Requirement:

Cost of Service Study.

Submission:

Please refer to Attachment 1.

SR-01

Cost of Service Study

TABLE OF CONTENTS

1. Cost of Service Study Methodology

1.1 Overview

From a cost-of-service methodology perspective, NS Power's customers fall into two broad categories, Below-the-line (BTL) and Above-the-line (ATL). The cost of service methodology subject to discussion in this section is concerned with the cost allocation to ATL classes only. Before costs are allocated to ATL classes, the total cost responsibility of this group must be determined by subtracting costs associated with serving BTL classes from the total revenue requirement of the company.

The overall objective of a cost of service study is to determine the costs associated with serving each customer class, and to identify any inter-class inequities that may be present with regard to over or under contribution to total allocated costs. This determination is based on a comparison of revenue/cost (R/C) ratios.

The first step in preparing a Cost of Service Study (COSS), once the test period is established, is to collect the detailed financial and operating information pertaining to that period. The data accumulated includes estimates for: plant-in-service, construction work in progress (CWIP), reserve for depreciation, working capital allowances, deferred charges, deferred credits, contract receivables, revenues, operating expenses, energy sales and demand statistics and customer counts.

The Cost of Service Study allocates the costs (therefore the revenue requirement) of providing electric service by the Company. This includes the appropriate assignment of operating and maintenance expenses, grants in lieu of taxes, depreciation and the responsibility for interest and corporate taxes incurred on those elements of the electric utility plant in service that are necessary in whole, or in part, to provide electric service to the various classifications of utility customers, as well as an approved return on investment.

Where possible, costs are assigned directly to classes of service based upon information acquired from the financial books and records of the Company or through additional analyses or studies.

Costs not directly assigned are analyzed by functional responsibility in groupings of accounts, such as production, transmission, distribution and retail. These groupings are then 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 comprises those items that are incurred in order to produce and deliver electric energy to customers as called for by them. Sufficient infrastructure must be installed to supply peak demand as required, while maintaining a required reserve margin.

Plant investment increases as units and facilities grow to meet demand. Consequently, these costs are allocated based on contributions to system coincident demand. Distribution facilities are allocated based on non-coincident demand to recognize that this infrastructure must be sized to provide that capacity. Class non-coincident demands are the demands that are imposed on the distribution system and, in general, are substantially larger than coincident demands. Consequently, the cost of service elements that increase with plant size and capacity are classified as demand costs.

Energy related costs are those items that vary with the annual volume of energy supplied to the various classes of service provided by the Company. The prime example of energy costs that vary with the volume of electricity generated and supplied is fuel costs. These costs increase as the quantity of fuel required to produce energy from generating units is increased.

The customer related costs are those items that vary with the number of customers served, and revenue related costs are those items that vary with the dollars of revenue received. An example of customer costs is customer service field expenses, including meter reading and electric wiring inspection expenses.

Costs associated with services related to miscellaneous revenues are not identified separately, rather these items are deducted from the overall cost assignment process.

Functionalization

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

Classification

Following the functionalization step, production, transmission, distribution and retail plant and operating expenses are **classified**. Classification is the process by which plant and operating costs are determined to be demand, energy, or customer related.

Allocation Factors

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

Allocation

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 operating expenses 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.

Exhibit 1 summarizes the results of the Cost of Service Study under present and proposed rates for the test period. The full analysis is provided in the various other Exhibits.

- Exhibits 2 and 3 detail the rate base analyses,
- Exhibits 4 to 6 show the analyses of operating costs and depreciation expense.
- Exhibit 7 contains the revenue analysis
- Exhibit 8 details the development of allocation factors.
- Exhibit 9 shows the analysis of sales and demand data.
- Exhibit 10 details the demand, energy and customer costs along with the revenue by class and the resulting Revenue/Cost Ratios for the test period under proposed rates.
- Exhibit 10A details the demand, energy and customer costs along with the revenue by class and the resulting Revenue/Cost Ratios under current rates for the test period.

1.2 Methodology

The method of cost assignment utilized is the Load Factor/3 Coincident Peak (LF/3 CP) method, as approved by the UARB in its September 29, 1995 Order NSPI-864.

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 demands the class places on the system, as well as the extent to which the class uses the facilities on an ongoing basis.

A percentage of costs, equal to the system peak load factor percentage is considered energy related and allocated on the kWh at generation. The remaining costs are considered demand-related and are allocated based on the sum of three coincident peak demands at generation for December, January and February (the peak winter period). Environmental and fuel conversion assets in the rate base are extracted up front and classified 100% as energy-related.

1.2.1 Rate Base

Exhibits 2, 2A and 2B

Exhibit 2 contains the net plant investment in the various asset categories, with allowance for working capital and allowance for materials and supplies.

In keeping with the Board's decision from the 2005 Rate Application, dated March 31, 2005, changes were made in this exhibit and subsequent rate base exhibits (2A, 2B and 3) to include construction work in progress (CWIP), deferred charges, and deferred credits.

The net plant investment, allowance for working capital, allowance for materials and supplies, deferred charges, deferred credits and contract receivables that are directly assigned are identified as the "Direct Capital" column in exhibit 2. Direct capital is subtracted from the total company rate base to arrive at the amounts to be allocated among COSS-based rate classes. As approved in the 2012 GRA, the rate base associated with the LED streetlight investment is treated as direct capital. This is consistent with the proposed ratemaking treatment of the LED services as a BTL category to be priced using an incremental cost approach.

Exhibits 3, 3A, 3B, 3C, 3D, 3E, 3F, 3G

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

The first allocation factors to be developed are those related to demand, energy sales and the number of customers. Exhibit 9A shows the projected energy sales for the test period and the quantity generated and purchased before line losses. Given these figures by class and the forecasted coincident peak demands by sector, load factors are applied to arrive at each class's 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 voltage 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, Hydro and LM6000 assets are allocated on the load factor and 3CP demand contribution, other gas turbine assets are allocated based on the 3CP demand only and wind assets are assigned 30% to 3CP demand and the remaining plant to energy.

Transmission plant is initially segregated between > 69 kV and < 138 kV voltage using a 76.6%/23.4% ratio. Both portions of these assets are classified on load factor and allocated on 3CP demand contribution to customer classes based on their required service voltage.

Distribution plant is more complex in its cost causalities than are the other functions. Substations are allocated in accordance with Exhibit 3B. The amounts invested in facilities that are dedicated to a single customer's use were identified and directly allocated to the customer's respective class. The remaining substation investment is allocated on the basis of primary demand levels. The totals for each class are carried forward as class allocations of substation investment, as shown in Exhibit 3.

Pole and wire investment also requires a more detailed analysis since the total is made up of both demand and customer components. Exhibit 3C 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 3D, by the appropriate allocation factors.

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

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

Meter costs are allocated on Exhibit 3G. 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.

The “Land” and “Other” assets, listed in Exhibit 3A, were allocated on the basis of total substation, pole and wire investments. The “non LED Street Lighting” investment was assigned directly to the unmetered customers.

The “General Property Plant” investment listed in Exhibit 3, was allocated on the basis of all other plant investment. Finally, allowance for working capital, allowance for materials and supplies, deferred charges, deferred credits and contract receivables were allocated in accordance with their cost causalities as defined by the allocation factors used.

To provide more transparency in the allocation of streetlight fixture-related costs, the distribution-related rate base information in exhibit 3 has been separated between the streetlight-related versus non-streetlight related categories.

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

1.2.2 Operating Expense

The analysis of operating costs begins in Exhibit 4 with functionalization. In this step total operating costs are grouped according to production, transmission, distribution, retail and direct assignment. The “Direct Expenses” column contains those costs that are not to be assigned to ATL customer classes as they represent costs incurred by BTL customers. As approved in the 2012 GRA, the "Direct Expense" column also reflects the capital-related costs associated with the BTL category of LED streetlight fixtures. The "Corporate Groups" operating expenses have been assigned to each function based on their overall responsibility to each primary business operation within the Company. "Cost of Goods Sold" (Net of Retail Sales), "Grants in Lieu of Taxes", "Depreciation" (by function), "Interest" (net of AFUDC), "Preferred Dividends" and "Corporate Taxes" are assigned to each function based on various rate base functionalizations. The Board-approved deferral of non-fuel related costs associated with serving the load of Extra Large Industrial customers assumed for the rate setting purposes of the 2012 GRA, is proposed to be amortized over 3 years starting in 2013 and has been reflected in the expense reports as a separate category. As approved by the Board in the 2009 General Rate Application, Demand Side Management expenses incurred in 2008 and 2009 are included in the COSS. These amortized costs are allocated in the same way as fixed generation costs and are expected to be fully recovered by 2014.[1]

In Exhibit 5, the functionalized expenses from Exhibit 4 are listed and sub-grouped, where necessary, in order to classify them as demand, energy and customer. To provide more clarity in the treatment of streetlight fixture-related costs they have been separated from all the other distribution-related costs to form a separate sub-group of the "Distribution Function".

Exhibit 6 summarizes the next stage of the study, which is the allocation of operating costs. First, those costs which are classified as "Demand" (generation, transmission and distribution) are allocated on the basis of the 3CP demand allocators. Consistent with the treatment of the streetlight fixture-related costs in exhibit 5, these costs are shown separately in Exhibit 6.

Exhibit 6A contains the analysis of total distribution operating expenses broken down by demand-, customer-, and retail-related categories. The basic allocation premise used is that costs should be allocated in the same manner as their rate base counterparts. Substation costs are allocated according to substation investment.

[1] DSM amortized costs are reflected in the Financial tables under the "regulatory amortization" component.

Overhead and underground expenses were assigned in relation to the pole and wire and underground investments. Line transformers are secondary demand related. Service expenses were allocated to secondary customers. Metering expenses were allocated according to the meter investment per class. Communications is related to primary demand and street lighting was assigned directly to the unmetered class. Exhibit 6B details the analysis of customer service field 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. In Exhibit 6, the “Call Centre” was assigned using total weighted customers. “Customer Service – H/O” and “Billing Services” were assigned using average customers, adjusted for seasonality. “Quality Assurance and Communication”, “Electrical Wiring Inspection” (head office) and “Payment Services” costs were assigned using average customers. “Marketing and Sales” and “Meter Data Services” costs were allocated on the basis of defined responsibility commitments to each customer class. Exhibit 6C details the allocation of credit services expenses. First, the “Bad Debt Expense” is split between domestic and all other classes based on gross write-off experience. The other portion of bad debt expense is assigned to each class based on secondary customer revenue. The other operating portion is distributed on the basis of average number of customers.

Depreciation is allocated by function as shown on Exhibit 6D. Consistent with the treatment of streetlight fixture related costs in exhibits 5 and 6, they are shown as separate sub-components under the Distribution Function category. With the streetlight fixture depreciation cost information being available from the company’s accounting information system, it is applied directly for the direct cost assignment purposes.

In Exhibit 6, grants in lieu of taxes are allocated on the basis of total production, transmission, distribution and retail net plant. Interest (net of AFUDC) preferred dividends and corporate taxes expense are allocated on the basis of total rate base assignment from Exhibit 3. The total costs for each class are then determined and adjusted by non-rate revenue and the return (profit/loss) to arrive at the net cost to each customer class. The resultant total then becomes the input to rate design.

Exhibit 7 serves the purpose of verifying the accuracy of the cost allocation analysis. The ATL revenues are shown against revenues of other categories, determined outside of the COSS, and retained earnings from the financial tables. Consistent with the treatment of the BTL categories, the LED fixture-related revenue component is placed under “Direct Revenue”.

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, under proposed rates for the test year. Exhibit 10A has been provided to show the equivalent information under present rates.

NOVA SCOTIA POWER INC.
COST OF SERVICE STUDY ANALYSIS

REFERENCE GUIDE

EXHIBIT 1

NOVA SCOTIA POWER INC.
SUMMARY OF REVENUE TO EXPENSE RECOVERY RATIOS

	2013	
CUSTOMER CLASS	PRESENT	PROPOSED
(1) DOMESTIC	100.52	99.00
(2) SMALL GENERAL	103.46	104.61
(3) GENERAL	103.46	103.48
(4) LARGE GENERAL	101.38	98.19
(5) SMALL INDUSTRIAL	101.55	102.55
(6) MEDIUM INDUSTRIAL	97.91	98.42
(7) LARGE INDUSTRIAL	97.74	95.55
(8) ELI 2P-RTP	91.33	N/A
(9) MUNICIPAL	98.11	97.39
(10) UNMETERED	101.26	100.00
(11) TOTAL	100.00	100.00

EXHIBIT 2

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) GENERATION	(3) TRANSMISSION	(4) DISTRIBUTION	(5) RETAIL	(6) DIRECT CAPITAL
PRODUCTION PLANT						
(1) STEAM	$1,389,088	$1,389,088	$0	$0	$0	$0
(2) HYDRO	345,695	324,454	0	0	0	21,241
(3) WIND	194,757	194,757	0	0	0	0
(4) LM6000	62,706	62,706	0	0	0	0
(5) GAS TURBINE - OTHER	6,599	6,599	0	0	0	0
(6) TOTAL PROD. PLANT	1,998,845	1,977,604	0	0	0	21,241
(7) Transmission < 138kV	101,481	0	101,481	0	0	0
(8) Transmission > 69kV	332,198	0	332,198	0	0	0
(9) TRANSMISSION PLANT	433,679	0	433,679	0	0	0
DISTRIBUTION PLANT						
(10) LAND	4,438	0	0	4,438	0	0
(11) EASEMENTS & SURVEY	16,044	0	0	16,044	0	0
(12) OTHER	2,103	0	0	2,103	0	0
(13) SUBSTATIONS	28,462	0	0	28,462	0	0
(14) POLES & FIXTURES	173,357	0	0	173,357	0	0
(15) O.H. LINES	114,863	0	0	114,863	0	0
(16) U.G. LINES	33,044	0	0	33,044	0	0
(17) LINE TRANSFORMERS	154,540	0	0	154,540	0	0
(18) SERVICES	57,705	0	0	57,705	0	0
(19) METERS	23,780	0	0	23,780	0	0
(20) STREET LIGHTING	26,970	0	0	15,950	0	11,020
(21) TOTAL DIST. PLANT	635,306	0	0	624,286	0	11,020
(22) SUB-TOTAL	3,067,830	1,977,604	433,679	624,286	0	32,261
(23) GEN. PROPERTY PLANT	243,157	158,411	34,739	50,007	0	0
(24) TOT. PLT.IN SERVICE	3,310,987	2,136,015	468,418	674,293	0	32,261
Working Capital & Deferred Charges/Credits						
(25) CASH - FUEL	0	0	0	0	0	0
(26) CASH - OTHER	43,271	20,831	4,072	18,146	0	221
(27) MAT. & SUP. - FUEL	88,682	88,682	0	0	0	0
(28) MAT. & SUP. - OTHER	28,089	18,299	4,013	5,777	0	0
(29) DEF. CHG. - Financing	75,865	49,424	10,839	15,602	0	0
(30) DEF. CHG. - Tax	21,479	13,993	3,069	4,417	0	0
(31) DEF. CHG. - Pension	66,431	32,146	6,283	28,002	0	0
(32) DEF. CHG. - Steam Assets	0	0	0	0	0	0
(33) DEF. CHG. - Fuel Deferral	14,080	14,080	0	0	0	0
(34) DEF. CHG. - Other	8,914	4,853	596	859	0	2,606
(35) DEF. CHG. - FCR	37,400	30,673	6,727	0	0	0
(36) DEF. CR. - ARO Steam	(41,394)	(41,394)	0	0	0	0
(37) DEF. CR. - ARO Hydro	(21,653)	(21,653)	0	0	0	0
(38) DEF. CR. - ARO Wind	(10,400)	(10,400)	0	0	0	0
(39) DEF. CR. - ARO CT	(3,944)	(3,944)	0	0	0	0
(40) DEF. CR. - ARO Trans	(23,425)	0	(23,425)	0	0	0
(41) DEF. CR. - Other	(6,589)	(6,589)	0	0	0	0
(42) CONTRACT RECEIVABLE	0	0	0	0	0	0
(43) TOT.WORKING CAPITAL	276,806	189,002	12,173	72,803	0	2,827
(44) TOTAL AVE. RATE BASE	$3,587,793	$2,325,017	$480,591	$747,096	$0	$35,088

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
GENERATION FUNCTION				
(1) STEAM PLANT	$1,389,088	$1,047,670	$341,418	$0
(2) HYDRO PLANT	324,454	319,306	5,148	0
(3) WIND PLANT	194,757	16,066	178,691	0
(4) LM6000 PLANT	62,706	62,706	0	0
(5) GAS TURBINE PLANT - OTHER	6,599	6,599	0	0
(6) TOTAL GENERATION PLANT	1,977,604	1,452,347	525,257	0
(7) GENERAL PROPERTY PLANT	158,411	116,337	42,074	0
(8) TOTAL PLANT IN SERVICE	2,136,015	1,568,684	567,331	0
Working Capital & Deferred Charges/Credits:				
(9) CASH - FUEL	0	0	0	0
(10) CASH - OTHER	20,831	5,704	15,127	0
(11) MAT. & SUPPLIES - FUEL	88,682	0	88,682	0
(12) MAT. & SUPPLIES - OTHER	18,299	13,439	4,860	0
(13) DEF. CHG. - Financing	49,424	36,297	13,127	0
(14) DEF. CHG. - Tax	13,993	10,276	3,717	0
(15) DEF. CHG. - Pension	32,146	8,802	23,343	0
(16) DEF. CHG. - Steam Assets	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	14,080	0	14,080	0
(18) DEF. CHG. - Other	4,853	3,564	1,289	0
(19) DEF. CHG. - FCR	30,673	22,527	8,147	0
(20) DEF. CR. - ARO Steam	(41,394)	(31,220)	(10,174)	0
(21) DEF. CR. - ARO Hydro	(21,653)	(21,309)	(344)	0
(22) DEF. CR. - ARO Wind	(10,400)	(10,235)	(165)	0
(23) DEF. CR. - ARO CT	(3,944)	(3,944)	0	0
(24) DEF. CR. - Other	(6,589)	(4,970)	(1,619)	0
(25) CONTRACT RECEIVABLE	0	0	0	0
(26) SUB-TOTAL	189,002	28,931	160,071	0
(27) TOTAL GENERATION FUNCTION	**2,325,017**	**1,597,615**	**727,402**	**0**
TRANSMISSION FUNCTION				
(28) TRANSMISSION PLANT < 138kV	101,481	101,481	0	0
(29) GENERAL PROPERTY PLANT	8,129	8,129	0	0
(30) TOTAL PLANT IN SERVICE	109,610	109,610	0	0
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	974	423	551	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	939	939	0	0
(35) DEF. CHG. - Financing	2,536	2,536	0	0
(36) DEF. CHG. - Tax	718	718	0	0
(37) DEF. CHG. - Pension	1,503	653	850	0
(38) DEF. CHG. - Other	140	140	0	0
(39) DEF. CHG. - ARO Trans.	(5,481)	(5,481)	0	0
(40) SUB-TOTAL	1,328	(73)	1,401	0
(41) TOTAL TRANS. < 138kV	110,938	109,537	1,401	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
(1) TRANSMISSION PLANT > 69kV	332,198	332,198	0	0
(2) GENERAL PROPERTY PLANT	26,610	26,610	0	0
(3) TOTAL PLANT IN SERVICE	358,808	358,808	0	0
Working Capital & Deferred Charges/Credits:				
(4) CASH - FUEL	0	0	0	0
(5) CASH - OTHER	3,098	1,345	1,753	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,074	3,074	0	0
(8) DEF. CHG. - Financing	8,302	8,302	0	0
(9) DEF. CHG. - Tax	2,351	2,351	0	0
(10) DEF. CHG. - Pension	4,781	2,076	2,704	0
(11) DEF. CHG. - Other	457	457	0	0
(12) DEF. CHG. - FCR	6,727	6,727	0	0
(13) DEF. CHG. - ARO Trans	(17,944)	(17,944)	0	0
(14) SUB-TOTAL	10,845	6,388	4,457	0
(15) TOTAL TRANS. > 69kV	369,653	365,196	4,457	0
(16) TOTAL TRANSMISSION FUNCTION	**$480,591**	**$474,733**	**$5,858**	**$0**

DISTRIBUTION FUNCTION

DISTRIBUTION PLANT:				
(17) LAND	4,438	3,024	0	1,414
(18) EASEMENTS & SURVEY	16,044	10,933	0	5,111
(19) OTHER	2,103	1,433	0	670
(20) SUBSTATIONS	28,462	28,462	0	0
(21) POLES & FIXTURES	173,357	112,682	0	60,675
(22) O.H. LINES	114,863	74,661	0	40,202
(23) U.G. LINES	33,044	21,479	0	11,565
(24) LINE TRANSFORMERS	154,540	154,540	0	0
(25) SERVICES	57,705	0	0	57,705
(26) METERS	23,780	0	0	23,780
(27) STREET LIGHTING	15,950	15,950	0	0
(28) TOTAL DISTRIBUTION PLANT	624,286	423,164	0	201,122
(29) GENERAL PROPERTY PLANT	50,007	33,897	0	16,110
(30) TOTAL PLANT IN SERVICE	674,293	457,061	0	217,232
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	18,146	6,558	0	11,588
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	5,777	3,916	0	1,861
(35) DEF. CHG. - Financing	15,602	10,576	0	5,026
(36) DEF. CHG. - Tax	4,417	2,994	0	1,423
(37) DEF. CHG. - Pension	28,002	10,120	0	17,882
(38) DEF. CHG. - Other	859	582	0	277
(39) SUB-TOTAL	72,803	34,746	0	38,057
(40) TOTAL DISTRIBUTION FUNCTION	**747,096**	**491,807**	**0**	**255,289**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
RETAIL FUNCTION				
DISTRIBUTION PLANT:				
(1) SERVICES	0	0	0	0
(2) METERS	0	0	0	0
(3) TOTAL RETAIL PLANT	0	0	0	0
(4) GENERAL PROPERTY PLANT	0	0	0	0
(5) TOTAL PLANT IN SERVICE	0	0	0	0
Working Capital & Deferred Charges/Credits:				
(6) CASH - FUEL	0	0	0	0
(7) CASH - OTHER	0	0	0	0
(8) MAT. & SUPPLIES - FUEL	0	0	0	0
(9) MAT. & SUPPLIES - OTHER	0	0	0	0
(10) DEF. CHG. - Financing	0	0	0	0
(11) DEF. CHG. - Tax	0	0	0	0
(12) DEF. CHG. - Pension	0	0	0	0
(13) DEF. CHG. - Other	0	0	0	0
(14) SUB-TOTAL	0	0	0	0
(15) TOTAL RETAIL FUNCTION	**0**	**0**	**0**	**0**
(16) TOTAL AVE. RATE BASE	**$3,552,705**	**$2,564,155**	**$733,260**	**$255,289**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
GENERATION FUNCTION									
(1) STEAM PLANT	$1,047,670	$341,418	$0	($592,667)	$592,667	$0	$455,003	$934,085	$0
(2) HYDRO PLANT	319,306	5,148	0	(180,631)	180,631	0	138,675	185,779	0
(3) WIND PLANT	16,066	178,691	0	(11,246)	11,246	0	4,820	189,937	0
(4) LM6000 PLANT	62,706	0	0	(35,473)	35,473	0	27,233	35,473	0
(5) GAS TURBINE PLANT - OTHER	6,599	0	0	0	0	0	6,599	0	0
(6) TOTAL GENERATION PLANT	1,452,347	525,257	0	(820,017)	820,017	0	632,330	1,345,274	0
(7) GENERAL PROPERTY PLANT	116,337	42,074	0	(65,686)	65,686	0	50,651	107,760	0
(8) TOTAL PLANT IN SERVICE	1,568,684	567,331	0	(885,703)	885,703	0	682,981	1,453,034	0
Working Capital & Deferred Charges/Credits:									
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0
(10) CASH - OTHER	5,704	15,127	0	0	0	0	5,704	15,127	0
(11) MAT. & SUPPLIES - FUEL	0	88,682	0	0	0	0	0	88,682	0
(12) MAT. & SUPPLIES - OTHER	13,439	4,860	0	(7,588)	7,588	0	5,851	12,448	0
(13) DEF. CHG. - Financing	36,297	13,127	0	(20,494)	20,494	0	15,803	33,621	0
(14) DEF. CHG. - Tax	10,276	3,717	0	(5,802)	5,802	0	4,474	9,519	0
(15) DEF. CHG. - Pension	8,802	23,343	0	0	0	0	8,802	23,343	0
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	14,080	0	0	0	0	0	14,080	0
(18) DEF. CHG. - Other	3,564	1,289	0	(2,012)	2,012	0	1,552	3,301	0
(19) DEF. CHG. - FCR	22,527	8,147	0	(12,719)	12,719	0	9,808	20,866	0
(20) DEF. CR. - ARO Steam	(31,220)	(10,174)	0	17,661	(17,661)	0	(13,559)	(27,835)	0
(21) DEF. CR. - ARO Hydro	(21,309)	(344)	0	12,055	(12,055)	0	(9,255)	(12,398)	0
(22) DEF. CR. - ARO Wind	(10,235)	(165)	0	5,790	(5,790)	0	(4,445)	(5,955)	0
(23) DEF. CR. - ARO CT	(3,944)	0	0	0	0	0	(3,944)	0	0
(24) DEF. CR. - Other	(4,970)	(1,619)	0	2,811	(2,811)	0	(2,158)	(4,431)	0
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(26) SUB-TOTAL	28,931	160,071	0	(10,298)	10,298	0	18,633	170,369	0
							0	0	0
(27) TOTAL GENERATION FUNCTION	1,597,615	727,402	0	(896,001)	896,001	0	701,614	1,623,403	0
TRANSMISSION FUNCTION									
(28) TRANSMISSION PLANT < 138kV	101,481	0	0	(57,408)	57,408	0	44,073	57,408	0
(29) GENERAL PROPERTY PLANT	8,129	0	0	(4,599)	4,599	0	3,530	4,599	0
(30) TOTAL PLANT IN SERVICE	109,610	0	0	(62,006)	62,006	0	47,604	62,006	0
Working Capital & Deferred Charges/Credits:									
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0
(32) CASH - OTHER	423	551	0	0	0	0	423	551	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	939	0	0	(531)	531	0	408	531	0
(35) DEF. CHG. - Financing	2,536	0	0	(1,435)	1,435	0	1,101	1,435	0
(36) DEF. CHG. - Tax	718	0	0	(406)	406	0	312	406	0
(37) DEF. CHG. - Pension	653	850	0	0	0	0	653	850	0
(38) DEF. CHG. - Other	140	0	0	(79)	79	0	61	79	0
(40) DEF. CR. - ARO Trans.	(5,481)	0	0	3,101	(3,101)	0	(2,381)	(3,101)	0
(41) SUB-TOTAL	(73)	1,401	0	650	(650)	0	577	751	0
(42) TOTAL TRANS. < 138kV	109,537	1,401	0	(61,356)	61,356	0	48,180	62,758	0

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1) TRANSMISSION PLANT > 69kV	332,198	0	0	(187,924)	187,924	0	144,274	187,924	0
(2) GENERAL PROPERTY PLANT	26,610	0	0	(15,053)	15,053	0	11,557	15,053	0
(3) TOTAL PLANT IN SERVICE	358,808	0	0	(202,978)	202,978	0	155,830	202,978	0
Working Capital & Deferred Charges/Credits:									
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0
(5) CASH - OTHER	1,345	1,753	0	0	0	0	1,345	1,753	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,074	0	0	(1,739)	1,739	0	1,335	1,739	0
(8) DEF. CHG. - Financing	8,302	0	0	(4,697)	4,697	0	3,606	4,697	0
(9) DEF. CHG. - Tax	2,351	0	0	(1,330)	1,330	0	1,021	1,330	0
(10) DEF. CHG. - Pension	2,076	2,704	0	0	0	0	2,076	2,704	0
(11) DEF. CHG. - Other	457	0	0	(258)	258	0	198	258	0
(12) DEF. CHG. - FCR	6,727	0	0	(3,805)	3,805	0	2,921	3,805	0
(13) DEF. CR. - ARO Trans	(17,944)	0	0	10,151	(10,151)	0	(7,793)	(10,151)	0
(14) SUB-TOTAL	6,388	4,457	0	(1,678)	1,678	0	4,710	6,135	0
(15) TOTAL TRANS. > 69kV	365,196	4,457	0	(204,656)	204,656	0	160,540	209,113	0
(16) TOTAL TRANSMISSION FUNCTION	$474,733	$5,858	$0	($266,012)	$266,012	$0	$208,721	$271,870	$0

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
DISTRIBUTION FUNCTION									
DISTRIBUTION PLANT:									
(1) LAND	$3,024	$0	$1,414	$0	$0	$0	$3,024	$0	$1,414
(2) EASEMENTS & SURVEY	10,933	0	5,111	0	0	0	10,933	0	5,111
(3) OTHER	1,433	0	670	0	0	0	1,433	0	670
(4) SUBSTATIONS	28,462	0	0	0	0	0	28,462	0	0
(5) POLES & FIXTURES	112,682	0	60,675	0	0	0	112,682	0	60,675
(6) O.H. LINES	74,661	0	40,202	0	0	0	74,661	0	40,202
(7) U.G. LINES	21,479	0	11,565	0	0	0	21,479	0	11,565
(8) LINE TRANSFORMERS	154,540	0	0	0	0	0	154,540	0	0
(9) SERVICES	0	0	57,705	0	0	0	0	0	57,705
(10) METERS	0	0	23,780	0	0	0	0	0	23,780
(11) STREET LIGHTING	15,950	0	0	0	0	0	15,950	0	0
(12) TOTAL DISTRIBUTION PLANT	423,164	0	201,122	0	0	0	423,164	0	201,122
(13) GENERAL PROPERTY PLANT	33,897	0	16,110	0	0	0	33,897	0	16,110
(14) TOTAL PLANT IN SERVICE	457,061	0	217,232	0	0	0	457,061	0	217,232
Working Capital & Deferred Charges/Credits:									
(15) CASH - FUEL	0	0	0	0	0	0	0	0	0
(16) CASH - OTHER	6,558	0	11,588	0	0	0	6,558	0	11,588
(17) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(18) MAT. & SUPPLIES - OTHER	3,916	0	1,861	0	0	0	3,916	0	1,861
(19) DEF. CHG. - Financing	10,576	0	5,026	0	0	0	10,576	0	5,026
(20) DEF. CHG. - Tax	2,994	0	1,423	0	0	0	2,994	0	1,423
(21) DEF. CHG. - Pension	10,120	0	17,882	0	0	0	10,120	0	17,882
(22) DEF. CHG. - Other	582	0	277	0	0	0	582	0	277
(23) SUB-TOTAL	34,746	0	38,057	0	0	0	34,746	0	38,057
(24) TOTAL DISTRIBUTION FUNCTION	$491,807	$0	$255,289	$0	$0	$0	$491,807	$0	$255,289
RETAIL FUNCTION									
DISTRIBUTION PLANT:									
(25) SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(26) METERS	0	0	0	0	0	0	0	0	0
(27) TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(28) GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(29) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
Working Capital & Deferred Charges/Credits:									
(30) CASH - FUEL	0	0	0	0	0	0	0	0	0
(31) CASH - OTHER	0	0	0	0	0	0	0	0	0
(32) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(33) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(34) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(35) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(36) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(37) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(38) SUB-TOTAL	0	0	0	0	0	0	0	0	0
(39) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0
(40) TOTAL AVE. RATE BASE	**$2,564,155**	**$733,260**	**$255,289**	**($1,162,013)**	**$1,162,013**	**$0**	**$1,402,142**	**$1,895,274**	**$255,289**

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$455,003	$258,496	$9,293	$104,434	$12,815	$9,032	$17,444	$28,442	$0	$9,407	$5,640	D-3A
(2) HYDRO PLANT	138,675	78,784	2,832	31,829	3,906	2,753	5,317	8,668	0	2,867	1,719	D-3A
(3) WIND PLANT	4,820	2,738	98	1,106	136	96	185	301	0	100	60	D-3A
(4) LM6000 PLANT	27,233	15,472	556	6,251	767	541	1,044	1,702	0	563	338	D-3A
(5) GAS TURBINE PLANT - OTHER	6,599	3,749	135	1,515	186	131	253	412	0	136	82	D-3A
(6) TOTAL GENERATION PLANT	632,330	359,239	12,914	145,134	17,810	12,552	24,243	39,527	0	13,073	7,838	
(7) GEN. PROPERTY PLANT	50,651	28,776	1,034	11,626	1,427	1,005	1,942	3,166	0	1,047	628	P-7
(8) TOTAL PLANT IN SERVICE	682,981	388,015	13,949	156,760	19,236	13,557	26,185	42,693	0	14,120	8,466	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(10) CASH - OTHER	5,704	3,241	116	1,309	161	113	219	357	0	118	71	O-1
(11) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(12) MAT. & SUPPLIES - OTHER	5,851	3,324	119	1,343	165	116	224	366	0	121	73	P-7
(13) DEF. CHG. - Financing	15,803	8,978	323	3,627	445	314	606	988	0	327	196	P-7
(14) DEF. CHG. - Tax	4,474	2,542	91	1,027	126	89	172	280	0	92	55	P-7
(15) DEF. CHG. - Pension	8,802	5,001	180	2,020	248	175	337	550	0	182	109	O-1
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	D-3A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	D-3A
(18) DEF. CHG. - Other	1,552	882	32	356	44	31	59	97	0	32	19	P-7
(19) DEF. CHG. - FCR	9,808	5,572	200	2,251	276	195	376	613	0	203	122	P-7
(20) DEF. CR. - ARO Steam	(13,559)	(7,703)	(277)	(3,112)	(382)	(269)	(520)	(848)	0	(280)	(168)	D-3A
(21) DEF. CR. - ARO Hydro	(9,255)	(5,258)	(189)	(2,124)	(261)	(184)	(355)	(579)	0	(191)	(115)	D-3A
(22) DEF. CR. - ARO Wind	(4,445)	(2,525)	(91)	(1,020)	(125)	(88)	(170)	(278)	0	(92)	(55)	D-3A
(23) DEF. CR. - ARO CT	(3,944)	(2,241)	(81)	(905)	(111)	(78)	(151)	(247)	0	(82)	(49)	D-3A
(24) DEF. CR. - Other	(2,158)	(1,226)	(44)	(495)	(61)	(43)	(83)	(135)	0	(45)	(27)	D-3A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	D-3A
(26) SUB-TOTAL	18,633	10,586	381	4,277	525	370	714	1,165	0	385	231	
(25) TOTAL GEN. FUNCTION	701,614	398,601	14,329	161,037	19,761	13,927	26,899	43,857	0	14,505	8,697	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	44,073	25,039	900	10,116	1,241	875	1,690	2,755	0	911	546	D-3B
(26) GEN. PROPERTY PLANT	3,530	2,006	72	810	99	70	135	221	0	73	44	P-8A
(30) TOTAL PLANT IN SERVICE	47,604	27,045	972	10,926	1,341	945	1,825	2,976	0	984	590	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(32) CASH - OTHER	423	240	9	97	12	8	16	26	0	9	5	O-2A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(34) MAT. & SUPPLIES - OTHER	408	232	8	94	11	8	16	25	0	8	5	P-8A
(35) DEF. CHG. - Financing	1,101	626	22	253	31	22	42	69	0	23	14	P-8A
(36) DEF. CHG. - Tax	312	177	6	72	9	6	12	19	0	6	4	P-8A
(37) DEF. CHG. - Pension	653	371	13	150	18	13	25	41	0	13	8	O-2A
(38) DEF. CHG. - Other	61	34	1	14	2	1	2	4	0	1	1	P-8A
(40) DEF. CR. - ARO Trans.	(2,381)	(1,352)	(49)	(546)	(67)	(47)	(91)	(149)	0	(49)	(30)	D-3B
(41) SUB-TOTAL	577	328	12	132	16	11	22	36	0	12	7	
(42) TOTAL TRANS. < 138kV	48,180	27,372	984	11,058	1,357	956	1,847	3,012	0	996	597	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	144,274	81,965	2,947	33,114	4,063	2,864	5,531	9,018	0	2,983	1,788	D-3A
(2) GENERAL PROPERTY PLANT	11,557	6,566	236	2,653	325	229	443	722	0	239	143	P-8B
(3) TOTAL PLANT IN SERVICE	155,830	88,530	3,183	35,767	4,389	3,093	5,974	9,741	0	3,222	1,932	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(5) CASH - OTHER	1,345	764	27	309	38	27	52	84	0	28	17	O-2B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) MAT. & SUPPLIES - OTHER	1,335	758	27	306	38	27	51	83	0	28	17	P-8B
(8) DEF. CHG. - Financing	3,606	2,048	74	828	102	72	138	225	0	75	45	P-8B
(9) DEF. CHG. - Tax	1,021	580	21	234	29	20	39	64	0	21	13	P-8B
(10) DEF. CHG. - Pension	2,076	1,180	42	477	58	41	80	130	0	43	26	O-2B
(11) DEF. CHG. - Other	198	113	4	46	6	4	8	12	0	4	2	P-8B
(12) DEF. CHG. - FCR	2,921	1,660	60	671	82	58	112	183	0	60	36	P-8B
(13) DEF. CR. - ARO Trans	(7,793)	(4,427)	(159)	(1,789)	(219)	(155)	(299)	(487)	0	(161)	(97)	D-3A
(14) SUB-TOTAL	4,710	2,676	96	1,081	133	93	181	294	0	97	58	
(15) TOTAL TRANS. > 69kV	160,540	91,206	3,279	36,848	4,522	3,187	6,155	10,035	0	3,319	1,990	
(14) TOTAL TRANS. FUNCTION	208,721	118,578	4,263	47,906	5,879	4,143	8,002	13,047	0	4,315	2,587	
DISTRIBUTION FUNCTION												
(15) DISTRIBUTION PLANT - Non Street	407,214	248,120	13,438	113,066	7,327	10,733	8,467	391	0	26	5,645	EXH. 3A
(16) DISTRIBUTION PLANT - Streetlight	15,950	0	0	0	0	0	0	0	0	0	15,950	EXH. 3A
	0	0	0	0	0	0	0	0	0	0	0	
(17) SUB-TOTAL	423,164	248,120	13,438	113,066	7,327	10,733	8,467	391	0	26	21,595	
(18) GEN. PROPERTY PLANT	33,897	20,654	1,119	9,412	610	893	705	33	0	2	470	P-9
	457,061	268,774	14,557	122,478	7,937	11,626	9,172	424	0	28	22,065	
Working Capital & Deferred Charges/Credits:												
(19) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(20) CASH - OTHER	6,558	3,354	182	1,552	166	149	189	1	0	0	966	O-3
(21) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(22) MAT. & SUPPLIES - OTHER	3,916	2,386	129	1,087	70	103	81	4	0	0	54	P-9
(23) DEF. CHG. - Financing	10,576	6,444	349	2,936	190	279	220	10	0	1	147	P-9
(24) DEF. CHG. - Tax	2,994	1,824	99	831	54	79	62	3	0	0	42	P-9
(25) DEF. CHG. - Pension	10,120	5,175	280	2,395	256	230	292	1	0	0	1,491	O-3
(26) DEF. CHG. - Other	582	355	19	162	10	15	12	1	0	0	8	P-9
(27) SUB-TOTAL	34,746	19,537	1,058	8,963	747	856	857	19	0	1	2,707	
(28) TOTAL DIST. FUNCTION	491,807	288,311	15,615	131,441	8,684	12,482	10,029	442	0	29	24,773	
(29) TOTAL DEMAND	**$1,402,142**	**$805,491**	**$34,207**	**$340,384**	**$34,324**	**$30,552**	**$44,931**	**$57,347**	**$0**	**$18,849**	**$36,057**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$934,085	$435,955	$23,496	$241,417	$39,272	$25,482	$49,072	$89,866	$0	$18,807	$10,718	E-1A
(2) HYDRO PLANT	185,779	86,707	4,673	48,015	7,811	5,068	9,760	17,873	0	3,741	2,132	E-1A
(3) WIND PLANT	189,937	88,647	4,778	49,090	7,986	5,181	9,978	18,273	0	3,824	2,179	E-1A
(4) LM6000 PLANT	35,473	16,556	892	9,168	1,491	968	1,864	3,413	0	714	407	E-1A
(5) GAS TURBINE PLANT - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(6) TOTAL GENERATION PLANT	1,345,274	627,865	33,839	347,690	56,559	36,699	70,674	129,426	0	27,086	15,436	
(7) GENERAL PROPERTY PLANT	107,760	50,294	2,711	27,851	4,531	2,940	5,661	10,367	0	2,170	1,236	P-10
(8) TOTAL PLANT IN SERVICE	1,453,034	678,158	36,550	375,541	61,090	39,638	76,335	139,793	0	29,256	16,672	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(10) CASH - OTHER	15,127	7,060	381	3,910	636	413	795	1,455	0	305	174	O-4
(11) MAT. & SUPPLIES - FUEL	88,682	41,390	2,231	22,920	3,728	2,419	4,659	8,532	0	1,786	1,018	E-1A
(12) MAT. & SUPPLIES - OTHER	12,448	5,810	313	3,217	523	340	654	1,198	0	251	143	P-10
(13) DEF. CHG. - Financing	33,621	15,692	846	8,689	1,414	917	1,766	3,235	0	677	386	P-10
(14) DEF. CHG. - Tax	9,519	4,443	239	2,460	400	260	500	916	0	192	109	P-10
(15) DEF. CHG. - Pension	23,343	10,895	587	6,033	981	637	1,226	2,246	0	470	268	O-4
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	E-1A
(17) DEF. CHG. - Fuel Deferral	14,080	6,571	354	3,639	592	384	740	1,355	0	283	162	E-1A
(18) DEF. CHG. - Other	3,301	1,541	83	853	139	90	173	318	0	66	38	P-10
(19) DEF. CHG. - FCR	20,866	9,738	525	5,393	877	569	1,096	2,007	0	420	239	P-10
(20) DEF. CR. - ARO Steam	(27,835)	(12,991)	(700)	(7,194)	(1,170)	(759)	(1,462)	(2,678)	0	(560)	(319)	E-1A
(21) DEF. CR. - ARO Hydro	(12,398)	(5,787)	(312)	(3,204)	(521)	(338)	(651)	(1,193)	0	(250)	(142)	E-1A
(22) DEF. CR. - ARO Wind	(5,955)	(2,779)	(150)	(1,539)	(250)	(162)	(313)	(573)	0	(120)	(68)	E-1A
(23) DEF. CR. - ARO CT	0	0	0	0	0	0	0	0	0	0	0	E-1A
(24) DEF. CR. - Other	(4,431)	(2,068)	(111)	(1,145)	(186)	(121)	(233)	(426)	0	(89)	(51)	E-1A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	E-1A
(26) SUB-TOTAL	170,369	79,514	4,285	44,032	7,163	4,648	8,950	16,391	0	3,430	1,955	
(24) TOTAL GEN. FUNCTION	1,623,403	757,673	40,835	419,574	68,253	44,286	85,286	156,184	0	32,686	18,627	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	57,408	26,793	1,444	14,837	2,414	1,566	3,016	5,523	0	1,156	659	E-1B
(29) GENERAL PROPERTY PLANT	4,599	2,146	116	1,188	193	125	242	442	0	93	53	P-11A
(30) TOTAL PLANT IN SERVICE	62,006	28,939	1,560	16,026	2,607	1,692	3,258	5,965	0	1,248	711	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(32) CASH - OTHER	551	257	14	142	23	15	29	53	0	11	6	O-5A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(34) MAT. & SUPPLIES - OTHER	531	248	13	137	22	14	28	51	0	11	6	P-11A
(35) DEF. CHG. - Financing	1,435	670	36	371	60	39	75	138	0	29	16	P-11A
(36) DEF. CHG. - Tax	406	190	10	105	17	11	21	39	0	8	5	P-11A
(37) DEF. CHG. - Pension	850	397	21	220	36	23	45	82	0	17	10	O-5A
(38) DEF. CHG. - Other	79	37	2	20	3	2	4	8	0	2	1	P-11A
(40) DEF. CR. - ARO Trans.	(3,101)	(1,447)	(78)	(801)	(130)	(85)	(163)	(298)	0	(62)	(36)	E-1B
(41) SUB-TOTAL	751	351	19	194	32	20	39	72	0	15	9	
(42) TOTAL TRANS. < 138kV	62,758	29,290	1,579	16,220	2,639	1,712	3,297	6,038	0	1,264	720	

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	187,924	87,708	4,727	48,570	7,901	5,127	9,873	18,080	0	3,784	2,156	E-1A
(2) GENERAL PROPERTY PLANT	15,053	7,026	379	3,891	633	411	791	1,448	0	303	173	P-11B
(3) TOTAL PLANT IN SERVICE	202,978	94,733	5,106	52,460	8,534	5,537	10,663	19,528	0	4,087	2,329	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(5) CASH - OTHER	1,753	818	44	453	74	48	92	169	0	35	20	O-5B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(7) MAT. & SUPPLIES - OTHER	1,739	812	44	449	73	47	91	167	0	35	20	P-11B
(8) DEF. CHG. - Financing	4,697	2,192	118	1,214	197	128	247	452	0	95	54	P-11B
(9) DEF. CHG. - Tax	1,330	621	33	344	56	36	70	128	0	27	15	P-11B
(10) DEF. CHG. - Pension	2,704	1,262	68	699	114	74	142	260	0	54	31	O-5B
(11) DEF. CHG. - Other	258	121	7	67	11	7	14	25	0	5	3	P-11B
(12) DEF. CHG. - FCR	3,805	1,776	96	983	160	104	200	366	0	77	44	P-11B
(13) DEF. CR. - ARO Trans	(10,151)	(4,738)	(255)	(2,623)	(427)	(277)	(533)	(977)	0	(204)	(116)	E-1A
(14) SUB-TOTAL	6,135	2,863	154	1,586	258	167	322	590	0	124	70	
(15) TOTAL TRANS. > 69kV	209,113	97,597	5,260	54,046	8,792	5,705	10,986	20,118	0	4,210	2,399	
(15) TOTAL TRANS. FUNCTION	271,870	126,887	6,839	70,266	11,430	7,417	14,283	26,156	0	5,474	3,119	
(16) TOTAL ENERGY	**$1,895,274**	**$884,560**	**$47,674**	**$489,839**	**$79,683**	**$51,703**	**$99,568**	**$182,340**	**$0**	**$38,160**	**$21,747**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	$201,122	$176,667	$9,328	$10,432	$18	$2,140	$195	$60	$0	$6	$2,275	EXH. 3A
(2) GEN. PROPERTY PLANT	16,110	14,151	747	836	1	171	16	5	0	1	182	P-12
(3) TOTAL PLANT IN SERVICE	217,232	190,818	10,075	11,268	19	2,312	210	65	0	7	2,458	
WORKING CAPITAL:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(5) CASH - OTHER	11,588	10,459	552	298	1	61	7	2	0	0	207	O-6
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(7) MAT. & SUPPLIES - OTHER	1,861	1,635	86	97	0	20	2	1	0	0	21	P-12
(8) DEF. CHG. - Financing	5,026	4,415	233	261	0	53	5	2	0	0	57	P-12
(9) DEF. CHG. - Tax	1,423	1,250	66	74	0	15	1	0	0	0	16	P-12
(10) DEF. CHG. - Pension	17,882	16,140	852	460	1	95	11	3	0	0	319	O-6
(11) DEF. CHG. - Other	277	243	13	14	0	3	0	0	0	0	3	P-12
(12) SUB-TOTAL	38,057	34,142	1,803	1,204	2	247	27	8	0	1	623	
(13) TOTAL DIST. FUNCTION	255,289	224,960	11,877	12,472	22	2,559	237	73	0	8	3,081	
RETAIL FUNCTION												
(14) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	EXH. 3A
(15) GEN. PROPERTY PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(16) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0	0	0	
WORKING CAPITAL:												
(17) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(18) CASH - OTHER	0	0	0	0	0	0	0	0	0	0	0	O-7
(19) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(20) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0	0	0	P-13
(21) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0	0	0	P-13
(22) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0	0	0	P-13
(23) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0	0	0	O-7
(24) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0	0	0	P-13
(25) SUB-TOTAL	0	0	0	0	0	0	0	0	0	0	0	
(26) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(27) TOTAL CUSTOMER	**255,289**	**224,960**	**11,877**	**12,472**	**22**	**2,559**	**237**	**73**	**0**	**8**	**3,081**	
(28) TOTAL AVE. RATE BASE	**$3,552,705**	**$1,915,011**	**$93,758**	**$842,695**	**$114,028**	**$84,814**	**$144,737**	**$239,760**	**$0**	**$57,017**	**$60,884**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) LAND	$3,024	$1,786	$97	$827	$88	$79	$102	$5	$0	$0	$41	P-3
(2) EASEMENTS & SURVEY	10,933	6,455	350	2,988	318	287	368	18	0	1	147	P-3
(3) OTHER	1,433	846	46	392	42	38	48	2	0	0	19	P-3
(4) SUBSTATIONS	28,462	16,129	874	7,584	1,065	735	1,320	365	0	24	367	EXH 3B
(5) POLES & FIXTURES	112,682	66,939	3,625	30,912	3,138	2,969	3,577	0	0	0	1,523	EXH 3D
(6) O.H. LINES	74,661	44,352	2,402	20,481	2,079	1,967	2,370	0	0	0	1,009	EXH 3F
(7) U.G. LINES	21,479	12,759	691	5,892	598	566	682	0	0	0	290	P-1
(8) LINE TRANSFORMERS	154,540	98,854	5,354	43,990	0	4,092	0	0	0	0	2,249	D-1
(9) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(10) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(11) STREET LIGHTING	15,950	0	0	0	0	0	0	0	0	0	15,950	DIRECT
(12) TOTAL DEMAND	423,164	248,120	13,438	113,066	7,327	10,733	8,467	391	0	26	21,595	
CUSTOMER												
(13) LAND	1,414	1,280	68	32	0	6	0	0	0.000	0	27	P-4
(14) EASEMENTS & SURVEY	5,111	4,629	244	116	0	23	1	0	0.000	0	97	P-4
(15) OTHER	670	607	32	15	0	3	0	0	0.000	0	13	P-4
(16) SUBSTATIONS	0	0	0	0	0	0	0	0	0.000	0	0	---
(17) POLES & FIXTURES	60,675	54,951	2,901	1,383	1	270	12	2	0.000	0	1,154	EXH 3D
(18) O.H. LINES	40,202	36,410	1,922	916	1	179	8	1	0.000	0	765	EXH 3F
(19) U.G. LINES	11,565	10,474	553	264	0	52	2	0	0.000	0	220	P-2
(20) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0.000	0	0	---
(21) SERVICES	57,705	47,959	2,532	6,034	0	1,180	0	0	0.000	0	0	C-2
(22) METERS	23,780	20,357	1,075	1,672	16	427	171	57	0.000	6	0	EXH 3G
(23) STREET LIGHTING	0	0	0	0	0	0	0	0	0.000	0	0	---
(24) TOTAL CUSTOMER	$201,122	$176,667	$9,328	$10,432	$18	$2,140	$195	$60	$0	$6	$2,275	
RETAIL												
(25) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(26) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(27) TOTAL RETAIL	0	0	0	0	0	0	0	0	0	0	0	
SUMMARY												
(28) LAND	4,438	3,066	164	859	88	86	102	5	0	0	68	P-3 & 4
(29) EASEMENTS & SURVEY	16,044	11,084	594	3,104	318	310	369	19	0	1	244	P-3 & 4
(30) OTHER	2,103	1,453	78	407	42	41	48	2	0	0	32	P-3 & 4
(31) SUBSTATIONS	28,462	16,129	874	7,584	1,065	735	1,320	365	0	24	367	EXH 3B
(32) POLES & FIXTURES	173,357	121,890	6,527	32,294	3,139	3,239	3,589	2	0	0	2,677	EXH 3D
(33) O.H. LINES	114,863	80,762	4,325	21,398	2,080	2,146	2,378	1	0	0	1,774	EXH 3F
(34) U.G. LINES	33,044	23,234	1,244	6,156	598	617	684	0	0	0	510	P-1 & 2
(35) LINE TRANSFORMERS	154,540	98,854	5,354	43,990	0	4,092	0	0	0	0	2,249	D-1
(36) SERVICES	57,705	47,959	2,532	6,034	0	1,180	0	0	0	0	0	C-2
(37) METERS	23,780	20,357	1,075	1,672	16	427	171	57	0	6	0	EXH 3G
(38) STREET LIGHTING	15,950	0	0	0	0	0	0	0	0	0	15,950	DIRECT
(39) TOTAL AVE. RATE BASE	**$624,286**	**$424,787**	**$22,766**	**$123,498**	**$7,345**	**$12,873**	**$8,662**	**$452**	**$0**	**$32**	**$23,871**	

EXHIBIT 3B

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) DIST. BULK PWR.	(3) DIST. DED. BULK PWR.	(4) DIST. GENERAL	(5) DIST. DED. GENERAL
(1) TOT. DIST. SUBSTATIONS	$28,462	$24,109	$436	$3,832	$86
ALLOCATION					
(2) DOMESTIC	16,129	13,917	0	2,212	0
(3) SMALL GENERAL	874	754	0	120	0
(4) GENERAL	7,584	6,522	26	1,037	0
(5) GENERAL LARGE	1,065	919	0	146	0
(6) SMALL INDUSTRIAL	735	634	0	101	0
(7) MEDIUM INDUSTRIAL	1,320	1,047	103	166	4
(8) LARGE INDUSTRIAL	365	0	284	0	82
(9) ELI 2P-RTP	0	0	0	0	0
(10) MUNICIPAL	24	0	24	0	0
(11) UNMETERED	367	317	0	50	0
(12) TOTAL	$28,462	$24,109	$436	$3,832	$86
ALLOCATION FACTOR		D-2	DIRECT	D-2	DIRECT

EXHIBIT 3C

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$173,357				
(2) PRIMARY ONLY (30%)	52,007	$52,007	$0	$0	$0
(3) 50% JOINT - PRI. (1)	60,675	30,337	30,337	0	0
(4) 50% JOINT - SEC. (1)	60,675	0	0	30,337	30,337
(5) TOTAL	$173,357	$82,345	$30,337	$30,337	$30,337

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3D

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$121,890	$47,533	$27,469	$19,406	$27,483
(2) SMALL GENERAL	6,527	2,574	1,450	1,051	1,451
(3) GENERAL	32,294	22,276	691	8,636	692
(4) GENERAL LARGE	3,139	3,138	1	0	0
(5) SMALL INDUSTRIAL	3,239	2,165	135	803	135
(6) MEDIUM INDUSTRIAL	3,589	3,577	12	0	0
(7) LARGE INDUSTRIAL	2	0	2	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	2,677	1,081	577	442	577
(11) TOTAL	$173,357	$82,345	$30,337	$30,337	$30,337
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3E

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$114,863				
(2) PRIMARY ONLY (30%)	34,459	$34,459	$0	$0	$0
(3) 50% JOINT - PRI. (1)	40,202	20,101	20,101	0	0
(4) 50% JOINT - SEC. (1)	40,202	0	0	20,101	20,101
(5) TOTAL	$114,863	$54,560	$20,101	$20,101	$20,101

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3F

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$80,762	$31,494	$18,200	$12,858	$18,209
(2) SMALL GENERAL	4,325	1,706	961	696	961
(3) GENERAL	21,398	14,760	458	5,722	458
(4) GENERAL LARGE	2,080	2,079	1	0	0
(5) SMALL INDUSTRIAL	2,146	1,435	90	532	90
(6) MEDIUM INDUSTRIAL	2,378	2,370	8	0	0
(7) LARGE INDUSTRIAL	1	0	1	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,774	717	382	293	382
(11) TOTAL	$114,863	$54,560	$20,101	$20,101	$20,101
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3G

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE METER INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	452,558	$34.00	$15,386,972	85.60	$20,357
(2) SMALL GENERAL	23,894	34.00	812,396	4.52	1,075
(3) GENERAL	11,387	111.00	1,263,957	7.03	1,672
(4) GENERAL LARGE	18	657.00	11,826	0.07	16
(5) SMALL INDUSTRIAL	2,227	145.00	322,915	1.80	427
(6) MEDIUM INDUSTRIAL	197	657.00	129,429	0.72	171
(7) LARGE INDUSTRIAL	32	1,338.00	42,816	0.24	57
(8) ELI 2P-RTP	0	1,338.00	0	0.00	0
(9) MUNICIPAL	8	520.00	4,160	0.02	6
(10) UNMETERED	9,504	N/A	0	0.00	0
(11) TOTAL	499,825		$17,974,471	100.00	$23,780

EXHIBIT 4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
POWER PRODUCTION						
(1) FUEL	$372,416	$342,028	$0	$0	$0	$30,388
PURCHASED POWER:						
(2) REGULAR	41,762	41,762	0	0	0	0
(3) WIND	60,826	60,826	0	0	0	0
(4) THERMAL - OPERATING & MAINT.	84,844	84,176	0	0	0	668
(5) HYDRO - OPERATING & MAINT.	9,566	7,364	0	0	0	2,202
(6) WIND - OPERATING & MAINT.	4,649	4,638	0	0	0	11
(7) BIOMASS - OPERATING & MAINT.	5,380	5,368	0	0	0	13
(8) LM6000 - OPERATING & MAINT.	329	328	0	0	0	1
(9) COMBUSTION TURBINE - OPER. & MAINT.	944	941	0	0	0	2
(10) ENERGY, FUELS & RISK MGMT.	3,819	3,810	0	0	0	9
(11) GENERATION DEVELOPMENT	0	0	0	0	0	0
(12) TOTAL PRODUCTION OPER. & MAINT.	109,530	106,624	0	0	0	2,906
CUSTOMER OPERATIONS:						
(13) TRANSMISSION & DISTRIBUTION	54,288	0	17,618	36,248	0	422
CUST. SERV. / MARKETING & SALES:						
(14) Qty. Ass., Comm., Call Ctr. & Rev. Ops.	37,026	0	0	599	36,428	0
OTHER OPERATING						
CORPORATE GROUPS:						
(15) EXECUTIVE MANAGEMENT	1,147	412	126	298	309	1
(16) CORP. SECRETARY & LEGAL SERVICES	8,530	3,068	937	2,215	2,301	9
(17) EXTERNAL RELATIONS & ENVIRONMENT	2,077	747	228	539	560	2
(18) REGULATORY AFFAIRS	6,332	2,277	696	1,645	1,708	7
(19) FINANCE GROUP	6,749	2,427	742	1,753	1,820	7
(20) ENTERPRISE SERVICES	21,728	7,814	2,388	5,643	5,860	24
(21) HUMAN RESOURCES	5,554	1,997	610	1,442	1,498	7
(22) TECHNICAL & CONSTRUCTION SERVICES	14,430	2,902	1,607	3,802	6,110	10
(23) SUSTAINABILITY	1,508	1,505	0	0	0	4
(24) SUB-TOTAL	68,055	23,148	7,333	17,337	20,166	70
(25) OTHER EXPENSES	11,135	4,004	1,224	2,892	3,003	12
(26) DIRECT ADMIN. & GEN. EXPENSE	0	(232)	(71)	(168)	(174)	645
(27) TOTAL OM&G EXPENSES	**280,034**	**133,545**	**26,104**	**56,908**	**59,423**	**4,054**
(28) COGS (NET OF SALES)	(438)	0	0	0	(438)	0
(29) DSM AMORTIZATION	2,150	2,059	0	0	0	91
(30) FCR DEFERRAL	16,500	13,532	2,968	0	0	0
(31) OTHER EXPENSES	0	0	0	0	0	0
(32) GRANTS IN LIEU OF TAXES	37,500	24,368	5,344	7,693	0	95
DEPRECIATION:						
(33) STEAM	63,508	63,359	0	0	0	149
(34) HYDRO	10,456	9,408	0	0	0	1,048
(35) WIND	8,186	8,166	0	0	0	19
(36) LM6000	2,084	2,079	0	0	0	5
(37) OTHER GAS TURBINE	1,183	1,180	0	0	0	3
(38) TRANSMISSION < 138kV	4,878	0	4,869	0	0	9
(39) TRANSMISSION > 69kV	15,967	0	15,938	0	0	29
(40) DISTRIBUTION - Non Streetlight Related	45,933	0	0	45,933	0	0
(41) DISTRIBUTION - Streetlight Related	2,946	0	0	2,342	0	604
(42) GENERAL PROPERTY	37,585	24,442	5,360	7,716	0	67
(43) INTEREST NET	133,900	85,794	17,734	27,568	0	2,804
(44) PREFERRED DIVIDENDS	8,000	5,206	1,076	1,673	0	45
(45) CORPORATE TAXES	52,350	34,021	7,032	10,932	0	365
(46) TOTAL EXPENSES	**$1,197,725**	**$851,777**	**$86,424**	**$160,764**	**$58,986**	**$39,773**
(47) NON-OPERATING REVENUE:						
(48) EXPORT SALES	(1,807)	(1,807)	0	0	0	0
(49) LATE PAYMENT CHARGE	(5,128)	0	0	0	(5,128)	0
(50) MISC. ELECTRIC	(1,909)	0	0	0	(1,909)	0
(51) OTHER REVENUE	(14,108)	(10,378)	(1,053)	(1,959)	(719)	0
(52) NET INCOME	123,837	77,978	16,118	25,056	0	4,685
(53) TOTAL NET EXPENSES	**$1,298,611**	**$917,570**	**$101,490**	**$183,862**	**$51,230**	**$44,458**

