CONFIDENTIAL (Attachment Only)

Request IR-157:

For each windfarm owned by or under contract to NSPI, for each month January 2009 through June 2011, please provide:

(a) Actual energy generation

(b) Actual wind capacity in service

Response IR-157:

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

CONFIDENTIAL (Attachment Only)

Request IR-158:

Please provide the current status of each renewable generation project under contract to NSPI (e.g., permitting status, financing status, construction status).

Response IR-158:

Please refer to Confidential Attachment 1. A complete list of renewable energy projects is provided in Appendix 1 of the 2012 General Rate Application.

CONFIDENTIAL (Attachment Only)

Request IR-159:

Please provide any reports received by NSPI since July 2010, from any renewable generation project under contract to NSPI, regarding the status and progress of the project.

Response IR-159:

Please refer to Confidential Attachments 1 to 4.

NON-CONFIDENTIAL

Request IR-160:

Please provide NSPI's current projection of RES compliance, by source by year, 2011–2015.

Response IR-160:

Please refer to NPB IR-117.

NON-CONFIDENTIAL

Request IR-161:

Please provide any analyses performed by or for NSPI since 2009 regarding the feasibility and benefits of mothballing or deactivating existing coal capacity.

Response IR-161:

NSPI has not completed an analysis as described in this request.

NON-CONFIDENTIAL

Request IR-162:

Please provide NSPI's current projection of load and capacity by year, through 2021.

Response IR-162:

Please refer to CA IR-165. The information is listed under System Planning in the 10 Year System Outlook 2011, as table 9, page 18 of 53.

CONFIDENTIAL (Attachment Only)

Request IR-163:

For each of the following responses, for which NSPI asserts confidentiality, please provide the basis of the assertion and explain the nature of the harm that would result from public disclosure of the response:

(a) CA IR-35 Attachment 1

(b) CA IR-36 Attachment 1

(c) CA IR-43 Attachment 1

(d) CA IR-58 Attachment 1

(e) CA IR-61 Attachment 1

(f) Multeese IR-1 Attachment 1

Response IR-163:

(a) This document is filed on a confidential basis due to system security concerns. Protection of the power system preserves reliability and reduces risks associated with external threats.

(b) This document is filed on a confidential basis due to system security concerns. Protection of the power system preserves reliability and reduces risks associated with external threats.

CONFIDENTIAL (Attachment Only)

(c) This document contains details respecting monthly energy generation and monthly peak load on the plant for Nova Scotia Power's gas turbines. Nova Scotia Power procures fuel, purchased power, services and capital equipment in a market that is driven by competitive forces and suppliers looking to create value for themselves. The more a supplier is aware of Nova Scotia Power's specific requirements, the better their ability to obtain the highest price, reduce competition and ultimately increase the cost for NSPI and its customers.

This information is commercially sensitive as it provides specific plant characteristics which could allow suppliers to respond to Requests for Proposals at prices that could, in absence of this detailed knowledge, otherwise be lower. Knowledge of these details would allow a sophisticated supplier to anticipate the needs of the Company and adapt bids accordingly.

(d) Upon further review, Nova Scotia Power has determined that this document is only partially confidential. Page 17 is confidential as it shows critical equipment infrastructure. Protection of the power system preserves reliability and reduces risks associated with external threats. Nova Scotia Power has redacted and re-filed the original attachment. Please refer to Partially Confidential Attachment 1.

(e) This document is filed on a confidential basis for security of the system security concerns as it shows critical equipment infrastructure. Protection of the power system preserves reliability and reduces risks associated with external threats.

(f) This document is the Cost of Service Study. It is filed on a confidential basis as the data input tables contain commercially sensitive financial information from 2011.

LIVERPOOL AREA DISTRIBUTION PLANNING STUDY

Report No. 265-0109-W68

Ting Zhang

January, 2009

EXECUTIVE SUMMARY

This study was initiated by the approaching capacity criteria violation at Milton substation due to planned construction of approximate 2 MVA of new commercial load in the next three years.

Transformer 50W-T53 is rated 12.5/14.8MVA. Since the load on 50W-T53 peaks in the winter time, the cold ambient temperature permits the rating to be increased to 133% of 14.8MVA which is 19.7 MVA. However, Polsky Energy (Brooklyn) has purchased 2.5 MVA capacity of this transformer for the contingency of losing their 138kV supply, there is only 17.2 MVA capacity available for other NSPI customers.

This new commercial load plus normal load growth is predicted to result in a load of 17.41 MVA on transformer 50W-T53 by the year 2020 exceeding the 17.2 MVA capacity.

25kV feeder 50W-412 is loaded to 200amps peak at present and is predicted to be loaded to 277 amps in 2011 at a growth rate of 1.5% per year as well as an additional 2 MVA new commercial load, and become 335amps if it is requested to supply 2.5 MVA reserves for Polsky Energy. However, it is still below the overload criteria for contingency. Load on feeder 412 under normal condition would exceed 300 amps in 2018.

This study recommends (1) transferring some load on Highway #3 off 50W-412 to 411 when overload criteria violation occurs on feeder 412 in 2018 and (2) replacing 50W-T53 by a larger unit (15/20/25 MVA) in 2020.

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LIST OF TABLES AND FIGURES

1.0 SCOPE

This study was initiated to develop a plan to deal with the approaching capacity criteria violation at Milton sub-station with 2 MVA of new commercial load in the next three years. Transformer load is predicted to exceed 133% of its top rating by 2020 including 2.5 MVA reserves for Polsky Energy (Brooklyn). Transformer loading, feeder loading and load growth on the 25kV distribution system in Milton has been reviewed in this planning study, and feeder voltage profiles and reconfiguration have been evaluated using the CYME model. This report covers the period between 2008 and 2023.

2.0 EXISTING SYSTEMS

2.1 Sub-Transmission

The 69kV Sub-transmission System in Liverpool area is supplied via the 138kV transmission system transformers identified in table 1 below.

Sub-station Name	Transformer	Transformer Data				
		Manufacturer	kV	Rating (MVA)	IMP.	Age
50W-Milton	50W-T1	Westinghouse	138-69	30/40/50	6.40%	1965

Table 1 Liverpool Area EHV Substations

Under normal operating conditions, Milton 138kV sub-station is fed by a loop, one end from the Bridgewater substation via L-6531, L-6006 and L-6025, and the other end from Tusket and Souriquois via L-6024 and L-6020. 50W is also used to supply Polsky and Bowater Mersey substation.

The Sub-transmission System Operation Diagram for this area is shown in Appendix A.

2.2 Distribution

This study is focused on 50W Milton sub-station transformer T53 and the two 25kV distribution feeders (411 and 412). 50W-411 and 50W-412 go along Milton E Rd. until they get Potanoc St., which is about 1.5kM from the substation. 50W-412 continues to go along Milton E Rd., 50W-411 goes west along Potanoc St. till it goes to West St. and feed down to Victoria Lake and Western Head areas after passing Downtown Liverpool. 50W-412 passes Highway 103 and #3 then supplies the areas of Brooklyn, Beach Meadows, West& East Berlin, Port Medway, Mill Village, Charleston, Italy Cross and Camperdown.

The distribution sub-station supplying Liverpool area is shown in Table 2.

Milton Feeder Circuits						
Sub-station Name	Xfmr Data					Feeder Numbers
	Manufacturer	kV	Rating (MVA)	IMP.	Age	
50W-Milton	Federal Pioneer	69-26.4	12.5/14.8	6.40%	1987	50W-411, 50W-412

Table 2 Milton Distribution Feeders

The distribution system under study is shown by the distribution system operating diagram in Appendix B.

3.0 LOAD HISTORY AND FORECAST

3.1 Load History

In Liverpool area, there are two distribution substations, Waterloo St. substation (48 W) supplies 4kV load within Downtown Liverpool area, and Milton substation (50W) supplies 25kV load. During the past years, due to transformer capacity and contingency criteria issues, some of 4kV load on 48W feeders has been converted to 25kV and fed from 50W instead, therefore in this planning study the load profile of the whole Liverpool area (48W+50W) is analyzed together. Load data dating back to 1993 was obtained for Milton transformer, L-5539 (48W transformer) and distribution feeders from the PI Data combining with monthly substation meter readings. The combined 48W and 50W load growth for Liverpool is shown in Figure 1 below:

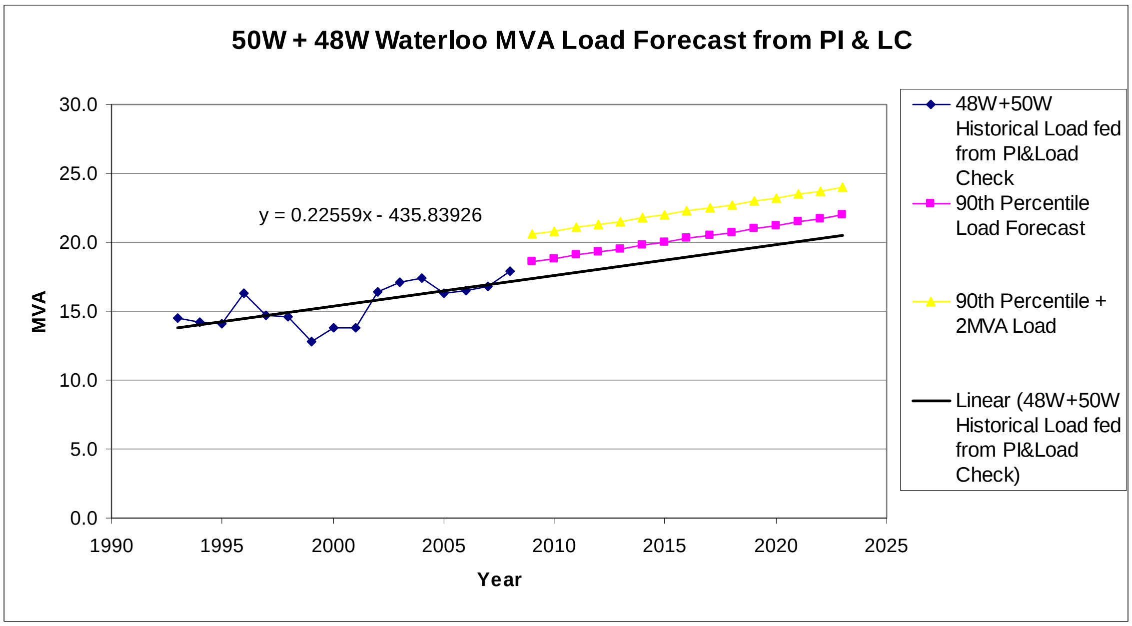


Figure 1 Historical and Forecast Annual Peak Load for Liverpool Area

3.2 Load Forecast

The load forecast will be determined by projecting with the calculated 1.5% per year growth rate. Table 3 below shows the forecasted load for the Milton and Waterloo St. Sub-station transformers if they were left in their present configuration.

Year	48W+50W Design Forecast (MVA)	48W-T1 Design Forecast (MVA)	50W-T53 + 2MVA Design Forecast (MVA)
2008/2009	18.17	5.48	12.69
2009/2010	18.44	5.56	12.88
2010/2011	18.72	5.65	13.07
2011/2012	21.00	5.73	15.27
2012/2013	21.29	5.82	15.47
2013/2014	21.57	5.90	15.67
2014/2015	21.86	5.99	15.87
2015/2016	22.16	6.00	16.16
2016/2017	22.46	6.00	16.46
2017/2018	22.78	6.00	16.78
2018/2019	23.08	6.00	17.08
2019/2020	23.41	6.00	17.41
2020/2021	23.72	6.00	17.72
2021/2022	24.05	6.00	18.05
2022/2023	24.38	6.00	18.38

Table 3 Load Forecast – Liverpool Area

48W –T1 rated at 7.5/10MVA can only be loaded to 6MVA due to contingency violation criteria at emergency, because the top rating of the available mobile transformer at 69 to 4kV in our system (3P) is 6MVA. From Table 3 above we can see that the load of 48W-T1 is predicted to exceed 6 MVA in 2016, and we have to convert some load to 25kV and transfer it to 50W circuit.

50W-T53 rated at 14.8MVA can be loaded to 133% of its top rating during winter (19.68MVA) before being considered to be in an overloaded condition. However, since Polsky Energy (Brooklyn) has purchased 2.5 MVA capacity in the transformer for the contingency of losing their 138kV supply, there is only 17.2 MVA capacity available for other NSPI customers.

There will be a planned new-constructed 2MVA commercial load along Highway #3 between Old Fall Rd. and Old Pepsi Rd. in the next three years. This new load growth includes a hotel, school, library and some sports facilities, which mostly depends on the future development and potential profitability of Bowater Mersey Paper Company. If that happens, plus the load transferred from 48W 4kV system, the design load growth forecast for 50W-T53 predicts that load will exceed its rating by 2019/2020 winter peak with a forecast load of 17.41MVA.

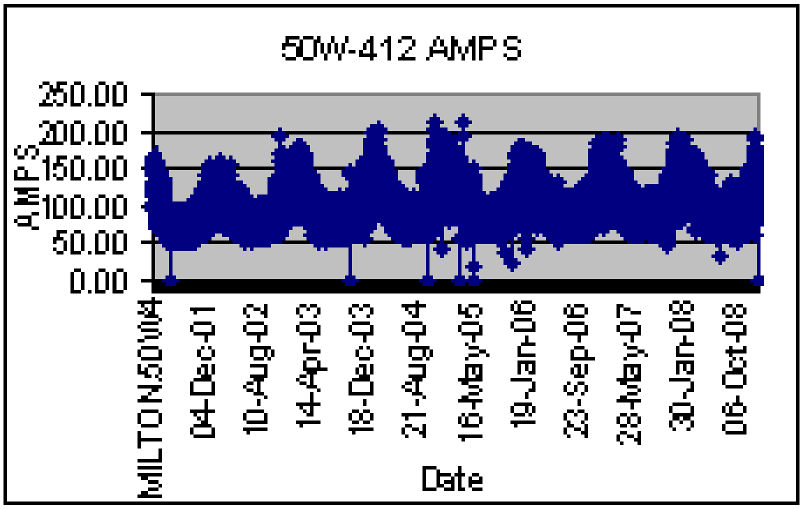
4.0 Capital Criteria Violations

4.1 Overloaded Power Transformers

With the forecast load growth, overload criteria violations will occur in 2020 as shown in Table 3 above with the additional 2MVA commercial load. 50W-T53 will exceed 133% of its top nameplate rating by then (provided that load continues to grow at the forecasted rate of 1.5% per year).

4.2 Feeder Overloads

As we discussed above, an approximate 2 MVA new load might be tapped off 50W-412 during 2010 and 2011. At present the feeder is loaded at around 200amps for winter peak, and historical feeder load profile is shown as Figure 3 below.



<u>Figure 2 50W-412 Feeder Historical Load Profile</u>

By 2011 50W-411 is predicted to be 125 amps, while 50W-412 is predicted to be loaded to 230 amps (provided that load continues to grow at the forecasted rate of 1.5% per year), and will increase to 277 amps with the inclusion of the 2 MVA of new commercial construction by 2011, which is still below 300 amps feeder capacity limit. It will be loaded up to 325 amps including Polsky reserves. However, there is no contingency violation, according to the feeder 90 percentage design forecast, a feeder can be loaded to 325 amps in the case of emergency (unless other restrictions apply such as recloser cold load pick-up, conductor capacity limits).

50W-412 is predicted to be loaded up to 302 amps under normal condition by 2018, while load on 50W-411 would be 138 amps. Load transfer from 50W-412 to 50W-411 is recommended if actual load grows as predicted.

Required work includes:

- Close switch D418-010 between 50W-411& 412 on Bristol Ave.

- Install a new switch at the cutout to replace the fuse as shown in Figure 4
- Build a 2 km double-circuit to pick up about 2.5 MVA load from 50W-412

Figure 3 Capital Work for load transfer in 2018

Cost of the capital work as indicated above would be roughly $240,000 at present value.

4.3 Contingency Loss of a Power Transformer

The contingency plan for loss of transformer 50W-T53 is installation of mobile transformer 5P and spare. Switching load to alternate substations is not possible in this study since there are no other 25kV circuits interconnected with 50W feeders.

4.4 Under-voltage

For 50W-412 simulation shows that low voltage may be experienced at the end of some single-phase feeder sections, which are shown in Appendix C. If the condition is verified by voltage recording in the field, single phase regulators will be required at the recommended locations which are also marked in the maps in Appendix C.

5.0 SOLUTIONS AND EVALUATION

Refer to Appendix E for relevant information on NSPI Capital Expenditure Justification Criteria.

Transformer 50W-T53 is predicted to be overloaded by 2020 if the new load growth is built as expected. Three alternatives were evaluated in this study. These included (1) the option to replace transformer 50W-T53 in 2020 by a larger unit (15/20/25 MVA) to prevent overload violation (2) the option to add a second transformer (7.5/10/12.5 MVA) in 50W substation in 2020 and (3) the option to add a new transformer (7.5/10/12.5 MVA) in 48W substation in 2020 and upgrade L-5539. Details of these options are presented as below.

Alternative 1: Replace transformer 50W-T53 in 2020 by a larger unit (15/20/25 MVA) to prevent overload violation

This option would require the replacement of existing transformer by a 15/20/25 MVA unit with OLTC. The existing Federal Pioneer transformer (12.5/14.8 MVA) can be stored as a system spare, or it can be put into other substations as required.

In addition to transformer replacement, LV bus upgrades are required. Two or three extra pole expansions will be installed to strengthen aerial conductor between the transformer and 25kV bus structure. The two spans of aerial conductor are 556 ACSR and 336 ACSR. The 336 ACSR, however, would be capable for 500 -550 Amps under summer conditions and around 750 Amps under winter conditions. Therefore, 336 ACSR would need to be replaced by then.

Alternative 2: Add a second transformer (7.5/10/12.5 MVA) in 50W substation in 2020

This option relies on installing a second transformer (7.5/10/12.5 MVA) in 50W substation with the existing 50W-T53 in service as well.

For this alternative, a transformer bay will be expanded from 69kV Bus B2, new switches and a circuit breaker at high voltage side will also be purchased at the same time. Existing LV bus has to be isolated by installing new switches for the existing two feeder exits, or a new LV bus structure would be built for one feeder or the other. System operating diagram of 50W substation is also attached in Appendix A.

Alternative 3: Add a new transformer (7.5/10/12.5 MVA) in 48W substation in 2020 and upgrade L-5539

This option includes adding a new 69 to 25kV transformer (7.5/10/12.5 MVA) in 48W substation. At present, there is only one 69 to 4kV transformer in Waterloo St. substation tapping off L-5539 and supplying downtown Liverpool area.

In this option, a separate fence on the yard towards Waterloo St. is recommended to accommodate the second transformer to feed some of 50W load in 2016. A draft of the 48W substation layout with the new transformer is attached in Appendix D. In this alternative we need to purchase a new high voltage switch and a recloser as well as the transformer. The pole structure for 69kV before coming into the substation needs to be rebuilt for the connection of 69kV line and transformer bushing. A set of poles for the feeder exit is also part of the capital work besides three spans of pole expansions for connecting with the existing 50W feeders.

The advantage of this option is that 48W is geographically close to the heavy-loaded area fed by 50W feeders, and it has less overall system loss in this scheme. However, L-5539 is a 69kV transmission line from Milton substation to Waterloo St. This line is a wood pole structure with a distance of 8.5km. The conductor size for the first 7.7 km out of Milton is 336 ACSR and the remaining 0.8 km is 4/0. Some transmission line up-grades and maintenance work would likely be done due to the ground clearance caused by additional load tapped off L-5539 by then.

Associated work includes:

- Installing a few new line structures and repairing some existing ones
- Replacing some wood poles due to damage or deterioration

Economic Analysis

The relevant financial data, economic analysis, NPV results, and alternative summary sheets have been attached in Appendix E of this report.

Alternative 1: Replace transformer 50W-T53 in 2020 by a larger unit (15/20/25 MVA)
(NPC = $770,510.9)
Alternative 2: Add a second transformer (7.5/10/12.5 MVA) in 50W substation in 2020
(NPC= $ 770,420.6)
Alternative 3: Add a second transformer (7.5/10/12.5 MVA) in 48W substation in 2020
and upgrade L-5539
(NPC = $905,879.5)

The results of the analysis show that the cost of Alternative 1, *Replace transformer 50W-T53 in 2020 by a larger unit (15/20/25 MVA)* is most economic.

Qualitative Analysis

In the course of valuating the options for Milton substation 50W-T53, the future of L-5539 and 48W substation supplying the 4kV system needs to be considered.

Transformer 48W-T1 was conducted in 1965, and it is now 43 years old and has reached 108% of the average service life for ‘Transmission Plant- Station Equipment’[1]. According to the IOWA State Survivor Curve R2.5, and based on an average service life of 40 years, we can estimate that 48W-T1 will reach the end of its service life in 2016.

By this date, it will probably have to be replaced and scrapped. Besides the transformer, the 4kV switch gear is old and 4kV cables are also old. The question is, will the choice being made on the 25kV system now be impacted by the 4kV system alternatives? The three choices available for the 4kV system are:

- maintain the 69-4kV system by replacing transformer 48W-T1, switch gear and cables as they fail
- convert the 4kV system to 25kV and eliminate substation 48W or
- replace 48W-T1 with a 25-4kV transformer and maintain the substation as a step-down substation

If Alternative 3 in 50W study is chosen then there will be a long term commitment to keep L-5539 at 69kV. If Alternative 1 and 2 are chosen then the option for L-5539 would still be open.

Another option for L-5539 would be to utilize it as a future 25kV feeder from 50W, after we retire 48W substation as a 69kV-4kV source. We would also require a neutral conductor by then.

However, it was felt to be outside the scope of this study to evaluate the 4kV system options at this time. The only aspect being considered here is supplying 4kV load growth by the 25kV system to keep the load on 48W-T1 under mobile rating.

Alternative 1: *Replace transformer 50W-T53 in 2020 by a larger unit (15/20/25 MVA)*

This is the most economic scheme with the least capital work comparing with other solutions. The majority part of capital would be the new transformer unit. However, the existing transformer 50W-T53 is fairly new-installed (in 1987); we can put it into other substation after it is overloaded at 50W. Therefore salvage value has to be taken into account during the Economic Analysis for this alternative.

This option also has the least total system loss obtained from CYME.

Alternative 2: *Add a second transformer (7.5/10/12.5 MVA) in 50W substation in 2020*

This option requires a second transformer in 50W substation. In this option, each transformer supplies one feeder. Capital cost also includes a new circuit breaker and LV recloser, besides we have to build a new LV bus for the second feeder.

Total system loss obtained from CYME for this option is 69kW/year more than that of Alternative 1.

Alternative 3: *Add a second transformer (7.5/10/12.5 MVA) in 48W substation in 2020 and upgrade L-5539*

This alternative is similar to Alternative 2, but instead of installing the transformer in Milton substation, we will put it into Waterloo St. substation. The only reason for this scheme is that 48W is the location relatively closer to the load center for 50W distribution circuits than 50W substation.

Comparing with Alternative 1, the total system loss for this option is 63.3kW/year more.

Besides those three alternatives stated above, there is another assumption being considered as an alternative in this study, which is to build a new substation with a 15/20/25 MVA transformer on Highway #3 tapping off L-6047&6048 near Polsky Substation. In this case distribution system has less losses and better load balance performance. 50W-T53 and two feeders could be retired by then and load could also be supplied from the new 138kV substation instead. We can also retire L-5539 by replacing 48W-T1 by a 25 to 4 kV transformer when 48W-T1 comes to the end of its life. This option will improve system performance and reliability; also minimize the cost of maintenance. However, this option turns out infeasible due to several reasons:

- This is the option with the highest capital cost.
- 50W-412 is requested to supply Polsky with 2.5 MVA reserves when they lose 138kV L-6047&6048 supply. If we feed 50W feeders by new substation, they will have the same source, and there would be contingency criteria violation.
- Bowaters would be subject to distribution faults causing voltage dips.
- Line protection on L-6047&6048 have to be revised at a high cost.

L-6047 is two-terminal differential with relays at 50W and 101W while L-6048 is three-terminal differential with relays at 50W, 101W and 104W. For load current or faults external to the line the relays on the given line will communicate to each other the magnitude and phase angle of the currents entering and leaving the line. Under normal conditions, the phasor sum should be close to zero and all relays restrained. The relay settings and characteristics will allow for a certain error to account for CT performance and possibly tapped load on the line. For a fault on the line the phasor sum of currents detected by the relays will have a net value equal to the fault current. The relays will communicate that to each other and they will trip.

If we tap new load off these two lines, L-6047&6048 relays would see the tapped load as error current (unless we tap at the 104W bus downstream of the 138 kV breaker), and of course if a fault occurred on the feeders supplied by the tap transformer this fault current would be seen as an error current by the differential relays and they would trip.

6.0 RECOMMENDATIONS

The foregoing economic analysis favours Alternative 1, which is to replace the existing transformer with a larger unit (15/20/25 MVA) in 50W substation in 2020. The capital project will solve the overload violation problems in Liverpool Area in the most economic manner over the next 15 years.

This option is recommended to replace the transformer as well as the low side switch. Two or Three pole expansions will also be required to strengthen aerial conductor between the transformer and 25kV bus structure. 336 ACSR aerial conductors would also need to be replaced by then.

Load transfer to feeder 50W-411 from 412 is recommended in 2018 when the feeder overload violation occurs on 50W-412. However, further planning study would be required to check the load profile again before implementing any recommendation within this study.

APPENDIX A

System Operating Diagram

[redacted]

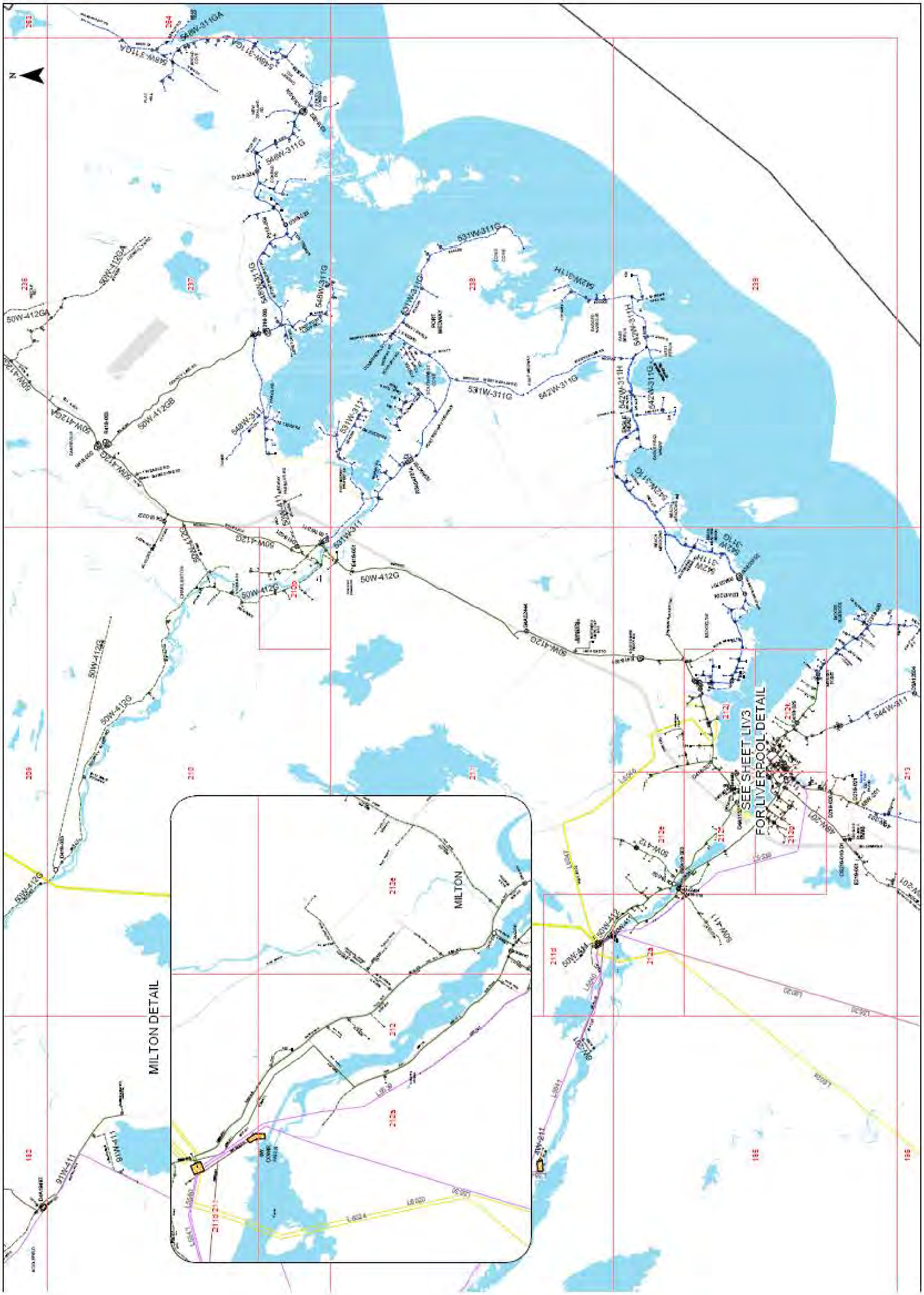
Appendix A System Operating Diagram

[redacted]

APPENDIX B

Distribution System Operating Diagram

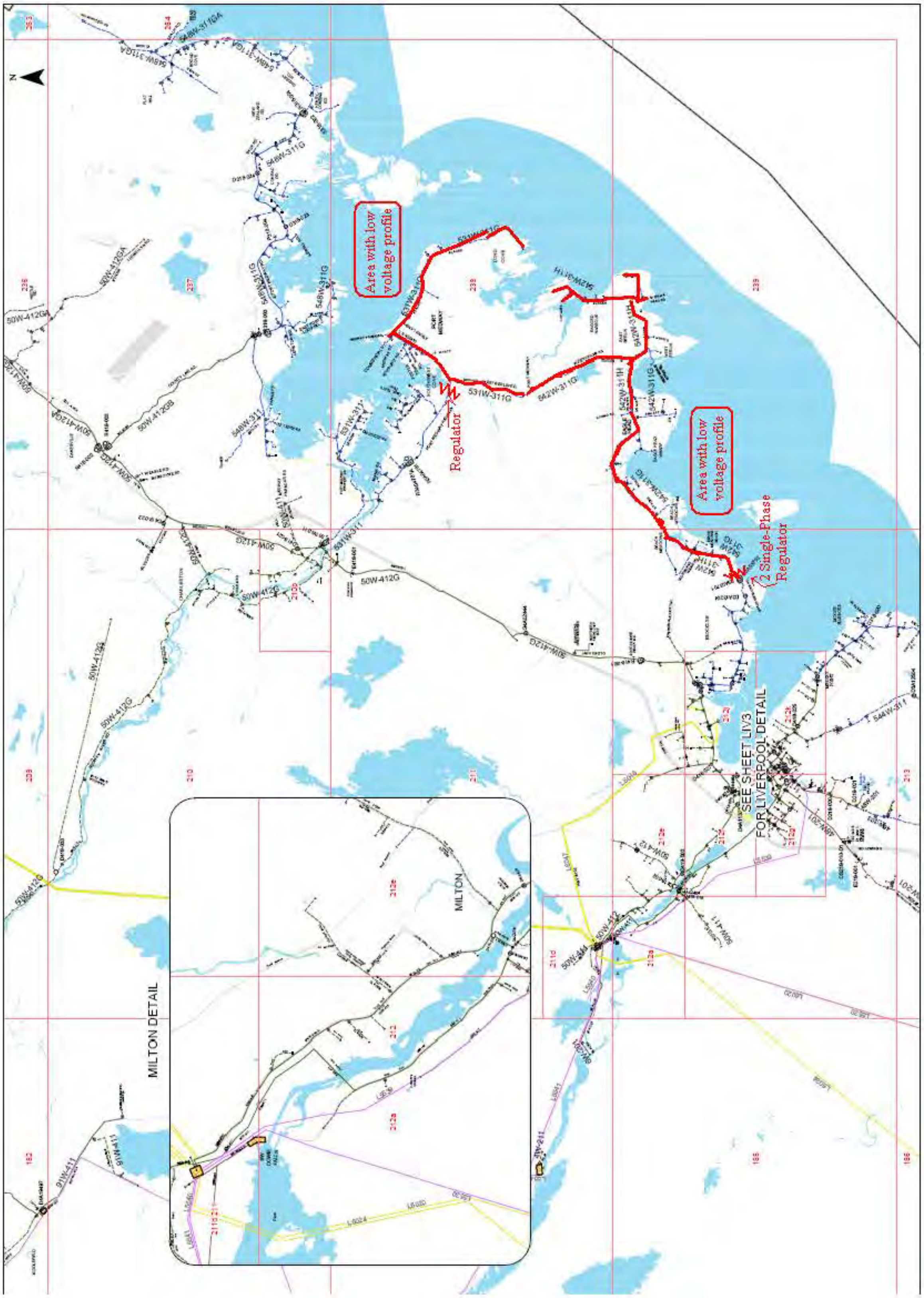
Appendix B Distribution System Operating Diagram

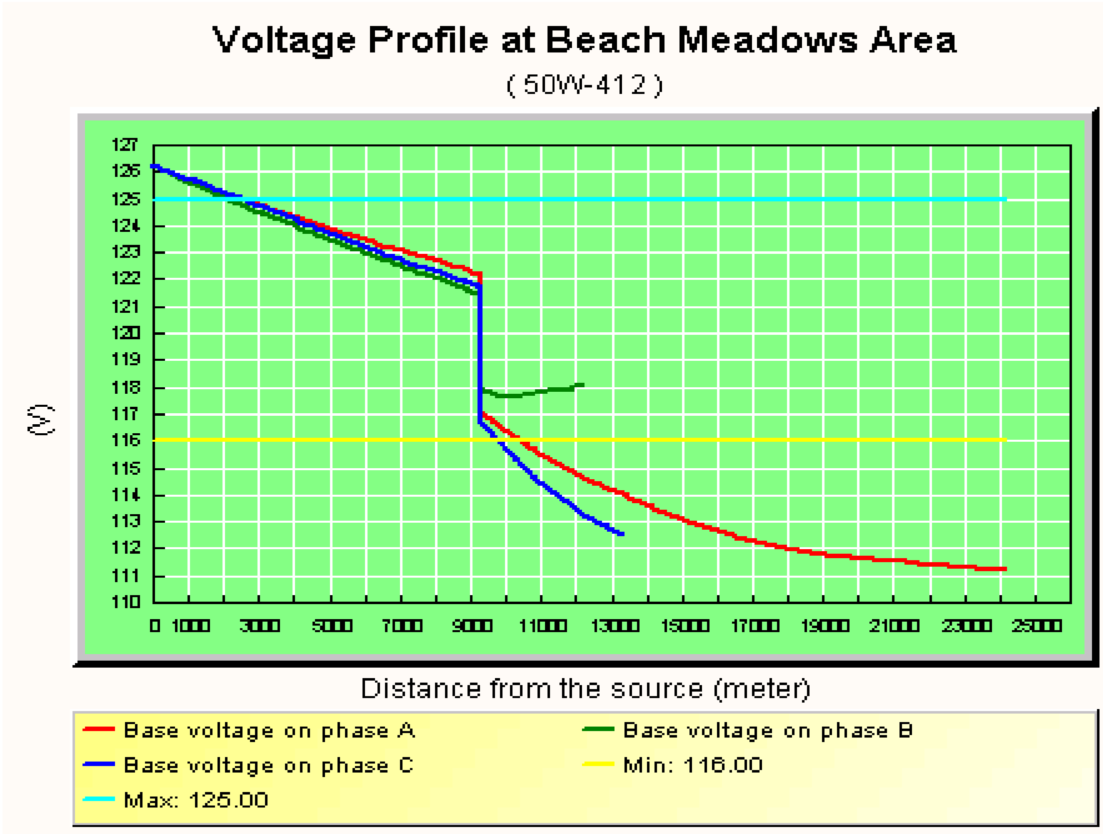


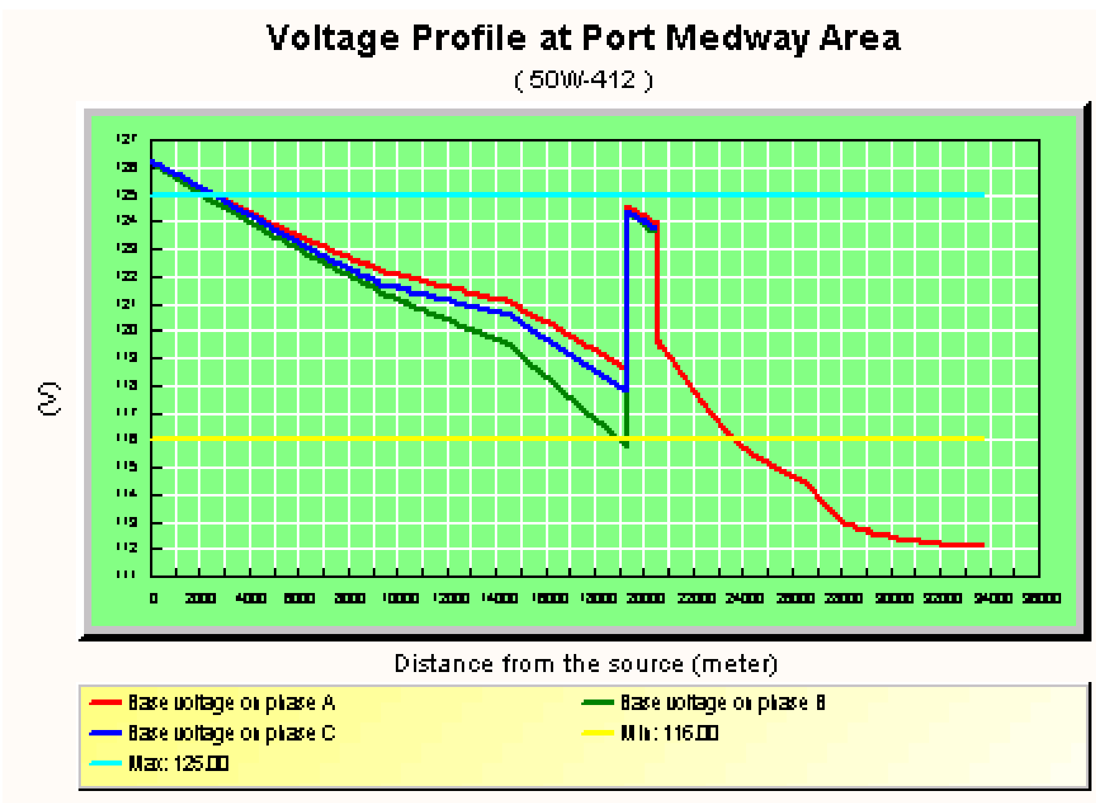
APPENDIX C

Recommendation of Voltage Regulators

Appendix C Recommendation of Voltage Regulators



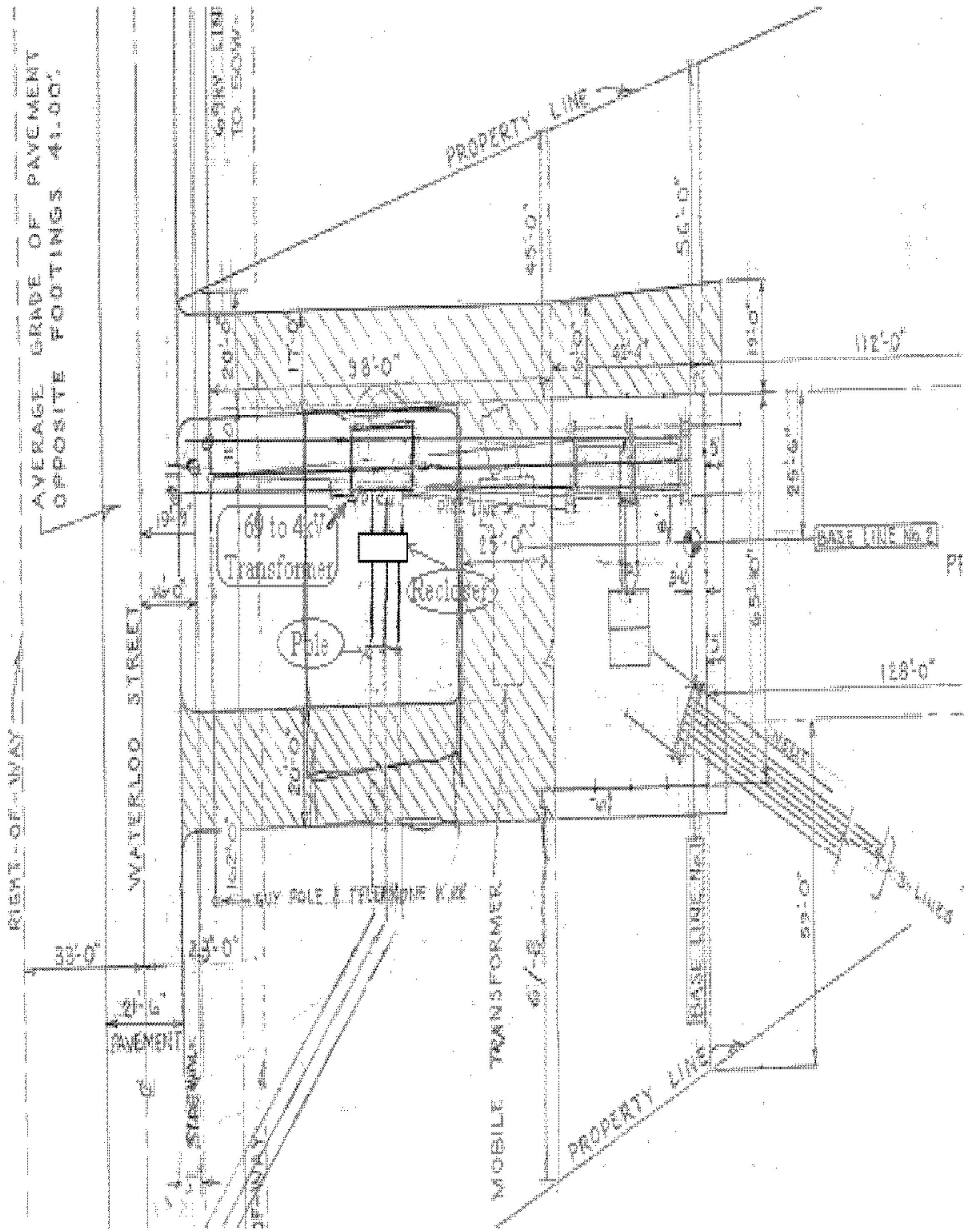

Voltage Profile at Beach Meadows Area
(50W-412)
(V)
127
126
125
124
123
122
121
120
119
118
117
116
115
114
113
112
111
110
0 1000 3000 5000 7000 9000 11000 13000 15000 17000 19000 21000 23000 25000
Distance from the source (meter)
Base voltage on phase A
Base voltage on phase B
Base voltage on phase C
Min: 116.00
Max: 125.00


Voltage Profile at Port Medway Area
(50W-412)
(V)
Distance from the source (meter)
Base voltage on phase A
Base voltage on phase B
Base voltage on phase C
Min: 116.00
Max: 125.00

APPENDIX D

Overview of Alternative 3

Appendix D Overview of Alternative 3



APPENDIX E

Economic Analysis

Print Summary Sheet

NOVA SCOTIA POWER
An Emera Company

Liverpool Area Distribution Planning Study
Summary of Alternatives

Admin: Unlock
Admin: Lock

Budget Year :	2009	Date :	3-Feb-09
Division :		CI Number:	
Department :		Project No. :	
Originator :			

	Alternative	After Tax WACC	PV of EVA / NPV	Rank	IRR	Disc Pay
A	Replace 50W-T53 with a larger unit in 2020	6.38%	-770,516	2	#NUM!	0.0 years
B	Add second transformer in 50W and a new feeder bay in 2020	6.38%	-775,421	3	#NUM!	0.0 years
C	Add a new transformer in 48W in 2020	6.38%	-905,880	4	#NUM!	0.0 years
D	Test 4	6.38%	0	1	#NUM!	0.0 years

Recommendation :

This study recommends replacing the transformer by a larger unit as well as the low side switch in 2016 when the overload violation occurs. Two or Three pole expansions will also be required to strengthen aerial conductor between the transformer and 25kV bus structure. 336 ACSR aerial conductors would need to be replaced by then, too

Notes/Comments :

Replace 50W-T53 with a larger unit in 2020

This option would require replacing the transformer as well as the low side switch. Two or Three pole expansions will also be required to strengthen aerial conductor between the transformer and 25kV bus structure. 336 ACSR aerial conductors would need to be replaced by then, too

Add second transformer in 50W and a new feeder bay in 2020

This option relies on installing a second transformer (7.5/10/12.5 MVA) in 50W substation with the existing 50W-T53 in service as well. In this alternative, a transformer bay will be expanded from 69kV Bus B2, new switches and a circuit breaker at high voltage side will also be purchased at the same time. Existing LV bus has to be isolated by installing new switches for two feeder exits, or a new LV bus structure would be built for the second feeder.

