produce an enlarged energy output at generating stations is increased.

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A readily identifiable example of customer costs is customer accounting, including meter reading and collection expenses, and the fixed cost associated with the customer cost component of the distribution system.

Costs associated with miscellaneous revenue are not identified separately, but, rather, the miscellaneous revenue items are deducted from the overall cost assignment.

The first step in the cost analysis is the functionalization of plant and expenses into the functional groups of production, transmission and distribution. From the books and records of the Company, plant investment is readily identifiable for production, transmission and distribution functions. Likewise, expenses for operation and maintenance for production, transmission and distribution are also readily identifiable. However, there are several components of plant, depreciation and expenses which are not maintained on a production, transmission, or distribution basis. These items are functionalized prior to classification and allocation.

Following the functionalization step, production, transmission, and distribution plant and expense are classified. Classification is the process by which plant or costs are deemed to be demand, energy, or customer related.

The third step in conducting the cost study consists of the determination of those demand, energy or customer allocation factors which are necessary to allocate plant or expense to the various classes of service.

The fourth and final step is the allocation procedure. This step involves applying the allocation factors, determined in step 3, to the classified plant and expense from step 2, to determine the overall cost assigned to each class of service based upon the total plant and expenses for the test period.

COST OF SERVICE PROCEDURES

The full development of the results of the analysis are provided in Exhibits AED-2 through 9. The analysis was based on the budgeted test period January 1993 - December 1993. Exhibit 1 summarizes the results of the Cost of Service Studies prepared for Fiscals 1992 and Calendar 1993. Exhibits 2 and 3 detail the rate base analyses, and Exhibits 4 to 6 show the analyses of operating costs and depreciation expense. Exhibit 7 contains the revenue analysis and Exhibit 8 details the development of allocation factors. Exhibit 9 shows the analysis of sales and demand data. (Note that exhibits referenced hereafter are for AED).

2. Discussion

2.1 Methodology

The method of cost assignment presently utilized is the Average and Excess (A&E) method.

This method considers both the demand and energy requirements of the various customer classes in allocating generation and transmission responsibility. It respects both the maximum demand the class placed on the system as well as the extent to which the class used the facilities installed for service.

A portion of costs, equal to the system peak load factor percentage is considered energy related and allocated on the average demand (energy divided by hours in the period). The remaining costs are allocated based on the excess demand (class non-coincident peak demand minus average demand).

2.2 Rate Base

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Exhibit 2 contains the net investment in the various plant categories and working capital as provided by the budget for the calendar year ending December 31, 1993. The investment and working capital which is directly assigned is identified and removed from the total Company balances to arrive at the amounts to be allocated.

Exhibit 3 details the allocation of rate base to the various customer classes.

The first allocation factors to be developed are those related to the number of customers, demand, and energy sales. Exhibit 9A shows the projected energy sales for calendar year 1993 and the quantity generated and purchased before line losses. Given these figures by class and the forecasted coincident peak demands by sector, load factors based on the Fiscal 1992 actual results are applied to arrive at each class demand contribution. Exhibit 9B makes use of the class non-coincident demands and the load levels of those customers known to take power at the various usage levels, in order to arrive at the individual class responsibilities for non-coincident demand at the secondary and primary levels with losses included. These two exhibits provide the data necessary to calculate the demand and energy allocation factors in Exhibit 8. The calculation of these factors is simply the class amount divided by the total. The remaining allocation factors are developed throughout as needed.

With the demand, energy and customer factors developed, the allocation phase proceeds. Steam, and hydro production plant are allocated on the average and excess demand contribution and gas turbine plant is allocated based on the excess demand only.

Distribution plant is more complex in its cost causalities than are the other functions. Substations are allocated in accordance with Exhibit 3A. The

COST OF SERVICE PROCEDURES

amounts invested in facilities which are dedicated to a single customer's use were identified and directly allocated to the customer's respective class. The remaining allocable dollars are allocated on the basis of primary demand levels. The totals for each class are carried forward as the class allocations of substation investment as shown on Exhibit 3.

Pole and wire investment also require a more detailed analysis since the total is made up of both demand and customer components. Exhibit 3B details the first step of the analysis. Based on construction and engineering estimates, 30% of the poles were estimated to be primary while the remainder was split 50% primary and 50% secondary. The total was divided accordingly and then split between customer and demand responsibilities based on 50% demand and 50% customer. The total pole investment, broken down into primary demand and customer and secondary demand and customer, is allocated on Exhibit 3C, by the appropriate allocation factors.

The analysis and allocation of wire investment is similar to that of poles and is detailed in Exhibits 3D and 3E.

Underground facilities were allocated on the basis of the totals of pole and wire investment. Line transformers which are used in the secondary system were allocated on secondary class non-coincident demands. Services were spread on a weighted customer basis.

Meter costs are allocated on Exhibit 3F. The average unit cost of installing a meter for each class was determined. These costs when multiplied by the number of customers in each class provide the cost causation relationships required for developing the allocation.

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Land and Other were allocated on the basis of total substation, pole and wire investments.

The street lighting investment was assigned directly to the unmetered customers.

General and Intangible investment was allocated on the basis of all other plant investment. Finally, the working capital amounts were allocated in accordance with their cost causalities as defined by the allocation factors used.

At this point, all rate base items have been assigned to the various classes recognizing the cost causation and cost utilization relationships defined above.

2.3 Operating Expense

The analysis of operating costs begins in Exhibit 4 with functionalization. The costs are again grouped according to production, transmission, distribution, administrative and general and other. This phase is more complex than that of rate base because the books of the Company are kept on a divisional basis and divisional costs are sometimes caused by various functions. As a comparison, Thermal Division is all production related, while System Planning and Operations costs are functionalized as production, transmission, distribution and administrative and general. The reasons for the multiple functionalizations are fairly clear for all divisions.

Each function's costs are then listed and sub-grouped where necessary in order to classify them as demand, energy, customer, other and direct. This analysis is contained in Exhibit 5.