EXHIBIT 4 - Detail A

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1)	**FUEL**	$372,416	$342,028	$0	$0	$0	$30,388
	PURCHASED POWER:						
(2)	REGULAR	41,762	41,762	0	0	0	0
(3)	WIND	60,826	60,826	0	0	0	0
(4)	TOTAL	475,005	444,617	0	0	0	30,388
	POWER PRODUCTION						
(5)	THERMAL OPERATING & MAINT.	84,844	84,176	0	0	0	668
(6)	HYDRO OPERATING & MAINT.	9,566	7,364	0	0	0	2,202
(7)	WIND - OPERATING & MAINT.	4,649	4,638	0	0	0	11
(8)	BIOMASS - OPERATING & MAINT.	5,380	5,368	0	0	0	13
(9)	LM6000 OPERATING & MAINT.	329	328	0	0	0	1
(10)	COMBUSTION TURBINE - OPER. & MAINT.	944	941	0	0	0	2
(11)	FUEL PROCUREMENT	3,819	3,810	0	0	0	9
(12)	GENERATION DEVELOPMENT	0	0	0	0	0	0
(13)							
(14)	**TOTAL POWER PRODUCTION**	109,530	106,624	0	0	0	2,906
(15)	**SUSTAINABILITY**	1,508	1,505	0	0	0	4
	CORPORATE GROUPS						
(16)	EXECUTIVE MANAGEMENT	1,147	412	126	298	309	1
(17)	CORP. SECRETARY	7,359	2,646	809	1,911	1,985	8
(18)	LEGAL SERVICES	1,171	421	129	304	316	1
(19)	EXTERNAL RELATIONS	2,077	747	228	539	560	2
(20)	ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0
(21)	Total Corporate Groups	11,754	4,227	1,292	3,053	3,170	12
	CUSTOMER OPERATIONS						
	TRANSMISSION & DISTRIBUTION:						
(22)	**TRANSMISSION:**						
(23)	**< 138kV**	4,221	0	4,214	0	0	8
(24)	**> 69kV**	13,819	0	13,404	0	0	415
	DISTRIBUTION:						
(25)	SUBSTATIONS	194	0	0	194	0	0
(26)	OVERHEAD LINES	25,350	0	0	25,350	0	0
(27)	UNDERGROUND LINES	440	0	0	440	0	0
(28)	LINE TRANSFORMERS	941	0	0	941	0	0
(29)	METERS (Meter Shop Only)	0	0	0	0	0	0
(30)	COMMUNICATIONS	5,630	0	0	5,630	0	0
(31)	STREET LIGHTING	3,694	0	0	3,694	0	0
(33)	**TOTAL DISTRIBUTION**	36,248	0	0	36,248	0	0
(34)	**TOTAL CUSTOMER OPERATIONS - T & D**	54,288	0	17,618	36,248	0	422
(35)	**TECHNICAL & CONSTRUCTION SERVICES**	14,430	2,902	1,607	3,802	6,110	10
	CUST. SERV. / MARKETING & SALES						
	ADMINISTRATION:						
(36)	CUSTOMER SERVICE - ADMIN.	711	0	0	0	711	0
(37)	ENERGY EFFICIENCY	476	0	0	0	476	0
(38)	CUST. COMM. & QTY ASSURANCE	1,857	0	0	0	1,857	0
(39)	CUSTOMER SOLUTIONS	0	0	0	0	0	0
(40)	**CALL CENTRE:**						
(41)	(a) CALL CENTRE - CSR's	7,016	0	0	0	7,016	0
(42)	(b) CALL CENTRE OPERATIONS	0	0	0	0	0	0
(43)	(c) CALL CENTRE - HALIFAX	0	0	0	0	0	0
(44)	(d) CALL NETWORK (COLLECTIONS)	374	0	0	0	374	0
(45)	(e) ELECTRICAL WIRING INSPECTION	4,457	0	0	0	4,457	0
(46)	**REVENUE OPERATIONS:**						
(47)	(a) BILLING SERVICES	3,676	0	0	0	3,676	0
(48)	(b) METER DATA SERVICES	468	0	0	0	468	0
(49)	(c) METER SERVICES - METER SHOP	599	0	0	599	0	0
(50)	(d) METER SERVICES - FIELD	6,105	0	0	0	6,105	0
(51)	(e) ELECTRICAL WIRING INSPECTION - FIELD	3,430	0	0	0	3,430	0
(52)	(f) PAYMENT SERVICES	703	0	0	0	703	0
(53)	(g) CREDIT SERVICES	0	0	0	0	0	0
(54)	(h) BAD DEBT EXPENSE	5,736	0	0	0	5,736	0
(55)	(i) MARKETING & SALES	1,154	0	0	0	1,154	0
(56)	(j) ELECTRICAL WIRING INSPECTION - H/O	265	0	0	0	265	0
(58)	**TOTAL CUST. SERV. / MARKETING & SALES**	37,026	0	0	599	36,428	0

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1) **REGULATORY AFFAIRS**	$6,332	$2,277	$696	$1,645	$1,708	$7
FINANCE GROUP						
(2) INTERNAL AUDIT	1,696	610	186	441	458	2
(3) INVESTOR RELATIONS	283	102	31	74	76	0
(4) DIRECTOR FINANCE	732	263	80	190	197	1
(5) TREASURER	785	282	86	204	212	1
(6) CORPORATE TAX	809	291	89	210	218	1
(7) GM FINANCE	0	0	0	0	0	0
(8) CORPORATE CONTROLLER	2,444	879	269	635	659	3
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0
(10) **TOTAL FINANCE**	6,749	2,427	742	1,753	1,820	7
ENTERPRISE SERVICES						
(11) PROCUREMENT & FACILITIES	9,991	3,593	1,098	2,595	2,695	11
(12) INFORMATION TECHNOLOGY	11,737	4,221	1,290	3,048	3,166	13
(13) **TOTAL ENTERPRISE SERVICES**	21,728	7,814	2,388	5,643	5,860	24
HUMAN RESOURCES						
(14) --HUMAN RESOURCES	5,554	1,997	610	1,442	1,498	7
(15) OTHER EXPENSES	11,135	4,004	1,224	2,892	3,003	12
(16) DIRECT ADM. & GEN. EXPENSE	0	(232)	(71)	(168)	(174)	645
(17) **TOTAL DIVISIONAL EXPENSES**	**280,034**	**133,545**	**26,104**	**56,908**	**59,423**	**4,054**
(18) **COGS (NET OF RETAIL SALES)**	**(438)**	**0**	**0**	**0**	**(438)**	**0**
(19) **DSM EXPENSES**	**2,150**	**2,059**	**0**	**0**	**0**	**91**
(20) **FCR DEFERRAL**	**16,500**	**13,532**	**2,968**	**0**	**0**	**0**
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**	
CAPITAL RELATED EXPENSES						
(22) GRANTS IN LIEU OF TAXES	37,500	24,368	5,344	7,693	0	95
(23) DEPRECIATION :						
(24) STEAM	63,508	63,359	0	0	0	149
(25) HYDRO	10,456	9,408	0	0	0	1,048
(26) WIND	8,186	8,166	0	0	0	19
(27) LM6000	2,084	2,079	0	0	0	5
(28) GAS TURBINE - OTHER	1,183	1,180	0	0	0	3
(29) TRANSMISSION < 138kV	4,878	0	4,869	0	0	9
(30) TRANSMISSION > 69kV	15,967	0	15,938	0	0	29
(31) DISTRIBUTION - Non Streetlight Related	45,933	0	0	45,933	0	0
(32) DISTRIBUTION - Streetlight Related	2,946	0	0	2,342	0	604
(33) GENERAL PROPERTY	37,585	24,442	5,360	7,716	0	67
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0
(35) INTEREST NET	133,900	85,794	17,734	27,568	0	2,804
(36) PREFERRED DIVIDENDS	8,000	5,206	1,076	1,673	0	45
(37) CORPORATE TAXES	52,350	34,021	7,032	10,932	0	365
(38) **TOTAL OPERATING EXPENSES**	**1,197,725**	**851,777**	**86,424**	**160,764**	**58,986**	**39,773**
(39) NON-OPERATING REVENUE:						0
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0
(41) EXPORT SALES	(1,807)	(1,807)	0	0	0	0
(42) LATE PAYMENT CHARGE	(5,128)	0	0	0	(5,128)	0
(43) MISC. ELECTRIC	(1,909)	0	0	0	(1,909)	0
(44) OTHER REVENUE	(14,108)	(10,378)	(1,053)	(1,959)	(719)	0
(45) **PROFIT/LOSS**	123,837	77,978	16,118	25,056	0	4,685
(46) **TOTAL NET EXPENSES**	**$1,298,611**	**$917,570**	**$101,490**	**$183,862**	**$51,230**	**$44,458**

EXHIBIT 4 - Detail B

FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE LRT

NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT

Fixed Cost Contribution $4.00
Load 322
$1,288

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) WEIGHTS		(8) DIRECT LRT
(1) **FUEL**	$372,416	$342,028	$0	$0	$0	$30,388	$0	0					0.00%	0.00%	$0.00
PURCHASED POWER:															
(2) REGULAR	41,762	41,762	0	0	0	0	0	0					0.00%	0.00%	$0.00
(3) WIND	60,826	60,826	0	0	0	0	0	0					0.00%	0.00%	$0.00
(4) TOTAL	475,005	444,617	0	0	0	30,388	0	0					0.00%	0.00%	$0.00
POWER PRODUCTION															
(5) THERMAL OPERATING & MAINT.	84,844	84,373	0	0	0	471	84,373	84,373	0				15.34%	15.34%	$197.63
(6) HYDRO OPERATING & MAINT.	9,566	7,381	0	0	0	2,185	7,381	7,381	0				1.34%	1.34%	$17.29
(7) WIND - OPERATING & MAINT.	4,649	4,649	0	0	0	0	4,649	4,649	0				0.85%	0.85%	$10.89
(8) BIOMASS - OPERATING & MAINT.	5,380	5,380	0	0	0	0	5,380	5,380	0				0.98%	0.98%	$12.60
(9) LM6000 OPERATING & MAINT.	329	329	0	0	0	0	329	329	0				0.06%	0.06%	$0.77
(10) COMBUSTION TURBINE - OPER. & MAINT.	944	944	0	0	0	0	944	944	0				0.17%	0.17%	$2.21
(11) FUEL PROCUREMENT	3,819	3,819	0	0	0	0	3,819	3,819	0				0.69%	0.69%	$8.95
(12) GENERATION DEVELOPMENT	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(13)									0				0.00%	0.00%	$0.00
(14) **TOTAL POWER PRODUCTION**	109,530	106,875	0	0	0	2,655	106,875	106,875	0				19.43%	19.43%	$250.34
(15) **SUSTAINABILITY**	1,508	1,508	0	0	0	0	1,508	1,508	0				0.27%	0.27%	$3.53
CORPORATE GROUPS															
(16) EXECUTIVE MANAGEMENT	1,147	413	126	298	310	0	510	413	97				0.09%	0.09%	$1.19
(17) CORP. SECRETARY	7,359	2,649	809	1,913	1,987	0	3,269	2,649	620				0.59%	0.59%	$7.66
(18) LEGAL SERVICES	1,171	422	129	305	316	0	520	422	99				0.09%	0.09%	$1.22
(19) EXTERNAL RELATIONS	2,077	748	228	540	561	0	923	748	175				0.17%	0.17%	$2.16
(20) ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
	11,754	4,231	1,293	3,056	3,173	0	5,222	4,231	990						$12.23
CUSTOMER OPERATIONS															
TRANSMISSION & DISTRIBUTION:															
(21) **TRANSMISSION:**															
(22) **< 138kV**	4,221	0	4,221	0	0	0	3,234	0	3234				0.59%	0.59%	$7.57
(23) **> 69kV**	13,819	0	13,428	0	0	391	10,286	0	10286				1.87%	1.87%	$24.09
DISTRIBUTION:															
(24) SUBSTATIONS	194	0	0	194	0	0	0	0	0				0.00%	0.00%	$0.00
(25) OVERHEAD LINES	25,350	0	0	25,350	0	0	0	0	0				0.00%	0.00%	$0.00
(26) UNDERGROUND LINES	440	0	0	440	0	0	0	0	0				0.00%	0.00%	$0.00
(27) LINE TRANSFORMERS	941	0	0	941	0	0	0	0	0				0.00%	0.00%	$0.00
(28) METERS (Meter Shop Only)	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(29) COMMUNICATIONS	5,630	0	0	5,630	0	0	0	0	0				0.00%	0.00%	$0.00
(30) STREET LIGHTING	3,694	0	0	3,694	0	0	0	0	0				0.00%	0.00%	$0.00
(31)									0				0.00%	0.00%	
(32) **TOTAL DISTRIBUTION**	36,248	0	0	36,248	0	0	0	0	0	0	0	0	0.00%	0.00%	$0.00
(33) **TOTAL CUSTOMER OPERATIONS - T & D**	54,288	0	17,649	36,248	0	391	13,519	0	13,519	0	0	0	2.46%	2.46%	$31.67
(34) **TECHNICAL & CONSTRUCTION SERVICES**	14,430	2,910	1,608	3,802	6,110	0	4,142	2,910	1232	0	0	0	0.75%	0.75%	$9.70
CUST. SERV. / MARKETING & SALES															
ADMINISTRATION:															
(35) CUSTOMER SERVICE - ADMIN.	711	0	0	0	711	0	0	0	0				0.00%	0.00%	$0.00
(36) ENERGY EFFICIENCY	476	0	0	0	476	0	0	0	0				0.00%	0.00%	$0.00
(37) CUST. COMM. & QTY ASSURANCE	1,857	0	0	0	1,857	0	0	0	0				0.00%	0.00%	$0.00
(38) CUSTOMER SOLUTIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(39) **CALL CENTRE:**															
(40) (a) CALL CENTRE - CSR's	7,016	0	0	0	7,016	0	0	0	0				0.00%	0.00%	$0.00
(41) (b) CALL CENTRE OPERATIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(42) (c) CALL CENTRE - HALIFAX	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(43) (d) CALL NETWORK (COLLECTIONS)	374	0	0	0	374	0	0	0	0				0.00%	0.00%	$0.00
(44) (e) ELECTRICAL WIRING INSPECTION	4,457	0	0	0	4,457	0	0	0	0				0.00%	0.00%	$0.00
(45) **REVENUE OPERATIONS:**															
(46) (a) BILLING SERVICES	3,676	0	0	0	3,676	0	0	0	0				0.00%	0.00%	$0.00
(47) (b) METER DATA SERVICES	468	0	0	0	468	0	0	0	0				0.00%	0.00%	$0.00
(48) (c) METER SERVICES - METER SHOP	599	0	0	599	0	0	0	0	0				0.00%	0.00%	$0.00
(49) (d) METER SERVICES - FIELD	6,105	0	0	0	6,105	0	0	0	0				0.00%	0.00%	$0.00
(50) (e) ELECTRICAL WIRING INSPECTION - FIELD	3,430	0	0	0	3,430	0	0	0	0				0.00%	0.00%	$0.00
(51) (f) PAYMENT SERVICES	703	0	0	0	703	0	0	0	0				0.00%	0.00%	$0.00
(52) (g) CREDIT SERVICES	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(53) (h) BAD DEBT EXPENSE	5,736	0	0	0	5,736	0	0	0	0				0.00%	0.00%	$0.00
(54) (i) MARKETING & SALES	1,154	0	0	0	1,154	0	0	0	0				0.00%	0.00%	$0.00
(55) (j) ELECTRICAL WIRING INSPECTION - H/O	265	0	0	0	265	0	0	0	0				0.00%	0.00%	$0.00
(57) **TOTAL CUST. SERV. / MARKETING & SALES**	37,026	0	0	599	36,428	0	0	0	0	0	0	0	0.00%	0.00%	$0.00

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
DEDICATED DIST.PLT.- LINE TRANSFORMERS
(IN THOUSANDS OF DOLLARS)

	FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE ELR						NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT								
	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) EXPENSES		(8) DIRECT LRT
(1) **REGULATORY AFFAIRS**	$6,332	$2,280	$697	$1,646	$1,710	$0	$2,813	$2,280	534				0.51%	0.51%	$6.59
FINANCE GROUP															
(2) INTERNAL AUDIT	1,696	611	187	441	458	0	754	$611	143				0.14%	0.14%	$1.77
(3) INVESTOR RELATIONS	283	102	31	74	76	0	126	$102	24				0.02%	0.02%	$0.29
(4) DIRECTOR FINANCE	732	263	81	190	198	0	325	$263	62				0.06%	0.06%	$0.76
(5) TREASURER	785	283	86	204	212	0	349	$283	66				0.06%	0.06%	$0.82
(6) CORPORATE TAX	809	291	89	210	218	0	359	$291	68				0.07%	0.07%	$0.84
(7) GM FINANCE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(8) CORPORATE CONTROLLER	2,444	880	269	635	660	0	1,086	$880	206				0.20%	0.20%	$2.54
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(10) **TOTAL FINANCE**	6,749	2,430	742	1,755	1,822	0	2,998	$2,430	569				0.55%	0.55%	$7.02
ENTERPRISE SERVICES															
(11) PROCUREMENT & FACILITIES	9,991	2,598	2,698	3,597	1,099	0	4,664	$2,598	2066				0.85%	0.85%	$10.93
(12) INFORMATION TECHNOLOGY	11,737	3,052	3,169	4,225	1,291	0	5,479	$3,052	2428				1.00%	1.00%	$12.83
(13) **TOTAL ENTERPRISE SERVICES**	21,728	5,649	5,867	7,822	2,390	0	10,143	$5,649	4494				1.84%	1.84%	$23.76
HUMAN RESOURCES															
(14) --HUMAN RESOURCES	5,554	1,500	1,999	611	1,444	0	3,031	$1,500	1532				0.55%	0.55%	$7.10
(15) OTHER EXPENSES	11,135	4,009	1,225	2,895	3,006	0	4,947	$4,009	938				0.90%	0.90%	$11.59
(16) DIRECT ADM. & GEN. EXPENSE	0	(232)	(71)	(168)	(174)	645	(287)	($232)	-54				-0.05%	-0.05%	($0.67)
(17) **TOTAL DIVISIONAL EXPENSES**	**280,034**	**131,158**	**31,009**	**58,265**	**55,909**	**3,691**	**154,912**	**131,158**	**23,753**				28.17%	28.17%	$362.86
(18) **COGS (NET OF RETAIL SALES)**	**(438)**	**0**	**0**	**0**	**(438)**	**0**	**0**	$0	0				0.00%	0.00%	$0.00
(19) **DSM EXPENSES**	**2,150**	**2,064**	**0**	**0**	**0**	**86**	**2,064**	$2,064	0				0.38%	0.38%	$4.83
(20) **FCR DEFERRAL**	**16,500**	**13,532**	**2,968**	**0**	**0**	**0**	**0**	$0					0	0	0
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**		**0**	$0	0				0.00%	0.00%	$0.00
CAPITAL RELATED EXPENSES															
(22) GRANTS IN LIEU OF TAXES	37,500	24,412	5,353	7,706	0	28	28,513	$24,412	4101				5.18%	5.18%	$66.79
(23) DEPRECIATION :									0						
(24) STEAM	63,508	63,508	0	0	0	0	63,508	$63,508	0				11.55%	11.55%	$148.76
(25) HYDRO	10,456	9,430	0	0	0	1,025	9,430	$9,430	0				1.71%	1.71%	$22.09
(26) WIND	8,186	8,186	0	0	0	0	8,186	$8,186	0				1.49%	1.49%	$19.17
(27) LM6000	2,084	2,084	0	0	0	0	2,084	$2,084	0				0.38%	0.38%	$4.88
(28) GAS TURBINE - OTHER	1,183	1,183	0	0	0	0	1,183	$1,183	0				0.22%	0.22%	$2.77
(29) TRANSMISSION < 138kV	4,878	0	4,878	0	0	0	3,736	$0	3736				0.68%	0.68%	$8.75
(30) TRANSMISSION > 69kV	15,967	0	15,967	0	0	0	12,230	$0	12230				2.22%	2.22%	$28.65
(31) DISTRIBUTION - Non Streetlight Related	45,933	0	0	45,933	0	0	0	$0	0				0.00%	0.00%	$0.00
(32) DISTRIBUTION - Streetlight Related	2,946	0	0	2,342	0	604	0	$0	0				0.00%	0.00%	$0.00
(33) GENERAL PROPERTY	37,585	24,486	5,370	7,730	0	0	28,599	$24,486	4113				5.20%	5.20%	$66.99
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(35) INTEREST NET	133,900	85,947	17,766	27,617	0	2,570	99,555	$85,947	13608				18.10%	18.10%	$233.20
(36) PREFERRED DIVIDENDS	8,000	5,216	1,078	1,676	0	30	6,041	$5,216	826				1.10%	1.10%	$14.15
(37) CORPORATE TAXES	52,350	34,081	7,045	10,951	0	273	39,477	$34,081	5396				7.18%	7.18%	$92.47
(38) **TOTAL OPERATING EXPENSES**	**1,197,725**	**849,903**	**91,433**	**162,221**	**55,472**	**38,697**	**459,518**	**391,754**	**67,764**	**0**	**0**	**0**	83.55%	83.55%	$1,076.37
(39) NON-OPERATING REVENUE:													0.00%	0.00%	$0.00
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(41) EXPORT SALES	(1,807)	(1,807)	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00
(42) LATE PAYMENT CHARGE	(5,128)	0	0	0	(5,128)	0	0	$0	0				0.00%	0.00%	$0.00
(43) MISC. ELECTRIC	(1,909)	0	0	0	(1,909)	0	0	$0	0				0.00%	0.00%	$0.00
(44) OTHER REVENUE	(14,108)	(10,345)	(1,113)	(1,975)	(675)	0	0	$0	0				0.00%	0.00%	$0.00
(45) **PROFIT/LOSS**	123,837	78,116	16,147	25,101	0	4,473	90,485	78,116	12369			0	16.45%	16.45%	$211.95
(46) **TOTAL NET EXPENSES**	**$1,298,611**	**$915,867**	**$106,467**	**$185,347**	**$47,760**	**$43,170**	**$550,003**	**$469,870**	**$80,133**	**$0**	**$0**	**$0**	100.00%	100.00%	**$1,288.320**

EXHIBIT 5
Page 1 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
GENERATION FUNCTION				
(1) FUEL	342,028	$0	$342,028	$0
(2) PURCHASED PWR REG - FIXED	18,793	6,009	12,784	0
(3) PURCHASED PWR REG - VAR.	22,969	0	22,969	0
(4) PURCHASED PWR WIND - FIXED	18,248	5,474	12,774	0
(5) PURCHASED PWR WIND - VAR.	42,578	0	42,578	0
(6) OPER. & MAINT. - STEAM	109,335	29,366	79,969	0
(7) OPER. & MAINT. - HYDRO/WIND/BI	22,561	6,060	16,501	0
(8) OPER. & MAINT. - LM6000	426	114	311	0
(9) OPER. & MAINT. - OTHER CT's	1,223	1,027	196	0
(10) DSM AMORTIZATION	2,059	658	1,401	0
(11) FCR DEFERRAL	13,532	4,084	9,449	0
(12) GRANTS IN LIEU OF TAXES	24,368	7,792	16,577	0
DEPRECIATION:				
(13) STEAM	63,359	20,754	42,605	0
(14) HYDRO	9,408	4,021	5,387	0
(15) WIND	8,166	202	7,964	0
(16) LM6000	2,079	903	1,176	0
(17) GAS TURBINE - OTHER	1,180	1,180	0	0
(18) GENERAL PROPERTY	24,442	7,815	16,627	0
(19) INTEREST NET OF AFUDC	85,794	25,890	59,904	0
(20) PREFERRED DIVIDENDS	5,206	1,571	3,635	0
(21) CORPORATE TAXES	34,021	10,266	23,754	0
NON-OPERATING REVENUE:				
(22) EXPORT SALES	(1,807)	0	(1,807)	0
(23) OTHER REVENUE	(10,378)	(1,623)	(8,755)	0
(24) RETURN (PROFIT/LOSS)	77,978	23,531	54,447	0
(25) TOTAL GENERATION	**917,570**	**155,095**	**762,476**	**0**
	917,570			
TRANSMISSION FUNCTION				
Transmission < 138kV:				
(26) O&M < 138kV	6,243	2,712	3,532	0
(27) GRANTS IN LIEU OF TAXES	1,234	536	698	0
DEPRECIATION:				
(28) TRANSMISSION	4,869	2,115	2,754	0
(29) GENERAL PROPERTY	1,254	545	710	0
(30) INTEREST NET OF AFUDC	4,094	1,778	2,316	0
(31) PREFERRED DIVIDENDS	248	108	141	0
(32) CORPORATE TAXES	1,623	705	918	0
NON-OPERATING REVENUE:				
(33) OTHER REVENUE	(246)	(107)	(139)	0
(35) RETURN (PROFIT/LOSS)	3,721	1,616	2,105	0
(36) TOTAL < 138kV	**23,040**	**10,006**	**13,034**	**0**

EXHIBIT 5
Page 2 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
Transmission > 69kV:				
(1) O&M > 69kV	19,860	8,625	11,235	0
(2) GRANTS IN LIEU OF TAXES	4,110	1,785	2,325	0
DEPRECIATION:				
(3) TRANSMISSION	15,938	6,922	9,016	0
(4) GENERAL PROPERTY	4,106	1,783	2,323	0
(5) INTEREST NET OF AFUDC	13,640	5,924	7,716	0
(6) PREFERRED DIVIDENDS	828	359	468	0
(7) CORPORATE TAXES	5,409	2,349	3,060	0
NON-OPERATING REVENUE:				
(8) OTHER REVENUE	(807)	(350)	(456)	0
(9) FCR DEFERRAL	2,968	1,289	1,679	0
(10) RETURN (PROFIT/LOSS)	12,398	5,384	7,013	0
(11) TOTAL > 69kV	**78,450**	**34,071**	**44,379**	**0**
(12) TOTAL TRANSMISSION	**$101,490**	**$44,077**	**$57,413**	**$0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
DISTRIBUTION FUNCTION				
BEFORE STREETLIGHTS				
(1) SUBSTATIONS	$300	$300	$0	$0
(2) OVERHEAD LINES	39,152	25,449	0	13,703
(3) UNDERGROUND LINES	679	441	0	238
(4) LINE TRANSFORMERS	1,453	1,453	0	0
(5) METERS	924	0	0	924
(6) COMMUNICATIONS	8,696	8,696	0	0
(7) GRANTS IN LIEU OF TAXES	7,528	4,900	0	2,629
DEPRECIATION:				
(8) DISTRIBUTION	45,933	31,135	0	14,798
(9) GENERAL PROPERTY	7,716	5,230	0	2,486
(10) INTEREST NET OF AFUDC	26,980	17,559	0	9,420
(11) PREFERRED DIVIDENDS	1,637	1,066	0	572
(12) CORPORATE TAXES	10,698	6,963	0	3,736
(13) RETURN (PROFIT/LOSS)	24,522	15,960	0	8,562
STREETLIGHTS				
non-LED				
(14) MAINTENACE	5,705	5,705	0	0
(15) GRANTS IN LIEU OF TAXES	164	164	0	0
(16) DEPRECIATION	2,342	2,342	0	0
(17) INTEREST NET OF AFUDC	589	589	0	0
(18) PREFERRED DIVIDENDS	36	36	0	0
(19) CORPORATE TAXES	233	233	0	0
(20) RETURN (PROFIT/LOSS)	535	535	0	0
Subtotal	9,604	9,604	0	0
(21) OTHER REVENUE	(1,959)	(1,368)	0	(591)
(22) TOTAL DISTRIBUTION	**183,862**	**127,386**	**0**	**56,476**
RETAIL FUNCTION				
(23) QTY. ASSURANCE. & COMM.	5,325	0	0	5,325
(24) CALL CENTRE	20,723	0	0	20,723
(25) BILLING SERVICES	6,430	0	0	6,430
(26) ELECT. WIRING INSPECT. - H/O	463	0	0	463
(27) METER DATA SERVICES	818	0	0	818
(28) METER READING - FIELD	10,678	0	0	10,678
(29) ELECT. WIRING INSPECT. - FIELD	5,999	0	0	5,999
(30) PAYMENT SERVICES	1,230	0	0	1,230
(31) CREDIT SERVICES	0	0	0	0
(32) BAD DEBT EXPENSE	5,736	0	0	5,736
(33) MARKETING & SALES	2,019	0	0	2,019
(34) COGS (NET OF RETAIL SALES)	(438)	0	0	(438)
(35) GRANTS IN LIEU OF TAXES	0	0	0	0
(36) DEPRECIATION:				
(37) DISTRIBUTION	0	0	0	0
(38) GENERAL PROPERTY	0	0	0	0
(39) INTEREST NET OF AFUDC	0	0	0	0
(40) PREFERRED DIVIDENDS	0	0	0	0
(41) CORPORATE TAXES	0	0	0	0
NON-OPERATING REVENUE:				
(42) LATE PAYMENT CHARGE	(5,128)	0	0	(5,128)
(43) MISC. ELECTRIC	(1,909)	0	0	(1,909)
(44) OTHER REVENUE	(719)	0	0	(719)
(45) RETURN (PROFIT/LOSS)	0	0	0	0
(46) TOTAL RETAIL	**51,230**	**0**	**0**	**51,230**
(47) TOTAL NET EXPENSES	**$1,254,153**	**$326,558**	**$819,889**	**$107,706**

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION												
(1) FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	D-3A
(2) PURCH. POWER REG - FIXED	6,009	3,414	123	1,379	169	119	230	376	0	124	74	D-3A
(3) PURCH. POWER WIND - FIXED	5,474	3,110	112	1,256	154	109	210	342	0	113	68	D-3A
(4) OPER. & MAINT. - STEAM	29,366	16,683	600	6,740	827	583	1,126	1,836	0	607	364	D-3A
(5) OPER. & MAINT. - HYDRO/WIND/BIOMASS	6,060	3,443	124	1,391	171	120	232	379	0	125	75	D-3A
(6) OPER. & MAINT. - LM6000	114	65	2	26	3	2	4	7	0	2	1	D-3A
(7) OPER. & MAINT. - OTHER CT's	1,027	584	21	236	29	20	39	64	0	21	13	D-3A
(8) DSM AMORTIZATION	658	374	13	151	19	13	25	41	0	14	8	D-3A
(9) FCR DEFERRAL	4,084	2,320	83	937	115	81	157	255	0	84	51	P-14
(10) GRANTS IN LIEU	7,792	4,427	159	1,788	219	155	299	487	0	161	97	P-7
(11) DEPRECIATION	34,875	19,813	712	8,005	982	692	1,337	2,180	0	721	432	EXH 6D
(12) INTEREST NET OF AFUDC	25,890	14,709	529	5,942	729	514	993	1,618	0	535	321	P-14
(13) PREFERRED DIVIDENDS	1,571	893	32	361	44	31	60	98	0	32	19	P-14
(14) CORPORATE TAXES	10,266	5,833	210	2,356	289	204	394	642	0	212	127	P-14
NON-OPERATING REVENUE:												
(15) OTHER REVENUE	(1,623)	(922)	(33)	(372)	(46)	(32)	(62)	(101)	0	(34)	(20)	O-8
(16) RETURN (PROFIT/LOSS)	23,531	13,368	481	5,401	663	467	902	1,471	0	486	292	P-14
(17) INTERR. RIDER DMD ADJ.	(5,786)	0	0	0	0	0	0	(5,786)	0	0	0	DIRECT
(18) ALLOC. OF INTERR. DMD. ADJ.	5,786	3,447	124	1,393	171	120	233	98	0	125	75	D-4
(19) ELI 2P-RTP DEMAND ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(20) ALLOC. OF ELI 2P-RTP DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-4
(21) ELI 2P-RTP PRIORITY DMD ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(22) ALLOC. OF ELI 2P-RTP PRI. DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-3B
(23) TOTAL GENERATION	155,095	91,559	3,291	36,990	4,539	3,199	6,179	4,007	0	3,332	1,998	
TRANSMISSION												
Transmission < 138kV												
(24) OPERATING & MAINT.	2,712	1,540	55	622	76	54	104	169	0	56	34	D-3B
(25) GRANTS IN LIEU	536	304	11	123	15	11	21	33	0	11	7	P-8A
(26) DEPRECIATION	2,659	1,511	54	610	75	53	102	166	0	55	33	EXH 6D
(27) INTEREST NET OF AFUDC	1,778	1,010	36	408	50	35	68	111	0	37	22	P-15A
(28) PREFERRED DIVIDENDS	108	61	2	25	3	2	4	7	0	2	1	P-15A
(29) CORPORATE TAXES	705	401	14	162	20	14	27	44	0	15	9	P-15A
NON-OPERATING REVENUE:												
(30) OTHER REVENUE	(107)	(61)	(2)	(25)	(3)	(2)	(4)	(7)	0	(2)	(1)	O-9A
(32) RETURN (PROFIT/LOSS)	1,616	918	33	371	46	32	62	101	0	33	20	P-15A
(33) TOTAL < 138kV	$10,006	$5,685	$204	$2,297	$282	$199	$384	$625	$0	$207	$124	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
Transmission > 69kV												
(1) OPERATING & MAINT.	8,625	4,900	176	1,980	243	171	331	539	0	178	107	D-3A
(2) GRANTS IN LIEU	1,785	1,014	36	410	50	35	68	112	0	37	22	P-8B
(3) DEPRECIATION	8,705	4,946	178	1,998	245	173	334	544	0	180	108	EXH 6D
(4) INTEREST NET OF AFUDC	5,924	3,366	121	1,360	167	118	227	370	0	122	73	P-15B
(5) PREFERRED DIVIDENDS	359	204	7	83	10	7	14	22	0	7	4	P-15B
(6) CORPORATE TAXES	2,349	1,335	48	539	66	47	90	147	0	49	29	P-15B
NON-OPERATING REVENUE:												
(7) FCR DEFERRAL	1,289	732	26	296	36	26	49	81	0	27	16	P-15B
(8) OTHER REVENUE	(350)	(199)	(7)	(80)	(10)	(7)	(13)	(22)	0	(7)	(4)	O-9B
(9) RETURN (PROFIT/LOSS)	5,384	3,059	110	1,236	152	107	206	337	0	111	67	P-15B
(10) TOTAL > 69kV	34,071	19,356	696	7,820	960	676	1,306	2,130	0	704	422	
(11) TOTAL TRANSMISSION	44,077	25,041	900	10,117	1,241	875	1,690	2,755	0	911	546	
DISTRIBUTION												
Non SL												
(12) OPERATING & MAINT.	36,338	21,499	1,164	9,948	1,063	957	1,213	4	0	0	489	EXH 6A
(13) GRANTS IN LIEU	4,900	2,985	162	1,360	88	129	102	5	0	0	68	P-9
(14) DEPRECIATION	36,365	22,158	1,200	10,097	654	958	756	35	0	2	504	EXH 6D
(15) INTEREST NET OF AFUDC	17,559	10,639	576	4,850	320	461	370	16	0	1	326	P-16
(16) PREFERRED DIVIDENDS	1,066	646	35	294	19	28	22	1	0	0	20	P-16
(17) CORPORATE TAXES	6,963	4,219	228	1,923	127	183	147	6	0	0	129	P-16
NON-OPERATING REVENUE:												
(18) OTHER REVENUE	(1,368)	(757)	(41)	(347)	(28)	(33)	(32)	(1)	0	(0)	(129)	O-10
(19) RETURN (PROFIT/LOSS)	15,960	9,670	524	4,408	291	419	336	15	0	1	296	P-16
SL												
non-LED												
(20) OPERATING & MAINT.	5,705	0	0	0	0	0	0	0	0	0	5,705	EXH 6A
(21) GRANTS IN LIEU OF TAXES	164	0	0	0	0	0	0	0	0	0	164	P-9A
(22) Depreciation	2,342	0	0	0	0	0	0	0	0	0	2,342	EXH 6D
(23) INTEREST NET OF AFUDC	589	0	0	0	0	0	0	0	0	0	589	P-16B
(23) PREFERRED DIVIDENDS	36	0	0	0	0	0	0	0	0	0	36	P-16B
(25) CORPORATE TAXES	233	0	0	0	0	0	0	0	0	0	233	P-16B
(26) OTHER REVENUE												
(27) RETURN (PROFIT/LOSS)	535	0	0	0	0	0	0	0	0	0	535	P-16B
Subtotal	9,604	0	0	0	0	0	0	0	0	0	9,604	
(28) TOTAL DISTRIBUTION	127,386	71,057	3,849	32,535	2,536	3,101	2,915	81	0	5	11,306	
(29) TOTAL DEMAND	$326,558	$187,658	$8,040	$79,642	$8,317	$7,175	$10,784	$6,843	$0	$4,248	$13,850	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION												
(1) FUEL	$342,028	$160,541	$8,615	$88,113	$14,250	$9,289	$17,827	$32,571	$0	$6,889	$3,933	DIRECT
(2) PURCH. POWER REG - FIXED	12,784	5,967	322	3,304	537	349	672	1,230	0	257	147	E-1A
(3) PURCH. POWER REG - VAR.	22,969	10,720	578	5,937	966	627	1,207	2,210	0	462	264	E-1A
(4) PURCH. POWER WIND - FIXED	12,774	5,962	321	3,301	537	348	671	1,229	0	257	147	E-1A
(5) PURCH. POWER WIND - VAR.	42,578	19,872	1,071	11,005	1,790	1,162	2,237	4,096	0	857	489	E-1A
(6) OPER. & MAINT. - STEAM	79,969	37,323	2,012	20,668	3,362	2,182	4,201	7,694	0	1,610	918	E-1A
(7) OPER. & MAINT. - HYDRO/WIND/BIOMASS	16,501	7,701	415	4,265	694	450	867	1,588	0	332	189	E-1A
(8) OPER. & MAINT. - LM6000	311	145	8	80	13	8	16	30	0	6	4	E-1A
(9) OPER. & MAINT. - OTHER CT's	196	91	5	51	8	5	10	19	0	4	2	E-1A
(10) DSM AMORTIZATION	1,401	654	35	362	59	38	74	135	0	28	16	E-1A
(11) FCR DEFERRAL	9,449	4,410	238	2,442	397	258	496	909	0	190	108	P-17
(12) GRANTS IN LIEU	16,577	7,737	417	4,284	697	452	871	1,595	0	334	190	P-10
(13) DEPRECIATION	73,760	34,425	1,855	19,063	3,101	2,012	3,875	7,096	0	1,485	846	EXH 6D
(14) INTEREST NET OF AFUDC	59,904	27,958	1,507	15,482	2,519	1,634	3,147	5,763	0	1,206	687	P-17
(15) PREFERRED DIVIDENDS	3,635	1,697	91	940	153	99	191	350	0	73	42	P-17
(16) CORPORATE TAXES	23,754	11,087	598	6,139	999	648	1,248	2,285	0	478	273	P-17
NON-OPERATING REVENUE:												
(17) EXPORT SALES	(1,807)	(843)	(45)	(467)	(76)	(49)	(95)	(174)	0	(36)	(21)	EXH 7
(18) OTHER REVENUE	(8,755)	(4,097)	(220)	(2,259)	(367)	(238)	(458)	(838)	0	(176)	(101)	O-11
(19) RETURN (PROFIT/LOSS)	54,447	25,411	1,370	14,072	2,289	1,485	2,860	5,238	0	1,096	625	P-17
(20) TOTAL GENERATION	762,476	356,760	19,190	196,783	31,928	20,759	39,917	73,026	0	15,354	8,757	
TRANSMISSION												
Transmission < 138kV												
(21) OPERATING & MAINT.	3,532	1,648	89	913	148	96	186	340	0	71	41	E-1B
(22) GRANTS IN LIEU	698	326	18	180	29	19	37	67	0	14	8	P-11A
(23) DEPRECIATION	3,464	1,617	87	895	146	94	182	333	0	70	40	EXH 6D
(24) INTEREST NET	2,316	1,081	58	599	97	63	122	223	0	47	27	P-18A
(25) PREFERRED DIVIDENDS	141	66	4	36	6	4	7	14	0	3	2	P-18A
(26) CORPORATE TAXES	918	429	23	237	39	25	48	88	0	18	11	P-18A
NON-OPERATING REVENUE:												
(27) OTHER REVENUE	(139)	(65)	(4)	(36)	(6)	(4)	(7)	(13)	0	(3)	(2)	O-12A
(28) RETURN (PROFIT/LOSS)	2,105	982	53	544	88	57	111	202	0	42	24	P-18A
(29) TOTAL < 138kV	13,034	6,083	328	3,369	548	356	685	1,254	0	262	150	
Transmission > 69kV												
(30) OPERATING & MAINT.	11,235	5,244	283	2,904	472	306	590	1,081	0	226	129	E-1A
(31) GRANTS IN LIEU	2,325	1,085	58	601	98	63	122	224	0	47	27	P-11B
(32) DEPRECIATION	11,339	5,292	285	2,931	477	309	596	1,091	0	228	130	EXH 6D
(33) INTEREST NET	7,716	3,601	194	1,994	324	211	405	742	0	155	89	P-18B
(34) PREFERRED DIVIDENDS	468	219	12	121	20	13	25	45	0	9	5	P-18B
(35) CORPORATE TAXES	3,060	1,428	77	791	129	83	161	294	0	62	35	P-18B
NON-OPERATING REVENUE:												
(36) FCR DEFERRAL	1,679	784	42	434	71	46	88	162	0	34	19	P-18B
(37) OTHER REVENUE	(456)	(213)	(11)	(118)	(19)	(12)	(24)	(44)	0	(9)	(5)	O-12B
(38) RETURN (PROFIT/LOSS)	7,013	3,273	176	1,813	295	191	368	675	0	141	80	P-18B
(39) TOTAL > 69kV	44,379	20,713	1,116	11,470	1,866	1,211	2,331	4,270	0	894	509	
(40) TOTAL TRANSMISSION	57,413	26,796	1,444	14,839	2,414	1,566	3,016	5,524	0	1,156	659	
(41) TOTAL ENERGY	$819,889	$383,556	$20,635	$211,621	$34,342	$22,326	$42,933	$78,549	$0	$16,510	$9,416	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION												
(1) OPERATING & MAINT.	$14,865	$13,417	$708	$383	$1	$79	$9	$3	$0	$0	$265	EXH 6A
(2) GRANTS IN LIEU	2,629	2,309	122	136	0	28	3	1	0	0	30	P-12
(3) DEPRECIATION	17,284	15,182	802	896	2	184	17	5	0	1	196	EXH 6D
(4) INTEREST NET OF AFUDC	9,420	8,301	438	460	1	94	9	3	0	0	114	P-19
(5) PREFERRED DIVIDENDS	572	504	27	28	0	6	1	0	0	0	7	P-19
(6) CORPORATE TAXES	3,736	3,292	174	182	0	37	3	1	0	0	45	P-19
NON-OPERATING REVENUE:												
(8) OTHER REVENUE	(591)	(524)	(28)	(25)	(0)	(5)	(1)	(0)	0	(0)	(8)	O-13
(9) RETURN (PROFIT/LOSS)	8,562	7,545	398	418	1	86	8	2	0	0	103	P-19
(10) TOTAL DISTRIBUTION	56,476	50,025	2,641	2,479	4	509	49	15	0	2	751	
RETAIL												
(11) METER READING & ELECTRIC INSPECT.	16,678	14,119	755	1,236	35	242	97	62	0	15	117	EXH 6A
(12) CUST. SERV. - H/O	5,325	4,807	262	125	0	24	2	0	0	0	104	C-7
(13) CALL CENTRE	20,723	16,657	879	2,096	66	410	181	118	0	29	287	C-3
(14) BILLING SERVICES	6,430	5,805	316	151	0	29	3	0	0	0	126	C-3
(15) ELECT. WIRING INSP. - H/O	463	418	23	11	0	2	0	0	0	0	9	C-7
(16) METER DATA SERVICES	818	44	43	102	132	102	102	191	0	102	0	O-16
(17) PAYMENT SERVICES	1,230	1,110	60	29	0	6	0	0	0	0	24	C-7
(18) CREDIT SERVICES	5,736	4,819	86	754	0	78	0	0	0	0	0	EXH 6C
(19) MARKETING & SALES	2,019	915	72	169	36	133	261	396	0	36	0	O-15
(20) COGS (NET OF SALES)	(438)	(395)	(22)	(10)	(0)	(2)	(0)	(0)	0	(0)	(9)	C-7
(22) GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	N/A
(23) DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	N/A
(24) INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	N/A
(25) PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	N/A
(26) CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	N/A
NON-OPERATING REVENUE:												
(28) LATE PAYMENT CHARGE	(5,128)	(3,976)	(121)	(886)	0	(69)	(59)	0	0	0	(17)	EXH 7
(29) MISC. ELECTRIC	(1,909)	(1,772)	(108)	(12)	0	0	0	0	0	0	(17)	EXH 7
(30) OTHER REVENUE	(719)	(581)	(29)	(58)	(4)	(13)	(9)	(12)	0	(3)	(9)	O-14
(31) RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	N/A
(32) TOTAL RETAIL	51,230	41,971	2,217	3,705	266	942	578	756	0	180	616	
(33) TOTAL CUSTOMER	**107,706**	**91,996**	**4,858**	**6,184**	**270**	**1,450**	**627**	**771**	**0**	**182**	**1,368**	
(34) TOTAL NET EXPENSES	**$1,254,153**	**$663,210**	**$33,533**	**$297,447**	**$42,930**	**$30,951**	**$54,344**	**$86,163**	**$0**	**$20,941**	**$24,633**	

EXHIBIT 6A

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTRIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$300	$170	$9	$80	$11	$8	$14	$4	$0	$0	$4	P-5
(2) OVERHEAD LINES	25,449	15,118	819	6,981	709	670	808	0	0	0	344	P-1
(3) UNDERGROUND LINES	441	262	14	121	12	12	14	0	0	0	6	P-1
(4) LINE TRANSFORMERS	1,453	929	50	414	0	38	0	0	0	0	21	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	8,696	5,020	272	2,352	331	229	378	0	0	0	114	D-2
(7) STREET LIGHTING	5,705	0	0	0	0	0	0	0	0	0	5,705	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	42,043	21,499	1,164	9,948	1,063	957	1,213	4	0	0	6,194	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(11) OVERHEAD LINES	13,703	12,410	655	312	0	61	3	0	0	0	261	P-2
(12) UNDERGROUND LINES	238	215	11	5	0	1	0	0	0	0	5	P-2
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	--
(14) METERS	924	791	42	65	1	17	7	2	0	0	0	P-6
(15) COMMUNICATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(16) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	--
(17) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(18) TOTAL CUSTOMER	14,865	13,417	708	383	1	79	9	3	0	0	265	
RETAIL												
(19) METERS	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) CUSTOMER SERVICE	16,678	14,119	755	1,236	35	242	97	62	0	15	117	EXHIBIT 6B
(20) TOTAL RETAIL	16,678	14,119	755	1,236	35	242	97	62	0	15	117	
SUMMARY												
(21) SUBSTATIONS	300	170	9	80	11	8	14	4	0	0	4	P-3
(22) OVERHEAD LINES	39,152	27,528	1,474	7,294	709	732	811	0	0	0	605	P-1
(23) UNDERGROUND LINES	679	477	26	127	12	13	14	0	0	0	10	P-1
(24) LINE TRANSFORMERS	1,453	929	50	414	0	38	0	0	0	0	21	D-1
(25) METERS	17,602	14,910	796	1,301	35	258	104	64	0	16	117	P-6
(26) COMMUNICATIONS	8,696	5,020	272	2,352	331	229	378	0	0	0	114	D-2
(27) STREET LIGHTING	5,705	0	0	0	0	0	0	0	0	0	5,705	DIRECT
(28) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(29) TOTAL DISTRIBUTION	$73,586	$49,035	$2,627	$11,566	$1,099	$1,277	$1,320	$68	$0	$16	$6,576	

EXHIBIT 6B

NOVA SCOTIA POWER INC.

ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) METER READING	(4) WIRING INSPECTION
(1) DOMESTIC	$14,119	$8,703	$5,416
(2) SMALL GENERAL	755	460	295
(3) GENERAL	1,236	1,095	141
(4) GENERAL LARGE	35	35	0
(5) SMALL INDUSTRIAL	242	214	27
(6) MEDIUM INDUSTRIAL	97	95	2
(7) LARGE INDUSTRIAL	62	62	0
(8) ELI 2P-RTP	0	0	0
(9) MUNICIPAL	15	15	0
(10) UNMETERED	117	0	117
(11) TOTAL	$16,678	$10,678	$5,999
ALLOCATION FACTOR		C-6	C-7

EXHIBIT 6C

NOVA SCOTIA POWER INC.

ALLOCATION OF CREDIT SERVICES EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	---------------BAD DEBT EXPENSE	-----------------		CREDIT	
	DIRECT	TO BE ALLOC.	TOTAL	SERVICES	TOTAL
(1) DOMESTIC	$4,819	$0	$4,819	$0	$4,819
(2) SMALL GENERAL	0	86	86	0	86
(3) GENERAL	0	754	754	0	754
(4) GENERAL LARGE	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	78	78	0	78
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	0	0
(11) TOTAL	$4,819	$918	$5,736	$0	$5,736
ALLOCATION FACTOR	DIRECT	R-1		C-7	

DOMESTIC - 84 %

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PRODUCTION	$20,754	$11,791	$424	$4,763	$585	$412	$796	$1,297	$0	$429	$257	D-3A
(2) HYDRO PRODUCTION	4,021	2,284	82	923	113	80	154	251	0	83	50	D-3A
(3) WIND PRODUCTION	202	115	4	46	6	4	8	13	0	4	3	D-3A
(4) LM6000 PRODUCTION	903	513	18	207	25	18	35	56	0	19	11	D-3A
(5) GAS TURBINE PROD. - OTHER	1,180	670	24	271	33	23	45	74	0	24	15	D-3A
(6) GENERAL PROPERTY	7,815	4,440	160	1,794	220	155	300	489	0	162	97	P-7
(7) TOTAL GENERATION FUNCTION	34,875	19,813	712	8,005	982	692	1,337	2,180	0	721	432	
TRANSMISSION FUNCTION												
(8) TRANSMISSION PLANT < 138kV	2,115	1,201	43	485	60	42	81	132	0	44	26	D-3B
(9) GENERAL PROPERTY	545	309	11	125	15	11	21	34	0	11	7	P-8A
TOTAL < 138kV	2,659	1,511	54	610	75	53	102	166	0	55	33	
(10) TRANSMISSION PLANT > 69kV	6,922	3,932	141	1,589	195	137	265	433	0	143	86	D-3A
(11) GENERAL PROPERTY	1,783	1,013	36	409	50	35	68	111	0	37	22	P-8B
(12) TOTAL > 69kV	8,705	4,946	178	1,998	245	173	334	544	0	180	108	
(13) TOTAL TRANSMISSION FUNCTION	11,364	6,456	232	2,608	320	226	436	710	0	235	141	
DISTRIBUTION FUNCTION												
(14) DISTRIBUTION PLANT - Non Streetlig	31,135	18,971	1,027	8,645	560	821	647	30	0	2	432	P-9
(14) DISTRIBUTION PLANT - Streetlight	2,342	0	0	0	0	0	0	0	0	0	2,342	Direct
(15) GENERAL PROPERTY	5,230	3,187	173	1,452	94	138	109	5	0	0	73	P-9
(16) TOTAL DISTRIBUTION FUNCTION	38,707	22,158	1,200	10,097	654	958	756	35	0	2	2,846	
(17) TOTAL DEMAND	**84,946**	**48,427**	**2,144**	**20,710**	**1,957**	**1,876**	**2,529**	**2,925**	**0**	**958**	**3,420**	
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(18) STEAM PRODUCTION	42,605	19,885	1,072	11,012	1,791	1,162	2,238	4,099	0	858	489	E-1A
(19) HYDRO PRODUCTION	5,387	2,514	136	1,392	226	147	283	518	0	108	62	E-1A
(20) WIND PRODUCTION	7,964	3,717	200	2,058	335	217	418	766	0	160	91	E-1A
(21) LM6000 PRODUCTION	1,176	549	30	304	49	32	62	113	0	24	13	E-1A
(22) GAS TURBINE PROD. - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(23) GENERAL PROPERTY	16,627	7,760	418	4,297	699	454	873	1,600	0	335	191	P-10
(24) TOTAL GENERATION FUNCTION	73,760	34,425	1,855	19,063	3,101	2,012	3,875	7,096	0	1,485	846	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	2,754	1,285	69	712	116	75	145	265	0	55	32	E-1B
(26) GENERAL PROPERTY	710	331	18	183	30	19	37	68	0	14	8	P-11A
(27) TOTAL < 138kV	3,464	1,617	87	895	146	94	182	333	0	70	40	
(28) TRANSMISSION PLANT > 69kV	9,016	4,208	227	2,330	379	246	474	867	0	182	103	E-1A
(29) GENERAL PROPERTY	2,323	1,084	58	600	98	63	122	223	0	47	27	P-11B
(30) TOTAL > 69kV	11,339	5,292	285	2,931	477	309	596	1,091	0	228	130	
(31) TOTAL TRANSMISSION FUNCTION	14,803	6,909	372	3,826	622	404	778	1,424	0	298	170	
(32) TOTAL ENERGY	**88,562**	**41,334**	**2,228**	**22,889**	**3,723**	**2,416**	**4,653**	**8,520**	**0**	**1,783**	**1,016**	

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUSTOMER CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	14,798	12,998	686	768	1	157	14	4	0	0	167	P-12
(2) GENERAL PROPERTY	2,486	2,184	115	129	0	26	2	1	0	0	28	P-12
(3) TOTAL DISTRIBUTION FUNCTION	17,284	15,182	802	896	2	184	17	5	0	1	196	
RETAIL FUNCTION												
(4) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(5) GENERAL PROPERTY	0	0	0	0	0	0	0	0	0	0	0	P-13
(6) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(7) TOTAL CUSTOMER	**17,284**	**15,182**	**802**	**896**	**2**	**184**	**17**	**5**	**0**	**1**	**196**	
(8) TOTAL DEPRECIATION	**$190,792**	**$104,943**	**$5,174**	**$44,496**	**$5,682**	**$4,476**	**$7,198**	**$11,451**	**$0**	**$2,742**	**$4,631**	

EXHIBIT 7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2013

(IN THOUSANDS OF DOLLARS)

	(1) REVENUE	(2) EXPORT SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE
ELECTRIC REVENUE				
(1) DOMESTIC	$656,557	$843	$3,976	$1,772
(2) SMALL GENERAL	35,079	45	121	108
(3) GENERAL	307,787	467	886	12
(4) LARGE GENERAL	42,151	76	0	0
(5) SMALL INDUSTRIAL	31,739	49	69	0
(6) MEDIUM INDUSTRIAL	53,486	95	59	0
(7) LARGE INDUSTRIAL	82,327	174	0	0
(8) ELI 2P-RTP	0	0	0	0
(9) MUNICIPAL	20,394	36	0	0
(10) UNMETERED	24,633	21	17	17
(11) SUB-TOTAL	1,254,153	$1,807	$5,128	$1,909
(12) EXPORT SALES	1,807			
(13) TOTAL ELECTRIC REVENUE	1,255,959			
NON-RATE REVENUE				
(14) LATE PAYMENT CHARGE	5,128			
(15) MISC. CUST. REVENUE	1,909			
(16) OTHER	14,108			
(17) TOTAL	21,145			
DIRECT REVENUE				
(18) BOWATER BASIC BLOCK	9,935			
(19) BOWATER ADDITIONAL ENERGY	10,283			
(20) GEN.REPL./LOAD FOLL	1,095			
(21) LRT	21,183			
(22) REAL TIME PRICING	0			
(23) LED	1,963			
(24) TOTAL	44,458			
(25) TRANSFER FROM (TO) RETAINED EARNINGS	(123,837)			
(26) TOTAL REVENUE	**$1,197,725**			
ALLOCATION FACTOR		E-1	DIRECT	DIRECT

EXHIBIT 8A

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,718,943	1,099,550	59,553	489,304	0	45,520	0	0	0	0	25,017	
(2) % RESPONSIBILITY	100.00%	63.97%	3.46%	28.47%	0.00%	2.65%	0.00%	0.00%	0.00%	0.00%	1.46%	D-1
(3) N.C. DEMAND PRI.	2,007,683	1,158,926	62,768	543,120	76,500	52,790	87,212	0	0	0	26,368	
(4) % RESPONSIBILITY	100.00%	57.72%	3.13%	27.05%	3.81%	2.63%	4.34%	0.00%	0.00%	0.00%	1.31%	D-2
(5) 3 CP DEMAND	5,936,656	3,372,733	121,245	1,362,599	167,207	117,844	227,607	371,097	0	122,733	73,592	
(6) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	D-3A
(7) 3 CP DEMAND - LESS ELIIR - 2	5,936,656	3,372,733	121,245	1,362,599	167,207	117,844	227,607	371,097	0	122,733	73,592	
(8) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	D-3B
(9) 3 CP DMD. - LESS INT. & ELIIR - 2	5,661,086	3,372,733	121,245	1,362,599	167,207	117,844	227,607	95,526	0	122,733	73,592	
(10) % RESPONSIBILITY	100.00%	59.58%	2.14%	24.07%	2.95%	2.08%	4.02%	1.69%	0.00%	2.17%	1.30%	D-4
(11) MW.h GEN. & PURCH.	9,997,846	4,666,182	251,486	2,583,975	420,339	272,739	525,238	961,872	0	201,299	114,717	
(12) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	E-1A
(13) MW.h GEN. & PURCH. Less EHV	9,997,846	4,666,182	251,486	2,583,975	420,339	272,739	525,238	961,872	0	201,299	114,717	
(14) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	E-1B
(15) AVERAGE CUSTOMERS	499,825	452,558	23,894	11,387	18	2,227	197	32	0	8	9,504	
(16) % RESPONSIBILITY	100.00%	90.54%	4.78%	2.28%	0.00%	0.45%	0.04%	0.01%	0.00%	0.00%	1.90%	C-1
(17) SECONDARY CUSTOMERS	490,066	452,558	23,894	11,387	0	2,227	0	0	0	0	0	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(19) WEIGHTED TOTAL	544,522	452,558	23,894	56,935	0	11,135	0	0	0	0	0	
(20) % RESPONSIBILITY	100.00%	83.11%	4.39%	10.46%	0.00%	2.04%	0.00%	0.00%	0.00%	0.00%	0.00%	C-2
(21) AVERAGE CUSTOMERS	499,825	452,558	23,894	11,387	18	2,227	197	32	0	8	9,504	
(22) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(23) WEIGHTED TOTAL	563,040	452,558	23,894	56,935	1,800	11,135	4,925	3,200	0	800	7,793	
(24) % RESPONSIBILITY	100.00%	80.38%	4.24%	10.11%	0.32%	1.98%	0.87%	0.57%	0.00%	0.14%	1.38%	C-3
(25) CUSTOMER SECONDARY	499,570	452,558	23,894	11,387	0	2,227	0	0	0	0	9,504	
(26) % RESPONSIBILITY	100.00%	90.59%	4.78%	2.28%	0.00%	0.45%	0.00%	0.00%	0.00%	0.00%	1.90%	C-4
(27) CUSTOMER PRIMARY	499,825	452,558	23,894	11,387	18	2,227	197	32	0	8	9,504	
(28) % RESPONSIBILITY	100.00%	90.54%	4.78%	2.28%	0.00%	0.45%	0.04%	0.01%	0.00%	0.00%	1.90%	C-5
(29) AVG. CUST. - LESS UNMETERED	490,321	452,558	23,894	11,387	18	2,227	197	32	0	8	0	
(30) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(31) WEIGHTED TOTAL	555,247	452,558	23,894	56,935	1,800	11,135	4,925	3,200	0	800	0	
(32) % RESPONSIBILITY	100.00%	81.51%	4.30%	10.25%	0.32%	2.01%	0.89%	0.58%	0.00%	0.14%	0.00%	C-6
(33) AVERAGE CUSTOMERS ADJ SEASONAL	485,846	438,579	23,894	11,387	18	2,227	197	32	0	8	9,504	
(34) % RESPONSIBILITY	100.00%	90.27%	4.92%	2.34%	0.00%	0.46%	0.04%	0.01%	0.00%	0.00%	1.96%	C-7