Add a new transformer in 48W in 2020

This option includes adding a second transformer (7.5/10/12.5 MVA) in 48W substation. In this alternative we have to purchase a new high voltage switch and a recloser as well as the transformer. The pole structure for 69kV before coming into the substation needs to be rebuilt for the new transformer horizontal bushing connection; besides, a set of poles as the feeder exit is also part of the capital work as well as three spans of pole expansions. Some transmission line up-grades and maintenance work would likely be done over next few years due to the ground clearance caused by additional load tapped off L-5539.

Test 4

Liverpool Area Distribution Planning Study
Replace 50W-T53 with a larger unit in 2020

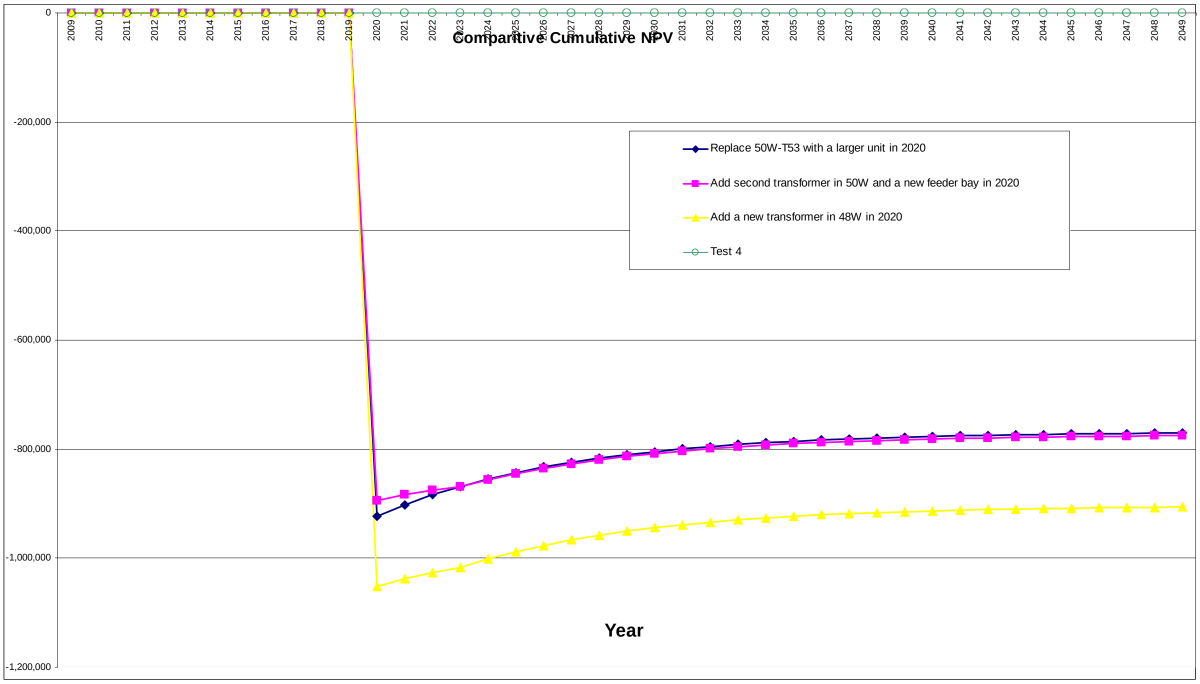
Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2009	-	-	-	-	-	-	-	-	1.000	-	-
2010	-	-	-	-	-	-	-	-	0.940	-	-
2011	-	-	-	-	-	-	-	-	0.884	-	-
2012	-	-	-	-	-	-	-	-	0.831	-	-
2013	-	-	-	-	-	-	-	-	0.781	-	-
2014	-	-	-	-	-	-	-	-	0.734	-	-
2015	-	-	-	-	-	-	-	-	0.690	-	-
2016	-	-	-	-	-	-	-	-	0.649	-	-
2017	-	-	-	-	-	-	-	-	0.610	-	-
2018	-	-	-	-	-	-	-	-	0.573	-	-
2019	-	-	-	-	-	-	-	-	0.539	-	-
2020	-	-	(1,844,948.6)	73,797.9	1,771,150.7	(1,844,948.6)	22,877.4	(1,822,071.3)	0.507	(923,081.9)	(923,081.9)
2021	-	-	-	141,692.1	1,629,458.6	-	43,924.5	43,924.5	0.476	20,918.7	(902,163.2)
2022	-	-	-	130,356.7	1,499,101.9	-	40,410.6	40,410.6	0.448	18,091.5	(884,071.7)
2023	-	-	-	119,928.2	1,379,173.8	-	37,177.7	37,177.7	0.421	15,646.4	(868,425.3)
2024	-	-	-	110,333.9	1,268,839.9	-	34,203.5	34,203.5	0.396	13,531.8	(854,893.6)
2025	-	-	-	101,507.2	1,167,332.7	-	31,467.2	31,467.2	0.372	11,702.9	(843,190.6)
2026	-	-	-	93,386.6	1,073,946.1	-	28,949.9	28,949.9	0.350	10,121.3	(833,069.4)
2027	-	-	-	85,915.7	988,030.4	-	26,633.9	26,633.9	0.329	8,753.4	(824,316.0)
2028	-	-	-	79,042.4	908,988.0	-	24,503.2	24,503.2	0.309	7,570.3	(816,745.7)
2029	-	-	-	72,719.0	836,268.9	-	22,542.9	22,542.9	0.290	6,547.2	(810,198.5)
2030	-	-	-	66,901.5	769,367.4	-	20,739.5	20,739.5	0.273	5,662.3	(804,536.1)
2031	-	-	-	61,549.4	707,818.0	-	19,080.3	19,080.3	0.257	4,897.1	(799,639.1)
2032	-	-	-	56,625.4	651,192.6	-	17,553.9	17,553.9	0.241	4,235.2	(795,403.9)
2033	-	-	-	52,095.4	599,097.2	-	16,149.6	16,149.6	0.227	3,662.8	(791,741.1)
2034	-	-	-	47,927.8	551,169.4	-	14,857.6	14,857.6	0.213	3,167.8	(788,573.3)
2035	-	-	-	44,093.6	507,075.8	-	13,669.0	13,669.0	0.200	2,739.7	(785,833.6)
2036	-	-	-	40,566.1	466,509.8	-	12,575.5	12,575.5	0.188	2,369.4	(783,464.2)
2037	-	-	-	37,320.8	429,189.0	-	11,569.4	11,569.4	0.177	2,049.2	(781,415.1)
2038	-	-	-	34,335.1	394,853.9	-	10,643.9	10,643.9	0.167	1,772.2	(779,642.9)
2039	-	-	-	31,588.3	363,265.6	-	9,792.4	9,792.4	0.157	1,532.7	(778,110.2)
2040	-	-	-	29,061.2	334,204.3	-	9,009.0	9,009.0	0.147	1,325.5	(776,784.6)
2041	-	-	-	26,736.3	307,468.0	-	8,288.3	8,288.3	0.138	1,146.4	(775,638.2)
2042	-	-	-	24,597.4	282,870.5	-	7,625.2	7,625.2	0.130	991.5	(774,646.8)
2043	-	-	-	22,629.6	260,240.9	-	7,015.2	7,015.2	0.122	857.5	(773,789.3)
2044	-	-	-	20,819.3	239,421.6	-	6,454.0	6,454.0	0.115	741.6	(773,047.7)
2045	-	-	-	19,153.7	220,267.9	-	5,937.7	5,937.7	0.108	641.4	(772,406.4)
2046	-	-	-	17,621.4	202,646.5	-	5,462.6	5,462.6	0.102	554.7	(771,851.7)
2047	-	-	-	16,211.7	186,434.7	-	5,025.6	5,025.6	0.095	479.7	(771,372.0)
2048	-	-	-	14,914.8	171,520.0	-	4,623.6	4,623.6	0.090	414.9	(770,957.1)
2049	-	-	-	13,721.6	157,798.4	-	5,230.7	5,230.7	0.084	441.2	(770,515.9)
Total	-	-	(1,844,948.6)	1,687,150.3	20,324,702.4	(1,844,948.6)	523,993.6	(1,320,955.1)	15.4	(770,515.9)	(24,179,525.0)

Liverpool Area Distribution Planning Study
Add second transformer in 50W and a new feeder bay in 2020

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2009	-	-	-	-	-	-	-	-	1.000	-	-
2010	-	-	-	-	-	-	-	-	0.940	-	-
2011	-	-	-	-	-	-	-	-	0.884	-	-
2012	-	-	-	-	-	-	-	-	0.831	-	-
2013	-	-	-	-	-	-	-	-	0.781	-	-
2014	-	-	-	-	-	-	-	-	0.734	-	-
2015	-	-	-	-	-	-	-	-	0.690	-	-
2016	-	-	-	-	-	-	-	-	0.649	-	-
2017	-	-	-	-	-	-	-	-	0.610	-	-
2018	-	-	-	-	-	-	-	-	0.573	-	-
2019	-	-	-	-	-	-	-	-	0.539	-	-
2020	-	(27,363.1)	(1,767,002.7)	70,680.1	1,696,322.6	(1,794,365.9)	30,393.4	(1,763,972.5)	0.507	(893,648.4)	(893,648.4)
2021	-	(28,697.2)	-	135,705.8	1,560,616.8	(28,697.2)	50,964.9	22,267.7	0.476	10,604.8	(883,043.6)
2022	-	(30,093.9)	-	124,849.3	1,435,767.5	(30,093.9)	48,032.4	17,938.5	0.448	8,030.9	(875,012.7)
2023	-	(31,565.5)	-	114,861.4	1,320,906.1	(31,565.5)	45,392.3	13,826.8	0.421	5,819.1	(869,193.6)
2024	-	-	-	105,672.5	1,215,233.6	-	32,758.5	32,758.5	0.396	12,960.1	(856,233.5)
2025	-	-	-	97,218.7	1,118,014.9	-	30,137.8	30,137.8	0.372	11,208.5	(845,025.0)
2026	-	-	-	89,441.2	1,028,573.7	-	27,726.8	27,726.8	0.350	9,693.7	(835,331.3)
2027	-	-	-	82,285.9	946,287.8	-	25,508.6	25,508.6	0.329	8,383.5	(826,947.8)
2028	-	-	-	75,703.0	870,584.8	-	23,467.9	23,467.9	0.309	7,250.5	(819,697.3)
2029	-	-	-	69,646.8	800,938.0	-	21,590.5	21,590.5	0.290	6,270.6	(813,426.7)
2030	-	-	-	64,075.0	736,863.0	-	19,863.3	19,863.3	0.273	5,423.1	(808,003.6)
2031	-	-	-	58,949.0	677,913.9	-	18,274.2	18,274.2	0.257	4,690.2	(803,313.4)
2032	-	-	-	54,233.1	623,680.8	-	16,812.3	16,812.3	0.241	4,056.3	(799,257.2)
2033	-	-	-	49,894.5	573,786.4	-	15,467.3	15,467.3	0.227	3,508.1	(795,749.1)
2034	-	-	-	45,902.9	527,883.4	-	14,229.9	14,229.9	0.213	3,034.0	(792,715.1)
2035	-	-	-	42,230.7	485,652.8	-	13,091.5	13,091.5	0.200	2,623.9	(790,091.2)
2036	-	-	-	38,852.2	446,800.5	-	12,044.2	12,044.2	0.188	2,269.3	(787,821.9)
2037	-	-	-	35,744.0	411,056.5	-	11,080.7	11,080.7	0.177	1,962.6	(785,859.4)
2038	-	-	-	32,884.5	378,172.0	-	10,194.2	10,194.2	0.167	1,697.3	(784,162.0)
2039	-	-	-	30,253.8	347,918.2	-	9,378.7	9,378.7	0.157	1,467.9	(782,694.1)
2040	-	-	-	27,833.5	320,084.8	-	8,628.4	8,628.4	0.147	1,269.5	(781,424.5)
2041	-	-	-	25,606.8	294,478.0	-	7,938.1	7,938.1	0.138	1,098.0	(780,326.6)
2042	-	-	-	23,558.2	270,919.7	-	7,303.1	7,303.1	0.130	949.6	(779,377.0)
2043	-	-	-	21,673.6	249,246.2	-	6,718.8	6,718.8	0.122	821.2	(778,555.7)
2044	-	-	-	19,939.7	229,306.5	-	6,181.3	6,181.3	0.115	710.2	(777,845.5)
2045	-	-	-	18,344.5	210,962.0	-	5,686.8	5,686.8	0.108	614.3	(777,231.2)
2046	-	-	-	16,877.0	194,085.0	-	5,231.9	5,231.9	0.102	531.2	(776,700.0)
2047	-	-	-	15,526.8	178,558.2	-	4,813.3	4,813.3	0.095	459.4	(776,240.6)
2048	-	-	-	14,284.7	164,273.5	-	4,428.2	4,428.2	0.090	397.3	(775,843.2)
2049	-	-	-	13,141.9	151,131.7	-	5,009.7	5,009.7	0.084	422.6	(775,420.6)
Total	-	(117,719.7)	(1,767,002.7)	1,615,871.1	19,466,018.9	(1,884,722.5)	538,348.9	(1,346,373.6)	15.4	(775,420.6)	(24,226,191.8)

Liverpool Area Distribution Planning Study
Add a new transformer in 48W in 2020

Year	Total Revenue	Operating Costs	Capital	CCA	UCC	CFBT	Applicable Taxes	CFAT	Discount Factor	PV of CF	CNPV
2009									1.000	-	-
2010	-	-	-	-	-	-	-	-	0.940	-	-
2011	-	-	-	-	-	-	-	-	0.884	-	-
2012	-	-	-	-	-	-	-	-	0.831	-	-
2013	-	-	-	-	-	-	-	-	0.781	-	-
2014	-	-	-	-	-	-	-	-	0.734	-	-
2015	-	-	-	-	-	-	-	-	0.690	-	-
2016	-	-	-	-	-	-	-	-	0.649	-	-
2017	-	-	-	-	-	-	-	-	0.610	-	-
2018	-	-	-	-	-	-	-	-	0.573	-	-
2019	-	-	-	-	-	-	-	-	0.539	-	-
2020	-	(25,333.8)	(2,086,063.8)	83,442.6	2,002,621.2	(2,111,397.6)	33,720.7	(2,077,677.0)	0.507	(1,052,574.6)	(1,052,574.6)
2021	-	(26,559.6)	-	160,209.7	1,842,411.5	(26,559.6)	57,898.5	31,338.9	0.476	14,924.9	(1,037,649.8)
2022	-	(27,848.2)	-	147,392.9	1,695,018.6	(27,848.2)	54,324.7	26,476.6	0.448	11,853.4	(1,025,796.4)
2023	-	(29,200.4)	-	135,601.5	1,559,417.1	(29,200.4)	51,088.6	21,888.2	0.421	9,211.7	(1,016,584.7)
2024	-	-	-	124,753.4	1,434,663.8	-	38,673.5	38,673.5	0.396	15,300.2	(1,001,284.5)
2025	-	-	-	114,773.1	1,319,890.7	-	35,579.7	35,579.7	0.372	13,232.4	(988,052.1)
2026	-	-	-	105,591.3	1,214,299.4	-	32,733.3	32,733.3	0.350	11,444.0	(976,608.1)
2027	-	-	-	97,144.0	1,117,155.4	-	30,114.6	30,114.6	0.329	9,897.3	(966,710.7)
2028	-	-	-	89,372.4	1,027,783.0	-	27,705.5	27,705.5	0.309	8,559.7	(958,151.0)
2029	-	-	-	82,222.6	945,560.4	-	25,489.0	25,489.0	0.290	7,402.8	(950,748.2)
2030	-	-	-	75,644.8	869,915.5	-	23,449.9	23,449.9	0.273	6,402.3	(944,345.9)
2031	-	-	-	69,593.2	800,322.3	-	21,573.9	21,573.9	0.257	5,537.1	(938,808.8)
2032	-	-	-	64,025.8	736,296.5	-	19,848.0	19,848.0	0.241	4,788.7	(934,020.1)
2033	-	-	-	58,903.7	677,392.8	-	18,260.2	18,260.2	0.227	4,141.5	(929,878.6)
2034	-	-	-	54,191.4	623,201.4	-	16,799.3	16,799.3	0.213	3,581.8	(926,296.8)
2035	-	-	-	49,856.1	573,345.3	-	15,455.4	15,455.4	0.200	3,097.7	(923,199.1)
2036	-	-	-	45,867.6	527,477.6	-	14,219.0	14,219.0	0.188	2,679.0	(920,520.1)
2037	-	-	-	42,198.2	485,279.4	-	13,081.4	13,081.4	0.177	2,317.0	(918,203.1)
2038	-	-	-	38,822.4	446,457.1	-	12,034.9	12,034.9	0.167	2,003.8	(916,199.3)
2039	-	-	-	35,716.6	410,740.5	-	11,072.1	11,072.1	0.157	1,733.0	(914,466.3)
2040	-	-	-	32,859.2	377,881.3	-	10,186.4	10,186.4	0.147	1,498.8	(912,967.5)
2041	-	-	-	30,230.5	347,650.8	-	9,371.5	9,371.5	0.138	1,296.2	(911,671.3)
2042	-	-	-	27,812.1	319,838.7	-	8,621.7	8,621.7	0.130	1,121.0	(910,550.3)
2043	-	-	-	25,587.1	294,251.6	-	7,932.0	7,932.0	0.122	969.5	(909,580.7)
2044	-	-	-	23,540.1	270,711.5	-	7,297.4	7,297.4	0.115	838.5	(908,742.2)
2045	-	-	-	21,656.9	249,054.6	-	6,713.6	6,713.6	0.108	725.2	(908,017.1)
2046	-	-	-	19,924.4	229,130.2	-	6,176.6	6,176.6	0.102	627.2	(907,389.9)
2047	-	-	-	18,330.4	210,799.8	-	5,682.4	5,682.4	0.095	542.4	(906,847.5)
2048	-	-	-	16,864.0	193,935.8	-	5,227.8	5,227.8	0.090	469.1	(906,378.4)
2049	-	-	-	15,514.9	178,420.9	-	5,914.3	5,914.3	0.084	498.9	(905,879.5)


Comparitive Cumulative NPV
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-600,000
-800,000
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Replace 50W-T53 with a larger unit in 2020
Add second transformer in 50W and a new feeder bay in 2020
Add a new transformer in 48W in 2020
Test 4
Year

CONFIDENTIAL (Attachment Only)

Request IR-164:

With regard to IR CA-25a, for each existing NSPI unit, please provide:

(a) The 10-minute load-following capacity provided by the unit.

(b) The unit's ramp rate up and ramp rate down.

Response IR-164:

(a-b) NSPI does not distinguish between the rate of ramping up and the rate of ramping down. Please refer to Confidential Attachment 1.

Request IR-165:

Please provide "NSPI's 10 Year Outlook Report."

Response IR-165:

The report can be found on the NSPI OASIS web site at the following link.

http://oasis.nspower.ca/en/home/default/forecastsandassessments.aspx

REDACTED

Request IR-166:

Please provide all available documentation of NSPI's "wind forecasting model" (IR CA-25h), including

(a) A description of the development of the model, including the names of any contractors, the dates of contract issuance and contractor work product delivery.

(b) A full description of the data sources used for the model,

(c) All available comparisons of actual and forecast values.

Response IR-166:

(a) The model was developed in-house by Nova Scotia Power. The basis of the model is forecasted wind speed and wind direction as it is relates to a point on the manufacture supplied efficiency curve of the specified wind generator. This gives a forecast MW output. Multiplying this output by the number of turbines operating at a given wind farm gives a forecast in MWs for each wind farm. The model was originally built in Excel. In 2010, it was ported into a Java scripted program.

(b) Data sources for the model include the forecasted wind speed and wind direction. This is provided by [redacted].

(c) Please refer to Attachment 1, filed electronically.

NON-CONFIDENTIAL

Request IR-167:

Question CA-30 requested an explanation of why NSPI "assigned [wind assets] 30% to 3CP demand and the remaining plant to energy." The response simply restates the question less clearly. Please explain why NSPI decided that 30% (and not more or less) of wind assets should be classified to 3CP demand and 70% to energy.

Response IR-167:

Please refer to part a of UARB IR-73 from the 2007 rate case provided in Attachment 1.

2007 **NSUARB-P-886**

NOVA SCOTIA UTILITY AND REVIEW BOARD

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

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

RESPONSE TO INFORMATION REQUEST

TO: **NSPI**

FROM: **UARB**

Question IR-73: **Appendix G**

a. **Page 5, (last line but one): Provide an explanation of why wind assets are assigned 30% to 3CP demand and the remaining plant to energy.**

b. **Exhibit 7: Why isn't line 17 the same as Appendix A, Table 2, line 5, column 5?**

c. **Exhibit 9A, line 8: Column 2 shows energy sales of 2,076.1 GW.h, the same value as used by NSPI in the ELIIR-2 hearing (P-883) for the cost of service study in SEB IR-1a. Column 6 shows a coincident demand of 264,400 KW versus the SEB IR-1a value of 247,000 KW. This results in a drop in customer load factor from 95.85% in SEB IR-1a to 89.64% in the present filing. Please provide an explanation for the higher peak demand forecast for this customer in the present filing while leaving energy sales constant between the two cost of service studies.**

Response IR-73: a. Wind energy is a variable resource. In Nova Scotia, the current installed wind generation has generally achieved approximately a 30 percent capacity factor, compared to nameplate rating. NSPI has used these results in the Cost of Service Study to assign 30 percent of wind assets to demand, with the remainder being assigned to energy.

2007 **NSUARB-P-886**

NOVA SCOTIA UTILITY AND REVIEW BOARD

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

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

RESPONSE TO INFORMATION REQUEST

TO: **NSPI**

FROM: **UARB**

Response IR-73: (cont'd)

b. The difference between Non-Rate Revenue of $9.3 million in Exhibit 7, line 17 and Misc. Revenue of $10.8 million in Table 2, line 5 of Appendix A is associated with $1.5 million in Retail Sales. This Retail Sales figure when netted against Cost of Goods Sold of $1.1 million in Table 2, line 10 of Appendix A results in a credit of $0.4 million that is identified in Exhibit 4, Line 24 of Appendix G.

c. The demand of 264,400 kW for 2007 is based on 2005 actual load shape information that was not available in the P-883 hearing.

REDACTED

Request IR-168:

CA IR-35 Attachment 1 shows a number of distribution step down substations (e.g., 3C, 11C, 13C, 46C, 47C, 52V, 53V, 41V, 48V) that are not listed in CA IR-36 Attachment 1. Please provide the data requested in CA IR-36 for each of the remaining step down substations shown on CA IR-35 Attachment 1.

Response IR-168:

The response to this request is confidential.

NON-CONFIDENTIAL

Request IR-169:

In the legend of CA IR-35 Attachment 1, the thinnest gray or black lines are identified as "26 kV & below." Is this category the color of the lines from 85S to 94S and 95S, or the lighter color of the numerous lines, such as those from 95S to 73S?

(a) If the lighter lines are not the 26 kV and below transmission, are they primary circuits, roads, or something else?

(b) If the lighter lines are not transmission lines, please explain the nature of the distribution step down substations (such as 33V, 41V, 48V, 102C, 64C, 65S, 61S, 56W, 90W and 49W) that are not shown as being connected or close to any other lines.

Response IR-169:

CA IR-35 requested a map of NSPI's transmission system. The legend "26 kV and below" on this map is to identify only facilities operating at this voltage that are classified as transmission. To display only the transmission facilities, the distribution facility layer of the provincial map was turned off. However, some of the distribution step-down stations - those which provide transformation between two distribution voltages - and some currently retired substations did not get turned off.

The lines connecting 85S to 94S and 95S are part of the Hydro Generation system in that area and are classified as transmission along with 85S although they operate at 25 kV.

(a) The lighter lines shown are roads.

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(b) 41V, 48V, and 102C are customer owned stations connected to NSPI's distribution system and should not have appeared on this map as NSPI transmission facilities. 61S and 65S are distribution step-downs that should not have appeared on the map as transmission facilities and 33V, 64C, 56W, 49W, and 90W are retired substations.

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Request IR-170:

Exhibit 3B to the COSS shows costs of dedicated substations that are direct-assigned to specific classes. CA IR-36 Attachment 1 states that “Dedicated customer transformers are not included” in that attachment. Both these sources thus indicate that NSPI can identify the dedicated substations. Yet CA IR-37 claims that NSPI does not know which substations are dedicated, or what classes they are dedicated to. Please reconcile these statements.

Response IR-170:

CA IR-36 references dedicated customer transformers, whereas CA IR-37 is referencing dedicated substations. These are two different components of NSPI’s infrastructure. The exclusion of dedicated transformers from the substation list, included in the response to CA IR-36, does not imply that the list comes short of dedicated substations.

NSPI did not retrieve and repeat the basis of each of the elements of the Cost of Service Study for this proceeding, many of which were approved by the Board in its 1995 Decision and have since been used repeatedly in general rate applications and FAM processes. The work to produce a list of dedicated customer substations and transformers and to identify customers who use dedicated substations would require further data research and analysis which cannot be completed in the time allotted for responding to Information Requests. This effort may be of interest in a review of the Cost of Service Study in a separate proceeding, which has been routinely opposed by the Consumer Advocate.

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Request IR-171:

CA IR-38 requested an explanation of the difference between "bulk power" and "general" distribution substations as those terms are used in Exhibit 3B to the COSS. The response does not explain this distinction. Please provide the requested explanation or state that the distinction is meaningless.

Response IR-171:

Since filing the response to CA IR-38, NSPI has retrieved archived materials from earlier regulatory proceedings which contained the explanation of the difference between "bulk power" and "general" distribution substations for cost of service purposes. Please refer to Attachment 1[1]. To NSPI's knowledge, this question has not been posed in a general rate application since 1989.

[1] Rate Case 1989, response to IR

NOVA SCOTIA POWER CORPORATION

RATE CASE 1989
RESPONSE TO INFORMATION REQUESTS

Question 211. Cost of Service Study

In AED-3A:

(a) What is the difference between "Bulk Power" (columns 2 and 3) and "General" (columns 4 and 5).

(b) Were the totals (Line 1) obtained by analysis of asset accounts?

Response 211. (a) Bulk Power is a substation category which represents that transformation from transmission voltage (69 kV or higher) to distribution voltage (below 69 kV).

"General" represents the substation category for transformations from one distribution voltage to a lower distribution voltage.

(b) Yes they were.

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Request IR-172:

The response to CA IR-38 says that "For the COSS purposes the rate base associated with the distribution substations has been split among the four categories …using the same proration approach since the last COSS hearing was held in 1995." Does this mean that the approach has been applied to the actual costs of the changing mix of dedicated and bulk distribution substations over time, that the same percentages have been used since 1995, or something else (and if so, what)?

Response IR-172:

The estimated percentages have changed as a result of applying the following approach:

The total distribution substation plant is segregated into the following six categories:

- A - Distribution Bulk Power

- B - Distribution Dedicated Bulk Power

- C - Distribution Customer Own Bulk Power

- D - Distribution General

- E - Distribution Dedicated General

- F - Distribution Customer Own General

NSPI has kept the gross plant values for categories B, C, E and F at constant dollar levels since 1996 and calculated their annual net plant values based on periodically updated depreciation

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rates. The annual net plant values of the two main categories A and D are modified to balance with the total net plant book value of all distribution substations. The modifications of A and D are put into effect by applying on an annual basis periodically updated depreciation rates to the estimates of gross plant values of A and D whose relative shares in the total gross plant value of all distribution substations, as simulated in these calculations, remain at approximately the same levels of 77 percent and 16 percent, respectively.

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Request IR-173:

CA IR-41 asked NSPI to identify the existing transmission facilities that "are required primarily to connect one or more generator to the transmission system, and the cost of those facilities." The response referred generally to the costs that might be incurred to interconnect hypothetical future facilities. Please provide the data requested in CA IR-41.

Response IR-173:

Please refer to CA IR-174.

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Request IR-174:

CA IR-42 asked NSPI to identify the existing transmission facilities "that are required primarily to transfer power from generation in the eastern portion of the province to load in the Halifax area, and the cost of those facilities." The response referred generally to the costs that might be incurred to "increase east to west energy flows." Please provide the data requested in CA IR-42.

Response IR-174:

NSPI has not compiled this specific information in preparation for this Application.

The NSUARB report on the Nova Scotia Open Access Transmission Tariff (OATT) can be viewed at NSPI offices. Section 5 addresses the cost allocations and revenue requirements associated with the existing transmission facilities in Nova Scotia. This large attachment is available electronically upon request.

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Request IR-175:

Please provide the exhibits cited in CA IR-45 Attachment 1.

Response IR-175:

Please refer to Attachment 1.

NOVA SCOTIA POWER INC.
COST OF SERVICE STUDY ANALYSIS
FOR THE YEAR ENDING DECEMBER 31, 1993
R E F E R E N C E G U I D E

EXHIBIT AED-1

NOVA SCOTIA POWER INC.
SUMMARY OF REVENUE TO EXPENSE RECOVERY
AVERAGE AND EXCESS METHODOLOGY
FOR THE YEARS AS INDICATED

		(1) ACTUAL FOR THE 12 MTHS. ENDED MARCH 1992	(2) PRESENT RATES FORECAST FOR THE 12 MTHS. ENDING DECEMBER 1993	(3) PROPOSED RATES FORECAST FOR THE 12 MTHS. ENDING DECEMBER 1993
(1)	DOMESTIC	92	93	93
(2)	SMALL GENERAL	97	101	101
(3)	GENERAL	108	108	107
(4)	LARGE GENERAL	103	100	100
(5)	SMALL INDUSTRIAL	127	125	125
(6)	MEDIUM INDUSTRIAL	119	117	117
(7)	LARGE INDUSTRIAL	111	105	106
(8)	INTERRUPTIBLE	105	101	101
(9)	MUNICIPAL	106	103	103
(10)	UNMETERED	97	102	103
(11)	TOTAL COMPANY	100	100	100

EXHIBIT AED-2

NOVA SCOTIA POWER INC.

RATE BASE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) UNALLOCATED	(3) TOTAL TO BE ALLOCATED
PRODUCTION PLANT			
(1) STEAM	$1,095,706	$0	$1,095,706
(2) HYDRO	188,527	10,306	178,221
(3) GAS TURBINE	9,931	0	9,931
(4) TOTAL PROD. PLANT	1,294,164	10,306	1,283,858
(5) TRANSMISSION PLANT	325,208	0	325,208
DISTRIBUTION PLANT			
(6) LAND	1,303	0	1,303
(7) EASEMENTS & SURVEY	5,165	0	5,165
(8) OTHER	22	0	22
(9) SUBSTATIONS	58,269	0	58,269
(10) POLES & FIXTURES	155,068	0	155,068
(11) O.H. LINES	81,046	0	81,046
(12) U.G. LINES	16,918	0	16,918
(13) LINE TRANSFORMERS	117,224	0	117,224
(14) SERVICES	47,611	0	47,611
(15) METERS	21,887	0	21,887
(16) STREET LIGHTING	19,582	0	19,582
(17) TOTAL DIST. PLANT	524,095	0	524,095
(18) GEN. PROPERTY PLANT	102,982	0	102,982
(19) TOT. PLT. IN SERVICE	2,246,449	10,306	2,236,143
WORKING CAPITAL			
(20) CASH - FUEL	4,668	0	4,668
(21) CASH - OTHER	3,165	146	3,019
(22) MAT. & SUP. - FUEL	40,879	0	40,879
(23) MAT. & SUP. - OTHER	31,553	0	31,553
(24) TOT. WORKING CAPITAL	80,265	146	80,119
(25) TOTAL RATE BASE	$2,326,714	$10,452	$2,316,262

NOVA SCOTIA POWER INC.

ALLOCATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
PRODUCTION PLANT												
(1) STEAM	$1,095,706	$517,830	$15,340	$318,850	$26,626	$18,737	$44,924	$41,308	$68,701	$29,584	$13,806	D-3
(2) HYDRO	178,221	84,227	2,495	51,862	4,331	3,048	7,307	6,719	11,174	4,812	2,246	D-3
(3) GAS TURBINE	9,931	5,303	182	3,225	180	148	282	243	0	224	144	D-4
(4) TOTAL PROD. PLANT	1,283,858	607,360	18,017	373,937	31,137	21,933	52,513	48,270	79,875	34,620	16,196	
(5) TRANSMISSION PLANT	325,208	153,691	4,553	94,636	7,903	5,561	13,334	12,260	20,391	8,781	4,098	D-3
DISTRIBUTION PLANT												
(6) LAND	1,303	844	30	328	20	19	35	5	2	1	19	P-2
(7) EASEMENTS & SURVEY	5,165	3,347	120	1,300	79	75	139	19	6	6	74	P-2
(8) OTHER	22	14	1	6	0	0	1	0	0	0	0	P-2
(9) SUBSTATIONS	58,269	30,350	919	18,813	1,522	1,068	3,021	1,080	353	330	813	EXHIBIT 3A
(10) POLES & FIXTURES	155,068	105,371	3,882	36,280	1,967	2,103	3,212	0	0	0	2,253	EXHIBIT 3C
(11) O.H. LINES	81,046	55,073	2,030	18,961	1,028	1,098	1,679	0	0	0	1,177	EXHIBIT 3E
(12) U.G. LINES	16,918	11,496	423	3,959	215	230	350	0	0	0	245	P-1
(13) LINE TRANSFORMERS	117,224	70,100	2,122	40,899	0	2,227	0	0	0	0	1,876	D-1
(14) SERVICES	47,611	37,137	1,647	8,118	0	671	0	0	38	0	0	C-2
(15) METERS	21,887	18,002	799	2,574	7	278	166	11	46	4	0	EXHIBIT 3F
(16) STREET LIGHTING	19,582	0	0	0	0	0	0	0	0	0	19,582	DIRECT
(17) TOTAL DIST. PLANT	524,095	331,734	11,973	131,238	4,838	7,769	8,603	1,115	445	341	26,039	
(18) GEN. PROPERTY PLANT	102,982	52,758	1,668	28,959	2,121	1,699	3,594	2,976	4,861	2,111	2,235	P-6
(19) TOT.PLT.IN SERVICE	2,236,143	1,145,543	36,211	628,770	45,999	36,962	78,044	64,621	105,572	45,853	48,568	
WORKING CAPITAL												
(20) CASH - FUEL	4,668	1,993	50	1,241	135	87	235	222	512	141	52	E-1
(21) CASH - OTHER	3,019	1,676	59	725	52	46	88	69	123	49	132	O-4
(22) MAT. & SUP. - FUEL	40,879	17,448	441	10,866	1,185	764	2,060	1,942	4,480	1,235	458	E-1
(23) MAT. & SUP. - OTHER	31,553	16,164	511	8,873	650	521	1,101	912	1,489	647	685	P-6
(24) TOT.WORKING CAPITAL	80,119	37,281	1,061	21,705	2,022	1,418	3,484	3,145	6,604	2,072	1,327	
(25) TOTAL RATE BASE	$2,316,262	$1,182,824	$37,272	$650,475	$48,021	$38,380	$81,528	$67,766	$112,176	$47,925	$49,895	

EXHIBIT AED-3

NOVA SCOTIA POWER INC. **EXHIBIT AED-3A**

ANALYSIS OF DISTRIBUTION SUBSTATION PLANT

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) DISTRIBUTION BULK POWER	(3) DIST. DED. BULK POWER	(4) DISTRIBUTION GENERAL	(5) DIST.DED. GENERAL
(1) TOT.DIST. SUBSTS.	$58,269	$51,240	$1,887	$4,479	$663
ALLOCATION					
(2) DOMESTIC	30,350	27,911	0	2,439	0
(3) SMALL GENERAL	919	845	0	74	0
(4) GENERAL	18,813	17,160	85	1,500	68
(5) LARGE GENERAL	1,522	1,368	0	120	34
(6) SMALL INDUSTRIAL	1,068	979	0	86	3
(7) MEDIUM INDUSTRIAL	3,021	2,229	453	195	144
(8) LARGE INDUSTRIAL	1,080	0	1,080	0	0
(9) INTERRUPTIBLE	353	0	164	0	189
(10) MUNICIPAL	330	0	105	0	225
(11) UNMETERED	813	748	0	65	0
(12) TOTAL	$58,269	$51,240	$1,887	$4,479	$663
(13) ALLOCATION FACTOR		D-2	DIRECT	D-2	DIRECT

NOVA SCOTIA POWER INC.