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The direct column contains those amounts which are not to be assigned to general customer classes. In production, fuel and purchased power is energy related, operating and maintenance are classified primarily as demand with a small percentage (16) being proportioned to energy during this step. Distribution costs are split between demand and customer. Administrative and general costs pertaining to the customer classification are so classified and the remainder or other portion is then allocated on the basis of all other operating and maintenance expenses, excluding fuel and purchased power, to the demand, energy and customer classifications. Grants in lieu of taxes, depreciation, interest, preferred dividends and taxes net will be allocated on the various rate base and the average and excess demand allocators and, therefore, classified as Other.

Exhibit 6 summarizes the next stage of the study which is allocation of operating costs. First, those costs classified as demand, (production operating and maintenance, and transmission) are allocated on the basis of the average and excess demand allocators.

The administrative and general costs which are demand related, were allocated on the basis of all other demand related operating costs. The analysis of distribution costs is more detailed.

Exhibit 6A contains the analysis of distribution costs in total and also the customer and demand breakdowns. Each of the component classifications are allocated using the same factors. Therefore, I will discuss the total section of the allocation only. The basic premise used throughout is that costs should be allocated in the same manner as their rate base counterparts. Land was allocated on the basis of substation, pole and wire investment. Substation costs are spread according to substation investment. Overhead and

COST OF SERVICE PROCEDURES

underground expenses were assigned in relation to the pole and wire and underground investments. Line transformers are secondary demand related. Services expense was allocated to secondary customers. Metering expenses were spread according to the meter investment per class. Communications is related to primary demand and street lighting was again assigned directly to the unmetered class. Exhibit 6B details the analysis of customer service expenses, for the distribution function, by class.

The second step requires the allocation of energy related costs such as fuel, purchased power, and operating and maintenance. These were allocated on the basis of energy generated and purchased.

Third, the customer related expenses are allocated. Again, the distribution costs are determined from Exhibit 6A. Billing and meter reading as well as customer services were assigned using total weighted customers. Exhibit 6C details the allocation of credit and collections expense. First, the bad debts expense is split between domestic and all other classes based on gross write off experience. The other class portion is assigned to each class based on the average number of customers served. The other portion is distributed on the basis of secondary customer revenue. Again, administrative and general costs which are customer related are allocated on the basis of all other customer related costs.

Finally, depreciation is allocated by function as shown on Exhibit 6D. Grants in lieu of taxes are allocated on the basis of total production, transmission and distribution plant. Interest, preferred dividends and taxes net expense is allocated based on the total rate base assignment from Exhibit 3. The total costs for each class are then determined and adjusted by non-rate revenue

COST OF SERVICE PROCEDURES

and the net income (loss) to arrive at the net cost by each customer class. The resultant total then becomes the input to rate design.

Using the total allocated costs for each class, a comparison is made with the revenues for each class to determine the percentage revenue to cost relationships. The results are shown on Exhibit 10.

3. Procedural Summary

3.1 Introduction

The rates charged by Nova Scotia Power to its customers for their consumption of electrical demand and energy, are developed through a systematic procedure of cost allocation (see Figure A-1 - Cost of Service Overview). This procedure attempts to charge to each existing (or proposed) rate class, the costs incurred by the Company in supplying the electrical requirements of that class.

While it is a primary concern that total system revenues cover the total cost of service, it is just as important that each sector of the public pay its individual fair share of the cost of providing electric service.

Cost allocation provides the best indication of how well this principle is being followed. While not an exact measurement, it is an accepted approximation and any differences are not considered sufficient to improperly influence conclusions drawn from the results.

COST OF SERVICE PROCEDURES

3.2 Procedure

Prior to preparing the actual study, the first task of the allocator is to secure and organize information pertaining to customer loads and consumption patterns, fixed asset detail, capital activity, operating data (both financial and system), as well as, system maps, one line diagrams, customer load studies, transmission, and distribution loss studies, particulars concerning dedicated facilities, etc.

The procedure can be subdivided into three major steps; Functionalization, Classification, and Allocation.

The following is a brief explanation of these steps as they are employed in transferring the Company's expenses and fixed assets, per the financial accounting responsibility system, to rate responsibility.

<u>Step 1 - Functionalize</u> (See Figure A-2)

- This is the procedure whereby expenses and fixed assets are re-grouped from the accounting system into functional cost groups. This activity is the most difficult and time consuming part of the cost allocation procedure, usually absorbing at least 60-70% of the total effort. It involves such activities as sub-dividing the transmission and distribution system components into the appropriate categories based on the different voltages at which service is rendered to the various customers and customer classifications. Also included is the sub-dividing of General Property, working capital provision, joint and common costs and plant, and the apportionment of contributed capital.

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Step 2 - Classify (See Figure A-3)

- This procedure effectively provides the total demand, energy, customer, and other costs. It separates each functionalized cost into its separate components and includes the selection of the appropriate methodologies based on sound utility criteria. Determination of the demand portion of the production costs can be based on any one of a number of acceptable criteria; coincident peak load factor, non-coincident peak load factor, or monthly average load factors for either peak. Distribution separation of customer and demand costs can be based on judgement, as well as, minimum customer or zero intercept methods. Any option chosen must be supportable and defensible based on the specific circumstances affecting the utility in the costing timeframe, as well as design, operating, and other functions as they may exist from time to time.

Step 3 - Allocate (See Figure A-4)

- In this step , all costs are assigned to the respective rate classes to arrive at the total cost attributable to that rate. For the sake of simplicity, only four classes are shown in the appendix and the non-rate revenues are deducted from the total costs allocated to each class. The result is further adjusted by the profit or loss provisions as appropriate. As well, individual cost components of major cost

  groupings are assigned based on factors developed from derivations of the major cost causation factor (e.g. various demand and energy factors are developed for individual distribution categories and losses at the various supply voltages). Various customer cost allocations are

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based on relative weights attached to the cost element (i.e. demand vs. straight energy meters). The key knowledge required for this step is a complete understanding of the various causation/utilization relationships that exist for all expenses so that they can be properly allocated to the various classes.

Where appropriate, all costs associated with the financing or operating of facilities (primarily Production and Transmission), dedicated or owned by one particular customer or class, are assigned directly to that customer or customer class.

Distribution demand costs are allocated based on the class non-coincident demand (the peak of the class, as a group, whenever it occurred, independent of system or individual customer peaks), and fuel on the kW.h generated for each class. Customer, Head Office and Other (Capital) costs are allocated based on the various factors which cause them to be incurred. It should be noted that where costs are referred to as Production, Transmission, Distribution, etc., that they are functional costs rather than divisional responsibility accounting costs.