EXHIBIT 8B
PAGE 1 OF 2

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE&WIRE INV.-DMD.	$187,343	$111,291	$6,028	$51,393	$5,217	$4,935	$5,947	$0	$0	$0	$2,532	
(2) % RESPONSIBILITY	100.00%	59.41%	3.22%	27.43%	2.78%	2.63%	3.17%	0.00%	0.00%	0.00%	1.35%	P-1
(3) POLE&WIRE INV.-CUST.	$100,877	$91,361	$4,824	$2,299	$2	$450	$20	$3	$0	$1	$1,919	
(4) % RESPONSIBILITY	100.00%	90.57%	4.78%	2.28%	0.00%	0.45%	0.02%	0.00%	0.00%	0.00%	1.90%	P-2
(5) SUB.,POLE&WIRE-DMD.	$215,805	$127,420	$6,901	$58,978	$6,281	$5,670	$7,267	$365	$0	$24	$2,899	
(6) % RESPONSIBILITY	100.00%	59.04%	3.20%	27.33%	2.91%	2.63%	3.37%	0.17%	0.00%	0.01%	1.34%	P-3
(7) SUB.,POLE&WIRE-CUST.	$100,877	$91,361	$4,824	$2,299	$2	$450	$20	$3	$0	$1	$1,919	
(8) % RESPONSIBILITY	100.00%	90.57%	4.78%	2.28%	0.00%	0.45%	0.02%	0.00%	0.00%	0.00%	1.90%	P-4
(9) SUBST. INVEST.-DMD.	$28,462	$16,129	$874	$7,584	$1,065	$735	$1,320	$365	$0	$24	$367	
(10) % RESPONSIBILITY	100.00%	56.67%	3.07%	26.65%	3.74%	2.58%	4.64%	1.28%	0.00%	0.08%	1.29%	P-5
(11) METER INVEST.-CUST	$23,780	$20,357	$1,075	$1,672	$16	$427	$171	$57	$0	$6	$0	
(12) % RESPONSIBILITY	100.00%	85.60%	4.52%	7.03%	0.07%	1.80%	0.72%	0.24%	0.00%	0.02%	0.00%	P-6
(13) DEMAND - GEN. PLANT	$632,330	$359,239	$12,914	$145,134	$17,810	$12,552	$24,243	$39,527	$0	$13,073	$7,838	
(14) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-7
(15) DEMAND - TRANS. PLT. < 138kV	$44,073	$25,039	$900	$10,116	$1,241	$875	$1,690	$2,755	$0	$911	$546	
(16) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-8A
(17) DEMAND - TRANS. PLT. > 69kV	$144,274	$81,965	$2,947	$33,114	$4,063	$2,864	$5,531	$9,018	$0	$2,983	$1,788	
(18) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-8B
(19) DEMAND - DIST. PLANT	$407,214	$248,120	$13,438	$113,066	$7,327	$10,733	$8,467	$391	$0	$26	$5,645	
(20) % RESPONSIBILITY	100.00%	60.93%	3.30%	27.77%	1.80%	2.64%	2.08%	0.10%	0.00%	0.01%	1.39%	P-9
(19) DEMAND - DIST. PLANT	$15,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,950	
(20) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-9A
(23) ENERGY - GEN. PLANT	$1,345,274	$627,865	$33,839	$347,690	$56,559	$36,699	$70,674	$129,426	$0	$27,086	$15,436	
(24) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-10
(25) ENERGY - TRANS. PLT. < 138kV	$57,408	$26,793	$1,444	$14,837	$2,414	$1,566	$3,016	$5,523	$0	$1,156	$659	
(26) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-11A
(27) ENERGY - TRANS. PLT. > 69kV	$187,924	$87,708	$4,727	$48,570	$7,901	$5,127	$9,873	$18,080	$0	$3,784	$2,156	
(28) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-11B
(29) CUSTOMER - DIST. PLANT	$201,122	$176,667	$9,328	$10,432	$18	$2,140	$195	$60	$0	$6	$2,275	
(30) % RESPONSIBILITY	100.00%	87.84%	4.64%	5.19%	0.01%	1.06%	0.10%	0.03%	0.00%	0.00%	1.13%	P-12
(31) CUSTOMER - RETAIL PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(32) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-13
(33) TOT.RATE BASE-DMD. (GEN.)	$701,614	$398,601	$14,329	$161,037	$19,761	$13,927	$26,899	$43,857	$0	$14,505	$8,697	
(34) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-14
(35) TOT.RATE BASE-DMD. (TRANS. < 138kV)	$48,180	$27,372	$984	$11,058	$1,357	$956	$1,847	$3,012	$0	$996	$597	
(36) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-15A
(37) TOT.RATE BASE-DMD. (TRANS. > 69kV)	$160,540	$91,206	$3,279	$36,848	$4,522	$3,187	$6,155	$10,035	$0	$3,319	$1,990	
(38) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	P-15B
(39) TOT.RATE BASE-DMD. (DIST.) Non Streetli	$475,857	$288,311	$15,615	$131,441	$8,684	$12,482	$10,029	$442	$0	$29	$8,823	
(40) % RESPONSIBILITY	100.00%	60.59%	3.28%	27.62%	1.82%	2.62%	2.11%	0.09%	0.00%	0.01%	1.85%	P-16
(41) TOT.RATE BASE-DMD. (DIST.) Streetlight	$15,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,950	
(42) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-16B
(43) TOT.RATE BASE-ENG. (GEN.)	$1,623,403	$757,673	$40,835	$419,574	$68,253	$44,286	$85,286	$156,184	$0	$32,686	$18,627	
(44) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-17
(45) TOT.RATE BASE-ENG. (TRANS. < 138kV)	$62,758	$29,290	$1,579	$16,220	$2,639	$1,712	$3,297	$6,038	$0	$1,264	$720	
(46) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-18A
(47) TOT.RATE BASE-ENG. (TRANS. > 69kV)	$209,113	$97,597	$5,260	$54,046	$8,792	$5,705	$10,986	$20,118	$0	$4,210	$2,399	
(48) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	P-18B

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TOT. RATE BASE-CUST. (DIST.)	$255,289	$224,960	$11,877	$12,472	$22	$2,559	$237	$73	$0	$8	$3,081	
(2) % RESPONSIBILITY	100.00%	88.12%	4.65%	4.89%	0.01%	1.00%	0.09%	0.03%	0.00%	0.00%	1.21%	P-19
(3) TOT.RATE BASE-CUST.(RETAIL)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(4) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-20
(5) DMD. - OPER.EXP. - GEN.	$29,366	$16,683	$600	$6,740	$827	$583	$1,126	$1,836	$0	$607	$364	
(6) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-1
(7) DMD. - OPER.EXP. - TRANS. < 138kV	$2,712	$1,540	$55	$622	$76	$54	$104	$169	$0	$56	$34	
(8) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-2A
(9) DMD. - OPER.EXP. - TRANS. > 69kV	$8,625	$4,900	$176	$1,980	$243	$171	$331	$539	$0	$178	$107	
(10) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-2B
(11) DMD. - OPER.EXP. - DIST.	$42,043	$21,499	$1,164	$9,948	$1,063	$957	$1,213	$4	$0	$0	$6,194	
(12) % RESPONSIBILITY	100.00%	51.14%	2.77%	23.66%	2.53%	2.28%	2.89%	0.01%	0.00%	0.00%	14.73%	O-3
(13) ENG. - OPER.EXP. - GEN.	$79,969	$37,323	$2,012	$20,668	$3,362	$2,182	$4,201	$7,694	$0	$1,610	$918	
(14) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-4
(15) ENG. - OPER.EXP. - TRANS. < 138kV	$3,532	$1,648	$89	$913	$148	$96	$186	$340	$0	$71	$41	
(16) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-5A
(17) ENG. - OPER.EXP. - TRANS. > 69kV	$11,235	$5,244	$283	$2,904	$472	$306	$590	$1,081	$0	$226	$129	
(18) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-5B
(19) CUST. - OPER. EXP. - DIST.	$14,865	$13,417	$708	$383	$1	$79	$9	$3	$0	$0	$265	
(20) % RESPONSIBILITY	100.00%	90.26%	4.77%	2.57%	0.01%	0.53%	0.06%	0.02%	0.00%	0.00%	1.78%	O-6
(21) CUST. - OPER. EXP. - RETAIL	$40,726	$33,660	$1,670	$3,267	$199	$651	$289	$310	$0	$132	$550	
(22) % RESPONSIBILITY	100.00%	82.65%	4.10%	8.02%	0.49%	1.60%	0.71%	0.76%	0.00%	0.32%	1.35%	O-7
(23) TOT. EXP. - DMD. (GEN.)	$133,186	$75,666	$2,720	$30,569	$3,751	$2,644	$5,106	$8,325	$0	$2,753	$1,651	
(24) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-8
(25) TOT. EXP. - DMD. (TRANS. < 138kV)	$8,497	$4,827	$174	$1,950	$239	$169	$326	$531	$0	$176	$105	
(26) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-9A
(27) TOT. EXP. - DMD. (TRANS. > 69kV)	$27,748	$15,764	$567	$6,369	$782	$551	$1,064	$1,735	$0	$574	$344	
(28) % RESPONSIBILITY	100.00%	56.81%	2.04%	22.95%	2.82%	1.99%	3.83%	6.25%	0.00%	2.07%	1.24%	O-9B
(29) TOT. EXP. - DMD. (DIST.)	$112,260	$62,145	$3,366	$28,473	$2,273	$2,716	$2,611	$67	$0	$4	$10,604	
(30) % RESPONSIBILITY	100.00%	55.36%	3.00%	25.36%	2.02%	2.42%	2.33%	0.06%	0.00%	0.00%	9.45%	O-10
(31) TOT. EXP. - ENG. (GEN.)	$718,591	$336,290	$18,087	$185,437	$30,082	$19,562	$37,610	$68,800	$0	$14,471	$8,253	
(32) % RESPONSIBILITY	100.00%	46.80%	2.52%	25.81%	4.19%	2.72%	5.23%	9.57%	0.00%	2.01%	1.15%	O-11
(33) TOT. EXP. - ENG. (TRANS. < 138 kV)	$11,068	$5,166	$278	$2,861	$465	$302	$581	$1,065	$0	$223	$127	
(34) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-12A
(35) TOT. EXP. - ENG. (TRANS. > 69 kV)	$36,143	$16,869	$909	$9,341	$1,520	$986	$1,899	$3,477	$0	$728	$415	
(36) % RESPONSIBILITY	100.00%	46.67%	2.52%	25.85%	4.20%	2.73%	5.25%	9.62%	0.00%	2.01%	1.15%	O-12B
(37) TOT. EXP. -CUST. (DIST.)	$48,505	$43,005	$2,271	$2,086	$4	$428	$41	$13	$0	$1	$656	
(38) % RESPONSIBILITY	100.00%	88.66%	4.68%	4.30%	0.01%	0.88%	0.09%	0.03%	0.00%	0.00%	1.35%	O-13
(39) TOT. EXP. -CUST. (RETAIL)	$42,308	$34,180	$1,721	$3,426	$235	$782	$549	$706	$0	$168	$541	
(40) % RESPONSIBILITY	100.00%	80.79%	4.07%	8.10%	0.56%	1.85%	1.30%	1.67%	0.00%	0.40%	1.28%	O-14
(41) MARKETING & SALES	99.99%	45.33%	3.59%	8.37%	1.79%	6.58%	12.92%	19.62%	0.00%	1.79%	0.00%	O-15
(42) METER DATA SERVICES	100.02%	5.39%	5.27%	12.46%	16.17%	12.46%	12.46%	23.35%	0.00%	12.46%	0.00%	O-16
(43) SECONDARY CUST. REVENUE	$374,604	$0	$35,079	$307,787	$0	$31,739	$0	$0	$0	$0	$0	
(44) % RESPONSIBILITY	100.00%	0.00%	9.36%	82.16%	0.00%	8.47%	0.00%	0.00%	0.00%	0.00%	0.00%	R-1

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) MW	(11) 3CP Contribution
(1) DOMESTIC	4,273,209	9.2%	4,666,182	1,037,311	100.0%	1,037,311	14.6%	1,189,128	44.79%	3,372,733	56.8%
(2) SMALL GENERAL	231,277	8.7%	251,486	56,182	64.9%	36,474	9.9%	40,080	71.63%	121,245	2.0%
(3) GENERAL	2,435,295	6.1%	2,583,975	487,597	82.5%	402,244	6.9%	429,973	68.60%	1,362,599	23.0%
(4) GENERAL LARGE	396,295	6.1%	420,339	72,580	70.4%	51,111	6.2%	54,263	88.43%	167,207	2.8%
(5) SMALL INDUSTRIAL	258,161	5.7%	272,739	47,509	78.8%	37,451	5.8%	39,635	78.55%	117,844	2.0%
(6) MEDIUM INDUSTRIAL	498,772	5.3%	525,238	85,067	82.8%	70,459	5.5%	74,316	80.68%	227,607	3.8%
(7) LARGE INDUSTRIAL	921,426	4.4%	961,872	139,431	83.9%	116,980	4.2%	121,884	90.09%	371,097	6.3%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A	-	0.0%
(9) MUNICIPAL	192,648	4.5%	201,299	40,959	98.8%	40,473	4.5%	42,305	54.32%	122,733	2.1%
(10) UNMETERED	104,393	9.9%	114,717	23,601	99.9%	23,575	10.5%	26,051	50.27%	73,592	1.2%
(11) SUB-TOTAL	9,311,477	7.4%	9,997,846	1,990,237	91.3%	1,816,078	11.1%	2,017,635	56.57%	5,936,656	100.0%
(12) BOWATER MERSEY	367,920	2.0%	375,389	42,000	100.0%	42,000	2.0%	42,857	99.99%	128,570	
(13) GEN.REPL./LOAD FOLL.	18,815	2.0%	19,199	23,900	0.2%	37	2.0%	38	N/A	315	
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A	0	
(15) LRT	322,080	2.0%	328,618	38,000	96.8%	36,767	2.0%	37,517	99.99%	112,552	
(16) TOTAL	10,020,291	7.0%	10,721,052	2,094,136	90.5%	1,894,882	10.7%	2,098,047	58.33%	6,178,093	

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JANUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	517,950	10.41%	571,868	1,016,646	97.1%	986,801	13.43%	1,119,298	68.67%
(2) SMALL GENERAL	25,350	9.54%	27,769	54,862	69.9%	38,371	9.68%	42,084	88.69%
(3) GENERAL	233,732	6.09%	247,974	487,597	93.2%	454,506	7.41%	488,175	68.27%
(4) GENERAL LARGE	33,329	6.37%	35,452	58,854	87.9%	51,738	6.57%	55,135	86.43%
(5) SMALL INDUSTRIAL	22,560	5.38%	23,775	44,509	88.7%	39,466	5.68%	41,708	76.62%
(6) MEDIUM INDUSTRIAL	42,925	4.88%	45,017	81,867	88.2%	72,186	5.20%	75,936	79.68%
(7) LARGE INDUSTRIAL	75,073	3.82%	77,942	122,180	88.4%	107,957	3.89%	112,161	93.40%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	20,071	4.34%	20,941	39,325	99.2%	38,991	5.86%	41,277	68.19%
(10) UNMETERED	10,891	10.42%	12,026	23,596	78.3%	18,466	13.98%	21,047	76.80%
(11) SUB-TOTAL	981,882		1,062,764	1,929,436	93.7%	1,808,482	10.41%	1,996,822	71.54%
(12) BOWATER MERSEY	31,248	1.83%	31,821	42,000	100.0%	42,000	2.04%	42,857	99.80%
(13) GEN.REPL./LOAD FOLL.	990	2.04%	1,010	18,501	-0.6%	-117	2.04%	-119	-1137.38%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	1,041,475	7.88%	1,123,506	2,027,937	93.1%	1,887,132	10.07%	2,077,076	72.70%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR FEBRUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	449,378	10.69%	497,403	1,037,311	100.0%	1,037,311	14.64%	1,189,128	62.25%
(2) SMALL GENERAL	23,282	9.89%	25,583	56,182	64.9%	36,474	9.89%	40,080	94.99%
(3) GENERAL	219,217	6.26%	232,932	475,530	84.6%	402,244	6.89%	429,973	80.62%
(4) GENERAL LARGE	30,888	6.09%	32,769	60,416	84.6%	51,111	6.17%	54,263	89.86%
(5) SMALL INDUSTRIAL	21,628	5.73%	22,867	43,040	87.0%	37,451	5.83%	39,635	85.85%
(6) MEDIUM INDUSTRIAL	38,731	5.23%	40,759	75,341	93.5%	70,459	5.47%	74,316	81.61%
(7) LARGE INDUSTRIAL	70,670	4.10%	73,566	125,598	93.1%	116,980	4.19%	121,884	89.82%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,070	4.27%	19,885	40,959	98.8%	40,473	4.53%	42,305	69.95%
(10) UNMETERED	9,230	10.20%	10,172	23,584	100.0%	23,575	10.50%	26,051	58.10%
(11) SUB-TOTAL	882,095		955,936	1,937,961	93.7%	1,816,078	11.10%	2,017,635	70.50%
(12) BOWATER MERSEY	28,224	2.03%	28,797	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,221	2.04%	1,246	19,501	0.2%	37	2.04%	38	4912.19%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	24,708	2.03%	25,209	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	936,247	8.00%	1,011,188	2,037,462	93.0%	1,894,882	10.72%	2,098,047	71.72%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MARCH 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	449,949	10.01%	494,980	890,747	93.2%	830,331	12.30%	932,461	71.35%
(2) SMALL GENERAL	22,297	9.83%	24,489	50,921	76.5%	38,948	10.23%	42,934	76.66%
(3) GENERAL	225,450	6.65%	240,449	427,619	97.8%	418,364	7.71%	450,616	71.72%
(4) GENERAL LARGE	33,709	6.52%	35,908	59,513	92.0%	54,731	6.79%	58,449	82.57%
(5) SMALL INDUSTRIAL	21,692	6.26%	23,051	38,282	97.5%	37,323	6.53%	39,760	77.92%
(6) MEDIUM INDUSTRIAL	41,333	5.65%	43,667	70,928	89.1%	63,227	5.79%	66,890	87.74%
(7) LARGE INDUSTRIAL	75,867	4.45%	79,244	114,735	93.0%	106,653	4.49%	111,443	95.57%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,062	4.90%	19,995	33,573	98.5%	33,084	5.06%	34,758	77.32%
(10) UNMETERED	9,130	9.69%	10,015	23,597	11.3%	2,665	7.89%	2,876	468.10%
(11) SUB-TOTAL	898,488		971,796	1,709,914	92.7%	1,585,325	9.77%	1,740,187	75.06%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	38	2.04%	39	1,842	-0.7%	-12	2.04%	-12	-428.70%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,276	2.01%	27,824	38,000	96.8%	36,767	2.04%	37,517	99.68%
(17) TOTAL	957,051	7.78%	1,031,542	1,791,756	92.9%	1,664,081	9.40%	1,820,549	76.16%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR APRIL 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	359,741	8.83%	391,490	790,074	95.8%	757,175	11.42%	843,671	64.45%
(2) SMALL GENERAL	18,910	8.95%	20,603	44,776	49.4%	22,123	8.51%	24,006	119.20%
(3) GENERAL	195,069	5.88%	206,534	383,834	87.5%	335,666	6.34%	356,958	80.36%
(4) GENERAL LARGE	30,768	5.98%	32,608	56,487	85.0%	48,002	6.05%	50,904	88.97%
(5) SMALL INDUSTRIAL	20,695	5.72%	21,878	39,448	81.8%	32,262	5.73%	34,112	89.08%
(6) MEDIUM INDUSTRIAL	41,190	5.34%	43,391	74,262	84.6%	62,834	5.37%	66,207	91.03%
(7) LARGE INDUSTRIAL	74,845	4.32%	78,077	122,441	89.0%	109,022	4.31%	113,723	95.36%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	15,531	4.65%	16,254	29,188	93.0%	27,144	4.71%	28,423	79.43%
(10) UNMETERED	8,187	9.32%	8,950	23,598	12.3%	2,896	6.97%	3,098	401.30%
(11) SUB-TOTAL	764,937		819,785	1,564,110	89.3%	1,397,122	8.87%	1,521,101	74.85%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,462	2.04%	1,492	22,397	0.7%	157	2.04%	160	1293.35%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	823,111	6.81%	879,140	1,666,507	88.6%	1,476,047	8.51%	1,601,635	76.24%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MAY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	323,119	8.84%	351,675	675,840	89.3%	603,391	10.47%	666,587	70.91%
(2) SMALL GENERAL	17,328	9.05%	18,895	40,048	79.2%	31,697	9.39%	34,672	73.25%
(3) GENERAL	183,886	6.28%	195,425	361,341	94.6%	341,631	7.05%	365,731	71.82%
(4) GENERAL LARGE	31,839	6.39%	33,872	60,556	92.8%	56,207	6.73%	59,989	75.89%
(5) SMALL INDUSTRIAL	20,858	6.09%	22,129	41,601	99.1%	41,233	6.45%	43,894	67.76%
(6) MEDIUM INDUSTRIAL	40,700	5.98%	43,134	75,707	89.8%	67,981	6.20%	72,194	80.30%
(7) LARGE INDUSTRIAL	75,137	4.98%	78,877	113,902	92.1%	104,953	4.97%	110,172	96.23%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,912	4.77%	14,576	24,728	99.0%	24,480	4.84%	25,666	76.33%
(10) UNMETERED	7,465	10.61%	8,258	23,597	13.7%	3,223	5.63%	3,405	325.99%
(11) SUB-TOTAL	714,244		766,841	1,417,319	89.9%	1,274,797	8.43%	1,382,309	74.56%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	442	2.04%	451	3,189	22.5%	718	2.04%	733	82.68%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	773,289	6.96%	827,084	1,500,509	90.3%	1,354,282	8.06%	1,463,415	75.96%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JUNE 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	264,738	7.10%	283,532	662,472	94.6%	626,625	10.74%	693,915	56.75%
(2) SMALL GENERAL	16,501	7.12%	17,675	40,159	61.7%	24,764	8.98%	26,987	90.96%
(3) GENERAL	185,946	5.57%	196,296	388,321	76.8%	298,117	6.61%	317,830	85.78%
(4) GENERAL LARGE	31,669	5.19%	33,313	62,199	75.2%	46,800	6.41%	49,800	92.91%
(5) SMALL INDUSTRIAL	21,775	5.04%	22,873	44,512	72.8%	32,403	6.15%	34,394	92.36%
(6) MEDIUM INDUSTRIAL	42,608	4.96%	44,721	78,672	83.3%	65,531	6.14%	69,555	89.30%
(7) LARGE INDUSTRIAL	71,592	4.12%	74,542	115,611	92.8%	107,238	5.05%	112,658	91.90%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	12,806	4.11%	13,332	24,169	100.0%	24,169	5.39%	25,473	72.69%
(10) UNMETERED	6,646	10.42%	7,339	23,597	11.6%	2,745	4.64%	2,873	354.82%
(11) SUB-TOTAL	654,281		693,624	1,439,713	85.3%	1,228,393	8.56%	1,333,486	72.24%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	577	2.04%	589	23,190	-0.1%	-29	2.04%	-30	-2762.43%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	711,570	5.69%	752,076	1,542,903	84.7%	1,307,131	8.16%	1,413,830	73.88%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JULY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	266,176	7.08%	285,021	583,480	76.7%	447,542	7.77%	482,325	79.43%
(2) SMALL GENERAL	17,006	7.46%	18,275	39,118	92.7%	36,273	8.11%	39,216	62.64%
(3) GENERAL	201,108	5.76%	212,694	399,320	98.8%	394,328	6.80%	421,137	67.88%
(4) GENERAL LARGE	36,217	5.75%	38,300	66,425	97.9%	65,040	6.19%	69,063	74.54%
(5) SMALL INDUSTRIAL	22,135	4.94%	23,228	45,623	91.1%	41,551	5.22%	43,718	71.41%
(6) MEDIUM INDUSTRIAL	42,569	4.82%	44,623	80,401	92.6%	74,473	5.11%	78,281	76.62%
(7) LARGE INDUSTRIAL	80,192	4.14%	83,512	128,189	97.3%	124,749	4.28%	130,085	86.29%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,128	4.05%	14,699	25,679	99.6%	25,579	4.10%	26,628	74.20%
(10) UNMETERED	6,926	10.40%	7,647	23,595	13.6%	3,204	4.67%	3,353	306.50%
(11) SUB-TOTAL	686,458		727,998	1,391,831	87.1%	1,212,739	6.68%	1,293,806	75.63%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,591	2.04%	1,624	23,449	10.4%	2,428	2.04%	2,478	88.09%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(16) TOTAL	746,652	5.73%	789,415	1,495,280	86.5%	1,293,934	6.39%	1,376,657	77.07%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR AUGUST 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	260,709	8.05%	281,686	585,948	84.0%	491,893	9.33%	537,790	70.40%
(2) SMALL GENERAL	17,119	8.71%	18,610	41,577	82.0%	34,073	9.22%	37,217	67.21%
(3) GENERAL	195,548	6.34%	207,938	421,845	95.8%	404,119	7.54%	434,607	64.31%
(4) GENERAL LARGE	36,538	6.72%	38,992	71,278	95.0%	67,686	7.22%	72,574	72.21%
(5) SMALL INDUSTRIAL	22,093	5.68%	23,347	47,509	84.6%	40,170	5.91%	42,545	73.76%
(6) MEDIUM INDUSTRIAL	42,615	5.61%	45,007	78,710	89.6%	70,531	5.81%	74,628	81.06%
(7) LARGE INDUSTRIAL	85,980	4.99%	90,269	131,834	95.0%	125,299	5.04%	131,613	92.19%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,928	4.78%	14,594	26,569	96.4%	25,603	4.83%	26,839	73.09%
(10) UNMETERED	7,522	10.56%	8,316	23,597	12.9%	3,051	5.14%	3,208	348.39%
(11) SUB-TOTAL	682,053		728,758	1,428,867	88.4%	1,262,425	7.81%	1,361,021	71.97%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	2,834	2.04%	2,892	23,447	75.9%	17,804	2.04%	18,167	21.39%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	743,490	6.45%	791,443	1,532,314	88.7%	1,358,996	7.40%	1,459,562	72.88%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR SEPTEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	261,087	6.73%	278,647	555,501	89.9%	499,491	7.79%	538,422	71.88%
(2) SMALL GENERAL	15,500	7.25%	16,622	38,189	84.4%	32,243	7.63%	34,704	66.53%
(3) GENERAL	181,397	5.22%	190,863	434,915	95.0%	413,358	6.56%	440,457	60.18%
(4) GENERAL LARGE	34,106	4.84%	35,758	72,580	94.7%	68,709	5.32%	72,367	68.63%
(5) SMALL INDUSTRIAL	20,651	4.72%	21,627	45,442	84.0%	38,146	4.86%	39,999	75.09%
(6) MEDIUM INDUSTRIAL	41,507	4.66%	43,443	81,487	86.9%	70,768	4.78%	74,152	81.37%
(7) LARGE INDUSTRIAL	80,788	4.08%	84,084	139,431	90.6%	126,263	4.12%	131,463	88.83%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,606	3.84%	14,128	27,387	96.7%	26,483	3.85%	27,503	71.35%
(10) UNMETERED	8,135	8.84%	8,855	23,598	12.2%	2,882	5.72%	3,047	403.61%
(11) SUB-TOTAL	656,778		694,026	1,418,529	90.1%	1,278,345	6.55%	1,362,114	70.77%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	6,682	2.04%	6,819	23,900	96.4%	23,047	2.04%	23,518	40.27%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	720,172	5.35%	758,708	1,522,429	90.7%	1,380,159	6.22%	1,466,005	71.88%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR OCTOBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	300,666	8.19%	325,278	669,062	90.9%	607,815	10.11%	669,265	65.33%
(2) SMALL GENERAL	17,287	7.42%	18,569	39,126	72.4%	28,337	7.56%	30,480	81.89%
(3) GENERAL	189,718	5.92%	200,952	409,561	87.0%	356,428	6.78%	380,605	70.97%
(4) GENERAL LARGE	33,150	5.99%	35,135	69,061	79.3%	54,753	6.25%	58,177	81.17%
(5) SMALL INDUSTRIAL	19,020	5.58%	20,081	42,356	96.7%	40,943	6.02%	43,408	62.18%
(6) MEDIUM INDUSTRIAL	41,853	5.39%	44,108	76,719	92.9%	71,300	5.66%	75,333	78.70%
(7) LARGE INDUSTRIAL	79,011	4.57%	82,622	120,084	94.4%	113,367	4.59%	118,569	93.66%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,663	4.47%	15,319	26,728	98.1%	26,220	4.55%	27,413	75.11%
(10) UNMETERED	8,764	8.35%	9,495	23,600	10.3%	2,439	6.50%	2,598	491.33%
(11) SUB-TOTAL	704,131		751,560	1,476,298	88.2%	1,301,601	8.01%	1,405,846	71.85%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,467	2.04%	1,497	7,533	19.7%	1,483	2.04%	1,513	132.94%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	764,201	6.37%	812,849	1,563,831	88.4%	1,381,851	7.66%	1,487,733	73.44%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR NOVEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	351,855	8.85%	382,982	778,802	100.0%	778,802	11.75%	870,342	61.12%
(2) SMALL GENERAL	18,096	8.29%	19,596	45,606	66.1%	30,135	8.47%	32,686	83.27%
(3) GENERAL	198,211	5.64%	209,382	399,664	89.6%	357,911	6.30%	380,451	76.44%
(4) GENERAL LARGE	31,996	5.80%	33,853	59,435	89.6%	53,242	6.00%	56,437	83.31%
(5) SMALL INDUSTRIAL	20,861	5.60%	22,028	42,945	78.4%	33,688	5.66%	35,595	85.95%
(6) MEDIUM INDUSTRIAL	40,988	4.96%	43,021	76,517	91.4%	69,961	5.17%	73,580	81.21%
(7) LARGE INDUSTRIAL	78,957	3.98%	82,102	124,960	75.1%	93,851	3.69%	97,316	117.17%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	16,406	4.00%	17,063	31,220	100.0%	31,220	5.44%	32,917	71.99%
(10) UNMETERED	10,238	9.04%	11,163	23,600	74.2%	17,516	8.19%	18,951	81.81%
(11) SUB-TOTAL	767,607		821,190	1,582,748	92.6%	1,466,325	9.00%	1,598,276	71.36%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,310	2.04%	1,337	21,278	92.6%	19,707	2.04%	20,109	9.23%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,551	2.05%	27,095	38,000	96.8%	36,767	2.04%	37,517	100.31%
(17) TOTAL	825,708	6.63%	880,476	1,684,026	92.9%	1,564,799	8.56%	1,698,759	71.99%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR DECEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	467,841	11.50%	521,620	969,221	95.9%	929,692	14.48%	1,064,308	65.87%
(2) SMALL GENERAL	22,601	9.72%	24,799	56,092	63.4%	35,553	9.93%	39,082	85.29%
(3) GENERAL	226,013	7.31%	242,536	451,215	90.9%	410,309	8.32%	444,450	73.35%
(4) GENERAL LARGE	32,087	7.15%	34,380	61,356	87.6%	53,773	7.50%	57,808	79.94%
(5) SMALL INDUSTRIAL	24,192	6.87%	25,855	46,813	72.9%	34,140	6.91%	36,500	95.21%
(6) MEDIUM INDUSTRIAL	41,753	6.21%	44,348	85,067	85.3%	72,584	6.57%	77,354	77.06%
(7) LARGE INDUSTRIAL	73,313	5.08%	77,036	130,647	99.5%	129,945	5.47%	137,052	75.55%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,464	5.39%	20,512	37,053	100.0%	37,053	5.66%	39,151	70.42%
(10) UNMETERED	11,257	10.87%	12,481	23,601	100.0%	23,601	12.26%	26,494	63.32%
(11) SUB-TOTAL	918,522		1,003,567	1,861,064	92.8%	1,726,650	11.33%	1,922,199	70.17%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	200	2.04%	204	1,495	26.0%	389	2.04%	397	69.22%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	977,325	8.82%	1,063,564	1,942,559	93.0%	1,805,807	10.92%	2,002,970	71.37%

EXHIBIT 9B

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COINCIDENT KW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 2013

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. KW SEC.	1,621,645	1,037,311	56,182	461,608	0	42,943	0	0	0	0	23,601
(2) LOSSES 6.00%	97,299	62,239	3,371	27,696	0	2,577	0	0	0	0	1,416
(3) SUB-TOTAL	1,718,943	1,099,550	59,553	489,304	0	45,520	0	0	0	0	25,017
(4) NON-COIN. KW PRI.	1,904,823	1,099,550	59,553	515,294	72,580	50,085	82,744	0	0	0	25,017
(5) LOSSES 5.40%	102,860	59,376	3,216	27,826	3,919	2,705	4,468	0	0	0	1,351
(6) SUB-TOTAL	2,007,683	1,158,926	62,768	543,120	76,500	52,790	87,212	0	0	0	26,368
(7) NON-COIN. KW TRANS.	2,190,396	1,158,926	62,768	543,120	76,500	52,790	89,535	139,431	0	40,959	26,368
(8) LOSSES 3.70%	81,045	42,880	2,322	20,095	2,830	1,953	3,313	5,159	0	1,515	976
(9) TOTAL	2,271,441	1,201,806	65,091	563,215	79,330	54,743	92,848	144,590	0	42,474	27,343

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2013

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	**2,039,559**	**1,119,298**	**42,084**	**488,175**	**55,135**	**41,708**	**75,936**	**112,161**	**0**	**41,277**	**21,047**	**42,857**	**(119)**	**0**	**37,517**
(2) FEBRUARY	**2,060,530**	**1,189,128**	**40,080**	**429,973**	**54,263**	**39,635**	**74,316**	**121,884**	**0**	**42,305**	**26,051**	**42,857**	**38**	**0**	**37,517**
(3) MARCH	1,783,032	932,461	42,934	450,616	58,449	39,760	66,890	111,443	0	34,758	2,876	42,857	(12)	0	37,517
(4) APRIL	1,564,118	843,671	24,006	356,958	50,904	34,112	66,207	113,723	0	28,423	3,098	42,857	160	0	37,517
(5) MAY	1,425,898	666,587	34,672	365,731	59,989	43,894	72,194	110,172	0	25,666	3,405	42,857	733	0	37,517
(6) JUNE	1,376,313	693,915	26,987	317,830	49,800	34,394	69,555	112,658	0	25,473	2,873	42,857	(30)	0	37,517
(7) JULY	1,339,140	482,325	39,216	421,137	69,063	43,718	78,281	130,085	0	26,628	3,353	42,857	2,478	0	37,517
(8) AUGUST	1,422,045	537,790	37,217	434,607	72,574	42,545	74,628	131,613	0	26,839	3,208	42,857	18,167	0	37,517
(9) SEPTEMBER	1,428,488	538,422	34,704	440,457	72,367	39,999	74,152	131,463	0	27,503	3,047	42,857	23,518	0	37,517
(10) OCTOBER	1,450,216	669,265	30,480	380,605	58,177	43,408	75,333	118,569	0	27,413	2,598	42,857	1,513	0	37,517
(11) NOVEMBER	1,661,242	870,342	32,686	380,451	56,437	35,595	73,580	97,316	0	32,917	18,951	42,857	20,109	0	37,517
(12) DECEMBER	**1,965,453**	**1,064,308**	**39,082**	**444,450**	**57,808**	**36,500**	**77,354**	**137,052**	**0**	**39,151**	**26,494**	**42,857**	**397**	**0**	**37,517**
(13) TOT. SUMMED DMD.	19,516,033	9,607,511	424,146	4,910,991	714,966	475,268	878,427	1,428,139	0	378,352	117,000	514,282	66,951	0	450,206
(14) 3 C/P DEMANDS	**6,065,542**	**3,372,733**	**121,245**	**1,362,599**	**167,207**	**117,844**	**227,607**	**371,097**	**0**	**122,733**	**73,592**	**128,570**	**315**	**0**	**112,552**
(15)					**3 C/P INTERRUPTIBLE RIDER DEMANDS**			**275,570**							
(16)					**NET 3 C/P LARGE INDUST. DEMANDS**			**95,526**							

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$187,658	$383,556	8.98	$91,996	$663,210	$656,557	99.00
(2) SMALL GENERAL	8,040	20,635	8.92	4,858	33,533	35,079	104.61
(3) GENERAL	79,642	211,621	8.69	6,184	297,447	307,787	103.48
(4) LARGE GENERAL	8,317	34,342	8.67	270	42,930	42,151	98.19
(5) SMALL INDUSTRIAL	7,175	22,326	8.65	1,450	30,951	31,739	102.55
(6) MEDIUM INDUSTRIAL	10,784	42,933	8.61	627	54,344	53,486	98.42
(7) LARGE INDUSTRIAL	6,843	78,549	8.52	771	86,163	82,327	95.55
(8) ELI 2P-RTP	0	0	0	0	0	0	0
(9) MUNICIPAL	4,248	16,510	8.57	182	20,941	20,394	97.39
(10) UNMETERED	13,850	9,416	9.02	1,368	24,633	24,633	100.00
(11) SUB-TOTAL	$326,558	$819,889	8.81	$107,706	1,254,153	1,254,153	100.00
(12) DIRECT EXP./ REV					39,773	44,458	N/A
(13) RETURN ON DIRECT EXP.					4,685	0	N/A
(14) TOTAL					$1,298,611	$1,298,611	100.00

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2013
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$158,291	$351,282	8.22	$83,978	$593,551	$588,717	99.19
(2) SMALL GENERAL	6,793	18,895	8.17	4,436	30,125	31,454	104.41
(3) GENERAL	67,232	193,749	7.96	5,730	266,712	275,984	103.48
(4) LARGE GENERAL	7,065	31,435	7.93	270	38,770	37,796	97.49
(5) SMALL INDUSTRIAL	6,061	20,439	7.92	1,357	27,858	28,460	102.16
(6) MEDIUM INDUSTRIAL	9,146	39,301	7.88	618	49,064	47,960	97.75
(7) LARGE INDUSTRIAL	4,752	71,897	7.80	768	77,416	73,821	95.36
(8) ELI 2P-RTP	0	0	0	0	0	0	0
(9) MUNICIPAL	3,561	15,118	7.85	182	18,861	18,287	96.96
(10) UNMETERED	12,580	8,622	8.26	1,257	22,459	22,338	99.46
(11) SUB-TOTAL	$275,482	$750,739	8.06	$98,595	1,124,815	1,124,816	100.00
(12) DIRECT EXP./ REV					39,642	44,060	N/A
(13) RETURN ON DIRECT EXP.					4,418	0	N/A
(14) TOTAL					$1,168,876	$1,168,876	100.00

NOVA SCOTIA POWER INC.
2014 COST OF SERVICE STUDY ANALYSIS
R E F E R E N C E   G U I D E

EXHIBIT 1

NOVA SCOTIA POWER INC.
SUMMARY OF REVENUE TO EXPENSE RECOVERY RATIOS

	2014	
CUSTOMER CLASS	**PRESENT**	**PROPOSED**
(1) DOMESTIC	99.00	99.44
(2) SMALL GENERAL	104.61	104.40
(3) GENERAL	103.48	102.84
(4) LARGE GENERAL	98.19	98.66
(5) SMALL INDUSTRIAL	102.55	102.04
(6) MEDIUM INDUSTRIAL	98.42	97.28
(7) LARGE INDUSTRIAL	95.55	95.00
(8) ELI 2P-RTP	N/A	N/A
(9) MUNICIPAL	97.39	97.96
(10) UNMETERED	100.00	100.00
(11) TOTAL	100.00	100.00

EXHIBIT 2

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) GENERATION	(3) TRANSMISSION	(4) DISTRIBUTION	(5) RETAIL	(6) DIRECT CAPITAL
PRODUCTION PLANT						
(1) STEAM	$1,370,531	$1,370,531	$0	$0	$0	$0
(2) HYDRO	371,461	351,261	0	0	0	20,200
(3) WIND	201,182	201,182	0	0	0	0
(4) LM6000	71,417	71,417	0	0	0	0
(5) GAS TURBINE - OTHER	6,513	6,513	0	0	0	0
(6) TOTAL PROD. PLANT	2,021,104	2,000,904	0	0	0	20,200
(7) Transmission < 138kV	109,080	0	109,080	0	0	0
(8) Transmission > 69kV	357,074	0	357,074	0	0	0
(9) TRANSMISSION PLANT	466,154	0	466,154	0	0	0
DISTRIBUTION PLANT						
(10) LAND	4,435	0	0	4,435	0	0
(11) EASEMENTS & SURVEY	16,882	0	0	16,882	0	0
(12) OTHER	2,190	0	0	2,190	0	0
(13) SUBSTATIONS	30,113	0	0	30,113	0	0
(14) POLES & FIXTURES	183,085	0	0	183,085	0	0
(15) O.H. LINES	121,259	0	0	121,259	0	0
(16) U.G. LINES	34,858	0	0	34,858	0	0
(17) LINE TRANSFORMERS	163,242	0	0	163,242	0	0
(18) SERVICES	60,998	0	0	60,998	0	0
(19) METERS	25,072	0	0	25,072	0	0
(20) STREET LIGHTING	34,507	0	0	10,251	0	24,256
(21) TOTAL DIST. PLANT	676,641	0	0	652,385	0	24,256
(22) SUB-TOTAL	3,163,899	2,000,904	466,154	652,385	0	44,456
(23) GEN. PROPERTY PLANT	234,273	150,270	35,009	48,995	0	0
(24) TOT. PLT.IN SERVICE	3,398,172	2,151,174	501,163	701,380	0	44,456
Working Capital & Deferred Charges/Credits						
(25) CASH - FUEL	0	0	0	0	0	0
(26) CASH - OTHER	27,900	13,449	2,607	11,611	0	233
(27) MAT. & SUP. - FUEL	84,441	84,441	0	0	0	0
(28) MAT. & SUP. - OTHER	28,661	18,384	4,283	5,994	0	0
(29) DEF. CHG. - Financing	65,674	42,125	9,814	13,735	0	0
(30) DEF. CHG. - Tax	9,838	6,310	1,470	2,057	0	0
(31) DEF. CHG. - Pension	82,097	39,907	7,736	34,455	0	0
(32) DEF. CHG. - Steam Assets	0	0	0	0	0	0
(33) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0
(34) DEF. CHG. - Other	9,215	1,796	295	413	0	6,710
(35) DEF. CHG. - FCR	23,250	18,857	4,393	0	0	0
(36) DEF. CR. - ARO Steam	(43,651)	(43,651)	0	0	0	0
(37) DEF. CR. - ARO Hydro	(22,762)	(22,762)	0	0	0	0
(38) DEF. CR. - ARO Wind	(10,861)	(10,861)	0	0	0	0
(39) DEF. CR. - ARO CT	(4,150)	(4,150)	0	0	0	0
(40) DEF. CR. - ARO Trans	(24,730)	0	(24,730)	0	0	0
(41) DEF. CR. - Other	(6,577)	(6,577)	0	0	0	0
(42) CONTRACT RECEIVABLE	0	0	0	0	0	0
(43) TOT.WORKING CAPITAL	218,345	137,268	5,868	68,265	0	6,943
(44) TOTAL AVE. RATE BASE	$3,616,517	$2,288,442	$507,031	$769,645	$0	$51,399

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
GENERATION FUNCTION				
(1) STEAM PLANT	$1,370,531	$1,045,169	$325,362	$0
(2) HYDRO PLANT	351,261	346,437	4,824	0
(3) WIND PLANT	201,182	30,599	170,583	0
(4) LM6000 PLANT	71,417	71,417	0	0
(5) GAS TURBINE PLANT - OTHER	6,513	6,513	0	0
(6) TOTAL GENERATION PLANT	2,000,904	1,500,135	500,769	0
(7) GENERAL PROPERTY PLANT	150,270	112,661	37,608	0
(8) TOTAL PLANT IN SERVICE	2,151,174	1,612,796	538,377	0
Working Capital & Deferred Charges/Credits:				
(9) CASH - FUEL	0	0	0	0
(10) CASH - OTHER	13,449	3,742	9,707	0
(11) MAT. & SUPPLIES - FUEL	84,441	0	84,441	0
(12) MAT. & SUPPLIES - OTHER	18,384	13,783	4,601	0
(13) DEF. CHG. - Financing	42,125	31,583	10,543	0
(14) DEF. CHG. - Tax	6,310	4,731	1,579	0
(15) DEF. CHG. - Pension	39,907	11,104	28,803	0
(16) DEF. CHG. - Steam Assets	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	0	0	0
(18) DEF. CHG. - Other	1,796	1,347	450	0
(19) DEF. CHG. - FCR	18,857	14,138	4,719	0
(20) DEF. CR. - ARO Steam	(43,651)	(33,288)	(10,363)	0
(21) DEF. CR. - ARO Hydro	(22,762)	(22,449)	(313)	0
(22) DEF. CR. - ARO Wind	(10,861)	(10,712)	(149)	0
(23) DEF. CR. - ARO CT	(4,150)	(4,150)	0	0
(24) DEF. CR. - Other	(6,577)	(5,016)	(1,561)	0
(25) CONTRACT RECEIVABLE	0	0	0	0
(26) SUB-TOTAL	137,268	4,811	132,457	0
(27) TOTAL GENERATION FUNCTION	**2,288,442**	**1,617,608**	**670,834**	**0**
TRANSMISSION FUNCTION				
(28) TRANSMISSION PLANT < 138kV	109,080	109,080	0	0
(29) GENERAL PROPERTY PLANT	8,192	8,192	0	0
(30) TOTAL PLANT IN SERVICE	117,272	117,272	0	0
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	624	271	353	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	1,002	1,002	0	0
(35) DEF. CHG. - Financing	2,296	2,296	0	0
(36) DEF. CHG. - Tax	344	344	0	0
(37) DEF. CHG. - Pension	1,851	803	1,048	0
(38) DEF. CHG. - Other	69	69	0	0
(39) DEF. CHG. - ARO Trans.	(5,787)	(5,787)	0	0
(40) SUB-TOTAL	400	(1,002)	1,402	0
(41) TOTAL TRANS. < 138kV	117,672	116,270	1,402	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
(1) TRANSMISSION PLANT > 69kV	357,074	357,074	0	0
(2) GENERAL PROPERTY PLANT	26,817	26,817	0	0
(3) TOTAL PLANT IN SERVICE	383,891	383,891	0	0
Working Capital & Deferred Charges/Credits:				
(4) CASH - FUEL	0	0	0	0
(5) CASH - OTHER	1,983	860	1,123	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,281	3,281	0	0
(8) DEF. CHG. - Financing	7,518	7,518	0	0
(9) DEF. CHG. - Tax	1,126	1,126	0	0
(10) DEF. CHG. - Pension	5,885	2,552	3,333	0
(11) DEF. CHG. - Other	226	226	0	0
(12) DEF. CHG. - FCR	4,393	4,393	0	0
(13) DEF. CHG. - ARO Trans	(18,943)	(18,943)	0	0
(14) SUB-TOTAL	5,468	1,013	4,456	0
(15) TOTAL TRANS. > 69kV	389,359	384,903	4,456	0
(16) TOTAL TRANSMISSION FUNCTION	**$507,031**	**$501,174**	**$5,857**	**$0**

DISTRIBUTION FUNCTION

DISTRIBUTION PLANT:				
(17) LAND	4,435	3,023	0	1,412
(18) EASEMENTS & SURVEY	16,882	11,505	0	5,377
(19) OTHER	2,190	1,493	0	697
(20) SUBSTATIONS	30,113	30,113	0	0
(21) POLES & FIXTURES	183,085	119,005	0	64,080
(22) O.H. LINES	121,259	78,818	0	42,441
(23) U.G. LINES	34,858	22,658	0	12,200
(24) LINE TRANSFORMERS	163,242	163,242	0	0
(25) SERVICES	60,998	0	0	60,998
(26) METERS	25,072	0	0	25,072
(27) STREET LIGHTING	10,251	10,251	0	0
(28) TOTAL DISTRIBUTION PLANT	652,385	440,108	0	212,277
(29) GENERAL PROPERTY PLANT	48,995	33,052	0	15,942
(30) TOTAL PLANT IN SERVICE	701,380	473,160	0	228,220
Working Capital & Deferred Charges/Credits:				
(31) CASH - FUEL	0	0	0	0
(32) CASH - OTHER	11,611	4,180	0	7,432
(33) MAT. & SUPPLIES - FUEL	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	5,994	4,044	0	1,950
(35) DEF. CHG. - Financing	13,735	9,266	0	4,469
(36) DEF. CHG. - Tax	2,057	1,388	0	669
(37) DEF. CHG. - Pension	34,455	12,402	0	22,052
(38) DEF. CHG. - Other	413	279	0	134
(39) SUB-TOTAL	68,265	31,558	0	36,708
(40) TOTAL DISTRIBUTION FUNCTION	**769,645**	**504,718**	**0**	**264,927**

NOVA SCOTIA POWER INC.
CLASSIFICATION OF RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)
		INITIAL CLASSIFICATION		
	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
RETAIL FUNCTION				
DISTRIBUTION PLANT:				
(1) SERVICES	0	0	0	0
(2) METERS	0	0	0	0
(3) TOTAL RETAIL PLANT	0	0	0	0
(4) GENERAL PROPERTY PLANT	0	0	0	0
(5) TOTAL PLANT IN SERVICE	0	0	0	0
Working Capital & Deferred Charges/Credits:				
(6) CASH - FUEL	0	0	0	0
(7) CASH - OTHER	0	0	0	0
(8) MAT. & SUPPLIES - FUEL	0	0	0	0
(9) MAT. & SUPPLIES - OTHER	0	0	0	0
(10) DEF. CHG. - Financing	0	0	0	0
(11) DEF. CHG. - Tax	0	0	0	0
(12) DEF. CHG. - Pension	0	0	0	0
(13) DEF. CHG. - Other	0	0	0	0
(14) SUB-TOTAL	0	0	0	0
(15) TOTAL RETAIL FUNCTION	**0**	**0**	**0**	**0**
(16) TOTAL AVE. RATE BASE	**$3,565,118**	**$2,623,499**	**$676,691**	**$264,927**

NOVA SCOTIA POWER INC.
CLASSIFICATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
GENERATION FUNCTION									
(1) STEAM PLANT	$1,045,169	$325,362	$0	($591,879)	$591,879	$0	$453,290	$917,241	$0
(2) HYDRO PLANT	346,437	4,824	0	(196,187)	196,187	0	150,250	201,011	0
(3) WIND PLANT	30,599	170,583	0	(21,419)	21,419	0	9,180	192,002	0
(4) LM6000 PLANT	71,417	0	0	(40,443)	40,443	0	30,974	40,443	0
(5) GAS TURBINE PLANT - OTHER	6,513	0	0	0	0	0	6,513	0	0
(6) TOTAL GENERATION PLANT	1,500,135	500,769	0	(849,929)	849,929	0	650,206	1,350,698	0
(7) GENERAL PROPERTY PLANT	112,661	37,608	0	(63,830)	63,830	0	48,831	101,439	0
(8) TOTAL PLANT IN SERVICE	1,612,796	538,377	0	(913,760)	913,760	0	699,037	1,452,137	0
Working Capital & Deferred Charges/Credits:									
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0
(10) CASH - OTHER	3,742	9,707	0	0	0	0	3,742	9,707	0
(11) MAT. & SUPPLIES - FUEL	0	84,441	0	0	0	0	0	84,441	0
(12) MAT. & SUPPLIES - OTHER	13,783	4,601	0	(7,809)	7,809	0	5,974	12,410	0
(13) DEF. CHG. - Financing	31,583	10,543	0	(17,894)	17,894	0	13,689	28,436	0
(14) DEF. CHG. - Tax	4,731	1,579	0	(2,680)	2,680	0	2,051	4,260	0
(15) DEF. CHG. - Pension	11,104	28,803	0	0	0	0	11,104	28,803	0
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0
(18) DEF. CHG. - Other	1,347	450	0	(763)	763	0	584	1,213	0
(19) DEF. CHG. - FCR	14,138	4,719	0	(8,010)	8,010	0	6,128	12,729	0
(20) DEF. CR. - ARO Steam	(33,288)	(10,363)	0	18,851	(18,851)	0	(14,437)	(29,214)	0
(21) DEF. CR. - ARO Hydro	(22,449)	(313)	0	12,713	(12,713)	0	(9,736)	(13,026)	0
(22) DEF. CR. - ARO Wind	(10,712)	(149)	0	6,066	(6,066)	0	(4,646)	(6,215)	0
(23) DEF. CR. - ARO CT	(4,150)	0	0	0	0	0	(4,150)	0	0
(24) DEF. CR. - Other	(5,016)	(1,561)	0	2,840	(2,840)	0	(2,175)	(4,402)	0
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0
(26) SUB-TOTAL	4,811	132,457	0	3,315	(3,315)	0	8,126	129,142	0
							0	0	0
(27) TOTAL GENERATION FUNCTION	1,617,608	670,834	0	(910,445)	910,445	0	707,163	1,581,279	0
TRANSMISSION FUNCTION									
(28) TRANSMISSION PLANT < 138kV	109,080	0	0	(61,772)	61,772	0	47,308	61,772	0
(29) GENERAL PROPERTY PLANT	8,192	0	0	(4,639)	4,639	0	3,553	4,639	0
(30) TOTAL PLANT IN SERVICE	117,272	0	0	(66,411)	66,411	0	50,861	66,411	0
Working Capital & Deferred Charges/Credits:									
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0
(32) CASH - OTHER	271	353	0	0	0	0	271	353	0
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(34) MAT. & SUPPLIES - OTHER	1,002	0	0	(568)	568	0	435	568	0
(35) DEF. CHG. - Financing	2,296	0	0	(1,300)	1,300	0	996	1,300	0
(36) DEF. CHG. - Tax	344	0	0	(195)	195	0	149	195	0
(37) DEF. CHG. - Pension	803	1,048	0	0	0	0	803	1,048	0
(38) DEF. CHG. - Other	69	0	0	(39)	39	0	30	39	0
(40) DEF. CR. - ARO Trans.	(5,787)	0	0	3,277	(3,277)	0	(2,510)	(3,277)	0
(41) SUB-TOTAL	(1,002)	1,402	0	1,175	(1,175)	0	173	226	0
(42) TOTAL TRANS. < 138kV	116,270	1,402	0	(65,236)	65,236	0	51,034	66,638	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1) TRANSMISSION PLANT > 69kV	357,074	0	0	(202,211)	202,211	0	154,863	202,211	0
(2) GENERAL PROPERTY PLANT	26,817	0	0	(15,186)	15,186	0	11,630	15,186	0
(3) TOTAL PLANT IN SERVICE	383,891	0	0	(217,397)	217,397	0	166,493	217,397	0
Working Capital & Deferred Charges/Credits:									
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0
(5) CASH - OTHER	860	1,123	0	0	0	0	860	1,123	0
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(7) MAT. & SUPPLIES - OTHER	3,281	0	0	(1,858)	1,858	0	1,423	1,858	0
(8) DEF. CHG. - Financing	7,518	0	0	(4,257)	4,257	0	3,260	4,257	0
(9) DEF. CHG. - Tax	1,126	0	0	(638)	638	0	488	638	0
(10) DEF. CHG. - Pension	2,552	3,333	0	0	0	0	2,552	3,333	0
(11) DEF. CHG. - Other	226	0	0	(128)	128	0	98	128	0
(12) DEF. CHG. - FCR	4,393	0	0	(2,488)	2,488	0	1,905	2,488	0
(13) DEF. CR. - ARO Trans	(18,943)	0	0	10,728	(10,728)	0	(8,216)	(10,728)	0
(14) SUB-TOTAL	1,013	4,456	0	1,359	(1,359)	0	2,372	3,097	0
(15) TOTAL TRANS. > 69kV	384,903	4,456	0	(216,038)	216,038	0	168,865	220,494	0
(16) TOTAL TRANSMISSION FUNCTION	$501,174	$5,857	$0	($281,274)	$281,274	$0	$219,899	$287,132	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
DISTRIBUTION FUNCTION									
DISTRIBUTION PLANT:									
(1) LAND	$3,023	$0	$1,412	$0	$0	$0	$3,023	$0	$1,412
(2) EASEMENTS & SURVEY	11,505	0	5,377	0	0	0	11,505	0	5,377
(3) OTHER	1,493	0	697	0	0	0	1,493	0	697
(4) SUBSTATIONS	30,113	0	0	0	0	0	30,113	0	0
(5) POLES & FIXTURES	119,005	0	64,080	0	0	0	119,005	0	64,080
(6) O.H. LINES	78,818	0	42,441	0	0	0	78,818	0	42,441
(7) U.G. LINES	22,658	0	12,200	0	0	0	22,658	0	12,200
(8) LINE TRANSFORMERS	163,242	0	0	0	0	0	163,242	0	0
(9) SERVICES	0	0	60,998	0	0	0	0	0	60,998
(10) METERS	0	0	25,072	0	0	0	0	0	25,072
(11) STREET LIGHTING	10,251	0	0	0	0	0	10,251	0	0
(12) TOTAL DISTRIBUTION PLANT	440,108	0	212,277	0	0	0	440,108	0	212,277
(13) GENERAL PROPERTY PLANT	33,052	0	15,942	0	0	0	33,052	0	15,942
(14) TOTAL PLANT IN SERVICE	473,160	0	228,220	0	0	0	473,160	0	228,220
Working Capital & Deferred Charges/Credits:									
(15) CASH - FUEL	0	0	0	0	0	0	0	0	0
(16) CASH - OTHER	4,180	0	7,432	0	0	0	4,180	0	7,432
(17) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(18) MAT. & SUPPLIES - OTHER	4,044	0	1,950	0	0	0	4,044	0	1,950
(19) DEF. CHG. - Financing	9,266	0	4,469	0	0	0	9,266	0	4,469
(20) DEF. CHG. - Tax	1,388	0	669	0	0	0	1,388	0	669
(21) DEF. CHG. - Pension	12,402	0	22,052	0	0	0	12,402	0	22,052
(22) DEF. CHG. - Other	279	0	134	0	0	0	279	0	134
(23) SUB-TOTAL	31,558	0	36,708	0	0	0	31,558	0	36,708
(24) TOTAL DISTRIBUTION FUNCTION	$504,718	$0	$264,927	$0	$0	$0	$504,718	$0	$264,927
RETAIL FUNCTION									
DISTRIBUTION PLANT:									
(25) SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(26) METERS	0	0	0	0	0	0	0	0	0
(27) TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(28) GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(29) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
Working Capital & Deferred Charges/Credits:									
(30) CASH - FUEL	0	0	0	0	0	0	0	0	0
(31) CASH - OTHER	0	0	0	0	0	0	0	0	0
(32) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(33) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(34) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(35) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(36) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(37) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(38) SUB-TOTAL	0	0	0	0	0	0	0	0	0
(39) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0
(40) TOTAL AVE. RATE BASE	**$2,623,499**	**$676,691**	**$264,927**	**($1,191,720)**	**$1,191,720**	**$0**	**$1,431,780**	**$1,868,411**	**$264,927**