EXHIBIT AED-3B

ANALYSIS OF POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET POLE COST	$155,068	$0	$0	$0	$0
(2) PRIMARY ONLY (30%)	46,520	46,520	0	0	0
(3) JOINT - PRI. (1)	54,274	27,137	27,137	0	0
(4) JOINT - SEC. (1)	54,274	0	0	27,137	27,137
(5) TOTAL	$155,068	$73,657	$27,137	$27,137	$27,137

(1) DEMAND COST - 50%

CUSTOMER COST - 50%

EXHIBIT AED-3C

NOVA SCOTIA POWER INC.

ALLOCATION OF POLE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$105,371	$40,121	$24,507	$16,228	$24,515
(2) SMALL GENERAL	3,882	1,215	1,088	491	1,088
(3) GENERAL	36,280	24,668	1,072	9,468	1,072
(4) LARGE GENERAL	1,967	1,967	0	0	0
(5) SMALL INDUSTRIAL	2,103	1,407	90	516	90
(6) MEDIUM INDUSTRIAL	3,212	3,204	8	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) INTERRUPTIBLE	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	2,253	1,075	372	434	372
(11) TOTAL	$155,068	$73,657	$27,137	$27,137	$27,137
(12) ALLOCATION FACTOR		D-2	C-5	D-1	C-4

NOVA SCOTIA POWER INC.

EXHIBIT AED-3D

ANALYSIS OF WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) TOTAL NET WIRE COST	$81,046	$0	$0	$0	$0
(2) PRIMARY ONLY (30%)	24,314	24,314	0	0	0
(3) JOINT - PRI. (1)	28,366	14,183	14,183	0	0
(4) JOINT - SEC. (1)	28,366	0	0	14,183	14,183
(5) TOTAL	$81,046	$38,497	$14,183	$14,183	$14,183

(1) DEMAND COST - 50%

CUSTOMER COST - 50%

NOVA SCOTIA POWER INC. **EXHIBIT AED-3E**

ALLOCATION OF WIRE INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL PLANT	(2) PRIMARY DEMAND	(3) PRIMARY CUSTOMER	(4) SECONDARY DEMAND	(5) SECONDARY CUSTOMER
(1) DOMESTIC	$55,073	$20,969	$12,809	$8,482	$12,813
(2) SMALL GENERAL	2,030	635	569	257	569
(3) GENERAL	18,961	12,893	560	4,948	560
(4) LARGE GENERAL	1,028	1,028	0	0	0
(5) SMALL INDUSTRIAL	1,098	735	47	269	47
(6) MEDIUM INDUSTRIAL	1,679	1,675	4	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) INTERRUPTIBLE	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	1,177	562	194	227	194
(11) TOTAL	$81,046	$38,497	$14,183	$14,183	$14,183
(12) ALLOCATION FACTOR		D-2	C-5	D-1	C-4

NOVA SCOTIA POWER INC.

EXHIBIT AED-3F

ANALYSIS OF METER INVESTMENT

FOR THE YEAR ENDING DECEMBER 31, 1993

	(1) TOTAL CUSTOMERS	(2) UNIT METER COST	(3) TOTAL COST	(4) PERCENT	(5) METER COST ($000)
(1) DOMESTIC	370,315	$34	$12,590,710	82.25	$18,002
(2) SMALL GENERAL	16,424	34	558,416	3.65	799
(3) GENERAL	16,213	111	1,799,643	11.76	2,574
(4) LARGE GENERAL	8	657	5,256	0.03	7
(5) SMALL INDUSTRIAL	1,342	145	194,590	1.27	278
(6) MEDIUM INDUSTRIAL	178	657	116,946	0.76	166
(7) LARGE INDUSTRIAL	6	1,338	8,028	0.05	11
(8) INTERRUPTIBLE	24	1,338	32,112	0.21	46
(9) MUNICIPAL	7	520	3,640	0.02	4
(10) UNMETERED	5,607	N/A	0	0.00	0
(11) TOTAL	410,124		$15,309,341	100.00	$21,887

EXHIBIT AED-4

NOVA SCOTIA POWER INC.

FUNCTIONALIZATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL EXPENSES	(2) PRODUCTION EXPENSES	(3) TRANS. EXPENSES	(4) DIST. EXPENSES	(5) ADMIN.&GEN. EXPENSES	(6) OTHER EXPENSES
THERMAL PRODUCTION						
(1) FUEL	$243,390	$243,390	$0	$0	$0	$0
(2) OPERATING & MAINT.	52,222	52,222	0	0	0	0
(3) PURCHASED POWER	8,956	8,956	0	0	0	0
SYSTEM OPERATIONS						
(4) HYDRO PLTS. O & M.	7,256	7,256	0	0	0	0
(5) OTHER	4,012	1,579	1,708	313	412	0
OTHER OPERATING						
(6) ENGINEERING	1,384	573	555	124	132	0
(7) TRANSMISSION & DIST.	44,988	0	7,611	37,377	0	0
(8) CUSTOMER FUNCTIONS	6,104	0	0	0	6,104	0
(9) PERSONNEL	6,093	1,923	706	2,273	1,191	0
(10) INDUST. RELATIONS	2,714	0	0	0	2,714	0
(11) FIN. PLAN. & OPER.	2,843	213	100	365	2,165	0
(12) TREASURER	1,059	0	0	0	1,059	0
(13) MGT. INFO. SERVICES	8,044	902	737	1,436	4,969	0
(14) GENERAL MANAGEMENT	2,359	0	0	0	2,359	0
(15) SYSTEM PLANNING	2,021	562	577	49	833	0
(16) SEC. & GEN. COUNSEL	3,638	1,657	120	431	1,430	0
(17) CORPORATE SERVICES	5,314	0	0	0	5,314	0
(18) CORPORATE ACCOUNTING	690	0	0	0	690	0
(19) ORGANIZATION & EFFECT.	1,150	363	134	429	224	0
(20) INTERNAL AUDIT	391	0	0	0	391	0
(21) ENVIRONMENT	946	0	0	0	946	0
(22) PREMISES MANAGEMENT	4,099	0	0	0	4,099	0
(23) PUBLIC AFFAIRS	1,099	0	0	0	1,099	0
(24) CORPORATE EFFICIENCIES	(2,000)	0	0	0	(2,000)	0
(25) GRANTS IN LIEU	5,088	0	0	0	0	5,088
(26) DEPRECIATION	76,036	0	0	0	0	76,036
(27) PR.DIV.;INT.&TAX NET	131,806	0	0	0	0	131,806
(28) TOTAL	$621,702	$319,596	$12,248	$42,797	$34,131	$212,930

EXHIBIT AED-5

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES	(5) OTHER EXPENSES	(6) DIRECT EXPENSES
PRODUCTION						
(1) FUEL	$243,390	$0	$226,081	$0	$0	$17,309
(2) PURCH. POWER- FIXED	0	0	0	0	0	0
(3) PURCH. POWER- VAR.	8,956	0	8,956	0	0	0
(4) OPERATING & MAINT.	67,250	50,105	9,544	0	0	7,601
(5) TOTAL PRODUCTION	319,596	50,105	244,581	0	0	24,910
(6) TRANSMISSION	12,248	12,116	0	0	0	132
DISTRIBUTION						
(7) SUBSTATIONS	2,149	2,149	0	0	0	0
(8) OVERHEAD LINES	18,497	12,024	0	6,473	0	0
(9) UNDERGROUND LINES	657	427	0	230	0	0
(10) LINE TRANSFORMERS	302	302	0	0	0	0
(11) METERS	4,548	0	0	4,548	0	0
(12) COMMUNICATIONS	421	421	0	0	0	0
(13) STREET LIGHTING	3,311	3,311	0	0	0	0
(14) CUSTOMER SERVICE	12,912	0	0	12,912	0	0
(15) TOTAL DISTRIBUTION	42,797	18,634	0	24,163	0	0
ADMINISTRATION & GENERAL						
(16) BILLING & RECEIPTS	4,133	0	0	4,133	0	0
(17) CUSTOMER SERVICE	3,289	0	0	3,289	0	0
(18) CREDIT & COLLECTION	2,200	0	0	2,200	0	0
(19) OTHER	24,509	13,612	1,608	5,690	0	3,599
(20) TOT. ADMIN. & GEN.	34,131	13,612	1,608	15,312	0	3,599
OTHER OPERATING						
(21) GRANTS IN LIEU	5,088	0	0	0	5,088	0
(22) DEPRECIATION	76,036	0	0	0	75,986	50
(23) PR.DIV.;INT.&TAX NET	131,806	0	0	0	126,797	5,009
(24) TOTAL OTHER OPER.	212,930	0	0	0	207,871	5,059
(25) TOTAL EXPENSES	$621,702	$94,467	$246,189	$39,475	$207,871	$33,700

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) PRODUCTION O & M	$50,105	$23,679	$701	$14,581	$1,218	$857	$2,054	$1,889	$3,142	$1,353	$631	D-3
(2) TRANSMISSION	12,116	5,725	170	3,526	294	207	497	457	760	327	153	D-3
(3) DISTRIBUTION	18,634	9,990	358	3,854	225	223	387	40	13	12	3,532	EXHIBIT 6A
(4) PURCH. POWER- FIXED	0	0	0	0	0	0	0	0	0	0	0	D-3
(5) ADMIN. & GEN.	13,612	6,633	207	3,697	293	216	494	402	659	284	727	O-1
(6) TOTAL	94,467	46,027	1,436	25,658	2,030	1,503	3,432	2,788	4,574	1,976	5,043	
ENERGY												
(7) PRODUCTION - FUEL	226,081	96,492	2,442	60,092	6,556	4,228	11,394	10,739	24,778	6,828	2,532	E-1
(8) PURCH. POWER- VAR.	8,956	3,823	97	2,381	260	167	451	425	982	270	100	E-1
(9) PRODUCTION O & M	9,544	4,074	103	2,537	277	178	481	453	1,046	288	107	E-1
(10) ADMIN. & GEN.	1,608	687	17	427	47	30	81	76	176	49	18	O-2
(11) TOTAL	246,189	105,076	2,659	65,437	7,140	4,603	12,407	11,693	26,982	7,435	2,757	
CUSTOMER												
(12) DISTRIBUTION	24,163	18,383	781	3,757	96	286	196	12	49	12	591	EXHIBIT 6A
(13) BILLING & RECEIPTS	4,133	3,012	133	659	5	55	11	5	19	6	228	C-3
(14) CUSTOMER SERVICE	3,289	2,396	106	525	4	43	9	4	15	5	182	C-3
(15) CREDIT & COLLECTION	2,200	1,724	56	379	0	28	0	0	0	0	13	EXHIBIT 6C
(16) ADMIN. & GEN.	5,690	4,298	181	896	18	69	36	3	14	4	171	O-3
(17) TOTAL	39,475	29,813	1,257	6,216	123	481	252	24	97	27	1,185	
OTHER												
(18) DEPRECIATION	75,986	40,294	1,305	21,029	1,434	1,237	2,443	1,892	3,052	1,336	1,964	EXHIBIT 6D
(19) GRANTS IN LIEU	5,088	2,607	82	1,431	105	84	178	147	240	104	110	P-6
(20) PR.DIV.;INT.&TAX NET	126,797	64,755	2,041	35,605	2,625	2,105	4,463	3,715	6,137	2,625	2,726	P-7
(21) TOTAL	207,871	107,656	3,428	58,065	4,164	3,426	7,084	5,754	9,429	4,065	4,800	
(22) TOTAL OPER. EXPENSES	588,002	288,572	8,780	155,376	13,457	10,013	23,175	20,259	41,082	13,503	13,785	
(23) NON-OPER. REVENUE	(9,445)	(6,225)	(233)	(1,990)	(73)	(155)	(259)	(112)	(233)	(74)	(91)	EXHIBIT 7
(24) ALLOC.OF PROFIT/LOSS	98,021	50,061	1,578	27,524	2,029	1,627	3,450	2,872	4,744	2,029	2,107	P-7
(25) NET OPER. EXPENSES	$676,578	$332,408	$10,125	$180,910	$15,413	$11,485	$26,366	$23,019	$45,593	$15,458	$15,801	

EXHIBIT AED-6

NOVA SCOTIA POWER INC.

ALLOCATION OF DISTIBUTION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
DEMAND												
(1) SUBSTATIONS	$2,149	$1,120	$34	$694	$56	$39	$111	$40	$13	$12	$30	P-3
(2) OVERHEAD LINES	12,024	8,169	301	2,814	153	164	249	0	0	0	174	P-1
(3) UNDERGROUND LINES	427	290	11	100	5	6	9	0	0	0	6	P-1
(4) LINE TRANSFORMERS	302	181	5	105	0	6	0	0	0	0	5	D-1
(5) METERS	0	0	0	0	0	0	0	0	0	0	0	---
(6) COMMUNICATIONS	421	230	7	141	11	8	18	0	0	0	6	D-2
(7) STREET LIGHTING	3,311	0	0	0	0	0	0	0	0	0	3,311	DIRECT
(8) CUSTOMER SERVICE	0	0	0	0	0	0	0	0	0	0	0	---
(9) TOTAL DEMAND	18,634	9,990	358	3,854	225	223	387	40	13	12	3,532	
CUSTOMER												
(10) SUBSTATIONS	0	0	0	0	0	0	0	0	0	0	0	---
(11) OVERHEAD LINES	6,473	4,398	162	1,515	82	88	134	0	0	0	94	P-1
(12) UNDERGROUND LINES	230	156	6	54	3	3	5	0	0	0	3	P-1
(13) LINE TRANSFORMERS	0	0	0	0	0	0	0	0	0	0	0	---
(14) METERS	4,548	3,740	166	535	1	58	35	2	10	1	0	P-4
(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	12,912	10,089	447	1,653	10	137	22	10	39	11	494	EXHIBIT 6B
(18) TOTAL CUSTOMER	24,163	18,383	781	3,757	96	286	196	12	49	12	591	
SUMMARY												
(19) SUBSTATIONS	2,149	1,120	34	694	56	39	111	40	13	12	30	P-3
(20) OVERHEAD LINES	18,497	12,567	463	4,329	235	252	383	0	0	0	268	P-1
(21) UNDERGROUND LINES	657	446	17	154	8	9	14	0	0	0	9	P-1
(22) LINE TRANSFORMERS	302	181	5	105	0	6	0	0	0	0	5	D-1
(23) METERS	4,548	3,740	166	535	1	58	35	2	10	1	0	P-4
(24) COMMUNICATIONS	421	230	7	141	11	8	18	0	0	0	6	D-2
(25) STREET LIGHTING	3,311	0	0	0	0	0	0	0	0	0	3,311	DIRECT
(26) CUSTOMER SERVICE	12,912	10,089	447	1,653	10	137	22	10	39	11	494	EXHIBIT 6B
(27) TOTAL DISTRIBUTION	$42,797	$28,373	$1,139	$7,611	$321	$509	$583	$52	$62	$24	$4,123	

EXHIBIT AED-6A

NOVA SCOTIA POWER INC. **EXHIBIT AED-6B**

ALLOCATION OF DISTRIBUTION - CUSTOMER SERVICE EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) BILLING & RECEIPTS	(3) CUSTOMER SERVICE	(4) CREDIT & COLLECTION	(5) TREASURY FUNCTION
(1) DOMESTIC	$10,089	$3,553	$2,336	$1,028	$3,172
(2) SMALL GENERAL	447	157	104	46	140
(3) GENERAL	1,653	778	511	225	139
(4) LARGE GENERAL	10	6	4	0	0
(5) SMALL INDUSTRIAL	137	64	42	19	12
(6) MEDIUM INDUSTRIAL	22	13	8	0	1
(7) LARGE INDUSTRIAL	10	6	4	0	0
(8) INTERRUPTIBLE	39	23	15	1	0
(9) MUNICIPAL	11	7	4	0	0
(10) UNMETERED	494	269	177	0	48
(11) TOTAL	$12,912	$4,876	$3,205	$1,319	$3,512
(12) ALLOCATION FACTOR		C-3	C-3	C-2	C-1

NOVA SCOTIA POWER INC. **EXHIBIT AED-6C**

ALLOCATION OF CREDIT & COLLECTION EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1)	(2)	(3)	(4)	(5)
	------BAD DEBT EXPENSE--------				
	DIRECT	TO BE ALLOC.	TOTAL	OTHER	TOTAL
(1) DOMESTIC	$854	$0	$854	$870	$1,724
(2) SMALL GENERAL	0	18	18	38	56
(3) GENERAL	0	341	341	38	379
(4) LARGE GENERAL	0	0	0	0	0
(5) SMALL INDUSTRIAL	0	25	25	3	28
(6) MEDIUM INDUSTRIAL	0	0	0	0	0
(7) LARGE INDUSTRIAL	0	0	0	0	0
(8) INTERRUPTIBLE	0	0	0	0	0
(9) MUNICIPAL	0	0	0	0	0
(10) UNMETERED	0	0	0	13	13
(11) TOTAL	$854	$384	$1,238	$962	$2,200
(12) ALLOCATION FACTOR	DIRECT	R-1		C-1	

NOVA SCOTIA POWER INC.

ALLOCATION OF DEPRECIATION EXPENSE

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL COMPANY	(2) PRODUCTION	(3) HYDRO	(4) GAS TURBINE	(5) TRANSMISSION	(6) DISTRIBUTION	(7) GENERAL PROPERTY
(1) DOMESTIC	$40,294	$13,240	$1,571	$276	$5,931	$16,244	$3,032
(2) SMALL GENERAL	1,305	392	47	9	176	585	96
(3) GENERAL	21,029	8,152	967	169	3,652	6,425	1,664
(4) LARGE GENERAL	1,434	681	81	9	305	236	122
(5) SMALL INDUSTRIAL	1,237	479	57	8	215	380	98
(6) MEDIUM INDUSTRIAL	2,443	1,149	136	15	515	421	207
(7) LARGE INDUSTRIAL	1,892	1,056	125	13	473	54	171
(8) INTERRUPTIBLE	3,052	1,757	208	0	787	21	279
(9) MUNICIPAL	1,336	756	90	12	339	18	121
(10) UNMETERED	1,964	353	42	8	158	1,275	128
(11) TOTAL	$75,986	$28,015	$3,324	$519	$12,551	$25,659	$5,918
(12) ALLOCATION FACTOR		D-3	D-3	D-4	D-3	P-5	P-6

EXHIBIT AED-6D

EXHIBIT AED-7

NOVA SCOTIA POWER INC.

REVENUE ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

ELECTRIC REVENUE	(1) TOTAL RATE REVENUE	(2) GRID SALES	(3) LATE PAYMENT CHARGE	(4) MISC. CUSTOMER REVENUE	(5) OTHER REVENUE	(6) TOTAL NON-OPER. REVENUE
(1) DOMESTIC	$308,623	$144	$3,052	$1,670	$1,359	$6,225
(2) SMALL GENERAL	10,212	4	94	94	41	233
(3) GENERAL	194,301	90	1,148	20	732	1,990
(4) LARGE GENERAL	15,411	10	0	0	63	73
(5) SMALL INDUSTRIAL	14,323	6	101	1	47	155
(6) MEDIUM INDUSTRIAL	30,901	17	133	0	109	259
(7) LARGE INDUSTRIAL	24,331	16	0	0	96	112
(8) INTERRUPTIBLE	46,264	37	2	0	194	233
(9) MUNICIPAL	15,959	10	0	0	64	74
(10) UNMETERED	16,253	4	16	6	65	91
(11) SUB-TOTAL	$676,578	$338	$4,546	$1,791	$2,770	$9,445
(12) GRID SALES	338					
(13) TOTAL ELECT.REVENUE	676,916					
NON-RATE REVENUE						
(14) LATE PAYMENT CHARGE	4,546					
(15) MISC. CUST. REVENUE	1,791					
(16) OTHER	2,770					
(17) TOTAL	9,107					
DIRECT REVENUE						
(18) BOW. MERSEY-ELECT.	25,236					
(19) GEN.REPL./LOAD FOLL	8,625					
(20) TOTAL	33,861					
(21) TRANSFER FROM (TO) RETAINED EARNINGS	(98,182)					
(22) TOTAL REVENUE	$621,702					
(23) ALLOCATION FACTOR		E-1	DIRECT	DIRECT	0-5	COLS. 2-5

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 1993

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) N.C. DEMAND SEC.	1,496,042	894,630	27,070	521,926	0	28,416	0	0	0	0	24,000	
(2) % RESPONSIBILITY	100.00	59.80	1.81	34.89	0.00	1.90	0.00	0.00	0.00	0.00	1.60	D-1
(3) N.C. DEMAND PRIMARY	1,707,790	930,415	28,153	571,908	45,572	32,545	74,237	0	0	0	24,960	
(4) % RESPONSIBILITY	100.00	54.47	1.65	33.49	2.67	1.91	4.35	0.00	0.00	0.00	1.46	D-2
(5) AVE. AND EXCESS DMD.	10,000	4,726	140	2,910	243	171	410	377	627	270	126	
(6) % RESPONSIBILITY	100.00	47.26	1.40	29.10	2.43	1.71	4.10	3.77	6.27	2.70	1.26	D-3
(7) EXCESS DEMAND	10,000	5,340	183	3,247	181	149	284	245	0	226	145	
(8) % RESPONSIBILITY	100.00	53.40	1.83	32.47	1.81	1.49	2.84	2.45	0.00	2.26	1.45	D-4
(9) MW.h GEN. & PURCH.	8,785,157	3,748,232	94,729	2,334,862	254,440	164,698	443,108	417,620	963,213	265,509	98,746	
(10) % RESPONSIBILITY	100.00	42.68	1.08	26.58	2.90	1.87	5.04	4.75	10.96	3.02	1.12	E-1
(11) AVERAGE CUSTOMERS	410,124	370,315	16,424	16,213	8	1,342	178	6	24	7	5,607	
(12) % RESPONSIBILITY	100.00	90.30	4.00	3.95	0.00	0.33	0.04	0.00	0.01	0.00	1.37	C-1
(13) SEC. CUSTOMERS	404,276	370,315	16,424	16,193	0	1,340	0	0	4	0	0	
(14) WEIGHTING FACTOR		1.00	1.00	5.00	75.00	5.00	7.50	100.00	100.00	100.00	5.00	
(15) WEIGHTED TOTAL	474,804	370,315	16,424	80,965	0	6,700	0	0	400	0	0	
(16) % RESPONSIBILITY	100.00	78.00	3.46	17.05	0.00	1.41	0.00	0.00	0.08	0.00	0.00	C-2
(17) WEIGHTED CUSTOMERS	410,124	370,315	16,424	16,213	8	1,342	178	6	24	7	5,607	
(18) WEIGHTING FACTOR		1.00	1.00	5.00	75.00	5.00	7.50	100.00	100.00	100.00	5.00	
(19) WEIGHTED TOTAL	508,184	370,315	16,424	81,065	600	6,710	1,335	600	2,400	700	28,035	
(20) % RESPONSIBILITY	100.00	72.87	3.23	15.95	0.12	1.32	0.26	0.12	0.47	0.14	5.52	C-3
(21) CUSTOMER SECONDARY	409,883	370,315	16,424	16,193	0	1,340	0	0	4	0	5,607	
(22) % RESPONSIBILITY	100.00	90.34	4.01	3.95	0.00	0.33	0.00	0.00	0.00	0.00	1.37	C-4
(23) CUSTOMER PRIMARY	410,062	370,315	16,424	16,213	8	1,342	134	3	10	6	5,607	
(24) % RESPONSIBILITY	100.00	90.31	4.01	3.95	0.00	0.33	0.03	0.00	0.00	0.00	1.37	C-5

EXHIBIT AED-8A

NOVA SCOTIA POWER INC.

DEVELOPMENT OF ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 1993

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1) POLE & WIRE INVEST.	$236,114	$160,444	$5,912	$55,241	$2,995	$3,201	$4,891	$0	$0	$0	$3,430	
(2) % RESPONSIBILITY	100.00	67.95	2.50	23.40	1.27	1.36	2.07	0.00	0.00	0.00	1.45	P-1
(3) SUB.,POLE &WIRE INV.	$294,383	$190,794	$6,831	$74,054	$4,517	$4,269	$7,912	$1,080	$353	$330	$4,243	
(4) % RESPONSIBILITY	100.00	64.81	2.32	25.16	1.53	1.45	2.69	0.37	0.12	0.11	1.44	P-2
(5) SUBSTATION INVEST.	$58,269	$30,350	$919	$18,813	$1,522	$1,068	$3,021	$1,080	$353	$330	$813	
(6) % RESPONSIBILITY	100.00	52.08	1.58	32.29	2.61	1.83	5.18	1.85	0.61	0.57	1.40	P-3
(7) METER INVESTMENT	$21,887	$18,002	$799	$2,574	$7	$278	$166	$11	$46	$4	$0	
(8) % RESPONSIBILITY	100.00	82.25	3.65	11.76	0.03	1.27	0.76	0.05	0.21	0.02	0.00	P-4
(9) DISTRIBUTION PLANT	$524,095	$331,734	$11,973	$131,238	$4,838	$7,769	$8,603	$1,115	$445	$341	$26,039	
(10) % RESPONSIBILITY	100.00	63.31	2.28	25.04	0.92	1.48	1.64	0.21	0.08	0.07	4.97	P-5
(11) PROD.,TRANS.&DIST.	$2,133,161	$1,092,785	$34,543	$599,811	$43,878	$35,263	$74,450	$61,645	$100,711	$43,742	$46,333	
(12) % RESPONSIBILITY	100.00	51.23	1.62	28.12	2.06	1.65	3.49	2.89	4.72	2.05	2.17	P-6
(13) TOTAL RATE BASE	$2,316,262	$1,182,824	$37,272	$650,475	$48,021	$38,380	$81,528	$67,766	$112,176	$47,925	$49,895	
(14) % RESPONSIBILITY	100.00	51.07	1.61	28.08	2.07	1.66	3.52	2.93	4.84	2.07	2.15	P-7
(15) DEMAND OPER. EXP.	$80,855	$39,394	$1,229	$21,961	$1,737	$1,287	$2,938	$2,386	$3,915	$1,692	$4,316	
(16) % RESPONSIBILITY	100.00	48.73	1.52	27.16	2.15	1.59	3.63	2.95	4.84	2.09	5.34	O-1
(17) ENERGY OPER. EXP.	$9,544	$4,074	$103	$2,537	$277	$178	$481	$453	$1,046	$288	$107	
(18) % RESPONSIBILITY	100.00	42.68	1.08	26.58	2.90	1.87	5.04	4.75	10.96	3.02	1.12	O-2
(19) CUSTOMER OPER. EXP.	$33,785	$25,515	$1,076	$5,320	$105	$412	$216	$21	$83	$23	$1,014	
(20) % RESPONSIBILITY	100.00	75.52	3.18	15.75	0.31	1.22	0.64	0.06	0.25	0.07	3.00	O-3
(21) TOT. D/E/C EXPENSES	$124,184	$68,983	$2,408	$29,818	$2,119	$1,877	$3,635	$2,860	$5,044	$2,003	$5,437	
(22) % RESPONSIBILITY	100.00	55.55	1.94	24.01	1.71	1.51	2.93	2.30	4.06	1.61	4.38	O-4
(23) TOT.EXPENSES + INT.	$588,002	$288,572	$8,780	$155,376	$13,457	$10,013	$23,175	$20,259	$41,082	$13,503	$13,785	
(24) % RESPONSIBILITY	100.00	49.08	1.49	26.42	2.29	1.70	3.94	3.45	6.99	2.30	2.34	O-5
(25) SEC. CUST. REVENUE	$218,836	$0	$10,212	$194,301	$0	$14,323	$0	$0	$0	$0	$0	
(26) % RESPONSIBILITY	100.00	0.00	4.66	88.79	0.00	6.55	0.00	0.00	0.00	0.00	0.00	R-1

EXHIBIT AED-8B

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 1993

	(1) MW.h SALES	(2) ENERGY LINE LOSSES	(3) MW.h GENERATED	(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 LOAD FACTOR
(1) DOMESTIC	3,365,294	11.38%	3,748,232	852,029	81.9%	697,737	20.54%	841,033	50.88%
(2) SMALL GENERAL	85,000	11.45%	94,729	25,781	59.8%	15,403	20.53%	18,565	58.25%
(3) GENERAL	2,098,025	11.29%	2,334,862	525,058	79.7%	418,334	20.16%	502,670	53.02%
(4) LARGE GENERAL	237,400	7.18%	254,440	43,819	84.8%	37,163	12.45%	41,790	69.50%
(5) SMALL INDUSTRIAL	148,242	11.10%	164,698	29,940	55.1%	16,483	19.61%	19,715	95.36%
(6) MEDIUM INDUSTRIAL	413,461	7.17%	443,108	73,385	66.0%	48,407	12.45%	54,434	92.93%
(7) LARGE INDUSTRIAL	402,100	3.86%	417,620	69,674	80.8%	56,278	6.38%	59,869	79.63%
(8) INTERRUPTIBLE	928,000	3.79%	963,213	257,400	51.7%	132,999	6.38%	141,484	77.72%
(9) MUNICIPAL	255,800	3.80%	265,509	51,077	96.4%	49,237	6.38%	52,378	57.87%
(10) UNMETERED	88,488	11.59%	98,746	22,857	72.1%	16,474	20.53%	19,856	56.77%
(11) SUB-TOTAL	8,021,810	9.52%	8,785,157	1,951,020	76.3%	1,488,515	17.69%	1,751,794	57.25%
(12) BOWATER MERSEY	582,000	1.40%	590,148	93,000	100.0%	93,000	1.87%	94,739	71.11%
(13) GEN.REPL./LOAD FOLL	235,000	3.87%	244,095	31,000	74.2%	23,000	6.38%	24,467	113.89%
(14) N.B.E.P.C.	8,000	10.00%	8,800	0	N/A	0	N/A	0	N/A
(15) TOTAL	8,846,810	8.83%	9,628,200	2,075,020	77.4%	1,604,515	16.61%	1,871,000	58.74%

EXHIBIT AED-9A

NOVA SCOTIA POWER INC.

DETERMINATION OF CLASS NON-COIN. kW DEMAND BY VOLTAGE LEVEL

FOR THE YEAR ENDING DECEMBER 31, 1993

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED
(1) NON-COIN. kW SEC.	1,424,802	852,029	25,781	497,072	0	27,063	0	0	0	0	22,857
(2) LOSSES 5.00%	71,240	42,601	1,289	24,854	0	1,353	0	0	0	0	1,143
(3) SUB-TOTAL	1,496,042	894,630	27,070	521,926	0	28,416	0	0	0	0	24,000
(4) NON-COIN. kW PRI.	1,642,106	894,630	27,070	549,912	43,819	31,293	71,382	0	0	0	24,000
(5) LOSSES 4.00%	65,684	35,785	1,083	21,996	1,753	1,252	2,855	0	0	0	960
(6) SUB-TOTAL	1,707,790	930,415	28,153	571,908	45,572	32,545	74,237	0	0	0	24,960
(7) NON-COIN. kW TRANS.	2,087,944	930,415	28,153	571,908	45,572	32,545	76,240	69,674	257,400	51,077	24,960
(8) LOSSES 3.90%	81,428	36,286	1,098	22,304	1,777	1,269	2,973	2,717	10,039	1,992	973
(9) TOTAL	2,169,372	966,701	29,251	594,212	47,349	33,814	79,213	72,391	267,439	53,069	25,933

EXHIBIT AED-9B

NOVA SCOTIA POWER INC.

DETERMINATION OF AVERAGE AND EXCESS DEMAND ALLOCATION FACTORS

FOR THE YEAR ENDING DECEMBER 31, 1993

	(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) LARGE GENERAL	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) INTERRUPTIBLE	(10) MUNICIPAL	(11) UNMETERED
GENERATION LEVEL											
(1) NON - COIN. kW DMD.	2,169,372	966,701	29,251	594,212	47,349	33,814	79,213	72,391	267,439	53,069	25,933
(2) AVERAGE DEMAND	1,002,872	427,880	10,814	266,537	29,046	18,801	50,583	47,674	109,956	30,309	11,272
(3) PERCENT OF TOTAL	100.00%	42.68%	1.08%	26.58%	2.90%	1.87%	5.04%	4.75%	10.96%	3.02%	1.12%
(4) EXCESS DEMAND	1,166,500	538,821	18,437	327,675	18,303	15,013	28,630	24,717	157,483	22,760	14,661
(5) INTERRUPTIBLE ADJ.	(157,483)	0	0	0	0	0	0	0	(157,483)	0	0
(6) REVISED EXCESS DMD.	1,009,017	538,821	18,437	327,675	18,303	15,013	28,630	24,717	0	22,760	14,661
(7) PERCENT OF TOTAL	100.00%	53.40%	1.83%	32.47%	1.81%	1.49%	2.84%	2.45%	0.00%	2.26%	1.45%
(8) AVG. & EXCESS DMD.	100.00%	47.26%	1.40%	29.10%	2.43%	1.71%	4.10%	3.77%	6.27%	2.70%	1.26%

(9) SYSTEM PEAK DEMAND LOAD FACTOR

$$\frac{8{,}785{,}157 \text{ MW.h} \times 1000}{1{,}751{,}794 \text{ kW} \times 8760 \text{ hrs.}} = 57.25\%$$

(10) CALCULATION OF AVG. & EXCESS DMD. ALLOCATOR

57.25% X LINE 3 + 42.75% X LINE 7

EXHIBIT AED-9C

EXHIBIT AED-10

NOVA SCOTIA POWER INC.

REVENUE TO EXPENSE COMPARISON

FOR THE YEAR ENDING DECEMBER 31, 1993

(IN THOUSANDS OF DOLLARS)

	(1) TOTAL OPER. EXPENSES	(2) TOTAL RATE REVENUE	(3) % REVENUE TO EXPENSES
(1) DOMESTIC	$332,408	$308,623	93
(2) SMALL GENERAL	10,125	10,212	101
(3) GENERAL	180,910	194,301	107
(4) LARGE GENERAL	15,413	15,411	100
(5) SMALL INDUSTRIAL	11,485	14,323	125
(6) MEDIUM INDUSTRIAL	26,366	30,901	117
(7) LARGE INDUSTRIAL	23,019	24,331	106
(8) INTERRUPTIBLE	45,593	46,264	101
(9) MUNICIPAL	15,458	15,959	103
(10) UNMETERED	15,801	16,253	103
(11) SUB-TOTAL	$676,578	$676,578	100
(12) DIR. CUST.EXP./REV.	33,700	33,861	N/A
(13) EXCESS DIR.CUST.REV	161	0	N/A
(14) TOTAL	$710,439	$710,439	100

NON-CONFIDENTIAL

Request IR-176:

Please provide all Area Distribution Planning Studies (of the type provided in CA IR-58 Attachment 1) prepared since 2000.

Response IR-176:

Please refer to Confidential Attachments 1 through 22, available for viewing at NSPI offices.

NON-CONFIDENTIAL

Request IR-177:

Please provide the "construction and engineering estimates" on which NSPI determined that "30% of the poles were estimated to be primary." (CA IR-45 Attachment 1 Page 6).

Response IR-177:

This principle has been in use as early as the 1980 rate case. Please refer to Attachment 1[1] (Section 8 – Poles, original page 8, paragraph 1). NSPI has not been able to retrieve the "construction and engineering estimates" on which the allocation was based.

[1] NSPI 1980 Rate Case, Board of Commissioners of Public Utilities, E-100bg, June 18, 1979, page 10 (Section 8 – Poles).

APPENDIX

COST OF SERVICE STUDY SUBMITTED BY THE NOVA SCOTIA POWER CORPORATION FOR THE YEAR ENDING MARCH 31, 1980, BASED UPON THE ALLOCATION OF PRODUCTION AND DISTRIBUTION PLANT ON THE BASIS OF COINCIDENT PEAK AND AVERAGE DEMAND, AND DISTRIBUTION PLANT ON THE BASIS OF CLASS NON-COINCIDENT DEMAND

RATE DESIGN OBJECTIVES

The Applicant's ultimate objective in setting rates is stated to be the providing of service at rates that distribute cost of an equitable basis, recognizing usage characteristics and cost causation. With ever changing conditions, data rate design will be an ongoing evolutionary process.

COST OF SERVICE ANALYSIS

The Applicant's proposed rates are based upon an analysis of its estimated rate base, also hereinafter referred to as "plant investments", and operating expenses, also hereinafter referred to as "operating costs", for the year ending March 31, 1980, and their subsequent allocation to the various customer classes. The Applicant analysed plant investments and operating costs in three stages:

(a) Functionalization, i.e. the plant investments and operating costs were functionalized according to the utility's functions of production, transmission, distribution, general or other;

(b) Classification, i.e. operating costs as functionalized were classified according to the system's demands, energy and customer responsibilities;

(c) Allocation, i.e. the plant investments and operating costs, as functionalized and classified, were then allocated to the customer classes.