For cost allocation purposes, the Transmission and Distribution functionalization split is taken at the 69 kV level. Everything below 69 kV is Distribution and all 69 kV and above is Transmission. In the case of substations where the incoming voltage is > or = to 69kV, and the outgoing voltage is < 69 kV, (Distribution Bulk Power) they are considered Distribution since their function is to supply a distribution voltage. Step-up stations at the generating plant are considered transmission for the same reason.

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All in all, the entire procedure must be examined in a manner which reflects its use as an indicator, not a dictator. The cost allocator must ensure that all viable alternative approaches are examined and that the final position chosen will be acceptable and reasonable and produce the fairest and most equitable results.

3.3 Performance Measurements

After adjusting total cost allocation by the various non-rate revenue items and the net income (loss) to arrive at net costs attributable to rate recovery, the revenue from each class is measured against the assigned total net cost to determine the class performance; this is expressed as a percentage recovery and is commonly referred to as the Revenue/Cost Ratio.

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4. Terms and Definitions

Fixed Costs:	those costs which do not vary materially with the volume of output or number of customers. They are generally related to the size and capacity of the plant installed to provide service. Costs such as interest, depreciation, operating labor and insurance are examples of fixed costs.
Variable Cost:	those costs which vary substantially with plant output. They are a direct function of the length of time plant facilities are used to furnish service. Fuel is a prime example of a variable cost.
Customer Costs:	those costs which relate to the number and size of customers and do not vary significantly with the volume of sales. They include such items as service and metering costs, customer accounting, and billing and collection costs.
Capacity Costs:	those costs which are related to the electrical capacity of the total power system or to its various components. This term is sometimes used interchangeably with fixed costs.

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Demand Costs:	those costs which are to be allocated to customer classifications on the basis of their respective use of system capacity. This term is sometimes used interchangeably with capacity costs or fixed costs.
Energy & kW.h Costs:	those costs which are to be allocated to customer classifications on the basis of their respective kilowatt hour consumptions (terms are used interchangeably).
Direct Costs:	those costs which are assigned directly to a particular customer or customer classification such as a specific line, substation, services, meters and street lighting facilities.
Indirect Costs:	those costs which are not exclusively identifiable with a specific operation or facility of the system. Administrative and general expense is an example of indirect costs.
Common Costs:	those costs that are incurred in the provision of more than one product or service. One example would be the cost relating to boiler maintenance where the utility is engaged in the sale of both electricity and steam (sometimes used interchangeably with joint costs).

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<u>Joint Costs</u>: those costs which are incurred to serve more than one classification of service. A typical example is the cost related to the generation of electricity and the high voltage transmission lines which tie together the power sources and load centers (sometimes used interchangeably with common costs).

<u>Cost Behavior</u>: the causation of the particular cost with which we are concerned. The cost of property insurance is associated with gross investment in plant, and depreciation expense is based on gross depreciable plant.

<u>Load Factor</u>: the ratio of the average load in kilowatts during a specific time period to the maximum load occurring in such period.

$$\frac{\text{Average kW}}{\text{Maximum Load kW}} \times 100 = \text{Percent}$$

<u>Diversity Factor</u>: the ratio of the sum of the maximum non-coincident loads in kilowatts to the coincident demand of the combined loads. The diversity factor cannot be less than 1.0 or unity. Example:

$$\frac{\text{Max. Load (100 kW) + Max. Load (300 kW)}}{\text{Max. Coincident Demand (200 kW)}} = 2.0$$

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Coincidence Factor:	the reciprocal of the diversity factor and always less than 1.0 or unity. Example: $\frac{\text{Max. Coincident Demand (200 kW)}}{\text{Max. Load (100 kW) + Max. load (300 kW)}} = .5$
Coincident Demand:	the sum of two or more individual kilowatt demands which occur in the same demand interval.
Non-coincident Demand:	the sum of two or more individual kilowatt demands which do not usually occur in the same demand interval, usually not to exceed one year.
Demand Interval:	the period of time during which the flow of electricity is averaged such as one hour, thirty minutes, fifteen minutes, etc.
Peak Demand:	the maximum demand imposed on a power system or component thereof within a particular demand interval.
Class Demand:	the maximum coincident kilowatt demand of a class of customers within a particular demand interval.

ATTACHMENT 3

The following approaches are used in classifying individual distribution plant costs.

A. Land - The purpose of distribution land is to provide space to accommodate distribution assets. These common or indirect costs can best be related to the direct costs of distribution assets such as substation, pole and wire. Therefore, the method used to classify land is based on the average split of all three assets between demand and customer-related costs.

B. Easements-Line Right of Way -The purpose of having easements and Right of ways is so that the assets such as substations, pole and wire have a place to locate. These common or indirect costs can best be related to these assets. Therefore, the method used to classify Easements & Surveys is based on the average split of all three assets between demand and customer related costs.

C. Buildings Structures & Grounds-The purpose of these common costs can best be related to the direct costs associated with Substation, Poles & Overhead Wire investment. Therefore, these common costs are classified on that basis.

D. Substations-Distribution substations are classified demand and direct. Where a substation can be identified as serving only one customer the station costs are analyzed and directly assigned to the class of service which the station served. Substations are analyzed by the following functions:

- Distribution Bulk Power
- Distribution Dedicated Bulk Power
- Distribution General
- Distribution Dedicated General

E. <u>Poles & Fixtures</u>-In 1977, the average historical cost for various size poles was determined from the books and records of the company. Using the minimum size concepts, 30 and 35 foot poles were determined to be the minimum size required to physically connect all customers to the system.

The average weighted cost of 30 and 35 foot poles weighing 30 foot poles at 2 and 35 foot at 1 was $104.10. Total number of poles multiplied by this cost equated to 63% of the total investment in poles. This 63% of the pole investment was classified as customer cost and the remaining 37% as demand cost.

This separation then recognizes the minimum size required to provide service to all customers on the distribution system and the demand component is that cost which is over the base or that is required to serve the demands for electricity placed on the system.