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$453,290	$257,585	$9,193	$104,526	$12,499	$9,095	$17,914	$27,916	$0	$9,287	$5,274	D-3A
(2) HYDRO PLANT	150,250	85,381	3,047	34,647	4,143	3,015	5,938	9,253	0	3,078	1,748	D-3A
(3) WIND PLANT	9,180	5,216	186	2,117	253	184	363	565	0	188	107	D-3A
(4) LM6000 PLANT	30,974	17,601	628	7,142	854	621	1,224	1,908	0	635	360	D-3A
(5) GAS TURBINE PLANT - OTHER	6,513	3,701	132	1,502	180	131	257	401	0	133	76	D-3A
(6) TOTAL GENERATION PLANT	650,206	369,484	13,187	149,934	17,929	13,047	25,695	40,043	0	13,322	7,565	
(7) GEN. PROPERTY PLANT	48,831	27,749	990	11,260	1,346	980	1,930	3,007	0	1,000	568	P-7
(8) TOTAL PLANT IN SERVICE	699,037	397,233	14,177	161,194	19,275	14,027	27,625	43,050	0	14,322	8,133	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(10) CASH - OTHER	3,742	2,126	76	863	103	75	148	230	0	77	44	O-1
(11) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(12) MAT. & SUPPLIES - OTHER	5,974	3,395	121	1,378	165	120	236	368	0	122	70	P-7
(13) DEF. CHG. - Financing	13,689	7,779	278	3,157	377	275	541	843	0	280	159	P-7
(14) DEF. CHG. - Tax	2,051	1,165	42	473	57	41	81	126	0	42	24	P-7
(15) DEF. CHG. - Pension	11,104	6,310	225	2,560	306	223	439	684	0	227	129	O-1
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	D-3A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	D-3A
(18) DEF. CHG. - Other	584	332	12	135	16	12	23	36	0	12	7	P-7
(19) DEF. CHG. - FCR	6,128	3,482	124	1,413	169	123	242	377	0	126	71	P-7
(20) DEF. CR. - ARO Steam	(14,437)	(8,204)	(293)	(3,329)	(398)	(290)	(571)	(889)	0	(296)	(168)	D-3A
(21) DEF. CR. - ARO Hydro	(9,736)	(5,533)	(197)	(2,245)	(268)	(195)	(385)	(600)	0	(199)	(113)	D-3A
(22) DEF. CR. - ARO Wind	(4,646)	(2,640)	(94)	(1,071)	(128)	(93)	(184)	(286)	0	(95)	(54)	D-3A
(23) DEF. CR. - ARO CT	(4,150)	(2,358)	(84)	(957)	(114)	(83)	(164)	(256)	0	(85)	(48)	D-3A
(24) DEF. CR. - Other	(2,175)	(1,236)	(44)	(502)	(60)	(44)	(86)	(134)	0	(45)	(25)	D-3A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	D-3A
(26) SUB-TOTAL	8,126	4,618	165	1,874	224	163	321	500	0	166	95	
(25) TOTAL GEN. FUNCTION	707,163	401,850	14,342	163,068	19,499	14,190	27,946	43,551	0	14,488	8,227	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	47,308	26,883	959	10,909	1,304	949	1,870	2,913	0	969	550	D-3B
(26) GEN. PROPERTY PLANT	3,553	2,019	72	819	98	71	140	219	0	73	41	P-8A
(30) TOTAL PLANT IN SERVICE	50,861	28,902	1,032	11,728	1,402	1,021	2,010	3,132	0	1,042	592	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(32) CASH - OTHER	271	154	5	62	7	5	11	17	0	6	3	O-2A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3B
(34) MAT. & SUPPLIES - OTHER	435	247	9	100	12	9	17	27	0	9	5	P-8A
(35) DEF. CHG. - Financing	996	566	20	230	27	20	39	61	0	20	12	P-8A
(36) DEF. CHG. - Tax	149	85	3	34	4	3	6	9	0	3	2	P-8A
(37) DEF. CHG. - Pension	803	456	16	185	22	16	32	49	0	16	9	O-2A
(38) DEF. CHG. - Other	30	17	1	7	1	1	1	2	0	1	0	P-8A
(40) DEF. CR. - ARO Trans.	(2,510)	(1,426)	(51)	(579)	(69)	(50)	(99)	(155)	0	(51)	(29)	D-3B
(41) SUB-TOTAL	173	99	4	40	5	3	7	11	0	4	2	
(42) TOTAL TRANS. < 138kV	51,034	29,001	1,035	11,768	1,407	1,024	2,017	3,143	0	1,046	594	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	154,863	88,002	3,141	35,711	4,270	3,107	6,120	9,537	0	3,173	1,802	D-3A
(2) GENERAL PROPERTY PLANT	11,630	6,609	236	2,682	321	233	460	716	0	238	135	P-8B
(3) TOTAL PLANT IN SERVICE	166,493	94,611	3,377	38,393	4,591	3,341	6,580	10,254	0	3,411	1,937	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(5) CASH - OTHER	860	489	17	198	24	17	34	53	0	18	10	O-2B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	D-3A
(7) MAT. & SUPPLIES - OTHER	1,423	809	29	328	39	29	56	88	0	29	17	P-8B
(8) DEF. CHG. - Financing	3,260	1,853	66	752	90	65	129	201	0	67	38	P-8B
(9) DEF. CHG. - Tax	488	278	10	113	13	10	19	30	0	10	6	P-8B
(10) DEF. CHG. - Pension	2,552	1,450	52	589	70	51	101	157	0	52	30	O-2B
(11) DEF. CHG. - Other	98	56	2	23	3	2	4	6	0	2	1	P-8B
(12) DEF. CHG. - FCR	1,905	1,083	39	439	53	38	75	117	0	39	22	P-8B
(13) DEF. CR. - ARO Trans	(8,216)	(4,669)	(167)	(1,894)	(227)	(165)	(325)	(506)	0	(168)	(96)	D-3A
(14) SUB-TOTAL	2,372	1,348	48	547	65	48	94	146	0	49	28	
(15) TOTAL TRANS. > 69kV	168,865	95,959	3,425	38,939	4,656	3,388	6,673	10,400	0	3,460	1,965	
(14) TOTAL TRANS. FUNCTION	219,899	124,959	4,460	50,708	6,063	4,412	8,690	13,543	0	4,505	2,558	
DISTRIBUTION FUNCTION												
(15) DISTRIBUTION PLANT - Non Street	429,856	261,619	14,752	119,356	7,548	11,436	9,178	363	0	24	5,581	EXH. 3A
(16) DISTRIBUTION PLANT - Streetlight	10,251	0	0	0	0	0	0	0	0	0	10,251	EXH. 3A
	0	0	0	0	0	0	0	0	0	0	0	
(17) SUB-TOTAL	440,107	261,619	14,752	119,356	7,548	11,436	9,178	363	0	24	15,832	
(18) GEN. PROPERTY PLANT	33,052	20,116	1,134	9,178	580	879	706	28	0	2	429	P-9
	473,160	281,735	15,886	128,534	8,128	12,315	9,884	391	0	25	16,261	
Working Capital & Deferred Charges/Credits:												
(19) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(20) CASH - OTHER	4,180	2,128	120	986	103	96	124	0	0	0	623	O-3
(21) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-9
(22) MAT. & SUPPLIES - OTHER	4,044	2,461	139	1,123	71	108	86	3	0	0	53	P-9
(23) DEF. CHG. - Financing	9,266	5,639	318	2,573	163	246	198	8	0	1	120	P-9
(24) DEF. CHG. - Tax	1,388	845	48	385	24	37	30	1	0	0	18	P-9
(25) DEF. CHG. - Pension	12,402	6,313	356	2,925	306	284	368	1	0	0	1,849	O-3
(26) DEF. CHG. - Other	279	170	10	77	5	7	6	0	0	0	4	P-9
(27) SUB-TOTAL	31,558	17,556	990	8,069	672	778	811	14	0	1	2,667	
(28) TOTAL DIST. FUNCTION	504,717	299,291	16,876	136,603	8,800	13,093	10,695	405	0	26	18,929	
(29) TOTAL DEMAND	**$1,431,779**	**$826,101**	**$35,678**	**$350,379**	**$34,363**	**$31,695**	**$47,332**	**$57,498**	**$0**	**$19,020**	**$29,714**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PLANT	$917,241	$427,538	$22,940	$237,360	$37,738	$25,278	$49,640	$88,450	$0	$18,413	$9,886	E-1A
(2) HYDRO PLANT	201,011	93,694	5,027	52,017	8,270	5,540	10,878	19,384	0	4,035	2,166	E-1A
(3) WIND PLANT	192,002	89,495	4,802	49,686	7,899	5,291	10,391	18,515	0	3,854	2,069	E-1A
(4) LM6000 PLANT	40,443	18,851	1,012	10,466	1,664	1,115	2,189	3,900	0	812	436	E-1A
(5) GAS TURBINE PLANT - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(6) TOTAL GENERATION PLANT	1,350,698	629,578	33,781	349,528	55,571	37,223	73,098	130,248	0	27,114	14,558	
(7) GENERAL PROPERTY PLANT	101,439	47,282	2,537	26,250	4,173	2,795	5,490	9,782	0	2,036	1,093	P-10
(8) TOTAL PLANT IN SERVICE	1,452,137	676,859	36,318	375,778	59,744	40,018	78,588	140,030	0	29,150	15,651	
Working Capital & Deferred Charges/Credits:												
(9) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(10) CASH - OTHER	9,707	4,524	243	2,512	399	268	525	936	0	195	105	O-4
(11) MAT. & SUPPLIES - FUEL	84,441	39,359	2,112	21,851	3,474	2,327	4,570	8,143	0	1,695	910	E-1A
(12) MAT. & SUPPLIES - OTHER	12,410	5,784	310	3,211	511	342	672	1,197	0	249	134	P-10
(13) DEF. CHG. - Financing	28,436	13,255	711	7,359	1,170	784	1,539	2,742	0	571	306	P-10
(14) DEF. CHG. - Tax	4,260	1,986	107	1,102	175	117	231	411	0	86	46	P-10
(15) DEF. CHG. - Pension	28,803	13,425	720	7,454	1,185	794	1,559	2,777	0	578	310	O-4
(16) DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0	0	0	E-1A
(17) DEF. CHG. - Fuel Deferral	0	0	0	0	0	0	0	0	0	0	0	E-1A
(18) DEF. CHG. - Other	1,213	565	30	314	50	33	66	117	0	24	13	P-10
(19) DEF. CHG. - FCR	12,729	5,933	318	3,294	524	351	689	1,227	0	256	137	P-10
(20) DEF. CR. - ARO Steam	(29,214)	(13,617)	(731)	(7,560)	(1,202)	(805)	(1,581)	(2,817)	0	(586)	(315)	E-1A
(21) DEF. CR. - ARO Hydro	(13,026)	(6,071)	(326)	(3,371)	(536)	(359)	(705)	(1,256)	0	(261)	(140)	E-1A
(22) DEF. CR. - ARO Wind	(6,215)	(2,897)	(155)	(1,608)	(256)	(171)	(336)	(599)	0	(125)	(67)	E-1A
(23) DEF. CR. - ARO CT	0	0	0	0	0	0	0	0	0	0	0	E-1A
(24) DEF. CR. - Other	(4,402)	(2,052)	(110)	(1,139)	(181)	(121)	(238)	(424)	0	(88)	(47)	E-1A
(25) CONTRACT RECEIVABLE	0	0	0	0	0	0	0	0	0	0	0	E-1A
(26) SUB-TOTAL	129,142	60,195	3,230	33,419	5,313	3,559	6,989	12,453	0	2,592	1,392	
(24) TOTAL GEN. FUNCTION	1,581,279	737,054	39,548	409,197	65,058	43,577	85,577	152,483	0	31,743	17,043	
TRANSMISSION FUNCTION												
(28) TRANSMISSION PLANT < 138kV	61,772	28,793	1,545	15,985	2,541	1,702	3,343	5,957	0	1,240	666	E-1B
(29) GENERAL PROPERTY PLANT	4,639	2,162	116	1,200	191	128	251	447	0	93	50	P-11A
(30) TOTAL PLANT IN SERVICE	66,411	30,955	1,661	17,186	2,732	1,830	3,594	6,404	0	1,333	716	
Working Capital & Deferred Charges/Credits:												
(31) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(32) CASH - OTHER	353	165	9	91	15	10	19	34	0	7	4	O-5A
(33) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1B
(34) MAT. & SUPPLIES - OTHER	568	265	14	147	23	16	31	55	0	11	6	P-11A
(35) DEF. CHG. - Financing	1,300	606	33	337	54	36	70	125	0	26	14	P-11A
(36) DEF. CHG. - Tax	195	91	5	50	8	5	11	19	0	4	2	P-11A
(37) DEF. CHG. - Pension	1,048	489	26	271	43	29	57	101	0	21	11	O-5A
(38) DEF. CHG. - Other	39	18	1	10	2	1	2	4	0	1	0	P-11A
(40) DEF. CR. - ARO Trans.	(3,277)	(1,527)	(82)	(848)	(135)	(90)	(177)	(316)	0	(66)	(35)	E-1B
(41) SUB-TOTAL	226	106	6	59	9	6	12	22	0	5	2	
(42) TOTAL TRANS. < 138kV	66,638	31,061	1,667	17,244	2,742	1,836	3,606	6,426	0	1,338	718	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TRANSMISSION PLANT > 69kV	202,211	94,253	5,057	52,327	8,319	5,573	10,943	19,499	0	4,059	2,179	E-1A
(2) GENERAL PROPERTY PLANT	15,186	7,078	380	3,930	625	419	822	1,464	0	305	164	P-11B
(3) TOTAL PLANT IN SERVICE	217,397	101,332	5,437	56,257	8,944	5,991	11,765	20,964	0	4,364	2,343	
Working Capital & Deferred Charges/Credits:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(5) CASH - OTHER	1,123	523	28	291	46	31	61	108	0	23	12	O-5B
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	E-1A
(7) MAT. & SUPPLIES - OTHER	1,858	866	46	481	76	51	101	179	0	37	20	P-11B
(8) DEF. CHG. - Financing	4,257	1,984	106	1,102	175	117	230	411	0	85	46	P-11B
(9) DEF. CHG. - Tax	638	297	16	165	26	18	35	61	0	13	7	P-11B
(10) DEF. CHG. - Pension	3,333	1,553	83	862	137	92	180	321	0	67	36	O-5B
(11) DEF. CHG. - Other	128	60	3	33	5	4	7	12	0	3	1	P-11B
(12) DEF. CHG. - FCR	2,488	1,160	62	644	102	69	135	240	0	50	27	P-11B
(13) DEF. CR. - ARO Trans	(10,728)	(5,000)	(268)	(2,776)	(441)	(296)	(581)	(1,034)	0	(215)	(116)	E-1A
(14) SUB-TOTAL	3,097	1,443	77	801	127	85	168	299	0	62	33	
(15) TOTAL TRANS. > 69kV	220,494	102,775	5,515	57,058	9,072	6,076	11,933	21,262	0	4,426	2,376	
(15) TOTAL TRANS. FUNCTION	287,132	133,836	7,181	74,303	11,813	7,913	15,539	27,688	0	5,764	3,095	
(16) TOTAL ENERGY	**$1,868,411**	**$870,890**	**$46,730**	**$483,499**	**$76,871**	**$51,490**	**$101,116**	**$180,171**	**$0**	**$37,506**	**$20,138**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) INDUSTRIAL LARGE	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	$212,277	$186,613	$9,845	$10,887	$20	$2,235	$205	$63	$0	$7	$2,403	EXH. 3A
(2) GEN. PROPERTY PLANT	15,942	14,015	739	818	1	168	15	5	0	1	180	P-12
(3) TOTAL PLANT IN SERVICE	228,220	200,628	10,584	11,705	21	2,403	220	68	0	7	2,584	
WORKING CAPITAL:												
(4) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(5) CASH - OTHER	7,432	6,710	354	190	0	39	5	1	0	0	132	O-6
(6) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-12
(7) MAT. & SUPPLIES - OTHER	1,950	1,715	90	100	0	21	2	1	0	0	22	P-12
(8) DEF. CHG. - Financing	4,469	3,929	207	229	0	47	4	1	0	0	51	P-12
(9) DEF. CHG. - Tax	669	589	31	34	0	7	1	0	0	0	8	P-12
(10) DEF. CHG. - Pension	22,052	19,910	1,050	563	1	116	14	4	0	0	393	O-6
(11) DEF. CHG. - Other	134	118	6	7	0	1	0	0	0	0	2	P-12
(12) SUB-TOTAL	36,708	32,970	1,739	1,123	2	231	26	8	0	1	607	
(13) TOTAL DIST. FUNCTION	264,927	233,598	12,324	12,828	24	2,634	246	75	0	8	3,191	
RETAIL FUNCTION												
(14) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	EXH. 3A
(15) GEN. PROPERTY PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(16) TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0	0	0	
WORKING CAPITAL:												
(17) CASH - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(18) CASH - OTHER	0	0	0	0	0	0	0	0	0	0	0	O-7
(19) MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0	0	0	P-13
(20) MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0	0	0	P-13
(21) DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0	0	0	P-13
(22) DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0	0	0	P-13
(23) DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0	0	0	O-7
(24) DEF. CHG. - Other	0	0	0	0	0	0	0	0	0	0	0	P-13
(25) SUB-TOTAL	0	0	0	0	0	0	0	0	0	0	0	
(26) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(27) TOTAL CUSTOMER	**264,927**	**233,598**	**12,324**	**12,828**	**24**	**2,634**	**246**	**75**	**0**	**8**	**3,191**	
(28) TOTAL AVE. RATE BASE	**$3,565,118**	**$1,930,589**	**$94,731**	**$846,706**	**$111,257**	**$85,819**	**$148,694**	**$237,745**	**$0**	**$56,535**	**$53,042**	

NOVA SCOTIA POWER INC.
ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) LAND	$3,023	$1,783	$101	$826	$86	$80	$105	$4	$0	$0	$38	P-3
(2) EASEMENTS & SURVEY	11,505	6,785	383	3,144	327	305	398	17	0	1	145	P-3
(3) OTHER	1,493	880	50	408	42	40	52	2	0	0	19	P-3
(4) SUBSTATIONS	30,113	17,077	963	8,037	1,102	786	1,422	339	0	22	364	EXH 3B
(5) POLES & FIXTURES	119,005	70,595	3,981	32,639	3,234	3,164	3,887	0	0	0	1,506	EXH 3D
(6) O.H. LINES	78,818	46,756	2,636	21,617	2,142	2,095	2,575	0	0	0	997	EXH 3F
(7) U.G. LINES	22,658	13,441	758	6,214	616	602	740	0	0	0	287	P-1
(8) LINE TRANSFORMERS	163,242	104,302	5,881	46,470	0	4,363	0	0	0	0	2,225	D-1
(9) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(10) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(11) STREET LIGHTING	10,251	0	0	0	0	0	0	0	0	0	10,251	DIRECT
(12) TOTAL DEMAND	440,107	261,619	14,752	119,356	7,548	11,436	9,178	363	0	24	15,832	
CUSTOMER												
(13) LAND	1,412	1,280	68	32	0	6	0	0	0.000	0	27	P-4
(14) EASEMENTS & SURVEY	5,377	4,871	257	121	0	24	1	0	0.000	0	102	P-4
(15) OTHER	697	632	33	16	0	3	0	0	0.000	0	13	P-4
(16) SUBSTATIONS	0	0	0	0	0	0	0	0	0.000	0	0	---
(17) POLES & FIXTURES	64,080	58,057	3,063	1,442	1	282	13	2	0.000	1	1,220	EXH 3D
(18) O.H. LINES	42,441	38,451	2,029	955	1	187	8	1	0.000	0	808	EXH 3F
(19) U.G. LINES	12,200	11,054	583	275	0	54	2	0	0.000	0	232	P-2
(20) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0.000	0	0	---
(21) SERVICES	60,998	50,780	2,679	6,305	0	1,234	0	0	0.000	0	0	C-2
(22) METERS	25,072	21,489	1,134	1,742	17	445	180	59	0.000	6	0	EXH 3G
(23) STREET LIGHTING	0	0	0	0	0	0	0	0	0.000	0	0	---
(24) TOTAL CUSTOMER	$212,277	$186,613	$9,845	$10,887	$20	$2,235	$205	$63	$0	$7	$2,403	
RETAIL												
(25) SERVICES	0	0	0	0	0	0	0	0	0	0	0	---
(26) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(27) TOTAL RETAIL	0	0	0	0	0	0	0	0	0	0	0	
SUMMARY												
(28) LAND	4,435	3,062	168	858	86	86	105	5	0	0	65	P-3 & 4
(29) EASEMENTS & SURVEY	16,882	11,657	640	3,265	327	329	399	17	0	1	247	P-3 & 4
(30) OTHER	2,190	1,512	83	424	42	43	52	2	0	0	32	P-3 & 4
(31) SUBSTATIONS	30,113	17,077	963	8,037	1,102	786	1,422	339	0	22	364	EXH 3B
(32) POLES & FIXTURES	183,085	128,652	7,043	34,081	3,235	3,446	3,900	2	0	1	2,726	EXH 3D
(33) O.H. LINES	121,259	85,207	4,665	22,572	2,143	2,282	2,583	1	0	0	1,806	EXH 3F
(34) U.G. LINES	34,858	24,494	1,341	6,489	616	656	742	0	0	0	519	P-1 & 2
(35) LINE TRANSFORMERS	163,242	104,302	5,881	46,470	0	4,363	0	0	0	0	2,225	D-1
(36) SERVICES	60,998	50,780	2,679	6,305	0	1,234	0	0	0	0	0	C-2
(37) METERS	25,072	21,489	1,134	1,742	17	445	180	59	0	6	0	EXH 3G
(38) STREET LIGHTING	10,251	0	0	0	0	0	0	0	0	0	10,251	DIRECT
(39) TOTAL AVE. RATE BASE	**$652,385**	**$448,231**	**$24,597**	**$130,243**	**$7,568**	**$13,671**	**$9,383**	**$426**	**$0**	**$30**	**$18,235**	

EXHIBIT 3B

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) DIST. BULK PWR.	(3) DIST. DED. BULK PWR.	(4) DIST. GENERAL	(5) DIST. DED. GENERAL
(1) TOT. DIST. SUBSTATIONS	$30,113	$25,725	$401	$3,904	$83
ALLOCATION					
(2) DOMESTIC	17,077	14,827	0	2,250	0
(3) SMALL GENERAL	963	836	0	127	0
(4) GENERAL	8,037	6,957	25	1,056	0
(5) GENERAL LARGE	1,102	957	0	145	0
(6) SMALL INDUSTRIAL	786	682	0	104	0
(7) MEDIUM INDUSTRIAL	1,422	1,150	94	175	4
(8) LARGE INDUSTRIAL	339	0	260	0	79
(9) ELI 2P-RTP	0	0	0	0	0
(10) MUNICIPAL	22	0	22	0	0
(11) UNMETERED	364	316	0	48	0
(12) TOTAL	$30,113	$25,725	$401	$3,904	$83
ALLOCATION FACTOR		D-2	DIRECT	D-2	DIRECT

EXHIBIT 3C

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$183,085				
(2) PRIMARY ONLY (30%)	54,926	$54,926	$0	$0	$0
(3) 50% JOINT - PRI. (1)	64,080	32,040	32,040	0	0
(4) 50% JOINT - SEC. (1)	64,080	0	0	32,040	32,040
(5) TOTAL	$183,085	$86,965	$32,040	$32,040	$32,040

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3D

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$128,652	$50,124	$29,021	$20,472	$29,036
(2) SMALL GENERAL	7,043	2,826	1,531	1,154	1,532
(3) GENERAL	34,081	23,518	721	9,121	721
(4) GENERAL LARGE	3,235	3,234	1	0	0
(5) SMALL INDUSTRIAL	3,446	2,307	141	856	141
(6) MEDIUM INDUSTRIAL	3,900	3,887	13	0	0
(7) LARGE INDUSTRIAL	2	0	2	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	1	0	1	0	0
(10) UNMETERED	2,726	1,069	610	437	610
(11) TOTAL	$183,085	$86,965	$32,040	$32,040	$32,040
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3E

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$121,259				
(2) PRIMARY ONLY (30%)	36,378	$36,378	$0	$0	$0
(3) 50% JOINT - PRI. (1)	42,441	21,220	21,220	0	0
(4) 50% JOINT - SEC. (1)	42,441	0	0	21,220	21,220
(5) TOTAL	$121,259	$57,598	$21,220	$21,220	$21,220

DEMAND COST - 50% }
} (1)
CUSTOMER COST - 50% }

EXHIBIT 3F

NOVA SCOTIA POWER INC.

ALLOCATION OF AVERAGE WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$85,207	$33,197	$19,221	$13,559	$19,231
(2) SMALL GENERAL	4,665	1,872	1,014	765	1,015
(3) GENERAL	22,572	15,576	477	6,041	478
(4) GENERAL LARGE	2,143	2,142	1	0	0
(5) SMALL INDUSTRIAL	2,282	1,528	93	567	93
(6) MEDIUM INDUSTRIAL	2,583	2,575	8	0	0
(7) LARGE INDUSTRIAL	1	0	1	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,806	708	404	289	404
(11) TOTAL	$121,259	$57,598	$21,220	$21,220	$21,220
ALLOCATION FACTOR		D-2	C-5	D-1	C-4

EXHIBIT 3G

NOVA SCOTIA POWER INC.

ANALYSIS OF AVERAGE METER INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	456,991	$34.00	$15,537,694	85.71	$21,489
(2) SMALL GENERAL	24,109	34.00	819,706	4.52	1,134
(3) GENERAL	11,349	111.00	1,259,739	6.95	1,742
(4) GENERAL LARGE	19	657.00	12,483	0.07	17
(5) SMALL INDUSTRIAL	2,221	145.00	322,045	1.78	445
(6) MEDIUM INDUSTRIAL	198	657.00	130,086	0.72	180
(7) LARGE INDUSTRIAL	32	1,338.00	42,816	0.24	59
(8) ELI 2P-RTP	0	1,338.00	0	0.00	0
(9) MUNICIPAL	8	520.00	4,160	0.02	6
(10) UNMETERED	9,604	N/A	0	0.00	0
(11) TOTAL	504,531		$18,128,729	100.00	$25,072

EXHIBIT 4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
POWER PRODUCTION						
(1) FUEL	$396,709	$365,712	$0	$0	$0	$30,997
PURCHASED POWER:						
(2) REGULAR	49,388	49,388	0	0	0	0
(3) WIND	67,576	67,576	0	0	0	0
(4) THERMAL - OPERATING & MAINT.	85,135	84,471	0	0	0	664
(5) HYDRO - OPERATING & MAINT.	9,787	7,519	0	0	0	2,267
(6) WIND - OPERATING & MAINT.	4,727	4,717	0	0	0	11
(7) BIOMASS - OPERATING & MAINT.	6,261	6,246	0	0	0	14
(8) LM6000 - OPERATING & MAINT.	329	328	0	0	0	1
(9) COMBUSTION TURBINE - OPER. & MAINT.	972	970	0	0	0	2
(10) ENERGY, FUELS & RISK MGMT.	3,909	3,900	0	0	0	9
(11) GENERATION DEVELOPMENT	0	0	0	0	0	0
(12) TOTAL PRODUCTION OPER. & MAINT.	111,119	108,151	0	0	0	2,968
CUSTOMER OPERATIONS:						
(13) TRANSMISSION & DISTRIBUTION	53,834	0	17,614	35,791	0	429
CUST. SERV. / MARKETING & SALES:						
(14) Qty. Ass., Comm., Call Ctr. & Rev. Ops.	37,358	0	0	607	36,751	0
OTHER OPERATING						
CORPORATE GROUPS:						
(15) EXECUTIVE MANAGEMENT	1,160	417	127	301	313	1
(16) CORP. SECRETARY & LEGAL SERVICES	8,833	3,176	971	2,294	2,382	9
(17) EXTERNAL RELATIONS & ENVIRONMENT	2,102	756	231	546	567	2
(18) REGULATORY AFFAIRS	6,236	2,243	685	1,620	1,682	6
(19) FINANCE GROUP	6,863	2,468	754	1,782	1,851	7
(20) ENTERPRISE SERVICES	22,254	8,003	2,445	5,780	6,002	24
(21) HUMAN RESOURCES	5,648	2,031	621	1,467	1,523	7
(22) TECHNICAL & CONSTRUCTION SERVICES	14,550	2,892	1,633	3,865	6,150	9
(23) SUSTAINABILITY	1,527	1,523	0	0	0	3
(24) SUB-TOTAL	69,171	23,509	7,468	17,655	20,470	69
(25) OTHER EXPENSES	11,616	4,177	1,276	3,017	3,133	12
(26) DIRECT ADMIN. & GEN. EXPENSE	0	(237)	(72)	(171)	(178)	658
(27) TOTAL OM&G EXPENSES	**283,098**	**135,601**	**26,286**	**56,898**	**60,177**	**4,137**
(28) COGS (NET OF SALES)	(432)	0	0	0	(432)	0
(29) DSM AMORTIZATION	1,058	970	0	0	0	88
(30) FCR DEFERRAL	16,500	13,382	3,118	0	0	0
(31) OTHER EXPENSES	0	0	0	0	0	0
(32) GRANTS IN LIEU OF TAXES	38,361	24,516	5,712	7,993	0	140
DEPRECIATION:						
(33) STEAM	65,371	65,222	0	0	0	149
(34) HYDRO	11,163	10,084	0	0	0	1,079
(35) WIND	8,186	8,167	0	0	0	19
(36) LM6000	2,084	2,079	0	0	0	5
(37) OTHER GAS TURBINE	1,202	1,199	0	0	0	3
(38) TRANSMISSION < 138kV	5,371	0	5,362	0	0	9
(39) TRANSMISSION > 69kV	17,580	0	17,549	0	0	31
(40) DISTRIBUTION - Non Streetlight Related	47,699	0	0	47,699	0	0
(41) DISTRIBUTION - Streetlight Related	3,604	0	0	2,240	0	1,364
(42) GENERAL PROPERTY	39,917	25,560	5,955	8,334	0	69
(43) INTEREST NET	142,589	89,216	19,767	30,005	0	3,601
(44) PREFERRED DIVIDENDS	8,000	5,082	1,126	1,709	0	83
(45) CORPORATE TAXES	56,632	35,985	7,973	12,102	0	572
(46) TOTAL EXPENSES	**$1,261,656**	**$899,739**	**$92,846**	**$166,981**	**$59,745**	**$42,345**
(47) NON-OPERATING REVENUE:						
(48) EXPORT SALES	(1,943)	(1,943)	0	0	0	0
(49) LATE PAYMENT CHARGE	(5,330)	0	0	0	(5,330)	0
(50) MISC. ELECTRIC	(2,003)	0	0	0	(2,003)	0
(51) OTHER REVENUE	(14,648)	(10,809)	(1,115)	(2,006)	(718)	0
(52) NET INCOME	124,745	76,898	17,038	25,862	0	4,948
(53) TOTAL NET EXPENSES	**$1,362,477**	**$963,884**	**$108,769**	**$190,837**	**$51,695**	**$47,292**

EXHIBIT 4 - Detail A

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1)	**FUEL**	$396,709	$365,712	$0	$0	$0	$30,997
	PURCHASED POWER:						
(2)	REGULAR	49,388	49,388	0	0	0	0
(3)	WIND	67,576	67,576	0	0	0	0
(4)	TOTAL	513,673	482,677	0	0	0	30,997
	POWER PRODUCTION						
(5)	THERMAL OPERATING & MAINT.	85,135	84,471	0	0	0	664
(6)	HYDRO OPERATING & MAINT.	9,787	7,519	0	0	0	2,267
(7)	WIND - OPERATING & MAINT.	4,727	4,717	0	0	0	11
(8)	BIOMASS - OPERATING & MAINT.	6,261	6,246	0	0	0	14
(9)	LM6000 OPERATING & MAINT.	329	328	0	0	0	1
(10)	COMBUSTION TURBINE - OPER. & MAINT.	972	970	0	0	0	2
(11)	FUEL PROCUREMENT	3,909	3,900	0	0	0	9
(12)	GENERATION DEVELOPMENT	0	0	0	0	0	0
(13)							
(14)	**TOTAL POWER PRODUCTION**	111,119	108,151	0	0	0	2,968
(15)	**SUSTAINABILITY**	1,527	1,523	0	0	0	3
	CORPORATE GROUPS						
(16)	EXECUTIVE MANAGEMENT	1,160	417	127	301	313	1
(17)	CORP. SECRETARY	7,647	2,750	840	1,986	2,063	8
(18)	LEGAL SERVICES	1,185	426	130	308	320	1
(19)	EXTERNAL RELATIONS	2,102	756	231	546	567	2
(20)	ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0
(21)	Total Corporate Groups	12,094	4,350	1,329	3,141	3,262	12
	CUSTOMER OPERATIONS						
	TRANSMISSION & DISTRIBUTION:						
(22)	**TRANSMISSION:**						
(23)	**< 138kV**	4,222	0	4,215	0	0	7
(24)	**> 69kV**	13,821	0	13,399	0	0	422
	DISTRIBUTION:						
(25)	SUBSTATIONS	196	0	0	196	0	0
(26)	OVERHEAD LINES	24,793	0	0	24,793	0	0
(27)	UNDERGROUND LINES	444	0	0	444	0	0
(28)	LINE TRANSFORMERS	949	0	0	949	0	0
(29)	METERS (Meter Shop Only)	0	0	0	0	0	0
(30)	COMMUNICATIONS	5,682	0	0	5,682	0	0
(31)	STREET LIGHTING	3,727	0	0	3,727	0	0
(33)	**TOTAL DISTRIBUTION**	35,791	0	0	35,791	0	0
(34)	**TOTAL CUSTOMER OPERATIONS - T & D**	53,834	0	17,614	35,791	0	429
(35)	**TECHNICAL & CONSTRUCTION SERVICES**	14,550	2,892	1,633	3,865	6,150	9
	CUST. SERV. / MARKETING & SALES						
	ADMINISTRATION:						
(36)	CUSTOMER SERVICE - ADMIN.	721	0	0	0	721	0
(37)	ENERGY EFFICIENCY	481	0	0	0	481	0
(38)	CUST. COMM. & QTY ASSURANCE	1,877	0	0	0	1,877	0
(39)	CUSTOMER SOLUTIONS	0	0	0	0	0	0
(40)	**CALL CENTRE:**						
(41)	(a) CALL CENTRE - CSR's	7,082	0	0	0	7,082	0
(42)	(b) CALL CENTRE OPERATIONS	0	0	0	0	0	0
(43)	(c) CALL CENTRE - HALIFAX	0	0	0	0	0	0
(44)	(d) CALL NETWORK (COLLECTIONS)	377	0	0	0	377	0
(45)	(e) ELECTRICAL WIRING INSPECTION	4,498	0	0	0	4,498	0
(46)	**REVENUE OPERATIONS:**						
(47)	(a) BILLING SERVICES	3,726	0	0	0	3,726	0
(48)	(b) METER DATA SERVICES	474	0	0	0	474	0
(49)	(c) METER SERVICES - METER SHOP	607	0	0	607	0	0
(50)	(d) METER SERVICES - FIELD	6,188	0	0	0	6,188	0
(51)	(e) ELECTRICAL WIRING INSPECTION - FIELD	3,476	0	0	0	3,476	0
(52)	(f) PAYMENT SERVICES	713	0	0	0	713	0
(53)	(g) CREDIT SERVICES	0	0	0	0	0	0
(54)	(h) BAD DEBT EXPENSE	5,704	0	0	0	5,704	0
(55)	(i) MARKETING & SALES	1,167	0	0	0	1,167	0
(56)	(j) ELECTRICAL WIRING INSPECTION - H/O	268	0	0	0	268	0
(58)	**TOTAL CUST. SERV. / MARKETING & SALES**	37,358	0	0	607	36,751	0

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES
(1) **REGULATORY AFFAIRS**	$6,236	$2,243	$685	$1,620	$1,682	$6
FINANCE GROUP						
(2) INTERNAL AUDIT	1,732	623	190	450	467	2
(3) INVESTOR RELATIONS	292	105	32	76	79	0
(4) DIRECTOR FINANCE	745	268	82	193	201	1
(5) TREASURER	793	285	87	206	214	1
(6) CORPORATE TAX	836	301	92	217	226	1
(7) GM FINANCE	0	0	0	0	0	0
(8) CORPORATE CONTROLLER	2,464	886	271	640	665	2
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0
(10) **TOTAL FINANCE**	6,863	2,468	754	1,782	1,851	7
ENTERPRISE SERVICES						
(11) PROCUREMENT & FACILITIES	10,129	3,642	1,113	2,631	2,732	11
(12) INFORMATION TECHNOLOGY	12,126	4,361	1,332	3,149	3,270	13
(13) **TOTAL ENTERPRISE SERVICES**	22,254	8,003	2,445	5,780	6,002	24
HUMAN RESOURCES						
(14) --HUMAN RESOURCES	5,648	2,031	621	1,467	1,523	7
(15) OTHER EXPENSES	11,616	4,177	1,276	3,017	3,133	12
(16) DIRECT ADM. & GEN. EXPENSE	0	(237)	(72)	(171)	(178)	658
(17) **TOTAL DIVISIONAL EXPENSES**	**283,098**	**135,601**	**26,286**	**56,898**	**60,177**	**4,137**
(18) **COGS (NET OF RETAIL SALES)**	**(432)**	**0**	**0**	**0**	**(432)**	**0**
(19) **DSM EXPENSES**	**1,058**	**970**	**0**	**0**	**0**	**88**
(20) **FCR DEFERRAL**	**16,500**	**13,382**	**3,118**	**0**	**0**	**0**
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**	
CAPITAL RELATED EXPENSES						
(22) GRANTS IN LIEU OF TAXES	38,361	24,516	5,712	7,993	0	140
(23) DEPRECIATION :						
(24) STEAM	65,371	65,222	0	0	0	149
(25) HYDRO	11,163	10,084	0	0	0	1,079
(26) WIND	8,186	8,167	0	0	0	19
(27) LM6000	2,084	2,079	0	0	0	5
(28) GAS TURBINE - OTHER	1,202	1,199	0	0	0	3
(29) TRANSMISSION < 138kV	5,371	0	5,362	0	0	9
(30) TRANSMISSION > 69kV	17,580	0	17,549	0	0	31
(31) DISTRIBUTION - Non Streetlight Related	47,699	0	0	47,699	0	0
(32) DISTRIBUTION - Streetlight Related	3,604	0	0	2,240	0	1,364
(33) GENERAL PROPERTY	39,917	25,560	5,955	8,334	0	69
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0
(35) INTEREST NET	142,589	89,216	19,767	30,005	0	3,601
(36) PREFERRED DIVIDENDS	8,000	5,082	1,126	1,709	0	83
(37) CORPORATE TAXES	56,632	35,985	7,973	12,102	0	572
(38) **TOTAL OPERATING EXPENSES**	**1,261,656**	**899,739**	**92,846**	**166,981**	**59,745**	**42,345**
(39) NON-OPERATING REVENUE:						0
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0
(41) EXPORT SALES	(1,943)	(1,943)	0	0	0	0
(42) LATE PAYMENT CHARGE	(5,330)	0	0	0	(5,330)	0
(43) MISC. ELECTRIC	(2,003)	0	0	0	(2,003)	0
(44) OTHER REVENUE	(14,648)	(10,809)	(1,115)	(2,006)	(718)	0
(45) **PROFIT/LOSS**	124,745	76,898	17,038	25,862	0	4,948
(46) **TOTAL NET EXPENSES**	**$1,362,477**	**$963,884**	**$108,769**	**$190,837**	**$51,695**	**$47,292**

EXHIBIT 4 - Detail B

FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE LRT

NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT

Fixed Cost Contribution		$4.00
	Load	322
		$1,288

	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) WEIGHTS		(8) DIRECT LRT
(1) **FUEL**	$396,709	$365,712	$0	$0	$0	$30,997	$0	0					0.00%	0.00%	$0.00
PURCHASED POWER:															
(2) REGULAR	49,388	49,388	0	0	0	0	0	0					0.00%	0.00%	$0.00
(3) WIND	67,576	67,576	0	0	0	0	0	0					0.00%	0.00%	$0.00
(4) TOTAL	513,673	482,677	0	0	0	30,997	0	0					0.00%	0.00%	$0.00
POWER PRODUCTION															
(5) THERMAL OPERATING & MAINT.	85,135	84,664	0	0	0	471	84,664	84,664	0				15.00%	15.00%	$193.22
(6) HYDRO OPERATING & MAINT.	9,787	7,537	0	0	0	2,250	7,537	7,537	0				1.34%	1.34%	$17.20
(7) WIND - OPERATING & MAINT.	4,727	4,727	0	0	0	0	4,727	4,727	0				0.84%	0.84%	$10.79
(8) BIOMASS - OPERATING & MAINT.	6,261	6,261	0	0	0	0	6,261	6,261	0				1.11%	1.11%	$14.29
(9) LM6000 OPERATING & MAINT.	329	329	0	0	0	0	329	329	0				0.06%	0.06%	$0.75
(10) COMBUSTION TURBINE - OPER. & MAINT.	972	972	0	0	0	0	972	972	0				0.17%	0.17%	$2.22
(11) FUEL PROCUREMENT	3,909	3,909	0	0	0	0	3,909	3,909	0				0.69%	0.69%	$8.92
(12) GENERATION DEVELOPMENT	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(13)									0				0.00%	0.00%	$0.00
(14) **TOTAL POWER PRODUCTION**	111,119	108,398	0	0	0	2,721	108,398	108,398	0				19.20%	19.20%	$247.39
(15) **SUSTAINABILITY**	1,527	1,527	0	0	0	0	1,527	1,527	0				0.27%	0.27%	$3.48
CORPORATE GROUPS															
(16) EXECUTIVE MANAGEMENT	1,160	418	128	302	313	0	515	418	98				0.09%	0.09%	$1.18
(17) CORP. SECRETARY	7,647	2,753	841	1,988	2,065	0	3,397	2,753	644				0.60%	0.60%	$7.75
(18) LEGAL SERVICES	1,185	427	130	308	320	0	527	427	100				0.09%	0.09%	$1.20
(19) EXTERNAL RELATIONS	2,102	757	231	546	568	0	934	757	177				0.17%	0.17%	$2.13
(20) ENVIRONMENTAL POLICIES & PROGRAMS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
	12,094	4,354	1,330	3,145	3,265	0	5,373	4,354	1019						$12.26
CUSTOMER OPERATIONS															
TRANSMISSION & DISTRIBUTION:															
(21) **TRANSMISSION:**															
(22) **< 138kV**	4,222	0	4,222	0	0	0	3,234	0	3234				0.57%	0.57%	$7.38
(23) **> 69kV**	13,821	0	13,423	0	0	398	10,282	0	10282				1.82%	1.82%	$23.47
DISTRIBUTION:															
(24) SUBSTATIONS	196	0	0	196	0	0	0	0	0				0.00%	0.00%	$0.00
(25) OVERHEAD LINES	24,793	0	0	24,793	0	0	0	0	0				0.00%	0.00%	$0.00
(26) UNDERGROUND LINES	444	0	0	444	0	0	0	0	0				0.00%	0.00%	$0.00
(27) LINE TRANSFORMERS	949	0	0	949	0	0	0	0	0				0.00%	0.00%	$0.00
(28) METERS (Meter Shop Only)	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(29) COMMUNICATIONS	5,682	0	0	5,682	0	0	0	0	0				0.00%	0.00%	$0.00
(30) STREET LIGHTING	3,727	0	0	3,727	0	0	0	0	0				0.00%	0.00%	$0.00
(31)									0				0.00%	0.00%	
(32) **TOTAL DISTRIBUTION**	35,791	0	0	35,791	0	0	0	0	0	0	0	0	0.00%	0.00%	$0.00
(33) **TOTAL CUSTOMER OPERATIONS - T & D**	53,834	0	17,645	35,791	0	398	13,516	0	13,516	0	0	0	2.39%	2.39%	$30.85
(34) **TECHNICAL & CONSTRUCTION SERVICES**	14,550	2,900	1,635	3,865	6,150	0	4,153	2,900	1253	0	0	0	0.74%	0.74%	$9.48
CUST. SERV. / MARKETING & SALES															
ADMINISTRATION:															
(35) CUSTOMER SERVICE - ADMIN.	721	0	0	0	721	0	0	0	0				0.00%	0.00%	$0.00
(36) ENERGY EFFICIENCY	481	0	0	0	481	0	0	0	0				0.00%	0.00%	$0.00
(37) CUST. COMM. & QTY ASSURANCE	1,877	0	0	0	1,877	0	0	0	0				0.00%	0.00%	$0.00
(38) CUSTOMER SOLUTIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(39) **CALL CENTRE:**															
(40) (a) CALL CENTRE - CSR's	7,082	0	0	0	7,082	0	0	0	0				0.00%	0.00%	$0.00
(41) (b) CALL CENTRE OPERATIONS	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(42) (c) CALL CENTRE - HALIFAX	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(43) (d) CALL NETWORK (COLLECTIONS)	377	0	0	0	377	0	0	0	0				0.00%	0.00%	$0.00
(44) (e) ELECTRICAL WIRING INSPECTION	4,498	0	0	0	4,498	0	0	0	0				0.00%	0.00%	$0.00
(45) **REVENUE OPERATIONS:**															
(46) (a) BILLING SERVICES	3,726	0	0	0	3,726	0	0	0	0				0.00%	0.00%	$0.00
(47) (b) METER DATA SERVICES	474	0	0	0	474	0	0	0	0				0.00%	0.00%	$0.00
(48) (c) METER SERVICES - METER SHOP	607	0	0	607	0	0	0	0	0				0.00%	0.00%	$0.00
(49) (d) METER SERVICES - FIELD	6,188	0	0	0	6,188	0	0	0	0				0.00%	0.00%	$0.00
(50) (e) ELECTRICAL WIRING INSPECTION - FIELD	3,476	0	0	0	3,476	0	0	0	0				0.00%	0.00%	$0.00
(51) (f) PAYMENT SERVICES	713	0	0	0	713	0	0	0	0				0.00%	0.00%	$0.00
(52) (g) CREDIT SERVICES	0	0	0	0	0	0	0	0	0				0.00%	0.00%	$0.00
(53) (h) BAD DEBT EXPENSE	5,704	0	0	0	5,704	0	0	0	0				0.00%	0.00%	$0.00
(54) (i) MARKETING & SALES	1,167	0	0	0	1,167	0	0	0	0				0.00%	0.00%	$0.00
(55) (j) ELECTRICAL WIRING INSPECTION - H/O	268	0	0	0	268	0	0	0	0				0.00%	0.00%	$0.00
(57) **TOTAL CUST. SERV. / MARKETING & SALES**	37,358	0	0	607	36,751	0	0	0	0	0	0	0	0.00%	0.00%	$0.00

NOVA SCOTIA POWER INC.
FUNCTIONALIZATION OF OPERATING EXPENSES
DEDICATED DIST.PLT.- LINE TRANSFORMERS
(IN THOUSANDS OF DOLLARS)

	FUNCTIONALIZATION OF OPERATING EXPENSES BEFORE ELR						NON-FUEL RELATED EXPENSES BY THE FUNCTIONAL AREAS AFFECTED BY LRT									
	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(1) TOTAL EXPENSES	(2) PROD. EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) RETAIL EXPENSES	(6) DIRECT EXPENSES	(7) EXPENSES		(8) DIRECT LRT	
(1) **REGULATORY AFFAIRS**	$6,236	$2,245	$686	$1,621	$1,684	$0	$2,770	$2,245	525				0.49%	0.49%	$6.32	
FINANCE GROUP																
(2) INTERNAL AUDIT	1,732	623	190	450	468	0	769	$623	146				0.14%	0.14%	$1.76	
(3) INVESTOR RELATIONS	292	105	32	76	79	0	130	$105	25				0.02%	0.02%	$0.30	
(4) DIRECTOR FINANCE	745	268	82	194	201	0	331	$268	63				0.06%	0.06%	$0.76	
(5) TREASURER	793	286	87	206	214	0	352	$286	67				0.06%	0.06%	$0.80	
(6) CORPORATE TAX	836	301	92	217	226	0	372	$301	70				0.07%	0.07%	$0.85	
(7) GM FINANCE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(8) CORPORATE CONTROLLER	2,464	887	271	641	665	0	1,095	$887	208				0.19%	0.19%	$2.50	
(9) CORP. PERFORMANCE & BACK OFFICE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(10) **TOTAL FINANCE**	6,863	2,471	755	1,784	1,853	0	3,049	$2,471	578				0.54%	0.54%	$6.96	
ENTERPRISE SERVICES																
(11) PROCUREMENT & FACILITIES	10,129	2,633	2,735	3,646	1,114	0	4,728	$2,633	2095				0.84%	0.84%	$10.79	
(12) INFORMATION TECHNOLOGY	12,126	3,153	3,274	4,365	1,334	0	5,660	$3,153	2508				1.00%	1.00%	$12.92	
(13) **TOTAL ENTERPRISE SERVICES**	22,254	5,786	6,009	8,012	2,448	0	10,389	$5,786	4603				1.84%	1.84%	$23.71	
HUMAN RESOURCES																
(14) --HUMAN RESOURCES	5,648	1,525	2,033	621	1,468	0	3,082	$1,525	1557				0.55%	0.55%	$7.03	
(15) OTHER EXPENSES	11,616	4,182	1,278	3,020	3,136	0	5,160	$4,182	979				0.91%	0.91%	$11.78	
(16) DIRECT ADM. & GEN. EXPENSE	0	(237)	(72)	(171)	(178)	659	(293)	($237)	-56				-0.05%	-0.05%	($0.67)	
(17) **TOTAL DIVISIONAL EXPENSES**	**283,098**	**133,150**	**31,299**	**58,294**	**56,578**	**3,778**	**157,125**	**133,150**	**23,975**				27.83%	27.83%	$358.60	$358.60
(18) **COGS (NET OF RETAIL SALES)**	**(432)**	**0**	**0**	**0**	**(432)**	**0**	**0**	$0	0				0.00%	0.00%	$0.00	
(19) **DSM EXPENSES**	**1,058**	**972**	**0**	**0**	**0**	**86**	**972**	$972	0				0.17%	0.17%	$2.22	
(20) **FCR DEFERRAL**	**16,500**	**13,382**	**3,118**	**0**	**0**	**0**	**0**	$0					0	0	0	
(21) **OTHER EXPENSES**	**0**	**0**	**0**	**0**	**0**		**0**	$0	0				0.00%	0.00%	$0.00	
CAPITAL RELATED EXPENSES																
(22) GRANTS IN LIEU OF TAXES	38,361	24,559	5,721	8,007	0	74	28,941	$24,559	4383				5.13%	5.13%	$66.05	
(23) DEPRECIATION :									0							
(24) STEAM	65,371	65,371	0	0	0	0	65,371	$65,371	0				11.58%	11.58%	$149.19	
(25) HYDRO	11,163	10,107	0	0	0	1,056	10,107	$10,107	0				1.79%	1.79%	$23.07	
(26) WIND	8,186	8,186	0	0	0	0	8,186	$8,186	0				1.45%	1.45%	$18.68	
(27) LM6000	2,084	2,084	0	0	0	0	2,084	$2,084	0				0.37%	0.37%	$4.76	
(28) GAS TURBINE - OTHER	1,202	1,202	0	0	0	0	1,202	$1,202	0				0.21%	0.21%	$2.74	
(29) TRANSMISSION < 138kV	5,371	0	5,371	0	0	0	4,114	$0	4114				0.73%	0.73%	$9.39	
(30) TRANSMISSION > 69kV	17,580	0	17,580	0	0	0	13,466	$0	13466				2.39%	2.39%	$30.73	
(31) DISTRIBUTION - Non Streetlight Related	47,699	0	0	47,699	0	0	0	$0	0				0.00%	0.00%	$0.00	
(32) DISTRIBUTION - Streetlight Related	3,604	0	0	2,240	0	1,364	0	$0	0				0.00%	0.00%	$0.00	
(33) GENERAL PROPERTY	39,917	25,604	5,965	8,348	0	0	30,173	$25,604	4569				5.35%	5.35%	$68.86	
(34) GLACE BAY WRITE-OFF	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(35) INTEREST NET	142,589	89,369	19,801	30,056	0	3,363	104,536	$89,369	15167				18.52%	18.52%	$238.58	
(36) PREFERRED DIVIDENDS	8,000	5,091	1,128	1,712	0	69	5,955	$5,091	864				1.05%	1.05%	$13.59	
(37) CORPORATE TAXES	56,632	36,047	7,987	12,123	0	476	42,164	$36,047	6118				7.47%	7.47%	$96.23	
(38) **TOTAL OPERATING EXPENSES**	**1,261,656**	**897,799**	**97,969**	**168,480**	**56,146**	**41,262**	**474,396**	**401,740**	**72,656**	**0**	**0**	**0**	84.04%	84.04%	$1,082.68	$1,082.68
(39) NON-OPERATING REVENUE:													0.00%	0.00%	$0.00	
(40) GREEN POWER SURCHARGE	0	0	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(41) EXPORT SALES	(1,943)	(1,943)	0	0	0	0	0	$0	0				0.00%	0.00%	$0.00	
(42) LATE PAYMENT CHARGE	(5,330)	0	0	0	(5,330)	0	0	$0	0				0.00%	0.00%	$0.00	
(43) MISC. ELECTRIC	(2,003)	0	0	0	(2,003)	0	0	$0	0				0.00%	0.00%	$0.00	
(44) OTHER REVENUE	(14,648)	(10,776)	(1,176)	(2,022)	(674)	0	0	$0	0				0.00%	0.00%	$0.00	
(45) **PROFIT/LOSS**	124,745	77,030	17,067	25,906	0	4,742	90,103	77,030	13073			0	15.96%	15.96%	$205.64	
(46) **TOTAL NET EXPENSES**	**$1,362,477**	**$962,109**	**$113,860**	**$192,364**	**$48,140**	**$46,004**	**$564,499**	**$478,769**	**$85,729**	**$0**	**$0**	**$0**	100.00%	100.00%	**$1,288.320**	

EXHIBIT 5
Page 1 of 3

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
GENERATION FUNCTION				
(1) FUEL	365,712	$0	$365,712	$0
(2) PURCHASED PWR REG - FIXED	22,225	7,222	15,003	0
(3) PURCHASED PWR REG - VAR.	27,164	0	27,164	0
(4) PURCHASED PWR WIND - FIXED	20,273	6,082	14,191	0
(5) PURCHASED PWR WIND - VAR.	47,303	0	47,303	0
(6) OPER. & MAINT. - STEAM	109,873	29,991	79,881	0
(7) OPER. & MAINT. - HYDRO/WIND/BI	24,040	6,562	17,478	0
(8) OPER. & MAINT. - LM6000	426	116	310	0
(9) OPER. & MAINT. - OTHER CT's	1,262	1,060	202	0
(10) DSM AMORTIZATION	970	315	654	0
(11) FCR DEFERRAL	13,382	4,135	9,247	0
(12) GRANTS IN LIEU OF TAXES	24,516	7,967	16,550	0
DEPRECIATION:				
(13) STEAM	65,222	21,571	43,650	0
(14) HYDRO	10,084	4,313	5,770	0
(15) WIND	8,167	373	7,794	0
(16) LM6000	2,079	902	1,177	0
(17) GAS TURBINE - OTHER	1,199	1,199	0	0
(18) GENERAL PROPERTY	25,560	8,306	17,254	0
(19) INTEREST NET OF AFUDC	89,216	27,569	61,647	0
(20) PREFERRED DIVIDENDS	5,082	1,570	3,512	0
(21) CORPORATE TAXES	35,985	11,120	24,865	0
NON-OPERATING REVENUE:				
(22) EXPORT SALES	(1,943)	0	(1,943)	0
(23) OTHER REVENUE	(10,809)	(1,686)	(9,122)	0
(24) RETURN (PROFIT/LOSS)	76,898	23,763	53,135	0
(25) TOTAL GENERATION	**963,884**	**162,450**	**801,435**	**0**
	963,884			
TRANSMISSION FUNCTION				
Transmission < 138kV:				
(26) O&M < 138kV	6,290	2,728	3,562	0
(27) GRANTS IN LIEU OF TAXES	1,326	575	751	0
DEPRECIATION:				
(28) TRANSMISSION	5,362	2,325	3,036	0
(29) GENERAL PROPERTY	1,393	604	789	0
(30) INTEREST NET OF AFUDC	4,587	1,990	2,598	0
(31) PREFERRED DIVIDENDS	261	113	148	0
(32) CORPORATE TAXES	1,850	802	1,048	0
NON-OPERATING REVENUE:				
(33) OTHER REVENUE	(261)	(113)	(148)	0
(35) RETURN (PROFIT/LOSS)	3,954	1,715	2,239	0
(36) TOTAL < 138kV	**24,763**	**10,740**	**14,023**	**0**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
Transmission > 69kV:				
(1) O&M > 69kV	19,996	8,672	11,324	0
(2) GRANTS IN LIEU OF TAXES	4,386	1,902	2,484	0
DEPRECIATION:				
(3) TRANSMISSION	17,549	7,611	9,938	0
(4) GENERAL PROPERTY	4,561	1,978	2,583	0
(5) INTEREST NET OF AFUDC	15,179	6,583	8,596	0
(6) PREFERRED DIVIDENDS	865	375	490	0
(7) CORPORATE TAXES	6,123	2,655	3,467	0
NON-OPERATING REVENUE:				
(8) OTHER REVENUE	(854)	(371)	(484)	0
(9) FCR DEFERRAL	3,118	1,352	1,766	0
(10) RETURN (PROFIT/LOSS)	13,083	5,674	7,409	0
(11) TOTAL > 69kV	**84,006**	**36,433**	**47,573**	**0**
(12) TOTAL TRANSMISSION	**$108,769**	**$47,173**	**$61,596**	**$0**

EXHIBIT 5
Page 3 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
DISTRIBUTION FUNCTION				
BEFORE STREETLIGHTS				
(1) SUBSTATIONS	$306	$306	$0	$0
(2) OVERHEAD LINES	38,758	25,192	0	13,565
(3) UNDERGROUND LINES	694	451	0	243
(4) LINE TRANSFORMERS	1,484	1,484	0	0
(5) METERS	948	0	0	948
(6) COMMUNICATIONS	8,882	8,882	0	0
(7) GRANTS IN LIEU OF TAXES	7,887	5,135	0	2,751
DEPRECIATION:				
(8) DISTRIBUTION	47,699	32,178	0	15,521
(9) GENERAL PROPERTY	8,334	5,622	0	2,712
(10) INTEREST NET OF AFUDC	29,605	19,277	0	10,328
(11) PREFERRED DIVIDENDS	1,686	1,098	0	588
(12) CORPORATE TAXES	11,941	7,775	0	4,166
(13) RETURN (PROFIT/LOSS)	25,518	16,615	0	8,902
STREETLIGHTS				
non-LED				
(14) MAINTENACE	5,827	5,827	0	0
(15) GRANTS IN LIEU OF TAXES	106	106	0	0
(16) DEPRECIATION	2,240	2,240	0	0
(17) INTEREST NET OF AFUDC	400	400	0	0
(18) PREFERRED DIVIDENDS	23	23	0	0
(19) CORPORATE TAXES	161	161	0	0
(20) RETURN (PROFIT/LOSS)	344	344	0	0
Subtotal	9,102	9,102	0	0
(21) OTHER REVENUE	(2,006)	(1,395)	0	(611)
(22) TOTAL DISTRIBUTION	**190,837**	**131,723**	**0**	**59,114**
RETAIL FUNCTION				
(23) QTY. ASSURANCE. & COMM.	5,402	0	0	5,402
(24) CALL CENTRE	20,979	0	0	20,979
(25) BILLING SERVICES	6,537	0	0	6,537
(26) ELECT. WIRING INSPECT. - H/O	471	0	0	471
(27) METER DATA SERVICES	832	0	0	832
(28) METER READING - FIELD	10,856	0	0	10,856
(29) ELECT. WIRING INSPECT. - FIELD	6,099	0	0	6,099
(30) PAYMENT SERVICES	1,251	0	0	1,251
(31) CREDIT SERVICES	0	0	0	0
(32) BAD DEBT EXPENSE	5,704	0	0	5,704
(33) MARKETING & SALES	2,047	0	0	2,047
(34) COGS (NET OF RETAIL SALES)	(432)	0	0	(432)
(35) GRANTS IN LIEU OF TAXES	0	0	0	0
(36) DEPRECIATION:				
(37) DISTRIBUTION	0	0	0	0
(38) GENERAL PROPERTY	0	0	0	0
(39) INTEREST NET OF AFUDC	0	0	0	0
(40) PREFERRED DIVIDENDS	0	0	0	0
(41) CORPORATE TAXES	0	0	0	0
NON-OPERATING REVENUE:				
(42) LATE PAYMENT CHARGE	(5,330)	0	0	(5,330)
(43) MISC. ELECTRIC	(2,003)	0	0	(2,003)
(44) OTHER REVENUE	(718)	0	0	(718)
(45) RETURN (PROFIT/LOSS)	0	0	0	0
(46) TOTAL RETAIL	**51,695**	**0**	**0**	**51,695**
(47) TOTAL NET EXPENSES	**$1,315,185**	**$341,346**	**$863,030**	**$110,809**

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION												
(1) FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	D-3A
(2) PURCH. POWER REG - FIXED	7,222	4,104	146	1,665	199	145	285	445	0	148	84	D-3A
(3) PURCH. POWER WIND - FIXED	6,082	3,456	123	1,402	168	122	240	375	0	125	71	D-3A
(4) OPER. & MAINT. - STEAM	29,991	17,043	608	6,916	827	602	1,185	1,847	0	614	349	D-3A
(5) OPER. & MAINT. - HYDRO/WIND/BIOMASS	6,562	3,729	133	1,513	181	132	259	404	0	134	76	D-3A
(6) OPER. & MAINT. - LM6000	116	66	2	27	3	2	5	7	0	2	1	D-3A
(7) OPER. & MAINT. - OTHER CT's	1,060	602	21	244	29	21	42	65	0	22	12	D-3A
(8) DSM AMORTIZATION	315	179	6	73	9	6	12	19	0	6	4	D-3A
(9) FCR DEFERRAL	4,135	2,350	84	954	114	83	163	255	0	85	48	P-14
(10) GRANTS IN LIEU	7,967	4,527	162	1,837	220	160	315	491	0	163	93	P-7
(11) DEPRECIATION	36,664	20,834	744	8,454	1,011	736	1,449	2,258	0	751	427	EXH 6D
(12) INTEREST NET OF AFUDC	27,569	15,666	559	6,357	760	553	1,089	1,698	0	565	321	P-14
(13) PREFERRED DIVIDENDS	1,570	892	32	362	43	32	62	97	0	32	18	P-14
(14) CORPORATE TAXES	11,120	6,319	226	2,564	307	223	439	685	0	228	129	P-14
NON-OPERATING REVENUE:												
(15) OTHER REVENUE	(1,686)	(958)	(34)	(389)	(46)	(34)	(67)	(104)	0	(35)	(20)	O-8
(16) RETURN (PROFIT/LOSS)	23,763	13,503	482	5,480	655	477	939	1,463	0	487	276	P-14
(17) INTERR. RIDER DMD ADJ.	(5,559)	0	0	0	0	0	0	(5,559)	0	0	0	DIRECT
(18) ALLOC. OF INTERR. DMD. ADJ.	5,559	3,310	118	1,343	161	117	230	93	0	119	68	D-4
(19) ELI 2P-RTP DEMAND ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(20) ALLOC. OF ELI 2P-RTP DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-4
(21) ELI 2P-RTP PRIORITY DMD ADJ.	0	0	0	0	0	0	0	0	0	0	0	DIRECT
(22) ALLOC. OF ELI 2P-RTP PRI. DMD. ADJ.	0	0	0	0	0	0	0	0	0	0	0	D-3B
(23) TOTAL GENERATION	162,450	95,623	3,413	38,803	4,640	3,376	6,650	4,539	0	3,448	1,958	
TRANSMISSION												
Transmission < 138kV												
(24) OPERATING & MAINT.	2,728	1,550	55	629	75	55	108	168	0	56	32	D-3B
(25) GRANTS IN LIEU	575	327	12	133	16	12	23	35	0	12	7	P-8A
(26) DEPRECIATION	2,930	1,665	59	676	81	59	116	180	0	60	34	EXH 6D
(27) INTEREST NET OF AFUDC	1,990	1,131	40	459	55	40	79	123	0	41	23	P-15A
(28) PREFERRED DIVIDENDS	113	64	2	26	3	2	4	7	0	2	1	P-15A
(29) CORPORATE TAXES	802	456	16	185	22	16	32	49	0	16	9	P-15A
NON-OPERATING REVENUE:												
(30) OTHER REVENUE	(113)	(64)	(2)	(26)	(3)	(2)	(4)	(7)	0	(2)	(1)	O-9A
(32) RETURN (PROFIT/LOSS)	1,715	974	35	395	47	34	68	106	0	35	20	P-15A
(33) TOTAL < 138kV	$10,740	$6,103	$218	$2,476	$296	$215	$424	$661	$0	$220	$125	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
Transmission > 69kV												
(1) OPERATING & MAINT.	8,672	4,928	176	2,000	239	174	343	534	0	178	101	D-3A
(2) GRANTS IN LIEU	1,902	1,081	39	439	52	38	75	117	0	39	22	P-8B
(3) DEPRECIATION	9,589	5,449	194	2,211	264	192	379	591	0	196	112	EXH 6D
(4) INTEREST NET OF AFUDC	6,583	3,741	134	1,518	182	132	260	405	0	135	77	P-15B
(5) PREFERRED DIVIDENDS	375	213	8	86	10	8	15	23	0	8	4	P-15B
(6) CORPORATE TAXES	2,655	1,509	54	612	73	53	105	164	0	54	31	P-15B
NON-OPERATING REVENUE:												
(7) FCR DEFERRAL	1,352	768	27	312	37	27	53	83	0	28	16	P-15B
(8) OTHER REVENUE	(371)	(211)	(8)	(85)	(10)	(7)	(15)	(23)	0	(8)	(4)	O-9B
(9) RETURN (PROFIT/LOSS)	5,674	3,224	115	1,308	156	114	224	349	0	116	66	P-15B
(10) TOTAL > 69kV	36,433	20,704	739	8,401	1,005	731	1,440	2,244	0	746	424	
(11) TOTAL TRANSMISSION	47,173	26,806	957	10,878	1,301	947	1,864	2,905	0	966	549	
DISTRIBUTION												
Non SL												
(12) OPERATING & MAINT.	36,315	21,453	1,210	9,939	1,038	965	1,249	3	0	0	458	EXH 6A
(13) GRANTS IN LIEU	5,135	3,126	176	1,426	90	137	110	4	0	0	67	P-9
(14) DEPRECIATION	37,800	23,006	1,297	10,496	664	1,006	807	32	0	2	491	EXH 6D
(15) INTEREST NET OF AFUDC	19,277	11,668	658	5,326	343	510	417	16	0	1	338	P-16
(16) PREFERRED DIVIDENDS	1,098	665	37	303	20	29	24	1	0	0	19	P-16
(17) CORPORATE TAXES	7,775	4,706	265	2,148	138	206	168	6	0	0	136	P-16
NON-OPERATING REVENUE:												
(18) OTHER REVENUE	(1,395)	(776)	(44)	(356)	(28)	(34)	(33)	(1)	0	(0)	(123)	O-10
(19) RETURN (PROFIT/LOSS)	16,615	10,057	567	4,590	296	440	359	14	0	1	292	P-16
SL												
non-LED												
(20) OPERATING & MAINT.	5,827	0	0	0	0	0	0	0	0	0	5,827	EXH 6A
(21) GRANTS IN LIEU OF TAXES	106	0	0	0	0	0	0	0	0	0	106	P-9A
(22) Depreciation	2,240	0	0	0	0	0	0	0	0	0	2,240	EXH 6D
(23) INTEREST NET OF AFUDC	400	0	0	0	0	0	0	0	0	0	400	P-16B
(23) PREFERRED DIVIDENDS	23	0	0	0	0	0	0	0	0	0	23	P-16B
(25) CORPORATE TAXES	161	0	0	0	0	0	0	0	0	0	161	P-16B
(26) OTHER REVENUE												
(27) RETURN (PROFIT/LOSS)	344	0	0	0	0	0	0	0	0	0	344	P-16B
Subtotal	9,102	0	0	0	0	0	0	0	0	0	9,102	
(28) TOTAL DISTRIBUTION	131,723	73,904	4,167	33,872	2,561	3,258	3,101	76	0	5	10,779	
(29) TOTAL DEMAND	$341,346	$196,333	$8,537	$83,553	$8,502	$7,581	$11,615	$7,520	$0	$4,419	$13,286	