ANALYSIS OF RATE BASE

The estimated Rate Base of the Applicant for the fiscal year ending March 31, 1980, amounting to $829,387,000 after the deduction of that portion of the rate base dedicated to specialized sales and services relating to combined steam and electric service, steam service, and the Mersey System totalling $29,459,000, was analysed as follows:

RATE BASE ANALYSIS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	TOTAL COMPANY	UNALLOCATED	TOTAL TO BE ALLOCATED
Production Plant			
(1) Steam	$249,979	$ 19,029	$230,950
(2) Hydro	167,404	3,471	163,933
(3) Gas Turbine	19,165	-	19,165
(4) TOTAL PRODUCTION PLANT	436,548	22,500	414,048
(5) Transmission Plant	130,883	-	130,883
Distribution Plant			
(6) Substations	26,576	163	26,413
(7) Other	199,188	-	199,188
(8) TOTAL DISTRIBUTION	225,764	163	225,601
(9) General Property and Intangibles	15,928	-	15,928
(10) Total Plant In Service	809,123	22,663	786,460
Working Capital			
(11) Cash - Fuel	16,670	3,756	12,914
(12) Cash - Other	5,463	610	4,853
(13) Materials & Supplies - Fuel	13,305	1,118	12,187
(14) Materials & Supplies - Other	14,285	1,312	12,973
(15) TOTAL WORK CAPITAL	49,723	6,796	42,927
TOTAL RATE BASE	$858,846	$ 29,459	$829,387

FUNCTIONALIZATION OF RATE BASE

The Applicant functionalized the net Rate Base of $829,387,000 through the use of its plant records; as follows:

FUNCTIONALIZATION OF RATE BASE
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	PRODUCTION	TRANSMISSION	DISTRIBUTION	OTHER	TOTAL
Production Plant					
(1) Steam	$230,950	$ -	$ -	$ -	$230,950
(2) Hydro	163,933	-	-	-	163,933
(3) Gas Turbine	19,165	-	-	-	19,165
(4) TOTAL PRODUCTION PLANT	414,048	-	-	-	414,048
(5) Transmission Plant	-	130,883	-	-	130,883
Distribution Plant					
(6) Substations	-	-	26,413	-	26,413
(7) Other	-	-	199,188	-	199,188
(8) TOTAL DISTRIBUTION	-	-	225,601	-	225,601
(9) General Property & Intangibles	-	-	-	15,928	15,928
(10) TOTAL PLANT IN SERVICE	414,048	130,883	225,601	15,928	786,460
Working Capital					
(11) Cash - Fuel	-	-	-	12,914	12,914
(12) Cash - Other	-	-	-	4,853	4,853
(13) Materials & Supplies - Fuel	-	-	-	12,187	12,187
(14) Materials & Supplies - Other	-	-	-	12,973	12,973
(15) TOTAL WORKING CAPITAL	-	-	-	42,927	42,927
(16) TOTAL RATE BASE	$414,048	$130,883	$225,601	$ 58,855	$829,387

CLASSIFICATION OF RATE BASE

The Applicant did not classify the Rate Base into Demand, Energy, Customer and Other and Direct as it considered this step unnecessary for the determination of the rate of return for each class.

ALLOCATION OF RATE BASE TO CUSTOMER CLASSES

The allocation of the rate base for the year ending March 31, 1980 to customer classes was made by the Applicant as follows:

Allocation of Rate Base
For The Year Ending March 31, 1980
($000)

	Domestic	Gen'l General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
Production													
(1) Steam	$ 66,930	$ 2,610	$ 50,370	$ 16,026	$ 4,665	$ 2,194	$ 14,781	$ 35,357	$ 3,141	$ 10,670	$ 3,772	$230,950	DF-1
(2) Hydro	65,229	1,590	37,426	12,637	3,000	1,845	10,739	20,574	-	7,738	3,164	163,933	DF-6
(3) Gas Turbine	7,626	166	4,775	1,475	351	222	1,255	2,772	-	975	370	19,165	DF-6
(4) Total	139,785	4,366	92,571	30,143	8,016	4,261	26,776	58,513	3,141	19,383	7,306	414,048	
(5) Transmission	49,264	1,477	25,546	9,083	2,644	1,263	8,377	20,169	1,780	6,047	2,251	130,883	DF-1
Distribution													
(6) Land	1,890	87	387	123	26	23	81	37	-	33	33	2,719	DF-2
(7) Substations	11,732	272	6,243	2,156	633	378	2,201	1,179	33	1,047	474	26,413	Sched. 3
(8) Poles	56,772	2,811	8,910	2,675	774	504	1,297	484	-	412	744	76,133	Sched. 3
(9) Wire-O.H.	30,877	1,496	5,359	1,634	244	305	777	300	-	255	566	41,595	Sched. 3
(10) Underground	4,446	219	727	219	33	41	106	40	-	34	77	5,944	CF-1
(11) Line Transformers	19,177	430	9,505	3,252	-	375	-	-	-	-	743	33,724	DF-2
(12) Services	14,757	867	2,910	408	-	144	78	8	4	4	339	19,519	CF-3
(13) Meters	8,561	500	1,102	202	2	71	88	17	8	4	-	10,557	Sched. 3
(14) Other	635	29	131	41	8	8	28	13	-	11	13	917	DF-2
(15) Street Lighting	-										9,254	9,254	
(16) Total	148,271	6,481	35,276	10,710	1,338	2,009	4,667	2,078	38	1,812	12,516	225,601	
(17) Gen & Intangible	7,391	290	3,224	1,032	249	156	823	1,660	102	362	460	15,928	DF-3
(18) Total Plant In-Service	364,911	12,808	199,217	50,970	12,247	7,707	40,643	82,420	5,052	27,724	26,755	786,460	
Working Capital													
(19) Cash-Fuel	4,415	169	2,610	747	292	85	793	2,599	459	577	178	12,914	EF-1
(20) Cash-Other	2,378	100	897	265	66	42	214	448	38	143	242	4,853	DF-3
(21) Inv.-Fuel	4,167	160	2,463	704	275	80	748	2,444	433	545	168	12,187	EF-1
(22) Inv.-Other	6,019	211	2,026	841	202	127	671	1,360	81	458	375	12,973	DF-3
(23) Total	16,979	640	6,996	2,557	835	334	2,426	6,851	1,011	1,723	963	42,927	
(24) Total Rate Base	$381,890	$13,448	$167,813	$53,527	$13,082	$8,041	$43,069	$89,269	$6,063	$29,447	$23,718	$829,387	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)

RATE BASE ALLOCATION FACTORS

The above allocation of the Applicant's rate base to the customer classifications was based on the use of the factors that follow each item of rate base. An explanation of the factors is as follows:

PRODUCTION PLANT

(1) Steam (DØ-1)

The steam plant, which is designed to meet base load, is allocated on the basis of system peak and average demand. The demand represents the sum of the system's coincident peak and average hourly consumption. Power supplied to Bowater Mersey and AECL Point Tupper was deducted in both cases. The average hourly demand was determined by dividing the net MWH by 8760 hours.

The Applicant first projected its energy sales, for fiscal year 1980, and the quantity of power generated and purchased before line losses, by classes. The load factors developed by the 1978 Ernst and Ernst study were adjusted for 1980 in accordance with overall system load factor and used to arrive at each class demand. The following are the results of the Applicant's calculations,

Sales and Generation Analysis
For the Year Ending March 31, 1980

	MWH Sales	% Losses	MWH Generated	System Coincident Load Factor	System Coincident Peak MW Demand	Coincident MW Demand	System Coincidence Factor	Diversified Class MW Demand
(1) Domestic	1,760,241	9.35	1,941,766	54.55	413	374	.925	453
(2) Small General	67,666	9.35	74,650	89.01	10	9	.900	10
(3) General Service Demand	1,040,714	9.35	1,148,048	55.52	237	214	.900	233
(4) General Service All-Electric	299,700	8.69	328,299	46.03	80	73	.925	79
(5) General Service Large	118,200	7.84	128,262	77.06	19	18	.975	[illegible]
(6) Industrial to 249 KVA	34,500	7.34	37,437	35.61	12	11	.875	[illegible]
(7) Industrial 250-3999 KVA	325,700	6.64	348,865	58.57	68	63	.875	72
(8) Industrial Large	1,091,600	4.13	1,138,669	99.99	130	125	.850	147
(9) Interruptible	193,100	4.13	201,426	-	-	-	-	40
(10) Bowaters Mersey	200,000	4.13	208,624	59.54	40	38	.900	42
(11) AECL Pt. Tupper	182,000	4.13	189,840	77.40	28	27	.975	[illegible]
(12) Municipal	243,200	4.13	253,607	59.10	49	47	.925	51
(13) Unmetered	70,800	9.35	78,101	44.58	20	18	1.000	18
(14) NSPC	-	-	-	-	-	-	-	-
(15) TOTAL	5,627,441	7.41	6,077,600		1,106	1,017		1,212
Deduct								
(10) Bowaters Mersey	200,000	4.13	208,624	59.54	40	33	.900	42
(11) AECL Pt. Tupper	182,000	4.13	189,840	77.40	28	27	.975	28
Net	5,245,441	7.56	5,679,136		1038	9.52		[illegible]

CALCULATION OF SYSTEM PEAK & AVERAGE DEMAND

Net System Coincident Peak MW Demand	1038
Average Consumption 5,679,128 / 8760	649
System Peak & Average Demand (MW) for Corporation	1687

The Applicant's system peak and average demand of 1687 MW was allocated by the Applicant between its customer classes as follows:

Development of Allocation Factors
For the Test Year March 31, 1969

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	[illegible]	Factor
System Peak & Average % Responsibility	1,687 100.00	635 37.64	19 1.13	368 21.81	117 6.94	34 2.02	16 0.95	108 6.40	260 15.41	23 1.36	78 4.62	29 1.72	DØ-1

The percentages, so derived, were used in the following allocation of the Steam Plant, valued at $230,950,000 to the various customer classifications:

Allocation of Rate Base
For The Year Ending March 31, 1969
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	[illegible]	Total	Factor
Production (1) Steam	$ 86,930	$ 2,610	$ 50,370	$ 16,820	$ 4,666	$ 2,194	$ 14,781	$ 35,599	$ 3,141	$ 10,630	$ 3,972	$230,951	DØ-1

PRODUCTION PLANT

(2) Hydro (DØ-6)

(3) Gas Turbine (DØ-6)

Hydro and gas turbine plants are designed to meet peaks and are allocated on the basis of system coincident peak that was determined by the following sales and generation analysis, shown above,

The Applicant's system coincident peak of 1038 MWH as so determined was allocated by the Applicant between the customer classes as follows:

Development of Allocation Factors
For the Test Year March 31, 1969

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	[illegible]	Factor
Coincident System Peak % Responsibility	1,038 100.00	413 39.79	10 .97	237 22.83	80 7.71	19 1.83	12 1.15	68 6.55	130 12.52	- -	49 4.72	20 1.93	DØ-4

The hydro plant of $163,933,000 and Gas Turbine Plant of $19,165,000 was next allocated to the customer classifications by the use of the above percentages, as follows:

- 6 -

Allocation of Rate Base
For The Year Ending March 31, 1969
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
[illegible]													
[illegible]	65,779	1,970	37,426	12,637	3,000	1,995	10,734	20,576	-	7,734	3,174	163,933	[illegible]
	7,628	194	4,715	1,475	351	232	1,255	2,392	-	915	370	19,161	[illegible]

(5) Transmission (DØ-1)

As the transmission system is designed to meet the demand, the Applicant allocated this portion of the plant investment on system peak and average demand. The total Applicant's system peak and average was determined, as noted above under Production (1) Steam (DØ-1), at 1687 MW. These were allocated as follows:

Development of Allocation Factors
For the Test Year March 31, 1969

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Peak & Average	1,687	635	19	368	117	34	16	108	260	23	78	29	
% Responsibility	100.00	37.64	1.13	21.81	6.94	2.02	0.95	6.40	15.41	1.36	4.62	1.72	DØ-1

Percentages so derived were used by the Applicant in allocating the Transmission Plant investment, valued at $130,883,000, between the various customer classifications as follows:

Allocation of Rate Base
For The Year Ending March 31, 1969
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
(5) Transmission	49,264	1,477	28,546	9,083	2,644	1,243	8,377	20,169	1,784	6,047	2,251	130,883	DØ-1

DISTRIBUTION PLANT

(6) Land (PØ-2)

Investment in land was allocated by the Applicant on the basis of substation, pole and wire investment as follows:

Development of Allocation Factors
For the Test Year March 31, 1969

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Sub., Pole & Wire Investment	$ 143,071	$ 99,053	$ 4,569	$20,512	$ 6,465	$1,271	$ 1,187	$ 4,286	$ 1,963	$ 17	$ 1,716	$ 2,032	
% Responsibility	100.00	69.23	3.19	14.34	4.52	.89	.83	3.00	1.38	-	1.20	1.42	PØ-2

The determination of these allocations are dealt with below in more detail, under Distribution (7) Substations (Schedule 3a), Distribution, Poles (Schedule 3c), and Demand (9) Wire Overhead (Schedule 3e).

The percetages derived from the Substation Pole and Wire Investment, were used by the Applicant in the allocation of Distribution - Land, Plant amounting to $2,716,000 as follows:

Allocation of Pole Wire
For The Year Ending March 31, 1980
($000)

Distribution	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
Land	1,690	67	309	139	34	23	[illegible]	38	-	33	19	2,716	[illegible]

DISTRIBUTION PLANT

(7) Substations (Schedule 3a)

Substation investments were allocated by the Applicant to customer classes as noted below, with the amounts invested in facilities dedicated to individual customer's uses being identified and directly allocated to the customer's respective class.

ANALYSIS OF DISTRIBUTION SUBSTATIONS COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	DISTRIBUTION BULK POWER	DIST.DED. BULK POWER	DIST.CUST. OWN BULK POW.	DISTRIBUTION GENERAL	DIST.DED. GENERAL	DIST.CUST. OWNED GEN.	TOTAL COST
(1) Total Dist. Substations	$20,143	$ 782	$ 22	$ 4,547	$ 896	$ 23	$26,413
ALLOCATION							
(2) Domestic	$ 9,620	$ -	$ -	$ 2,172	$ -	$ -	$11,792
(3) Small General	222	-	-	50	-	-	272
(4) General	5,040	-	-	1,138	65	-	6,243
(5) General All Electric	1,686	-	-	381	89	-	2,156
(6) General Large	441	-	-	99	93	-	633
(7) Industrial to 249 KVA	302	2	-	68	6	-	378
(8) Industrial 250-3999 KVA	1,426	107	1	322	321	23	2,200
(9) Industrial Large	542	396	11	122	108	-	1,179
(10) Interruptible	-	-	10	-	7	-	17
(11) Municipal	461	277	-	104	207	-	1,049
(12) Unmetered	403	-	-	91	-	-	494
(13) TOTAL	$20,143	$ 782	$ 22	$ 4,547	$ 896	$ 23	$26,413
Allocation Factor	DØ-3*	Direct	Direct	DØ-3*	Direct	Direct	

The non-dedicated substation investments were allocated on the basis of percentages derived from class non-coincident primary demand. Details are as follows:

* Development of Allocation Factors For the Test Year March 31, 1980

	Total System	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
(5) Class N.C. Demand Primary	1,003	479	11	251	84	22	15	71	27	-	23	20	
(6) % Responsibility	100.00	47.76	1.10	25.02	8.37	2.19	1.50	7.08	2.69		2.29	2.00	DF-3

The resulting allocation of Substation Plant, valued at $26,413,000, was as follows:

Allocation of Rate Base
For The Year Ending March 31, 1980
($000)

Distribution	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
(7) Substations	11,792	272	6,243	2,156	433	376	2,300	1,179	17	1,043	634	26,413	Demand. 1

DISTRIBUTION PLANT

(8) Poles (Schedule 3c)

Based upon construction and engineering estimates, the Applicant proposes that 30% of the poles be treated as primary while the balance be split 50% primary and 50% secondary.

Subsequently, the totals were split 63% to customer responsibility and 37% to demand responsibility. The split is based on the concept that 30 and 35 feet poles are the minimum size poles required to service all customers. Weighting 30 feet poles at 2, and 35 feet poles at 1, the average weighted cost of 30 and 35 feet poles was $104.10. This amount multiplied by the total number of poles equals 63% of the total pole investment, which was accordingly allocated 63% to customer responsibility, and 37% to demand responsibility.

ANALYSIS OF POLE INVESTMENT
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	TOTAL COST	PRIMARY DEMAND (37%)	PRIMARY CUSTOMER (63%)	SECONDARY DEMAND (37%)	SECONDARY CUSTOMER (63%)
(1) Total Net Pole Cost	$74,833				
(2) Primary Only (30%)	22,450	$ 8,307	$14,143	$ -	$ -
(3) 50% Joint-Primary	26,192	9,691	16,501	-	-
(4) 50% Joint-Secondary	26,191	-	-	9,691	16,500
(5) TOTAL	$74,833	$17,998	$30,644	$9,691	$16,500

The total pole investment of $74,833,000 is allocated to customer classes by the relevant allocation factors set out below,

ALLOCATION OF POLE INVESTMENT
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	TOTAL COST	PRIMARY DEMAND	PRIMARY CUSTOMER	SECONDARY DEMAND	SECONDARY CUSTOMER
(1) Domestic	$56,392	$ 8,596	$27,476	$5,516	$14,804
(2) Small General	2,801	198	1,615	118	870
(3) General	8,910	4,503	1,085	2,740	582
(4) General All-Electric	2,675	1,507	150	937	81
(5) General Large	394	394	-	-	-
(6) Industrial to 249 KVA	504	270	52	154	28
(7) Industrial 250-3999 KVA	1,289	1,274	15	-	-
(8) Industrial Large	484	484	-	-	-
(9) Interruptible	-	-	-	-	-
(10) Municipal	412	412	-	-	-
(11) Unmetered	972	360	251	226	135
(12) TOTAL	$74,833	$17,998	$30,644	$9,691	$16,500
(13) Allocation Factor		DØ-3	CØ-5	DØ-2	CØ-4

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Customer Secondary	312,109	280,061	16,450	11,024	1,542	-	543	-	-	-	-	2,549	
% Responsibility	100.00	89.72	5.27	3.53	.49	-	.17	-	-	-	-	.82	CØ-4
Customer Primary	312,348	280,061	16,450	11,043	1,546	3	545	147	2	-	2	2,549	
% Responsibility	100.00	89.66	5.27	3.54	.49	-	.17	.05	-	-	-	.82	CØ-5
Class N.C. Demand Secondary	817	465	10	231	79	-	13	-	-	-	-	19	
% Responsibility	100.00	56.92	1.22	28.27	9.67		1.59					2.33	DØ-2
Class N.C. Demand Primary	1,003	479	11	251	84	22	15	71	27	-	23	20	
% Responsibility	100.00	47.76	1.10	25.02	8.37	2.19	1.50	7.08	2.69		2.29	2.00	DØ-3

As a result of the above calculations, <u>Distribution Plant - Poles</u>, valued at $74,833,000, was allocated by the Applicant to the customer classifications as follows;

Allocation of Rate Base
For The Year Ending March 31, 1980
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
Distribution Poles	56,392	2,801	8,910	2,675	394	504	1,289	484	-	412	972	74,833	[illegible]

DISTRIBUTION PLANT

(9) Wire-Overhead (Schedule 3e)

The wire investment of the Applicant amounting to $41,825,000 was split by the Applicant on construction and engineering estimates on the basis of 30% to primary and the balance, 50% primary and 50% secondary.

The customer demand split was made on the basis of minimum wire size of #1/0 copper and #2/0 aluminum wire required to service each customer. The installed costs of these two types of wire is $131.38/1000 feet. The total cost of these wires when compared with the total of the wire investment, establishes that 59% of the wire investment is customer related and 41% demand related. The final analysis of wire investment is as follows:

ANALYSIS OF WIRE INVESTMENT
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	TOTAL COST	PRIMARY DEMAND	PRIMARY CUSTOMER	SECONDARY DEMAND	SECONDAY CUSTOMER
		(41%)	(59%)	(41%)	(59%)
(1) TOTAL NET WIRE COST	$41,825				
(2) Primary Only (30%)	12,548	$ 5,145	$ 7,403	$ -	$ -
(3) 50% Joint - Primary	14,639	6,002	8,637	-	-
(4) 50% Joint - Secondary	14,638	-	-	6,002	8,636
(5) TOTAL	$41,825	$11,147	$16,040	$6,002	$8,636

The Applicant then allocated the wire investment to the various customer classifications on the same allocation factors (DØ-3, CØ-5, DØ-2 and CØ-5) set out above under Distribution (8) Poles.

ALLOCATION OF WIRE INVESTMENT
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	TOTAL COST	PRIMARY DEMAND	PRIMARY CUSTOMER	SECONDARY DEMAND	SECONDARY CUSTOMER
(1) Domestic	$30,869	$ 5,324	$14,381	$ 3,416	$ 7,748
(2) Small General	1,496	123	845	73	455
(3) General Service	5,359	2,789	568	1,697	305
(4) General All-Electric	1,634	933	79	580	42
(5) General Large	244	244	-	-	-
(6) Industrial to 249 KVA	305	167	27	96	15
(7) Industrial 250-3,999 KVA	797	789	8	-	-
(8) Industrial Large	300	300	-	-	-
(9) Interruptible	-	-	-	-	-
(10) Municipal	255	255	-	-	-
(11) Unmetered	566	223	132	140	71
(12) TOTAL	$41,825	$11,147	$16,040	$ 6,002	$ 8,636
(13) Allocation Factor		DØ-3	CØ-5	DØ-2	CØ-4

As a result of these calculations, the Applicant then allocated Distribution - Wires Overhead plant, valued at $41,825,000, as follows:

NOVA SCOTIA POWER CORPORATION
Allocation of Pole Cost
For The Year Ending March 31, 1980
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Wire-O.H.	30,869	1,496	5,359	1,634	244	305	797	300	-	255	566	41,825

DISTRIBUTION PLANT

(10) Underground (PØ-1)

Underground facilities were allocated by the Applicant on the totals of pole and wire investments, as follows:

Development of Allocation Factors
For the Test Year March 31, 1980
($000)

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Wire Investment Responsibility	$ 116,658	$ 87,261	$ 4,297	$14,269	$ 4,309	$ 638	$ 809	$ 2,086	$ 784	$ -	$ 667	$ 1,538	
	100.00	74.80	3.69	12.23	3.69	.55	.69	1.79	.67	-	.57	1.32	PØ-1

The pole and wire investment allocations were as shown above under Distribution (8) Poles and (9) Wire.

Based upon the above approach, the Applicant allocated Distribution - Underground Plant, valued at $5,944,000, as follows:

Allocation of Pole Dept
For The Year Ending March 31, 1980
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
(10) Underground	4,446	219	727	219	35	41	106	40	-	34	79	5,944

DISTRIBUTION PLANT

(11) Line Transformers (DØ-2)

Line transformers, being used in the secondary system, were allocated by the Applicant on secondary class non-coincident demands as follows:

Determination of Class Non-Coincident MW by Voltage Level
For the Year Ending March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All-Elec.	General Large	Industrial To 249 KVA	Industrial 250-3,999KVA	Industrial Large	Interruptible	Municipal	Unmetered
Non Coin. KW Secondary	796	453	10	225	77	-	13	-	-	-	-	18
Losses 2.6%	21	12	-	6	2	-	0	-	-	-	-	1
Sub Total	817	465	10	231	79	-	13	-	-	-	-	19

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
N.C. Demand Secondary	817	465	10	231	79	-	13	-	-	-	-	19	
% Responsibility	100.00	56.92	1.22	28.27	9.67		1.59					2.33	DØ-2

Using the percentages so derived, the Applicant allocated plant described as Distribution - Line Transformers as follows:

[illegible]

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
[illegible]	817	[illegible]	10	[illegible]	79	-	13	-	-	-	-	19	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]					[illegible]	[illegible]

DISTRIBUTION PLANT

(12) Services (CØ-3)

Services were spread by the Applicant on a weighted customer basis as follows:

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
al Customers	312,387	280,061	16,450	11,043	1,546	3	545	149	14	7	8	2,561	
Weighting Factor		1.0	1.0	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	2.5	
Weighted Total	370,379	280,061	16,450	55,215	7,730	15	2,725	1,490	140	70	80	6,403	
% Responsibility	100.00	75.61	4.44	14.91	2.09	-	.74	.40	0.04	0.02	0.02	1.73	CØ-3

The Applicant allocated the Distribution Plant - Services, valued at $19,518,000 on the basis of the above percentages, as follows:

Allocation of [illegible]
For The Year Ending March 31, 1980
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Line Transformers	19,139	430	9,909	3,252	-	535	-	-	-	-	947	33,624

DISTRIBUTION PLANT

(13) Meters (Schedule 3f)

Meter investment for each class of customer was determined by multiplying the unit cost of installing the type of meter used by each class by the number of customers in the class, as follows:

ANALYSIS OF METER INVESTMENT
FOR THE YEAR ENDING MARCH 31, 1980

	CUSTOMERS	UNIT METER COST	TOTAL COST	%	METER COST ($000)
(1) Domestic	280,061	$ 34.00	$9,522,074	81.09	$ 8,561
(2) Small General	16,450	34.00	559,300	4.76	502
(3) General Service	11,043	111.00	1,225,773	10.44	1,102
(4) General All-Electric	1,546	145.00	224,170	1.91	202
(5) General Large	3	657.00	1,971	.02	2
(6) Industrial to 249 KVA	545	145.00	79,025	.67	71
(7) Industrial 250-3,999 KVA	149	657.00	97,893	.83	88
(8) Industrial Large	14	1,338.00	18,732	.16	17
(9) Interruptible	7	1,338.00	9,366	.08	8
(10) Municipal	8	520.00	4,160	.04	4
(11) Unmetered	2,561	-	-	-	-
(12) TOTAL	312,387		$11,742,464	100.00	$10,557

The Distribution Plant - Meters, valued at $10,557,000 was allocated by the Applicant on the above determination as follows:

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Pole & Wire Investment Responsibility	$ 143,071 100.00	$ 99,053 69.23	$ 4,569 3.19	$20,512 14.34	$ 6,465 4.52	$1,271 .89	$ 1,187 .83	$ 4,286 3.00	$ 4,963 3.34	$ 17 -	$ 1,716 1.20	$ 2,032 1.42	PW-2

DISTRIBUTION PLANT

(14) Other (PØ-2)

Other distribution costs were allocated between customer classifications on the basis of the following substation, pole and wire investment percentages determined as shown under Distribution Plant (6) Land, above.

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Pole & Wire Investment Responsibility	$ 143,071 100.00	$ 99,053 69.23	$ 4,569 3.19	$20,512 14.34	$ 6,465 4.52	$1,271 .89	$ 1,187 .83	$ 4,286 3.00	$ 1,963 1.38	$ 17 -	$ 1,716 1.20	$ 2,032 1.42	PØ-2

This plant valued at $917,000 was allocated by the Applicant on the basis of the PØ2 percentages as follows:

Allocation of [illegible]
For The Year Ending March 31, 1980
($000)

Distribution	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Other	635	29	137	41	8	8	28	13	-	11	13	917

DISTRIBUTION PLANT

(15) Street Lighting

The Street Lighting Plant, valued at $9,254,000 was assigned directly to the unmetered class.

(17) General and Intangible (PØ-3)

The general and intangible plant investment was allocated to the customer classification on the basis of percentages of all other plant investment, namely, Production, Transmission and Distribution Plant investment as follows:

NOVA SCOTIA POWER CORPORATION
Development of Allocation Factors
For the Test Year March 31, 1980
($000)

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Production, Trans & Distribution $ Responsibility	$ 770,532 100.00	$357,520 46.40	$12,548 1.63	$155,973 20.24	$49,938 6.48	$11,998 1.56	$ 7,551 .98	$ 39,818 5.17	$80,758 10.48	$ 4,950 .64	$27,162 3.53	$22,295 2.89	PØ-3

These percentages were then used by the Applicant in allocating the General and Intangible Plant to customer classifications as follows:

Allocation of [illegible]
For The Year Ending March 31, 1980
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total	Factor
(17) Gen & Intangible	7,391	260	3,224	1,032	249	156	823	1,669	102	562	460	15,928	[illegible]

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WORKING CAPITAL

(19) Cash - Fuel (EØ-1)

The Cash-Fuel item of Working Capital was allocated to customer classes on percentages determined as follows:

Development of Allocation Factors
For the Test Year March 31, 1989

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
[illegible] Generated & Purchased	5,679,128	1,941,766	74,658	1,148,048	328,209	128,262	37,437	348,865	1,138,609	201,426	253,687	78,101	
% Responsibility	100.00	34.19	1.31	20.21	5.78	2.26	0.66	6.14	20.05	3.55	4.47	1.38	EØ-1

Working Capital - Cash-Fuel, valued at $12,914,000 was allocated by the Applicant on the above percentages as follows:

Allocation of Rate Base
For The Year Ending March 31, 1990
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Working Capital												
Cash-Fuel	4,415	169	2,610	747	292	85	793	2,589	459	577	178	12,914

WORKING CAPITAL

(20) Cash-Other (OØ-3)

The Working Capital representing Cash-Other was allocated between the customer classification on the basis of percentages of the total operating costs determined as follows:

Development of Allocation Factors
For the Test Year March 31, 1989

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
otal Operating Costs	$ 51,555	$ 25,473	$ 1,057	$ 9,528	$ 2,809	$ 701	$ 446	$ 2,278	$ 4,762	$ 410	$ 1,520	$ 2,571	
% Responsibility	100.00	49.41	2.05	18.48	5.45	1.36	.86	4.42	9.24	.79	2.95	4.99	OØ-3

Working Capital--Cash-Other, valued at $4,853,000 was allocated by the Applicant on the above percentages as follows:

Allocation of Rate Base
For The Year Ending March 31, 1990
($000)

	Domestic	Small General	General Service Demand	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Working Capital												
Cash-Other	2,398	100	897	265	66	42	214	448	38	143	242	4,853

WORKING CAPITAL

(21) Inventories - Fuel (EØ-1)

Inventories-Fuel were allocated to the customer classes on the basis of percentages derived from MWH Generated and Purchased, as

Development of Allocation Factors
For the Test Year March 31, 1969

	Total Company	Domestic	Small General	General Bound	General All Elec.	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
Generated & Purchased	5,679,128	1,943,766	74,658	1,148,048	328,209	128,262	37,437	348,865	1,138,669	201,426	253,687	78,101	
Responsibility	100.00	34.19	1.31	20.21	5.78	2.26	0.66	6.14	20.05	3.55	4.47	1.34	EØ-1

The percentages so derived enabled the Applicant to allocate the Working Capital. Inventories - Fuel valued at $12,187,000, between the Customer Classification as follows:

Allocation of Rate Base
For The Year Ending March 31, 1969
($000)

	Domestic	Small General	General Service Bound	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Inv.-Fuel	4,167	160	2,463	706	275	80	748	2,444	433	545	164	12,187

WORKING CAPITAL

(22) Inventories - Other (PØ-3)

Inventories - Other were distributed among the customer classifications on percentages based upon the allocations of production, transmission and distribution plant as shown above.

Development of Allocation Factors
For the Test Year March 31, 1969
($000)

	Total Company	Domestic	Small General	General Bound	General All Elec.	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered
Production, Trans & Distribution	$770,532	$357,520	$12,548	$155,993	$49,938	$11,998	$7,551	$39,816	$80,759	$4,950	$27,162	$22,295
% Responsibility	100.00	46.40	1.63	20.24	6.48	1.56	.98	5.17	10.48	.64	3.53	2.89

The percentages were then used by the Applicant to allocate the Inventories - Other, amounting to $12,973,000 among the customer classifications, as follows:

Allocation of Rate Base
For The Year Ending March 31, 1969
($000)

	Domestic	Small General	General Service Bound	General All-Electric	General Large	Industrial To 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible Service	Municipal	Unmetered	Total
Inv.-Other	6,019	211	2,626	841	202	127	671	1,360	81	458	375	12,973

II OPERATING EXPENSES

The Operating Expenses (Operating Costs) of the Applicant were processed as follows before being allocated to the various customer classifications,

(a) Functionalization into Production, Transmission, Distribution, Administration and General and Other Costs;

(b) Classification into Demand, Energy, Costomer, Other and Direct;

(c) Allocation to Customer Classifications.

FUNCTIONALIZATION OF COSTS

The total Operating Costs of the Applicant amounting to $334,839,000 for the year ending March 31, 1980 were functionalized by the Applicant as follows:

FUNCTIONALIZATION OF COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	PRODUCTION COSTS	TRANSMISSION COSTS	DISTRIBUTION COSTS	ADMIN.& GEN. COSTS	OTHER	TOTAL
(1) Thermal	$164,658	$ -	$ -	$ -	$ -	$164,658
(2) System Planning & Operations	7,615	1,252	95	211	-	9,173
(3) Design & Construction	247	362	-	25	-	634
(4) Distribution	-	1,365	13,383	-	-	14,748
(5) Customer Services	-	-	-	1,455	-	1,455
(6) Personnel	1,590	448	1,224	2,062	-	5,324
(7) Financial Planning & Operations	22	5	63	988	-	1,078
(8) Treasury	-	-	-	4,090	-	4,090
(9) Secretary & General Counsel	1,141	132	237	349	-	1,859
(10) Information Processing	-	-	-	2,912	-	2,912
(11) General Administration	-	27	240	2,366	-	2,633
(12) Grants In Lieu of Taxes	-	-	-	-	4,002	4,002
(13) Depreciation	-	-	-	-	32,341	32,341
(14) Public Utility Board Assessment	-	-	-	120	-	120
(15) Labour Adjustment	-	-	-	695	-	695
(16) Contributed Capital	-	-	-	-	1,068	1,068
(17) Wreck Cove Deferral	1,318	-	-	-	-	1,318
(18) Sub-Total-Operating	176,591	3,591	15,242	15,263	37,411	248,098
(19) Return on Rate Base	-	-	-	-	89,756	89,756
(20) Miscellaneous Revenue	-	-	-	-	(3,015)	(3,015)
(21) TOTAL	$176,591	$3,591	$15,242	$15,263	$124,152	$334,839

In distributing the costs between functions, the Applicant notes that the Corporation's accounts are kept on a divisional basis, and divisional costs may or may not be related to different functions. As a comparison, the Thermal Division costs are all production related, whereas the System Planning and Operations Division costs are related to Production, Transmission, Distribution and Administration and General. The Distribution Division incurs expenses relating to Transmission as well as Distribution.

CLASSIFICATION

The Operating Costs, as functionalized, have been classified into Demand, Energy, Customer, Other and Direct as follows:

Classification of Costs
For the Year Ending March 31, 1980
($000)

		Demand	Energy	Customer	Other	Direct	Total
	PRODUCTION						
(1)	Fuel	$ -	$102,321	$ -	$ -	$ 37,669	$ 139,990
(2)	Purchased Power	973	2,504	-	-	-	3,477
(3)	Operating and Maintenance	26,220	-	-	-	5,586	31,806
(4)	Wreck Cove Deferral	1,318	-	-	-	-	1,318
(5)	TOTAL PRODUCTION	28,511	104,825	-	-	43,255	176,591
(6)	Transmission	3,581	-	-	-	10	3,591
	DISTRIBUTION						
(7)	Land	632	-	638	-	-	1,270
(8)	Substations	2,437	-	-	-	83	2,520
(9)	Overhead Lines	1,030	-	1,649	-	-	2,679
(10)	Underground Lines	53	-	84	-	-	137
(11)	Line Transformers	917	-	-	-	-	917
(12)	Services	-	-	1,413	-	-	1,413
(13)	Meters	-	-	1,043	-	-	1,043
(14)	Customer Service and Contracts	-	-	1,570	-	-	1,570
(15)	Customer Premise Expense	-	-	900	-	-	900
(16)	Communications	648	-	-	-	-	648
(17)	Street Lighting	1,823	-	-	-	-	1,823
(18)	Meter Testing	-	-	322	-	-	322
(19)	TOTAL DISTRIBUTION	7,540	-	7,619	-	83	15,242
	ADMINISTRATION AND GENERAL						
(20)	Billing and Meter Reading	-	-	4,018	-	-	4,018
(21)	Customer Service	-	-	1,537	-	-	1,537
(22)	Credit and Collection	-	-	1,040	-	-	1,040
(23)	Other	4,998	-	1,903	-	1,767	8,668
(24)	TOTAL ADMINISTRATION AND GENERAL	4,998	-	8,498	-	1,767	15,263
(25)	Grants in Lieu of Taxes	-	-	-	3,852	150	4,002
(26)	Depreciation	-	-	-	30,960	1,381	32,341
(27)	Contributed Capital	-	-	-	1,068	-	1,068
(28)	TOTAL OPERATING	44,630	104,825	16,117	35,880	46,646	248,098
(29)	Return on Rate Base	-	-	-	86,725	3,031	89,756
(30)	Miscellaneous Revenue	-	-	-	(3,019)	-	(3,015)
(31)	TOTAL	$44,630	$104,825	$16,117	$119,590	$49,677	$334,839

ALLOCATION OF OPERATING EXPENSES TO CUSTOMER CLASSIFICATIONS

The Operating Costs of the Applicant, as functionalized and later classified into the functions of Demand, Energy, Customer, Other and Direct, were allocated to the Customer Classifications as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Interruptible	Municipal	Unmetered	Total	Factor
Demand													
1) Prod O & M	$ 9,869	$ 296	$5,719	$1,820	$ 530	$ 249	$1,678	$4,040	$ 357	$1,211	$ 451	$26,220	DØ-1
2) Transmission	1,348	40	781	249	72	34	229	552	49	165	62	3,591	DØ-1
3) Distribution	3,166	103	1,222	410	84	71	287	143	2	126	1,926	7,540	Schedule 6a
4) Wreck Cove Deferral	496	15	287	91	27	13	84	203	18	61	23	1,318	DØ-1
5) Prod. - Purch. - Other	366	7	216	68	20	9	62	150	13	45	17	773	DØ-1
6) A & G	1,925	58	1,034	332	92	48	204	634	54	201	326	[illegible]	OØ-1
7) Total	17,170	519	9,259	2,970	825	424	2,634	5,722	493	1,809	2,805	44,630	
Energy													
8) Prod.- Fuel	34,984	1,340	20,679	5,914	2,313	675	6,283	20,515	3,632	6,574	1,412	102,321	EØ-1
9) Prod.- Purch.Power	856	32	506	145	57	16	154	502	89	112	35	[illegible]	EØ-1
10) Total	35,840	1,372	21,185	6,059	2,370	691	6,437	21,017	3,721	6,686	1,447	[illegible]	
Customer													
11) Distribution	6,160	349	755	162	15	42	62	24	1	17	32	7,619	Schedule 6a
12) Billing & Meter Read.	3,038	178	599	84	-	30	16	2	1	1	69	4,018	CØ-3
13) Customer Service	1,162	68	229	32	-	12	6	1	-	-	27	1,537	CØ-3
14) Credit & Collection	730	23	223	52	-	8	-	-	-	-	4	1,040	Schedule 6d
15) A & G	1,485	83	242	44	2	12	11	4	-	2	18	1,913	OØ-2
16) Total	12,575	701	2,048	374	17	104	95	31	2	20	150	16,117	
17) Depreciation	14,861	522	6,482	2,075	500	314	1,656	3,356	205	1,131	926	32,028	PØ-3
18) Grants in Lieu	1,787	63	780	249	60	38	199	404	25	136	111	3,852	PØ-3
19) Total Operating Cost	82,233	3,177	39,754	11,727	3,772	1,571	11,021	30,530	4,446	7,782	5,439	201,452	
20) Misc Rev.	(1,495)	(39)	(507)	(125)	(23)	(14)	(73)	(546)	(34)	(119)	(40)	(3,015)	Schedule 7
21) Sub. Total	80,738	3,138	39,247	11,602	3,749	1,557	10,948	29,984	4,412	7,663	5,399	198,437	
22) Return	24,610	1,421	28,425	6,533	1,356	1,001	4,980	11,749	1,532	2,384	2,724	[illegible]	
23) Required Rate Revenue	$105,348	$4,559	$67,672	$18,135	$5,105	$ 2,558	$15,928	$41,733	$5,944	$10,047	$ 8,123	[illegible]	
24) $ Return	6.44	10.57	16.94	12.21	10.37	12.45	11.59	13.16	25.26	8.10	11.46	10.45	
25) % of Overall	6.44%	101.05	161.95	116.73	99.14	119.02	110.80	125.81	241.49	77.44	109.75	100.00	

In allocating the Operating Costs for the year ending March 31, 1980 to the various customer classifications, the Applicant used various factors that will be dealt with individually,

DEMAND

(1) Production - Operating and Maintenance (DØ-1)
(2) Transmission (DØ-1)
(4) Wreck Cove Deferral (DØ-1)
(5) Production, Purchased Power and Other (DØ-1)

The above Operating Costs relating to the Demand functions were allocated by the Applicant on the basis of System Peak and Average Demand.