Based upon engineering and construction estimates, 30% of the poles were then functionalized as primary only and the remaining 70% was functionalized 50% primary-50% secondary. These costs were then classified 63% customer-37% demand.

In 1982 we changed the relationship for that portion serving both the customer and demand classifications to a 50/50 split. The 50/50 relationship selected represented our best judgmental split based on data presented in previous hearings, general knowledge and assumptions, discussions with corporate engineering and distribution personnel and input from corporate consultants.

At the present time we see no reason why this relationship should be changed.

F. Overhead Lines-In 1977 an analysis was made for distribution wire investments using the same minimum size concepts used in the pole analysis. Number 1/0 copper and number 2/8 aluminum were deemed to be the minimum wire sizes required to provide the ability for the customers to take service from the distribution system. Based upon a sample review of the installed cost of this wire, 59% was deemed to be required for minimum size purposes. This was predicated on a weighted cost per foot weighing #6 wire twice and all other wire once. This equated to a cost of $131.38 per thousand feet. This cost, when multiplied by the total feet of wire provides for 59% of the total wire cost to be customer related. The remaining 41% is then demand related. This is done on the basis that cost above the base is there to meet the load or demand that the customer places on the system. As with poles, 30% of the wire was functionalized as primary and the remaining 70% was functionalized 50% primary and 50% secondary. These functions were then classified 59% customer related cost and 41% demand related cost. .

In 1982 we changed the relationship for that portion serving both the customer and demand classification to a 50/50 split. The same criteria was used as outlined in the pole investment.

At the present time, we see no reason why this relationship should be changed.

G. Underground Lines-Underground facilities perform a similar function to Overhead lines. Therefore, the cost split is based on the same split used for Overhead line costs explained above.

H. Transformers-The purpose of line transformers is to control the demand on the secondary system. Line transformers are classified as demand-related costs.

I. Services-Services relate to the costs of providing service to a customer's premises and are therefore a customer-related cost.

J. Meters-Meter investment is assigned to each customer class based on a pre-determined meter cost for each class. The investments classified as customer-related.

K. Street Lighting-Street Lighting investment is classified as demand-related and assigned directly to the unmetered class.

As indicated above, the pole and wire accounts have been classified to both customer and demand-related costs based on a fixed percentage classification concept. This method is the simplest way of classifying these costs and is practised by several Canadian Utilities.

While the classification of the above account groupings are important, there are only a few commonly accepted methods for classifying distribution plant.

These methods include the Minimum Size and Minimum Intercept (zero–intercept) Methods.

The minimum system identifies the costs associated with providing the minimal service and, as such, does not vary with demand. These fixed costs are classified as customer-related.

The minimum size method uses costs associated with the minimal service based on current-day prices.

The minimum intercept method uses costs associated with various sizes of equipment using average installed book costs. The technique is to relate installed costs to current capacity or demand rating, create a curve for various sizes of the equipment using regression techniques and extend the curve to a no-load intercept. The cost related to the zero intercept load is the desired customer component. This method seeks to identify the portion of plant related to a hypothetical no-load or zero intercept situation.

This method requires considerably more data and calculation than does the minimum size method and although more accurate the difference between the two can be relatively small.

NON-CONFIDENTIAL

Request IR-46:

Please provide the basis for the assumption that the cost of poles carrying both primary and secondary lines is 50% due to the secondary lines (Exhibit 3B). In addition,

(a) Please provide all studies and analyses supporting this estimate.

(b) Please provide any analysis supporting NSPI's believe that the cost of a pole supporting both primary and secondary lines would have been lower if the secondary lines were not required.

(c) Please provide NSPI's estimate of the increased cost of a pole that now supports only primary lines, if NSPI were to use it to support secondary lines.

Response IR-46:

(a-c) The basis for the assumption that the cost of poles carrying both primary and secondary lines is 50 percent due to the secondary lines are discussed in CA IR-45 Attachment 1, page 6, and CA IR-45 Attachment 2, page 3.

NON-CONFIDENTIAL

Request IR-47:

Please provide any data available to NSPI regarding the number of feet of overhead cable and wire in service, by type (e.g., copper, ACSR) and size (i.e., gauge or diameter).

Response IR-47:

Transmission line information is provided in Attachment 1. NSPI does not have this breakdown for distribution conductor.

Transmission Line Lengths

Size/Type	Feet
556, ACSR	5414788
336.5, ACSR	2006999
1/0, ACSR	72422
636, ACSR	94726
795, ACSR	3612690
556, ASC	22435
4/0, ACSR	1341586
No.1, ACSR	29454
336.4, ACS	68519
795.0, ASC	50938
2/0, ACSR	1064557
No.2, ACSR	5248
4, ACSR	1771
4/0, ACS	24370
2/0, Copp	135825
1113.0, ACSR	2841923
626.7, ACSR	14432
339.3, ACSR	3050
Unknown	9086
950, AASCR	2788
626.7, ASCR	19221
2156, AASCR	9053
2156.0, ACSR	30766
Total	16876650

Legend

AAC - All Aluminum Conductor
ACSR - Aluminum Conductor Steel Reinforced
AASC - Aluminum Alloy Stranded Conductor
ASC - Aluminum Stranded Conductor
AASCR - Aluminum Alloy Steel Reinforced

NON-CONFIDENTIAL

Request IR-48:

Please provide the basis for classifying primary-only pole investment as 100% demand-related (Exhibit 3C).

(a) Include all studies, analyses, calculations and workpapers

Response IR-48:

The classification of primary-only pole investment as 100 percent demand-related has been applied consistently in all GRA submissions since 1995. The investment represents 30 percent of the total pole plant investment as determined through engineering and construction estimates. Its classification as demand-related only is reflective of its load-based cost causation principle. Similarly to distribution substations, the primary feeders reflect higher load diversity and their investment is driven primarily by the growth in load, as opposed to that in the number of customers. Also, please refer to response to CA IR-51.

NON-CONFIDENTIAL

Request IR-49:

Please provide the basis for classifying joint-primary and joint-secondary pole investment as 50% demand-related and 50% customer-related (Exhibit 3C).

(a) Include all studies, analyses, calculations and workpapers.

Response IR-49:

Please refer to CA IR-45.