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
ENERGY CLASSIFICATION												
GENERATION												
(1) FUEL	$365,712	$170,740	$9,160	$94,569	$15,013	$10,062	$19,732	$35,157	$0	$7,343	$3,937	DIRECT
(2) PURCH. POWER REG - FIXED	15,003	6,993	375	3,882	617	413	812	1,447	0	301	162	E-1A
(3) PURCH. POWER REG - VAR.	27,164	12,661	679	7,029	1,118	749	1,470	2,619	0	545	293	E-1A
(4) PURCH. POWER WIND - FIXED	14,191	6,615	355	3,672	584	391	768	1,368	0	285	153	E-1A
(5) PURCH. POWER WIND - VAR.	47,303	22,049	1,183	12,241	1,946	1,304	2,560	4,561	0	950	510	E-1A
(6) OPER. & MAINT. - STEAM	79,881	37,234	1,998	20,671	3,287	2,201	4,323	7,703	0	1,604	861	E-1A
(7) OPER. & MAINT. - HYDRO/WIND/BIOMASS	17,478	8,147	437	4,523	719	482	946	1,685	0	351	188	E-1A
(8) OPER. & MAINT. - LM6000	310	145	8	80	13	9	17	30	0	6	3	E-1A
(9) OPER. & MAINT. - OTHER CT's	202	94	5	52	8	6	11	19	0	4	2	E-1A
(10) DSM AMORTIZATION	654	305	16	169	27	18	35	63	0	13	7	E-1A
(11) FCR DEFERRAL	9,247	4,310	231	2,393	380	255	500	892	0	186	100	P-17
(12) GRANTS IN LIEU	16,550	7,714	414	4,283	681	456	896	1,596	0	332	178	P-10
(13) DEPRECIATION	75,646	35,260	1,892	19,575	3,112	2,085	4,094	7,295	0	1,519	815	EXH 6D
(14) INTEREST NET OF AFUDC	61,647	28,734	1,542	15,953	2,536	1,699	3,336	5,945	0	1,237	664	P-17
(15) PREFERRED DIVIDENDS	3,512	1,637	88	909	144	97	190	339	0	70	38	P-17
(16) CORPORATE TAXES	24,865	11,590	622	6,434	1,023	685	1,346	2,398	0	499	268	P-17
NON-OPERATING REVENUE:												
(17) EXPORT SALES	(1,943)	(906)	(49)	(503)	(80)	(54)	(105)	(187)	0	(39)	(21)	EXH 7
(18) OTHER REVENUE	(9,122)	(4,255)	(228)	(2,360)	(375)	(251)	(493)	(878)	0	(183)	(98)	O-11
(19) RETURN (PROFIT/LOSS)	53,135	24,767	1,329	13,750	2,186	1,464	2,876	5,124	0	1,067	573	P-17
(20) TOTAL GENERATION	801,435	373,832	20,057	207,325	32,940	22,070	43,313	77,175	0	16,089	8,633	
TRANSMISSION												
Transmission < 138kV												
(21) OPERATING & MAINT.	3,562	1,660	89	922	147	98	193	343	0	72	38	E-1B
(22) GRANTS IN LIEU	751	350	19	194	31	21	41	72	0	15	8	P-11A
(23) DEPRECIATION	3,825	1,783	96	990	157	105	207	369	0	77	41	EXH 6D
(24) INTEREST NET	2,598	1,211	65	672	107	72	141	251	0	52	28	P-18A
(25) PREFERRED DIVIDENDS	148	69	4	38	6	4	8	14	0	3	2	P-18A
(26) CORPORATE TAXES	1,048	488	26	271	43	29	57	101	0	21	11	P-18A
NON-OPERATING REVENUE:												
(27) OTHER REVENUE	(148)	(69)	(4)	(38)	(6)	(4)	(8)	(14)	0	(3)	(2)	O-12A
(28) RETURN (PROFIT/LOSS)	2,239	1,044	56	579	92	62	121	216	0	45	24	P-18A
(29) TOTAL < 138kV	14,023	6,536	351	3,629	577	386	759	1,352	0	281	151	
Transmission > 69kV												
(30) OPERATING & MAINT.	11,324	5,278	283	2,930	466	312	613	1,092	0	227	122	E-1A
(31) GRANTS IN LIEU	2,484	1,158	62	643	102	68	134	240	0	50	27	P-11B
(32) DEPRECIATION	12,521	5,836	313	3,240	515	345	678	1,207	0	251	135	EXH 6D
(33) INTEREST NET	8,596	4,007	215	2,224	354	237	465	829	0	173	93	P-18B
(34) PREFERRED DIVIDENDS	490	228	12	127	20	13	27	47	0	10	5	P-18B
(35) CORPORATE TAXES	3,467	1,616	87	897	143	96	188	334	0	70	37	P-18B
NON-OPERATING REVENUE:												
(36) FCR DEFERRAL	1,766	823	44	457	73	49	96	170	0	35	19	P-18B
(37) OTHER REVENUE	(484)	(226)	(12)	(125)	(20)	(13)	(26)	(47)	0	(10)	(5)	O-12B
(38) RETURN (PROFIT/LOSS)	7,409	3,454	185	1,917	305	204	401	714	0	149	80	P-18B
(39) TOTAL > 69kV	47,573	22,174	1,190	12,311	1,957	1,311	2,575	4,587	0	955	513	
(40) TOTAL TRANSMISSION	61,596	28,711	1,541	15,939	2,534	1,697	3,333	5,940	0	1,236	664	
(41) TOTAL ENERGY	**$863,030**	**$402,543**	**$21,598**	**$223,264**	**$35,474**	**$23,767**	**$46,647**	**$83,114**	**$0**	**$17,326**	**$9,297**	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUST. CLASSIFICATION												
DISTRIBUTION												
(1) OPERATING & MAINT.	$14,756	$13,323	$703	$377	$1	$78	$10	$3	$0	$0	$263	EXH 6A
(2) GRANTS IN LIEU	2,751	2,419	128	141	0	29	3	1	0	0	31	P-12
(3) DEPRECIATION	18,232	16,028	846	935	2	192	18	5	0	1	206	EXH 6D
(4) INTEREST NET OF AFUDC	10,328	9,107	480	500	1	103	10	3	0	0	124	P-19
(5) PREFERRED DIVIDENDS	588	519	27	28	0	6	1	0	0	0	7	P-19
(6) CORPORATE TAXES	4,166	3,673	194	202	0	41	4	1	0	0	50	P-19
NON-OPERATING REVENUE:												
(8) OTHER REVENUE	(611)	(541)	(29)	(26)	(0)	(5)	(1)	(0)	0	(0)	(8)	O-13
(9) RETURN (PROFIT/LOSS)	8,902	7,849	414	431	1	89	8	3	0	0	107	P-19
(10) TOTAL DISTRIBUTION	59,114	52,377	2,763	2,588	5	532	51	16	0	2	781	
RETAIL												
(11) METER READING & ELECTRIC INSPECT.	16,955	14,370	767	1,242	37	243	98	62	0	16	119	EXH 6A
(12) CUST. SERV. - H/O	5,402	4,878	265	125	0	24	2	0	0	0	106	C-7
(13) CALL CENTRE	20,979	16,888	891	2,097	70	410	183	118	0	30	291	C-3
(14) BILLING SERVICES	6,537	5,904	321	151	0	30	3	0	0	0	128	C-3
(15) ELECT. WIRING INSP. - H/O	471	425	23	11	0	2	0	0	0	0	9	C-7
(16) METER DATA SERVICES	832	45	44	104	134	104	104	194	0	104	0	O-16
(17) PAYMENT SERVICES	1,251	1,129	61	29	0	6	1	0	0	0	24	C-7
(18) CREDIT SERVICES	5,704	4,791	85	749	0	78	0	0	0	0	0	EXH 6C
(19) MARKETING & SALES	2,047	928	73	171	37	135	264	402	0	37	0	O-15
(20) COGS (NET OF SALES)	(432)	(390)	(21)	(10)	(0)	(2)	(0)	(0)	0	(0)	(8)	C-7
(22) GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	N/A
(23) DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	N/A
(24) INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	N/A
(25) PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	N/A
(26) CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	N/A
NON-OPERATING REVENUE:												
(28) LATE PAYMENT CHARGE	(5,330)	(4,133)	(126)	(921)	0	(72)	(62)	0	0	0	(17)	EXH 7
(29) MISC. ELECTRIC	(2,003)	(1,859)	(113)	(13)	0	0	0	0	0	0	(17)	EXH 7
(30) OTHER REVENUE	(718)	(580)	(29)	(57)	(4)	(13)	(9)	(12)	0	(3)	(9)	O-14
(31) RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	N/A
(32) TOTAL RETAIL	51,695	42,398	2,243	3,677	275	945	584	765	0	183	625	
(33) TOTAL CUSTOMER	**110,809**	**94,774**	**5,006**	**6,265**	**280**	**1,476**	**635**	**781**	**0**	**185**	**1,407**	
(34) TOTAL NET EXPENSES	**$1,315,185**	**$693,650**	**$35,141**	**$313,082**	**$44,256**	**$32,825**	**$58,897**	**$91,415**	**$0**	**$21,929**	**$23,989**	
TOTAL REVENUE	**$1,315,185**	**$689,768**	**$36,687**	**$321,964**	**$43,662**	**$33,495**	**$57,293**	**$86,844**	**$0**	**$21,483**	**$23,989**	

EXHIBIT 6A

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTRIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$306	$174	$10	$82	$11	$8	$14	$3	$0	$0	$4	P-5
(2) OVERHEAD LINES	25,192	14,944	843	6,909	685	670	823	0	0	0	319	P-1
(3) UNDERGROUND LINES	451	267	15	124	12	12	15	0	0	0	6	P-1
(4) LINE TRANSFORMERS	1,484	948	53	422	0	40	0	0	0	0	20	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	8,882	5,119	289	2,402	330	236	397	0	0	0	109	D-2
(7) STREET LIGHTING	5,827	0	0	0	0	0	0	0	0	0	5,827	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	42,142	21,453	1,210	9,939	1,038	965	1,249	3	0	0	6,284	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(11) OVERHEAD LINES	13,565	12,290	648	305	0	60	3	0	0	0	258	P-2
(12) UNDERGROUND LINES	243	220	12	5	0	1	0	0	0	0	5	P-2
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	--
(14) METERS	948	813	43	66	1	17	7	2	0	0	0	P-6
(15) COMMUNICATIONS	0	0	0	0	0	0	0	0	0	0	0	--
(16) STREET LIGHTING	0	0	0	0	0	0	0	0	0	0	0	--
(17) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(18) TOTAL CUSTOMER	14,756	13,323	703	377	1	78	10	3	0	0	263	
RETAIL												
(19) METERS	0	0	0	0	0	0	0	0	0	0	0	N/A
(20) CUSTOMER SERVICE	16,955	14,370	767	1,242	37	243	98	62	0	16	119	EXHIBIT 6B
(20) TOTAL RETAIL	16,955	14,370	767	1,242	37	243	98	62	0	16	119	
SUMMARY												
(21) SUBSTATIONS	306	174	10	82	11	8	14	3	0	0	4	P-3
(22) OVERHEAD LINES	38,758	27,235	1,491	7,215	685	729	826	0	0	0	577	P-1
(23) UNDERGROUND LINES	694	487	27	129	12	13	15	0	0	0	10	P-1
(24) LINE TRANSFORMERS	1,484	948	53	422	0	40	0	0	0	0	20	D-1
(25) METERS	17,904	15,183	810	1,307	38	260	105	65	0	16	119	P-6
(26) COMMUNICATIONS	8,882	5,119	289	2,402	330	236	397	0	0	0	109	D-2
(27) STREET LIGHTING	5,827	0	0	0	0	0	0	0	0	0	5,827	DIRECT
(28) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	EXHIBIT 6B
(29) TOTAL DISTRIBUTION	$73,853	$49,146	$2,680	$11,557	$1,076	$1,286	$1,357	$69	$0	$16	$6,667	

EXHIBIT 6B

NOVA SCOTIA POWER INC.

ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) METER READING	(4) WIRING INSPECTION
(1) DOMESTIC	$14,370	$8,862	$5,508
(2) SMALL GENERAL	767	468	300
(3) GENERAL	1,242	1,100	141
(4) GENERAL LARGE	37	37	0
(5) SMALL INDUSTRIAL	243	215	28
(6) MEDIUM INDUSTRIAL	98	96	2
(7) LARGE INDUSTRIAL	62	62	0
(8) ELI 2P-RTP	0	0	0
(9) MUNICIPAL	16	16	0
(10) UNMETERED	119	0	119
(11) TOTAL	$16,955	$10,856	$6,099
ALLOCATION FACTOR		C-6	C-7

EXHIBIT 6C

NOVA SCOTIA POWER INC.

ALLOCATION OF CREDIT SERVICES EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2014

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	---------------BAD DEBT EXPENSE		-----------------	CREDIT	
	DIRECT	TO BE ALLOC.	TOTAL	SERVICES	TOTAL
(1) DOMESTIC	$4,791	$0	$4,791	$0	$4,791
(2) SMALL GENERAL	0	85	85	0	85
(3) GENERAL	0	749	749	0	749
(4) GENERAL LARGE	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	78	78	0	78
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) ELI 2P-RTP	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	0	0
(11) TOTAL	$4,791	$913	$5,704	$0	$5,704
ALLOCATION FACTOR	DIRECT	R-1		C-7	

DOMESTIC - 84 %

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND CLASSIFICATION												
GENERATION FUNCTION												
(1) STEAM PRODUCTION	$21,571	$12,258	$438	$4,974	$595	$433	$852	$1,328	$0	$442	$251	D-3A
(2) HYDRO PRODUCTION	4,313	2,451	87	995	119	87	170	266	0	88	50	D-3A
(3) WIND PRODUCTION	373	212	8	86	10	7	15	23	0	8	4	D-3A
(4) LM6000 PRODUCTION	902	512	18	208	25	18	36	56	0	18	10	D-3A
(5) GAS TURBINE PROD. - OTHER	1,199	681	24	276	33	24	47	74	0	25	14	D-3A
(6) GENERAL PROPERTY	8,306	4,720	168	1,915	229	167	328	512	0	170	97	P-7
(7) TOTAL GENERATION FUNCTION	36,664	20,834	744	8,454	1,011	736	1,449	2,258	0	751	427	
TRANSMISSION FUNCTION												
(8) TRANSMISSION PLANT < 138kV	2,325	1,321	47	536	64	47	92	143	0	48	27	D-3B
(9) GENERAL PROPERTY	604	343	12	139	17	12	24	37	0	12	7	P-8A
TOTAL < 138kV	2,930	1,665	59	676	81	59	116	180	0	60	34	
(10) TRANSMISSION PLANT > 69kV	7,611	4,325	154	1,755	210	153	301	469	0	156	89	D-3A
(11) GENERAL PROPERTY	1,978	1,124	40	456	55	40	78	122	0	41	23	P-8B
(12) TOTAL > 69kV	9,589	5,449	194	2,211	264	192	379	591	0	196	112	
(13) TOTAL TRANSMISSION FUNCTION	12,519	7,114	254	2,887	345	251	495	771	0	256	146	
DISTRIBUTION FUNCTION												
(14) DISTRIBUTION PLANT - Non Streetlig	32,178	19,584	1,104	8,935	565	856	687	27	0	2	418	P-9
(14) DISTRIBUTION PLANT - Streetlight	2,240	0	0	0	0	0	0	0	0	0	2,240	Direct
(15) GENERAL PROPERTY	5,622	3,422	193	1,561	99	150	120	5	0	0	73	P-9
(16) TOTAL DISTRIBUTION FUNCTION	40,041	23,006	1,297	10,496	664	1,006	807	32	0	2	2,731	
(17) TOTAL DEMAND	**89,223**	**50,954**	**2,295**	**21,837**	**2,020**	**1,992**	**2,751**	**3,061**	**0**	**1,010**	**3,303**	
ENERGY CLASSIFICATION												
GENERATION FUNCTION												
(18) STEAM PRODUCTION	43,650	20,346	1,092	11,296	1,796	1,203	2,362	4,209	0	876	470	E-1A
(19) HYDRO PRODUCTION	5,770	2,690	144	1,493	237	159	312	556	0	116	62	E-1A
(20) WIND PRODUCTION	7,794	3,633	195	2,017	321	215	422	752	0	156	84	E-1A
(21) LM6000 PRODUCTION	1,177	549	29	305	48	32	64	114	0	24	13	E-1A
(22) GAS TURBINE PROD. - OTHER	0	0	0	0	0	0	0	0	0	0	0	E-1A
(23) GENERAL PROPERTY	17,254	8,042	432	4,465	710	475	934	1,664	0	346	186	P-10
(24) TOTAL GENERATION FUNCTION	75,646	35,260	1,892	19,575	3,112	2,085	4,094	7,295	0	1,519	815	
TRANSMISSION FUNCTION												
(25) TRANSMISSION PLANT < 138kV	3,036	1,415	76	786	125	84	164	293	0	61	33	E-1B
(26) GENERAL PROPERTY	789	368	20	204	32	22	43	76	0	16	9	P-11A
(27) TOTAL < 138kV	3,825	1,783	96	990	157	105	207	369	0	77	41	
(28) TRANSMISSION PLANT > 69kV	9,938	4,632	249	2,572	409	274	538	958	0	199	107	E-1A
(29) GENERAL PROPERTY	2,583	1,204	65	668	106	71	140	249	0	52	28	P-11B
(30) TOTAL > 69kV	12,521	5,836	313	3,240	515	345	678	1,207	0	251	135	
(31) TOTAL TRANSMISSION FUNCTION	16,347	7,619	409	4,230	673	450	885	1,576	0	328	176	
(32) TOTAL ENERGY	**91,993**	**42,879**	**2,301**	**23,806**	**3,785**	**2,535**	**4,979**	**8,871**	**0**	**1,847**	**991**	

NOVA SCOTIA POWER INC.
ALLOCATION OF DEPRECIATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
CUSTOMER CLASSIFICATION												
DISTRIBUTION FUNCTION												
(1) DISTRIBUTION PLANT	15,521	13,644	720	796	1	163	15	5	0	0	176	P-12
(2) GENERAL PROPERTY	2,712	2,384	126	139	0	29	3	1	0	0	31	P-12
(3) TOTAL DISTRIBUTION FUNCTION	18,232	16,028	846	935	2	192	18	5	0	1	206	
RETAIL FUNCTION												
(4) DISTRIBUTION PLANT	0	0	0	0	0	0	0	0	0	0	0	P-13
(5) GENERAL PROPERTY	0	0	0	0	0	0	0	0	0	0	0	P-13
(6) TOTAL RETAIL FUNCTION	0	0	0	0	0	0	0	0	0	0	0	
(7) TOTAL CUSTOMER	**18,232**	**16,028**	**846**	**935**	**2**	**192**	**18**	**5**	**0**	**1**	**206**	
(8) TOTAL DEPRECIATION	**$199,449**	**$109,862**	**$5,441**	**$46,578**	**$5,806**	**$4,720**	**$7,747**	**$11,937**	**$0**	**$2,857**	**$4,501**	

EXHIBIT 7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) REVENUE	(2) EXPORT SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE
ELECTRIC REVENUE				
(1) DOMESTIC	$689,768	$906	$4,133	$1,859
(2) SMALL GENERAL	36,687	49	126	113
(3) GENERAL	321,964	503	921	13
(4) LARGE GENERAL	43,662	80	0	0
(5) SMALL INDUSTRIAL	33,495	54	72	0
(6) MEDIUM INDUSTRIAL	57,293	105	62	0
(7) LARGE INDUSTRIAL	86,844	187	0	0
(8) ELI 2P-RTP	0	0	0	0
(9) MUNICIPAL	21,483	39	0	0
(10) UNMETERED	23,989	21	17	17
(11) SUB-TOTAL	1,315,185	$1,943	$5,330	$2,003
(12) EXPORT SALES	1,943			
(13) TOTAL ELECTRIC REVENUE	1,317,128			
NON-RATE REVENUE				
(14) LATE PAYMENT CHARGE	5,330			
(15) MISC. CUST. REVENUE	2,003			
(16) OTHER	14,648			
(17) TOTAL	21,980			
DIRECT REVENUE				
(18) BOWATER BASIC BLOCK	9,782			
(19) BOWATER ADDITIONAL ENERGY	10,241			
(20) GEN.REPL./LOAD FOLL	1,072			
(21) LRT	21,856			
(22) REAL TIME PRICING	0			
(23) LED	4,341			
(24) TOTAL	47,292			
(25) TRANSFER FROM (TO) RETAINED EARNINGS	(124,745)			
(26) TOTAL REVENUE	**$1,261,656**			
ALLOCATION FACTOR		E-1	DIRECT	DIRECT

EXHIBIT 8A

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,719,617	1,098,733	61,954	489,526	0	45,965	0	0	0	0	23,440	
(2) % RESPONSIBILITY	100.00%	63.89%	3.60%	28.47%	0.00%	2.67%	0.00%	0.00%	0.00%	0.00%	1.36%	D-1
(3) N.C. DEMAND PRI.	2,009,264	1,158,064	65,299	543,365	74,713	53,306	89,812	0	0	0	24,706	
(4) % RESPONSIBILITY	100.00%	57.64%	3.25%	27.04%	3.72%	2.65%	4.47%	0.00%	0.00%	0.00%	1.23%	D-2
(5) 3 CP DEMAND	5,922,996	3,365,786	120,127	1,365,814	163,320	118,848	234,070	364,769	0	121,351	68,910	
(6) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	D-3A
(7) 3 CP DEMAND - LESS ELIIR - 2	5,922,996	3,365,786	120,127	1,365,814	163,320	118,848	234,070	364,769	0	121,351	68,910	
(8) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	D-3B
(9) 3 CP DMD. - LESS INT. & ELIIR - 2	5,653,248	3,365,786	120,127	1,365,814	163,320	118,848	234,070	95,022	0	121,351	68,910	
(10) % RESPONSIBILITY	100.00%	59.54%	2.12%	24.16%	2.89%	2.10%	4.14%	1.68%	0.00%	2.15%	1.22%	D-4
(11) MW.h GEN. & PURCH.	9,986,292	4,654,738	249,760	2,584,209	410,860	275,205	540,444	962,980	0	200,464	107,631	
(12) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	E-1A
(13) MW.h GEN. & PURCH. Less EHV	9,986,292	4,654,738	249,760	2,584,209	410,860	275,205	540,444	962,980	0	200,464	107,631	
(14) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	E-1B
(15) AVERAGE CUSTOMERS	504,531	456,991	24,109	11,349	19	2,221	198	32	0	8	9,604	
(16) % RESPONSIBILITY	100.00%	90.58%	4.78%	2.25%	0.00%	0.44%	0.04%	0.01%	0.00%	0.00%	1.90%	C-1
(17) SECONDARY CUSTOMERS	494,670	456,991	24,109	11,349	0	2,221	0	0	0	0	0	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(19) WEIGHTED TOTAL	548,950	456,991	24,109	56,745	0	11,105	0	0	0	0	0	
(20) % RESPONSIBILITY	100.00%	83.25%	4.39%	10.34%	0.00%	2.02%	0.00%	0.00%	0.00%	0.00%	0.00%	C-2
(21) AVERAGE CUSTOMERS	504,531	456,991	24,109	11,349	19	2,221	198	32	0	8	9,604	
(22) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(23) WEIGHTED TOTAL	567,675	456,991	24,109	56,745	1,900	11,105	4,950	3,200	0	800	7,875	
(24) % RESPONSIBILITY	100.00%	80.50%	4.25%	10.00%	0.33%	1.96%	0.87%	0.56%	0.00%	0.14%	1.39%	C-3
(25) CUSTOMER SECONDARY	504,274	456,991	24,109	11,349	0	2,221	0	0	0	0	9,604	
(26) % RESPONSIBILITY	100.00%	90.62%	4.78%	2.25%	0.00%	0.44%	0.00%	0.00%	0.00%	0.00%	1.90%	C-4
(27) CUSTOMER PRIMARY	504,531	456,991	24,109	11,349	19	2,221	198	32	0	8	9,604	
(28) % RESPONSIBILITY	100.00%	90.58%	4.78%	2.25%	0.00%	0.44%	0.04%	0.01%	0.00%	0.00%	1.90%	C-5
(29) AVG. CUST. - LESS UNMETERED	494,927	456,991	24,109	11,349	19	2,221	198	32	0	8	0	
(30) WEIGHTING FACTOR		1.00	1.00	5.00	100.00	5.00	25.00	100.00	100.00	100.00	0.82	
(31) WEIGHTED TOTAL	559,800	456,991	24,109	56,745	1,900	11,105	4,950	3,200	0	800	0	
(32) % RESPONSIBILITY	100.00%	81.63%	4.31%	10.14%	0.34%	1.98%	0.88%	0.57%	0.00%	0.14%	0.00%	C-6
(33) AVERAGE CUSTOMERS ADJ SEASONAL	490,561	443,021	24,109	11,349	19	2,221	198	32	0	8	9,604	
(34) % RESPONSIBILITY	100.00%	90.31%	4.91%	2.31%	0.00%	0.45%	0.04%	0.01%	0.00%	0.00%	1.96%	C-7

EXHIBIT 8B
PAGE 1 OF 2

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE&WIRE INV.-DMD.	$197,824	$117,351	$6,617	$54,256	$5,375	$5,259	$6,462	$0	$0	$0	$2,504	
(2) % RESPONSIBILITY	100.00%	59.32%	3.34%	27.43%	2.72%	2.66%	3.27%	0.00%	0.00%	0.00%	1.27%	P-1
(3) POLE&WIRE INV.-CUST.	$106,520	$96,508	$5,091	$2,397	$2	$469	$21	$3	$0	$1	$2,028	
(4) % RESPONSIBILITY	100.00%	90.60%	4.78%	2.25%	0.00%	0.44%	0.02%	0.00%	0.00%	0.00%	1.90%	P-2
(5) SUB.,POLE&WIRE-DMD.	$227,936	$134,428	$7,580	$62,293	$6,477	$6,045	$7,884	$339	$0	$22	$2,868	
(6) % RESPONSIBILITY	100.00%	58.98%	3.33%	27.33%	2.84%	2.65%	3.46%	0.15%	0.00%	0.01%	1.26%	P-3
(7) SUB.,POLE&WIRE-CUST.	$106,520	$96,508	$5,091	$2,397	$2	$469	$21	$3	$0	$1	$2,028	
(8) % RESPONSIBILITY	100.00%	90.60%	4.78%	2.25%	0.00%	0.44%	0.02%	0.00%	0.00%	0.00%	1.90%	P-4
(9) SUBST. INVEST.-DMD.	$30,113	$17,077	$963	$8,037	$1,102	$786	$1,422	$339	$0	$22	$364	
(10) % RESPONSIBILITY	100.00%	56.71%	3.20%	26.69%	3.66%	2.61%	4.72%	1.13%	0.00%	0.07%	1.21%	P-5
(11) METER INVEST.-CUST	$25,072	$21,489	$1,134	$1,742	$17	$445	$180	$59	$0	$6	$0	
(12) % RESPONSIBILITY	100.00%	85.71%	4.52%	6.95%	0.07%	1.78%	0.72%	0.24%	0.00%	0.02%	0.00%	P-6
(13) DEMAND - GEN. PLANT	$650,206	$369,484	$13,187	$149,934	$17,929	$13,047	$25,695	$40,043	$0	$13,322	$7,565	
(14) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-7
(15) DEMAND - TRANS. PLT. < 138kV	$47,308	$26,883	$959	$10,909	$1,304	$949	$1,870	$2,913	$0	$969	$550	
(16) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-8A
(17) DEMAND - TRANS. PLT. > 69kV	$154,863	$88,002	$3,141	$35,711	$4,270	$3,107	$6,120	$9,537	$0	$3,173	$1,802	
(18) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-8B
(19) DEMAND - DIST. PLANT	$429,856	$261,619	$14,752	$119,356	$7,548	$11,436	$9,178	$363	$0	$24	$5,581	
(20) % RESPONSIBILITY	100.00%	60.86%	3.43%	27.77%	1.76%	2.66%	2.14%	0.08%	0.00%	0.01%	1.30%	P-9
(19) DEMAND - DIST. PLANT	$10,251	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,251	
(20) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-9A
(23) ENERGY - GEN. PLANT	$1,350,698	$629,578	$33,781	$349,528	$55,571	$37,223	$73,098	$130,248	$0	$27,114	$14,558	
(24) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-10
(25) ENERGY - TRANS. PLT. < 138kV	$61,772	$28,793	$1,545	$15,985	$2,541	$1,702	$3,343	$5,957	$0	$1,240	$666	
(26) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-11A
(27) ENERGY - TRANS. PLT. > 69kV	$202,211	$94,253	$5,057	$52,327	$8,319	$5,573	$10,943	$19,499	$0	$4,059	$2,179	
(28) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-11B
(29) CUSTOMER - DIST. PLANT	$212,277	$186,613	$9,845	$10,887	$20	$2,235	$205	$63	$0	$7	$2,403	
(30) % RESPONSIBILITY	100.00%	87.91%	4.64%	5.13%	0.01%	1.05%	0.10%	0.03%	0.00%	0.00%	1.13%	P-12
(31) CUSTOMER - RETAIL PLANT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(32) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-13
(33) TOT.RATE BASE-DMD. (GEN.)	$707,163	$401,850	$14,342	$163,068	$19,499	$14,190	$27,946	$43,551	$0	$14,488	$8,227	
(34) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-14
(35) TOT.RATE BASE-DMD. (TRANS. < 138kV)	$51,034	$29,001	$1,035	$11,768	$1,407	$1,024	$2,017	$3,143	$0	$1,046	$594	
(36) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-15A
(37) TOT.RATE BASE-DMD. (TRANS. > 69kV)	$168,865	$95,959	$3,425	$38,939	$4,656	$3,388	$6,673	$10,400	$0	$3,460	$1,965	
(38) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	P-15B
(39) TOT.RATE BASE-DMD. (DIST.) Non Streetli	$494,466	$299,291	$16,876	$136,603	$8,800	$13,093	$10,695	$405	$0	$26	$8,678	
(40) % RESPONSIBILITY	100.00%	60.53%	3.41%	27.63%	1.78%	2.65%	2.16%	0.08%	0.00%	0.01%	1.75%	P-16
(41) TOT.RATE BASE-DMD. (DIST.) Streetlight	$10,251	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,251	
(42) % RESPONSIBILITY	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	P-16B
(43) TOT.RATE BASE-ENG. (GEN.)	$1,581,279	$737,054	$39,548	$409,197	$65,058	$43,577	$85,577	$152,483	$0	$31,743	$17,043	
(44) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-17
(45) TOT.RATE BASE-ENG. (TRANS. < 138kV)	$66,638	$31,061	$1,667	$17,244	$2,742	$1,836	$3,606	$6,426	$0	$1,338	$718	
(46) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-18A
(47) TOT.RATE BASE-ENG. (TRANS. > 69kV)	$220,494	$102,775	$5,515	$57,058	$9,072	$6,076	$11,933	$21,262	$0	$4,426	$2,376	
(48) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	P-18B

EXHIBIT 8B
PAGE 2 OF 2

NOVA SCOTIA POWER INC.
DEVELOPMENT OF ALLOCATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) TOT. RATE BASE-CUST. (DIST.)	$264,927	$233,598	$12,324	$12,828	$24	$2,634	$246	$75	$0	$8	$3,191	
(2) % RESPONSIBILITY	100.00%	88.17%	4.65%	4.84%	0.01%	0.99%	0.09%	0.03%	0.00%	0.00%	1.20%	P-19
(3) TOT.RATE BASE-CUST.(RETAIL)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(4) % RESPONSIBILITY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	P-20
(5) DMD. - OPER.EXP. - GEN.	$29,991	$17,043	$608	$6,916	$827	$602	$1,185	$1,847	$0	$614	$349	
(6) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-1
(7) DMD. - OPER.EXP. - TRANS. < 138kV	$2,728	$1,550	$55	$629	$75	$55	$108	$168	$0	$56	$32	
(8) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-2A
(9) DMD. - OPER.EXP. - TRANS. > 69kV	$8,672	$4,928	$176	$2,000	$239	$174	$343	$534	$0	$178	$101	
(10) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-2B
(11) DMD. - OPER.EXP. - DIST.	$42,142	$21,453	$1,210	$9,939	$1,038	$965	$1,249	$3	$0	$0	$6,284	
(12) % RESPONSIBILITY	100.00%	50.91%	2.87%	23.58%	2.46%	2.29%	2.96%	0.01%	0.00%	0.00%	14.91%	O-3
(13) ENG. - OPER.EXP. - GEN.	$79,881	$37,234	$1,998	$20,671	$3,287	$2,201	$4,323	$7,703	$0	$1,604	$861	
(14) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-4
(15) ENG. - OPER.EXP. - TRANS. < 138kV	$3,562	$1,660	$89	$922	$147	$98	$193	$343	$0	$72	$38	
(16) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-5A
(17) ENG. - OPER.EXP. - TRANS. > 69kV	$11,324	$5,278	$283	$2,930	$466	$312	$613	$1,092	$0	$227	$122	
(18) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-5B
(19) CUST. - OPER. EXP. - DIST.	$14,756	$13,323	$703	$377	$1	$78	$10	$3	$0	$0	$263	
(20) % RESPONSIBILITY	100.00%	90.29%	4.76%	2.55%	0.01%	0.53%	0.06%	0.02%	0.00%	0.00%	1.78%	O-6
(21) CUST. - OPER. EXP. - RETAIL	$41,175	$34,061	$1,692	$3,266	$205	$654	$292	$313	$0	$133	$558	
(22) % RESPONSIBILITY	100.00%	82.72%	4.11%	7.93%	0.50%	1.59%	0.71%	0.76%	0.00%	0.32%	1.36%	O-7
(23) TOT. EXP. - DMD. (GEN.)	$140,374	$79,768	$2,847	$32,369	$3,871	$2,817	$5,547	$8,645	$0	$2,876	$1,633	
(24) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-8
(25) TOT. EXP. - DMD. (TRANS. < 138kV)	$9,138	$5,193	$185	$2,107	$252	$183	$361	$563	$0	$187	$106	
(26) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-9A
(27) TOT. EXP. - DMD. (TRANS. > 69kV)	$29,778	$16,921	$604	$6,867	$821	$597	$1,177	$1,834	$0	$610	$346	
(28) % RESPONSIBILITY	100.00%	56.83%	2.03%	23.06%	2.76%	2.01%	3.95%	6.16%	0.00%	2.05%	1.16%	O-9B
(29) TOT. EXP. - DMD. (DIST.)	$116,158	$64,623	$3,644	$29,638	$2,293	$2,853	$2,775	$63	$0	$4	$10,266	
(30) % RESPONSIBILITY	100.00%	55.63%	3.14%	25.51%	1.97%	2.46%	2.39%	0.05%	0.00%	0.00%	8.84%	O-10
(31) TOT. EXP. - ENG. (GEN.)	$759,365	$354,227	$19,005	$196,437	$31,209	$20,910	$41,036	$73,117	$0	$15,245	$8,180	
(32) % RESPONSIBILITY	100.00%	46.65%	2.50%	25.87%	4.11%	2.75%	5.40%	9.63%	0.00%	2.01%	1.08%	O-11
(33) TOT. EXP. - ENG. (TRANS. < 138 kV)	$11,932	$5,561	$298	$3,088	$491	$329	$646	$1,151	$0	$240	$129	
(34) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-12A
(35) TOT. EXP. - ENG. (TRANS. > 69 kV)	$38,882	$18,123	$972	$10,062	$1,600	$1,072	$2,104	$3,749	$0	$781	$419	
(36) % RESPONSIBILITY	100.00%	46.61%	2.50%	25.88%	4.11%	2.76%	5.41%	9.64%	0.00%	2.01%	1.08%	O-12B
(37) TOT. EXP. -CUST. (DIST.)	$50,822	$45,069	$2,378	$2,183	$4	$449	$44	$13	$0	$1	$682	
(38) % RESPONSIBILITY	100.00%	88.68%	4.68%	4.30%	0.01%	0.88%	0.09%	0.03%	0.00%	0.00%	1.34%	O-13
(39) TOT. EXP. -CUST. (RETAIL)	$42,790	$34,599	$1,744	$3,427	$242	$787	$556	$715	$0	$170	$550	
(40) % RESPONSIBILITY	100.00%	80.86%	4.08%	8.01%	0.57%	1.84%	1.30%	1.67%	0.00%	0.40%	1.29%	O-14
(41) MARKETING & SALES	99.99%	45.33%	3.59%	8.37%	1.79%	6.58%	12.92%	19.62%	0.00%	1.79%	0.00%	O-15
(42) METER DATA SERVICES	100.02%	5.39%	5.27%	12.46%	16.17%	12.46%	12.46%	23.35%	0.00%	12.46%	0.00%	O-16
(43) SECONDARY CUST. REVENUE	$392,146	$0	$36,687	$321,964	$0	$33,495	$0	$0	$0	$0	$0	
(44) % RESPONSIBILITY	100.00%	0.00%	9.36%	82.10%	0.00%	8.54%	0.00%	0.00%	0.00%	0.00%	0.00%	R-1

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) MW	(11) 3CP Contribution
(1) DOMESTIC	4,257,230	9.3%	4,654,738	1,036,540	100.0%	1,036,540	14.7%	1,188,498	44.71%	3,365,786	56.8%
(2) SMALL GENERAL	229,386	8.9%	249,760	58,447	61.5%	35,922	10.0%	39,526	72.13%	120,127	2.0%
(3) GENERAL	2,433,009	6.2%	2,584,209	487,817	82.8%	403,748	7.0%	432,030	68.28%	1,365,814	23.1%
(4) GENERAL LARGE	386,956	6.2%	410,860	70,885	70.0%	49,632	6.3%	52,776	88.87%	163,320	2.8%
(5) SMALL INDUSTRIAL	260,263	5.7%	275,205	47,973	78.3%	37,551	6.0%	39,786	78.96%	118,848	2.0%
(6) MEDIUM INDUSTRIAL	512,810	5.4%	540,444	87,602	82.3%	72,050	5.6%	76,073	81.10%	234,070	4.0%
(7) LARGE INDUSTRIAL	921,772	4.5%	962,980	138,738	81.5%	113,095	4.3%	117,949	93.20%	364,769	6.2%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A	-	0.0%
(9) MUNICIPAL	191,729	4.6%	200,464	40,907	97.8%	39,997	4.5%	41,806	54.74%	121,351	2.0%
(10) UNMETERED	97,813	10.0%	107,631	22,113	99.9%	22,088	10.8%	24,483	50.19%	68,910	1.2%
(11) SUB-TOTAL	9,290,967	7.5%	9,986,292	1,991,022	90.9%	1,810,625	11.2%	2,012,926	56.63%	5,922,996	100.0%
(12) BOWATER MERSEY	367,920	2.0%	375,389	42,000	100.0%	42,000	2.0%	42,857	99.99%	128,570	
(13) GEN.REPL./LOAD FOLL.	18,815	2.0%	19,199	23,900	0.2%	37	2.0%	38	N/A	315	
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A	0	
(15) LRT	322,080	2.0%	328,618	38,000	96.8%	36,767	2.0%	37,517	99.99%	112,552	
(16) TOTAL	9,999,782	7.1%	10,709,498	2,094,922	90.2%	1,889,429	10.8%	2,093,337	58.40%	6,164,433	

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JANUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	516,258	10.54%	570,685	1,013,128	97.1%	983,362	13.44%	1,115,541	68.76%
(2) SMALL GENERAL	25,143	9.71%	27,584	54,406	70.1%	38,108	9.83%	41,853	88.58%
(3) GENERAL	233,512	6.26%	248,124	487,817	93.2%	454,711	7.46%	488,643	68.25%
(4) GENERAL LARGE	32,543	6.58%	34,684	57,463	87.9%	50,514	6.74%	53,919	86.46%
(5) SMALL INDUSTRIAL	22,744	5.57%	24,010	44,936	88.7%	39,844	5.79%	42,151	76.56%
(6) MEDIUM INDUSTRIAL	44,133	5.05%	46,361	85,129	87.3%	74,312	5.31%	78,256	79.63%
(7) LARGE INDUSTRIAL	74,672	4.02%	77,673	121,617	86.6%	105,347	4.70%	110,293	94.66%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,935	4.45%	20,821	39,114	99.2%	38,782	4.64%	40,581	68.96%
(10) UNMETERED	10,205	10.84%	11,311	22,108	78.3%	17,302	13.14%	19,576	77.66%
(11) SUB-TOTAL	979,144		1,061,252	1,925,716	93.6%	1,802,282	10.46%	1,990,813	71.65%
(12) BOWATER MERSEY	31,248	1.83%	31,821	42,000	100.0%	42,000	2.04%	42,857	99.80%
(13) GEN.REPL./LOAD FOLL.	990	2.04%	1,010	18,501	-0.6%	-117	2.04%	-119	-1137.38%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	1,038,737	8.02%	1,121,994	2,024,217	92.9%	1,880,932	10.11%	2,071,068	72.82%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR FEBRUARY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	447,869	10.84%	496,399	1,036,540	100.0%	1,036,540	14.66%	1,188,498	62.15%
(2) SMALL GENERAL	23,091	10.05%	25,412	57,717	62.2%	35,922	10.03%	39,526	95.67%
(3) GENERAL	219,011	6.41%	233,053	477,307	84.6%	403,748	7.00%	432,030	80.27%
(4) GENERAL LARGE	30,161	6.28%	32,054	58,667	84.6%	49,632	6.33%	52,776	90.38%
(5) SMALL INDUSTRIAL	21,804	5.87%	23,084	43,613	86.1%	37,551	5.95%	39,786	86.34%
(6) MEDIUM INDUSTRIAL	39,821	5.40%	41,970	77,859	92.5%	72,050	5.58%	76,073	82.10%
(7) LARGE INDUSTRIAL	70,292	4.25%	73,281	124,051	91.2%	113,095	4.29%	117,949	92.45%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	18,948	4.39%	19,780	40,907	97.8%	39,997	4.52%	41,806	70.41%
(10) UNMETERED	8,648	10.56%	9,562	22,097	100.0%	22,088	10.84%	24,483	58.12%
(11) SUB-TOTAL	879,645		954,595	1,938,759	93.4%	1,810,625	11.17%	2,012,926	70.57%
(12) BOWATER MERSEY	28,224	2.03%	28,797	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,221	2.04%	1,246	19,501	0.2%	37	2.04%	38	4912.19%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	24,708	2.03%	25,209	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	933,798	8.14%	1,009,847	2,038,260	92.7%	1,889,429	10.79%	2,093,337	71.79%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MARCH 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	448,408	10.15%	493,942	887,289	93.2%	826,992	12.35%	929,143	71.45%
(2) SMALL GENERAL	22,114	10.00%	24,326	50,502	76.6%	38,677	10.35%	42,679	76.61%
(3) GENERAL	225,239	6.80%	240,549	427,739	97.8%	418,481	7.76%	450,974	71.69%
(4) GENERAL LARGE	32,914	6.70%	35,118	58,108	92.1%	53,507	6.92%	57,210	82.51%
(5) SMALL INDUSTRIAL	21,869	6.43%	23,275	38,591	97.6%	37,673	6.63%	40,169	77.88%
(6) MEDIUM INDUSTRIAL	42,496	5.80%	44,961	72,921	89.3%	65,086	5.92%	68,937	87.66%
(7) LARGE INDUSTRIAL	75,457	4.60%	78,927	114,150	92.2%	105,208	4.62%	110,068	96.38%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	18,941	4.99%	19,886	33,399	98.5%	32,913	5.10%	34,592	77.27%
(10) UNMETERED	8,555	9.93%	9,404	22,110	11.3%	2,497	7.66%	2,688	470.14%
(11) SUB-TOTAL	895,992		970,388	1,704,810	92.7%	1,581,034	9.83%	1,736,462	75.11%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	38	2.04%	39	1,842	-0.7%	-12	2.04%	-12	-428.70%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,276	2.01%	27,824	38,000	96.8%	36,767	2.04%	37,517	99.68%
(17) TOTAL	954,554	7.92%	1,030,133	1,786,652	92.9%	1,659,789	9.46%	1,816,824	76.21%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR APRIL 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	358,526	8.97%	390,670	787,516	95.8%	754,661	11.46%	841,129	64.51%
(2) SMALL GENERAL	18,756	9.09%	20,462	44,408	49.5%	21,980	8.71%	23,894	118.94%
(3) GENERAL	194,886	6.00%	206,572	383,448	87.6%	335,936	6.42%	357,497	80.25%
(4) GENERAL LARGE	30,042	6.11%	31,879	55,152	85.1%	46,953	6.16%	49,844	88.83%
(5) SMALL INDUSTRIAL	20,864	5.83%	22,080	39,767	81.9%	32,581	5.82%	34,478	88.94%
(6) MEDIUM INDUSTRIAL	42,349	5.43%	44,650	76,348	84.8%	64,715	5.44%	68,235	90.88%
(7) LARGE INDUSTRIAL	74,438	4.41%	77,718	121,813	88.4%	107,639	4.38%	112,351	96.08%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	15,463	4.73%	16,194	29,110	93.0%	27,070	4.76%	28,358	79.31%
(10) UNMETERED	7,671	9.39%	8,391	22,110	12.3%	2,713	7.17%	2,908	400.83%
(11) SUB-TOTAL	762,995		818,616	1,559,671	89.4%	1,394,249	8.93%	1,518,694	74.86%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,462	2.04%	1,492	22,397	0.7%	157	2.04%	160	1293.35%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	821,169	6.92%	877,972	1,662,068	88.6%	1,473,173	8.56%	1,599,229	76.25%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR MAY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	321,861	8.99%	350,788	673,187	89.3%	600,903	10.55%	664,326	70.97%
(2) SMALL GENERAL	17,186	9.20%	18,767	39,719	79.2%	31,474	9.48%	34,459	73.20%
(3) GENERAL	183,713	6.40%	195,464	360,986	94.7%	341,706	7.11%	365,984	71.78%
(4) GENERAL LARGE	31,088	6.50%	33,109	59,127	92.9%	54,946	6.78%	58,670	75.85%
(5) SMALL INDUSTRIAL	21,028	6.19%	22,330	41,938	99.2%	41,617	6.44%	44,298	67.75%
(6) MEDIUM INDUSTRIAL	41,845	6.06%	44,382	77,834	89.9%	69,976	6.23%	74,332	80.25%
(7) LARGE INDUSTRIAL	74,730	5.06%	78,509	113,305	91.6%	103,834	5.03%	109,058	96.76%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,868	4.81%	14,535	24,677	99.0%	24,430	4.85%	25,615	76.27%
(10) UNMETERED	6,995	10.56%	7,734	22,109	13.7%	3,020	5.43%	3,184	326.45%
(11) SUB-TOTAL	712,316		765,619	1,412,882	90.0%	1,271,905	8.49%	1,379,927	74.57%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	442	2.04%	451	3,189	22.5%	718	2.04%	733	82.68%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	771,360	7.07%	825,862	1,496,072	90.3%	1,351,391	8.11%	1,461,033	75.98%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JUNE 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	263,546	7.18%	282,475	665,640	94.6%	629,524	9.80%	691,192	56.76%
(2) SMALL GENERAL	16,366	7.18%	17,541	40,230	61.7%	24,808	8.07%	26,810	90.87%
(3) GENERAL	185,771	5.59%	196,155	387,816	77.6%	300,830	5.66%	317,844	85.71%
(4) GENERAL LARGE	30,922	5.21%	32,534	60,712	76.0%	46,157	5.45%	48,673	92.83%
(5) SMALL INDUSTRIAL	21,952	5.02%	23,055	45,324	72.8%	32,994	5.15%	34,693	92.30%
(6) MEDIUM INDUSTRIAL	43,808	4.93%	45,966	80,855	84.2%	68,050	5.12%	71,536	89.24%
(7) LARGE INDUSTRIAL	76,496	4.18%	79,690	124,550	92.8%	115,566	4.13%	120,335	91.98%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	12,778	4.12%	13,304	24,358	100.0%	24,358	4.37%	25,422	72.68%
(10) UNMETERED	6,227	10.17%	6,861	22,109	11.6%	2,572	3.92%	2,673	356.47%
(11) SUB-TOTAL	657,866		697,578	1,451,595	85.8%	1,244,859	7.58%	1,339,179	72.35%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	577	2.04%	589	23,190	-0.1%	-29	2.04%	-30	-2762.43%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	715,155	5.72%	756,030	1,554,785	85.1%	1,323,597	7.25%	1,419,523	73.97%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR JULY 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	264,900	7.22%	284,027	580,449	76.9%	446,200	7.89%	481,390	79.30%
(2) SMALL GENERAL	16,867	7.58%	18,145	38,796	92.9%	36,043	8.13%	38,974	62.58%
(3) GENERAL	200,920	5.82%	212,604	398,918	98.9%	394,684	6.76%	421,374	67.82%
(4) GENERAL LARGE	35,364	5.79%	37,410	64,855	98.1%	63,625	6.14%	67,534	74.46%
(5) SMALL INDUSTRIAL	22,315	4.97%	23,425	45,991	91.3%	41,966	5.16%	44,132	71.34%
(6) MEDIUM INDUSTRIAL	43,767	4.85%	45,890	82,658	92.8%	76,710	5.07%	80,598	76.53%
(7) LARGE INDUSTRIAL	79,763	4.16%	83,078	126,972	97.3%	123,570	4.25%	128,816	86.69%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,080	4.10%	14,657	25,639	99.6%	25,539	4.11%	26,589	74.09%
(10) UNMETERED	6,490	10.32%	7,160	22,108	13.6%	3,002	5.03%	3,153	305.20%
(11) SUB-TOTAL	684,465		726,396	1,386,387	87.4%	1,211,340	6.71%	1,292,562	75.54%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,591	2.04%	1,624	23,449	10.4%	2,428	2.04%	2,478	88.09%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(16) TOTAL	744,659	5.80%	787,812	1,489,835	86.8%	1,292,535	6.41%	1,375,413	76.99%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR AUGUST 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	259,435	8.21%	280,734	583,793	84.0%	490,139	9.44%	536,427	70.34%
(2) SMALL GENERAL	16,979	8.84%	18,481	41,234	82.1%	33,849	9.28%	36,992	67.15%
(3) GENERAL	195,364	6.42%	207,903	422,127	95.8%	404,390	7.52%	434,799	64.27%
(4) GENERAL LARGE	35,677	6.77%	38,093	69,711	95.0%	66,198	7.19%	70,955	72.16%
(5) SMALL INDUSTRIAL	22,273	5.73%	23,549	47,973	84.6%	40,562	5.89%	42,951	73.69%
(6) MEDIUM INDUSTRIAL	43,815	5.66%	46,294	81,056	89.6%	72,633	5.80%	76,849	80.97%
(7) LARGE INDUSTRIAL	85,523	5.01%	89,806	131,155	94.6%	124,091	5.03%	130,328	92.62%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,883	4.81%	14,552	26,526	96.4%	25,562	4.82%	26,793	73.00%
(10) UNMETERED	7,048	10.57%	7,793	22,110	12.9%	2,859	5.47%	3,015	347.36%
(11) SUB-TOTAL	679,998		727,204	1,425,684	88.4%	1,260,282	7.84%	1,359,109	71.92%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	2,834	2.04%	2,892	23,447	75.9%	17,804	2.04%	18,167	21.39%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	741,435	6.54%	789,888	1,529,131	88.7%	1,356,853	7.43%	1,457,650	72.83%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR SEPTEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	259,862	6.87%	277,712	552,662	90.0%	497,196	8.53%	539,626	71.48%
(2) SMALL GENERAL	15,373	7.35%	16,503	37,876	84.5%	31,986	7.66%	34,437	66.56%
(3) GENERAL	181,226	5.27%	190,777	434,599	95.0%	413,057	6.48%	439,809	60.25%
(4) GENERAL LARGE	33,303	4.86%	34,923	70,885	94.7%	67,104	5.24%	70,620	68.68%
(5) SMALL INDUSTRIAL	20,819	4.75%	21,808	45,821	84.0%	38,465	4.81%	40,315	75.13%
(6) MEDIUM INDUSTRIAL	42,676	4.67%	44,667	83,798	86.9%	72,776	4.73%	76,219	81.39%
(7) LARGE INDUSTRIAL	80,361	4.07%	83,630	138,738	89.9%	124,733	4.06%	129,794	89.49%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	13,566	3.88%	14,092	27,312	96.7%	26,411	3.85%	27,426	71.36%
(10) UNMETERED	7,623	8.75%	8,289	22,110	12.2%	2,700	5.73%	2,855	403.24%
(11) SUB-TOTAL	654,808		692,401	1,413,801	90.1%	1,274,428	6.80%	1,361,102	70.65%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	6,682	2.04%	6,819	23,900	96.4%	23,047	2.04%	23,518	40.27%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,472	2.03%	27,010	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	718,203	5.41%	757,083	1,517,701	90.7%	1,376,242	6.45%	1,464,994	71.78%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR OCTOBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	299,381	8.32%	324,301	666,350	90.9%	605,415	10.17%	666,979	65.35%
(2) SMALL GENERAL	17,145	7.55%	18,440	38,805	72.5%	28,144	7.66%	30,301	81.80%
(3) GENERAL	189,540	6.01%	200,935	409,155	87.2%	356,584	6.80%	380,828	70.92%
(4) GENERAL LARGE	32,368	6.07%	34,333	67,431	79.4%	53,536	6.29%	56,903	81.10%
(5) SMALL INDUSTRIAL	19,175	5.67%	20,262	42,759	96.7%	41,333	5.99%	43,809	62.16%
(6) MEDIUM INDUSTRIAL	43,031	5.44%	45,372	78,875	93.1%	73,407	5.65%	77,553	78.63%
(7) LARGE INDUSTRIAL	78,588	4.61%	82,213	119,469	93.9%	112,118	4.61%	117,283	94.22%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	14,607	4.51%	15,267	26,663	98.1%	26,156	4.55%	27,347	75.04%
(10) UNMETERED	8,211	8.43%	8,903	22,112	10.3%	2,285	6.42%	2,432	492.04%
(11) SUB-TOTAL	702,047		750,026	1,471,619	88.3%	1,298,978	8.04%	1,403,436	71.83%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,467	2.04%	1,497	7,533	19.7%	1,483	2.04%	1,513	132.94%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	762,116	6.46%	811,315	1,559,151	88.5%	1,379,228	7.69%	1,485,323	73.42%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR NOVEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	350,596	8.97%	382,045	776,138	100.0%	776,138	11.76%	867,425	61.17%
(2) SMALL GENERAL	17,948	8.43%	19,461	45,312	66.1%	29,941	8.58%	32,510	83.14%
(3) GENERAL	198,025	5.73%	209,379	399,991	89.6%	358,203	6.34%	380,904	76.35%
(4) GENERAL LARGE	31,242	5.91%	33,088	58,137	89.6%	52,079	6.07%	55,239	83.19%
(5) SMALL INDUSTRIAL	21,031	5.68%	22,226	43,298	78.6%	34,022	5.72%	35,967	85.83%
(6) MEDIUM INDUSTRIAL	42,141	5.04%	44,263	78,808	91.4%	72,057	5.19%	75,800	81.10%
(7) LARGE INDUSTRIAL	78,531	4.04%	81,705	124,268	75.5%	93,876	3.79%	97,438	116.46%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	16,324	4.03%	16,982	31,119	100.0%	31,119	4.06%	32,382	72.84%
(10) UNMETERED	9,592	9.25%	10,480	22,112	74.2%	16,412	8.48%	17,803	81.76%
(11) SUB-TOTAL	765,431		819,629	1,579,182	92.7%	1,463,845	8.99%	1,595,467	71.35%
(12) BOWATER MERSEY	30,240	2.03%	30,854	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	1,310	2.04%	1,337	21,278	92.6%	19,707	2.04%	20,109	9.23%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	26,551	2.05%	27,095	38,000	96.8%	36,767	2.04%	37,517	100.31%
(17) TOTAL	823,532	6.73%	878,915	1,680,460	93.0%	1,562,319	8.55%	1,695,951	71.98%

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR DECEMBER 2011

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR
(1) DOMESTIC	466,588	11.65%	520,959	965,934	96.0%	927,091	14.52%	1,061,747	65.95%
(2) SMALL GENERAL	22,417	9.92%	24,640	58,447	60.2%	35,197	10.09%	38,749	85.47%
(3) GENERAL	225,801	7.48%	242,695	451,524	90.9%	410,591	8.41%	445,141	73.28%
(4) GENERAL LARGE	31,331	7.36%	33,636	60,007	87.6%	52,591	7.67%	56,625	79.84%
(5) SMALL INDUSTRIAL	24,389	7.03%	26,103	47,271	72.9%	34,474	7.07%	36,910	95.06%
(6) MEDIUM INDUSTRIAL	42,928	6.38%	45,668	87,602	85.3%	74,747	6.68%	79,742	76.97%
(7) LARGE INDUSTRIAL	72,922	5.25%	76,748	130,016	99.5%	129,317	5.58%	136,527	75.56%
(8) ELI 2P-RTP	0	N/A	0	0	N/A	0	N/A	0	N/A
(9) MUNICIPAL	19,337	5.48%	20,395	36,870	100.0%	36,870	5.68%	38,964	70.36%
(10) UNMETERED	10,548	11.35%	11,745	22,113	100.0%	22,113	12.38%	24,851	63.52%
(11) SUB-TOTAL	916,260		1,002,588	1,859,785	92.6%	1,722,992	11.39%	1,919,257	70.21%
(12) BOWATER MERSEY	31,248	2.03%	31,882	42,000	100.0%	42,000	2.04%	42,857	99.99%
(13) GEN.REPL./LOAD FOLL.	200	2.04%	204	1,495	26.0%	389	2.04%	397	69.22%
(14) REAL TIME PRICING	0	N/A	0	0	N/A	0	N/A	0	N/A
(15) EXPORT SALES	0	N/A	0	0	N/A	0	N/A	0	N/A
(16) LRT	27,355	2.03%	27,910	38,000	96.8%	36,767	2.04%	37,517	99.99%
(17) TOTAL	975,063	8.98%	1,062,585	1,941,280	92.8%	1,802,148	10.98%	2,000,028	71.41%

EXHIBIT 9B

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COINCIDENT KW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 2014

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. KW SEC.	1,622,280	1,036,540	58,447	461,817	0	43,363	0	0	0	0	22,113
(2) LOSSES 6.00%	97,337	62,192	3,507	27,709	0	2,602	0	0	0	0	1,327
(3) SUB-TOTAL	1,719,617	1,098,733	61,954	489,526	0	45,965	0	0	0	0	23,440
(4) NON-COIN. KW PRI.	1,906,323	1,098,733	61,954	515,526	70,885	50,575	85,211	0	0	0	23,440
(5) LOSSES 5.40%	102,941	59,332	3,346	27,838	3,828	2,731	4,601	0	0	0	1,266
(6) SUB-TOTAL	2,009,264	1,158,064	65,299	543,365	74,713	53,306	89,812	0	0	0	24,706
(7) NON-COIN. KW TRANS.	2,191,301	1,158,064	65,299	543,365	74,713	53,306	92,204	138,738	0	40,907	24,706
(8) LOSSES 3.70%	81,078	42,848	2,416	20,104	2,764	1,972	3,412	5,133	0	1,514	914
(9) TOTAL	2,272,379	1,200,913	67,715	563,469	77,477	55,278	95,615	143,871	0	42,420	25,620

EXHIBIT 9C

NOVA SCOTIA POWER INC.