The appropriate allocation percentages, DØ-1 were disucssed above under Production Plant (1) Steam, (DØ-1), and the following percentages were derived in the allocation to customer classifications:

7

The percentages, so derived, were used in the allocations to Customer Classifications of the following Operating Costs,

(i) Production - Operating and Maintenance $26,220,000

(ii) Transmission $3,581,000

(iii) Wreck Cove Deferral $1,318,000

(iv) Production - Purchased Power and Other $973,000

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Inter-ruptible	Munic-ipal	Unmetered	Total
nd												
O & M	$ 9,869	$ 296	$5,719	$1,820	$ 530	$ 249	$1,678	$4,040	$ 357	$1,211	$ 451	$26,220
omission	1,348	40	781	249	72	34	229	552	49	165	62	3,581
k Cove Deferral	496	15	287	91	27	13	84	203	18	61	23	1,318
. - Purch. - Other	366	7	216	68	20	9	62	150	13	45	17	973

DEMAND

(3) Distribution (Schedule 6a)

The Distribution Operating Costs were allocated by the Applicant to the customer classifications as follows:

NOVA SCOTIA POWER CORPORATION
Allocation of Distribution Operating Costs
For the Year Ending March 31, 1980
($000)

	Domestic	Small General	General	General All Electric	General Large	Industrial To 249KVA	Industrial 250-1,999KVA	Industrial Large	Interruptible	Municipal	Unmetered	Total	Factor
Demand													
Land	$ 437	$ 20	$ 91	$ 28	$ 6	$ 5	$ 19	$ 9	$ -	$ 8	$ 9	$ 632	DV-2
Substations	1,088	25	576	199	58	35	203	109	2	97	45	2,437	DV-4
Overhead	770	38	126	[illegible]	5	7	[illegible]	7	-	6	14	1,030	DV-1
Underground	40	2	6	3	-	-	[illegible]	1	-	-	1	53	DV-1
Line Trans.	522	11	260	[illegible]	-	14	-	-	-	-	21	917	DV-2
Services	-	-	-	-	-	-	-	-	-	-	-	-	CV-2
Meters	-	-	-	-	-	-	-	-	-	-	-	-	-
Cust. Serv & Contr.	-	-	-	-	-	-	-	-	-	-	-	-	
Cust. Premises	-	-	-	-	-	-	-	-	-	-	-	-	
Communications	307	7	163	[illegible]	14	10	[illegible]	17	-	13	13	[illegible]	DV-3
Street Lighting											1,823	1,823	Direct
Meter Testing	-	-	-	-	-	-	-	-	-	-	-	-	
Total	$3,166	$103	$1,222	$[illegible]	$[illegible]	$[illegible]	$[illegible]	$[illegible]	$2	$126	$1,926	$[illegible]	

The Applicant allocated the Demand Operating Costs in the same manner as their Rate Base counterparts. Land was allocated on the basis of substation, pole and wire investment. Substation costs were spread according to substation investment. Overhead and underground expenses were assigned in relation to the pole and wire investments. Line transformers are secondary demand related. Services expense was allocated to secondary customers. Meter and meter testing expenses were spread according to the meter investment per class. Communications is related to primary demands and street lighting was again assigned directly to the unmetered class.

DEMAND

(6) Administration and General (OØ-1)

The Administration and General Operating Costs wereallocated by the Applicant on the basis of other Demand Operating Costs, as follows,

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
(9) Demand Operating Costs	$ 37,341	$ 14,383	$ 439	$ 7,722	$ 2,479	$ 686	$ 354	$ 2,194	$ 4,735	$ 406	$ 1,502	$ 2,439	
(10) % Responsibility	100.00	38.52	1.17	20.68	6.64	1.84	.95	5.88	12.68	1.09	4.02	6.53	OØ-1

The Administration and General Operating Costs, amounting to $4,998,000 were allocated by the Applicant by using the above percentages as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

Demand	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Interruptible	Municipal	Unmetered	Total
A & G	1,925	58	1,034	332	92	48	294	634	54	201	326	4,998

ENERGY

(8) Production - Fuel (EØ-1)
(9) Production - Purchased Power (EØ-1)

Fuel costs and purchased power were both allocated by the Applicant on percentages based upon MWH generated and purchased as follows:

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
(33) MWH Generated & Purchased	5,679,128	1,941,766	74,658	1,148,048	328,209	128,262	37,437	348,865	1,138,608	201,426	253,687	78,301	
(34) % Responsibility	100.00	34.19	1.31	20.21	5.78	2.26	0.66	6.14	20.05	3.55	4.47	1.38	EØ-1

The Applicant allocated the Production - Fuel Operating Costs, amounting to $102,321,000, and Production - Purchased Power Costs amounting to $2,504,000 on the basis of the above percentages, as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Interruptible	Municipal	Unmetered	Total
Energy												
Prod.- Fuel	34,984	1,340	20,679	5,914	2,313	675	6,283	20,515	3,632	4,574	1,412	102,321
Prod.- Purch.Power	856	32	506	145	57	16	154	502	89	112	35	2,504

CUSTOMER

(11) Distribution (Schedule 6a]

The Customer Distribution Operating Expenses were allocated by the Applicant as follows:

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Customer													
27) Land	$ 441	$ 20	$ 92	$ 29	$ 6	$ 5	$ 19	$ 9	$ -	$ 4	$ 9	$ 634	Cy-2
28) Substations	-	-	-	-	-	-	-	-	-	-	-	-	
29) Overhead	1,233	61	202	61	9	11	30	11	-	9	22	1,649	Cy-1
30) Underground	61	3	11	3	-	1	1	1	-	-	1	86	Cy-1
31) Line Trans	-	-	-	-	-	-	-	-	-	-	-	-	
32) Services	1,073	64	215	30		11	-	-	-	-	-	1,473	Cy-2
33) Meters	846	49	109	20	-	7	9	2	1	-	-	1,143	Schedule 3f
34) Cust. Serv. & Contr.	1,413	87	59	8	-	3	-	-	-	4	-	1,570	Schedule 6b
35) Cust. Premises	810	30	33	5	-	2	-	-	-	-	-	949	Schedule 6a
36) Communications	-	-	-	-	-	-	-	-	-	-	-	-	
37) Street Lights	-	-	-	-	-	-	-	-	-	-	-	-	
38) Meter Testing	261	15	34	6	-	2	1	1	-	-	-	322	Schedule 3f
39) Total	$ 6,160	$349	$ 755	$ 162	$ 15	$ 42	$ 62	$ 24	$ 1	$ 17	$ 32	$ 7,619	

The allocation of these operating costs was made in the same manner as their Rate Base counterparts (Rates - Distribution Plant, supra).

CUSTOMER

(12) Billing and Meter Reading (CØ-3)
(13) Customer Service (CØ-3)

The Billing and Meter Reading Costs of $4,018,000 and Customer Service Costs of $1,537,000 were allocated by the Applicant on the basis of percentages derived from total weighted customers, as follows:

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Dealer
1) Total Customers	312,347	280,061	16,450	11,043	1,546	3	565	149	24	7	8	3,561	
2) Weighting Factor		1.0	1.0	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	2.5	
3) Weighted Total	370,379	280,061	16,450	55,215	7,730	15	2,825	1,490	240	70	80	6,403	
4) % Responsibility	100.00	75.61	4.44	14.91	2.09	-	.76	.40	0.06	0.02	0.02	1.73	CØ-3

The resulting division of the costs were as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

Customer	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Inter-ruptible	Munic-ipal	Unmetered	Total
Billing & Meter Read.	3,038	178	599	84	-	30	16	2	1	1	69	4,018
Customer Service	1,162	68	229	32	-	12	6	1	-	-	27	1,537

CUSTOMER

(14) Credit and Collection (Schedule 6d)

Credit and Collection Costs were allocated by the Applicant as follows:

Allocation of Credit & Collections Expense
For the Year Ending March 31, 1980
($000)

		Bad Debt. Expense	Credit & Collection	Total
(1)	Domestic	$294	$436	$ 730
(2)	Small General	8	15	23
(3)	General	195	28	223
(4)	General All-Electric	50	2	52
(5)	General Large	-	-	-
(6)	Industrial to 249 KVA	7	1	8
(7)	Industrial 250-3,999 KVA	-	-	-
(8)	Industrial Large	-	-	-
(9)	Interruptible	-	-	-
(10)	Municipal	-	-	-
(11)	Unmetered	-	4	4
(12)	TOTAL	$554	$486	$1,040
(13)	ALLOCATION FACTOR	RØ-1	CØ-1	

The Bad Debt Expense of $554,000 was distributed above using percentages derived on the basis of secondary customer revenue as follows:

Development of Allocation Factors
For the Test Year March 31, 1980
($000)

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered
Secondary Customer Revenue	$ 172,512	$ 91,571	$ 2,600	$ 60,642	$15,522	$ -	$ 2,177	$ -	$ -	$ -	$ -	$ -
% Responsibility	100.00	53.08	1.51	35.15	9.00	-	1.26	-	-	-	-	-

The Credit and Collection Expenses of $486,000 were distributed above using percentages derived on the basis of total customers as follows:

Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered
Total Customers	312,347	280,061	16,490	11,043	1,546	3	545	149	14	7	8	2,541
% Responsibility	100.00	89.65	5.27	3.53	0.50	-	0.17	0.05	0.01	-	-	0.82

As a result of the above calculations, Credit and Collection costs of $1,040,000 were distributed by the Applicant between the various customer classifications as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Inter-ruptible	Munic-ipal	Unmetered	Total
edit & Collection	730	23	223	52	-	8	-	-	-	-	4	1,040

CUSTOMER

(15) Administration and General (OØ-2)

Customer-related Administration and General Costs were distributed by the Applicant on percentages based on Customer Operating Costs as follows:

NOVA SCOTIA POWER CORPORATION
Development of Allocation Factors
For the Test Year March 31, 1980

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial to 249 KVA	Industrial 250-1,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
(11) Customer Operating Costs	$ 14,214	$ 11,070	$ 616	$ 1,806	$ 330	$ 15	$ 92	$ 64	$ 27	$ 2	$ 18	$ 132	
(12) % Responsibility	100.00	78.03	4.35	12.71	2.32	.11	.66	.39	.19	-	.13	.93	OØ-2

Using the percentages so derived, the Administration and General Costs amounting to $1,903,000 were allocated to customer classifications as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Inter-ruptible	Munic-ipal	Unmetered	Total	Factor
G	1,485	83	242	44	2	12	11	4	-	2	18	1,903	OØ-2

(17) Depreciation (PØ-3)
(18) Grants in Lieu of Taxes (PØ-3)

Depreciation and Grants in Lieu of Taxes were allocated by the Applicant on the basis of Production, Transmission and Distribution Plant, with the following percentages,

NOVA SCOTIA POWER CORPORATION
Development of Allocation Factors
For the Test Year March 31, 1980
($000)

	Total Company	Domestic	Small General	General Demand	General All Elec.	General Large	Industrial To 249 KVA	Industrial 250-3,999 KVA	Industrial Large	Interruptible	Municipal	Unmetered	Factor
(5) Production, Trans & Distribution$	770,532	$357,520	$12,548	$155,973	$47,936	$11,996	$ 7,551	$ 39,816	$80,759	$ 4,950	$27,142	$22,295	
(6) % Responsibility	100.00	46.40	1.63	20.24	6.48	1.56	.98	5.17	10.48	.64	3.53	2.89	[illegible]

The Applicant used these percentages and allocated Depreciation, amounting to $32,028,000 and Grants in Lieu of Taxes amounting to $3,852,000, to the Customer Classifications as follows:

ALLOCATION OF OPERATING COSTS
FOR THE YEAR ENDING MARCH 31, 1980
($000)

	Domestic	Small General	General	General All Elect	General Large	Industrial To 249KVA	Indust. 250-3999	Indust. Large	Inter-ruptible	Munic-ipal	Unmetered	Total
epreciation	14,861	522	6,482	2,075	500	314	1,656	3,356	205	1,131	926	32,0[illegible]
rants in Lieu	1,787	63	780	249	60	38	199	404	25	136	111	3,8[illegible]

NON-CONFIDENTIAL

Request IR-178:

With regard to CA IR-61 Attachment 1,

(a) Please explain the meaning of a CADPAD Load Point.

(b) Please explain the meaning of a CADPAD Primary Service.

(c) Please explain the difference between the solid blue line and the dashed blue lines, both of which appear to refer to 7200/12470 primary distribution.

(d) Please explain the meaning of the asterisk symbols shown along certain of the distribution lines, such as at the intersection of Murray Rd. and Highway 6.

(e) Please explain why only one distribution transformer is shown in this entire area (on Pleasure Cove Rd.).

(f) Please provide a distribution diagram for this area, showing all transformers.

Response IR-178:

(a) A CADPAD Load Point is an estimated location for the load on a feeder section. These would be in place to simulate transformer loading for an area and would generally represent a number of local distribution transformers. We are currently collecting the individual transformer locations as part of a three year GIS data collection project.

(b) A CADPAD Primary Service typically identifies the location a three phase customer who has a dedicated primary service fed from equipment such as a pad mounted transformer or transformers in a vault. A CADPAD Primary Service can also represent the location of a single phase pad mounted transformer.

(c) The solid blue line represents a three phase distribution line, while a dashed line represents a single phase line. Although none are indicated on this part of the system, a dashed line with dots would represent two phase distribution lines.

(d) These asterisks denote a conductor tap point. Not every tap location has been updated to be identified in this manner.

(e) Only one distribution transformer has been identified on this map as this area has not been collected as part of the GIS Data Collection project referenced in part (a) above. This individual transformer was a more recent addition to the system and was added prior to the start of the GIS Data Collection project.

(f) Such a distribution diagram does not exist at this time.

CONFIDENTIAL (Attachment Only)

Request IR-179:

Please provide diagrams similar to CA IR-61 Attachment 1, but including all transformers and (if possible) customer locations, for

(a) Purcells Cove Rd., Halifax

(b) Fraser St., Halifax

(c) Upper Partridge River Road, East Preston

Response IR-179:

(a) Please refer to Confidential Attachment 2.

(b) Please refer to Confidential Attachment 1.

(c) Please refer to Confidential Attachment 3.

NON-CONFIDENTIAL

Request IR-180:

Please explain the difference between the “SUB” and “UG” types in CA IR-70 Attachment 1.

Response IR-180:

“SUB” would represent submarine cable while “UG” would represent regular underground cable buried on land.

NON-CONFIDENTIAL

Request IR-181:

CA IR-72 requested "the analysis of weighted service costs, with all supporting documents and analysis." The response consisted of a reference to the 1993 COSS, which stated that such an analysis was conducted.

(a) Please provide the analysis described in SR-01 Attachment 1 Page 9, or state that NSPI has no such analysis for the current 2010 COSS.

(b) Please provide the analysis described in CA IR-45 Attachment 9, Page 6, or state that NSPI has no such analysis for the 1993 COSS.

Response IR-181:

(a) NSPI has not attempted to retrieve and repeat the basis of this principle in this proceeding. Please refer to CA IR-170.

(b) Weighted services costs have been applied in all NSPI cost of service filings since, at least, 1980. Please refer to page 13 (Section 12) of Attachment 1 to CA IR-177 for the illustration on how services were spread on a weighted customer basis.

NON-CONFIDENTIAL

Request IR-182:

Please explain how "Using historical trends, NSPI is able to take into consideration any customer classes that share a service drop." (CA IR-73)

(a) Please provide all data and computations regarding the sharing of services between customers in multi-family housing.

Response IR-182:

The analysis of service costs is based on the number of customer accounts. Therefore, if one account serves multiple families, they are not accounted for in the weighted service costs. However, if a multi-family unit has multiple accounts (that is, each unit has its own meter), these customers would be accounted for in the analysis of service costs.

(a) NSPI does not track services shared by customers in multi-family housing.

NON-CONFIDENTIAL

Request IR-183:

CA IR-74 requested "the derivation of 'The average unit cost of installing a meter for each class.'" The response consisted of a reference to the 1993 COSS, which stated that such an analysis was conducted.

(a) Please provide the meter cost analysis described in SR-01 Attachment 1 Page 9, or state that NSPI has no such analysis for the current 2010 COSS.

(b) Please provide the meter cost analysis described in CA IR-45 Attachment 9, Page 6, or state that NSPI has no such analysis for the 1993 COSS.

Response IR-183:

(a) NSPI has not attempted to retrieve and repeat the basis of this principle in this proceeding. Please refer to CA IR-45.

(b) The average unit costs of installing a meter have been applied consistently in all NSPI filings since at least 1993. Please refer to the following attachments for the foundational background behind current Cost of Service Studies.

a. Attachment 1 (regulatory record from the 1989 GRA regarding examination of meter installation cost analysis)
b. Attachment 2: Cost of Service Studies Volume 1 prepared by Ernst & Ernst for the years ended March 31st, 1977 and March 31st, 1978 (page 31 of 62, lines 4 to 14).
c. Attachment 3: Cost of Service Studies Volume 2 prepared by Ernst & Ernst for the years ended March 31, 1977 and March 31, 1978 (Schedule 15, page 73 of 89).

NSPC
(RC378I0007)

RATE CASE #030
DEC 1988 - NSPC APPLICATION TO REVISE RATES AND REGULATIONS

DATE: 900906
PAGE: 9

VL SL	DATE FILED	EXHIB NUM	QUES NUM	REQUESTED BY	WITNESS / REQUESTED OF	REQ DATE	TRANS REF PG	DESCRIPTION
06.58	890223			NDP	A.E. DOMINIE	890124		FILE COPIES OF VOLUME 1 AND 2 OF THE COST OF SERVICE STUDIES FOR THE YEARS ENDED MARCH 31/77 AND MARCH 31/78.

CLERK A.B. DEMPSEY

PROVINCE OF NOVA SCOTIA

Board of Commissioners of Public Utilities

1526 DRESDEN ROW
P.O. BOX 3058
HALIFAX SOUTH POSTAL STATION
Halifax, N.S.
B3J 3G7

PLEASE ADDRESS ALL COMMUNICATIONS TO THE BOARD

TELEPHONE (902) 424-4448
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copy to
Shirley Dean
89/01/27 for
investigation

January 24, 1989

Mr. Maurice MacDonald,
Manager, Corporate Relations,
18th Floor,
1930 Barrington Street,
P.O. Box 910,
Halifax, Nova Scotia
B3J 2W5

Re: Cost of Service Studies

Dear Mr. MacDonald:

The Board has received a request from Mr. Ian Johnson, Researcher with the Nova Scotia NDP Caucus Office that copies of Volumes 1 and 2 of the Cost of Service Studies for the years ending March 31, 1977 and March 31, 1978 be made available to him.

We would ask that you provide these items to Mr. Johnson as quickly as possible.

Yours very truly,

A.B. Dempsey

A.B. Dempsey,
Clerk

/abd

cc: Mr. Ian Johnson
cc: Mr. Peter G. Gurnham

030.06.58

nova scotia power corporation

BY COURIER

1989 01 31

Mr. Ian Johnson
Researcher
Nova Scotia NDP Caucus Office
1657 Barrington St.
HALIFAX, N.S.

Dear Mr. Johnson:

Re: Cost of Service Studies

Further to your request which we received from the Board of Commissioners of Public Utilities, enclosed please find a copy of the Cost of Service Studies for the Years Ended March 31, 1977 and March 31, 1978 Volumes 1 and 2.

We trust the attached is satisfactory.

Yours very truly,

Edith Lilly
for M.F. MacDonald
Manager, Corporation Relations

Encl.

C: A.B. Dempsey
P.W. Gurnham
File
C.L./Circ. File

Ernst & Ernst

Cost of Service Studies for the Years Ended March 31, 1977 and March 31, 1978

Volume 1

Prepared for

Nova Scotia Power Corporation

December 1978

In its Order of May 11, 1977, the Nova Scotia Board of Commissioners of Public Utilities ordered the Nova Scotia Power Corporation to complete a historical cost of service study. Per the Order, the attached report presents such a cost analysis for two historical time periods. These periods are the fiscal years ending March, 31, 1977 and March, 31, 1978.

It was further ordered that a historical cost of service study be completed on a seasonal and time of day basis.

Because of the complexity of allocation of costs on a seasonal and time-of-day basis, we have not been able to address that issue in this report.

This aspect of the study has been viewed as forming part of the Peak Load Pricing Study. This study is presently getting under way and it is difficult to say, at this time, when the Corporation may be able to report on these specific issues.

The scope of the project detailed in this report was to measure the cost effectiveness of the rates ordered by the Board which became effective March 2, 1977. In order to measure the cost effectiveness, the revenue for the fiscal year 1977 was pro-formed at rates effective

March 2, 1977. Thus, the results of the rate schedule can be measured, over time, at comparable revenue levels.

The bench mark used for measuring cost effectiveness is return on rate base. Thus interest costs are not allocated to the classes of service but are recovered in the return provided by each class. From the two yearly analyses, each rate schedule can then be compared as to its relationship to overall Corporation rate of return. What this comparison does is measure each rate schedules rate of return as a percent of the overall return.

Illustratively, the comparison can be viewed as follows:

	Return on Rate Base	
	Fiscal 1977	Fiscal 1978
Overall Corporation return	20%	10%
Rate schedule XYZ	12%	4%

This comparison tells us that in 1977 Rate XYZ was earning 60% of the overall rate of return in 1977 based upon 1978 rate levels. However, in 1978, the rate was earning 40% of the overall return at the same rate level. Thus, as cost increased from 1977 to 1978, the rate did not respond to cost increases and its relationship to overall return declined.

It is critical to remember in this type of analysis that revenues have been set at comparable levels and that costs are on an as incurred basis. Thus, true measurement of a rates response to cost can be measured. In the above example, the return declined by 50% for the overall company whereas the return for rate XYZ declined 66.7%. Thus the cost response of the rate was less than that of system total.

In responding to the Board's Order we have prepared three cost studies for each time period. Study number 1 allocates production and transmission plant on the basis of coincident peak and distribution plant on the basis of customer non-coincident demand. Study number 2 allocates production and transmission plant on the basis of coincident peak and average demand and distribution plant on the basis of class non-coincident demand. Study number 3 allocates production and transmission plant as well as distribution plant on the basis of class non-coincident demand.

Although the Board in its Order specified only the concepts used in study number 1, the other studies were utilized to show the cost patterns under various methods, also, the original cost study presented by NSPC in the 1976-77 rate case was based upon the methodology set forth in study 3. Thus the Board can at this time review the historical results of three standard cost allocation methodologies.

These cost studies are conducted on historical periods. Thus they measure the performance of a set of rates against past costs rather than future costs. Cost of service studies conducted on historical data provide apportioned costs which are useful as approximations or guidelines as to the reasonableness of rates. This statement is predicated on the assumption that rate relationships should depend entirely on cost relationships. This concept thus excludes all non-cost factors such as political or social considerations, statutory mandate, value of service, past commission practice and orders and vested interest. While it can be argued that all of these factors have a place in rate design, their recognition is beyond the purview of the cost analyst when evaluating rate level on a pure cost comparison basis. Thus cost of service or cost apportionment studies are designed to reflect relative differentials in cost.

A cost of service study consists of an allocation to the various classifications of utility customers of all costs relative to the furnishing of electric service by a utility. This includes the appropriate assignment of operating and maintenance expenses, depreciation, grants in lieu of taxes and the resultant determination of earned return on those elements of electric utility rate base in service necessary to provide electric service. All of these costs are allocated to those groups of customers which either cause or use the cost as incurred by the utility.

Where possible costs were assigned directly to classes of service based upon details derived from the books and records of the Corporation or by special analysis and studies.

Cost not directly assigned were analyzed by functional responsibility and groupings of accounts, such as production, transmission and distribution. These costs are then allocated to the various classes of service on the basis of the respective demands, energy use, number of customers and revenues associated with the functional responsibility appropriate for each class of service.

In general, demand components of cost are those items which are incurred in order to attain and maintain the ability to delivery electric energy to customers as called for by them, and are associated with meeting the class peak and the class demand at the time of the system peak. The energy use components of cost are those items which vary with the volume of energy supplied to the various classes of service as provided by the utility. The customer components of cost are those items which vary with the number of customers served and revenue related costs are those items which vary with the dollars of revenue received.

Costs which vary in accordance with the above description can be described on an example basis using some of the more obvious cost types. It is well established that large demands for electric energy requires the use of production and transmission facilities to meet these demands. Plant investment increases as such units and facilities are enlarged to meet these demands. Consequently, those production and transmission facilities are allocated upon a firm system peak demand responsibility recognizing the cost causation and utilization of these facilities by the various classes of service. The same concept is used in the distribution system where it is necesary to recognize customers served on the system.

An example of energy costs, costs which vary with the volume of kWh supplied, would be fuel cost. This cost increases as the quantity of fuel required to meet an increased output at the transmission and distribution level is increased.

A readily identifiable example of customer cost is that for customer accounting, including meter reading costs. In terms of plant, meter cost and service cost are readily identifiable as customer costs.

Conducting a cost of service study of the type presented in this analysis is based upon extensive use of Corporation records, comparative data of other utilities and a degree of informed judgement concerning those areas where hard empirical data is not available. Our initial action was to review the entire filing in the NSPC 1976-1977 rate case, the Boards Order in that case, the 1978 rate filing and related decisions. Following and concurrent with this review detailed examination was made of the Corporation's books covering plant in service, billing determinants, actual metered data, and operating costs. Detailed review of this data was also completed through discussion with Corporation personnel so as to derive as much data as possible on an actual basis.

Consequently, three studies were done for each of the fiscal years 1977 and 1978. The studies utilize load data for each year, where available, and combination data from the two years where single year data was unavailable. Sales volumes and revenue are stated as booked with one exception. Revenue for 1977 has been restated at rates ordered into effect March 2, 1977. This was done so that the cost responsivness of these rates could be measured against total cost changes as well as on a class by class comparative basis.

The cost studies presented here are done on a step by step basis. Briefly the steps are as follows:

- Determination of demand, energy and customer allocation factors
- Separation of steam and dedicated Mersey River System sales

- Classification of Plant and Working Capital.
- Allocation of Rate Base.
- Determination of Revenues.
- Classification of Operating Cost.
- Allocation of Operating Cost.
- Development of Return on Rate Base.
- Comparison of relative class returns.

Before going into each of the above in detail, let us review the results of the studies first. Thus we can proceed with an understanding of the answer as we review the detail of how that result was determined. The results of the studies immediately follow this narrative under the tab "Results". This one page document shows the measurement of each rate schedules rate of return as compared to the overall earned return of NSPC.

For each study, total Corporation earned return is represented as 100 percent. Each class of services earned return is then measured as its percent of the overall return. For example, if the earned return of the Corporation is 10%, then a class earning an 8% return would be shown on the summary schedule at 80% of system average. The same would be true for a class earning 12%. This class would show on the summary schedule that it was at a level of 120% of system average. Thus we can observe each class of services relationship to the overall system as well as the inter class relationships.

For purposes of this presentation, return has been defined as that income available after reducing revenue by the following costs:

- Operating and Maintenance expense including fuel costs
- Customer accounting costs
- Customer Relations and Information costs
- Administrative and General costs
- Depreciation costs
- Grants in Lieu of Taxes costs

Thus the remaining revenues must meet the capital recovery cost including interest expense, principal repayment and contingency costs. The most important point to be emphasized at this time is that the studies measure the relative cost relationship of each class of service. Argument and debate over what is to be included in return or capital recovery do not change the relative results of this measurement. This is due to the simple concept that earned results are being studied at an earned level. Thus the study does not attempt to measure the propriety of those earnings either in total or for each class of service. The sole measurement is the relative returns of each rate schedule over cost changes at a constant rate schedule. Thus we are able to evaluate the performance of a rate schedule relative to the total Corporation and all other rate schedules without clouding the argument with debate over the propriety of the revenue level.

Based on the following table, which is a recasting of the Summary of Results, we can review the rate schedule relationships for the two years. These relationships represent the final results of the studies. For both years, total Corporation earned return is expressed as 100%. Each rate schedules relationship to this is expressed as to the return ranges based on three different primary allocation methods:

Rate Schedule	1977	1978
Total Company	100%	100%
Domestic	59%- 65%	48%- 55%
General Connected Load	89%-104%	111%-132%
General Demand	159%-163%	173%-184%
General All-Electric	101%-106%	119%-129%
General Large	99%-120%	97%-108%
Industrial to 249 KVA	121%-136%	115%-141%
Industrial 250 KVA-3999 KVA	100%-105%	95%-102%
Industrial Large	151%-196%	150%-199%
Municipal	100%-118%	86%-101%
Unmetered	79%- 83%	94%-106%

Analytically these results tell us the response of each rate schedule to changes in cost. From this we can then measure the relative need in terms of a requirement to spread future rate increases. Once a future test years costs have been allocated on a comparable basis, comparison of those results to those of the historical periods form the parameters for the distribution of future rate increases.

From the above table we can see that the Domestic rate has not responded in a positive direction as compared to system cost increases. The relative return level fell from a high of 65% of average to 55% of average and the low from 59% to 48%. As a comparison, the Industrial Large rate remained relatively static over the period. This is observed by relating the change in relative return of a low range of 151%-150% of average and a high of 196%-199% of average.

Conversely, the Unmetered rate schedule shows an improvement as compared with the changes in cost. This is seen in the change from 79% to 94% of the overall return at the low range to a high of 83% to 106% in the high range. Thus the rate responded in a positive direction as compared to Domestics negative response and Industrial Larges static response. A similar comparison can be made for each rate schedule and an appropriate observation of the rate schedules performance can be evaluated

I have intentionally omitted the Interruptible rate schedules results from the table. Depending on the allocation method used, the results for this type of rate schedule vary dramatically. Interruptible service is substantially different than firm service from a conceptual viewpoint and also must be evaluated in terms of the utilities current and long term power planning concepts. Thus, Interruptible service should be evaluated on its own merits and in terms of the value and use of such load on the system.

Thus we have now reviewed, in general terms, the answers provided by the studies. Keeping in mind that we are measuring historical results or performance of a rate schedule, we can now review the detailed calculations which developed these results.

Volume II of this report sets forth the base working papers which developed the results of the study. We will review the study in the order in which it was conducted. Schedule 1 of Volume II is the summary of results for 1977 and 1978 which has been previously discussed.

Schedule 2 sets forth the development of each rate schedules customer and class non-coincident demand as well as the class contribution to the system peak demand. As the Board is well aware, NSPC has no recording demand meters on its system. Thus coincident demands and class non-coincident demands which require time determination are based upon mathematical evaluations using NSPC data and data from comparable type loads from various studies conducted in the United States. Thus all time required demand data is based upon calculation rather than actual meter readings. For those classes where indicating demand metering is available, these demands were used as a starting point. Thus there is a basic metered foundation for the demand responsibility of all classes except Domestic, General Connected Load, and Unmetered service.

These calculations are predicated upon the data submitted in the testimony of W. L. Fraser, H. J. VanderVeen and G. Baker in the 1977 rate case and the testimony of W. L. Fraser and G. Baker in the 1978 rate case. In all cases, H. J. VanderVeen of Ernst & Ernst has reviewed the 1977 and 1978 demand calculations with both Mr. Fraser and Mr. Baker. It can best be said that the data presented on Schedule 2 represents the concepts and criteria used by the above parties in NSPC's last two rate case proceedings. Substantial testimony has been given before this Board as to the strengths and weaknesses of this data.

For purposes of this report, the data can be said to be the best that is currently available and further debate will only lead us to the conclusion reached in 1977 that load research is definitely needed. To this extent, NSPC has received the funding to conduct such studies and their implementation is currently in progress. In the future, the preparation of cost of service studies will be based upon metered data.

For those rate schedules which have indicating demand meters such as General Service Demand, the following description is representative of the methods used in determining class non-coincident and coincident demands.

From the indicating demand meters, the class non-diversified demands could be determined for the month of December. This data provided a non-diversified class load factor. This load factor was then compared to similar type customers for which load studies have been conducted in the U.S. From this load factor class coincidence factors were determined on a judgemental and experience basis for the month of December. This provided a class diversified non-coincident demand and load factor.

A system coincidence factor was developed from load studies on comparable type loads as served by other utilities and informed judgement as presented in NSPC's last two rate cases. This coincidence factor then established each class's contribution to system peak. This methodology was utilized for each class of service which had indicating demand meters. The coincidence factors developed were then checked against scatter diagrams for each class as developed by NSPC. These diagrams show the relationship of each customers demand in the class thus providing the classes maximum demand as compared to the same data for the month of December. Load factor relationships can also be observed from this analysis. This cross check was then used as a fine tuning mechanism for the demand metered classes.

Unmetered service was based on approximately 4,000 hours of use per month. This reflects the average burning hours of street and outdoor lighting as well as other types of load served under this schedule.

General Service-Connected Load was based upon certain connected load data available from the Corporation records and analysis of comparable customers on other systems. Although the non-diversified and diversified class load factors seemed unusually high on an annual basis, they were accepted on the basis that in December many of the rates seasonal customers are not on line thus providing annual KWH and winter KW, thus high load factors based upon December demands which would be lower than the summer demand.

The next step was to calculate each rate schedules contribution to system peak except for Domestic. By subtraction, the Domestic contribution could be determined. Acceptance of the calculations were based upon the following conditions:

- Annual Domestic non-diversified load factor on December's demand should be 30-35% -Class coincidence factor 70-75% -System coincidence factor 80-85%

These conditions were met for 1977. As a check, the calculations for 1978 were based on the 1977 results for all classes except Domestic. Domestic coincident demand was again determined by subtraction, using load factors and coincident factors from 1977 applied to 1978. The results, for Domestic for 1978, fell within the 1977 parameters. At this point, it was felt that sufficient checks and balances had been employed and the data was accepted for utilization in the studies.

Following the determination of class coincident demands, kWh sales were analyzed so as to determine energy sales at generation. This study involves the determination of loss factors over the various voltage levels of the NSPC system. Schedule 3 sets forth the energy sales by class and the resultant generation requirement. Schedule 2 shows the loss factor used for each class. These factors recognize the various voltage levels at which customers are served based upon common loss factors on electric systems. Determination of the voltage level loss factors is predicated on the data submitted in the Corporation's 1977 rate case.

For purposes of allocating the demand cost portion of the distribution system, it is necessary to develop customer and class non-coincident demands. Customer non-coincident demand is the sum of the maximum demands of all customers in the class. Class non-coincident demand is the greatest demand the class places on the system.

These demands were developed for each class, in total, on Schedule 2. However, since many customers have dedicated plant such as substations, which are classified as a demand cost, it is necessary to develop these demands on a voltage level basis. It is also required to recognize the difference in primary and secondary voltage level demand costs. A customer served at the primary level should not be allocated any of the secondary costs, thus the use of voltage level demand factors provide a proper recognition of cost causation and utilization. Schedules 4 and 5 show the determination of each classes non-coincident demands for 1977 and 1978. Schedule 4 is for customer non-coincident demand and Schedule 5 is for class non-coincident demand. For those customers where there are dedicated substation investment or customer owned facilities, which provide a determination of the service voltage, December demands were determined. These demands were then subtracted from total non-coincident demand to arrive at each classes demand at the lowest common voltage level. Identified demands are then added in by voltage level to provide each classes non-coincident demand at the highest common voltage level.

Losses are also added at each voltage level so as to provide the total demand at each voltage level.

This process completes that portionof the study necessary to develop the demand and energy allocation factors used to allocate costs to the classes of service. All of the allocation factors used are set forth in Schedule 46 for both 1977 and 1978 for all three studies. In each case, the factors are numbered sequentially. Following the determination of the demand and energy allocation factors, the process of allocating costs to the classes can begin.

The first step in the study is the allocation of rate base. From the Corporation's books and records, plant in service by primary account is determined. Schedules 6 and 26 summarize this data in total for 1977 and 1978 respectively. Schedule numbering for Schedule 6 through 45 are set up on a plus twenty basis. Thus Schedule 6, is for 1977 and Schedule 26 is for 1978. This concept applies throughout the presentation. Thus Schedule 19 would be a 1977 schedule and 39 would be the exact same schedule only for 1978. In review, Schedule 1 is the summary, 2-5 are the demand and energy data for 1977 and 1978, 6-25 are all of the detailed schedules for the 1977 cost allocation, 26-45 are the same as 6-25 only for 1978 and Schedule 46 sets forth all allocation factors used for both years. Thus for purposes of explanation, this report will describe 1977 in detail with reference to the appropriate schedule for 1978. All allocations for each of the three studies done for 1977 are repeated for 1978.

The purpose of the cost studies is to evaluate the rate schedules as approved in the 1977 rate case. For purposes of this evaluation it was necessary to remove the steam sale at Glace Bay to AECL, the steam and electric sale at Point Tupper to AECL and the sale of electricity dedicated to Bowaters from the Mersey Hydro system. These sales represent rates for dedicated facilities for specialized sales and type of service. Thus, the cost associated with these sales are based upon formulae developed through hearings before this Board and represent fixed cost determination methodologies. Consequently, on Schedule 6, plant in service for each of these sales is deducted from total plant to arrive at plant in service which is applicable to electric sales which are covered by the base rate schedules for 1977. The same process is applied on Schedule 26 to arrive at plant in service for 1978. Plant in service is stated at net depreciated value for each of the years. As previously stated, net plant was determined from direct analysis of the Corporation's books and records showing gross plant and accumulated reserve for depreciation.

The next step in the cost study is to classify plant in service in working capital by primary cost causation and utilization. Schedule 8, page 1 sets forth the classification of rate base for 1977. Since 3 studies were prepared using different allocation responsibilities for production and transmission plant, Schedule 8 shows these facilities being classified under all three methods. These are all demand classifications and are as follows:

- Peak responsibility
- Peak and average responsibility
- Class non-coincident responsibility

Thus, production and transmission plant are classified as a demand cost and allocated to the classes based upon the class responsibility for each of the above demand factors. Directly classified production and transmission plant are those facilities which are dedicated to serving the AECL load at Glace Bay and the dedicated Mersey River System serving Bowaters.

Distribution plant is likewise classified between demand, customer, direct and other. There are two demand classifications for distribution plant. In the study where production and transmission plant is classified and allocated on the basis of coincident peak, distribution costs that are classified as demand related are allocated on the basis of the customer non-coincident demand. In the other two studies, distribution demand costs classified as demand related are allocated on the basis of class non-coincident demand.

Distribution substations are classified demand and direct. Where a substation can be identified as serving only one customer, the station costs are analyzed and directly assigned to the class of service which the station served. Page 2 of Schedule 8 summarizes this analysis. Substations were analyzed by the following functions:

- Distribution bulk power
- Distribution dedicated bulk power
- Distribution bulk power customer owned
- Distribution general

- Distribution dedicated general
- Distribution general customer owned

Based upon this review, approximately $1.9 million of direct substation costs were determined by class of service. The remaining distribution substation costs were then classified as demand related costs.