The basis for classifying joint-primary and joint-secondary pole investment as 50 percent demand-related and 50 percent customer-related is discussed in CA IR-45 Attachment 1, page 6.

NON-CONFIDENTIAL

Request IR-50:

Please provide the basis for classifying joint-primary and joint-secondary wire investment as 50% demand-related and 50% customer-related (Exhibit 3E).

(a) Include all studies, analyses, calculations and workpapers.

Response IR-50:

The basis for classifying joint-primary and joint-secondary wire investment as 50 percent demand-related and 50 percent customer-related is discussed in CA IR-45, Attachment 1, page 6.

NON-CONFIDENTIAL

Request IR-51:

Please provide the basis for classifying primary-only wire investment as 100% demand-related (Exhibit 3E).

(a) Include all studies, analyses, calculations and workpapers

Response IR-51:

The classification of primary-only wire investment as 100 percent demand-related has been used consistently by NSPI in GRA submissions since 1995. The investment represents 30 percent of the total wire plant investment as determined through engineering and construction estimates. Its classification as demand-related only is reflective of its load-based cost causation principle. Also, please refer to response to CA IR-48.

NON-CONFIDENTIAL

Request IR-52:

Please explain how the number or cost of poles changes as customers are added along a street with existing electric service.

Response IR-52:

Typically the number or cost of poles along the street does not change as customers are added along a street with existing electrical service. Additional service poles may be required to reach the customer service entrance depending for the most part on distance from the current pole line.

NON-CONFIDENTIAL

Request IR-53:

If half the customers along an overhead primary feeder (e.g., every second customer) had never existed, what percentage of poles would have been avoided?

Response IR-53:

In general, the number of poles along the road which make up the overhead primary feeder would not change if half the customers did not exist. The only poles which would not be required, would be individual service poles to those customers if they were located a significant distance from the overhead primary feeder along the road. Approximately 20 percent of our customers require a service pole; therefore, potentially 10 percent of the service poles would be avoided.

NON-CONFIDENTIAL

Request IR-54:

Please indicate whether the Company has ever added distribution lines due to current or anticipated overloading on the existing system.

Response IR-54:

Yes, the Company has added distribution lines to address current overloaded lines as well as in anticipation of projected load requirements.

NON-CONFIDENTIAL

Request IR-55:

Please indicate whether the Company has ever added distribution lines purely to serve increased loads of existing customers or to serve new customers in geographical areas served by existing lines.

Response IR-55:

Yes, the Company has added distribution lines purely to serve increased loads of existing customers. For example when a customer currently served by single phase converts to three phase additional line is required. The Company has also added distribution lines for new customers in geographical areas served by existing lines.

NON-CONFIDENTIAL

Request IR-56:

Please indicate whether the Company has ever had to bypass existing lines to hook-up new customers because the capacity on the existing lines is insufficient to serve the added load.

Response IR-56:

Yes, the Company has bypassed existing lines to hook up new customers in instances where doing so is better service reliability for customers overall.

NON-CONFIDENTIAL

Request IR-57:

Please indicate whether the Company has analyzed the amount of distribution equipment installed to meet increases in loads of existing customers (rather than new customers). If so, please provide

(a) the Company's analyses, including workpapers, and

(b) supporting materials, such as project planning and justification documents.

Response IR-57:

(a – b) The Company has not analyzed the amount of distribution equipment installed to meet increases in loads of existing customers rather than new customers.

CONFIDENTIAL (Attachment Only)

Request IR-58:

Please provide the Company's most recent study of the need for new distribution facilities and for upgrades to existing equipment.

Response IR-58:

The Company performs distribution planning studies as required, focusing on areas of load growth where overloading has occurred or is imminent. Planning studies recommend improvements and/or upgrades based on anticipated load growth, current overloaded conditions, other technical criteria related to customer supply, and the addition of large customers to the system. The most recent study is the Liverpool Area Distribution Planning Study, report no. 265-0109-W68. Please refer to Confidential Attachment 1.

NON-CONFIDENTIAL

Request IR-59:

How does NSPI's cost allocation for pole account for the costs of cross arms and other equipment required for primary voltages, but not generally for secondary voltages?

Response IR-59:

NSPI does not normally record the data requested. We are unable to compile such information within the time prescribed to respond to this request. Please refer to CA IR-45.

NON-CONFIDENTIAL

Request IR-60:

Please provide any available data on the breakdown of NSPI's pole function between poles per se and other equipment (guys, cross arms, insulators, etc.).

Response IR-60:

NSPI assumes that the question is concerned with the breakdown of costs of these components. For a typical three phase line extension, the average breakdown of costs (excluding the cost of the transformer) would be as follows:

Material Breakdown	Total Cost[1] (%)
Poles	34.8
Conductor	21.9
Cross arms	6.2
Insulators	5.9
Misc	31.2
Total	100

1. Excludes the cost of the Transformer

CONFIDENTIAL (Attachment Only)

Request IR-61:

Please provide circuit maps or diagrams for all NSPI overhead primary circuits, showing each pole, transformer and customer connection.

Response IR-61:

At this time NSPI does not have circuit maps for all NSPI overhead primary circuits, showing each pole, transformer and customer connection.

The existing level of detail available for all circuit maps for NSPI overhead primary circuits can be seen in example in Confidential Attachment 1. It would require almost 1500 drawings to provide this detail for the total system.

NON-CONFIDENTIAL

Request IR-62:

Please explain why the ratios for wire costs in SR-01 Attachment 1, Exhibit 3E are the same as for poles in Exhibit 3B.

(a) Does Exhibit 3E assume that the length of secondary wire or cable connected to a pole will equal the length of primary wire or cable connected to a pole? If so, please explain why that should be true.

(b) Does Exhibit 3E assume that, if a pole carries any secondary conductor, the secondary almost always extends in both directions from the pole?

Response IR-62:

For an explanation as to why the ratios in SR-01 Attachment 1, Exhibit 3C (pole investment) and 3E (wire investment) are the same, please refer to CA IR-45 Attachment 2 (Sections E and F).

(a-b) Please refer to CA IR-64.

NON-CONFIDENTIAL

Request IR-63:

Please provide all of NSPI's distribution planning and construction guidelines, rules, handbooks, or other materials guiding designers and field staff in selecting distribution equipment topology, including but not limited to the height of poles, the arrangement of equipment along the poles, the sizing of conductor, the requirements for messenger wire, and acceptable length of secondary runs.