DETAIL OF MONTHLY CLASS SYSTEM COINCIDENT KW DEMAND

FOR THE YEAR ENDING DECEMBER 31, 2014

MONTH	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUST.	(7) MEDIUM INDUST.	(8) LARGE INDUST.	(9) ELI 2P-RTP	(10) MUNICIPAL	(11) UNMETERED	(12) MERSEY SYSTEM	(13) GRLF	(14) REAL TIME PRICING	(15) LRT
(1) JANUARY	**2,033,551**	**1,115,541**	**41,853**	**488,643**	**53,919**	**42,151**	**78,256**	**110,293**	**0**	**40,581**	**19,576**	**42,857**	**(119)**	**0**	**37,517**
(2) FEBRUARY	**2,055,820**	**1,188,498**	**39,526**	**432,030**	**52,776**	**39,786**	**76,073**	**117,949**	**0**	**41,806**	**24,483**	**42,857**	**38**	**0**	**37,517**
(3) MARCH	1,779,307	929,143	42,679	450,974	57,210	40,169	68,937	110,068	0	34,592	2,688	42,857	(12)	0	37,517
(4) APRIL	1,561,711	841,129	23,894	357,497	49,844	34,478	68,235	112,351	0	28,358	2,908	42,857	160	0	37,517
(5) MAY	1,423,516	664,326	34,459	365,984	58,670	44,298	74,332	109,058	0	25,615	3,184	42,857	733	0	37,517
(6) JUNE	1,382,006	691,192	26,810	317,844	48,673	34,693	71,536	120,335	0	25,422	2,673	42,857	(30)	0	37,517
(7) JULY	1,337,896	481,390	38,974	421,374	67,534	44,132	80,598	128,816	0	26,589	3,153	42,857	2,478	0	37,517
(8) AUGUST	1,420,133	536,427	36,992	434,799	70,955	42,951	76,849	130,328	0	26,793	3,015	42,857	18,167	0	37,517
(9) SEPTEMBER	1,427,476	539,626	34,437	439,809	70,620	40,315	76,219	129,794	0	27,426	2,855	42,857	23,518	0	37,517
(10) OCTOBER	1,447,806	666,979	30,301	380,828	56,903	43,809	77,553	117,283	0	27,347	2,432	42,857	1,513	0	37,517
(11) NOVEMBER	1,658,433	867,425	32,510	380,904	55,239	35,967	75,800	97,438	0	32,382	17,803	42,857	20,109	0	37,517
(12) DECEMBER	**1,962,511**	**1,061,747**	**38,749**	**445,141**	**56,625**	**36,910**	**79,742**	**136,527**	**0**	**38,964**	**24,851**	**42,857**	**397**	**0**	**37,517**
(13) TOT. SUMMED DMD.	19,490,167	9,583,424	421,183	4,915,827	698,969	479,661	904,131	1,420,241	0	375,876	109,622	514,282	66,951	0	450,206
(14) 3 C/P DEMANDS	**6,051,882**	**3,365,786**	**120,127**	**1,365,814**	**163,320**	**118,848**	**234,070**	**364,769**	**0**	**121,351**	**68,910**	**128,570**	**315**	**0**	**112,552**
(15)					**3 C/P INTERRUPTIBLE RIDER DEMANDS**			**269,747**							
(16)					**NET 3 C/P LARGE INDUST. DEMANDS**			**95,022**							

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$196,333	$402,543	9.46	$94,774	$693,650	$689,768	99.44
(2) SMALL GENERAL	8,537	21,598	9.42	5,006	35,141	36,687	104.40
(3) GENERAL	83,553	223,264	9.18	6,265	313,082	321,964	102.84
(4) LARGE GENERAL	8,502	35,474	9.17	280	44,256	43,662	98.66
(5) SMALL INDUSTRIAL	7,581	23,767	9.13	1,476	32,825	33,495	102.04
(6) MEDIUM INDUSTRIAL	11,615	46,647	9.10	635	58,897	57,293	97.28
(7) LARGE INDUSTRIAL	7,520	83,114	9.02	781	91,415	86,844	95.00
(8) ELI 2P-RTP	0	0	0	0	0	0	0
(9) MUNICIPAL	4,419	17,326	9.04	185	21,929	21,483	97.96
(10) UNMETERED	13,286	9,297	9.51	1,407	23,989	23,989	100.00
(11) SUB-TOTAL	$341,346	$863,030	9.29	$110,809	1,315,185	1,315,185	100.00
(12) DIRECT EXP./ REV					42,345	47,292	N/A
(13) RETURN ON DIRECT EXP.					4,948	0	N/A
(14) TOTAL					$1,362,477	$1,362,477	100.00

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 2014
(IN THOUSANDS OF DOLLARS)

	(1) TOTAL DMD.RELATED EXPENSES	(2) TOTAL ENG.RELATED EXPENSES	(3) UNIT COST ENG.RELATED (C / kW.h)	(4) TOTAL CUST.RELATED EXPENSES	(5) TOTAL OPER. EXPENSES	(6) TOTAL RATE REVENUE	(7) % REVENUE TO EXPENSES
(1) DOMESTIC	$180,890	$386,119	9.07	$90,556	$657,565	$654,440	99.52
(2) SMALL GENERAL	7,872	20,717	9.03	4,784	33,372	34,808	104.30
(3) GENERAL	77,007	214,146	8.80	6,029	297,183	305,474	102.79
(4) LARGE GENERAL	7,858	34,025	8.79	279	42,162	41,426	98.25
(5) SMALL INDUSTRIAL	6,990	22,796	8.76	1,428	31,213	31,779	101.81
(6) MEDIUM INDUSTRIAL	10,727	44,740	8.72	631	56,098	54,358	96.90
(7) LARGE INDUSTRIAL	6,436	79,717	8.65	780	86,932	82,372	94.76
(8) ELI 2P-RTP	0	0	0	0	0	0	0
(9) MUNICIPAL	4,060	16,618	8.67	184	20,863	20,382	97.70
(10) UNMETERED	12,467	8,917	9.12	1,348	22,733	23,081	101.53
(11) SUB-TOTAL	$314,307	$827,795	8.91	$106,020	1,248,122	1,248,122	100.00
(12) DIRECT EXP./ REV					42,384	47,212	N/A
(13) RETURN ON DIRECT EXP.					4,827	0	N/A
(14) TOTAL					$1,295,333	$1,295,333	100.00

Requirement:

Load Forecast Report.

Submission:

Please refer to Attachment 1.

NOVA SCOTIA POWER
An Emera Company

2012 Load Forecast

Prepared

April 2012

Table of Contents

List of Figures

Appendices

Executive Summary

The Nova Scotia Power Inc. (NS Power) 2012 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for 2012 to 2022. As well, it describes the considerations, assumptions and methodology used in the preparation of the forecast. The NS Power Forecast provides the basis for the financial planning and overall operating activities of the Company.

The forecast is based on analyses of sales history, weather, economic indicators, customer surveys, technological and demographic changes in the market and the price and availability of other energy sources.

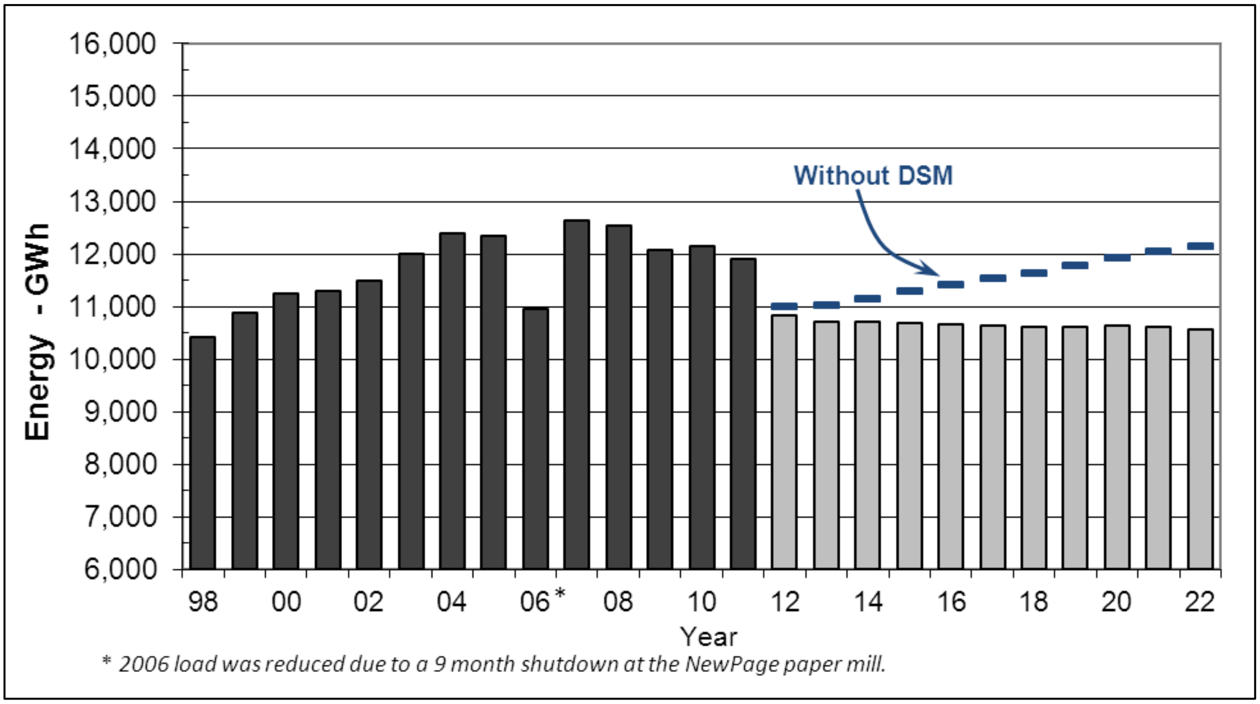
As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, the health of the economy, changes in large customer loads, the number of electric appliances and end-use equipment installed, as well as the manner and degree to which they are used. This forecast presents NS Power's "expected" or "most likely" case and also provides less probable, but possible high and low scenarios for longer term planning purposes.

NS Power billed energy sales are initially modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Input variables for each sector are updated and forecast sales are then calculated using the sector models. The sum of these in-province billed sales plus associated system transmission and distribution losses and changes to unbilled sales are then determined. This is referred to as the Net System Requirement (NSR).

For the five years ending in 2008, the NSR grew at an average annual rate of 0.9 percent but then dropped by 3.7 percent in 2009 due to the economic recession that affected sales, primarily in the industrial sector. Load growth began to recover in 2010. However; it dropped by 2.1 percent in 2011 due to production changes at the major paper mills. The forecast load for 2012 and onward is lower than recent years due to the assumption that the largest paper mill will remain closed indefinitely, removing over 1,500 GWh from the annual load. The 2013 NSR is projected to be 10,721 GWh with little growth over the remaining forecast period.

For 2022, NSR is forecast to be 10,562 GWh, an annual reduction of 0.3 percent over the ten year forecast. The growth rates are generally lower than those observed in the recent past, due to the anticipated effects of conservation and energy efficiency programs (demand side management or DSM) planned for the coming years. The underlying 10-year annual growth rate, without the DSM effects is 1.0 percent. The growth in annual net system requirement is shown in Figure 1.

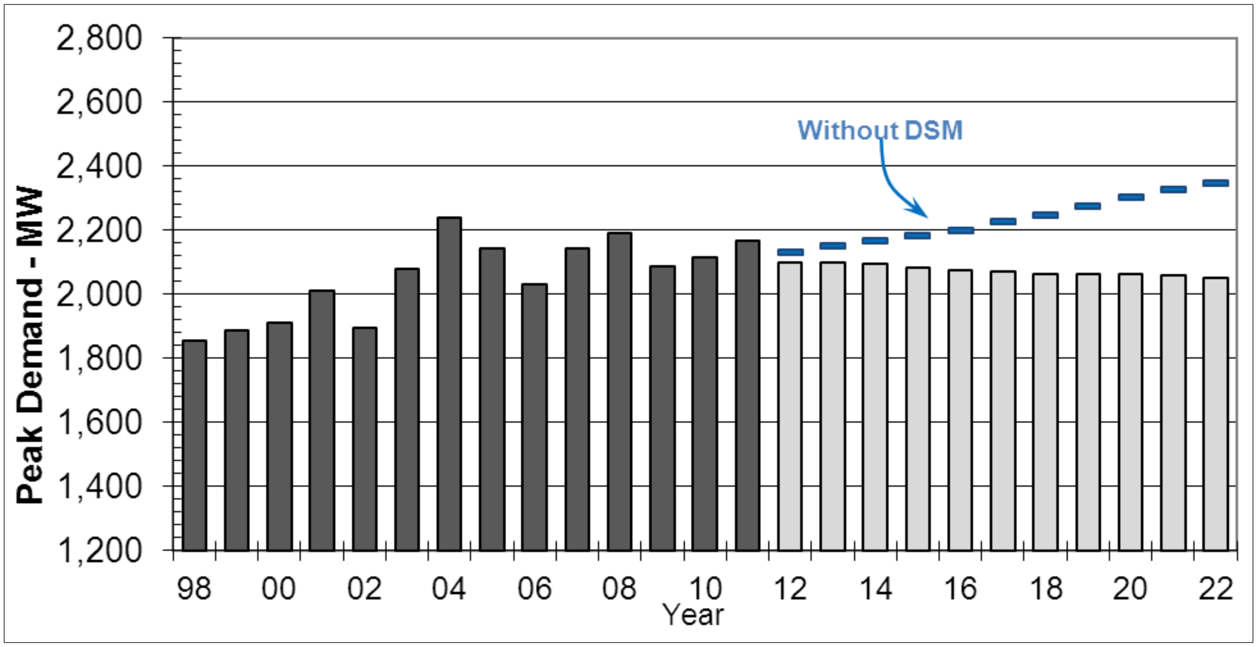
Figure 1 Annual Net System Requirement



In addition to annual energy requirements, NS Power also forecasts the peak hourly demand for future years. The forecast methodology uses forecast energy requirements and expected load shapes (hourly consumption profiles) for the various customer classes. Load shapes are derived from historical analysis, adjusted for any expected changes (e.g. customer plans to add major equipment). Growth in annual net system peak is shown in Figure 2.

Over the longer term, Net System Peak is forecast to decrease from 2,168 MW in winter 2010/11, to 2,053 MW in 2021/22. In addition to the reduction caused by the indefinite closure of the largest paper mill, this relatively flat projection is due to the anticipated effects of DSM programs. Without the effects of DSM, the Net System Peak would be 2,345MW in 2021/22 a increase of 292MW.

Figure 2 Annual Net System Peak (Winter-ending)



The hourly peak demand in the year 2011 occurred in January and was 2,168 MW with temperatures of approximately -13°C (Winter peaks are typically set when cold temperatures drive residential and commercial electric space heating load, on weekdays with temperatures in the range of -15°C or colder). The forecast peak for 2013 is 2,098 MW, assuming typical winter temperatures and the continued closure of the largest paper mill.

New load forecasting methodology under development at NS Power

A review of NS Power's load forecasting methodology in 2008 recognized that load forecasting could be enhanced with better integration of DSM savings by adopting an end-use model framework.

NS Power continues to review methods of updating its load forecasting methodology to employ Statistically-Adjusted End-use (SAE) modeling. This structure allows the retention of some of the economic inputs of the prior model, but also allows for more detailed modeling of end-use types and efficiency trends of those end-use appliances. It is expected that this will allow for improved analysis and integration of DSM effects in the load forecast. In April 2011, NS Power filed a first draft of an end-use forecast model which was then reviewed by Synapse Energy Economics. Work is ongoing to develop cost effective, improved model inputs and meaningful results.

Introduction

NS Power annually develops a forecast of energy sales and peak demand requirements to assess the effects of customer, demographic and economic factors on the future provincial system load. It is a fundamental input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2011-2012 and using information available at the time, this forecast covers the period of 2012 - 2022. Unless otherwise noted, average growth rates stated report the average annual rate calculated between 2012 and 2022.

Forecast Models

Nova Scotia electric energy sales are modeled and forecast as three provincial customer sectors: residential, commercial and industrial. Energy forecasts for sector electricity sales are calculated using econometric models in conjunction with forecasts for the independent variables used in those models. Individual customer load forecast survey information is also used for large customers in the Commercial and Industrial sectors.

The sector econometric models are multiple linear regression equations that are designed to capture the relationships between electricity consumption and several independent variables. The models then use these relationships to predict future energy loads. An examination of these variables provides a meaningful explanation of the load growth in each sector. The individual econometric model details are shown in the Appendices of this report.

The variables used in the preparation of the forecast include population, residential customer growth, inflation, GDP, retail sales, oil and electricity prices, appliance saturation levels and average energy use, water and space heat saturation levels and heating degree-days. The primary source of economic and other provincial statistics used in the load forecast is the Conference Board of Canada's *Economic Outlook*, which is released quarterly. This forecast provides a provincial perspective and considers specific Nova Scotia projects and demographics.

Discussion of Major Inputs

The Gross Domestic Product (GDP) for Nova Scotia was estimated at $27,460 million (in constant 2002 dollars) in 2011, and is forecast to increase by 1.8 percent in 2012 and 2.5 percent in 2013.

The provincial Consumer Price index (CPI) for 2011 showed 3.8 percent annual growth, an increase from 2010 of 2.2 percent. It is forecast to grow at 1.9 percent for 2012 and 2.3 percent in 2013, and remain in the 2 percent range for the next several years as the Bank of Canada maintains watch on inflation targets.

Housing starts for NS were estimated at 4,255 units in 2011 (singles: 2,340), and were forecast by the Conference Board of Canada (CBoC) to decrease to 3,591 for 2012 (singles: 2,268). For 2013, total housing starts are forecast at 3,307, and 3,086 for the year 2014. Despite the decreasing overall construction trend, the continued urbanization and aging population trend is expected to drive a shift to more multi-unit housing and condominiums.

Retail sales, with only 0.2 percent growth in 2009, rebounded with 2.3 percent growth in 2010. For 2011, no real growth occurred, but it is expected to grow by 2.1 percent in 2012 and 1.2 percent in 2013.

Nova Scotia population in 2011 was estimated to be 945,531 with annual growth remaining relatively flat in the past five years. There is little indication that the prevailing trends will be altered soon. Further population growth in the forecast is marginal with the estimate for 2013 at 950,032 for an annual growth rate of 0.2 percent.

In late 2011, the federal government announced a major shipbuilding contract for the Halifax shipyard. This $25 billion injection of funds is expected to provide a significant boost to the Nova Scotia economy. The economic forecast provided by CBoC includes the effects of this project however it is their opinion that growth will be offset in the near term by the difficulties in the Forestry sector and the effects that has across the Nova Scotia economy.

Figure 3 lists the annual growth rates of some of the major independent variables that affect the load forecast. For financial measures, the variables are presented in constant dollars, eliminating the inflation effects from the series.

Figure 3 Forecast Variables

Forecast Variables	2011 Actual Growth Rate	2012 Forecast Growth Rate	2013 Forecast Growth Rate
N.S. Population	0.1%	0.1%	0.3%
N.S. Consumer Price Index	3.8%	1.9%	2.3%
N.S. Personal Disposable Income	-1.8%	1.0%	1.0%
N.S. GDP	1.5%	1.8%	2.5%
N.S. Retail Sales	0.0%	2.1%	1.2%
N.S. Consumer Goods Sales	-0.9%	2.2%	1.0%
Home heating oil price	20.5%	0.0%	-4.3%

Demand-Side Management

Demand-side management (DSM) and conservation plans continue to play a major role in the use of electricity in Nova Scotia. The effects of DSM programs are provided by the agency Efficiency Nova Scotia (ENSC) and are integrated into this load forecast. Where relevant, load growth rates with and without the influence of DSM programs are stated throughout this report.

Although NS Power uses the DSM conservations targets provided by ENSC in the load forecasting process, they may appear to be different from numbers stated in other publications or elsewhere. The reasons for this difference in appearance are:

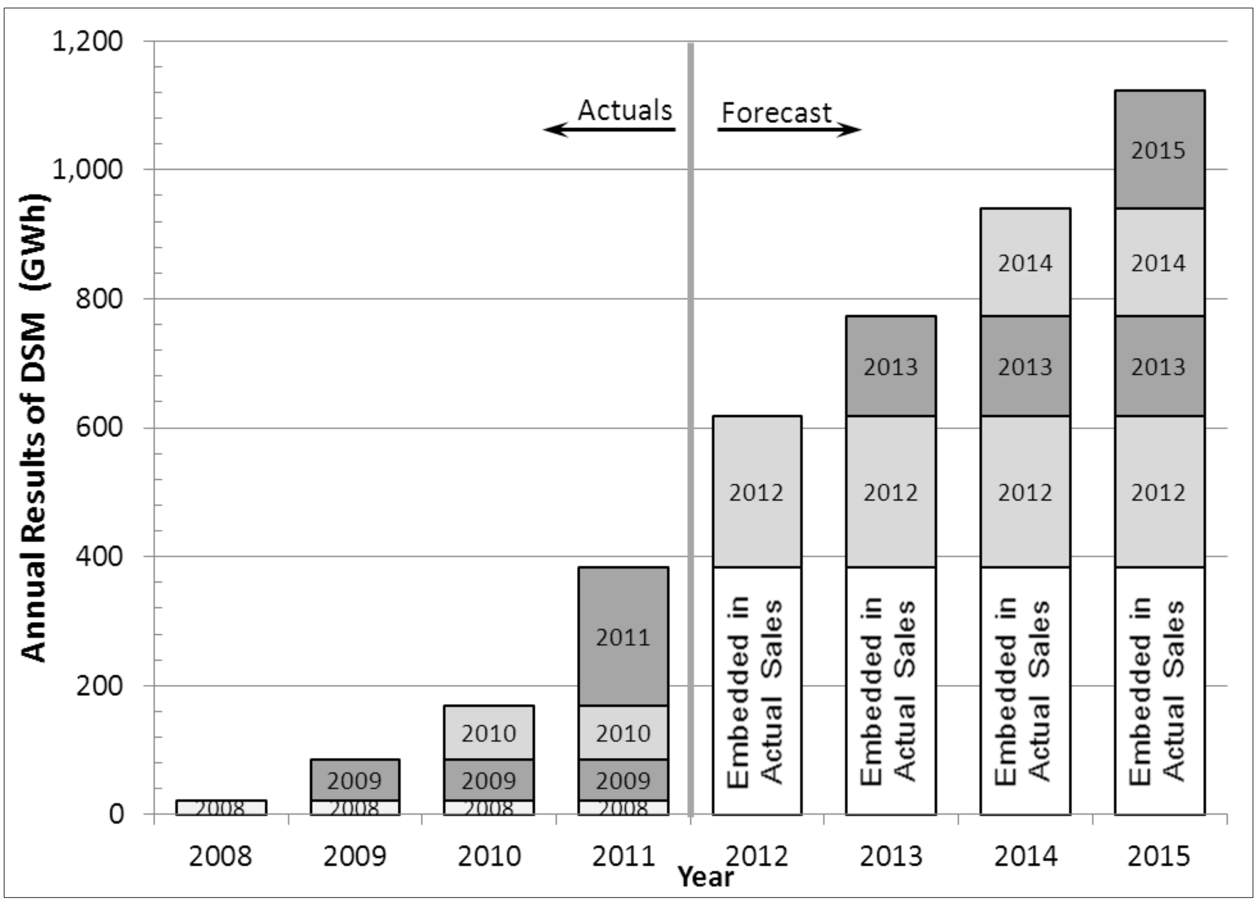
1) Since this is a forecast, the effects of past DSM programs are embedded in the actual sales trend. This forecast describes only the influence of future DSM programs on projected load. Other related documents may present the accumulated DSM savings beginning with the program inception in 2008, rather than from the present as this forecast describes. This difference in approach is demonstrated in Figure 4 which shows the cumulative results of the annual DSM programs for historical and forecast periods.

2) Since the DSM programs cannot all be implemented in the first day of the year, but will instead be gradually implemented throughout the calendar year, this forecast makes an

allowance for this installation rate. The forecast assumes that 50 percent of the DSM target will be attained by year-end and the remaining 50 percent of that plan will be achieved in the following year. These calculations are shown below in Figure 5. NS Power does assume that the DSM target will be fully achieved, but that there will be a slight delay before the savings are fully realized.

3) At the time of preparation of this load forecast, the 2013 DSM plan from ENSC was not yet complete. To proceed with this forecast development, draft DSM targets from preliminary discussions with ENSC were used. These DSM numbers will differ slightly from the final DSM conservation targets filed by ENSC.

Figure 4 Cumulative Effects of Annual DSM Savings



**Based on results data from Figure 4.8 ENSC 2013-2015 DSM Filing (E-ENSC-R-12)*

The DSM targets and calculated 2012 load forecast adjustments are shown in figure 5 below.

Figure 5 DSM Adjustments for 2012 Load Forecast

Source	Calendar Year	DSM Target GWh	NS Power Forecast DSM Methodology: 50% of current Year Plan GWh	50% of prior Year Plan GWh	Realized Annual Increment GWh	Cumulative Future DSM Savings GWh
2011 DSM Plan	2011	158				
2012 DSM Plan	2012	134	67	79	146	**146**
Preliminary 2013 DSM Plan Estimates	2013	133	67	67	134	**280**
	2014	133	67	67	133	**413**
	2015	138	69	67	136	**549**
	2016	140	70	69	139	**688**
	2017	142	71	70	141	**828**
	2018	142	71	71	142	**970**
	2019	142	71	71	142	**1112**
	2020	142	71	71	142	**1253**
	2021	142	71	71	142	**1395**
	2022	142	71	71	142	**1537**

Sector Model Inputs

One factor influencing the residential forecast involves market effects including the price of electricity versus other alternatives (e.g. fuel oil) and the effects of natural gas distribution. The stock of electric appliances is estimated through maturities and conversion rates to and from electric units as well as the electric heat penetration for new construction. Technology factors are considered through increases in efficiency and the introduction of new equipment.

The outlook for the retail price of furnace oil (#2 light) is based on futures pricing and, for the long-term, escalated at rates consistent with other fuel price forecasts used by NS Power. The ratio of oil prices to electricity prices is used in calculating the saturation of residential water and space heating equipment. Furnace oil prices in NS are estimated to average $1.09 per litre in 2012 and $1.06 in 2013.

Assumptions regarding the effects of natural gas distribution in the province are based on the potential loss of electric space heating and water heating load, primarily in the residential sector. The gas impact on this forecast is projected to remain small however, due to a limited rollout in the growing residential areas of Nova Scotia and limited uptake observed to date in the residential sector.

Electricity sales in the commercial sector are influenced by the level of business activity and as a result, are closely related to the provincial GDP and consumer confidence. Electricity sales to small and medium industrial customers are correlated to general economic growth in the province. However, energy use in the industrial sector is also influenced by large industries such as forestry and pulp & paper. Since changing economic conditions, exchange rates and trade policies can create large fluctuations in sales as companies expand, contract or endure inventory shutdowns; the large industrial forecast relies heavily on input from customer surveys.

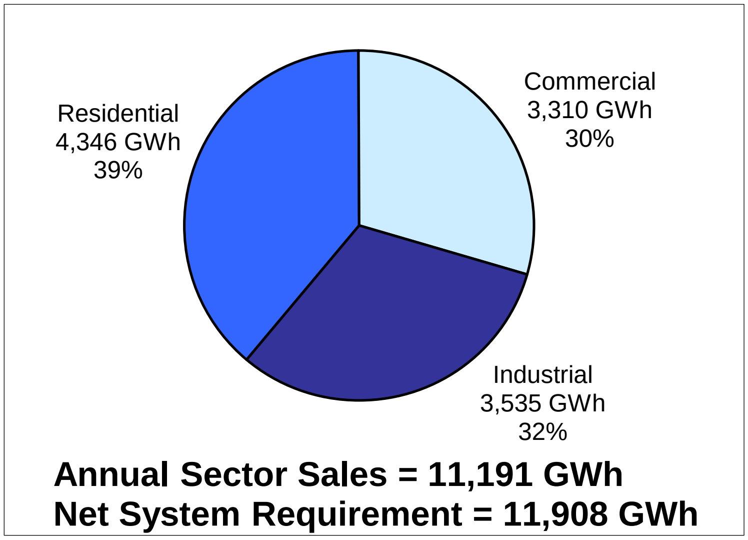
Losses

System losses have averaged 6.4 percent of NSR over the past five years and are expected to remain in the 6.5 to 6.6 percent range over the 10 year forecast period.

Energy Forecast Details

For forecasting, modeling and sales reporting, Nova Scotia electric load is divided into three sector requirements: residential, commercial and industrial. The relative sizes of sector sales are shown in Figure 6.

Figure 6 2011 NS Power Sector Sales



Residential Sector Sales

In 2011, residential customers represented approximately 39 percent of total Nova Scotia energy sales. In addition to direct domestic customers of the Company, the sector also includes residential customers served by six municipal utilities. Seasonal residences comprised 6.5 percent of the residential base.

The residential sector offers an opportunity for more detailed modeling due to the relative similarity of customer end-uses, compared to the wide variations in end-use by commercial and industrial customers. The residential sector forecast is prepared using an econometric model that uses forecast retail sales, an overall end-use appliance index, a variable representing electric heating load, residential electricity cost per kWh and residential electric load from the previous year. A series of end-use models are used to calculate the appliance index and space heating variable forecasts.

A population forecast is used in conjunction with customer formation trends to produce a residential customer count forecast. Sector average electricity costs per kWh and forecast furnace oil prices are used in a market share model to estimate the annual electric space and water heat penetration rates. A composite variable (CHDD) is calculated for use in the residential model that takes into account the annual number of all-electric customers and the forecast heating degree-days.

Household appliance load is modeled using non-linear regression methods that forecast the annual saturation rates of major appliances. Efficiency improvements for new units are accounted for in the stock vintage models that calculate the overall system average use for each appliance type given the age and efficiency mix of the total stock. This appliance saturation and average use information is used to create a composite variable (AIDX), which is used in the residential sector econometric model.

The real cost of electricity is another factor that may affect residential electricity consumption. Consumers may respond to increases in energy prices by reducing consumption or delaying the acquisition of a major appliance, however the price elasticity of this sector appears to be small in the near-term. The econometric model uses the average sector customer price per kWh after tax measured in constant dollars (RREP).

Provincial economic trends are represented in the residential sector model through the forecast of Consumer Goods Spending (RCGOODS), as measured in current dollars. This variable is combined with the forecast of the NS consumer price index to recalculate it in constant dollars for long-term modeling purposes.

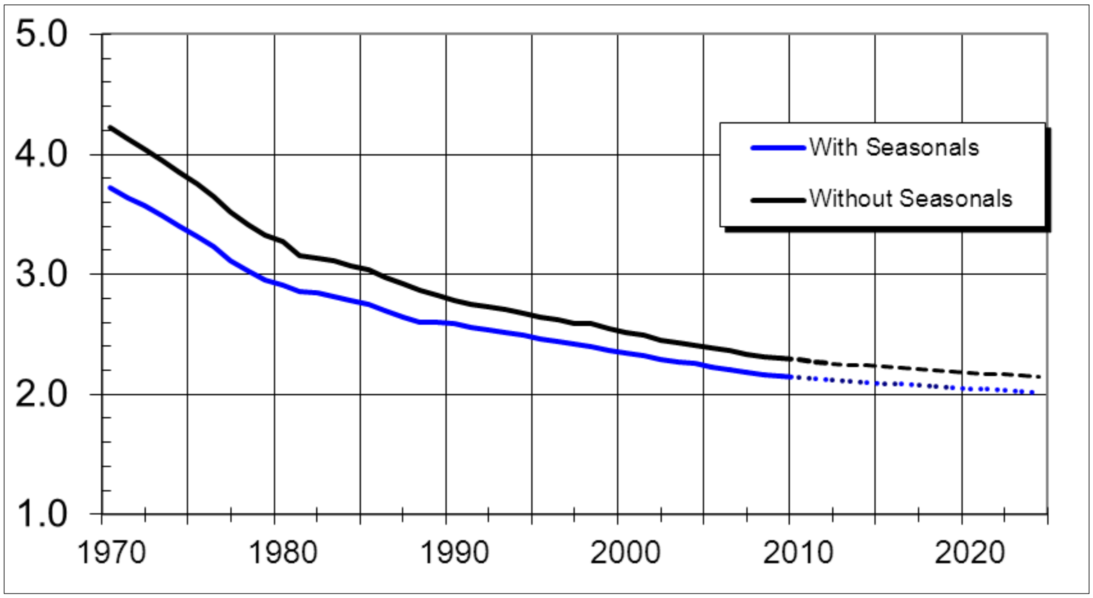
To capture the other sector growth trends, the residential electric load of the previous year is included in the model as a lagged dependent variable. It should be noted however, that the coefficients applied to this and the other variables are the result of estimates using data compiled over a 20-year period, and are therefore reflective of longer term relationships and not just the prior year's results. The data period for this model has been shortened to 20 years from the 25-year period used in the model last year. It is believed that a shorter period will better represent the current structural conditions in the market.

The residential econometric model is shown below. Complete residential sector model fit statistics and model specifications are provided in the Appendix of this report.

$$\textit{Residential Load} = 363.2\,AIDX + 0.2470\,CHDD - 41.97\,RREP + 0.0963\,RCGOODS + 0.4979\ \textit{Residential load}_{-1}$$

The forecast for new customers for 2012 is 3,554 diminishing to 2,840 by 2022. The number of actual additions has been decreasing steadily from more than 4,500 in 1997. Although the provincial population is expected to grow at a very low rate, Nova Scotians are becoming more urbanized and increasingly choosing to live in smaller households. This trend is indicated in Figure 7. The result is an increase in the overall number of households, which in turn boosts the total number of electric customers for a given population.

Figure 7 Persons per Residential Account



Within the residential sector forecast, large household appliances are modeled by type, considering age, efficiency trends, and acquisition rates. Since these improvements apply only to new appliances, the resulting effect on the overall system load is gradual as older appliances are retired and replaced with more efficient models.

Although natural gas availability continues to grow in Nova Scotia, the primary choice for the majority of residential customers remains oil or electricity for space heating and water heating. The projected saturations of space heat and water heat are derived from consumer uptake models based on forecasts of oil prices and electricity prices which influence the consumer's decision at the time to purchase or replace a furnace or water heater. For the new construction market, saturations of electric space heat and water heat are estimated based on data collected through the wiring inspection process which is then used to calibrate the model and project forward using the forecast oil/electricity price ratios. For the existing market, there is less detailed information available, and the conversion curves for "to electric" and "from electric" are balanced to

Statistics Canada saturation data in conjunction with any other available survey data and projected forward using the oil/electricity price ratio.

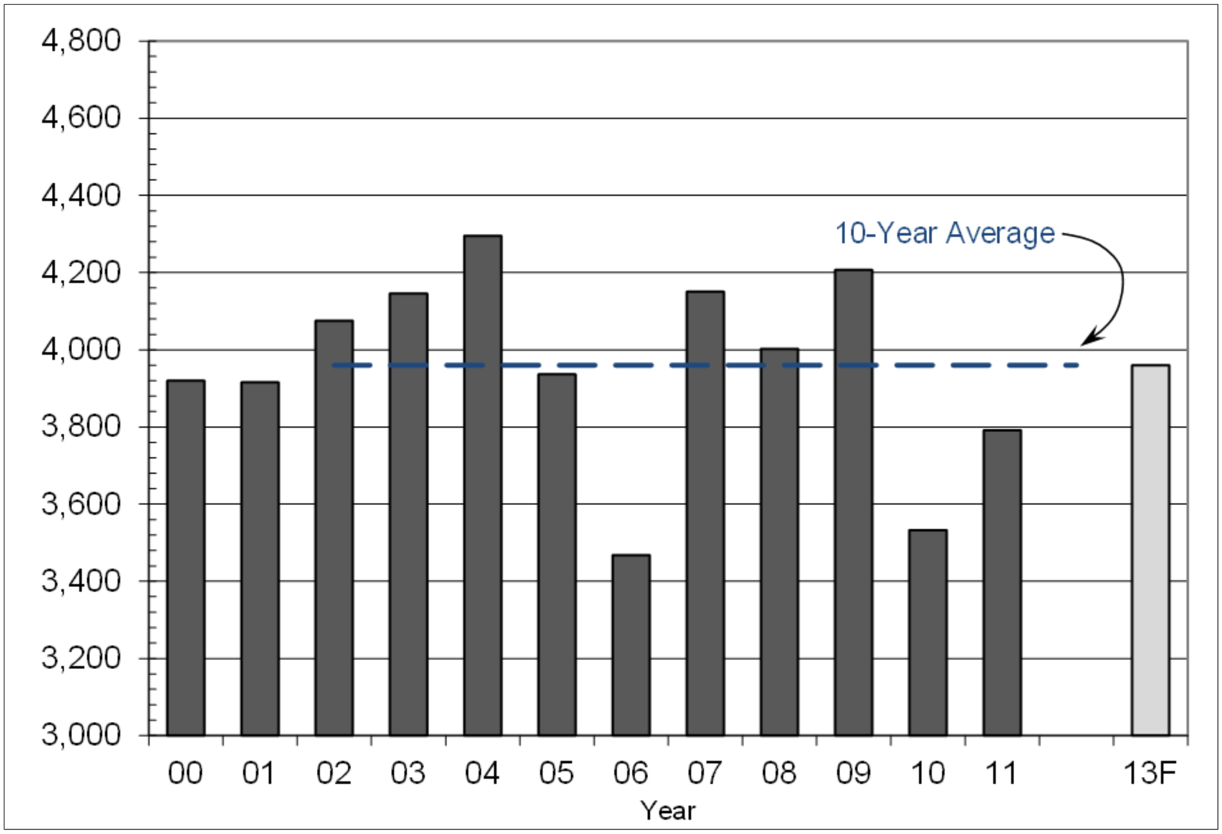
The saturation of electric space heat has been in the mid to high 20 percent range in recent years and is estimated to be 30 percent in 2012. The saturation of electric water heating currently hovers around 60 percent and is forecast to grow to 66 percent over the 10-year forecast period.

The forecast saturation of electric space heat is multiplied by the projection of residential customers to produce a forecast of all-electric customers (electric space heating). The number of all-electric customers multiplied by the annual heating degree-days produces a composite variable CHDD which is used in the regression to model the amount of space heat in the residential forecast. Wiring inspection data also indicates a rapidly growing portion of all-electric homes that are choosing more energy efficient heating solutions such as heat pumps instead of the typical on-demand electric baseboard heating. This trend, in conjunction with improved building envelope efficiency, will affect the efficiency improvement trend within the CHDD variable in future years.

The forecast for weather effects uses 10-year average temperatures, measured in heating degree-days (HDD). Heating degree-days are a common measure of heating requirement, based on the degree departure between the daily mean temperature and a given standard temperature. The standard temperature of 18°C is used for these calculations, which is assumed to be a comfortable room temperature below which space heating is generally required. The forecast uses the Environment Canada HDD data for Shearwater Airport for the years 2001-2010 which is 3,960 HDD.

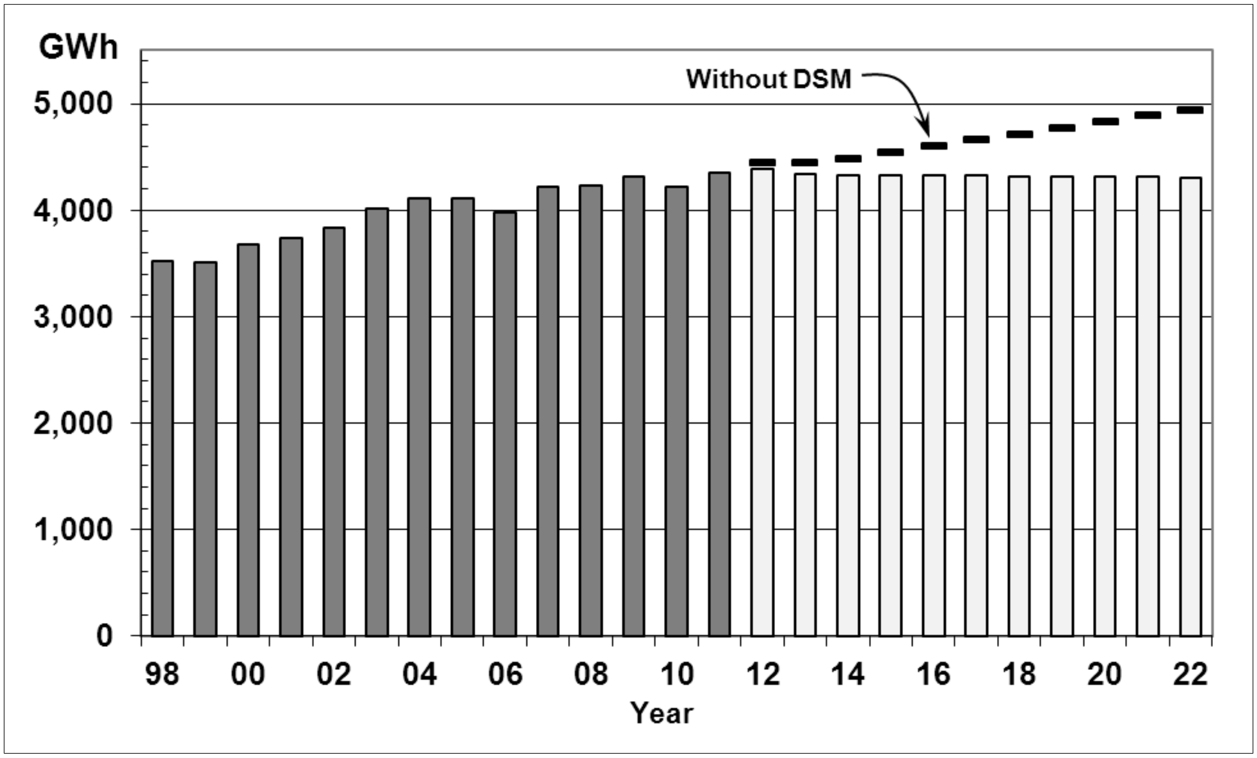
Figure 8 shows the variation in the actual annual HDDs over the past ten years and the projection used for the forecast.

Figure 8 Annual NS Heating Degree-Days



The residential sector load has grown at an average annual rate of 0.5 percent over the past five years (0.8 percent when adjusted for the effects of weather). Annual residential loads are shown in Figure 9.

Figure 9 Annual Energy – Residential Sector



Growth in this sector is expected to be flat or slightly declining. The 2013 load forecast for this sector is 4,340 GWh which is just slightly below the load in 2011. Without the effects of DSM, 2013 sales are forecast at 4,444 GWh or 1.1 percent annual increase on 2011.

Figure 10 Residential Sector Energy

Year	Residential Sector GWh	Growth Rate %	Without future DSM Residential GWh	Growth Rate %
2002	3,829	2.3	3,829	2.3
2003	4,011	4.7	4,011	4.7
2004	4,114	2.4	4,114	2.4
2005	4,114	0.0	4,114	0.0
2006	3,979	-3.3	3,979	-3.3
2007	4,218	6.0	4,218	6.0
2008[1]	4,232	0.3	4,232	0.3
2009	4,318	2.0	4,318	2.0
2010	4,216	-2.4	4,216	-2.4
2011	4,346	3.1	4,346	3.1
2012F	4,384	0.9	4,437	2.1
2013F	4,340	-1.0	4,444	0.2
2014F	4,323	-0.4	4,482	0.8
2015F	4,324	0.0	4,538	1.3
2016F	4,326	0.0	4,599	1.3
2017F	4,325	0.0	4,656	1.3
2018F	4,310	-0.3	4,701	1.0
2019F	4,316	0.1	4,766	1.4
2020F	4,317	0.0	4,827	1.3
2021F	4,314	-0.1	4,884	1.2
2022F	4,304	-0.2	4,933	1.0

Annual residential sector loads are shown in Figure 10. Over the 10 year forecast period, the residential load growth is expected to decrease by 0.2 percent annually. Without the effects of DSM, residential sector loads would increase by 1.1 percent per year.

Commercial Sector Sales

Energy sales to the commercial sector in 2011 represented 30 percent of Nova Scotia sales. This customer group includes restaurants, hotels, offices, recreational facilities, stores warehouses hospitals, schools and universities and street and traffic lights, as well as commercial customers served by municipal utilities.

The level of business activity in the province is a major factor in determining the energy sales to this sector. The level of business activity is captured in GDP and for this commercial model, the

[1] The actual results of 2008 to 2011 include the effects of past DSM programs.

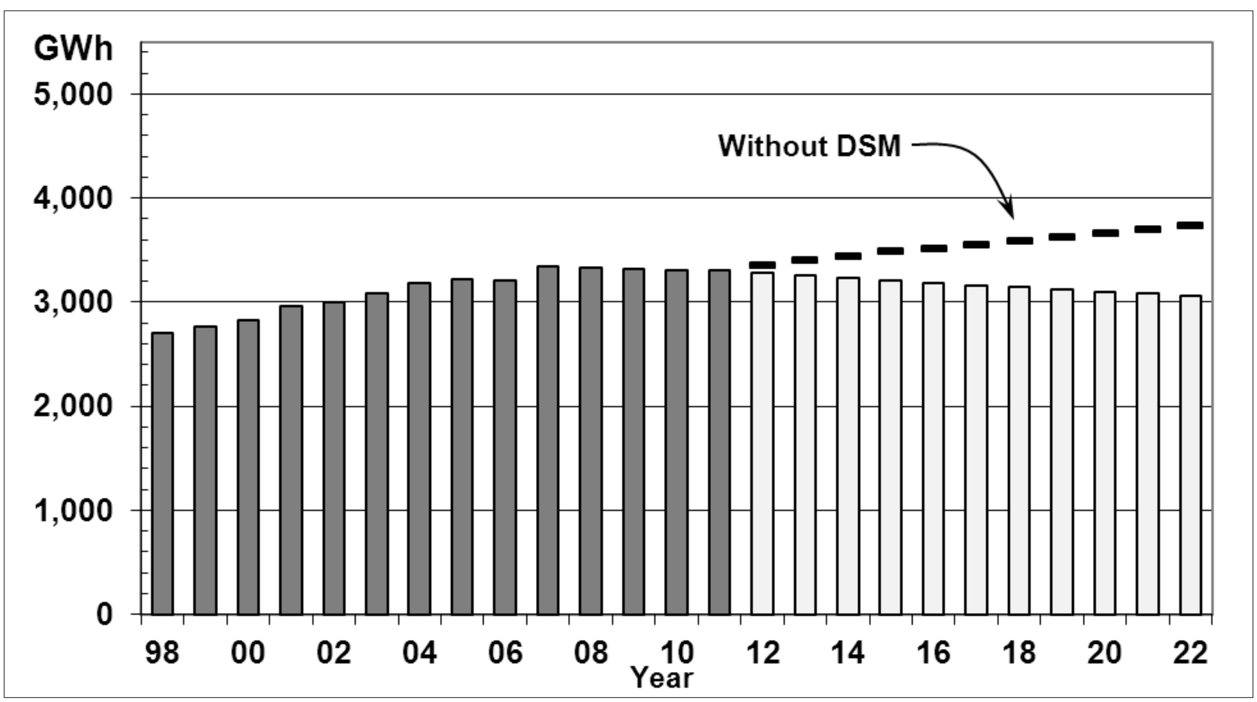
service sector of GDP is well correlated to the commercial sector sales. This is a change from the commercial models of prior years, and also allowed for the removal of the domestic sales as a variable in the commercial sales model. This indirect link to the domestic sales and its intrinsic weather effects was replaced by an actual heating degree-day variable in the commercial model. As in the residential sector, the historical period used for the commercial model was shortened to 20 years from 25 to better represent the recent trends in the market.

The commercial sector forecast is produced using the following econometric model with real GDP for the service sector (RQSRS), annual heating degree-days (HDD), and the commercial electricity sales from the previous year. The equation is shown below. Complete details of the commercial sector model are presented in the Appendix of this report.

$$Commercial = 0.05947\ RQSRS + 0.1129\ HDD + 0.5015\ Commercial\ load_{-1}$$

Additionally, the largest commercial customers are surveyed to obtain their forecasts of any foreseen load changes. This information is used in a reconciliation of the sector load by rate class. Annual commercial sector loads are indicated in Figure 11.

Figure 11 Annual Energy – Commercial Sector



Annual growth in this sector has averaged 0.6 percent over the past 5 years but is forecast to decrease over the forecast period. With the effects of DSM, the annual load rate is expected to decline an average 0.7 percent over the next 10 year period (or increase 1.1 percent without conservation effects). The annual commercial sector loads are shown in Figure 12.

Figure 12 Commercial Sector Energy

Year	Commercial With future DSM GWh	Growth Rate %	Commercial Without future DSM GWh	Growth Rate %
2002	2,997	1.3	2,997	1.3
2003	3,091	3.1	3,091	3.1
2004	3,188	3.1	3,188	3.1
2005	3,223	1.1	3,223	1.1
2006	3,211	-0.4	3,211	-0.4
2007	3,343	4.1	3,343	4.1
2008[2]	3,327	-0.5	3,327	-0.5
2009	3,320	-0.2	3,320	-0.2
2010	3,305	-0.5	3,305	-0.5
2011	3,310	0.1	3,310	0.1
2012F	3,279	-0.9	3,351	1.3
2013F	3,259	-0.6	3,395	1.3
2014F	3,238	-0.6	3,438	1.3
2015F	3,214	-0.7	3,479	1.2
2016F	3,186	-0.9	3,516	1.1
2017F	3,161	-0.8	3,552	1.0
2018F	3,141	-0.7	3,588	1.0
2019F	3,121	-0.6	3,626	1.0
2020F	3,102	-0.6	3,664	1.0
2021F	3,082	-0.6	3,701	1.0
2022F	3,059	-0.8	3,734	0.9

Industrial Sector Sales

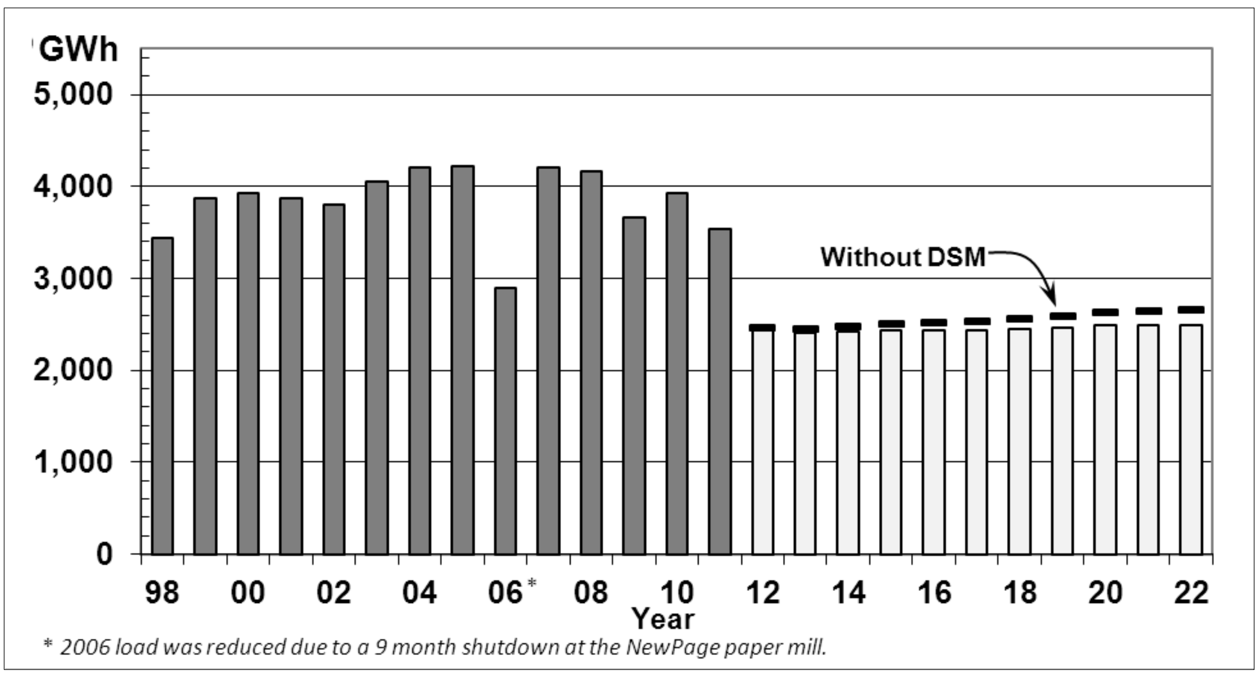
In 2011, the industrial sector represented 32 percent of Nova Scotia total electricity sales. This group is comprised of customers who process raw materials or manufacture finished goods. It includes both primary resource industries such as mining and forestry as well as secondary industries such as manufacturing and food processing. While this sector is made up of over

[2] The actual results of 2008 to 2011 include the effects of past DSM programs.

2,000 customers, a few large customers represent most of the energy consumption. In recent years, the five largest customers used two-thirds of the energy in this sector and one-quarter of in-province energy sales. With relatively few customers representing a large proportion of the load in this sector, changes in production levels, equipment and technology changes, expansion or downsizing can have a significant impact on the load.

The demand for manufactured and processed goods is driven by exports as well as the health of the provincial economy. Annual industrial sector loads are shown in Figure 13. The 12 percent drop in 2009 sales was the result of the economic downturn which directly affected the markets for many industrial customers. The drop in 2006 sales depicted in the figure was the result of a 9-month shutdown at the province's largest paper mill. This same mill closed indefinitely in September 2011, resulting in the large reduction in industrial sales shown in the forecast period.

Figure 13 Annual Energy – Industrial Sector



The load for this sector is forecast using a combination of econometric modeling and large customer surveys. The Small Industrial customer class model uses NS Manufacturing GDP and Non-Residential Investment as economic inputs and the Medium Industrial customer class model uses NS Manufacturing GDP as the economic drivers. Both models use the previous year's sales as a lagged dependent variable.

The Small Industrial econometric model equation is shown below. Complete fit statistics and model specifications are shown in the Appendix to this report.

$$SM\_IND = 0.00483\ GDP + 0.008804\ NonRes\_Inv + 0.4507\ SM\_IND_{-1}$$

The Medium Industrial econometric model equation is shown below.

$$MED\_IND = 0.08241\ GDP\_Man + 0.6025\ MED\_IND_{-1}$$

Large customer forecasts are based on trends and customer input. Customers are surveyed regularly in order to gather their forecast monthly electricity requirements over the next three year period, any planned production levels or equipment changes. The information is used as input to prepare the large industrial load forecast by rate class. The annual industrial sector loads are shown in Figure 14.

Figure 14 Industrial Sector Energy

Year	With future DSM Industrial GWh	Growth Rate %	Without future DSM Industrial GWh	Growth Rate %
2002	3,799	-1.9	3,799	-1.9
2003	4,046	6.5	4,046	6.5
2004	4,212	4.1	4,212	4.1
2005	4,215	0.1	4,215	0.1
2006	2,888	-31.5	2,888	-31.5
2007	4,205	45.6	4,205	45.6
2008[3]	4,161	-1.0	4,161	-1.0
2009	3,658	-12.1	3,658	-12.1
2010	3,932	7.5	3,932	7.5
2011	3,535	-10.1	3,535	-10.1
2012F	2,437	-31.1	2,453	-30.6
2013F	2,406	-1.2	2,437	-0.7
2014F	2,423	0.7	2,467	1.2
2015F	2,431	0.3	2,490	0.9
2016F	2,435	0.2	2,508	0.7
2017F	2,438	0.1	2,526	0.7
2018F	2,448	0.4	2,550	1.0
2019F	2,468	0.8	2,584	1.3

[3] The actual sales for 2008 to 2011 include the effects of past DSM programs.

Year	With future DSM Industrial GWh	Growth Rate %	Without future DSM Industrial GWh	Growth Rate %
2020F	2,485	0.7	2,617	1.2
2021F	2,490	0.2	2,636	0.7
2022F	2,485	-0.2	2,645	0.3

With the indefinite closure of the largest paper mill and no new expansions or customer additions of large magnitude anticipated, combined with slow recovery from the economic recession, growth in the industrial sector is expected to remain low. DSM is expected to further diminish overall growth in this sector.

Industrial sector load growth averaged 1.4 percent per year from 2000-2005, but dipped by 20 percent in 2006 due to the paper mill shutdown. For the five year period ending 2008, the average annual growth was 0.6 percent, encompassing the 2003 expansion at the largest paper mill. The industrial load for 2009 dropped 12 percent with many customers operating below full load due to market conditions during the recession. In 2010, the industrial sector began a recovery from the recession, posting a growth rate of 7.5 percent, however; the shutdown of the pulp and paper mill in Port Hawkesbury towards the end of 2011 led to a drop in load of almost 1,000 GWh. Between 2012-2022, assuming the Port Hawkesbury mill does not restart, industrial sales are expected to remain stable around 2,450 GWh. Without DSM effects, the sector is forecast to grow at 0.8 percent annually. Should the mill restart, an additional 1,000 GWh per year are expected.

Total Sales

Given the combined activities of each sector, including large industrial shutdowns, expansions, etc., total sales grew at an average annual rate of 1 percent over the 5 years ending 2008, but then had a 3.6 percent drop in 2009 due to the economic slowdown. With the shutdown of Newpage in Q3 2011, overall sales are forecast to decrease 9.8 percent in 2012 relative to 2011. Combining each of the sector sales forecasts, total Nova Scotia sales are expected to decline with an average annual growth rate of 0.3 percent over the 10 year forecast period due to the effects of energy conservation. Billed sales are therefore expected to decline from 11,191 GWh in 2011 to 9,848 GWh by the year 2022. Without the effects of conservation measures, growth is expected to average 1.0 percent per year.

System Losses and Unbilled Sales

The load forecast is developed using Nova Scotia Power "billed" sales rather than "accrued" sales to provide a longer historical time series upon which to base the models. Billed sales refers to the amount of energy billed to customers in a given time period such as a calendar month or a year, whereas accrued sales recognizes the amount of energy actually generated and consumed during that specific time period. Due to the periodic nature and delays inherent in any meter reading and billing process, billed sales will vary somewhat from accrued sales. Energy generated and sold but not yet billed, is referred to as "Unbilled" sales.

The difference between energy generated for use within provincial borders and the total NS Power billed sales comprises transmission and distribution system losses as well as changes to the level of unbilled sales.

Based on historical estimates, losses are forecast to range between 6.7 and 6.8 percent of the total Nova Scotia energy requirement over the forecast period.

Net System Requirement

The Net System Requirement (NSR) is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. Annual NSR is shown in Figure 15.

Figure 15 Net System Requirement

Year	With future DSM Net System Requirement GWh	Growth Rate %	Without future DSM Net System Requirement GWh	Growth Rate %
2002	11,501	1.8	11,501	1.8
2003	12,009	4.4	12,009	4.4
2004	12,388	3.2	12,388	3.2
2005	12,338	-0.4	12,338	-0.4
2006	10,946	-11.3	10,946	-11.3
2007	12,640	15.5	12,639	15.5
2008[4]	12,539	-0.8	12,539	-0.8
2009	12,073	-3.7	12,073	-3.7
2010	12,158	0.7	12,158	0.7
2011	11,908	-2.1	11,908	-2.1
2012F	10,840	-9.0	10,990	-7.7
2013F	10,721	-1.1	11,014	0.2
2014F	10,710	-0.1	11,145	1.2
2015F	10,694	-0.1	11,274	1.2
2016F	10,668	-0.2	11,396	1.1
2017F	10,646	-0.2	11,519	1.1
2018F	10,617	-0.3	11,632	1.0
2019F	10,624	0.1	11,780	1.3
2020F	10,624	0.0	11,922	1.2
2021F	10,604	-0.2	12,044	1.0
2022F	10,562	-0.4	12,143	0.8

The NSR for the province has grown at an average of 0.9 percent per year in the five year period from 2003-2008 and then declined by 3.7 percent in 2009 due to the recession. NSR is forecast to decline by 0.3 percent per year over the next 10 years with the effects of DSM. Without DSM effects, growth is forecast to average 1.0 percent annually.

Rate Class Sales

Forecast sales by sector are allocated into 13 rate classes for revenue forecasting purposes. The following section describes these rate classes and their expected energy requirements for the forecast period. In most cases, load growth trends by rate class are due to the same factors that affect the sector to which they belong, however, migration of customers between rate classes in the same sector can affect both historical and forecast energy requirements by class. Sales

[4] The actual system load for 2008 to 2011 includes the effects of past DSM programs.

requirements by class are computed using historical and forecast trends and customer migration between classes.

Residential

This class includes residential sector customers served directly by NS Power and represented 39 percent of total NS Power sales in 2011. All-electric, non-all-electric and residential Time-of-Day (TOD) rate customers are included in this class. As of December 2011, there were 446,370 domestic customers responsible for annual billed sales of 4,274 GWh, an average of 9,575 kWh/customer. Residential class sales grow for the reasons stated in the residential sector description, and are forecast to diminish by 0.2 percent annually over the forecast period with the effects of DSM.