Page 3 of Schedule 8 summarizes the classification of distribution pole investment. Average historical cost for various size poles was determined from the books and records of the Corporation. Using the base system concept, 30 and 35 foot poles were determined to be the minimum size required to provide each customer with the pole facilities to take service. Under this concept, this would be the minimum size pole installed just to physically connect all customers to the system. The average weighted cost of 30 and 35 foot poles, weighting 30 foot poles at 2 and 35 foot at 1, was $104.10. Total number of poles multiplied by this cost equated to 63% of the total investment in poles. Thus, 63% of the pole investment was classified as customer cost and the remaining 37% as demand cost.

This separation then recognizes the base component, that is needed to provide service to all customers on the distribution system, and the demand component, that cost component which is over the base or that required to serve the demands for electricity placed on the system. Based upon engineering and construction estimates, 30% of the poles were then functionalized as primary only and the remaining 70% was functionalized 50% primary - 50% secondary. These costs were then classified 63% customer - 37% demand. Page 3 of Schedule 8 sets forth the results of this analysis for 1977 as does page 3 of Schedule 28 for 1978.

The same type of base system analysis was also made for distribution wire investment. Minimum size wire was based upon the same concepts used in the pole analysis. Number 1/0 copper and number 2-8 aluminum were deemed to be the minimum wire sizes required to provide the ability for the customers to take service from the distribution system. Based upon sample review of the installed cost of this wire, 59% was deemed to be required for base system purposes. This was predicated on a weighted cost per foot weighing #6 wire twice transmission costs and customer non-coinident demand for the allocation of the demand portion of cost incurred in the distribution system. The schedule shows each allocation in detail and the factor used in the allocation is noted in the right hand column. Thus by referring to Schedule 46, each allocation can be determined. As an example, production plant is allocated on factor D-1. Turning to Schedule 46, page 1, the D-1 factor can be observed.

Following production plant, transmission plant is also allocated on the D-1 factor. Each of the distribution accounts are separately allocated. Distribution land is basically substation and right-of-way land. This is allocated on the basis of the customer non-coincident demand. The allocation of distribution substations is shown in total on Schedules 9, 10, and 11. Schedule 12 shows the detailed allocation of the distribution substations. Page 1 of Schedule 12 shows the allocation based upon customer non-coincident demand and is used in conjunction with the coincident peak demand responsibility method. Page 2 of Schedule 12 sets forth the allocation of substations based on the class non-coincident demand responsibility and is used with the coincident peak and average and the class non-coincident allocations of production and transmission plant. Schedule 32 shows the same data for 1978. Schedules 13 and 33 are the distribution substation analysis by customer by rate schedule. This schedule provides the required base data for the determination of dedicated substation investment and the associated demands and energy requirements of the customers served by the particular station.

Distribution pole and wire are shown in total on Schedules 9, 10, and 11 for 1977. The detail of the allocation is shown on Schedule 14 for 1977 and 34 for 1978. As with substations, page 1 of Schedule 14, shows the allocation as based on customer non-coincident demand, page 2 shows the allocation based on class non-coincident demand.

Returning to Schedule 9, underground investment is allocated on the basis of pole and wire investment. Book details as to installed cost of underground distribution facilities by type, underground domestic distribution, commercial, and Industrial, are currently unavailable. Consequently, it was assumed to be installed pro-rata to the overhead system.

Line transformers are allocated based upon each class's demand responsibility at the secondary level based upon either the customer or class non-coincident demand. This allocation recognizes that line transformers are only applicable to those customers who take secondary service.

Meters are allocated directly. Schedules 9, 10, and 11 show the allocation in total for 1977. Schedule 15 shows the detail of the allocation for 1977 and Schedule 35 for 1978. Meter cost by type and size of meter was analyzed based upon the books and records of the Corporation. From this study, the unit meter costs were determined for each class of service based upon the most common metering components to the class. Thus small watt hour meters were assigned to domestic while large demand and watt hour meters including current and potential transformers were assigned to the Large Industrial customers. Thus the substantial cost differentials for meters are recognized through this direct assignment of costs. Street lighting costs are directly assigned to the unmetered class of service.

The allocation of working capital follows on the same basis. That portion of working cpaital related to fuel is allocated on an energy basis. The portion of cash related to the financing of Operating & Maintenance cost is allocated to the classes based upon each class's responsibility for the Operating & Maintenance expense excluding fuel costs. Materials and supplies held as spare parts are allocated to the classes on the basis of allocated production, transmission and distribution plant.

Reviewing the allocation of rate base, the 1977 study is presented under three different primary allocation factors. Schedule 9 shows the allocation of production and transmission on the basis of coincident peak responsibility, Schedule 10, on coincident peak and average and Schedule 11 shows it under the class non-coincident demand basis. Schedule 29, 30, and 31 show the same data for 1978. Following the allocation of rate base, the next step is the analysis of revenue.

The analyses to determine the revenues applicable to each class of service are shown in Schedules 16 and 36 for 1977 and 1978 respectively. The first step is to extract the revenue from steam and joint operations. Then, the revenue collected for each class of service is determined. The classwise revenues for 1978 are actual amounts while the revenue for 1977 has been pro-formed to reflect the rates put into effect on March 2, 1977. This adjustment has been made in order to make the studies for each year comparable. The revenues remaining are miscellaneous revenues to be allocated to each class.

As stated above, the electric revenues are assigned directly to each class of service. The forfeited discount revenue for 1978 is allocated direct since these records were available in 1978. These amounts are then used to calculate an allocation factor to be used for the 1977 analysis since the 1977 records did not permit direct classwise identification of forfeited discounts. After a pro forma adjustment to 1977 revenue for the use of March 2, 1977 rates, the allocation factor described above is used to distribute the 1977 discounts. The electric and forfeited discount revenues by class are added together. These subtotals form the basis for allocating the remaining miscellaneous revenue. For each class, the sum of electric, discount and miscellaneous revenue represents that classes total share of revenue to be used in conjunction with the cost allocations to follow, in order to arrive at classwise rates of return.

Following the analysis and allocation of revenues, the next step in the preparation of a fully allocated cost of service study is to classify and allocate expenses in a manner which will best identify the classwise cost responsibilities. This analysis is similar to that for rate base since most expense components are closely aligned with the rate base accounts. A detailed description of the classification and allocation philosophies follows.

First, as with rate base, the operating costs which are not directly associated with the Corporation's electric business are removed. Schedule 17 details this analysis for 1977 and Schedule 27 shows the results for 1978. The operating costs to be removed come mainly from the production costs. In 1977, a total of $20,721,000 is removed from the production operating costs for the dedicated portion of the Mersey system, AECL portion of Point Tupper #1 and the AECL steam portion of Glace Bay. In 1978, the figure is $23,740,000. In

1978, an additional $45,000 is removed from customer accounting since this is a directly assignable uncollectible to A.E.C.L. The final column of these schedules show the common electric operating costs which are to be allocated over the classes of service.

Schedule 18 details the classification of the operating costs according to the cost causation categories to be used in the various studies. The common production and transmission expenses are classified in accordance with the three studies perforned, coincident peak responsibility, coincident peak and average responsibility and class non-coincident peak responsibility. The amounts removed from the analysis as described above are classified direct while fuel and purchased power-fuel are classified as energy related expenses for all studies. Under distribution expenses, land, substations, overhead lines and underground lines are classified as other. These expenses are related to various plant components and are therefore to be allocated in accordance with those plant items. Line transformers are demand related and are classified as customer non-coincident peak related for the coincident peak study and class non-coincident peak related for the coincident peak and average and class non-coincident peak studies. Meters are classified direct since these costs are directly related to meter investment. Customer services and contracts and customer premise expense are split between direct and customer. A portion of these costs have directly identifiable class responsibilities and, therefore, are classified direct. The remaining amounts are classified as customer related expenses. Communication operating costs are demand related and are classified as class non-coincident peak and customer non-coincident peak as were line transformers. Street lighting costs are directly assignable to the unmetered customers.

Under customer accounting, all billing, a portion of customer service and a portion of credit and collection are classified as customer. Those amounts assignable to a particular class are classified direct.

Customer relations and information expenses are customer related. Administration and General expenses are classified as other since they relate to the levels of the other allocable expenses. Finally depreciation and grants in lieu of taxes are plant in service rate base related and are also classified as other.

These classifications are used to determine the amounts allocated under the various cost causation philosophies. The classification of 1978 operating costs is the same and is detailed in Schedule 38.

Allocation of the operating costs is accomplished by using the appropriate allocation factors, direct assignments and other analyses as required by the cost causation and utilization philosophy applicable to each cost category and study. The allocations for 1977 are shown in Schedules 19, 20 and 21. The 1978 analyses are shown in Schedules 39, 40 and 41. The results for the coincident peak responsibility study are in Schedules 19 and 39. The coincident peak and average studies are detailed in Schedules 20 and 40 and the class non-coincident peak allocations are in Schedules 21 and 41. A general discussion of the allocations for each study follows. Again, the analyses for both 1977 and 1978 are parallel.

As stated earlier, the major difference in the three studies is the method by which demand related items are allocated. In the coincident peak responsibility study, the basis for demand related production and transmission is a classwise coincident peak factor. This factor is used to allocate all transmission expenses and non-energy related production costs, i.e. operating and purchased power - other. Fuel and purchased power-fuel are allocated on the basis of each classes responsibility for mWh generated and purchased.

Under distribution operating costs, land is allocated on the basis of substations and pole and wire investment as contained in therate base analyses for the same study. Substation expenses are spread in accordance with the comparable plant category. Overhead and underground lines expense is allocated as the pole and wire investment. Line transformers are allocated as customer non-coincident demand at the secondary level for the coincident peak study. Communications is the same except the primary level demands are used. The other two studies use class non-coincident demand. A weighted secondary customer factor is used to allocate the services costs. This factor is designed to recognize the higher expenses associated with larger customers. Since meter operating costs are related to the number and size of the meters, these costs were allocated as meter investment from Schedule 15. Customer service and contracts as well as customer premise expenses are allocated partially direct and partially customer.

Investigation by the Corporation showed that 90% of these expenses are attributable to domestic service. The remainder is allocated to secondary customers. The detailed allocations can be found in Schedules 22 and 23 for 1977 and Schedules 42 and 43 for 1978. Street lighting costs are assigned directly to the unmetered class.

The billing expense component of the customer accounting costs is allocated on the basis of a weighted customer count. The weights reflect the higher expenses associated with generating hand bills and the additional detail involved in billing large customers. Customer service costs are composed of meter testing, record keeping and other customer related activities. The meter testing portion is assigned as meter investment and the remainder is allocated using the weighted customer count. The details are found in Schedule 24 for 1977 and 44 for 1978. Finally, the credit and collections component is allocated as shown in Schedules 25 and 45 for 1977 and 1978 respectively. First, identifiable bad debts are assigned. The remaining bad debt expense is then allocated on the basis of revenue and finally the collections costs are spread in accordance with the number of customers.

Customer relations and information expenses, which are monies spent for conservation and other consulting activities, is assigned to the classes on the basis of number of customers. Administrative and general costs are spread in proporation to the allocation of all other operating costs excluding fuel costs. Depreciation and grants in lieu of taxes are allocated in proportion to the classwise assignments of production, transmission and distribution plant from the related rate base allocation schedules for each study.

At this point, all operating costs for each class of service under each study method are known. These are compared with classwise revenues to determine the return for each class. These returns divided by the associated rate base totals provide the rate of return for each class of service.

The operating cost analyses for the other two studies are similar. The changes occur in demand related components of production and transmission costs. The distribution categories are essentially similar except for demand and plant related allocations. For demand, class non-coincident peak factors are used. Plant related allocations use the same categories which are derived from the rate base allocations.

Schedule 46 details the allocation factors used throughout the six studies of this report. Page 1 contains the demand allocation factors used in the demand related allocations of the studies. The factors represent the percentage by which a particular class demand level bears to the total. A factor is presented for each definition of demand used in the studies. Page 2 shows the factors for energy related allocations. Page 3 contains the customer related allocation factors. Where a weighted customer measure is used, the weights are also shown. The demand, energy and customer factors are all derived from company records and are exogenous to the study. The plant factors, however, are generated from other allocations and direct assignments in the studies. These factors are detailed on page 4. The operating cost factors on page 5 are also generated by using previous allocations and direct assignments. Page 6 details the revenue factors which are derived from the revenue analysis.

This completes the overview of the cost studies. Returning to Schedule 1, a review of the results of the three studies can be made in light of the range of returns. For purpose of evaluation, a reasonable range in returns should be in the area of 20%. In other words, if the overall company return is stated as 100% then all class returns should be in the 80%-120% range.

This range provides the degree of flexability that is required in these times of rate change and rate increases. Due to the complexity of rate design and when related to the many other important factors which should be incorporated, including past considerations, more emphasis on cost and price elasticity, a range of this magnitude is required in the transition period. It is also very important to recognize in the range that, at this time, NSPC does not have time of day metering, thus all demand data is based on research from other utilities. Upon completion of its load research project, the range can be narrowed to 10-15%. As can be seen from the studies, 5 of the 11 classes of service do not fall within the range in 1977 and 1978.

Thus there still remains the need for additional rate review and cost analysis. The cost of service studies presented in this report are based upon allocation methodologies commonly used before various regulatory bodies in North America. The results provide a guideline as to the direction in which rate design or revenue to be derived by class should move from the average rate increase. These types of studies provide guidelines to determine this direction, but in no way set forth a definitive measurement for the determination of revenue assignment when evaluating increases in rate structures. The evaluation of the amount of increase to be assigned to each class of service should be based not only upon the direction indicated by the cost of service study, but upon many other factors including competitive conditions, alternative fuel capability, historical acceptance of rate structures in the past and the inclusion of those historical considerations of this Board that are incorporated in the current rate structure. Value of service, political and economic considerations are also part of the real world of rate design and rate level. Thus the cost study is a guideline or indicator as to appropriate rate level not the dictator of the required revenue.

As can be seen from Schedule 1, there is still need to adjust certain rates in future cases.

Summarizing the study, the following comments briefly describe the results of the study by rate class.

- Domestic - as cost increased from 1977 to 1978 the rate did not match the cost rise. In fact, in relationship to overall return, the decline was approximately 20%.
- General Connected Load - as cost increased from 1977 to 1978 the rate responded quite favorably. The range of return went from a level of approximately 96% to the high end of the range.
- General - the level of return was substantially above the upper limits of the range for both 1977 and 1978.
- General All-Electric - the rate responded very well to the cost increase from 1977 to 1978 as is evident in the return going from approximately 105% of average to more than 120% of average.
- General Large - there was a slight decline in the overall average return, however, the rate is well within the defined range of reasonableness.
- Industrial to 249 KVA - The rate approximately matched the cost and provided an overall return above the 20% range.

- Industrial 250-3,999 KVA - Overall this class provides a return in both years that is equal to the overall return.
- Industrial Large - This rate provides a return that is substantially above the defined range of reasonableness. However, the rate tracked the cost increase quite well as the relative level of return remained unchanged.
- Interruptible - As previously mentioned, returns on this type of service are very volitile and interruptible rates are more value-of-service oriented than cost related.
- Unmetered - The rate responded to cost in a very positive manner and a marked improvement in overall return can be seen.

In conclusion, we would strongly recommend that comparable studies be completed on fiscal 1979. This would provide an evaluation of the last rate change and provide both the Board and the Corporation the ability to assess the distribution of future rate increases. In completing this study, substantial work has been done in reviewing and evaluating the Corporation's records and data bases. The primary conclusion is that this information is adequate, however, additional detailed information should be developed for future cost analysis. Refinements in record maintenance and detail would facilitate an improvement in the overall quality of future cost studies. In our opinion, the conclusions and recommendations reached in this report fairly and objectively evaluate the performance of the rate schedules ordered by the Board in its Order of May 11, 1977.

GLOSSARY OF TERMINOLOGY

1. Customer Non-Coincident Demand

   - sum of the maximum demand, regardless of time, of each customer in a class. This demand represents the sum total of each customers maximum demand within the class.

2. Class Non-Coincident Demand

   - the maximum demand of the class at a given point in time. This is the classes maximum demand and is time related to a fixed point representing a class maximum. This demand must be equal to or less than the customer non-coincident demand.

3. Coincident Demand

   - the class demand at the time of the system peak. This is based on the fixed hour of the system peak. It must be equal to or less than the class non-coincident demand.

4. Average Demand

- the average demand is the annual kWh generated for each class divided by the number of hours in the year.

5. Bulk Power Distribution Substation

- a substation which has an incoming voltage of 69 kv or greater and transforms to a lower voltage providing service to the distribution system.

6. Bulk Power Dedicated Substation

- a substation, as in 5 above, dedicated to serving a specific customer.

7. Bulk Power Distribution Substation Customer Owned

- a substation, as in 5 above, owned by the customer where the Corporation may have a limited investment in protective or other minor equipment

8. General Distribution Substation

- a substation which has an incoming voltage of less than 69 kv and transforms to another primary voltage serving the distribution system. Primary voltage is defined as less than

69 kv but more than 600 v.

9. General Dedicated Distribution Substation

- a substation, as in 8 above, but dedicated to serving a specific customer. In this case, it may transform at 600 v or less.

10. General Distribution Substation Customer Owned

- a substation, as in 8 above, owned by the customer where the Corporation may have a limited investment in protective or other minor equipment.

NOVA SCOTIA POWER CORPORATION

Cost of Service Study Summaries

For the Years Ended March 31, 1977 and 1978

Percentage Relationship of Class Return to Average Return

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)
	Year Ended March 31, 1977												
1)	Coincident Peak	100.00	59.0	99.3	161.5	101.4	115.4	125.7	104.5	190.9	4,796.8	105.5	78.8
2)	Coincident Peak and Average	100.00	65.0	88.6	158.9	105.1	99.1	136.4	99.5	150.6	326.2	107.6	79.9
3)	Class Non Coincident Peak	100.00	60.2	104.0	163.4	106.4	119.6	121.1	104.6	195.6	66.1	116.4	83.4
	Year Ended March 31, 1978												
4)	Coincident Peak	100.00	48.0	124.3	175.1	119.0	97.4	127.7	101.6	196.0	2,611.5	85.7	93.6
5)	Coincident Peak and Average	100.00	55.2	111.0	173.0	122.1	86.3	140.8	100.1	149.8	388.1	83.5	97.2
6)	Class Non Coincident Peak	100.00	49.6	131.8	183.5	128.7	107.5	114.6	94.9	198.7	7.6	100.6	106.2

SCHEDULE 1

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For the Year Ended March 31, 1977

Coincident Peak Responsibility

($000)

		Total Co. Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Allocation Factors (13)
1)	Production Plant	$173,951	$ 71,998	$ 1,235	$ 38,356	$ 14,890	$ 3,148	$ 1,235	$ 10,333	$ 21,553	$ -	$ 8,228	$ 2,975	D-1
2)	Transmission Plant	$ 74,568	$ 30,864	$ 529	$ 16,442	$ 6,383	$ 1,350	$ 529	$ 4,430	$ 9,239	$ -	$ 3,527	$ 1,275	D-1
	Distribution Plant													
3)	Land	$ 2,505	$ 1,803	$ 52	$ 341	$ 112	$ 21	$ 11	$ 72	$ 31	$ 1	$ 32	$ 29	P-3
4)	Substations	22,941	11,951	134	4,500	1,749	484	166	1,748	954	19	940	296	Sched. 12 Pg 1
5)	Poles	51,376	40,146	1,322	5,979	1,785	224	165	735	216	-	231	573	Sched. 14 Pg 1
6)	Wire - O. H.	27,759	21,368	681	3,407	1,049	134	96	440	129	-	138	317	Sched. 14 Pg 1
7)	Underground	4,246	3,300	107	504	152	19	14	63	19	-	20	48	P-1
8)	Line Transformers	26,562	17,334	197	6,062	2,332	-	207	-	-	-	-	430	D-8
9)	Services	14,217	10,107	419	3,253	405	-	33	-	-	-	-	-	C-9
10)	Meters	9,200	7,066	293	1,488	242	2	19	65	15	6	4	-	Sched. 15
11)	Other	67	48	1	9	3	1	-	2	1	-	1	1	P-3
12)	Street Lighting	8,000	-	-	-	-	-	-	-	-	-	-	8,000	Direct
13)	Total	$166,873	$113,123	$ 3,206	$ 25,543	$ 7,829	$ 885	$ 711	$ 3,125	$ 1,365	$ 26	$ 1,366	$ 9,694	
14)	General, Intangible & Future Use	$ 5,945	$ 3,091	$ 71	$ 1,150	$ 416	$ 77	$ 36	$ 256	$ 460	$ 1	$ 188	$ 199	P-5
15)	Total Plant in Service	$421,337	$219,076	$ 5,041	$ 81,491	$ 29,518	$ 5,460	$ 2,511	$ 18,144	$ 32,617	$ 27	$ 13,309	$ 14,143	
	Working Capital													
16)	Cash-Fuel	$ 3,042	$ 1,114	$ 30	$ 609	$ 197	$ 69	$ 13	$ 175	$ 586	$ 74	$ 137	$ 38	E-1
17)	Cash	3,358	1,737	45	654	219	41	19	137	252	-	102	152	O-1
18)	Mat. & Supp. - Fuel	3,674	1,345	37	735	238	83	16	212	708	89	165	46	E-1
19)	Mat. & Supp. - Other	11,054	5,747	133	2,138	774	144	66	475	856	1	349	371	P-5
20)	Total	$ 21,128	$ 9,943	$ 245	$ 4,136	$ 1,428	$ 337	$ 114	$ 999	$ 2,402	$ 164	$ 753	$ 607	
21)	Total Rate Base	$442,465	$229,019	$ 5,286	$ 85,627	$ 30,946	$ 5,797	$ 2,625	$ 19,143	$ 35,015	$ 191	$ 14,062	$ 14,750	

SCHEDULE 9

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base For The Year Ended March 31, 1977

Coincident Peak and Average Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Plant													
1)	Steam	$131,085	$ 51,765	$ 1,062	$ 27,803	$ 10,185	$ 2,609	$ 813	$ 7,904	$ 19,650	$ 1,219	$ 6,030	$ 2,045	D-3
2)	Hydro	19,677	8,144	140	4,339	1,684	356	140	1,169	2,438	-	931	336	D-1
3)	Gas Turbine	23,189	9,598	165	5,113	1,985	420	165	1,377	2,873	-	1,097	396	D-1
4)	Total	$173,951	$ 69,507	$ 1,367	$ 37,255	$ 13,854	$ 3,385	$ 1,118	$ 10,450	$ 24,961	$ 1,219	$ 8,058	$ 2,777	
5)	**Transmission Plant**	$ 74,568	$ 29,447	$ 604	$ 15,816	$ 5,794	$ 1,484	$ 462	$ 4,496	$ 11,178	$ 694	$ 3,430	$ 1,163	D-3
	Distribution Plant													
6)	Land	$ 2,505	$ 1,717	$ 54	$ 385	$ 132	$ 23	$ 12	$ 79	$ 33	$ 1	$ 36	$ 33	P-4
7)	Substations	22,941	10,526	155	5,203	2,060	532	187	1,905	979	19	1,014	361	Sched. 12 Pg. 2
8)	Poles	51,376	38,866	1,343	6,669	2,091	252	185	828	231	-	274	637	Sched. 14 Pg. 2
9)	Wire-O.H.	27,759	20,601	695	3,820	1,232	151	108	495	138	-	164	355	Sched. 14 Pg. 2
10)	Underground	4,246	3,190	110	563	178	22	16	71	20	-	23	53	P-2
11)	Line Transformers	26,562	15,565	231	7,164	2,829	-	239	-	-	-	-	534	D-11
12)	Services	14,217	10,107	419	3,253	405	-	33	-	-	-	-	-	C-9
13)	Meters	9,200	7,066	293	1,488	242	2	19	65	15	6	4	-	Schedule 15
14)	Other	67	46	1	10	4	1	20	2	1	-	1	1	P-4
15)	Street Lighting	8,000	-	-	-	-	-	-	-	-	-	-	8,000	Direct
16)	Total	$166,873	$107,684	$ 3,301	$ 28,555	$ 9,173	$ 983	$ 801	$ 3,444	$ 1,417	$ 26	$ 1,516	$ 9,973	
17)	**Gen., Intan, and Future Plant**	$ 5,945	$ 2,957	$ 76	$ 1,168	$ 413	$ 84	$ 34	$ 263	$ 537	$ 28	$ 186	$ 199	P-6
18)	**Total Plant In Service**	$421,337	$209,595	$ 5,348	$ 82,794	$ 29,234	$ 5,936	$ 2,415	$ 18,653	$ 38,093	$ 1,967	$ 13,190	$ 14,112	
	Working Capital													
19)	Cash Fuel	$ 3,042	$ 1,114	$ 30	$ 609	$ 197	$ 69	$ 13	$ 175	$ 586	$ 74	$ 137	$ 38	E-1
20)	Cash-Other	3,358	1,675	47	651	209	45	~~18~~ 11	141	303	~~18~~ 17	100	151	O-2
21)	Mat. & Supp.-Fuel	3,674	1,345	37	735	238	83	16	212	708	89	165	46	E-1
22)	Mat. & Supp.-Other	11,054	5,499	140	2,172	767	156	63	490	959	52	346	370	P-6
23)	Total	$ 21,128	$ 9,633	$ 254	$ 4,167	$ 1,411	$ 353	$ 110	$ 1,018	$ 2,596	$ 233	$ 748	$ 605	
24)	**Total Rate Base**	$442,465	$219,228	$ 5,602	$ 86,961	$ 30,645	$ 6,289	$ 2,525	$ 19,671	$ 40,689	$ 2,200	$ 13,938	$ 14,717	

SCHEDULE 10

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For The Year Ending March 31, 1977

Class Non-Coincident Responsibility

($000)

	Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Industrial Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1) Production Plant	$173,951	$ 73,807	$ 1,096	$ 36,025	$ 13,429	$ 3,009	$ 1,218	$ 10,072	$ 21,309	$ 3,949	$ 7,497	$ 2,540	D-17
2) Transmission Plant	$ 74,568	$ 31,639	$ 470	$ 15,443	$ 5,757	$ 1,290	$ 522	$ 4,317	$ 9,134	$ 1,693	$ 3,214	$ 1,089	D-17
Distribution Plant													
3) Land	$ 2,505	$ 1,717	$ 54	$ 385	$ 132	$ 23	$ 12	$ 79	$ 33	$ 1	$ 36	$ 33	P-4
4) Substations	22,941	10,526	155	5,203	2,060	532	187	1,905	979	19	1,014	361	Sched 12 Pg 2
5) Poles	51,376	38,866	1,343	6,669	2,091	252	185	828	231	-	274	637	Sched 14 Pg 2
6) Wire - O.H.	27,759	20,601	695	3,820	1,232	151	108	495	138	-	164	355	Sched 14 Pg 2
7) Underground	4,246	3,190	110	563	178	22	16	71	20	-	23	53	P-2
8) Line Transformers	26,562	15,565	231	7,164	2,829	-	239	-	-	-	-	534	D-11
9) Services	14,217	10,107	419	3,253	405	-	33	-	-	-	-	-	C-9
10) Meters	9,200	7,066	293	1,488	242	2	19	65	15	6	4	-	Sched 15
11) Other	67	46	1	10	4	1	2	1	1	-	1	-	P-4
12) Street Lighting	8,000	-	-	-	-	-	-	-	-	-	-	8,000	Direct
13) Total	$166,873	$107,684	$ 3,301	$ 28,555	$ 9,173	$ 983	$ 801	$ 3,444	$ 1,417	$ 26	$ 1,516	$ 9,973	
14) General Intangible & Future Use	$ 5,945	$ 3,050	$ 70	$ 1,146	$ 406	$ 76	$ 36	$ 255	$ 456	$ 81	$ 175	$ 194	P-7
15) Total Plant In Service	$421,337	$216,180	$ 4,937	$ 81,169	$ 28,765	$ 5,358	$ 2,577	$ 18,088	$ 32,316	$ 5,749	$ 12,402	$ 13,796	
Working Capital													
16) Cash - Fuel	$ 3,042	$ 1,114	$ 30	$ 609	$ 197	$ 69	$ 13	$ 175	$ 586	$ 74	$ 137	$ 38	E-1
17) Cash - Other	3,358	1,735	43	642	212	40	19	139	239	45	96	149	O-3
18) Mat. & Supp. - Fuel	3,674	1,345	37	735	238	83	16	212	708	89	165	46	E-1
19) Mat. & Supp. - Other	11,054	5,672	129	2,130	755	140	67	474	848	152	325	362	P-7
20) Total	$ 21,128	$ 9,866	$ 239	$ 4,116	$ 1,402	$ 332	$ 115	$ 999	$ 2,381	$ 360	$ 723	$ 595	
21) Total Rate Base	$442,465	$226,046	$ 5,176	$ 85,285	$ 30,167	$ 5,690	$ 2,692	$ 19,087	$ 34,697	$ 6,109	$ 13,125	$ 14,391	

SCHEDULE 11

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1977

Coincident Peak Responsiblity

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Cost													
1)	Fuel	$ 59,329	$ 21,726	$ 593	$ 11,872	$ 3,838	$ 1,347	$ 261	$ 3,417	$ 11,427	$ 1,442	$ 2,664	$ 742	E-1
2)	Operating	19,035√	7,879	135	4,197	1,629	345	135	1,131	2,358	-	900	326	D-1
3)	Purchased Power - Fuel	1,807	662	18	362	117	41	8	104	348	44	81	22	E-1
4)	Purchased Power - Other	3,421√	1,416	24	754	293	62	24	203	424	-	162	59	D-1
5)	Total Production	$ 83,592	$ 31,683	$ 770	$ 17,185	$ 5,877	$ 1,795	$ 428	$ 4,855	$ 14,557	$ 1,486	$ 3,807	$ 1,149	
6)	Transmission Operating Cost	$ 2,051√	$ 849	$ 15	$ 452	$ 175	$ 37	$ 15	$ 122	$ 254	$ -	$ 97	$ 35	D-1
	Distribution Operating Cost													
7)	Land	$ 1,135	$ 817	$ 24	$ 154	$ 51	$ 9	$ 5	$ 33	$ 14	$ -	$ 15	$ 13	P-3
8)	Substations	1,872	975	11	367	143	40	13	143	78	1	77	24	P-8
9)	Overhead Lines	2,403	1,868	61	285	86	11	8	36	10	-	11	27	P-1
10)	U. G. Lines	133	103	3	16	5	1	-	2	1	-	1	1	P-1
11)	Line Transformers	812	530	6	185	71	-	7	-	-	-	-	13	D-5
12)	Services	1,249	888	37	286	35	-	3	-	-	-	-	-	C-9
13)	Meters	767	589	24	124	20	-	2	5	1	1	1	-	Schedule 15
14)	Customer Service & Contracts	926	833	34	52	6	-	1	-	-	-	-	-	Schedule 22
15)	Customer Premise	806	725	29	46	6	-	-	-	-	-	-	-	Schedule 23
16)	Communications	502	286	3	108	39	9	4	30	9	-	9	7	D-7
17)	Street Light	1,325	-	-	-	-	-	-	-	-	-	-	1,325	Direct
18)	Total Distribution	$ 11,930√	$ 7,614	$ 232	$ 1,621	$ 462	$ 70	$ 43	$ 249	$ 113	$ 2	$ 114	$ 1,410	
	Customer Accounting													
19)	Billing	$ 3,178	$ 2,213	$ 87	$ 713	$ 89	$ -	$ 7	$ 10	$ 1	$ 1	$ 1	$ 56	C-10
20)	Customer Service	1,026	737	30	210	28	-	3	4	1	-	-	13	Schedule 24
21)	Credit & Collection	868	562	20	218	58	-	7	-	-	-	-	3	Schedule 25
22)	Total Customer Accounting	$ 5,072√	$ 3,512	$ 137	$ 1,141	$ 175	$ -	$ 12	$ 14	$ 2	$ 1	$ 1	$ 72	
23)	Customer Relations & Information	$ 546√	$ 485	$ 20	$ 31	$ 4	$ -	$ 1	$ -	$ -	$ -	$ -	$ 5	C-1
24)	Administrative & General	$ 3,805	$ 1,968	$ 51	$ 742	$ 248	$ 46	$ 21	$ 156	$ 285	$ 1	$ 115	$ 172	O-1
25)	Depreciation	$ 18,079	$ 9,399	$ 217	$ 3,497	$ 1,266	$ 235	$ 109	$ 777	$ 1,399	$ 2	$ 571	$ 607	P-5
26)	Grants in Lieu of Taxes	$ 2,954	$ 1,536	$ 35	$ 571	$ 207	$ 39	$ 18	$ 127	$ 229	$ -	$ 93	$ 99	P-5
27)	Total Cost	$128,029	$ 57,046	$ 1,477	$ 25,240	$ 8,414	$ 2,222	$ 652	$ 6,300	$ 16,839	$ 1,492	$ 4,798	$ 3,549	
28)	Total Revenue	$205,087	$ 80,560	$ 2,391	$ 49,332	$ 13,880	$ 3,387	$ 1,227	$ 9,784	$ 28,483	$ 3,088	$ 7,382	$ 5,573	Schedule 16
29)	Return	$ 77,058	$ 23,514	$ 914	$ 24,092	$ 5,466	$ 1,165	$ 575	$ 3,484	$ 11,644	$ 1,596	$ 2,584	$ 2,024	
30)	Rate of Return	17.42	10.27	17.29	28.14	17.66	20.10	21.90	18.20	33.25	835.60	18.38	13.72	
		4.54	(.30)	7.17	13.86	.72	18.84	8.76	13.59	5.01	659.16	6.62	3.06	
31)	Percentage of Average	100.00	58.96	99.25	161.54	101.38	115.39	125.72	104.48	190.87	4,796.79	105.51	78.76	
			(6.61)	157.93	305.29	15.86	414.98	192.95	299.[illegible]	110.35	14,518.94	145.81	67.46	

SCH. 19

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Cost

For the Year Ended March 31, 1977

Coincident Peak and Average

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Cost													
1)	Fuel	$ 59,329	$ 21,726	$ 593	$ 11,872	$ 3,838	$ 1,347	$ 261	$ 3,417	$ 11,427	$ 1,442	$ 2,664	$ 742	E-1
2)	Operating	19,035	7,517	154	4,037	1,479	379	118	1,148	2,853	177	876	297	D-3
3)	Purchased Power - Fuel	1,807	662	18	362	117	41	8	104	348	44	81	22	E-1
4)	Purchased Power - Other	3,421	1,351	28	726	266	68	21	206	513	32	157	53	D-3
5)	Total Production	$ 83,592	$ 31,256	$ 793	$ 16,997	$ 5,700	$ 1,835	$ 408	$ 4,875	$ 15,141	$ 1,695	$ 3,778	$ 1,114	
6)	Transmission Operating Cost	$ 2,051	$ 810	$ 17	$ 435	$ 159	$ 41	$ 13	$ 124	$ 307	$ 19	$ 94	$ 32	D-3
	Distribution Operating Cost													
7)	Land	$ 1,135	$ 778	$ 24	$ 175	$ 60	$ 11	$ 5	$ 36	$ 15	$ -	$ 16	$ 15	P-4
8)	Substations	1,872	859	13	425	168	43	15	155	80	2	83	29	P-9
9)	Overhead Lines	2,403	1,807	62	318	101	12	9	40	11	-	13	30	P-2
10)	U. G. Lines	133	99	3	18	6	1	2	1	-	-	1	2	P-2
11)	Line Transformers	812	476	7	219	87	-	7	-	-	-	-	16	D-11
12)	Services	1,249	887	37	286	36	-	3	-	-	-	-	-	C-9
13)	Meters	767	589	24	124	20	-	2	5	1	1	1	-	Schedule 15
14)	Customer Serv. & Cont.	926	833	34	52	6	-	1	-	-	-	-	-	Schedule 22
15)	Customer Premise	806	725	29	46	6	-	-	-	-	-	-	-	Schedule 23
16)	Communications	502	252	4	123	47	10	4	33	9	-	11	9	D-13
17)	Street Lights	1,325	-	-	-	-	-	-	-	-	-	-	1,325	Direct
18)	Total Distribution	$ 11,930	$ 7,305	$ 237	$ 1,786	$ 537	$ 77	$ 48	$ 270	$ 116	$ 3	$ 125	$ 1,426	
	Customer Accounting													
19)	Billing	$ 3,178	$ 2,213	$ 87	$ 713	$ 89	$ -	$ 7	$ 10	$ 1	$ 1	$ 1	$ 56	C-10
20)	Customer Service	1,026	737	30	210	28	-	3	4	1	-	-	13	Schedule 24
21)	Credit & Collection	868	562	20	218	58	-	7	-	-	-	-	3	Schedule 25
22)	Total Customer Accounting	$ 5,072	$ 3,512	$ 137	$ 1,141	$ 175	$ -	$ 17	$ 14	$ 2	$ 1	$ 1	$ 72	
23)	Customer Relations & Information	$ 546	$ 485	$ 20	$ 31	$ 4	$ -	$ 1	$ -	$ -	$ -	$ -	$ 5	C-1
24)	Administrative & General	$ 3,805	$ 1,898	$ 54	$ 738	$ 237	$ 51	$ 20	$ 160	$ 343	$ 21	$ 113	$ 170	O-2
25)	Depreciation	$ 18,079	$ 8,992	$ 230	$ 3,552	$ 1,255	$ 255	$ 103	$ 801	$ 1,634	$ 85	$ 566	$ 606	P-6
26)	Grants in Lieu of Taxes	$ 2,954	$ 1,469	$ 38	$ 580	$ 205	$ 42	$ 17	$ 131	$ 267	$ 14	$ 92	$ 99	P-6
27)	Total Cost	$128,029	$ 55,727	$ 1,526	$ 25,260	$ 8,272	$ 2,301	$ 627	$ 6,375	$ 17,810	$ 1,838	$ 4,769	$ 3,524	
28)	Total Revenue	$205,087	$ 80,560	$ 2,391	$ 49,332	$ 13,880	$ 3,387	$ 1,227	$ 9,784	$ 28,483	$ 3,088	$ 7,382	$ 5,573	Schedule 16
29)	Return	$ 77,058	$ 24,833	$ 865	$ 24,072	$ 5,608	$ 1,086	$ 600	$ 3,409	$ 10,673	$ 1,250	$ 2,613	$ 2,049	
30)	Rate of Return	17.42	11.33	15.44	27.68	18.30	17.27	23.76	17.33	26.23	56.82	18.75	13.92	
31)	Percentage of Average	100.00	65.04	88.63	158.90	105.05	99.14	136.40	99.48	150.57	326.18	107.64	79.91	