Response IR-63:

NSPI designers and field staff use the Nova Scotia Power Distribution Standards Manuals when selecting and designing distribution systems.

These manuals can be viewed at NSPI offices.

NON-CONFIDENTIAL

Request IR-64:

Please explain the concept of "50% joint" conductors in Exhibit 3E. Since each conductor carries either primary or secondary power, but not both, how can any conductor be "50% joint"?

Response IR-64:

The labels: "50% JOINT – PRI. (1)" and "50% JOINT – SEC. (1)", as used in Exhibit 3E, are not indicative of the physical characteristics of the conductors involved or distribution network configuration. They are reflective of the 50 percent split allocation principle applied in the re-functionalization of 70 percent of wire rate base between secondary and primary services. Please refer to part F of attachment 2 of CA IR-45 for more details.

Request IR-65:

Please provide any data on the percentages of NSPI's overhead primary distribution system that are single-phase, two-phase, and three-phase.

Response IR-65:

The overhead primary distribution system is comprised of the following:

- Single Phase – 70 percent
- Two Phase – 1 percent
- Three Phase – 29 percent

NON-CONFIDENTIAL

Request IR-66:

Please provide any data on the percentages of NSPI's overhead secondary distribution that are single-phase, two-phase, and three-phase.

Response IR-66:

NSPI does not have the data requested.

NON-CONFIDENTIAL

Request IR-67:

Please explain why "Underground facilities were allocated on the basis of the totals of pole and wire investment." (SR-01 Attachment 1 Page 9)

Response IR-67:

Please refer to CA IR-45 Attachment 2 (Section G).

NON-CONFIDENTIAL

Request IR-68:

Please provide any data on the percentages of NSPI's underground primary distribution system that are single-phase, two-phase, and three-phase.

Response IR-68:

The underground primary distribution system is comprised of the following:

- Single Phase – 25.59 percent
- Two Phase – 0.02 percent
- Three Phase – 74.39 percent

NON-CONFIDENTIAL

Request IR-69:

Please provide any data on the percentages of NSPI's underground secondary distribution that are single-phase, two-phase, and three-phase.

Response IR-69:

NSPI does not have the data requested.

NON-CONFIDENTIAL

Request IR-70:

Please provide any data available to NSPI regarding the number of feet of underground conductor in service, by type (e.g., copper, ACSR) and size (i.e., gauge or diameter).

Response IR-70:

NSPI has data related to primary underground conductors and is provided in Attachment 1.

Underground Conductor by type, size & lengh

NK = not known

Material	Size	Phase/Type	Span Length (m)	Total Conductor Length (ft)
AASC	#2	Single SUB	446.19	1,463.88
AASC	2/0	Single SUB	535.09	1,755.53
ACSR	#1	Single SUB	1,037.99	3,405.49
ACSR	1/0	Single SUB	21,880.31	71,785.79
ACSR	2/0	Single SUB	7.38	24.22
AL	750	Single SUB	5.82	19.08
CU	#2	Single SUB	12,280.20	40,289.37
NK	NK	Single SUB	2,271.05	7,450.95
SOCU	#2	Single SUB	2,681.40	8,797.25
SOCU	#4	Single SUB	189.35	621.23
AASC	#1	Single UG	714.77	2,345.05
AASC	#2	Single UG	1,261.45	4,138.61
AASC	1	Single UG	3.09	10.13
AASC	1/0	Single UG	2.74	8.99
AASC	2/0	Single UG	716.84	2,351.84
ACSR	#1	Single UG	26,419.60	86,678.46
ACSR	#2	Single UG	3,117.92	10,229.39
ACSR	#4	Single UG	158.07	518.62
ACSR	1/0	Single UG	26,154.88	85,809.97
ACSR	2/0	Single UG	1,713.04	5,620.19
ACSR	3/0	Single UG	1,811.95	5,944.71
AL	750	Single UG	115.12	377.69
CUW	#6	Single UG	84.54	277.37
NK	NK	Single UG	3,240.29	10,630.87
NK	350	Single UG	18.20	59.72
NK	NK	Single UG	8,277.37	27,156.73
SOCU	#2	Single UG	2,988.37	9,804.37
SOCU	#4	Single UG	935.28	3,068.51
SOCU	#6	Single UG	81.13	266.18
ACSR	#1	Three SUB	672.64	6,620.44
ACSR	1/0	Three SUB	1,385.88	13,640.58
ASC	336	Three SUB	10.43	102.62
NK	NK	Three SUB	53.97	531.23
SOCU	#2	Three SUB	701.64	6,905.88
AASC	#1	Three UG	1,153.33	11,351.71
AASC	#2	Three UG	1,355.35	13,340.07
AASC	1/0	Three UG	1.86	18.31

<u>Underground Conductor by type, size & lengh</u>

NK = not known

Material	Size	Phase/Type	Span Length (m)	Total Conductor Length (ft)
AASC	2/0	Three UG	2,584.19	25,434.89
AASC	3/0	Three UG	5.41	53.23
AASC	350	Three UG	50.79	499.87
AASC	4/0	Three UG	374.20	3,683.05
AASC	NK	Three UG	35.10	345.45
ACSR	#1	Three UG	63,925.61	629,189.03
ACSR	#2	Three UG	1,166.81	11,484.33
ACSR	#4	Three UG	569.72	5,607.50
ACSR	1/0	Three UG	37,670.99	370,777.44
ACSR	2/0	Three UG	4,716.54	46,422.65
ACSR	3/0	Three UG	12,944.53	127,406.78
ACSR	336	Three UG	10.00	98.43
ACSR	4/0	Three UG	190.42	1,874.25
AL	500	Three UG	270.38	2,661.23
AL	750	Three UG	40,302.40	396,677.18
AL	NK	Three UG	589.78	5,804.92
ASC	#1	Three UG	572.23	5,632.21
ASC	336	Three UG	8,870.35	87,306.60
CU	1/0	Three UG	37.45	368.64
CU	2/0	Three UG	93.46	919.92
CU	500	Three UG	314.39	3,094.39
NK	NK	Three UG	937.48	9,227.18
NK	NK	Three UG	154.71	1,522.69
NK	1/0	Three UG	54.98	541.16
NK	350	Three UG	5,591.23	55,031.81
NK	750	Three UG	65.04	640.15
NK	NK	Three UG	36,374.34	358,015.18
OTH	350	Three UG	570.02	5,610.48
SOCU	#2	Three UG	234.40	2,307.07
SOCU	#4	Three UG	986.67	9,711.33
SOCU	#6	Three UG	480.88	4,733.08
AL	750	Two UG	55.08	361.39
		Total	**345,284.12**	**2,616,464.59**