Small General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was less than 12,000 kWh. This threshold was changed to 32,000 kWh/yr by January 2005. This moved some customers previously billed under the General (medium commercial) rate to Small General, thereby decreasing the load in the General class and increasing the Small General load. At the end of 2011, this class comprised 23,475 customers that consumed 241 GWh in 2011. It is forecast at 231 GWh in 2013.

General

Prior to 2004, this class comprised commercial sector customers whose annual energy consumption was greater than 12,000 KWh and for whom no other class was applicable. As discussed in the Small General class section, this threshold was changed, causing a migration of customers from General to Small General. As of 2011, this class had approximately 11,505 customers accounting for the major portion of commercial sector energy and 22 percent of total NS Power sales for 2011. For 2013, energy sales for this class are anticipated to be 2,435 GWh.

Large General

This class comprises large commercial sector customers (malls, universities, hospitals, etc) whose regular maximum demand is 2,000 kVA or more. As of December 2011, there were 18 customers in this class representing 3.7 percent of NS Power sales. For 2013, energy sales for this class are forecast to be 396 GWh.

Small Industrial

This class comprises small industrial, farming and processing customers whose regular demand is less than 250 kVA. This class was made up of 2,236 customers as of December 2011, and had sales representing 2.3 percent of NS Power energy sales. For 2013, energy sales for this class are projected to be 258 GWh.

Medium Industrial

This class is applicable to any industrial customer having a regular demand of at least 250 kVA, but less than 2,000 kVA. As of December 2011, there were 193 customers in this class, representing about 4.4 percent of NS Power sales. For 2013, energy sales for this class are projected to be 499 GWh.

Large Industrial

This class is available to larger industrial customers having a regular demand of 2,000 KVA or more. Customers in this class may choose to have all or a portion of their load served as interruptible with the remaining load considered firm. Customers on the interruptible rider receive a reduction in demand charge. As of December 2011, there were 24 customers with the interruptible rider and four customers taking firm service only. The combined energy for the firm and interruptible customers was 915 GWh, and represented 8.2 percent of 2011 Nova Scotia Power energy sales. The anticipated combined energy for firm and interruptible customers in 2013 is 921 GWh, or 9.2 percent of energy sales.

Municipal

This class comprises municipal utilities that purchase wholesale electricity from NS Power and distribute it within their own service territories. The six municipalities are: Antigonish, Berwick, Canso, Lunenburg, Mahone Bay and Riverport. Loads within these municipalities include customers in residential, commercial and industrial sectors, and have been included in Nova Scotia Power's total sector sales estimates. Energy in this class also includes the losses incurred by the municipal utility in delivering the electricity requirements. These losses are estimated to average approximately 4 percent of sales.

An Open Access Transmission Tariff (OATT), which supports the opening of the electricity market in Nova Scotia, is now available to the six municipal utilities. Beginning in 2007, it has been possible for these municipalities to source their electricity from providers other than NS Power.

While this forecast currently assumes that Nova Scotia Power continues to serve this load, adjustments will have to be made if the volume becomes significant in terms of long-term forecasting. In 2011, the municipal class represented 1.7 percent of total Nova Scotia Power sales. The anticipated energy sales in 2013 are 193 GWh including the effects of energy conservation programs.

Unmetered Services

This class is comprised of street and area lighting, as well as miscellaneous lighting and small loads. In 2011, unmetered sales represented approximately 1.0 percent of total Nova Scotia Power sales. The anticipated energy sales in 2013 are 104 GWh including the effects of a street light relamping project. An estimated 4 GWh is projected to be saved in the first year of the project to replace most of the street lights in Nova Scotia with light-emitting diode (LED) technology. The project is expected to span a five year period beginning in 2012 and result in total annual savings of 44 GWh after all lights are converted.

Generation Replacement and Load Following

This class is available to customers who have their own generation capacity of no less than 2,000 kW. As of December 2011, this class had three customers and represented about 0.1 percent of total Nova Scotia Power sales. This class is also interruptible load and is currently forecast to remain near its 2011 level of approximately 17 GWh annually.

Mersey System

This class involves specific contract energy to one customer, Bowater Mersey Paper Company, in accordance with the Mersey System Agreement.

Load Retention Tariff (LRT)

This rate is granted to existing large industrial customers only in circumstances where retaining the customers' load, at the price offered by this rate, is better for other electric customers than losing the load in question. For 2013, one customer is expected to consume 322 GWh under this rate.

Extra Large Industrial 2 Part Real Time Pricing (ELI 2P-RTP)

This rate operates with a standard energy rate and credits/charges for actual loads below/above the customer's pre-determined baseline load level (CBL). This rate was designed to create a mechanism enabling customers to gain benefits equal to the benefit created by altering load usage in accordance with hourly price signals. The customer pays a standard energy charge with credits based on decremental energy below the CBL and costs added for incremental energy taken above the CBL. In addition, it is priority interruptible in nature from a supply perspective. Sales under this rate in 2011 were 1,475 GWh or approximately 13 percent of NS Power sales. As of 2012, there are no customers under this rate and we have removed it from our tariff book.

One-Part Real Time Price (1P-RTP)

This is an energy-only rate based on NS Power's 20 minute-ahead forecast hourly marginal energy costs plus differing fixed cost adders for on-peak and off-peak usage. It is available to customers served at transmission or distribution voltages with loads of 2,000 kVA or more. The fixed cost adders are calculated annually in advance and are based on NS Power's budgeted costs. Potentially lower prices in off-peak periods can provide an incentive to customers to shift energy consumption from weekdays to nights and weekends, off the NS Power system peak. This rate was used significantly in 2001 and 2002, but became unattractive to customers in 2003 as off-peak marginal costs rose.

System Losses and Unbilled Sales

This category includes Nova Scotia Power transmission losses, distribution losses and the year-over-year change in unbilled sales. Losses on sales within the service area of municipal utilities are not included in this class, but are included in the municipal rate class to which they belong. Transmission losses are forecast at approximately 3 percent of the transmission system energy requirement. NS Power distribution losses are forecast at approximately 5.5 percent of distribution level sales. Residential and commercial classes tend to have higher losses due to the lower voltages at which they are served. The overall mix of sales to each sector results in total NS Power losses which are forecast to average 6.8 percent of NSR over the forecast period.

Peak Demand

The total system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads and due to the weather-sensitive load component in Nova Scotia, the total system peak occurs in the period from December through February.

Peak demands are measured on an individual hour-by-hour basis and are not directly related to monthly heating degree days, but rather to the daily or hourly temperatures which drive space heating load. On some cold weather occasions, load does not reach the anticipated peak due to NS Power requests for interruption or the ELI-2P-RTP customers responding to price signals.

For the winter of 2010/2011, the January peak reached 2,168 MW at a temperature of -13°C with the largest industrial customers operating below full load.

With the exception of large customer classes, monthly and annual net system peaks are computed using forecast monthly energy and average historical coincident load factors for each of the rate classes. Monthly peak loss percentages are applied to each monthly sales peak to produce losses by class and are then summed to produce the total peak demand forecast. This method produces forecast peaks that while not explicitly tied to a particular hourly temperature, recognize and average the actual peak and energy relationships from recent years.

The system peak for 2013 is forecast at 2,098 MW. Over the longer term, net system peak is forecast to decrease slightly to 2,053 MW in 2022, which represents decline of 0.3 percent annual growth rate due to the effects of conservation and DSM programs. Without these programs, annual growth averages 1.1 percent.

Non-Firm Coincident Peak

NS Power offers interruptible or "non-firm" service to industrial customers. Certain industrial customers who meet specific criteria may utilize discounted rates in exchange for agreeing to have their electricity supply interrupted on short notice in order to meet any necessary emergency peak reductions required to maintain system stability. These rate classes are the "Generation Replacement and Load Following" rate, the "Extra Large Industrial Two Part Real Time Pricing" rate and the "Interruptible" rider of the Large Industrial rate. The combined interruptible demand of these customers coincident with the monthly system peaks has, in past, exceeded 400 MW. At the January 2011 peak, there were 30 customers on these rates, representing a combined coincident non-firm peak of 265 MW.

Non-firm coincident peak demand is forecast explicitly by customer for the near-term and an allowance is made for customer growth in the longer term. With the shutdown of the Newpage Port Hawkesbury paper mill, the non-firm coincident peak has been reduced by over 170 MW and is expected to remain in the 130 MW to 140 MW range over the forecast period assuming there are no major changes made to the rate's availability or requirements.

Total Coincident Firm Peak

Total Coincident Firm Peak is the demand at the time of Nova Scotia Power's system peak that is attributable to all firm classes (e.g.: residential, small general, etc.), but excluding the non-firm customer classes mentioned above.

Total Non-coincident Firm Peak is defined as the highest peak demand for the combined firm classes, which may or may not be coincident with the time of NS Power's total system peak, depending upon non-firm customer demand fluctuations. Load shape statistics indicate that especially during winter months, the non-coincident firm peak and the coincident firm peak are usually close, due to the peak often being driven by cold temperatures.

Load Forecast

Appendices

Appendix A

2012 NS Power Forecast

Residential Sector Econometric Model Detail

$$DOMENG = 363.2\ AIDX + 0.247\ CHDD - 41.97\ RREP + 0.09636\ RRCGOODS + 0.4979\ DOMENG_{-1}$$

Forecast Model for DOMENG

Model Details

Dynamic regression
Regression(5 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
AIDX	363.2	83.72	4.338	0.9994
CUSTHDD	0.2470	0.02968	8.323	1.000
RRCGOODS	0.09636	0.03671	2.625	0.9809
RREP	-41.97	17.44	-2.406	0.9705
DomEng1	0.4979	0.1111	4.480	0.9996

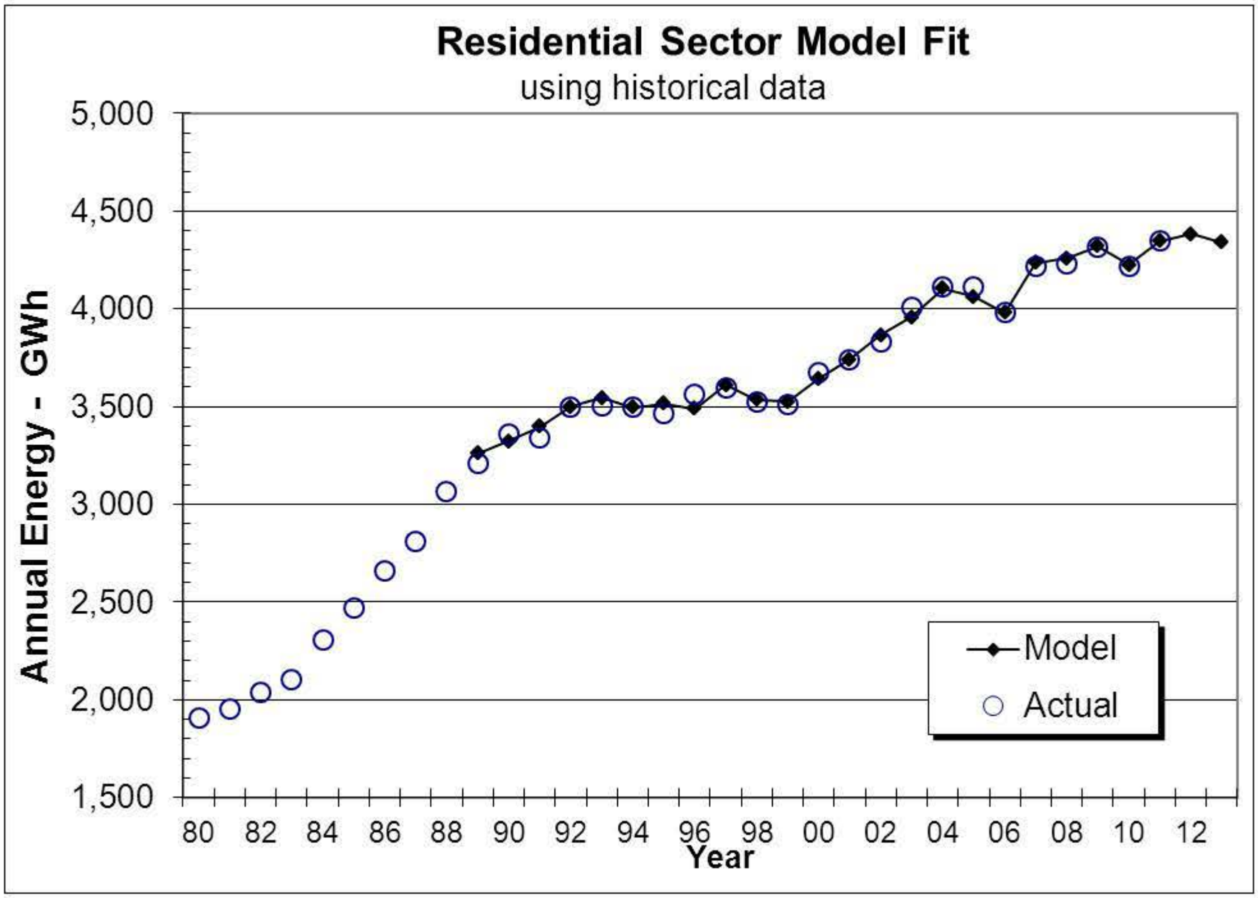
Within-Sample Statistics

Sample size	20	No. parameters	5
Mean	3847.60	Std. deviation	323.35
Adj. R-square	0.99	Durbin-Watson	2.64
Ljung-Box(10)	13.5 P=0.80	Forecast error	34.62
BIC	43.59	MAPE	0.57%
MAD	21.68		

Residential Model Input Variables and Contributions

Year	AIDX	AIDX Contrib.	CHDD	CHDD Contrib.	Electric Price	Electric Price Contrib.	Consumer Goods Sales	Consumer Goods Contrib.	DomEng[-1]	DomEng[-1] Contrib.	Nat. Gas Effect	Future DSM	DomEng*	Actual	Growth
		GWh		GWh		GWh		GWh		GWh	GWh	GWh	GWh	GWh	%
1994	1.799	653	3,567	881	11.90	-500	7,554	728	3,481.1	1,733			**3,496**	**3,498**	-0.2%
1995	1.783	648	3,587	886	11.74	-493	7,484	721	3,519.4	1,752			**3,514**	**3,463**	-1.0%
1996	1.767	642	3,603	890	12.02	-504	7,552	728	3,484.4	1,735			**3,490**	**3,565**	2.9%
1997	1.771	643	3,735	922	11.73	-492	7,814	753	3,585.7	1,785			**3,612**	**3,595**	0.8%
1998	1.750	636	3,357	829	11.72	-492	8,061	777	3,588.8	1,787			**3,536**	**3,524**	-2.0%
1999	1.728	628	3,229	798	12.17	-511	8,442	813	3,610.9	1,798			**3,526**	**3,512**	-0.4%
2000	1.696	616	3,562	880	11.68	-490	8,647	833	3,626.3	1,806			**3,644**	**3,672**	4.6%
2001	1.695	616	3,671	907	11.42	-479	8,684	837	3,738.8	1,862			**3,742**	**3,741**	1.9%
2002	1.669	606	3,980	983	11.11	-466	8,917	859	3,785.5	1,885			**3,867**	**3,829**	2.3%
2003	1.656	602	4,163	1028	11.01	-462	9,022	869	3,858.4	1,921			**3,958**	**4,010**	4.7%
2004	1.638	595	4,416	1091	10.78	-452	9,146	881	3,996.3	1,990			**4,104**	**4,114**	2.6%
2005	1.626	590	4,159	1027	11.21	-471	9,265	893	4,060.1	2,022			**4,061**	**4,112**	0.0%
2006	1.599	581	3,719	919	11.55	-485	9,422	908	4,133.5	2,058			**3,980**	**3,979**	-3.2%
2007	1.585	576	4,630	1144	10.98	-461	9,668	932	4,108.4	2,046			**4,236**	**4,218**	6.5%
2008	1.535	557	4,570	1129	11.20	-470	9,983	962	4,175.3	2,079			**4,270**	**4,232**	0.8%
2009	1.531	556	4,921	1215	12.42	-521	10,032	967	4,221.8	2,102			**4,320**	**4,318**	1.2%
2010	1.517	551	4,236	1046	11.55	-485	10,178	981	4,282.0	2,132			**4,226**	**4,216**	-2.2%
2011	1.497	544	4,654	1150	11.62	-488	10,086	972	4,356.2	2,169			**4,346**	**4,346**	2.8%
2012	1.479	537	5,001	1235	12.53	-526	10,310	993	4,413.7	2,198	1.0	53	**4,384**		0.9%
2013	1.461	531	5,126	1266	13.48	-566	10,418	1,004	4,437.1	2,209	1.1	104	**4,340**		-1.0%
2014	1.445	525	5,228	1291	13.32	-559	10,501	1,012	4,443.8	2,213	1.2	158	**4,323**		-0.4%
2015	1.431	520	5,331	1317	13.05	-548	10,573	1,019	4,481.6	2,231	1.3	214	**4,324**		0.0%
2016	1.417	515	5,447	1345	12.95	-543	10,613	1,023	4,538.3	2,260	1.4	273	**4,326**		0.0%
2017	1.406	510	5,567	1375	13.00	-546	10,661	1,027	4,598.6	2,290	1.4	332	**4,325**		0.0%
2018	1.395	507	5,687	1405	13.38	-562	10,725	1,033	4,656.2	2,318	1.4	391	**4,310**		-0.3%
2019	1.387	504	5,806	1434	13.13	-551	10,791	1,040	4,701.0	2,341	1.5	451	**4,316**		0.1%
2020	1.379	501	5,925	1464	13.17	-553	10,827	1,043	4,766.5	2,373	1.5	510	**4,317**		0.0%
2021	1.373	499	6,046	1493	13.22	-555	10,835	1,044	4,827.4	2,404	1.5	570	**4,314**		-0.1%
2022	1.367	496	6,161	1522	13.27	-557	10,802	1,041	4,884.2	2,432	1.5	629	**4,304**		-0.2%

* - to align forecast to actuals in 2011, the modeled DomEng contains a launch adjustment of 0.8 GWh for 2011-2022


Residential Sector Model Fit
using historical data
Annual Energy - GWh
5,000
4,500
4,000
3,500
3,000
2,500
2,000
1,500
80 82 84 86 88 90 92 94 96 98 00 02 04 06 08 10 12
Year
Model
Actual

Commercial Sector Econometric Model Detail

$$COMENG = 0.05947\ RQSRS + 0.1129\ HDD + 0.5015\ COMENG_{-1}$$

Forecast Model for ComEng

Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
RQSRS	0.05947	0.01767	3.365	0.9963
ComEng[-1]	0.5015	0.1414	3.547	0.9975
HDD	0.1129	0.02903	3.891	0.9988

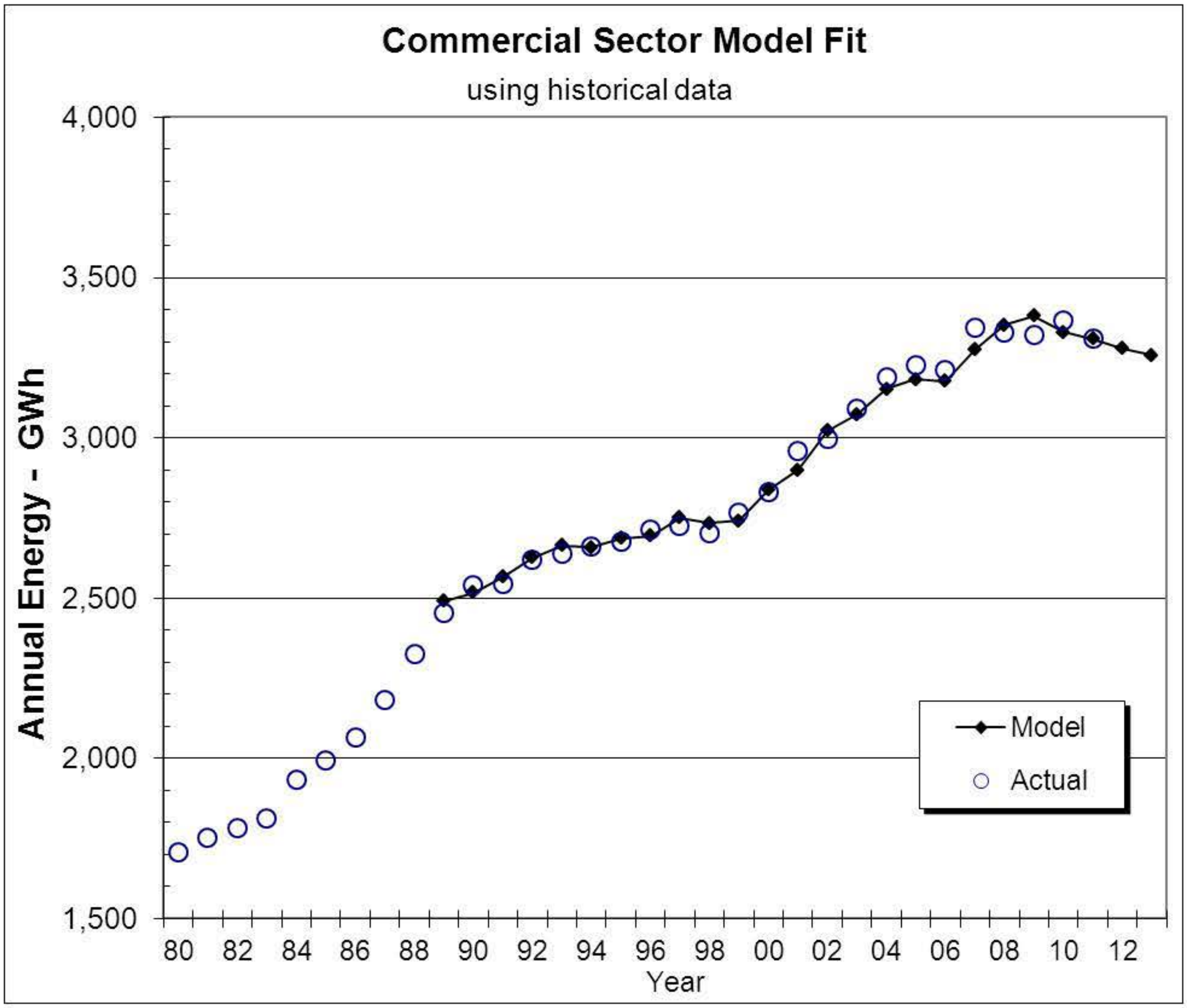
Within-Sample Statistics

Sample size	20	No. parameters	3
Mean	2980.21	Std. deviation	278.70
Adj. R-square	0.98	Durbin-Watson	1.49
Ljung-Box(12)	9.1 P=0.31	Forecast error	37.43
BIC	43.21	MAPE	0.96%
MAD	29.49		

Commercial Model Input Variables and Contributions

Year	RQSRS	RQSRS contrib	HDD	HDD contrib	$ComEng_{[-1]}$	$ComEng_{[-1]}$ contrib	Future DSM Effects	ComEng*	Actual	Growth
		GWh		GWh		GWh	GWh	GWh	GWh	%
1994	14,565	866	4,154	469	2,638	1,323		**2,658**	2,660	0.8%
1995	14,800	880	4,152	469	2,666	1,337		**2,686**	2,676	0.6%
1996	14,853	883	4,154	469	2,676	1,342		**2,694**	2,713	1.4%
1997	15,252	907	4,283	484	2,713	1,360		**2,751**	2,725	0.5%
1998	15,713	934	3,829	432	2,725	1,367		**2,733**	2,702	-0.8%
1999	16,464	979	3,606	407	2,702	1,355		**2,742**	2,767	2.4%
2000	16,954	1008	3,909	441	2,767	1,388		**2,837**	2,829	2.3%
2001	17,482	1040	3,911	442	2,829	1,419		**2,900**	2,959	4.6%
2002	18,129	1078	4,075	460	2,959	1,484		**3,022**	2,996	1.3%
2003	18,530	1102	4,146	468	2,996	1,503		**3,073**	3,091	3.1%
2004	18,785	1117	4,295	485	3,091	1,550		**3,152**	3,188	3.1%
2005	19,159	1139	3,936	444	3,188	1,599		**3,182**	3,225	1.2%
2006	19,712	1172	3,422	386	3,225	1,617		**3,176**	3,211	-0.4%
2007	20,123	1197	4,142	468	3,211	1,610		**3,275**	3,343	4.1%
2008	20,591	1225	3,990	450	3,343	1,676		**3,303**	3,327	-1.2%
2009	20,822	1238	4,190	473	3,327	1,668		**3,322**	3,320	0.6%
2010	21,286	1266	3,532	399	3,320	1,665		**3,272**	3,365	-1.5%
2011	21,548	1281	3,791	428	3,305	1,658		**3,310**	3,310	1.1%
2012	21,888	1302	3,960	447	3,310	1,660	72	**3,279**		-0.9%
2013	22,278	1325	3,960	447	3,351	1,681	137	**3,258**		-0.6%
2014	22,627	1346	3,960	447	3,395	1,703	200	**3,238**		-0.6%
2015	22,959	1365	3,960	447	3,438	1,724	265	**3,214**		-0.7%
2016	23,229	1381	3,960	447	3,479	1,745	330	**3,186**		-0.9%
2017	23,525	1399	3,960	447	3,516	1,763	391	**3,161**		-0.8%
2018	23,829	1417	3,960	447	3,552	1,781	447	**3,141**		-0.7%
2019	24,156	1437	3,960	447	3,588	1,799	504	**3,121**		-0.6%
2020	24,476	1456	3,960	447	3,626	1,818	561	**3,102**		-0.6%
2021	24,779	1474	3,960	447	3,664	1,837	618	**3,082**		-1.2%
2022	25,031	1489	3,960	447	3,701	1,856	675	**3,059**		-1.4%

* - to align forecast to actuals in 2011, the modeled ComEng contains a launch adjustment of -57.5 GWh for 2011-2022


Commercial Sector Model Fit
using historical data
Annual Energy - GWh
4,000
3,500
3,000
2,500
2,000
1,500
80
82
84
86
88
90
92
94
96
98
00
02
04
06
08
10
12
Year
Model
Actual

Industrial Econometric Model Details

Small and Medium Industrial class models are shown below.

$$SM\_IND = 0.004832\ GDP + 0.008804\ NonRes\_Inv + 0.4507\ SM\_IND_{-1}$$

$$MED\_IND = 0.08241\ GDP\_Man + 0.6025\ MED\_IND_{-1}$$

Small Industrial

Dynamic regression
Regression(3 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
RQTOS	0.004832	0.0007970	6.062	0.9999
SMIND[-1]	0.4507	0.08299	5.431	0.9998
RRINRBS	0.008804	0.002009	4.383	0.9991

Within-Sample Statistics

Sample size	15	No. parameters	3
Mean	231.25	Std. deviation	24.87
Adj. R-square	0.98	Durbin-Watson	1.82
Ljung-Box(7)	7.2 P=0.60	Forecast error	3.44
BIC	4.03	MAPE	1.03%
MAD	2.37		

Medium Industrial

Dynamic regression
Regression(2 regressors, 0 lagged errors)

Term	Coefficient	Std. Error	t-Statistic	Percentile
RQMFS	0.08241	0.02164	3.808	0.9978
MEDIND[-1]	0.6025	0.1079	5.586	0.9999

Within-Sample Statistics

Sample size	15	No. parameters	2
Mean	509.54	Std. deviation	54.36
Adj. R-square	0.90	Durbin-Watson	1.33
Ljung-Box(8)	11.6 P=0.83	Forecast error	17.15
BIC	19.12	MAPE	2.68%
MAD	13.75		

Industrial Model Input Variables and Contributions

Small Industrial

Year	GDP	NonRes_Inv	GDP contrib	NonRes_Inv contrib	Sm_Ind[-1]	Sm_Ind[-1] contrib	Sm_Ind Model	Sm_Ind Actual	Growth
	$M2002	$M2002	GWh	GWh		GWh	GWh	GWh	%
1994	19,069	486	92	4.3	136	62	158	139	2.0%
1995	19,455	577	94	5.1	139	63	162	147	5.9%
1996	19,490	631	94	5.6	147	66	166	153	3.7%
1997	20,027	636	97	5.6	153	69	171	168	10.0%
1998	20,772	1,812	100	16.0	168	76	192	192	14.3%
1999	21,971	2,398	106	21.1	192	87	214	216	12.3%
2000	22,729	1,429	110	12.6	216	97	220	214	-1.0%
2001	23,531	1,509	114	13.3	214	96	223	222	4.0%
2002	24,509	1,379	118	12.1	222	100	231	234	5.3%
2003	24,955	1,357	121	11.9	234	106	238	238	1.8%
2004	25,250	1,298	122	11.4	238	107	241	239	0.4%
2005	25,593	1,070	124	9.4	239	108	241	241	0.8%
2006	25,774	1,047	125	9.2	241	109	242	240	-0.5%
2007	26,216	920	127	8.1	240	108	243	248	3.4%
2008	26,582	966	128	8.5	248	112	249	254	2.6%
2009	26,490	1,193	128	10.5	254	115	253	253	-0.7%
2010	27,046	1,099	131	9.7	253	114	254	254	0.7%
2011	27,460	1,075	133	9.5	254	115	253	253	-0.4%
2012	27,949	1,153	135	10.2	253	114	256		1.0%
2013	28,655	1,241	138	10.9	256	115	261		2.1%
2014	29,125	1,109	141	9.8	261	118	265		1.3%
2015	29,565	1,098	143	9.7	265	119	268		1.4%
2016	29,887	1,136	144	10.0	268	121	272		1.3%
2017	30,243	1,070	146	9.4	272	123	275		1.0%
2018	30,674	1,036	148	9.1	275	124	278		1.1%
2019	31,174	1,024	151	9.0	278	125	281		1.3%
2020	31,626	1,052	153	9.3	281	127	285		1.5%
2021	32,046	1,067	155	9.4	285	129	289		1.4%
2022	32,297	1,083	156	9.5	289	130	292		1.1%

* - to align forecast to actuals in 2011, the model contains a launch adjustment of -3.5 GWh for 2011-2022

Medium Industrial

Year	GDP_Man	GDP_Man contrib	Med_Ind$_{[-1]}$	Med_Ind$_{[-1]}$ contrib	Med_Ind Model	Med_Ind Actual	Growth
	$M2002	GWh		GWh	GWh	GWh	%
1994	1904	157	381	230	387	389	2.0%
1995	2048	169	389	234	403	382	-1.8%
1996	2044	168	382	230	399	378	-1.1%
1997	2154	177	378	228	405	401	6.1%
1998	2216	183	401	242	424	414	3.3%
1999	2412	199	414	249	448	454	9.6%
2000	2408	198	454	273	472	490	7.9%
2001	2421	199	490	295	494	518	5.8%
2002	2662	219	518	312	531	531	2.6%
2003	2629	217	531	320	537	558	4.9%
2004	2848	235	558	336	571	567	1.8%
2005	2822	233	567	342	574	557	-1.8%
2006	2569	212	557	336	547	567	1.8%
2007	2554	210	567	342	552	568	0.1%
2008	2504	206	568	342	549	539	-5.0%
2009	2367	195	539	325	520	492	-8.8%
2010	2521	208	492	296	504	495	0.6%
2011	2610	215	495	298	492	492	-0.6%
2012	2657	219	492	296	494		0.4%
2013	2852	235	494	297	511		3.5%
2014	2964	244	511	308	531		3.8%
2015	3057	252	531	320	550		3.7%
2016	3074	253	550	331	563		2.4%
2017	3163	261	563	339	578		2.7%
2018	3306	272	578	349	599		3.6%
2019	3517	290	599	361	629		5.0%
2020	3624	299	629	379	656		4.3%
2021	3622	299	656	395	672		2.4%
2022	3576	295	672	405	678		0.9%

* - to align forecast to actuals in 2011, the model contains a launch adjustment of -21.5 GWh for 2011-2022

Table A1: Energy Requirement – 2012 NS Power Forecast

Energy Forecast with Future DSM Program Effects

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Total Sales	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	786	12,338	-0.4
2006	3,979	-3.3	3,211	-0.4	2,888	-31.5	10,078	-12.8	868	10,946	-11.3
2007	4,218	6.0	3,343	4.1	4,205	45.6	11,767	16.8	873	12,639	15.5
2008	4,232	0.3	3,327	-0.5	4,161	-1.0	11,720	-0.4	819	12,539	-0.8
2009	4,318	2.0	3,320	-0.2	3,658	-12.1	11,297	-3.6	777	12,073	-3.7
2010	4,216	-2.4	3,305	-0.5	3,932	7.5	11,453	1.4	704	12,158	0.7
2011	4,346	3.1	3,310	0.1	3,535	-10.1	11,191	-2.3	717	11,908	-2.1
2012	4,384	0.9	3,279	-0.9	2,437	-31.1	10,099	-9.8	737	10,839	-9.0
2013	4,340	-1.0	3,259	-1.5	2,406	-1.2	10,005	-0.9	716	10,721	-1.1
2014	4,323	-0.4	3,238	-0.6	2,423	0.7	9,984	-0.2	725	10,710	-0.1
2015	4,324	0.0	3,214	-0.7	2,431	0.3	9,969	-0.2	724	10,694	-0.1
2016	4,326	0.0	3,186	-0.9	2,435	0.2	9,947	-0.2	721	10,668	-0.2
2017	4,325	0.0	3,161	-0.8	2,438	0.1	9,924	-0.2	722	10,646	-0.2
2018	4,310	-0.3	3,141	-0.7	2,448	0.4	9,899	-0.3	719	10,617	-0.3
2019	4,316	0.1	3,121	-0.6	2,468	0.8	9,905	0.1	719	10,623	0.1
2020	4,317	0.0	3,102	-0.6	2,485	0.7	9,905	0.0	719	10,624	0.0
2021	4,314	-0.1	3,082	-0.6	2,490	0.2	9,887	-0.2	717	10,604	-0.2
2022	4,304	-0.2	3,059	-0.8	2,485	-0.2	9,848	-0.4	714	10,562	-0.4

Table A2: Energy Requirement – 2012 NS Power Forecast

Energy Forecast without Future DSM Program Effects

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Total Sales	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
1994	3,498	0.4	2,660	1.0	2,756	0.3	8,914	0.5	679	9,593	0.0
1995	3,463	-1.0	2,676	0.6	2,864	3.9	9,003	1.0	671	9,674	0.8
1996	3,565	2.9	2,713	1.4	2,774	-3.1	9,052	0.5	701	9,753	0.8
1997	3,595	0.8	2,725	0.5	2,867	3.3	9,187	1.5	778	9,965	2.2
1998	3,524	-2.0	2,702	-0.8	3,442	20.1	9,668	5.2	743	10,412	4.5
1999	3,512	-0.4	2,767	2.4	3,872	12.5	10,150	5.0	720	10,870	4.4
2000	3,672	4.6	2,829	2.3	3,930	1.5	10,431	2.8	809	11,240	3.4
2001	3,741	1.9	2,959	4.6	3,873	-1.5	10,573	1.4	730	11,303	0.6
2002	3,829	2.3	2,996	1.3	3,799	-1.9	10,624	0.5	877	11,501	1.8
2003	4,010	4.7	3,091	3.1	4,046	6.5	11,147	4.9	862	12,009	4.4
2004	4,114	2.6	3,188	3.1	4,212	4.1	11,513	3.3	874	12,388	3.2
2005	4,114	0.0	3,223	1.1	4,215	0.1	11,553	0.3	785	12,338	-0.4
2006	3,979	-3.3	3,211	-0.4	2,888	-31.5	10,078	-12.8	868	10,946	-11.3
2007	4,218	6.0	3,343	4.1	4,205	45.6	11,767	16.8	873	12,639	15.5
2008	4,232	0.3	3,327	-0.5	4,161	-1.0	11,720	-0.4	819	12,539	-0.8
2009	4,318	2.0	3,320	-0.2	3,658	-12.1	11,297	-3.6	777	12,073	-3.7
2010	4,216	-2.4	3,305	-0.5	3,932	7.5	11,453	1.4	704	12,158	0.7
2011	4,346	3.1	3,310	0.1	3,535	-10.1	11,191	-2.3	717	11,908	-2.1
2012	4,437	2.1	3,351	1.3	2,453	-31.1	10,242	-8.7	749	10,990	-7.7
2013	4,444	0.2	3,395	1.3	2,437	-0.7	10,276	0.3	739	11,014	0.2
2014	4,482	0.8	3,438	1.3	2,467	1.2	10,386	1.1	759	11,145	1.2
2015	4,538	1.3	3,479	1.2	2,490	0.9	10,508	1.2	766	11,274	1.2
2016	4,599	1.3	3,516	1.1	2,508	0.7	10,623	1.1	773	11,396	1.1
2017	4,656	1.3	3,552	1.0	2,526	0.7	10,734	1.0	784	11,519	1.1
2018	4,701	1.0	3,588	1.0	2,550	1.0	10,840	1.0	792	11,632	1.0
2019	4,766	1.4	3,626	1.0	2,584	1.3	10,977	1.3	803	11,780	1.3
2020	4,827	1.3	3,664	1.0	2,617	1.2	11,108	1.2	814	11,922	1.2
2021	4,884	1.2	3,701	1.0	2,636	0.0	11,221	1.0	823	12,044	1.0
2022	4,933	1.0	3,734	0.9	2,645	0.3	11,312	0.8	831	12,143	0.8

Table A3: Coincident Peak Demand - 2012 NS Power Forecast

Peak Forecast with Future DSM Program Effects

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010	2,114	1.0	295	10.0	1,820	-0.3
2011	2,168	2.5	265	-10.2	1,903	11.4
2012	2,121	-2.2	146	-44.8	1,975	-2.5
2013	2,098	-1.1	141	-3.8	1,958	-0.9
2014	2,093	-0.2	140	-0.4	1,953	-0.2
2015	2,084	-0.4	139	-0.7	1,945	-0.4
2016	2,073	-0.5	138	-0.6	1,935	-0.5
2017	2,070	-0.1	137	-0.9	1,933	-0.1
2018	2,064	-0.3	136	-0.7	1,928	-0.3
2019	2,065	0.0	135	-0.8	1,930	0.1
2020	2,064	0.0	134	-0.7	1,930	0.0
2021	2,060	-0.2	133	-0.9	1,928	-0.1
2022	2,053	-0.4	132	-0.7	1,921	-0.4

Table A4: Coincident Peak Demand - 2012 NS Power Forecast

Peak Forecast without Future DSM Program Effects

Year	Net System Peak MW	Growth %	Non-Firm Peak MW	Growth %	Firm Peak MW	Growth %
2000	2,009	6.6	412	33.3	1,597	1.3
2001	1,988	-1	369	-10.4	1,619	1.4
2002	2,078	4.5	348	-5.7	1,730	6.9
2003	2,074	-0.2	291	-16.4	1,783	3.1
2004	2,238	7.9	377	29.6	1,861	4.4
2005	2,143	-4.2	392	4.0	1,751	-5.9
2006	2,029	-5.3	386	-1.5	1,644	-6.1
2007	2,145	5.7	381	-1.3	1,764	7.3
2008	2,192	2.2	352	-7.5	1,840	4.3
2009	2,092	-4.5	268	-23.9	1,824	-0.8
2010	2,114	1.0	295	10.0	1,820	-0.3
2011	2,168	2.5	265	-10.2	1,903	11.4
2012	2,101	-3.1	147	-44.4	1,954	-3.6
2013	2,148	2.3	142	-3.4	2,006	2.7
2014	2,167	0.9	142	0.1	2,024	0.9
2015	2,182	0.7	143	0.2	2,040	0.8
2016	2,199	0.8	143	0.1	2,056	0.8
2017	2,223	1.1	143	-0.2	2,081	1.2
2018	2,245	1.0	143	0.1	2,102	1.0
2019	2,274	1.3	143	0.0	2,131	1.4
2020	2,301	1.2	143	0.1	2,158	1.3
2021	2,325	2.3	143	-0.1	2,183	2.4
2022	2,345	1.9	143	-0.1	2,203	2.1

Table A3: Energy Sales by Rate Class - 2010 NS Power Forecast

Rate Class Energy Sales
With Future DSM Program Effects

Class Billed Sales (GWh)	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012	2013
Residential	4,156	4,244	4,144	4,275	4,320	4,273
Small General	239	237	235	241	233	231
General Demand	2,463	2,458	2,447	2,448	2,437	2,435
Large General	419	417	416	415	406	396
Unmetered	112	112	113	113	111	104
Small Industrial	254	253	254	253	254	258
Medium Industrial	539	492	495	492	487	499
Large Industrial	996	901	929	915	932	921
RTP	0	0	0	0	0	0
Mersey System	369	291	356	363	369	368
GR&LF	11	6	20	17	19	19
Municipal	197	198	193	191	194	193
ELI Rate / LRT	1,976	1,695	1,857	1,475	356	322
Total Billed Sales	11,732	11,304	11,461	11,198	10,118	10,020
Losses & Δ Unbilled	807	769	697	709	722	701
Net System Requirement	12,539	12,073	12,158	11,908	10,839	10,721

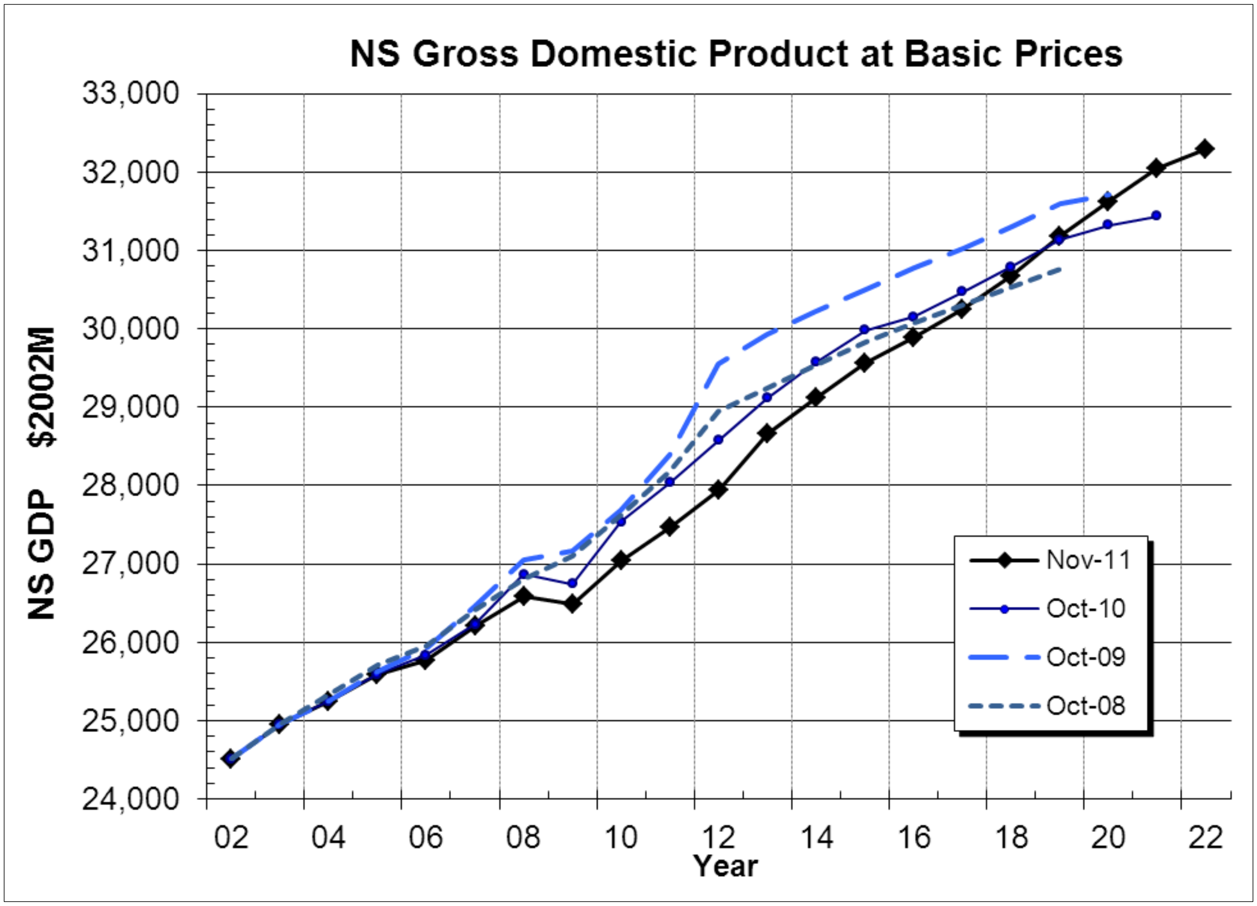
Rate Class Energy Sales
Without Future DSM Program Effects

Class Billed Sales (GWh)	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012	2013
Residential	4,156	4,244	4,144	4,275	4,369	4,375
Small General	239	237	235	241	236	237
General Demand	2,463	2,458	2,447	2,448	2,489	2,530
Large General	419	417	416	415	417	417
Unmetered	112	112	113	113	115	116
Small Industrial	254	253	254	253	256	261
Medium Industrial	539	492	495	492	494	511
Large Industrial	996	901	929	915	940	936
RTP	0	0	0	0	0	0
Mersey System	369	291	356	363	369	368
GR&LF	11	6	20	17	19	19
Municipal	197	198	193	191	198	199
ELI Rate / LRT	1,976	1,695	1,857	1,475	356	322
Total Billed Sales	11,732	11,304	11,461	11,198	10,257	10,292
Losses & Δ Unbilled	807	769	697	709	733	723
Net System Requirement	12,539	12,073	12,158	11,908	10,990	11,014

Appendix B

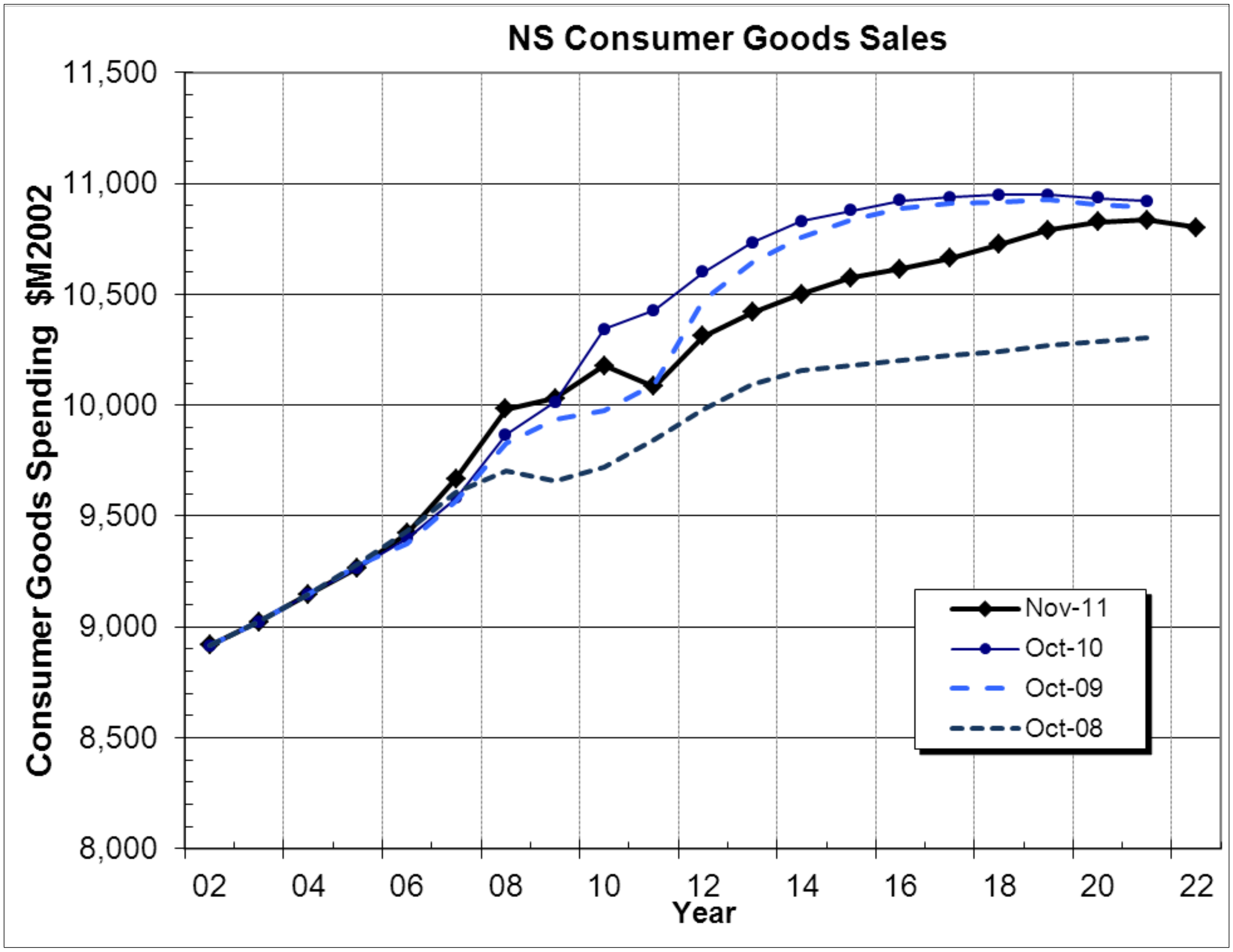
Figures

Figure B1: Nova Scotia Gross Domestic Product Basic Prices



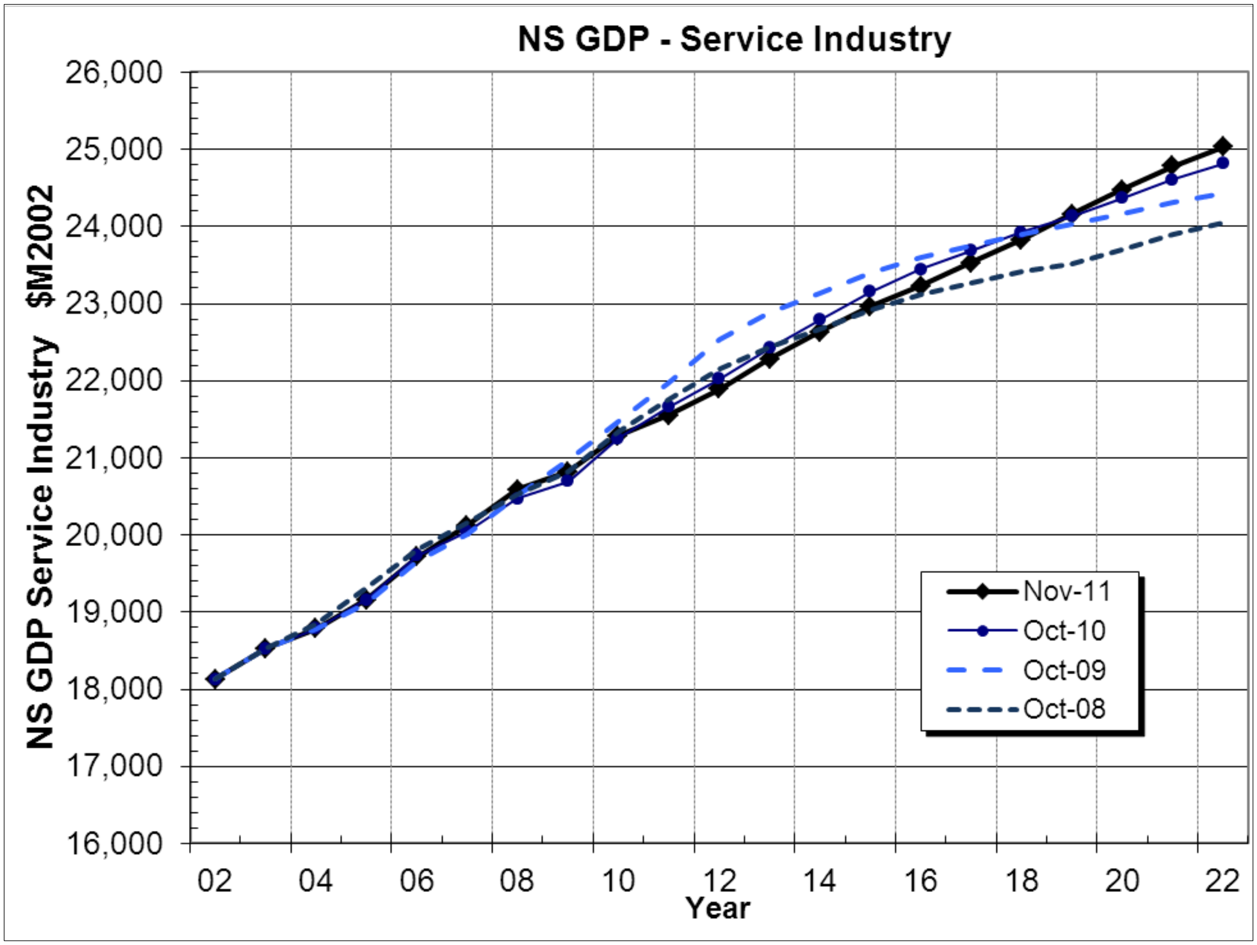
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B2: Nova Scotia Consumer Goods Sales



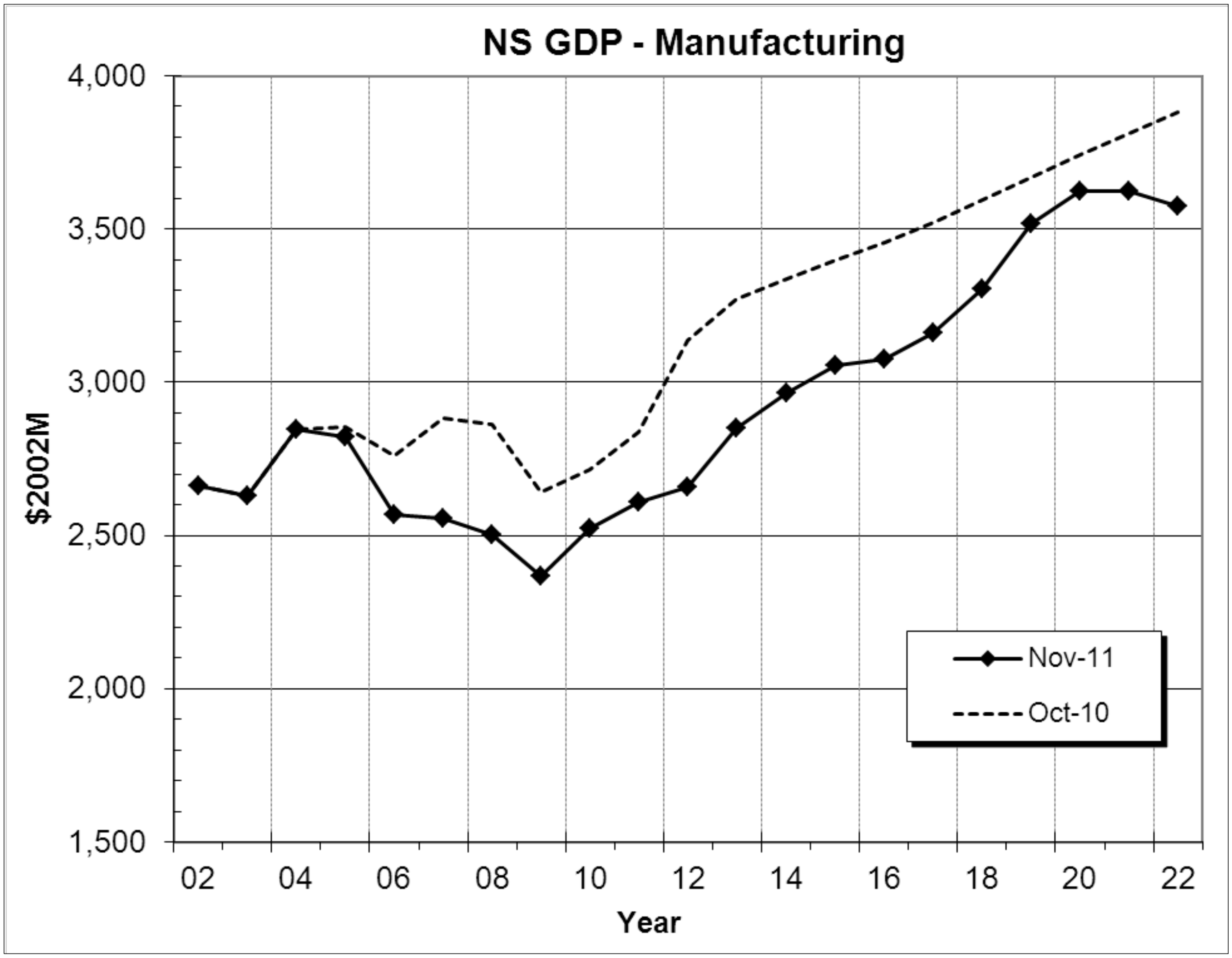
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B3: Nova Scotia Real Disposable Income



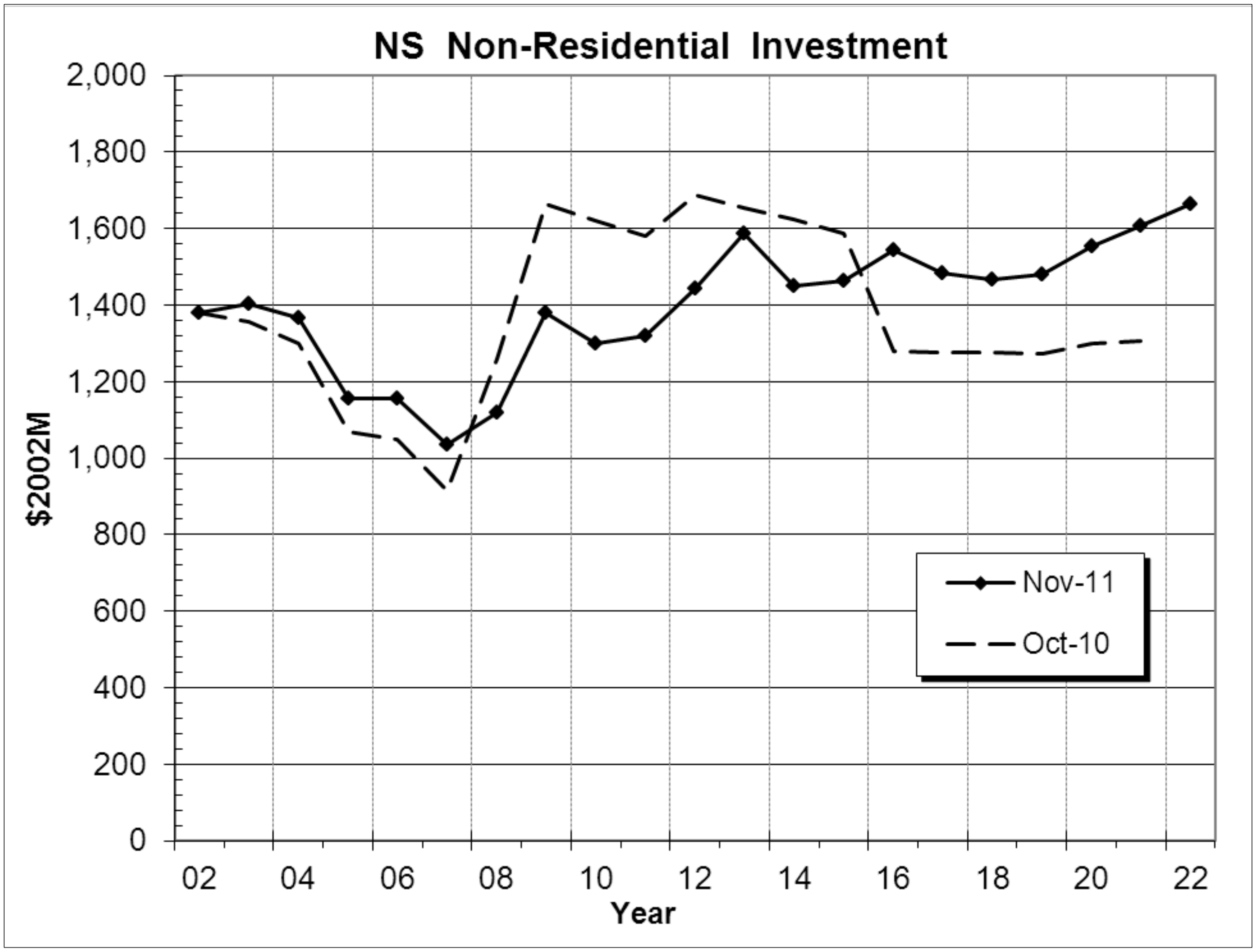
Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B4: Nova Scotia GDP - Manufacturing



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B5: Nova Scotia Non-Residential Investment



Note: Statistics Canada often re-estimates historical information to reconcile with changes in variable composition and to ensure historical consistency with forecasts. This is the case in the graph above.