SCH. 20

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1977

Class Non-Coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Cost													
1)	Fuel	$ 59,329	$ 21,726	$ 593	$ 11,872	$ 3,838	$ 1,347	$ 261	$ 3,417	$ 11,427	$ 1,442	$ 2,664	$ 742	E-1
2)	Operating	19,035	8,094	120	3,946	1,509	329	137	1,119	2,235	432	836	278	D-17
3)	Purchased Power - Fuel	1,807	662	18	362	117	41	8	104	348	44	81	22	E-1
4)	Purchased Power - Other	3,421	1,455	21	709	271	59	25	201	402	78	150	50	D-17
5)	Total Production	$ 83,592	$ 31,937	$ 752	$ 16,889	$ 5,735	$ 1,776	$ 431	$ 4,841	$ 14,412	$ 1,996	$ 3,731	$ 1,092	
6)	**Transmission Operating Cost**	$ 2,051	$ 872	$ 13	$ 425	$ 163	$ 35	$ 15	$ 121	$ 241	$ 46	$ 90	$ 30	D-17
	Distribution Operating Cost													
7)	Land	$ 1,135	$ 778	$ 24	$ 175	$ 60	$ 11	$ 5	$ 36	$ 15	$ -	$ 16	$ 15	P-4
8)	Substations	1,872	859	13	425	168	43	15	155	80	2	83	29	P-9
9)	Overhead Lines	2,403	1,806	62	319	101	12	9	40	11	-	13	30	P-2
10)	U. G. Lines	133	100	3	18	5	1	-	2	1	-	1	2	P-2
11)	Line Transformers	812	476	7	219	87	-	7	-	-	-	-	16	D-11
12)	Services	1,249	888	37	286	35	-	3	-	-	-	-	-	C-9
13)	Meters	767	589	24	124	20	-	2	5	1	1	1	-	Schedule 15
14)	Customer Service & Contracts	926	833	34	52	6	1	-	-	-	-	-	-	Schedule 22
15)	Customer Premise	806	725	29	46	6	-	-	-	-	-	-	-	Schedule 23
16)	Communications	502	252	4	123	47	10	4	33	9	-	11	9	D-13
17)	Street Lights	1,325	-	-	-	-	-	-	-	-	-	-	1,325	Direct
18)	Total Distribution	$ 11,930	$ 7,306	$ 237	$ 1,787	$ 535	$ 78	$ 45	$ 271	$ 117	$ 3	$ 125	$ 1,426	
	Customer Accounting													
19)	Billing	$ 3,178	$ 2,213	$ 87	$ 713	$ 89	$ -	$ 7	$ 10	$ 1	$ 1	$ 1	$ 56	C-10
20)	Customer Service	1,026	737	30	210	28	-	3	4	1	-	-	13	Schedule 24
21)	Credit & Collection	868	562	20	218	58	-	7	-	-	-	-	3	Schedule 25
22)	Total Customer Accounting	$ 5,072	$ 3,512	$ 137	$ 1,141	$ 175	$ -	$ 17	$ 14	$ 2	$ 1	$ 1	$ 72	
23)	**Customer Relations & Information**	$ 546	$ 485	$ 20	$ 31	$ 4	$ -	$ 1	$ -	$ -	$ -	$ -	$ 5	C-1
24)	**Administrative & General**	$ 3,805	$ 1,966	$ 49	$ 727	$ 240	$ 45	$ 22	$ 156	$ 271	$ 51	$ 109	$ 169	O-3
25)	**Depreciation**	$ 18,079	$ 9,276	$ 211	$ 3,484	$ 1,235	$ 230	$ 110	$ 776	$ 1,387	$ 248	$ 531	$ 591	P-7
26)	**Grants in Lieu of Taxes**	$ 2,954	$ 1,516	$ 34	$ 569	$ 202	$ 37	$ 18	$ 127	$ 227	$ 40	$ 87	$ 97	P-7
27)	**Total Cost**	$128,029	$ 56,870	$ 1,453	$ 25,053	$ 8,289	$ 2,201	$ 659	$ 6,306	$ 16,657	$ 2,385	$ 4,674	$ 3,482	
28)	**Total Revenue**	$205,087	$ 80,560	$ 2,391	$ 49,332	$ 13,880	$ 3,387	$ 1,227	$ 9,784	$ 28,483	$ 3,088	$ 7,382	$ 5,573	Schedule 16
29)	**Return**	$ 77,058	$ 23,690	$ 938	$ 24,279	$ 5,591	$ 1,186	$ 568	$ 3,478	$ 11,826	$ 703	$ 2,708	$ 2,091	
30)	**Rate of Return**	17.42 4.54	10.48 (.22)	18.12 7.79	28.47 14.14	18.53 1.15	20.84 19.56	21.10 8.28	18.22 13.60	34.08 5.58	11.51 5.99	20.63 2.04	14.53 3.61	
31)	**Percentage of Return**	100.00	60.16 (4.85)	104.02 171.59	163.43 311.45	106.37 25.33	119.63 430.84	121.13 182.38	104.59 299.56	195.64 122.91	66.07 131.94	118.43 177.09	83.41 79.52	

SCH. 21

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For the Year Ended March 31, 1978

Coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial to 249 KVA (7)	Industrial 250 to 3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1)	Production Plant	$311,415	$131,108	$ 2,273	$ 70,909	$ 24,913	$ 6,166	$ 3,239	$ 20,055	$ 32,699	$ -	$ 14,232	$ 5,824	D-2
2)	Transmission Plant	$ 85,815	$ 36,128	$ 626	$ 19,540	$ 6,865	$ 1,699	$ 892	$ 5,527	$ 9,011	$ -	$ 3,922	$ 1,605	D-2
	Distribution Plant													
3)	Land	$ 2,508	$ 1,822	$ 50	$ 342	$ 100	$ 21	$ 15	$ 72	$ 30	$ -	$ 27	$ 29	P-12
4)	Substations	23,184	12,080	141	4,607	1,620	507	247	1,826	951	18	871	316	Sched 32 Pg. 1
5)	Poles	58,390	45,757	1,376	6,879	1,833	268	274	887	257	-	228	631	Sched 34 Pg. 1
6)	Wire-O.H.	31,507	24,316	709	3,915	1,076	160	160	531	154	-	136	350	Sched 34 Pg. 2
7)	Underground	4,849	3,780	113	582	157	23	23	77	22	-	19	53	P-10
8)	Line Transformers	29,154	19,008	225	6,743	2,332	-	350	-	-	-	-	496	D-6
9)	Services	15,870	11,333	424	3,685	382	-	46	-	-	-	-	-	C-11
10)	Meters	9,556	7,379	275	1,568	213	2	36	68	15	7	3	-	Schedule 35
11)	Other	278	202	6	38	11	2	2	8	3	-	3	3	P-12
12)	Street Lighting	8,253	-	-	-	-	-	-	-	-	-	-	8,253	Direct
13)	Total Distribution Plant	$183,549	$125,677	$ 3,319	$ 28,359	$ 7,724	$ 983	$ 1,143	$ 3,469	$ 1,432	$ 25	$ 1,287	$ 10,131	
14)	General Plant, Intangible, and Future Use	$ 6,142	$ 3,097	$ 66	$ 1,257	$ 418	$ 93	$ 56	$ 307	$ 456	$ 1	$ 206	$ 185	P-14
	Working Capital													
15)	Cash Fuel	$ 8,528	$ 3,102	$ 83	$ 1,756	$ 544	$ 199	$ 51	$ 519	$ 1,538	$ 229	$ 395	$ 112	E-2
16)	Cash	4,361	1,838	47	883	271	85	29	237	608	73	173	117	O-4
17)	Mat. Supp. - Fuel	7,266	2,643	71	1,496	464	169	44	142	1,310	195	336	96	E-2
18)	Mat. Supp. - Other	11,266	5,601	121	2,305	766	171	103	563	837	1	378	340	P-14
19)	Total Working Capital	$ 31,421	$ 13,264	$ 322	$ 6,440	$ 2,045	$ 624	$ 227	$ 1,761	$ 4,293	$ 498	$ 1,282	$ 665	
20)	Total Rate Base	$618,342	$309,271	$ 6,606	$126,505	$ 41,965	$ 9,565	$ 5,557	$ 31,119	$ 47,891	$ 524	$ 20,929	$ 18,410	

SCHEDULE 29

NOVA SCOTIA POWER CORPORATION

Allocation Of Rate Base

For The Year Ended March 31, 1978

Coincident Peak And Average Responsibility

($000)

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
	Production Plant													
1)	Steam	$126,727	$ 50,526	$ 1,052	$ 27,778	$ 9,314	$ 2,674	$ 1,128	$ 8,022	$ 17,007	$ 1,293	$ 5,829	$ 2,104	D-4
2)	Hydro	162,797	68,538	1,188	37,069	13,024	3,223	1,693	10,484	17,094	-	7,440	3,044	D-2
3)	Gas Turbine	21,891	9,216	160	4,985	1,751	433	228	1,410	2,299	-	1,000	409	D-2
4)	Total	$311,415	$128,280	$ 2,400	$ 69,832	$ 24,089	$ 6,330	$ 3,049	$ 19,916	$ 36,400	$ 1,293	$ 14,269	$ 5,557	
5)	Transmission Plant	$ 85,815	$ 34,214	$ 712	$ 18,811	$ 6,307	$ 1,811	$ 764	$ 5,432	$ 11,516	$ 875	$ 3,948	$ 1,425	D-4
	Distribution Plant													
6)	Land	$ 2,508	$ 1,737	$ 51	$ 385	$ 118	$ 23	$ 17	$ 82	$ 31	$ 1	$ 30	$ 33	D-13
7)	Substations	23,184	10,603	164	5,311	1,903	559	277	2,054	977	18	934	384	Sched 32 Pg 2
9)	Poles	58,390	44,282	1,401	7,660	2,149	302	308	1,038	274	-	269	707	Sched 34 Pg 2
9)	Wire - O.H.	31,507	23,434	725	4,362	1,265	180	180	620	164	-	161	396	Sched 34 Pg 2
10)	Underground	4,849	3,653	115	649	184	26	26	89	24	-	23	60	P-11
11)	Line Transformers	29,154	17,073	262	7,968	2,831	-	402	-	-	-	-	618	D-12
12)	Services	15,870	11,333	424	3,685	382	-	46	-	-	-	-	-	C-11
13)	Meters	9,556	7,379	275	1,568	213	2	26	68	15	7	3	-	Sched 35
14)	Other	278	192	6	43	13	3	2	9	3	-	3	4	P-13
15)	Street Lighting	8,253	-	-	-	-	-	-	-	-	-	-	8,253	Direct
16)	Total	$183,549	$119,686	$ 3,423	$ 31,651	$ 9,058	$ 1,095	$ 1,284	$ 3,960	$ 1,488	$ 26	$ 1,423	$ 10,455	
17)	Gen. Plant, Intangible & Future Use	$ 6,142	$ 2,984	$ 69	$ 1,272	$ 417	$ 98	$ 54	$ 310	$ 523	$ 23	$ 208	$ 184	P-15
	Working Capital													
18)	Cash Fuel	$ 8,528	$ 3,102	$ 83	$ 1,756	$ 544	$ 199	$ 51	$ 518	$ 1,538	$ 229	$ 395	$ 113	E-2
19)	Cash	4,361	1,805	49	881	267	86	28	237	636	83	174	115	O-5
20)	Mat. & Supp. - Fuel	7,266	2,643	71	1,496	464	169	44	442	1,310	195	336	96	E-2
21)	Mat. & Supp. - Other	11,266	5,474	126	2,333	765	179	99	569	959	43	381	338	P-15
22)	Total	$ 31,421	$ 13,024	$ 329	$ 6,466	$ 2,040	$ 633	$ 222	$ 1,766	$ 4,443	$ 550	$ 1,286	$ 662	
23)	Total Rate Base	$618,342	$298,188	$ 6,933	$128,032	$ 41,911	$ 9,967	$ 5,373	$ 31,384	$ 54,370	$ 2,767	$ 21,134	$ 18,283	

31,421
586,921

SCHEDULE 30

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For the Year Ended March 31, 1978

Class Non-Coincident Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1)	Production Plant	$311,415	$133,192	$ 2,055	$ 65,833	$ 22,702	$ 5,761	$ 3,363	$ 20,398	$ 32,356	$ 7,848	$ 13,080	$ 4,827	D-18
2)	Transmission Plant	$ 85,815	$ 36,703	$ 566	$ 18,141	$ 6,256	$ 1,588	$ 927	$ 5,621	$ 8,916	$ 2,163	$ 3,604	$ 1,330	D-18
	Distribution Plant													
3)	Land	$ 2,508	$ 1,737	$ 51	$ 385	$ 118	$ 23	$ 17	$ 82	$ 31	$ 1	$ 30	$ 33	P-13
4)	Substations	23,184	10,603	164	5,311	1,903	559	277	2,054	977	18	934	384	Sched 32 Pg 2
5)	Poles	58,390	44,282	1,401	7,660	2,149	302	308	1,038	274	-	269	707	Sched 34 Pg 2
6)	Wire - O.H.	31,507	23,434	725	4,382	1,265	180	180	620	164	-	161	396	Sched 34 Pg 2
7)	Underground	4,849	3,653	114	649	184	26	26	89	24	-	24	60	P-11
8)	Line Transformers	29,154	17,073	262	7,968	2,831	-	402	-	-	-	-	618	D-12
9)	Services	15,870	11,333	424	3,685	382	-	46	-	-	-	-	-	C-11
10)	Meters	9,556	7,379	275	1,568	213	2	26	68	15	7	3	-	Schedule 35
11)	Other	278	192	6	43	13	2	3	9	3	-	3	4	P-13
12)	Street Lighting	8,253	-	-	-	-	-	-	-	-	-	-	8,253	Direct
13)	Total	$183,549	$119,686	$ 3,422	$ 31,651	$ 9,058	$ 1,094	$ 1,285	$ 3,960	$ 1,488	$ 26	$ 1,424	$ 10,455	
14)	Gen. Plant, Intan. & Future Use	$ 6,142	$ 3,062	$ 64	$ 1,223	$ 402	$ 89	$ 59	$ 317	$ 452	$ 106	$ 192	$ 176	P-16
	Working Capital													
15)	Cash Fuel	$ 8,528	$ 3,102	$ 83	$ 1,756	$ 544	$ 199	$ 51	$ 519	$ 1,538	$ 229	$ 395	$ 112	E-2
16)	Cash	4,361	1,832	47	874	267	84	30	239	607	97	170	114	O-6
17)	Mat. & Supp. - Fuel	7,266	2,643	71	1,496	464	169	44	442	1,310	195	336	96	E-2
18)	Mat. & Supp. - Other	11,256	5,617	117	2,243	738	164	108	581	829	195	352	322	P-16
19)	Total	$ 31,421	$ 13,194	$ 318	$ 6,369	$ 2,013	$ 616	$ 233	$ 1,781	$ 4,284	$ 716	$ 1,253	$ 644	
20)	Total Rate Base	$618,342	$305,837	$ 6,425	$123,217	$ 40,431	$ 9,148	$ 5,967	$ 32,077	$ 47,496	$ 10,859	$ 19,553	$ 17,432	

SCHEDULE 31

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1978

Coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
	Production Costs													
1)	Fuel	$ 76,436	$ 27,807	$ 741	$ 15,746	$ 4,877	$ 1,781	$ 459	$ 4,647	$ 13,781	$ 2,049	$ 3,539	$ 1,009	E-2
2)	Operating	20,558	8,655	150	4,681	1,645	407	214	1,324	2,159	-	939	384	D-2
3)	Purchased Power - Fuel	1,064	387	10	219	68	25	6	65	192	29	49	14	E-2
4)	Purchased Power - Other	3,393	1,429	25	773	271	67	35	219	356	-	155	63	D-2
5)	Total Production	$101,451	$ 38,278	$ 926	$ 21,419	$ 6,861	$ 2,280	$ 714	$ 6,255	$ 16,488	$ 2,078	$ 4,682	$ 1,470	
6)	Transmission Operating Costs	$ 2,708	$ 1,140	$ 20	$ 616	$ 217	$ 54	$ 28	$ 174	$ 284	$ -	$ 124	$ 51	D-2
	Distribution Operating Costs													
7)	Land	$ 1,067	$ 775	$ 21	$ 145	$ 43	$ 9	$ 6	$ 31	$ 13	$ -	$ 12	$ 12	P-12
8)	Substations	1,896	987	12	377	132	42	20	149	78	2	71	26	P-17
9)	Overhead Lines	2,804	2,186	65	337	91	13	13	44	13	-	11	31	P-10
10)	U. G. Lines	204	159	5	24	7	1	1	3	1	-	1	2	P-10
11)	Line Transformers	866	565	7	200	69	-	10	-	-	-	-	15	D-6
12)	Services	1,284	917	34	298	31	-	4	-	-	-	-	-	C-11
13)	Meters	900	695	26	148	20	-	2	6	2	1	-	-	Schedule 35
14)	Customer Service & Contracts	1,044	940	35	62	6	-	1	-	-	-	-	-	Schedule 42
15)	Customer Premise	733	660	25	43	4	-	1	-	-	-	-	-	Schedule 43
16)	Communications	507	287	3	108	36	10	6	32	9	-	8	8	D-8
17)	Street Lights	1,618	-	-	-	-	-	-	-	-	-	-	1,618	Direct
18)	Total Distribution	$ 12,923	$ 8,171	$ 233	$ 1,742	$ 439	$ 75	$ 64	$ 265	$ 116	$ 3	$ 103	$ 1,712	
	Customer Accounting													
19)	Billing	$ 3,258	$ 2,262	$ 87	$ 755	$ 79	$ -	$ 9	$ 11	$ 1	$ 1	$ 1	$ 52	C-12
20)	Customer Service	1,095	784	30	233	26	-	3	5	1	-	-	13	Schedule 44
21)	Credit & Collection	1,427	777	27	213	54	-	5	-	347	-	-	4	Schedule 45
22)	Total Customer Accounting	$ 5,780	$ 3,823	$ 144	$ 1,201	$ 159	$ -	$ 17	$ 16	$ 349	$ 1	$ 1	$ 69	
23)	Customer Relations & Info.	$ 755	$ 674	$ 25	$ 44	$ 5	$ -	$ 1	$ -	$ -	$ -	$ -	$ 6	C-2
24)	Admin. & General	$ 4,552	$ 1,918	$ 50	$ 921	$ 263	$ 89	$ 30	$ 247	$ 635	$ 76	$ 181	$ 122	O-4
25)	Depreciation	$ 19,692	$ 9,931	$ 211	$ 4,029	$ 1,339	$ 299	$ 179	$ 984	$ 1,463	$ 2	$ 660	$ 595	P-14
26)	Grants in Lieu of Taxes.	$ 3,623	$ 1,827	$ 39	$ 741	$ 246	$ 55	$ 33	$ 181	$ 269	$ -	$ 122	$ 110	P-14
27)	Total Cost	$151,484	$ 65,762	$ 1,648	$ 30,713	$ 9,549	$ 2,852	$ 1,066	$ 8,122	$ 19,604	$ 2,160	$ 5,873	$ 4,135	
28)	Total Revenue	$204,376	$ 78,440	$ 2,350	$ 49,645	$ 13,816	$ 3,649	$ 1,673	$ 10,827	$ 27,631	$ 3,330	$ 7,408	$ 5,607	Schedule 36
29)	Return	$ 52,892	$ 12,678	$ 702	$ 18,932	$ 4,267	$ 797	$ 607	$ 2,705	$ 8,027	$ 1,170	$ 1,535	$ 1,472	
30)	Rate of Return	8.55	4.10	10.63	14.97	10.17	8.33	10.92	8.69	16.76	223.28	7.33	8.00	
31)	Percentage of Average	100.00	47.95	124.33	175.09	118.95	97.43	127.22	101.64	196.03	2611.46	85.73	93.57	

SCHEDULE 39

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1978

Coincident Peak & Average Responsibility

($000)

		Total Company Less Steam & Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Costs													
1)	Fuel	$ 76,436	$ 27,807	$ 741	$ 15,746	$ 4,877	$ 1,781	$ 459	$ 4,647	$ 13,781	$ 2,049	$ 3,539	$ 1,009	E-2
2)	Operating	20,558	8,196	171	4,506	1,511	434	183	1,301	2,759	210	946	341	D-4
3)	Purchased Power - Fuel	1,064	387	10	219	68	25	6	65	192	29	49	14	E-2
4)	Purchased Power - Other	3,393	1,353	28	744	249	72	30	215	455	35	156	56	D-4
5)	Total Production	$101,451	$ 37,743	$ 950	$ 21,215	$ 6,705	$ 2,312	$ 678	$ 6,228	$ 17,187	$ 2,323	$ 4,690	$ 1,420	
6)	Transmission Operating Costs	$ 2,708	$ 1,080	$ 22	$ 594	$ 199	$ 57	$ 24	$ 171	$ 363	$ 28	$ 125	$ 45	D-4
	Distribution Operating Costs													
7)	Land	$ 1,067	$ 739	$ 22	$ 164	$ 50	$ 10	$ 7	$ 35	$ 13	$ -	$ 13	$ 14	P-13
8)	Substations	1,896	867	13	434	156	46	23	168	80	2	76	31	P-18
9)	Overhead Lines	2,801	2,112	66	375	107	15	15	52	14	-	13	35	P-11
10)	U. G. Lines	204	154	5	27	8	1	1	4	1	-	1	2	P-11
11)	Line Transformers	866	508	8	236	84	-	12	-	-	-	-	18	D-12
12)	Services	1,284	917	34	298	31	-	4	-	-	-	-	-	C-11
13)	Meters	900	695	26	148	20	-	2	6	2	1	-	-	Schedule 35
14)	Cust. Serv. & Contracts	1,041	940	35	62	6	-	1	-	-	-	-	-	Schedule 42
15)	Customer Premise	733	660	25	43	4	-	1	-	-	-	-	-	Schedule 43
16)	Communications	507	252	4	125	43	11	6	37	10	-	10	9	D-14
17)	Street Lighting	1,613	-	-	-	-	-	-	-	-	-	-	1,618	Direct
18)	Total Distribution	$ 12,923	$ 7,844	$ 238	$ 1,912	$ 509	$ 83	$ 72	$ 302	$ 120	$ 3	$ 113	$ 1,727	
	Customer Accounting													
19)	Billing	$ 3,253	$ 2,262	$ 87	$ 755	$ 79	$ -	$ 9	$ 11	$ 1	$ 1	$ 1	$ 52	C-12
20)	Customer Service	1,095	784	30	233	26	-	3	5	1	-	-	13	Schedule 44
21)	Credit & Collection	1,427	777	27	213	54	-	5	-	347	-	-	4	Schedule 45
22)	Total Customer Accounting	$ 5,780	$ 3,823	$ 144	$ 1,201	$ 159	$ -	$ 17	$ 16	$ 349	$ 1	$ 1	$ 69	
23)	Customer Relations & Information	$ 755	$ 674	$ 25	$ 44	$ 5	$ -	$ 1	$ -	$ -	$ -	$ -	$ 6	C-2
24)	Admin. & General	$ 4,552	$ 1,884	$ 51	$ 920	$ 279	$ 90	$ 29	$ 247	$ 664	$ 86	$ 182	$ 120	O-5
25)	Depreciation	$ 19,692	$ 9,568	$ 221	$ 4,078	$ 1,337	$ 313	$ 173	$ 994	$ 1,676	$ 75	$ 666	$ 591	P-15
26)	Grants In Lieu of Taxes	$ 3,623	$ 1,760	$ 41	$ 750	$ 246	$ 58	$ 32	$ 183	$ 308	$ 14	$ 122	$ 109	P-15
27)	Total Cost	$151,484	$ 64,376	$ 1,692	$ 30,714	$ 9,439	$ 2,913	$ 1,026	$ 8,141	$ 20,667	$ 2,530	$ 5,899	$ 4,087	
28)	Total Revenue	$204,376	$ 78,440	$ 2,350	$ 49,645	$ 13,816	$ 3,649	$ 1,673	$ 10,827	$ 27,631	$ 3,330	$ 7,408	$ 5,607	Schedule 36
29)	Return	$ 52,892	$ 14,064	$ 658	$ 18,931	$ 4,377	$ 736	$ 647	$ 2,686	$ 6,964	$ 800	$ 1,509	$ 1,520	
30)	Rate of Return	8.55	4.72	9.49	14.79	10.44	7.38	12.04	8.56	12.81	28.91	7.14	8.31	
31)	Percentage of Average	100.00	55.20	110.99	172.98	122.11	86.32	140.82	100.12	149.82	338.13	83.51	97.19	

SCHEDULE 40

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1978

Class Non-coincident Peak Responsibility

($000)

		Total Company Less Stoam and Joint (1)	Domestic (2)	General-Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptable Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Costs													
1)	Fuel	$ 76,436	$ 27,807	$ 741	$ 15,746	$ 4,877	$ 1,781	$ 459	$ 4,647	$ 13,781	$ 2,049	$ 3,539	$ 1,009	E-2
2)	Operating	20,558	8,793	136	4,346	1,499	380	222	1,346	2,136	518	863	319	D-18
3)	Purchased Power-Fuel	1,064	387	10	219	68	25	6	65	192	29	49	14	E-2
4)	Purchased Power-Other	3,393	1,451	22	717	247	63	37	222	353	86	142	53	D-18
5)	Total Production	$101,451	$ 38,438	$ 909	$ 21,028	$ 6,691	$ 2,249	$ 734	$ 6,280	$ 16,462	$ 2,682	$ 4,593	$ 1,395	
6)	**Transmission Operating Costs**	$ 2,708	$ 1,158	$ 18	$ 573	$ 198	$ 50	$ 29	$ 177	$ 281	$ 68	$ 114	$ 42	D-18
	Distribution Operating Costs													
7)	Land	$ 1,067	$ 739	$ 22	$ 164	$ 50	$ 10	$ 7	$ 35	$ 13	$ -	$ 13	$ 14	P-13
8)	Substations	1,896	867	13	434	156	46	23	168	80	2	76	31	P-18
9)	Overhead Lines	2,904	2,112	66	375	107	15	15	52	14	-	13	35	P-11
10)	U. Ground Lines	204	154	5	27	8	1	1	4	1	-	1	2	P-11
11)	Line Transformers	866	508	8	236	84	-	12	-	-	-	-	18	D-12
12)	Services	1,284	917	34	298	31	-	4	-	-	-	-	-	C-11
13)	Meters	900	695	26	148	20	-	2	6	2	1	-	-	Schedule 35
14)	Cust. Serv & Contracts	1,044	940	35	62	6	-	1	-	-	-	-	-	Schedule 42
15)	Customer Premise	733	660	25	43	4	-	1	-	-	-	-	-	Schedule 43
16)	Communications	507	252	4	125	43	11	6	37	10	-	10	9	D-14
17)	St. Lighting	1,618	-	-	-	-	-	-	-	-	-	-	1,618	Direct
18)	Total Distribution	$ 12,923	$ 7,844	$ 238	$ 1,912	$ 509	$ 83	$ 72	$ 302	$ 120	$ 3	$ 113	$ 1,727	
	Customer Accounting													
19)	Billing	$ 3,258	$ 2,262	$ 87	$ 755	$ 79	$ -	$ 9	$ 11	$ 1	$ 1	$ 1	$ 52	C-12
20)	Customer Service	1,095	784	30	233	26	-	3	5	1	-	-	13	Schedule 44
21)	Credit & Collection	1,427	777	27	213	54	-	5	-	347	-	-	4	Schedule 45
22)	Total Customer Acc.	$ 5,780	$ 3,823	$ 144	$ 1,201	$ 159	$ -	$ 17	$ 16	$ 349	$ 1	$ 1	$ 69	
23)	**Customer Relations & Information**	$ 755	$ 674	$ 25	$ 44	$ 5	$ -	$ 1	$ -	$ -	$ -	$ -	$ 6	C-2
24)	**Admin. & General**	$ 4,552	$ 1,912	$ 49	$ 912	$ 279	$ 88	$ 31	$ 249	$ 634	$ 101	$ 178	$ 119	0-6
25)	**Depreciation**	$ 19,692	$ 9,818	$ 205	$ 3,921	$ 1,290	$ 286	$ 189	$ 1,016	$ 1,449	$ 341	$ 614	$ 563	P-16
26)	**Grants in Lieu of Taxes**	$ 3,623	$ 1,806	$ 38	$ 721	$ 237	$ 52	$ 35	$ 187	$ 267	$ 63	$ 113	$ 104	P-16
27)	**Total Cost**	$151,484	$ 65,473	$ 1,626	$ 30,312	$ 9,368	$ 2,808	$ 1,098	$ 8,227	$ 19,562	$ 3,259	$ 5,726	$ 4,025	
28)	**Total Revenue**	$204,376	$ 78,440	$ 2,350	$ 49,645	$ 13,816	$ 3,649	$ 1,673	$ 10,827	$ 27,631	$ 3,330	$ 7,408	$ 5,607	Schedule 38
29)	**Return**	$ 52,892	$ 12,967	$ 724	$ 19,333	$ 4,448	$ 841	$ 575	$ 2,600	$ 8,069	$ 71	$ 1,682	$ 1,582	
30)	**Rate of Return**	8.55	4.24	11.27	15.69	11.00	9.19	9.80	8.11	16.99	.65	8.60	9.08	
31)	**Percentage of Average**	100.00	49.59	131.81	183.51	128.65	107.48	114.62	94.85	198.71	7.60	100.58	106.20	

SCHEDULE 41

Ernst & Ernst

Cost of Service Studies for the Years Ended March 31, 1977 and March 31, 1978

Volume 2

Prepared for

Nova Scotia Power Corporation

December 1978

SCHEDULE 1

NOVA SCOTIA POWER CORPORATION

Cost of Service Study Summaries

For the Years Ended March 31, 1977 and 1978

Percentage Relationship of Class Return to Average Return

	Total Company Less Steam And Joint (1)	Domestic (2)	General Comm. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)
Year Ended March 31, 1977												
1) Coincident Peak	100.00	59.0	99.3	161.5	101.4	115.4	125.7	104.5	190.9	4,796.8	105.5	78.8
2) Coincident Peak and Average	100.00	65.0	88.6	158.9	105.1	99.1	136.4	99.5	150.6	326.2	107.6	79.9
3) Class Non Coincident Peak	100.00	60.2	104.0	163.4	106.4	119.6	121.1	104.6	195.6	66.1	118.4	83.4
Year Ended March 31, 1978												
4) Coincident Peak	100.00	48.0	124.3	175.1	119.0	97.4	127.7	101.6	196.0	2,611.5	85.7	93.6
5) Coincident Peak and Average	100.00	55.2	111.0	173.0	122.1	86.3	140.8	100.1	149.8	388.1	83.5	97.2
6) Class Non Coincident Peak	100.00	49.6	131.8	183.5	128.7	107.5	114.6	94.9	198.7	7.6	100.6	106.2

SCHEDULE 2

NOVA SCOTIA POWER CORPORATION

Load Analysis

For the Years Ending March 31, 1977 and 1978

	Class	Customers Served (1)	MWH Sales (2)	Losses (3)	MWH Generated & Purchased (4)	Non Diversified Class L.F. at Dec KW (5)	Non Diversified Class KW Demand December (6)	Class Coincident Factor (7)	Diversified Class Load Factor (8)	Diversified Class KW Demand (9)	System Coincidence Factor (10)	Coincident KW Demand (11)	Losses (12)	System Coincident KW Demand (13)
	1977													
1)	Domestic	257,891	1,771,621	10.8	1,962,940	32.50	622,276	.722	45.01	449,294	.825	370,668	10.8	410,700
2)	Gen. Serv. Connt. Load	10,710	48,618	10.8	53,869	78.97	7,028	.950	83.12	6,677	.900	6,009	10.8	6,658
3)	Gen. Serv. Demand	16,627	968,059	10.8	1,072,609	47.86	230,906	.950	50.37	219,361	.900	197,425	10.8	218,747
4)	Gen. Serv. All Electric	2,069	314,226	10.3	346,591	41.72	85,969	.975	42.79	83,820	.925	77,534	10.3	85,519
5)	Gen. Serv. Large	3	111,661	9.0	121,710	62.85	20,282	.925	67.94	18,761	.875	16,416	9.0	17,893
6)	Industrial to 249 KVA	166	21,399	9.0	23,325	29.63	8,245	.925	32.02	7,627	.875	6,674	9.0	7,274
7)	Industrial 250-3,999 KVA	124	286,452	7.8	308,795	48.11	67,969	.925	52.01	62,871	.875	55,012	7.8	59,303
8)	Industrial Large	14	985,165	4.8	1,032,453	71.88	157,558	.875	81.57	137,863	.850	117,184	4.8	122,808
9)	Interruptible	6	124,277	4.8	130,242	50.00	28,373	.900	55.56	25,536	-	-	-	-
10)	Bowaters Mersey	1	200,000	4.8	209,600	54.39	41,979	1.000	54.39	41,979	.900	37,781	4.8	39,959
11)	A.E.C.L. Pt. Tupper	1	148,961	4.8	156,111	70.56	24,100	.975	72.37	23,498	.975	22,911	4.8	24,011
12)	Municipal	8	229,703	4.8	240,729	52.68	49,770	.975	54.04	48,526	.925	44,887	4.8	47,042
13)	Unmetered	2,623	60,456	10.8	66,985	44.75	15,421	1.000	44.75	15,421	1.000	15,421	10.8	17,086
14)	N.B.E.P.C.	1	1,659	4.8	1,739	-	-	-	-	-	-	-	-	-
15)	Total	290,244	5,272,257	8.638	5,727,698		1,359,876			1,141,234		967,922	9.252	1,057,000
	1978													
16)	Domestic	264,465	1,741,588	10.3	1,920,889	32.20	617,087	.722	44.62	445,537	.825	367,568	10.3	405,427
17)	Gen. Serv. Connt. Load	9,855	46,645	10.3	51,449	73.58	7,236	.950	77.46	6,874	.900	6,187	10.3	6,824
18)	Gen. Serv. Demand	17,215	995,884	10.3	1,087,430	48.48	232,156	.950	51.03	220,548	.900	198,493	10.3	218,938
19)	Gen. Serv. All Electric	1,792	307,822	9.5	337,065	45.08	77,956	.975	46.23	76,007	.925	70,307	9.5	76,986
20)	Gen. Serv. Large	3	113,542	8.5	123,193	60.61	21,384	.925	58.81	19,780	.875	17,308	8.5	18,779
21)	Industrial to 249 KVA	218	29,407	8.5	31,907	27.56	12,182	.925	26.74	11,268	.875	9,860	8.5	10,698
22)	Industrial 250-3,999 KVA	126	299,816	7.1	321,103	47.69	71,762	.925	46.28	66,380	.875	58,082	7.1	62,206
23)	Industrial Large	14	912,508	4.3	951,746	80.01	130,193	.875	82.07	113,919	.850	96,831	4.3	100,995
24)	Interruptible	6	135,436	4.3	141,260	50.00	30,921	.900	49.86	27,829	-	-	-	-
25)	Bowaters Mersey	1	200,000	4.3	208,600	56.37	42,240	.975	49.80	41,184	.900	37,066	4.3	38,659
26)	A.E.C.L. Pt. Tupper	1	163,691	4.3	170,730	77.86	24,000	.925	75.55	22,200	.975	21,645	4.3	22,576
27)	Municipal	8	234,154	4.3	244,223	56.96	46,930	.975	-	45,757	.925	42,325	4.3	44,145
28)	Unmetered	2,380	63,226	10.3	69,738	44.80	16,108	1.000	-	16,108	1.000	16,108	10.3	17,767
29)	N.B.E.P.C.	1	2,163	4.3	2,256	-	-	-	-	-	-	-	-	-
30)	Total	296,085	5,235,882	8.131	5,661,589		1,330,155			1,113,391		941,780		1,024,000

NOVA SCOTIA POWER CORPORATION

SCHEDULE 3

Analysis Of MWH Sold And Generated

For The Years Ended March 31, 1977 And 1978

		Year Ended March 31, 1977		Year Ended March 31, 1978	
		MWH Sales (1)	MWH Generation (2)	MWH Sales (3)	MWH Generation (4)
1)	Domestic	1,771,621	1,962,940	1,741,588	1,920,889
2)	Gen. Conn Load	48,618	53,869	46,645	51,449
3)	General	968,059	1,072,609	985,884	1,087,430
4)	General All Electric	314,226	346,591	307,822	337,065
5)	General Large	111,661	121,710	113,542	123,193
6)	Industrial To 249 KVA	21,399	23,325	29,407	31,907
7)	Industrial 250 - 3,999 KVA	286,452	308,795	299,816	321,103
8)	Industrial Large	985,165	1,032,453	912,508	951,746
9)	Interruptible	124,277	130,242	135,436	141,260
10)	Municipal	229,703	240,729	234,154	244,223
11)	Unmetered	60,456	66,985	63,226	69,738
12)	Sub-Total	4,921,637	5,360,248	4,870,028	5,280,003
13)	AECL Pt. Tupper	148,961	156,111	163,691	170,730
14)	Bowaters Mersey	200,000	209,600	200,000	208,600
15)	N.B.E.P.C.	1,659	1,739	2,163	2,256
16)	Total	5,272,257	5,727,698	5,235,882	5,661,589

SCHEDULE 4

NOVA SCOTIA POWER CORPORATION

Determination Of Customer Non-Coincident KW By Voltage Level

For The Years Ended March 31, 1977 And 1978

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible (10)	Municipal (11)	Unmetered (12)
	Year Ended March 31, 1977												
1)	Non Coin. KW Secondary	953,557	622,276	7,028	217,632	83,747	-	7,453	-	-	-	-	15,421
2)	Losses 2.6%	24,792	16,179	183	5,658	2,177	-	194	-	-	-	-	401
3)	Sub-Total	978,349	638,455	7,211	223,290	85,924	-	7,647	-	-	-	-	15,822
4)	Non Coin. KW Primary	1,121,639	638,455	7,211	236,564	88,146	20,282	8,439	66,113	19,637	-	20,970	15,822
5)	Losses 3.6%	40,377	22,984	260	8,516	3,173	730	304	2,380	707	-	754	569
6)	Sub-Total	1,162,016	661,439	7,471	245,080	91,319	21,012	8,743	68,493	20,344	-	21,724	16,391
7)	Non Coin. KW DBPS	1,352,410	661,439	7,471	245,080	91,319	21,012	8,743	71,353	150,705	28,373	50,524	16,391
8)	Losses 2.0%	27,048	13,229	149	4,902	1,826	420	175	1,427	3,014	568	1,010	328
9)	Sub-Total	1,379,458	674,668	7,620	249,982	93,145	21,432	8,918	72,780	153,719	28,941	51,534	16,719
10)	Total at Trans. Level	1,379,458	674,668	7,620	249,982	93,145	21,432	8,918	72,780	153,719	28,941	51,534	16,719
	Year Ended March 31, 1978												
11)	Non Coin. KW Secondary	946,437	617,087	7,236	218,882	75,734	-	11,390	-	-	-	-	16,108
12)	Losses 2.6%	24,607	16,044	188	5,691	1,969	-	296	-	-	-	-	419
13)	Sub-Total	971,044	633,131	7,424	224,573	77,703	-	11,686	-	-	-	-	16,527
14)	Non Coin. KW Primary	1,117,310	633,131	7,424	237,847	79,925	21,384	12,478	70,005	20,459	-	18,130	16,527
15)	Losses 3.1%	34,636	19,627	230	7,373	2,478	663	387	2,170	634	-	562	512
16)	Sub-Total	1,151,946	652,758	7,654	245,220	82,403	22,047	12,865	72,175	21,093	-	18,692	17,039
17)	Non Coin. KW DBPS	1,324,261	652,758	7,654	245,220	82,403	22,047	12,865	75,035	130,827	30,921	47,492	17,039
18)	Losses 2.0%	26,485	13,055	153	4,904	1,648	441	257	1,501	2,617	618	950	341
19)	Sub-Total	1,350,746	665,813	7,807	250,124	84,051	22,488	13,122	76,536	133,444	31,539	48,442	17,380
20)	Total At Trans. Level	1,350,746	665,813	7,807	250,124	84,051	22,488	13,122	76,536	133,444	31,539	48,442	17,380