Material	Size	Span Length (m)	Total Conductor Length (ft)
AAC	4/0	50.00	164.06
AASC	#1	5.73	18.79
AASC	#2	114.16	374.54
AASC	1/0	1,341.24	4,400.41
AASC	2/0	725.03	2,378.72
AASC	3/0	5.41	17.74
AASC	4/0	31.34	102.82
ACSR	Missing	149.72	491.21
ACSR	#1	10,214.05	33,510.65
ACSR	1/0	4,990.80	16,374.03
ACSR	2/0	7,686.91	25,219.53
ACSR	3/0	5,042.25	16,542.81
ACSR	Not Known	671.14	2,201.89
AL	Missing	34.05	111.71
AL	750	456.19	1,496.70
ASC	#1	401.71	1,317.96
ASC	Not Known	9.63	31.58
CU	#1	227.02	744.81
CU	Not Known	5,451.42	17,885.22
Missing	Missing	268,827.88	881,981.23
Missing	#1	57.97	190.19
Missing	1/0	572.71	1,878.97
Missing	Not Known	249.49	818.53
Not Known	Missing	70.98	232.86
Not Known	#1	199.46	654.39
Not Known	1/0	251.57	825.36
Not Known	2/0	26.35	86.43
Not Known	Not Known	29,561.60	96,986.87
SOCU	Missing	279.16	915.87
SOCU	Not Known	1,477.50	4,847.45
	Total	**339,182.46**	**1,112,803.36**

NON-CONFIDENTIAL

Request IR-71:

Please provide any data available to NSPI regarding the number of feet of underground conductor in conduit, as opposed to direct-buried.

(a) Please provide any data available to NSPI regarding the percentage underground primary conductor in conduit, as opposed to direct-buried.

(b) Please provide any data available to NSPI regarding the percentage underground secondary conductor in conduit, as opposed to direct-buried.

Response IR-71:

(a-b) NSPI has no data on the percentage of underground conductor in conduit as opposed to direct buried for both primary and secondary voltages.

NON-CONFIDENTIAL

Request IR-72:

Please provide the analysis of weighted service costs, with all supporting documents and analysis (SR-01 Attachment 1 Page 9).

Response IR-72:

For the confirmation of the weighted service cost approach please refer to CA IR-45 Attachment 1, Page 6.

NON-CONFIDENTIAL

Request IR-73:

Please explain how the analysis of service costs accounts for the percentage of customers who share service drops.

Response IR-73:

In preparation of filing the general rate application, NSPI uses the actual year-end active customer count as of December 2010 and applies a customer growth factor (based on historical trends) for each class in 2011 and 2012. Using historical trends, NSPI is able to take into consideration any customer classes that share a service drop.

NON-CONFIDENTIAL

Request IR-74:

Please provide the derivation of "The average unit cost of installing a meter for each class."

Response IR-74:

Please refer to CA IR-45.

NON-CONFIDENTIAL

Request IR-75:

Please explain how pole and wire investments require land analysis (SR-01 Attachment 1 Page 9).

Response IR-75:

SR-01 Attachment 1 (page 9) does not imply that pole and wire investments require land analysis. Rather, it indicates that the land assets were allocated on the basis of total substation, pole and wire investments.

NON-CONFIDENTIAL

Request IR-76:

Please provide any available data on the breakdown of NSPI distribution "Land" assets substations, and distribution lines.

Response IR-76:

Please refer to SR-01 Attachment 1 (Exhibit 2) of the Application for the breakdown of NSPI's distribution land, substation and distribution lines.

NON-CONFIDENTIAL

Request IR-77:

Please explain how land, easements and surveys used for generation and transmission are treated in the Cost of Service Study.

Response IR-77:

The land, easements and surveys, which are functionalized as transmission-related in NSPI's accounting system, are included in the aggregate transmission rate base amount as stated in SR-01, Attachment 1, Exhibit 2 on page 15, lines 7 and 8.

The land, easements and surveys, which are part of General Property Plant, as reported in NSPI's Accounting system, are functionalized among the generation, transmission and distribution areas, in the Cost of Service Study. This is accomplished based on the relative shares of these areas in the total net plant value before the general property plant and working capital.

NON-CONFIDENTIAL

Request IR-78:

Please provide a list of the parcels included in the "Land," "Easements," and "Survey" functions in Exhibit 3A, and the underlying functions they serve.

Response IR-78:

NSPI does not normally record the data as requested. We are unable to compile such information within the time prescribed to respond to this request. Please refer to CA IR-45.

NON-CONFIDENTIAL

Request IR-79:

Please provide any information available to NSPI on the number of services by class, reflecting the sharing of services by small customers in a multi-customer building.

Response IR-79:

NSPI does not have information reflecting the sharing of services by small customers in a multi-customer building.

NON-CONFIDENTIAL

Request IR-80:

Please provide NSPI's estimate of the percentage of its domestic customers who live in multi-family buildings.

Response IR-80:

NSPI does not have information of the percentage of its domestic customers who live in multi-family buildings. NSPI does estimate that of the approximate 441,000 residential households, approximately 145,000 are rented dwellings based on Statistics Canada's 2009 survey of household spending and dwelling characteristics[1].

[1] Statistic Canada Table 11-4 *Survey of household spending (SHS), dwelling characteristics at the time of interview, by province, territory and selected metropolitan areas, annual.*

NON-CONFIDENTIAL

Request IR-81:

Please explain whether NSPI typically serves a multi-family building with a single service, or with a separate service for each customer.

Response IR-81:

NSPI normally supplies a residential multi-occupancy building with one set of utility supply conductors, but we do supply some residential multi-occupancy buildings with more than one set of supply conductors.