Figure B6: Nova Scotia Energy Sales

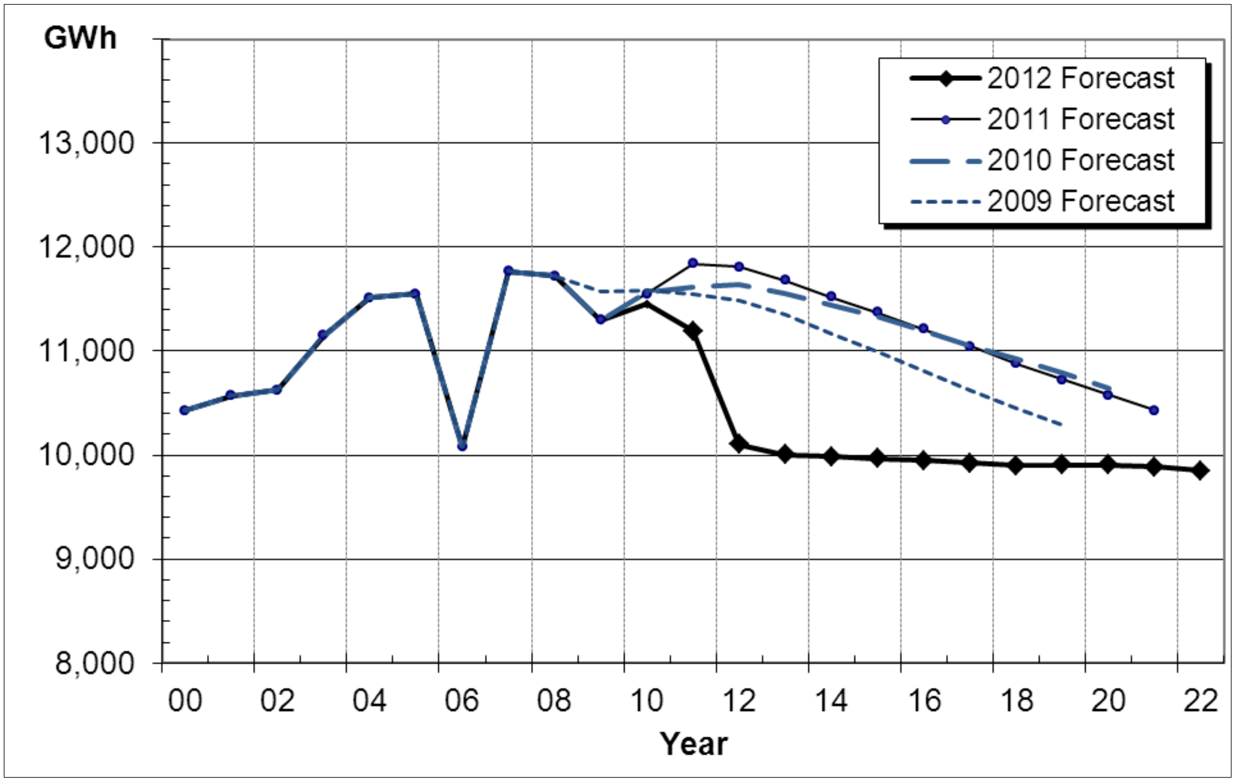


Figure B7: Total Nova Scotia Energy Losses

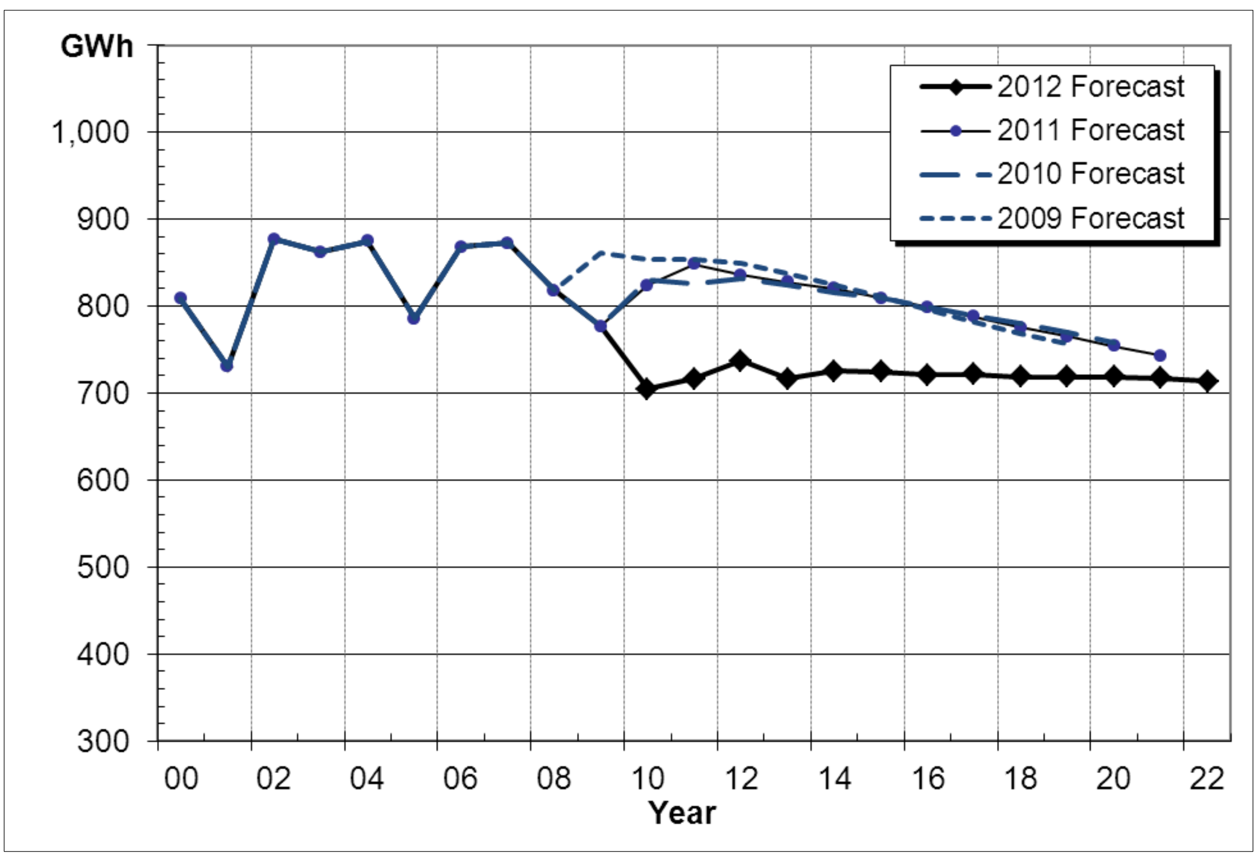


Figure B8: Total Nova Scotia Energy Requirement (NSR)

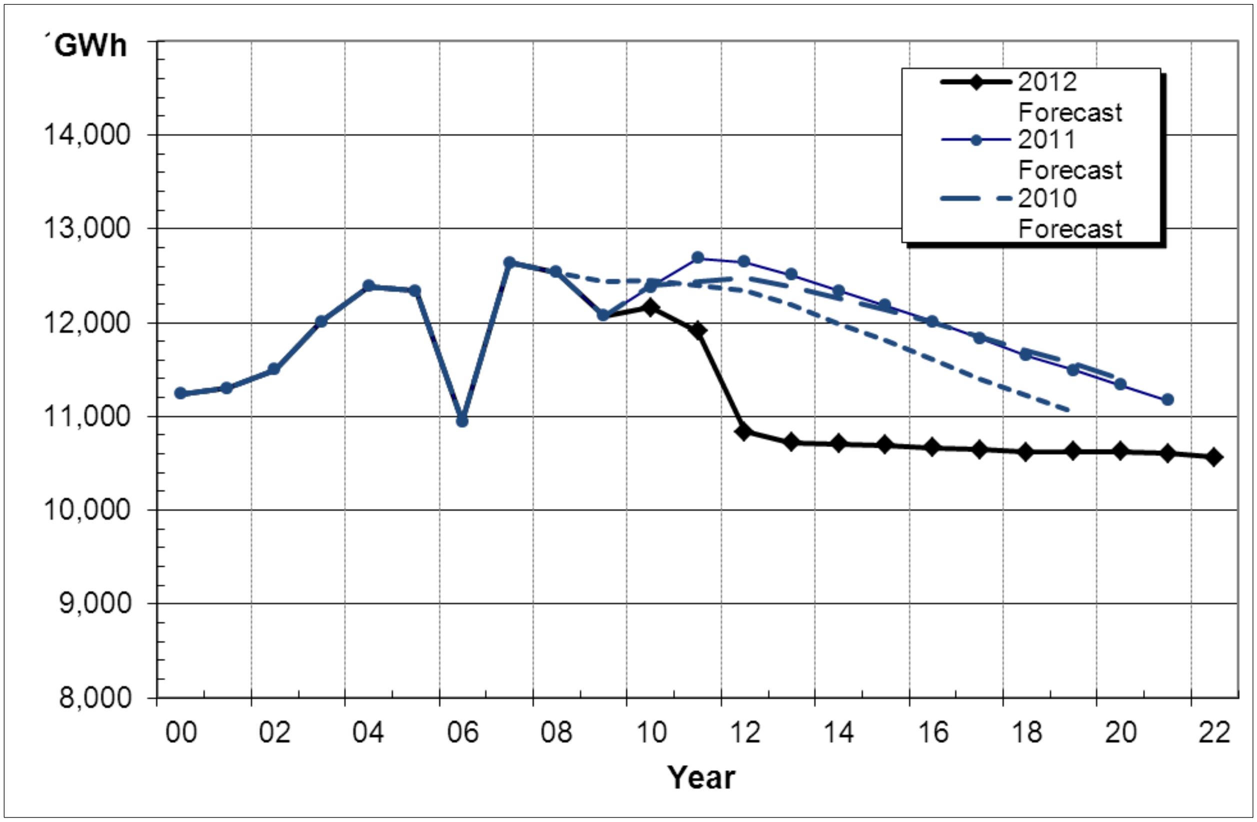
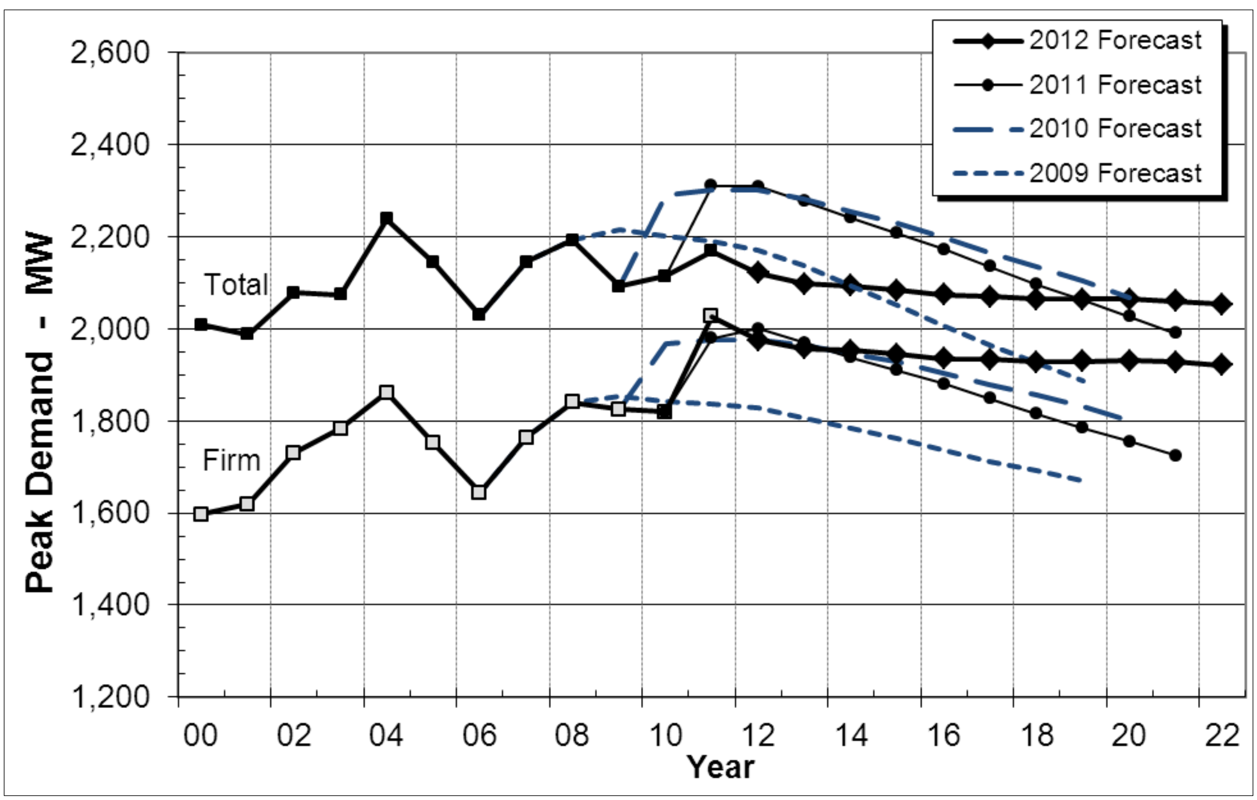


Figure B9: Net System Peak Demand and Firm Peak Demand



Appendix C

Forecast Sensitivity by Major Variable

Appendix C: Forecast Sensitivity by Major Variable

Forecast Sensitivity by Major Variable

Based upon the 2012 load forecast models, the following table shows the relative sensitivity of the forecast to changes in various input assumptions.

Variable	Assumed Change	Effect on 2011 Load GWh	Effect on 2016 Load GWh
Lagged Dependent Variable *2% growth on base year, 2011*	Residential	23.3	0.6
	Commercial	17.9	0.5
	Industrial	5.0	0.3
	All	46.2	1.4
NS Consumer Goods Sales	+2%/yr (2012 on)	21.1	229.5
NS Gross Domestic Product (GDP)	+2%/yr (2012 on)	2.9	31.6
NS GDP - Service Sector	+2%/yr (2012 on)	27.8	310.8
NS GDP - Manufacturing	+2%/yr (2012 on)	4.6	63.8
NS Investment – Non-Residential	+2%/yr (2012 on)	0.2	2.0
Residential Electricity Price	+10% in 2012	-57.0	-143.5
Heating Degree-Days	+ 200 HDD/yr (2012 on)	92.0	193.0
Heating Oil Price	+10¢ per litre (2012 on)	0.0	20.3
Residential Customer Additions	+2000/yr (2012 on)	18.0	180.3
New Construction Elec. Heat Penetration	+5%/yr (2012 on)	1.8	16.5
Electric Heating Saturation	+1%/yr (2012 on)	43.2	89.7
DSM Program Effects	half of projected reduction	73.2	414.2

Note: This table portrays changes to individual variables only. In many cases, there are interdependencies that would require scenario development for more complete evaluation.

Requirement:

Fuel Price Forecasts (industry forecasts used to indicate future trends in gas, oil, and coal prices).

Submission:

<u>2013:</u>

The following industry information has been used to develop the fuel forecast used in NS Power's 2013 Rate Application for 2013:

- Price strip for natural gas from NYMEX, basis to [redacted] broker quote
- Price strip for Heavy Fuel Oil (full price strips for forecast period were not available, used strips for 03/2012 to 02/2013)
- Price strip for Light Fuel Oil, (full price strips for forecast period were not available, used strips for 03/2012 to 02/2013)
- McCloskey's FAX: International Coal Market Update
- Wood MacKenzie Quarterly Price Forecast
- ICAP Price Forecast[1]
- Indicative Prices

[1] NS Power used the ICAP Price Forecast to determine the price for mid-sulphur coal for the 2013 forecast. The data for mid-sulphur coal supplied by Wood MacKenzie at the time of the forecast produced a price for mid-sulphur that was higher than that being experienced in industry. Following consultation with external experts, NSPI elected to use the ICAP data which resulted in a lower price forecast for mid-sulphur coal.

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2014:

The following industry information has been used to develop the fuel forecast used in NS Power's 2013 Rate Application for 2014:[2]

- Price strip for natural gas from NYMEX, basis to [redacted] broker quote
- Price strip for Heavy Fuel Oil, broker quotes
- Price strip for Light Fuel Oil, broker quotes
- Jacob's Consultancy
- ICAP Price Forecast
- Indicative Prices

This information has been purchased from various industry associations and is copyrighted. NS Power cannot therefore reproduce these reports for distribution to other parties. This information is available for viewing at NS Power offices.

[2] The Plan of Administration does not specify a multi-year methodology. For example, data was not published out to 2014 in the McCloskey's Fax and Wood Mackenzie data sources, therefore NS Power obtained the required data from ICAP and used Jacob's Consultancy to determine an escalation factor from the Wood Mackenzie 2013 estimate for petcoke.

Requirement:

Lead-Lag Study.

Submission:

Please refer to Attachment 1.

JTBrowne
Consulting

Nova Scotia Power Inc.

Lead-Lag Study
For Determining
Cash Working Capital

March 30, 2011

Costing &
Regulatory Consulting

TABLE OF CONTENTS

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INTRODUCTION

Nova Scotia Power Inc. ("NSPI") is an integrated electric utility. Its rates are regulated by the Nova Scotia Utility and Review Board ("NSUARB") using a return on rate base methodology. This methodology allows NSPI an opportunity to recover through its regulated rates a fair return on its rate base. To support the amount of cash working capital included in its 2012 rate base, the utility has conducted a lead-lag study.

Based on its lead-lag study which reflects its estimates as of March 25, 2011, NSPI has estimated its cash working capital requirement for the 2012 test year to be $66.6 million. The calculation of this amount is set out in Table 1 which replicates Table 12 in the "Summary of Results" section.

Table 1 presents:

- the major categories of cash operating expenses;
- the revenue lag ("Rev Lag") for each expense category which is discussed in a later section and which is the same for each expense category except for Cost of Goods Sold;
- the expense lag ("Exp Lag") for each expense category which are discussed in a later section;
- the net lag for each expense category which is equal to the revenue lag less the expense lag;
- the cash working capital percentage ("CWC %") for each expense category which is equal to the net lag divided by 366[1];
- the cash working capital for each expense category which is equal to the cash operating expense multiplied by the cash working capital percentage;
- the total of the cash working capital for each of the cash operating expense categories;
- the cash working capital associated with the harmonized sales tax ("HST") the goods and services tax ("GST") and demand side management ("DSM") which are discussed in a later section; and
- the total cash working capital that should be included in NSPI's 2012 rate base.

---

[1] The net lag is divided by the number of days in the year. Normally this is 365, but 2012 will be a leap year with 366 days.

Table 1

Nova Scotia Power Inc. Cash Working Capital 2012[2]						
	2012 ($ mm)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($ mm)
Fuels	612.2	51.86	27.13	24.73	6.8	41.4
Cost of Goods Sold	1.5	0	38.89	-38.89	-10.6	-0.2
OM&G - Labour	127.0	51.86	23.37	28.49	7.8	9.9
OM&G - Excl'd Labour	125.8	51.86	26.48	25.38	6.9	8.7
Grants in lieu of Taxes	36.4	51.86	-136.66	188.52	51.5	18.8
Income Taxes	33.6	51.86	210.04	-158.18	-43.2	-14.5
						64.1
HST-Collected	213.9			-12.07	-3.3	-7.1
HST / GST - Paid	67.3			29.02	7.9	5.3
DSM	43.7			35.80	9.8	4.3
						66.6

2 The numbers in the tables may not add, or multiply across, due to rounding.

In Table 1, there is no revenue lag for Cost of Goods Sold. Many customers pay at the time of purchase (or shortly thereafter), and the amounts are immaterial. Therefore, to be conservative, NSPI assumed a zero revenue lag for this expense.

NSPI asked me as a chartered accountant and economist with experience in addressing regulatory issues[3] to:

- Advise on the methodology for its lead-lag study.
- Review its lead-lag study to determine whether the methodology is reasonable and adequately supports the determination of the net cash working capital that is to be included in NSPI's rate base for the 2012 test year.

Based on my understanding of NSPI's methodology as set out in the "Opinion" section, the methodology that NSPI used in its lead-lag study is a reasonable application of the traditional approach used by regulated utilities to establish their cash working capital requirement, and therefore, for purposes of establishing its 2012 rate base, the methodology adequately supports the determination of NSPI's cash working capital requirement. As discussed in the "Opinion" section, my opinion deals solely with the methodology employed by NSPI.

The next five sections of this report sets out my understanding of NSPI's lead-lag study. The next section presents the basic methodology used in the study. This is followed by sections that discuss the revenue lag; the expense lags for each of the cash operating expense categories; the impact of the HST / GST and DSM on NSPI's cash working capital; and the summary of the study results.

The last section presents my opinion on the methodology used in NSPI's lead-lag study.

[3] A copy of my resume has been attached as Exhibit JTBC-1.

METHODOLOGY

NSPI has completed a lead-lag study to support the cash working capital that will be included in its rate base for the 2012 test year.

CASH WORKING CAPITAL

In carrying out its operations, a utility incurs costs that are recovered through its revenues. However, there is usually a lag from the time that a utility pays for the costs to provide service and the time it collects the revenues to recover those costs. Cash working capital represents the investment required to fund cash operating expenses until they are recovered through the collection of revenues.

NSPI is regulated under a return on rate base methodology whereby a return is included in the revenue requirement that it is allowed to recover through rates. The return is expected to compensate the utility for the cost of its investment in regulated operations and is calculated by multiplying the utility's average rate base by its weighted average cost of capital. This rate base should equal its investment required for regulated operations, including the amount required to fund cash working capital.

SCOPE

NSPI has employed the definition of cash working capital traditionally used by regulated utilities. This traditional definition defines cash working capital as the investment required to finance cash operating expenses from the time they are paid until the time they are recovered from customers.

In determining cash working capital, the traditional definition considers payables associated with cash operating expenses and receivables associated with the revenues intended to recover these costs.

Cash working capital based on the traditional definition is what the NSUARB approved in the last decision in which it specifically dealt with this issue[4].

LEAD-LAG STUDY

NSPI has used a lead-lag study to determine its cash working capital. This method of estimating the amount of cash working capital is the one most commonly used by major Canadian utilities.

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4 Nova Scotia Utilities and Review Board: NSUARB-NSPI-P-882; March 10, 2006.

With a lead-lag study, a utility determines the average time from payment of cash operating expenses to the time those costs are recovered from customers. This establishes the average amount of cash working capital required per dollar of cash operating expenses. The result is applied to the estimated amount of cash operating expenses to determine the cash working capital that should be included in the utility's rate base. A lead-lag study tends to reflect the most accurate measure of the cash working capital required by a utility.

The measurement of the time between payment and recovery of cash operating expenses is usually broken into two steps: the time between the provision of service and the time of recovery; and the time between the provision of service and payment. The net lag (or lead) is determined by subtracting the second period of time from the first.

A lead-lag study involves the following steps:

- Determine the average net lag from the time of sale to the time that the revenues are collected from customers (i.e., revenue lag).

- Determine the average net lag from the time of sale to the time of payment for each major category of cash operating expense (i.e., expense lag).

- Calculate the average net lag for each category of cash operating expense by subtracting the average expense lag for that category from the average revenue lag.

- Calculate the net cash working capital associated with each category of cash operating expense (i.e., expense * net lag / number of days in the year)

- Calculate the total of the working capital associated with each cash operating expense.

- Add the net impact of the collection and payment of sales taxes and similar items (i.e., HST / GST and DSM) on working capital.

DATA

In completing its lead-lag study, NSPI used data from 2009. At the time the study was undertaken, this was the most recent year for which a complete year of data was available.

With regards to the revenues and expenses used in the study, NSPI started with the amounts from its 2009 regulated statements. NSPI then removed the amounts listed in Table 2 from its expenses because they were not cash operating expenses.

Table 2

Lead - Lag Study Exclusions From 2009 Expenses	
	$mm
Depreciation Expense	140.2
Accretion Expense	3.3
Regulatory Amortization	27.2
Fuel Adjustment Mechanism	13.5
Future Income Taxes	-5.2
Bad Debt Expense	4.6
Interest	111.5
Preferred Dividends	9.5
AFUDC	-6.5
	298.1

HEDGES

NSPI enters into hedging arrangements for foreign exchange and commodity prices to help manage the risk associated with its fuel purchases. These hedges may affect the timing of the cash flows associated with its purchases, and therefore affect the related net expense lag.

The impact of the hedges on NSPI's cash working capital requirements is difficult to estimate, and over time, it is expected the impacts will tend to average out to zero. As a result, in establishing individual expense lags, the impact of hedges was not included in the calculations.

This is consistent with how hedges were treated in NSPI's previous lead-lag study

ADJUSTMENTS FOR 2012

Once the study was completed using data from 2009, the results were adjusted for estimated changes between 2009 and 2012. These changes are set out in the "Summary of Results" section and are based on NSPI's estimates as of March 25, 2011.

NET LAG - REVENUES

The net revenue lag represents the average number of days between the provision of service and the date that the revenue from the service is collected from customers. It is comprised of three lags:

- service lag - the number of days between the provision of service and the end of the service period;
- billing lag - the number of days between the end of the service period and the date that an invoice is issued; and
- collection lag – the number of days between the date that an invoice is issued and the date the money is collected from customers.

NSPI calculated a weighted average revenue lag of 51.56 days. As set out in Table 3, this is a weighted average of the lags for each of the following revenue categories:

- Bi-monthly Customers
- Monthly Customers
- Large Customers
- Grid Sales
- Ecoenergy Rebates
- Natural Gas Sales

BI-MONTHLY AND MONTHLY CUSTOMERS

Domestic (i.e. residential), commercial and industrial customers other than large customers (discussed below) are billed either bi-monthly or monthly with billing dates spread throughout the month. Standard payment terms are 30 days for bi-monthly customers and 20 days for monthly customers.

The average service lag was 29.92 days for bi-monthly customers and 14.71 days for monthly customers. The billing lag for both types of customers was 2 days.

The average collection lag was determined by dividing the average accounts receivable by the average daily billings (i.e., total billings divided by 365). Prior to this calculation, the allowance for doubtful accounts was removed from accounts receivable and the bad debt expense was removed from the total billings. Except for a specific allowance related to large customers, it was assumed that both the allowance for doubtful accounts and the bad debts expense applied only to the bi-monthly and monthly customers.

Table 3

Revenue Net Lag 2009						
	2009 Revenues		Lag			
	$, 000	%	Service	Billing & Collection	Net	Weighted Average
Bi-monthly Customers	635,983	50.59	29.92	35.21	65.13	32.95
Monthly Customers	328,985	26.17	14.71	24.31	39.02	10.21
Large Customers	247,943	19.72	14.71	20.37	35.08	6.92
Grid Sales	895	0.07	14.81	20.18	34.99	0.02
Natural Gas Sales	42,643	3.39	14.66	25.48	40.14	1.36
Ecoenergy Rebates	735	0.06	45.13	124.63	169.75	0.10
	1,257,183					51.56

After removing the amount related to large customers, the remainder of the allowance for doubtful accounts was allocated to the bi-monthly and monthly customer classes on the basis of their average accounts receivable balances. The bad debt expense was then allocated on the same basis as the allowance for doubtful accounts.

The average accounts receivable was calculated as the average of the weekly balances. Only 46 weeks of data were available. For the other six weeks, the average for the previous and subsequent weeks was used.

The above calculations produced a weighted average collection lag of 33.21 days for bi-monthly customers and 22.31 days for monthly customers. With the billing lag of two days, the total billing and collection lags were 35.21 days and 24.31 days.

LARGE CUSTOMERS

In 2009, 65 customers fell in the category of Large Customers. They are billed monthly on the first business day following the month that service is provided. However, the invoices are dated the last day of the month for which service was provided. The standard payment terms are 20 days.

Since Large Customers are billed monthly, the average service lag was 14.71 days; and since the invoices are dated the last day of the month for which service was provided, the billing lag was zero days.

To determine the average collection period, NSPI conducted a detailed review of all billings to Large Customers in 2009. NSPI identified the invoice date and the payment date for each bill and calculated a weighted average collection lag of 20.37 days.

GRID SALES

Grid sales are power sales to customers outside of Nova Scotia. Sales for each month are invoiced in the following month with settlement in the latter part of that month. It was assumed that any sales are made evenly throughout each month resulting in a service lag ranging from 13.5 to 15 days.

NSPI reviewed each of the invoices covering its grid sales in 2009 to identify the service, billing and collection lags. NSPI then calculated the total net lag for each invoice and the weighted average net lag for all invoices.

NATURAL GAS SALES

Where it has excess gas, NSPI resells its natural gas. Sales for each month are invoiced in the following month with settlement towards the end of that month. It was assumed that sales are made evenly throughout each month resulting in a service lag ranging from 13.5 to 15 days.

NSPI reviewed each of the invoices covering its natural gas sales in 2009 to identify the service, billing and collection lags. It then calculated the total net lag for each invoice and the weighted average net lag for all invoices.

ECOENERGY REBATES

Ecoenergy rebates are amounts received through the Federal Government's Ecoenergy program. The rebates offset the cost of renewable power.

At the end of each quarter, a claim is made to the Federal Government for the rebates.

In 2009, the claims were made by an IPP that sold power to NSPI. The IPP then passed on to NSPI its share of the rebates. NSPI reviewed each of the four payments covering the rebates to identify the service, billing and collections lags. It then calculated the total net lag for each payment and the weighted average net lag for all of the payments.

In 2012, it is expected that NSPI will continue to receive rebates indirectly through IPPs but will also make claims directly for renewable energy that it produces. This is not expected to have a material impact on NSPI's net revenue lag.

NET LAG - CASH OPERATING EXPENSES

The expense lag represents the time from the provision of service by NSPI to the time the related cash operating expenses are paid. It can comprise three lags:

- service lag – where a supplier provides a service over a period of time, the average number of days between the provision of service by the supplier and the end of the service period;
- billing lag - the number of days between the end of the service period, or the date goods are acquired, and the date that an invoice is issued; and
- payment lag – the number of days between the date that an invoice is issued and the date the amount is paid to the supplier.

NSPI divided its cash operating expenses into the following categories and calculated a net expense lag for each category:

- Fuels
- Cost of Goods Sold
- OM&G – Labour
- OM&G – Other
- Grants in Lieu of Taxes
- Income Taxes

FUELS

Fuels includes fuel for generation, additives used in the production of power, solid fuel handling costs and purchased power.

The expense lag is usually determined in relation to the point in time the related services are provided to NSPI's customers. However, in some cases, fuel is placed in inventory and the average amount of inventory is included in NSPI's rate base. In these cases, the net expense lead should be calculated as:

- the average time in inventory; less
- the average time between the fuel being inventoried and paid.

Since the time in inventory is recognized by including the average inventory in rate base, the time between the fuel being inventoried and the supplier being paid should be recognized as a reduction in cash working capital. Therefore, where the cost of the fuel is inventoried, the expense lag is determined by the average time between the fuel being added to inventory and the time payment is made to the suppliers.

Table 4 sets out the calculation of the weighted average expense lag for fuels.

Table 4

Fuels Net Lag 2009				
	2009 ($,000)	%	Net Lag	Weighted Net Lag
Natural Gas	180,914.1	33.05	39.06	12.91
Heavy Fuel Oil	0.0	0.00	15.52	0.00
Light Fuel Oil	2,158.8	0.39	37.28	0.15
Diesel	3,151.3	0.58	34.45	0.20
Solid Fuel	289,017.2	52.79	22.88	12.08
Solid Fuel Handling Costs	4,139.8	0.76	37.96	0.29
Additives - 2009	4,964.0	0.91	35.01	0.32
Additives - Mercury Sorbents	452.0	0.08	38.74	0.03
Purchased Power	37,440.9	6.84	34.19	2.34
IPPs	25,199.5	4.60	24.36	1.12
TOTAL	547,437.6			29.43

Natural Gas

Natural gas is acquired and either burned or re-sold throughout the month resulting in a service lag of between 13.5 and 15 days. To determine the service, billing and payment lags for natural gas, NSPI reviewed all of the purchases for 2009. After calculating the net lag for each purchase as the sum of the service, billing and payment lags, the weighted average of the net lags was calculated.

Heavy Fuel Oil, Light Fuel Oil, Diesel and Solid Fuel (Coal and Petcoke)

To determine the average time between the date heavy fuel oil, light fuel oil, diesel and solid fuel were recorded in inventory[5] and the date the suppliers were paid, NSPI considered all of the purchases for 2009. After determining the net lag for each purchase, the weighted average of the net lags was calculated for each type of fuel.

In 2009, NSPI faced the unusual situation of having a negative expense for heavy fuel oil. This was the result of low consumption combined with favourable hedges. As a result, for purposes of calculating the weighted net lag for fuel in 2009, the heavy fuel oil expense was deemed to be zero. In arriving at the weighted net lag for 2012, the estimated heavy fuel oil expense for 2012 was used.

Solid Fuel Handling Costs

Solid fuel handling costs are expensed as incurred and not inventoried

The net expense lags for each of the expense categories in solid fuel handling costs were taken from the net expense lags for similar types of OM&G expenses. A weighted average of these net lags was then calculated.

Additives

Additives - 2009

Excluding mercury sorbents, there are three categories of additives: limestone, fireshield and targeted in-furnace injection (“TIFI”).

To determine the average time between the date the additives were recorded in inventory, or expensed, and the date the suppliers were paid, NSPI reviewed all purchases in 2009. After determining the net lag for each purchase, the weighted average of the net lags was calculated.

Additives – Mercury Sorbents

Mercury sorbents were not used in full production during 2009. Therefore purchases from June 2010 were used to estimate the expense lag associated with these additives.

To determine the average time between the date the additives were recorded in inventory, or expensed, and the date the suppliers were paid, NSPI reviewed all purchases in June

[5] A small portion of the total purchases related to services provided or environment fees associated with fuel, and these purchases were expensed. In the case of these purchases, the net lag was calculated from the time the services were provided until the supplier was paid.

2010. After determining the net lag for each purchase, the weighted average of the net lags was calculated.

Purchased Power & IPPs

NSPI is billed monthly for purchased power and power purchased from in-province independent power producers ("IPPs"), and it was assumed that this power is acquired throughout the month. As a result the service lag varied from 13.5 to 15 days. To determine the service, billing lag and payment lags, NSPI reviewed all of the purchased power acquired in 2009. After calculating the net lag for each purchase as the sum of the service, billing and payment lags, the weighted average of the net lags was calculated for each type of purchased power.

COST OF GOODS SOLD

Cost of goods sold refers to the cost of electro thermal storage ("ETS") units and their installation.

The net lag was calculated as the weighted average of the net lag on the cost of the ETS units and the net lag on the cost of installation.

- To estimate the net lag on the cost of the ETS units, invoices from 2009 equal to 94% of the estimated purchases in 2009 were reviewed. Information from these invoices was used to establish the lag from the time the units were placed in inventory till the time the suppliers were paid.

- To estimate the net lag on the cost of installation, invoices representing 38% of the installation costs expensed in 2009 were reviewed to establish the net lag from the date of installation to the date the suppliers were paid.

OM&G – LABOUR

As a result of labour costs, payments are made to employees, the government for taxes and other parties for employee benefits. To estimate the weighted average expense lag associated with these costs, NSPI reviewed the majority of the payments related to its OM&G labour expense in 2009.

Table 5 sets out the weighted average expense lag for labour.

Net Pay to Employees

The payments to employees are net of deductions for income taxes, the employees' share of other government payments (e.g., EI and CPP) and employee benefits.

Table 5

OMG - Labour Net Lag 2009				
	2009 ($,000)	%	Net Lag	Weighted Net Lag
Bi- Weekly				
Net Pay	78,890.5	52.2	14.42	7.53
Government Payments	44,448.9	29.4	21.54	6.34
Benefit Supplier Payments	7,346.3	4.9	109.05	5.30
Other Payments – Payroll Dates	12,812.1	8.5	14.42	1.22
Other Payments – Non-payroll Dates	3,487.8	2.3	39.63	0.91
Incentive				
Net Pay	1,900.3	1.3	232.00	2.92
Government Payments	1,909.1	1.3	237.00	3.00
Other Payments – Payroll Dates	54.7	.00	239.00	0.09
Other Payments – Non-payroll Dates	206.6	0.1	231.00	0.32
TOTAL	151,056.5			27.63

NSPI employees are paid bi-weekly. They are paid for the two weeks ending each second Thursday, with payments deposited in their bank accounts on the following Friday, except where there is a holiday in which case they are paid on the preceding day.

The payments are funded by NSPI on the day of deposit. This results in a service lag of 6.5 days and an average payment lag of slightly less than 8 days, for a total average net lag of 14.42 days.

An incentive payment or bonus is paid to employees in February of the following year. Since only half the payment is recognized as an expense for regulatory purposes, only half the payment was considered in the lead-lag study. The service period covers the entire year resulting in an average service period of 182 days. The payments for 2009 were deposited in employee accounts on February 19, 2010, resulting in a payment lag of 50 days. Combining the service and payment lags resulted in a total net lag of 232 days.

Government Payments

Government payments include the employees' income tax deductions, the employee and employer share of Employment Insurance ("EI") and Canada Pension Plan ("CPP") payments, and the employer's Workman's Compensation Benefits ("WCB") payments.

NSPI reviewed the actual payments made to the government associated with each pay period and the incentive payment to establish the average payment lag for both the bi-weekly payroll and the incentive pay. The service periods were the same as with the net pay to employees.

The review found a weighted average payment lag of 15.04 days for the government payments associated with the bi-weekly payroll, and 55 days for the government payment associated with the incentive payment. Combined with the service lags, this produced a net lag of 21.54 days for the bi-weekly payroll and 237 days for the incentive payroll.

Benefit Supplier Payments

The benefit supplier payments are the employee and employer shares of the payments for long term disability, life, dental and health insurance. These payments only relate to the bi-weekly pay payroll and not the incentive pay.

NSPI reviewed the actual payments made to its benefit supplier for each pay period to establish the average payment lag. The review found a weighted average payment lag of 102.55 days. Combined with the service lag, which was the same as with the net pay to employees, this resulted in net lag of 109.05 days.

In 2012, NSPI will be using a new benefit supplier. Under terms agreed to with the new supplier, payments related to any payroll paid in the month are to be paid on the last day of the month.

Other Payments – Payroll Dates and Non-payroll Dates

Other payments refer to amounts deducted from employees' pay and paid to other parties for pensions, Canada savings bonds, etc. It also includes the employer portion of these payments other than the pension payments included in "OM&G - Excluding Labour" as

"Employee Benefits". These latter payments are the employer pension payments in excess of those that match the employee pension payments.

The payments were divided into two categories: those paid on the same day employees are paid and those paid on other dates. In both cases the service periods were the same as with the net pay to employees

In the case of the payments paid on the same date as the payroll, the payment lag and net lag for the bi-weekly pay were the same as for the associated net pay. For the incentive pay, the payment was made on the date of the next regular payroll which was seven days after the incentive payment was made to employees. This added seven days to the payment lag and net lag compared to the incentive net pay.

In the case of payments made on other dates and related to the biweekly payroll, NSPI reviewed 78% of the payments and used the resulting weighted average payment lag of 33.13 days for all of the payments. Combined with the service lag, this resulted in net lag of 39.63 days

In the case of the payment made on another date related to the incentive pay, NSPI reviewed the payment to determine that the payment lag was 49 days. Combined with the service lag, this resulted in a net lag of 231 days.

OM&G – EXCLUDING LABOUR

Table 6 sets out the weighted average expense lag for OM&G – Excluding Labour (hereafter referred to as OM&G).

To estimate the weighted average expense lag for OM&G, NSPI first estimated a net expense lag for 11 of the 12 largest categories of OM&G expense, representing $98.1 million or 81.9% of the gross OM&G expense. The rent category was excluded since about 95% of the amount in this category related to rent for the Barrington Tower. With NSPI's relocation in 2011, these rental payments will not be relevant in 2012.

The weighted average of the 11 estimated net lags was 35.64 days and this amount was used as the net expense lag for all OM&G.

To estimate the expense lags for each of the 11 categories, NSPI reviewed purchases that related to 2009 and were paid in 2009. In total, NSPI reviewed 186 invoices plus the bi-weekly invoice details from Canada Post. In aggregate, it reviewed purchases totalling $34.7 million. This was equal to 35.3% of the total expenses for the 11 categories in 2009 and 28.9% of the gross OM&G expenses in 2009.

For the individual categories, the amounts reviewed as a percent of 2009 expense ranged from 11.1 % to 99.9%. In all cases where the percentage was below 50%, at least 15 invoices were reviewed.

Table 6

OM&G - Excluding Labour Net Lag 2009				
	2009 ($,000)	%	Net Lag	Weighted Net Lag
Materials	12,654.9	12.9	50.62	6.53
Contracts	46,345.1	47.2	42.19	19.93
Freight, Post. & Del.	2,424.4	2.5	32.98	0.81
Telephones	1,749.3	1.8	53.69	0.96
Consulting	8,335.8	8.5	82.04	6.97
Fleet Fuel	2,984.8	3.0	51.73	1.57
Rental & Maint.	3,131.9	3.2	45.27	1.44
Legal & Audit	6,373.2	6.5	59.93	3.89
Employee Benefits	8,724.2	8.9	7.85	0.70
Insurance	3,676.5	3.7	-120.33	-4.51
Data Communications	1,721.5	1.8	-151.66	-2.66
	98,121.7			35.64
Other OM&G Expenses	21,702.5			
	119,824.2			

For each category, NSPI determined the net lag for each purchase reviewed and then calculated the weighted average of the individual net lags. These weighted average net lags were used as the estimated net lags for the categories.

In 2012, the estimated weighted average net lag is estimated to decrease from 35.64 days to 26.48 days. This decrease is due primarily to the expected increase in the “Employee Benefits” category from $8.7 million in 2009 to $34.7 million in 2012 and the resulting greater weight given to its net lag of 7.85 days.

GRANTS IN LIEU OF TAXES

NSPI does not pay municipal taxes other than deed transfer tax. Instead it pays grants in lieu of taxes to the Provincial Government. The amounts are paid in two instalments each year:

- January 31 – covering the period January 1 through December 31 of the current year
- June 1 – covering the period from April 1 of the current year through March 31 of the following year.

Table 7 sets out the weighted average expense lag for "Grants in Lieu of Taxes".

Table 7

Grants In Lieu of Taxes
Net Lag
2009

Payment	2009 Expense ($,000)	%	Service Lag	Payment Lead	Net Lead	Weighted Net Lead
June 2008	4,324.6	12.4	44.5	302.0	257.5	31.91
January 2009	17,298.2	49.6	182.0	335.0	153.0	75.85
June 2009	13,272.0	38.0	137.0	213.0	76.0	28.91
	34,894.8					136.66

INCOME TAXES

NSPI makes instalments on its federal and provincial income taxes, provincial capital tax ("PCT") and Part VI.I tax at the end of each month. All of these taxes are combined under the heading Income Taxes. Where the actual tax expense exceeds the amount of the instalments, there is a final true-up at the end of February of the following year. Where the actual tax expense is less than the amount of the instalments, a refund is received after NSPI files its tax return.

The Income Tax payments for 2009 had characteristics that are not expected to be repeated in 2012. Therefore the net lag was calculated using the expected instalments and true-up for 2012.

In 2012, it is expected that NSPI will be making monthly instalments based on its taxes payable for 2011. As NSPI's taxes payable for 2012 are expected to be significantly higher than in 2011, NSPI's 2012 monthly instalments are expected to cover a small portion of NSPI's 2012 taxes, resulting in the majority of the 2012 taxes being paid at the end of February 2013. As a result, NSPI has estimated the weighted average expense lag for Income Taxes to be 210.04 days.

HST / GST & DSM

The harmonized sales tax ("HST"), the goods and services tax ("GST") and demand side management ("DSM") are not part of NSPI expenses. They are amounts that NSPI is required to collect and then remits to a third party; or in the case of the HST credit, is required to pay and then receives a refund from the government. Although not an expense, NSPI is required to make the associated payments, and the difference between the time of payment and the related recovery affects NSPI's financing requirements.

The impact of the HST and GST on NSPI cash working capital in 2009 is set out in Table 8. The impact of DSM is not included on the table since it did not apply in 2009.

Table 8

HST / GST Impact on Working Capital 2009				
	($ mm)	Net Lag	CWC %	Working Capital ($ mm)
HST Collected	157.5	-15.98	-4.4	-6.9
HST / GST Paid	58.7	27.15	7.4	4.4
				-2.5

HST COLLECTED

NSPI collects HST from its customers which it then remits to the government. NSPI has the use of the HST it collects from the time it is collected from customers until the time it remits the funds on to the government. This reduces NSPI's net financing requirements.

NSPI collects HST on most of its in-province sales although there are some exceptions, such as sales to first nations customers. NSPI does not collect HST on sales to customers outside of Canada or to affiliates: many of its grid sales and most of its natural gas sales are to such customers.

The amounts collected are usually paid to the government at the end of the month following the month in which the customer's invoice is dated. In the case of some customers that fall into the Large Customer category, the amounts collected are paid to the government at the end of the second month following the month in which the customer's invoice is dated

In 2009, there was a provincial rebate program under which the Province of Nova Scotia provided rebates to NSPI equal to the provincial portion of the HST on a portion of domestic residential sales. NSPI remitted HST to the Federal Government as if the rebates did not exist, but credited customers for the amount of the rebates at the time the customer invoices were generated. The Provincial Government than provided the rebates to NSPI. In 2012, the rebates are expected to cover the entire provincial portion of the HST on domestic residential sales.

NSPI estimated the HST collected by category of sale. It also estimated the average net lead for each category. This net lead represented the time from when the HST was collected from customers, or the Province, to when NSPI remitted the HST. Except for Grid Sales and Natural Gas Sales, this net lead was calculated as the difference between:

- the number of days between the date an invoice was issued and the date the HST related to the invoice (including the portion covered by the provincial rebate) was paid to the government; and
- the number of days between the date an invoice was issued and the date HST included in the invoice was collected from customers or the rebate related to the invoice was collected from the Province.

In the case of Regular Customers – Rebates (i.e., regular customers that qualify for the provincial rebate) the net lead was a weighted average of:

- The net lead for HST recoverable from customers; and
- The net lead for HST covered by the rebate.

In the case of Grid Sales and Natural Gas Sales, the time between the collection of HST and the date the related amounts were refunded was calculated directly

For each category of sale, the estimated amount of HST was multiplied by the net lead. The weighted average of the net leads was then calculated. Table 9 sets out the net leads associated with each of the customer categories and the weighted average net lead.

HST/GST PAID

NSPI pays HST as part of the cost of many of its goods and services and pays the goods and services tax ("GST") to the government on imports. NSPI then receives a refund from the government for the HST and GST paid. NSPI must fund the HST and GST payments from the time it pays them until the time it receives a refund from the government. This increases NSPI's net financing requirements.

Table 9

Impact of HST Collected on Working Capital 2009				
	HST			
	$, 000	%	Net Lead	Weighted Net Lead
Regular Customers - Rebates	69,060	43.9	5.19	2.27
Regular Customers - Other	54,598	34.7	23.04	7.99
Large Customers	32,143	20.4	26.18	5.34
Grid Sales	63	0.0	40.91	0.02
Natural Gas Sales	1,616	1.0	34.87	0.36
	157,480			15.98

For purposes of the lead-lag study, only HST and GST related to cash operating expenses were considered.

NSPI pays the HST when it pays the invoices bearing the HST. The refund for HST paid is netted against the payment to the government for HST collected at the end of the month following the month that the invoice is dated. Invoices not processed before the end of the month are included with the invoices in the following month, or possibly even later, thereby delaying the refund of HST. NSPI has not considered this possibility in the calculation of its net cash working capital and this tends to reduce its estimated cash working capital requirement.

NSPI estimated the HST paid by category of expense. It also estimated the average lag for each category from the time HST is paid until the time it is refunded as the difference between:

- the number of days between the date an invoice was issued and the date the HST included in the invoice was refunded; and
- the number of days between the date an invoice was issued and the date HST included in the invoice was paid to suppliers.

NSPI assumed invoices are issued throughout the month resulting in an average time from the issuing of an invoice to receiving a refund of 45.63 days. The time from the issuing of an invoice to the payment date is the payment lag which was determined in establishing the expense lags for each category.

In the case of the GST, the amounts are paid to the government at the end of the month and refunded at the end of the next month resulting in a net lag of 30.42 days.

Table 10 sets out the net lags associated with each of the major expense categories and the weighted average net lag.

Table 10

Impact of HST/GST Paid on Working Capital 2009

	HST / GST		Invoice Date to			
	$, 000	%	Refund	Paid	Net	Weighted Net Lag
OM&G	13,295	22.65	45.63	36.69	8.94	2.02
Fuels	36,271	61.79	45.63	12.62	33.01	20.40
Total HST	49,566					
GST	9,134	15.56			30.42	4.73
	58,700					27.15

DSM

In 2009, NSPI was responsible for DSM programs. However, beginning in 2010, an independent administrator, Efficiency Nova Scotia Corporation ("ENSC"), has been established to administer the DSM programs for the province of Nova Scotia.

In 2012, NSPI will collect a DSM Cost Recovery Rider Charge ("DCRR") on behalf of ENSC. The DCRR will be a separate charge included on most customer bills and collected when customers pay their bills.

Each month, NSPI will make a payment to ENSC that reflects the DCRR included in forecast revenues for the previous month, even if those revenues are not billed until after the month end. The payment will be made on the first scheduled wire transfer date in each month.

For 2012, the net lag will be calculated as the difference between:

- the number of days between the date service associated with the DCCR is provided and date the DCCR is paid to ENSC; and

- the number of days between the date service is provided and the date the associated revenues are collected from customers.

The first amount will assume that revenue is earned evenly throughout the month. The latter amount will reflect the relevant lags determined in arriving at the net revenue lag.

SUMMARY OF RESULTS

Table 11 summarizes NSPI's cash working capital based primarily on 2009 data. It reflects what has been discussed in previous sections.

Table 11

Nova Scotia Power Inc.
Cash Working Capital
2009

	2009 ($ mm)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($ mm)
Fuels	543.7	51.56	29.43	22.13	6.1	33.0
Cost of Goods Sold	1.7		38.89	-38.89	-10.7	-0.2
OM&G - Labour	109.4	51.56	27.63	23.93	6.6	7.2
OM&G - Excl'd Labour	103.4	51.56	35.64	15.92	4.4	4.5
Grants in lieu of Taxes	34.9	51.56	-136.66	188.22	51.6	18.0
Income Taxes	54.4	51.56	210.04	-158.48	-43.4	-23.6
						38.8
HST-Collected	157.5			-15.98	-4.4	-6.9
HST-Paid	58.7			27.15	7.4	4.4
						36.3

To estimate its cash working capital for 2012, NSPI started with its results for 2009 and then, to reflect changes expected between 2009 and 2012, made a number of adjustments based on NSPI's estimates as of March 25, 2011. These adjustments include the following:

- replaced the 2009 amounts for each major category of cash operating expense with the estimates for 2012;

- changed the revenue lag to reflect changes in the mix of revenues by customer type;

- changed the expense lag for fuels to reflect changes in the expected mix of fuels;

- changed the expense lag for labour to reflect the expected payment terms for the supplier of long term disability, life, dental and health insurance;

- changed the expense lag for OM&G to reflect changes in the mix of OM&G expenses;

- changed the impact of HST/GST on cash working capital to reflect the increase in HST by two percentage points to 15%, the expansion of the provincial rebate program, estimated changes in the amounts to which HST/GST will be applied, and changes in the mix of revenues and expenses to which the HST/ GST will be applied; and

- added the impact of DSM on cash working capital.

With the above changes, NSPI's estimated its cash working capital for 2012 to be $66.6 million as calculated in Table 12.

Table 12

Nova Scotia Power Inc. Cash Working Capital 2012						
	2012 ($ mm)	Rev Lag	Exp Lag	Net Lag	CWC %	Working Capital ($ mm)
Fuels	612.2	51.86	27.13	24.73	6.8	41.4
Cost of Goods Sold	1.5	0	38.89	-38.89	-10.6	-0.2
OM&G - Labour	127.0	51.86	23.37	28.49	7.8	9.9
OM&G - Excl'd Labour	125.8	51.86	26.48	25.38	6.9	8.7
Grants in lieu of Taxes	36.4	51.86	-136.66	188. 52	51.5	18.8
Income Tax	33.6	51.86	210.04	-158.18	-43.2	-14.5
						64.1
HST-Collected	213.9			-12.07	-3.3	-7.1
HST-Paid	67.3			29.02	7.9	5.3
DSM	43.7			35.80	9.8	4.3
						66.6

OPINION

I have reviewed the NSPI lead-lag study that is to be used to support the cash working capital requirement that will be included in NSPI's rate base for the 2012 test year.

The lead-lag study was completed by NSPI, although I advised NSPI on the methodology used in the study, including the application of the basic methodology to the major categories of NSPI's revenues and expenses.

NSPI's study was conducted using data from 2009. 2009 was chosen because it was the most recent year for which a complete year of data was available at the time the study was undertaken. The initial results were then updated for estimated differences between 2009 and 2012. Based on the estimates as of March 25, 2011, NSPI's cash working capital requirement for 2012 is $66.6 million.

The lead-lag study used various financial data and other information as inputs. For example, NSPI collected information on the time between the date of various invoices and the date those invoices were paid, and it provided information on its operations that affected the estimation of its cash working capital. I did not perform verification procedures on these inputs or the calculations provided by NSPI.

The focus of my opinion, and the review to support it, was the reasonableness and adequacy of the methodology employed in NSPI's lead-lag study. This methodology included the application of the basic methodology to the major categories of NSPI's revenues and expenses.

My understanding of the methodology used by NSPI has been summarized in the previous sections of this report. This understanding is based on my review which included the following:

- I reviewed documentation on NSPI's methodology that had been prepared by the utility.
- I reviewed the schedules used in NSPI's lead-lag study[6] to assist in understanding the methodology employed by the utility.
- I had a number of discussions with NSPI employees.

Based on my understanding of NSPI's methodology as set out above, the methodology that NSPI used in its lead-lag study is a reasonable application of the traditional approach

[6] Other than changes that were discussed with me and which are reflected in the previous sections, NSPI has stated that it did not make any material changes to the schedules from the time I reviewed them until March 25, 2011.

used by regulated utilities to establish their cash working capital requirement, and therefore, for purposes of establishing its 2012 rate base, the methodology adequately supports the determination of NSPI's cash working capital requirement.

RESUME - JOHN T. BROWNE

Summary:	John Browne has been assisting clients in applying regulatory principles and resolving financial, accounting and costing issues related to rate regulation for over 25 years. Prior to establishing his own practice 11 years ago, he was a consultant with Deloitte and Touche LLP, the last seven years as a partner. He has directed and worked on a wide range of studies for rate-regulated entities that have dealt with accounting and cost allocation principles, the determination of rate base, cost of service determination, product costing/pricing, rate of return, capital structure, and methods of regulation. He has appeared as an expert witness on accounting, costing and financial issues before following regulatory tribunals: Canadian Radio-television and Telecommunications Commission, Canadian Transport Commission, the Alberta Public Utilities Board / the Alberta Energy and Utilities Board, the Manitoba Public Utilities Board, Newfoundland and Labrador Board of Commissioners of Public Utilities and the Nova Scotia Board of Commissioners of Public Utilities.
Education / Professional Qualifications:	➢ Bachelor of Commerce - Queen's University ➢ Master of Arts (Economics) - Queen's University ➢ Chartered Accountant
Committees/ Publications	Mr. Browne was Chairman of the Canadian Institute of Chartered Accountants (“CICA”) Study Group that produced the CICA research report “Financial Reporting By Rate Regulated Enterprises”. He authored or co-authored the CA Magazine articles “A Matter Of Principles - Part I” “A Matter Of Principles - Part II” and "Regulatory Assets". These articles dealt with accounting by rate-regulated enterprises. He co-authored the Deloitte & Touche publication “Basics of Canadian Rate Regulation” and authored the Deloitte & Touche monograph “The Contractual Pitfalls of Relying on GAAP”. He has also authored a number of papers for distribution to clients and potential clients such as “Fundamentals of Rate Regulation” (an update of “Basics of Canadian Rate Regulation”).

Key Clients: Mr. Browne's major clients have included: Newfoundland Power Inc., Nova Scotia Power Inc., New Brunswick Power Corporation, Hydro Quebec, Ontario Hydro, Manitoba Hydro, SaskPower, Edmonton Power, Ottawa Hydro, Canadian Electricity Association, Ontario Energy Board, Atco Gas, Enbridge, Newfoundland Telephone Company Ltd., Bell Canada, Manitoba Telephone System, Saskatchewan Telecommunications, AGT/TELUS, Teleglobe, Telesat Canada, Southwestern Bell Telephone Company, New York Telephone, The Telecommunication Authority of Singapore and Dhiraagu (Maldives).

Selected Assignments:

- Completed a survey of Canadian regulators to determine what they viewed as their objectives and how they interpreted those objectives.

- Researched and analysed the methodology for calculating working capital for Edmonton Power. Prepared evidence on the issue and appeared as an expert witness.

- Assisted a telecommunications company in developing and supporting a position on working capital for a regulatory hearing.

- Advised Nova Scotia Power on the methodology for a lead-lag study and reviewed the methodology employed to determine whether it was reasonable and adequately supported the utility's net cash working capital. The opinion was included in the utility's rate submission (issue was resolved as part of negotiated settlement).

- Advised Newfoundland Power on issues related to the calculation of cash working capital, reviewed the methodology it used to establish its cash working capital, and provided an opinion as to whether the methodology was consistent with established regulatory practice and appropriate in the context of the utility. The opinion was included in the utility's rate submission (issue was resolved as part of negotiated settlement).

- Assisted Hydro-Québec by researching issues related to the determination of rate base for a first time rate application and preparing a report that recommended how the utility's rate base should be established at its initial rate hearing.

- Assisted Newfoundland Power by providing an opinion on regulatory accounting policies including: relationship of regulatory accounting policies to GAAP, the use of the accrual vs. billed method for recognizing revenue, the treatment of unrecognized unbilled revenue and policies related to the utility's transition to an asset rate base methodology. The opinion was submitted to the utility's regulator and expert testimony was provided.

- Prepared a report for Hydro-Québec TransÉnergie that addressed regulatory issues related to the transfer of assets into the utility's regulated rate base.

- Reviewed various regulatory issues as part of the due diligence for Altalink's purchase of TransAlta's transmission assets in Alberta.

- Provided a written opinion for Nova Scotia Power on its regulatory treatment of amounts related to an income tax dispute. The report dealt with past taxes that had not been recovered in allowed rates and future taxes that may not be payable.

- Prepared a report for SaskPower, an integrated electric utility, that addressed the issues related to including or excluding non-core operations from the scope of rate regulation and the regulatory implications for any dealings between these types of operations and its core regulated operations.

- Provided a one-day workshop on regulatory issues to an electric utility with both distribution and transmission operations. The key focus was on performance-based regulation and affiliate transactions.

- Provided a written opinion for Newfoundland Light & Power on accounting and regulatory issues related to future employee benefits and the company's hydro production equalization reserve. The opinion was included in the company's rate submission.

- Completed a study for New Brunswick Power that identified and evaluated the options for restructuring the electric power industry in New Brunswick and privatizing all or part of the Company. As part of the assignment, reviewed the developments occurring throughout the world with a focus on North America.

- Provided a written opinion for Nova Scotia Power that addressed whether its proposal to change from market value to market related value in determining its pension expense was consistent with generally accepted accounting principles and established regulatory principles.

- Assisted a diversified energy company by reviewing its transfer prices to and from regulated operations and recommending changes.

- Researched and analysed the issue of a deferral plan for the introduction of a new plant into rate base. Prepared evidence on the issue for Nova Scotia Power and appeared as an expert witness. Subsequently prepared evidence and appeared as an expert witness on changes to the deferral of the costs on the plant due to changes in circumstances.

- Prepared a report that dealt with the corporate charges from a parent company to a regulated gas utility. The report evaluated the consistency of the charges with the past decisions of the OEB and its Affiliate Relationships Code for Gas Distributors. The report was submitted to the OEB.

- Assisted Ontario Hydro Services Company (now Hydro One), in understanding its regulatory options by researching and providing advice on a number of regulatory issues related to transfer pricing, structural organization, accounting for income taxes, relationships with affiliated companies, performance-based regulation, etc.

- Researched and evaluated options for the regulation of Nova Scotia Power. A recommendation was submitted to the utility's regulator and expert testimony provided.

- Advised New Brunswick Power Distribution and Customer Service Corporation on regulatory issues related to a proposed fuel deferral account.

- Analysed the issue of the appropriate accounting and regulatory treatment of Nova Scotia Power's defeasance program. Prepared evidence and appeared as an expert witness on the issue.

- Researched and evaluated the appropriateness of Newfoundland Power Inc.'s inter-corporate charges. A recommendation with support was submitted to the Newfoundland and Labrador Board of Commissioners of Public Utilities.

- Completed a study and recommended a cost of equity rate for Edmonton Power for each of the years 1985, 1986, 1987, 1988, 1989, 1993 and 1996. The reports for 1985, 1986 and 1996 were included in the Company's rate submissions to the Public Utilities Board of Alberta / Alberta Electric and Utility Board and expert testimony was provided at a public hearing.

- Assisted New Brunswick Electric Power in addressing various accounting issues related to its first rate hearing.

- Completed a study to establish an appropriate capital structure for Edmonton Power and prepared a report recommending an appropriate capital structure for regulatory purposes that formed part of the utility's 1996 submission to the Alberta Energy and Utility Board.

- Advised Manitoba Hydro on the development of appropriate financial targets and prepared evidence on the issue for submission to the utility's regulator. The assignment required researching and analysing the issue of appropriate financial targets for a government owned utility.

- Researched, analysed and prepared a recommendation on the issue of whether Nova Scotia Power should recover a purchase premium paid by the utility on the purchase of a distribution utility.

- Prepared and delivered a half day seminar on accounting for the effects of rate regulation for a Canadian electric utility.

- Participated in the in the OEB consultation process dealing with the transition to IFRS. As part of this participation, made a presentation on proposed principles to guide the development and maintenance of regulatory accounting policies (RAP) and a framework for evaluating proposed changes in RAP.

- Advised the business unit of a major telecommunications company on the appropriate basis for establishing the transfer prices to be charged to other business units within the company.

- Evaluated the ability of a telecommunications company's existing costing systems to meet CRTC Phase III costing requirements and provided an opinion on whether the methodology would be defensible.