Where more than one set of utility supply conductors is run to a residential multi-occupancy building:

i) The occupancies shall be completely self-contained (i.e. no indoor access between occupancies); and
ii) The occupancies shall not be located one above the other; and
iii) The occupancies shall have a separate entrance with direct access to ground level.

Complex structures may have more than one utility supply. Both the Supply and Inspection Authorities must approve all installations where more than one supply service is requested or required.

NON-CONFIDENTIAL

Request IR-82:

Please indicate whether NSPI subtracts out customer contributions from its estimate of each class' share of distribution costs.

(a) If so, document the calculations, including all data, assumptions, workpapers and spreadsheets (with formulas intact) relied upon.

(b) If not, estimate the cost by distribution component and rate class adjusted for the customer contribution and provide the basis for these estimates.

Response IR-82:

Yes, the "contributions in aid of construction" are subtracted from the rate base total value for ratemaking purposes. The records of these contributions are not tracked by individual rate classes but by the functional areas of distribution and transmission.

(a) These calculations are completed within our financial systems before allocation in the cost of service model. The implicit effect of these contributions, as embedded in net rate base values by the distribution and transmission areas, is flown through to rate classes using the approved rate base classification and cost classification and allocation methodology.

Not applicable.

NON-CONFIDENTIAL

Request IR-83:

Please provide the basis and supporting documents and computations for the estimates by month and class in Exhibit 9A of each of the following:

(a) Energy line losses

(b) Class non-coincident demand

(c) System coincident factor

(d) System coincident demand

(e) Demand line losses

(f) System coincident peak demand

(g) System coincident L/D factor

Response IR-83:

Please refer to Multeese IR-1 Attachment 1 (Input Data Two Tab and Exhibit 9A) and CA IR-45.

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Request IR-84:

Please provide the basis and supporting documents and computations for the estimates of class non-coincident kW demand in Exhibit 9B.

Response IR-84:

Please refer to Multeese IR-1 Attachment 1 (Exhibit 9B) and CA IR-45.

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Request IR-85:

Please provide NSPI's estimate of the date and time of the historical non-coincident kW demand for each class, on which Exhibit 9B is based.

Response IR-85:

The estimate for non-coincident kW demand is based on historical hourly load profiles for each class. These profiles are scaled to the forecast class energy sales and the maximum hourly demands are selected from the resulting load shapes.

The table below shows the date and time of the non-coincident kW demand peaks from the original load profiles.

Class	Date	Time Hour-ending
Domestic	21-Jan-08	18:00
Small General	21-Jan-08	18:00
General	21-Jan-08	12:00
Large General	8-Jul-08	13:00
Small Industrial	17-Dec-08	14:00
Medium Industrial	28-May-08	14:00
Large Industrial	27-Aug-08	10:00
ELI 2P-RTP	29-Apr-08	3:00
Municipal	21-Jan-08	19:00
Unmetered	30-Nov-08	1:00
Total	21-Jan-08	19:00

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Request IR-86:

Please provide NSPI's estimate of the date and time of the 2012 non-coincident kW demand for each class, as shown in Exhibit 9B.

Response IR-86:

Please refer to CA IR-45.

NSPI does not make such an estimate.

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Request IR-87:

Please provide all load research studies relied upon by the Company in developing the load-based allocators for its COS study.

Response IR-87:

Please refer to CA IR-45.

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Request IR-88:

Please explain the computation of the "Unit Cost Eng. Related (¢/kW.h)" in Exhibits 10 and 10A.

Response IR-88:

Unit Cost Eng. Related (¢/kWh) is calculated through the following formula:

Unit Cost Eng. Related = Total Energy Related Expenses ÷ (MWH Sales/100)

Please refer to the electronically filed Multeese IR-1 Attachment 1. Total Energy Related Expenses can be found in Exhibit 6, page 3 of 4, line 39. MWh Sales can be found in Exhibit 9a (annual), Column 1.

Request IR-89:

Please explain how NSPI functionalizes, classifies, and allocates A&G costs.

Response IR-89:

The functionalization of the A&G costs is determined by the traditional PUB Chart of Accounts[1]. Please refer to CA IR-45 Attachment 1, Section 2.3 (pages 7 and 8) for information on classification and allocation of these costs.

[1]NSPI 1995 Cost of Service and Rate Design, UARB Decision NSUARB – NSPI – 864, September 22, 1995

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Request IR-90:

Please provide the derivation of each proposed rate schedule in an Excel spreadsheet.

Response IR-90:

Please refer to CA IR-91 Attachment 1.

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Request IR-91:

Please provide the "proof of revenue" calculations for each of the Company's proposed rate schedules in an Excel spreadsheet (with formulae intact).

Response IR-91:

Please refer to Attachment 1, filed electronically with formulas intact.

Request IR-92:

For each rate class, please provide in an Excel spreadsheet a comparison of bills under existing versus proposed rates for a representative sample of bill sizes.

Response IR-92:

Please refer to Attachment 1, filed electronically.

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Request IR-93:

Please provide bill frequency data for each rate class in an Excel spreadsheet.

Response IR-93:

Please refer to Attachment 1.

Rate Class	Bill Frequency	Monthly	Bi-Monthly	Seasonal
Domestic Service Rate Codes 02,03,04	Bi-Monthly & Monthly	271	397,443	**27,914**
Domestic Sevice Time-of-Day Rate Code 06	Bi-Monthly	-	7,581	**74**
Small General Rate Code 10	Bi-Monthly & Monthly	5,263	16,642	**1,110**
General Rate Code 11	Monthly	10,963	365	
Large General Rate Code 12	Monthly	18	-	
Small Industrial Rate Code 21	Monthly	1,398	826	
Medium Industrial Rate Code 22	Monthly	196	2	
Large Industiral Rate Code 23	Monthly	7	-	
Municipal Rate Code 24	Monthly	6	-	
Large Industrial Interrupible Rate Code 25	Monthly	26	-	
Generation & Loadfollowing Rate Code 26	Monthly	1	-	
Real Time Pricing Rate Code 36	Monthly	1	-	
Outdoor Recreations Lighting Rate Code 41	Seasonal Bi-monthly- 3 bills per year (May - Nov)	-	58	