SCHEDULE 5

NOVA SCOTIA POWER CORPORATION

Determination Of Class Non-Coincident KW By Volume Level

For The Years Ended March 31, 1977 And 1978

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)
	Year Ended March 31, 1977												
1)	Non Coin KW Secondary	766,691	449,294	6,677	206,751	81,654	-	6,894	-	-	-	-	15,421
2)	Losses 2.6%	19,934	11,682	174	5,375	2,123	-	179	-	-	-	-	401
3)	Sub-Total	786,625	460,976	6,851	212,126	83,777	-	7,073	-	-	-	-	15,822
4)	Non Coin. KW Primary	919,678	460,976	6,851	224,736	85,943	18,761	7,806	61,154	17,183	-	20,446	15,822
5)	Losses 3.6%	33,109	16,595	247	8,090	3,094	675	281	2,202	619	-	736	570
6)	Sub-Total	952,787	477,571	7,098	232,826	89,037	19,436	8,087	63,356	17,802	-	21,182	16,392
7)	Non Coin. KW DBPS	1,123,115	477,571	7,098	232,826	89,037	19,436	8,087	66,002	131,868	25,536	49,262	16,392
8)	Losses 2.0%	22,461	9,551	142	4,656	1,781	389	162	1,320	2,637	510	985	328
9)	Sub-Total	1,145,576	487,122	7,240	237,482	90,818	19,825	8,249	67,322	134,505	26,046	50,247	16,720
10)	Non Coin. KW Trans.	1,145,576	487,122	7,240	237,482	90,818	19,825	8,249	67,322	134,505	26,046	50,247	16,720
11)	Losses 2.6%	29,782	12,665	188	6,174	2,361	515	214	1,750	3,497	677	1,306	435
12)	Sub-Total	1,175,358	499,787	7,428	243,656	93,179	20,340	8,463	69,072	138,002	26,723	51,553	17,155
13)	Total At Generation	1,175,358	499,787	7,428	243,656	93,179	20,340	8,463	69,072	138,002	26,723	51,553	17,155
	Year Ended March 31, 1978												
14)	Non Coin. KW Secondary	760,833	445,537	6,874	207,938	73,841	-	10,535	-	-	-	-	16,108
15)	Losses 2.6%	19,782	11,584	179	5,406	1,920	-	274	-	-	-	-	419
16)	Sub-Total	780,615	457,121	7,053	213,344	75,761	-	10,809	-	-	-	-	16,527
17)	Non Coin. KW Primary	918,952	457,121	7,053	225,954	77,927	19,780	11,542	67,469	17,902	-	17,677	16,527
18)	Losses 3.1%	28,489	14,171	219	7,005	2,416	613	358	2,092	555	-	548	512
19)	Sub-Total	947,441	471,292	7,272	232,959	80,343	20,393	11,900	69,561	18,457	-	18,225	17,039
20)	Non Coin. KW DBPS	1,102,012	471,292	7,272	232,959	80,343	20,393	11,900	72,207	114,474	27,828	46,305	17,039
21)	Losses 2.0%	22,040	9,426	145	4,659	1,607	408	238	1,444	2,289	557	926	341
22)	Sub-Total	1,124,052	480,718	7,417	237,618	81,950	20,801	12,138	73,651	116,763	28,385	47,231	17,380
23)	Non Coin. KW Trans.	1,124,052	480,718	7,417	237,618	81,950	20,801	12,138	73,651	116,763	28,385	47,231	17,380
24)	Losses 2.6%	29,227	12,499	193	6,178	2,131	541	316	1,915	3,036	738	1,228	452
25)	Sub-Total	1,153,279	493,217	7,610	243,796	84,081	21,342	12,454	75,566	119,799	29,123	48,459	17,832
26)	Total At Generation	1,153,279	493,217	7,610	243,796	84,081	21,342	12,454	75,566	119,799	29,123	48,459	17,832

NOVA SCOTIA POWER CORPORATION

SCHEDULE 26

Analysis Of Plant In Service Glace Bay Steam Sales,
Point Tupper Steam Sales And Electric And Bowater Mersey Electric Sales
For The Year Ended March 31, 1978
($000)

		Total Company (1)	Glace Bay (2)	Point Tupper (3)	Mersey System (4)	Total (5)
	Production Plant					
1)	Steam Other	$ 91,481	$ -	$ -	$ -	$ 91,481
2)	Mersey System	4,264	-	-	4,215	49
3)	Other Hydro	162,748	-	-	-	162,748
4)	Gas Turbine	21,891	-	-	-	21,891
5)	Pt. Tupper	13,741	-	8,328	-	5,413
6)	Glace Bay	23,979	13,599	-	-	10,380
7)	Water Street	19,453	-	-	-	19,453
8)	Total	$337,557	$ 13,599	$ 8,328	$ 4,215	$311,415
	Transmission Plant					
9)	Substations	$ 32,103	$ -	$ -	$ -	$ 32,103
10)	All Other	53,712	-	-	-	53,712
11)	Total	$ 85,815	$ -	$ -	$ -	$ 85,815
	Distribution Plant					
12)	Land	$ 2,508	$ -	$ -	$ -	$ 2,508
13)	Substations	23,350	-	166	-	23,184
14)	Poles	58,390	-	-	-	58,390
15)	Wire - O.H.	31,507	-	-	-	31,507
16)	Underground	4,849	-	-	-	4,849
17)	Line Transformers	29,154	-	-	-	29,154
18)	Services	15,870	-	-	-	15,870
19)	Meters	9,556	-	-	-	9,556
20)	Other	278	-	-	-	278
21)	Street Lighting	8,253	-	-	-	8,253
22)	Total	$183,715	$ -	$ 166	$ -	$183,549
23)	General Plant	$ 5,999	$ -	$ -	$ -	$ 5,999
24)	Intangible Plant	$ 47	$ -	$ -	$ -	$ 47
25)	Future Use	$ 96	$ -	$ -	$ -	$ 96
	CWIP					
26)	Production	$ 49,299	$ -	$ -	$ -	$ 49,299
27)	Transmission	9,818	-	-	-	9,818
28)	Distribution	6,069	-	-	-	6,069
29)	General	5,552	-	-	-	5,552
30)	Total	$ 70,738	$ -	$ -	$ -	$ 70,738
31)	Total Plant	$683,967	$ 13,599	$ 8,494	$ 4,215	$657,659

NOVA SCOTIA POWER CORPORATION

SCHEDULE 27

Analysis of Working Capital for Glace Bay Steam,

Point Tupper Steam & Electric and Bowaters Mersey Electric Sales

For the Year Ending March 31, 1978

($000)

		Total Company (1)	Glace Bay (2)	Point Tupper (3)	Mersey System (4)	Total (5)
	Cash					
1)	Fuel	$11,592	$ 655	$ 1,957	$ -	$ 8,980
2)	Purchased Power	208	-	-	-	208
3)	Labour	3,525	229	127	65	3,104
4)	Other	3,318	179	309	67	2,763
5)	Sub-Total	$18,643	$ 1,063	$ 2,393	$ 132	$15,055
	Deduct					
6)	Consumer Deposits	$(991)	$ -	$ -	$ -	$(991)
7)	Fed. Coal Subvention	(660)	-	-	-	(660)
8)	Change Prov. For Nov. 1 Losses	(500)	-	-	-	(500)
9)	C. & R. Bowaters Mersey	(650)	-	-	(650)	(-)
10)	Refundable Cap. Cont.	(15)	-	-	-	(15)
11)	Total Deduct	$(2,816)	$ -	$ -	$(650)	$(2,166)
12)	Net Cash Work. Cap.	$15,827	$ 1,063	$ 2,393	$(518)	$12,889
	Mat. & Supp. Inventories					
13)	Fuel	$ 7,933	$ 454	$ 213	$ -	$ 7,266
14)	Line Stores	8,445	-	-	-	8,445
15)	Thermal	3,773	309	831	-	2,633
16)	Mobile Serv.	75	-	-	-	75
17)	Trans. & Subst.	113	-	-	-	113
18)	Total Mat. & Supp.	$20,339	$ 763	$ 1,044	$ -	$18,532
19)	Total Work. Cap.	$36,166	$ 1,826	$ 3,437	$(518)	$31,421

NOVA SCOTIA POWER CORPORATION

Classification of Plant In Service

For the Year Ended March 31, 1978

($000)

		Total Company (1)	Coincident Peak (2)	Peak and Average (3)	Class N.C. Peak (4)	Customer N.C. Peak (5)	Energy (6)	Customer (7)	Revenue (8)	Direct (9)	As Other (10)
	Production Plant										
1)	Steam Other	$ 91,481	$ 91,481	$ 91,481	$ 91,481	$ -	$ -	$ -	$ -	$ -	$ -
2)	Mersey System	4,264	49	-	49	-	-	-	-	4,215	-
3)	Other Hydro	162,748	162,748	-	162,748	-	-	-	-	-	-
4)	Gas Turbine	21,891	21,891	-	21,891	-	-	-	-	-	-
5)	Point Tupper	13,741	5,413	5,413	5,413	-	-	-	-	8,238	-
6)	Glace Bay	25,301	10,952	10,952	10,952	-	-	-	-	14,349	-
7)	Water Street	19,453	19,453	19,453	19,453	-	-	-	-	-	-
8)	Total	$338,879	$311,987	$127,299	$311,987	$ -	$ -	$ -	$ -	$ 26,802	$ -
	Transmission Plant										
9)	Substations	$ 32,103	$ 32,103	$ 32,103	$ 32,103	$ -	$ -	$ -	$ -	$ -	$ -
10)	All Other	53,712	53,712	53,712	53,712	-	-	-	-	-	-
11)	Total	$ 85,815	$ 85,815	$ 85,815	$ 85,815	$ -	$ -	$ -	$ -	$ -	$ -
	Distribution Plant										
12)	Land	$ 2,508	$ -	$ -	$ 2,508	$ 2,508	$ -	$ -	$ -	$ -	$ -
13)	Substations	23,350	-	-	21,317	21,317	-	-	-	2,033	-
14)	Poles	58,390	-	-	21,605	21,605	-	36,785	-	-	-
15)	Wire - O.H.	31,507	-	-	12,917	12,917	-	18,590	-	-	-
16)	Underground	4,849	-	-	-	-	-	-	-	-	4,849
17)	Line Transformers	29,154	-	-	29,154	29,154	-	-	-	-	-
18)	Services	15,870	-	-	-	-	-	15,870	-	-	-
19)	Meters	9,556	-	-	-	-	-	-	-	9,556	-
20)	Other	278	-	-	-	-	-	-	-	-	278
21)	Street Lighting	8,253	-	-	-	-	-	-	-	8,253	-
22)	Total	$183,715	$ -	$ -	$ 87,501	$ 87,501	$ -	$ 71,245	$ -	$ 19,842	$ 5,127
23)	**General, Intangible & Future Use**	$ 6,142	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,142
	Working Capital										
24)	Cash - Fuel	$ 8,528	$ -	$ -	$ -	$ -	$ 8,528	$ -	$ -	$ -	$ -
25)	Cash - Other	4,361	-	-	-	-	-	-	-	-	4,361
26)	Mat. & Supp. - Fuel	7,266	-	-	-	-	7,266	-	-	-	-
27)	Mat. & Supp. - Other	11,266	-	-	-	-	-	-	-	-	11,266
28)	Total	$ 31,421	$ -	$ -	$ -	$ -	$ 15,794	$ -	$ -	$ -	$ 15,627
	CWIP										
29)	Production - Hydro	$ 180	$ 180	$ -	$ 180	$ -	$ -	$ -	$ -	$ -	$ -
30)	Production - Steam	49,119	49,119	49,119	49,119	-	-	-	-	-	-
31)	Transmission	9,818	9,818	9,818	9,818	-	-	-	-	-	-
32)	Distribution	6,069	-	-	-	-	-	-	-	-	6,069
33)	General	5,552	-	-	-	-	-	-	-	-	5,552
34)	Total	$ 70,738	$ 59,117	$ 58,937	$ 59,117	$ -	$ -	$ -	$ -	$ -	$ 11,621
35)	**Total**	$710,568	$456,919	$272,051	$544,420	$ 87,801	$ 15,794	$ 71,245	$ -	$ 46,644	$ 38,517

NOVA SCOTIA POWER CORPORATION

Analysis Of Distribution Substation Costs

For The Year Ended March 31, 1978

		Distrubition Bulk Power (1)	Dist. Ded. Bulk Power (2)	Dist. Cost Owned Bulk Power (3)	Distribution General (4)	Dist. Ded. General (5)	Dist. Cust. Owned Gen. (6)	Total Cost (7)
1)	Total Dist. Substations - 1977	$21,020,700	$ 1,181,618	$ 32,319	$ 6,698,201	$ 1,320,136	$ 33,344	$30,286,318
2)	1978 Net Additions	196,423	-	-	-	-	-	196,423
3)	Total 1978	$21,217,123	$ 1,181,618	$ 32,319	$ 6,698,201	$ 1,320,136	$ 33,344	$30,482,741
4)	Total Net Dist. Subst. - 1977	$15,922,562	$ 895,041	$ 24,481	$ 5,073,690	$ 999,964	$ 25,257	$22,940,995
5)	Depreciation @ 3.5%	498,443	(41,357)	(857)	(177,579)	(34,999)	(884)	242,767
6)	Total Net Dist. Subst. - 1978	$16,421,005	$ 853,684	$ 23,624	$ 4,896,111	$ 964,965	$ 24,373	$23,183,762
7)	Municipal		$ 301,706			$ 223,382		
8)	Interruptible			$ 10,303		$ 7,581		
9)	Industrial To 249 KVA		$ 2,167			$ 6,433		
10)	Industrial 250 - 3,999 KVA		$ 117,804	$ 797		$ 346,670	$ 24,373	
11)	Industrial Large		$ 432,007	$ 12,524		$ 116,385		
12)	General					$ 69,002		
13)	General All Electric					$ 95,313		
14)	General Large					$ 100,199		

NOVA SCOTIA POWER CORPORATION

Analysis of Pole Investment

For the Year Ended March 31, 1978

($000)

		Total Cost (1)	Primary Demand (2)	Primary Customer (3)	Secondary Demand (4)	Secondary Customer (5)
1)	Total Net Pole Cost 1978	$58,390				
2)	Primary Only (30%)	$17,517	$ 6,481	$11,036	$ -	$ -
3)	50% Joint Primary	20,437	7,562	12,875	-	-
4)	50% Joint Secondary	20,436	-	-	7,562	12,874
5)	Total	$58,390	$14,043	$23,911	$ 7,562	$12,874

Demand Cost 37%

Customer Cost 63%

NOVA SCOTIA POWER CORPORATION

SCHEDULE 28
PAGE 4 OF 4

Analysis of Wire Investment

For the Year Ended March 31, 1978

($000)

		Total Cost (1)	Primary Demand (2)	Primary Customer (3)	Secondary Demand (4)	Secondary Customer (5)
1)	Total Net Cost 1978	$31,507				
2)	Primary Only	$ 9,452	$ 3,875	$ 5,577	$ -	$ -
3)	50% Joint Primary	11,028	4,521	6,507	-	-
4)	50% Joint Secondary	11,027	-	-	4,521	6,506
5)	Total	$31,507	$ 8,396	$12,084	$ 4,521	$ 6,506

Demand Cost 41%

Customer Cost 59%

SCHEDULE 29

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For the Year Ended March 31, 1978

Coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial to 249 KVA (7)	Industrial 250 to 3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1)	Production Plant	$311,415	$131,108	$ 2,273	$ 70,909	$ 24,913	$ 6,166	$ 3,239	$ 20,055	$ 32,699	$ -	$ 14,232	$ 5,824	D-2
2)	Transmission Plant	$ 85,815	$ 36,128	$ 626	$ 19,540	$ 6,865	$ 1,699	$ 892	$ 5,527	$ 9,011	$ -	$ 3,922	$ 1,605	D-2
	Distribution Plant													
3)	Land	$ 2,508	$ 1,822	$ 50	$ 342	$ 100	$ 21	$ 15	$ 72	$ 30	$ -	$ 27	$ 29	P-12
4)	Substations	23,184	12,080	141	4,607	1,620	507	247	1,826	951	18	871	316	Sched 32 Pg. 1
5)	Poles	58,390	45,757	1,376	6,879	1,833	268	274	887	257	-	228	631	Sched 34 Pg. 1
6)	Wire-O.H.	31,507	24,316	709	3,915	1,076	160	160	531	154	-	136	350	Sched 34 Pg. 2
7)	Underground	4,849	3,780	113	582	157	23	23	77	22	-	19	53	P-10
8)	Line Transformers	29,154	19,008	225	6,743	2,332	-	350	-	-	-	-	496	D-6
9)	Services	15,870	11,333	424	3,685	382	-	46	-	-	-	-	-	C-11
10)	Meters	9,556	7,379	275	1,568	213	2	26	68	15	7	3	-	Schedule 35
11)	Other	278	202	6	38	11	2	2	8	3	-	3	3	P-12
12)	Street Lighting	8,253	-	-	-	-	-	-	-	-	-	-	8,253	Direct
13)	Total Distribution Plant	$183,549	$125,677	$ 3,319	$ 28,359	$ 7,724	$ 983	$ 1,143	$ 3,469	$ 1,432	$ 25	$ 1,287	$ 10,131	
14)	General Plant, Intangible, and Future Use	$ 6,142	$ 3,097	$ 66	$ 1,257	$ 418	$ 93	$ 56	$ 307	$ 456	$ 1	$ 206	$ 185	P-14
	Working Capital													
15)	Cash Fuel	$ 8,528	$ 3,102	$ 83	$ 1,756	$ 544	$ 199	$ 51	$ 519	$ 1,538	$ 229	$ 395	$ 112	E-2
16)	Cash	4,361	1,838	47	883	271	85	29	237	608	73	173	117	O-4
17)	Mat. Supp. - Fuel	7,266	2,643	71	1,496	464	169	44	142	1,310	195	336	96	E-2
18)	Mat. Supp. - Other	11,266	5,681	121	2,305	766	171	103	563	837	1	378	340	P-14
19)	Total Working Capital	$ 31,421	$ 13,264	$ 322	$ 6,440	$ 2,045	$ 624	$ 227	$ 1,761	$ 4,293	$ 498	$ 1,282	$ 665	
20)	Total Rate Base	$618,342	$309,271	$ 6,606	$126,505	$ 41,965	$ 9,565	$ 5,557	$ 31,119	$ 47,891	$ 524	$ 20,929	$ 18,410	

NOVA SCOTIA POWER CORPORATION

Allocation Of Rate Base

For The Year Ended March 31, 1978

Coincident Peak And Average Responsibility

($000)

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
	Production Plant													
1)	Steam	$126,727	$ 50,526	$ 1,052	$ 27,778	$ 9,314	$ 2,674	$ 1,128	$ 8,022	$ 17,007	$ 1,293	$ 5,829	$ 2,104	D-4
2)	Hydro	162,797	68,538	1,188	37,069	13,024	3,223	1,693	10,484	17,094	-	7,440	3,044	D-2
3)	Gas Turbine	21,891	9,216	160	4,985	1,751	433	228	1,410	2,299	-	1,000	409	D-2
4)	Total	$311,415	$128,280	$ 2,400	$ 69,832	$ 24,089	$ 6,330	$ 3,049	$ 19,916	$ 36,400	$ 1,293	$ 14,269	$ 5,557	
5)	**Transmission Plant**	$ 85,815	$ 34,214	$ 712	$ 18,811	$ 6,307	$ 1,811	$ 764	$ 5,432	$ 11,516	$ 875	$ 3,948	$ 1,425	D-4
	Distribution Plant													
6)	Land	$ 2,508	$ 1,737	$ 51	$ 385	$ 118	$ 23	$ 17	$ 82	$ 31	$ 1	$ 30	$ 33	D-13
7)	Substations	23,184	10,603	164	5,311	1,903	559	277	2,054	977	18	934	384	Sched 32 Pg 2
8)	Poles	58,390	44,282	1,401	7,660	2,149	302	308	1,038	274	-	269	707	Sched 34 Pg 2
9)	Wire - O.H.	31,507	23,434	725	4,382	1,265	180	180	620	164	-	161	396	Sched 34 Pg 2
10)	Underground	4,849	3,653	115	649	184	26	26	89	24	-	23	60	P-11
11)	Line Transformers	29,154	17,073	262	7,968	2,831	-	402	-	-	-	-	618	D-12
12)	Services	15,870	11,333	424	3,685	382	-	46	-	-	-	-	-	C-11
13)	Meters	9,556	7,379	275	1,568	213	2	26	68	15	7	3	-	Sched 35
14)	Other	278	192	6	43	13	3	2	9	3	-	3	4	P-13
15)	Street Lighting	8,253	-	-	-	-	-	-	-	-	-	-	8,253	Direct
16)	Total	$183,549	$119,686	$ 3,423	$ 31,651	$ 9,098	$ 1,095	$ 1,284	$ 3,960	$ 1,488	$ 26	$ 1,423	$ 10,455	
17)	**Gen. Plant, Intangible & Future Use**	$ 6,142	$ 2,984	$ 69	$ 1,272	$ 417	$ 98	$ 54	$ 310	$ 523	$ 23	$ 208	$ 184	P-15
	Working Capital													
18)	Cash Fuel	$ 8,528	$ 3,102	$ 83	$ 1,756	$ 544	$ 199	$ 51	$ 518	$ 1,538	$ 229	$ 395	$ 113	E-2
19)	Cash	4,361	1,805	49	881	267	86	28	237	636	83	174	115	O-5
20)	Mat. & Supp. - Fuel	7,265	2,643	71	1,496	464	169	44	442	1,310	195	336	96	E-2
21)	Mat. & Supp. - Other	11,266	5,474	126	2,333	765	179	99	569	959	43	381	338	P-15
22)	Total	$ 31,421	$ 13,024	$ 329	$ 6,466	$ 2,040	$ 633	$ 222	$ 1,766	$ 4,443	$ 550	$ 1,286	$ 662	
23)	**Total Rate Base**	$618,342	$298,188	$ 6,933	$128,032	$ 41,911	$ 9,967	$ 5,373	$ 31,384	$ 54,370	$ 2,767	$ 21,134	$ 18,263	

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For the Year Ended March 31, 1978

Class Non-Coincident Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1)	Production Plant	$311,415	$133,192	$ 2,055	$ 65,833	$ 22,702	$ 5,761	$ 3,363	$ 20,398	$ 32,356	$ 7,848	$ 13,080	$ 4,827	D-18
2)	Transmission Plant	$ 85,815	$ 36,703	$ 566	$ 18,141	$ 6,256	$ 1,588	$ 927	$ 5,621	$ 8,916	$ 2,163	$ 3,604	$ 1,330	D-18
	Distribution Plant													
3)	Land	$ 2,508	$ 1,737	$ 51	$ 385	$ 118	$ 23	$ 17	$ 82	$ 31	$ 1	$ 30	$ 33	P-13
4)	Substations	23,184	10,603	164	5,311	1,903	559	277	2,054	977	18	934	384	Sched 32 Pg 2
5)	Poles	58,390	44,282	1,401	7,660	2,149	302	308	1,038	274	-	269	707	Sched 34 Pg 2
6)	Wire - O.H.	31,507	23,434	725	4,382	1,265	180	180	620	164	-	161	396	Sched 34 Pg 2
7)	Underground	4,849	3,653	114	649	184	26	26	89	24	-	24	60	P-11
8)	Line Transformers	29,154	17,073	262	7,968	2,831	-	402	-	-	-	-	618	D-12
9)	Services	15,870	11,333	424	3,685	382	-	46	-	-	-	-	-	C-11
10)	Meters	9,556	7,379	275	1,568	213	2	26	68	15	7	3	-	Schedule 35
11)	Other	278	192	6	43	13	2	3	9	3	-	3	4	P-13
12)	Street Lighting	8,253	-	-	-	-	-	-	-	-	-	-	8,253	Direct
13)	Total	$183,549	$119,686	$ 3,422	$ 31,651	$ 9,058	$ 1,094	$ 1,285	$ 3,960	$ 1,489	$ 26	$ 1,424	$ 10,455	
14)	Gen. Plant, Intan. & Future Use	$ 6,142	$ 3,062	$ 64	$ 1,223	$ 402	$ 89	$ 59	$ 317	$ 452	$ 106	$ 192	$ 176	P-16
	Working Capital													
15)	Cash Fuel	$ 8,528	$ 3,102	$ 83	$ 1,756	$ 544	$ 199	$ 51	$ 519	$ 1,538	$ 229	$ 395	$ 112	E-2
16)	Cash	4,361	1,832	47	874	267	84	30	239	607	97	170	114	O-6
17)	Mat. & Supp. - Fuel	7,266	2,643	71	1,496	464	169	44	442	1,310	195	336	96	E-2
18)	Mat. & Supp. - Other	11,266	5,617	117	2,243	738	164	108	581	829	195	352	322	P-16
19)	Total	$ 31,421	$ 13,194	$ 318	$ 6,369	$ 2,013	$ 616	$ 233	$ 1,781	$ 4,284	$ 716	$ 1,253	$ 644	
20)	Total Rate Base	$618,342	$305,837	$ 6,425	$123,217	$ 40,431	$ 9,148	$ 5,867	$ 32,077	$ 47,496	$ 10,859	$ 19,553	$ 17,432	

NOVA SCOTIA POWER CORPORATION

Allocation of Distribution Substation Costs

For the Year Ended March 31, 1978

Coincident Peak Responsibilty

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1)	Distribution Bulk Power	$16,421,005	$ 9,305,784	$ 108,379	$3,496,032	$1,174,102	$ 313,641	$ 183,915	$1,029,597	$ 300,504	$ -	$ 266,020	$ 243,031	D-8
2)	Dist. Bulk Power Dedicated	853,684	-	-	-	-	-	2,167	117,804	432,007	-	301,706	-	Sched 28 Pg 2
3)	Dist. Cust. Owned Bulk Power	23,624	-	-	-	-	-	-	797	12,524	10,303	-	-	Sched 28 Pg 2
4)	Distribution General	4,896,111	2,774,626	32,314	1,042,382	350,072	93,516	54,836	306,986	89,599	-	79,317	72,463	D-8
5)	Distribution Dedicated General	964,965	-	-	69,002	95,313	100,199	6,433	346,670	116,385	7,581	223,382	-	Sched 28 Pg 2
6)	Dist. Cust. Owned Gen.	24,373	-	-	-	-	-	-	24,373	-	-	-	-	Sched 28 Pg 2
7)	Total Allocated Cost	$23,183,762	$12,080,410	$ 140,693	$4,607,416	$1,619,487	$ 507,356	$ 247,351	$1,826,227	$ 951,019	$ 17,884	$ 870,425	$ 315,494	

Note: Allocations done on Customer Non-Coincident for this study.

NOVA SCOTIA POWER CORPORATION

Allocation Of Distribution Substation Costs

For The Year Ended March 31, 1978

Peak & Average And Class Non-Coincident Peak Responsibility

	Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1) Distr. Bulk Power	$16,421,005	$ 8,167,808	$ 126,442	$4,037,925	$1,392,501	$ 353,052	$ 206,905	$1,205,302	$ 320,209	$ -	$ 315,283	$ 295,578	D-14
2) Dist. Bulk Power Dedicated	853,684	-	-	-	-	-	2,167	117,804	432,007	-	301,706	-	Sched 28 Pg 2
3) Dist. Cust. Owned Bulk Power	23,624	-	-	-	-	-	-	797	12,524	10,303	-	-	Sched 28 Pg 2
4) Distr. General	4,896,111	2,435,326	37,700	1,203,954	415,190	105,266	61,691	359,375	95,474	-	94,005	88,130	D-14
5) Dist. Dedicated General	964,965	-	-	69,002	95,313	100,199	6,433	346,670	116,385	7,581	223,382	-	Sched 28 Pg 2
6) Dist. Customer Owned General	24,373	-	-	-	-	-	-	24,373	-	-	-	-	Sched 28 Pg 2
7) Total Allocated Cost	$23,183,762	$10,603,134	$ 164,142	$5,310,881	$1,903,004	$ 558,517	$ 277,196	$2,054,321	$ 976,599	$ 17,884	$ 934,376	$ 383,708	

Note: Allocations done on Class Non-Coincident for these studies.

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - General Service

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	37 H	Police Station	DD	$25,202					23/.6	148	79	154	983
2)	33 H	Bank of Montreal	DD	13,170					23/.6	720	250	780	2,887
3)	49 H	N. S. Hospital	DD	9,607					23/4.1	648	311	684	3,752
4)	63 H	Holiday Inn	DD	7,361					23/.2	264	81	336	1,474
5)	69 H	D.O.T. Marine Service	DD	4,002					23/.6	560	230	864	3,061
6)	47 H	Naval Arm	COD						23	1,152	171	1,152	2,787
7)	53 H	Bedford Magazine	COD						23	558	213	596	1,626
8)	45 H	Osborne Head	COD						23	120	57	120	583
9)	50 C	D.O.T. Pt. Hastings	COD						23 KV	104	42	106	322
10)	50-51 H	CFB Shearwater	COD		2,052	930	2,340	11,010	23 KV				
11)	12 H	Statacona	COD		1,404	573	1,404	7,806	23 KV	1,620	722	1,680	8,300
12)	25 H	Royal Bank	DD	24,253						756	258	900	3,404
13)	46 V	Stevens Lumber	DD	10,805						114	3	144	86
14)	41 V	Minas Basin Mill	COD							200	25	208	206
15)	58 V	Greenwood	COD							2,240	1,106	2,320	11,040
16)	59 V	Greenwood Shopping	COD							134	59	185	765
17)	74 V	Cornwallis Base	COD							2,000	996	2,160	11,389
18)	51 W	Bowater Mill	DBP							1	0	1	0
19)	60 N	I.M. Matheson	COD							100	21	192	209
20)		Total DD		$94,400	3,210	1,212	3,862	15,647					
21)		Total COD			10,064	4,915	12,463	97,743					
22)		Total DBP			1		1						

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - General - All Electric

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	38 H	Citadel Inn	DD	$ 25,202					23/.6	438	182	451	2,284
2)	29 H	Law Courts	DD	21,345					23/.6	1,040	316	1,080	4,543
3)	36 H	Young Street	DD	30,567					23/.6	528	162	552	2,384
4)	74 S	Keltic Lodge	DD	53,279					23/.6	216	74	368	1,245
5)		Total DD		$130,393						2,222	734	2,451	10,456

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - General Large

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	11 H	Dock Yard	COD	Cust.	5,054	1,752	5,054	22,346	23 KV				
2)	28 H	Scotia Square	DD	$137,079	10,476	5,618	11,016	56,027	23/.6				
3)	24,27,30 31,32 H	Dalhousie	COD	Cust.	4,752	2,576	4,752	30,144	23 KV				
4)		Total DD		$137,079	10,476	5,618	11,016	56,027					
5)		Total COD			9,806	4,328	9,806	52,490					

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Industrial to 249KVA

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	44 C	Bd. of Ed. Little River	DBPD	$3,000					69/.6	603	5	612	847
2)	24 N	C. E. Harrisons Mill	DD	8,801	189	30	205	291	24/.6				
3)		Total DD		$8,801	189	30	205	291					
4)		Total DBP		$3,000	603	5	612	847		603	5	612	847

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Industrial 250-3,999 KVA

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	18 C	Canso Seafoods	DD	$ 2,000	1,584	746	1,584	8,046	23 KV	1,562	634	1,642	8,910
2)	60 C	Evans Coal	DD	5,402	252	30	252	269	25/2.3	280	26	320	352
3)	13 C	Georgia Pacific 6B	DBPD	17,473					69/.6	320	62	336	652
4)	45 C	Georgia Pacific	DD	17,472					25/.6	512	32	512	308
5)	43 C	Dept. of Environment	DBPD	6,228					69/.6	696	271	960	4,031
6)	90 W	C.O.T.C. - (Tellstake)	DD	176,265	684	344	869	4,207	24/4.16	653	344	970	4,192
7)	114 H	National Gypsum	DD	36,016					23/2.3	960	112	1,480	2,146
8)	102 H	Pockwock Pumps	DBPD	30,660					69/4.16	1,280	752	1,840	7,116
9)	13 H	Halifax Shipyard	COD	-	2,304	1,064	2,376	8,988	23	2,560	776	2,640	7,396
10)	66 N	River Herbert Coal	DD	9,004	261	49	270	586	23/2.4	297	43	306	514
11)	18 N	Enheat - Rolling Mill #4	COBP	1,091	749	143	916	1,432	69				
12)	59 N	Maritime Steel	COD	-	713	113	745	985	24	1,044	118	1,158	1,318
13)	63 N	Thorborn Mine	COD		551	95	616	239	23	551	115	583	1341
14)	23 N	Christy Crops	DD	10,805	97	54	97	750	24/.6				
15)	39 V	Fundy Gypsum - Hansport	COD	-	691	38	706	5,376	23	864	43	912	629
16)	37 V	Fundy Gypsum - W.	COD	-	1,044	188	1,116	2,440	23	1,040	64	1,680	2,928
17)	38 V	Fundy Gypsum - Man.	COD	-	576	146	648	1,660	23	720	154	800	2,140
18)	71 V	United Elastics	DD	14,254	691	191	763	2,173	23/.6	840	214	936	2,511
19)	23 V	DND Newport Corner	COD	-	846	574	972	7,439	23	1,200	708	1,280	9,840
20)	83-84 V	L.E. Shaw - Lantz	COD	-	1,123	379	1,253	3,966	23	1,368	271	1,392	4,023
21)	32-33 V	Dresser Minerals	COD	-	1,584	636	1,728	7,296	23	1,760	652	1,920	8,232
22)	18 H	National HB In Bd.	COD		1,584	284	2,304	4,272	23	2,080	332	2,560	4,092
23)	19 H	National HB Pin C.	COD		594	252	702	2,682	23	720	363	1,020	3,354
24)	26 H	Dover Mills	COD		792	399	846	4,413	23	1,020	361	1,020	4,571
25)	46 H	National Gypsum	COD		792	99	846	651	23	960	79	1,100	1,083
26)	66 H	Dart. Marine Ships	COD		828	222	900	2,560	23	760	172	1,200	2,630
27)	61 H	Moosehead	COD		742	307	821	3,770	23	880	294	960	3,738
28)	55 H	City of Dartmouth	DD	16,547	497	192	508	2,890	23/.6	456	209	504	2,828
29)	67 H	Hermie Electronics	DD	14,287	108	50	324	691	23/.6	152	17	192	216
30)	74 H	Maritime Paper	DD	10,237	547	300	619	3,073	23/.6	752	286	912	3,299
31)	71 H	Phillips Cables	DD	22,313	216	17	288	256	23/.6	136	16	304	199

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule-Industrial 250-3,999 KVA

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
32)	75 H	Sivaco Maritime	DD	$ 18,409	360	143	432	1,656	23/.6	600	184	640	1,904
33)	70 H	City of Dart.-Lake Major	DD	48,023	1,022	388	1,037	5,224	23/2.4	576	404	1,184	4,921
34)	80 H	Municipal Spraying-OP	DD	6,936	1,188	375	1,224	2,668	23/.6	1,560	372	1,560	2,313
35)	81 H	Municipal Spraying-Asphalt	DD	7,000					23/.6				
36)	82 H	Municipal Spraying-Crusher	DD	14,799		ONE BILL			23/.6				
37)	59 S	Kaizer Celestile Mine	DBPD	139,356 ✓	45	15	666	1,445	23/.6				
38)	30 S	Kaizer	COBP		CLOSED DOWN - NOV 76				69/12.5				
39)	34 S	Dev. Co. P.C.	COD	31,844	1,685	554	1,814	7,185	69/.6				
40)	61 V	Greenwood Base Airport	COD	-					23	1,512	511	2,016	5,825
41)	63 S	National Sea Prod.	DD	44,499	648	204	774	2,732	23/.6				
42)	21 S	Devco Shops	COD	1,500	562	1,884	648	1,261	23	1,104	342	1,176	4,864
43)		1977 Portion			25,960	10,475	29,634	103,281					
44)		1978 Portion			3,391	1,229	4,615	14,253					
45)		Total			29,351	11,704	34,279	117,534					
46)		Total DD		$ 474,268	9,480	3,227	11,534	37,675					
47)		Total DBP		$ 186,758	2,111	1,100	3,488	13,244					
48)		Total COD		$ 33,344	17,011	7,234	19,041	65,183					
49)		Total COBP		$ 1,091	749	143	916	1,432					
				$ 731,791	29,351	11,704	34,279	117,534					

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Industrial Large

	Subst.	Customer	Code	Cost	1977 Dec. KW	1977 Dec. MWH	1977 Annual KW	1977 Annual MWH	Voltage	1978 Dec. KW	1978 Dec. MWH	1978 Annual KW	1978 Annual MWH
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1)	12,13,29 W	Dominion Textile	DBPD	$113,176 ✓	3,607	1,431	3,607	17,702	69/.6	3,380	1,311	3,872	17,123
2)	26 S	Devco #26	DD	159,222 7833	6,912	2,976	7,488	23,744	22/6.6	6,192	3,109	7,488	37,770
3)	8&9 S	Sysco	DBPD	20,061 ✓	12,710	6,211	17,642	71,740	138/23	11,281	5,501	14,166	61,020
4)	80 S	Lingan Mine	DBPD	7,884 23,422	6,696	1,836	6,696	20,652	69/6.9	6,372	2,058	7,020	24,636
5)	19 S	A.E.C.L. G.B.	COBP	17,132	20,430	13,398	20,430	134,988	69	4,500	2,814	15,818	72,366
6)	74 W	Michelin BW	DBPD	73,055 ✓	6,054	3,435	6,513	43,597	138/12.5	6,468	3,692	6,738	46,401
7)	85 W	Masonite Canada	COT	-	7,560	3,480	7,776	41,232	69	5,400	2,688	8,856	37,332
8)	47 C	Nova Scotia Forest Ind.	DBPD	-	40,352	18,980	46,051	257,426	138/13.8	29,688	15,641	38,062	227,485
9)	46 C	Gulf Oil - Pt. Tupper	COBP	-	8,511	4,922	8,983	51,586	138	7,920	4,767	9,180	56,557
10)	49 N	Michelin Granton	DBPD	86,419 ✓	9,891	6,125	10,107	76,645	138/12.5	10,125	6,217	10,602	79,408
11)	52 N	Canso Chem.	DBPD	317,424 276,305	17,412	11,914	20,067	149,554	69/13.8	17,958	12,943	18,662	148,016
12)	11 N	Canada Cement	COBP	-	4,698	2,097	13,860	25,794	69	6,642	1,872	6,642	27,396
13)		Total DD		$159,222	6,912	2,976	7,488	23,744		6,192	3,109	7,488	37,770
14)		Total DBP		$597,958	96,722	49,932	110,683	637,316		85,272	47,363	99,122	604,089
15)		Total COD		$ -	-	-	-	-		-	-	-	-
16)		Total COBP		$ 17,132	33,639	20,417	43,273	212,368		19,062	9,453	31,640	156,319
17)		Total COT		$ -	7,560	3,480	7,776	41,232		5,400	2,688	8,856	37,332
				$774,312	144,833	76,805	169,220	914,660		115,926	62,433	147,106	835,510

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Interruptible

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	8,9,47,48 V	Minas Basin	DD	$10,372		739		16,134	23 KV				
2)	53 N	Scott Paper	COBP	14,096		352		15,898			2		15
3)		Total DD		$10,372		739		16,134					
4)		Total COBP		$14,096		352		15,898					

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Municipal

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	52 V	Town of Berwick	DBP	$52,593 ✓	2,419 ✓	1,099	2,549	13,272	69/4.1				
2)	77 V	Conway (Digby C.P.B.)	DBP	83,310 ✓	17,755 ✓	7,200	17,755	70,999	69/12.4				
3)	53 V	Kentville	COD		6,624 ✓	3,456	7,704	43,688	23 KV				
4)	76 W	Mahome Bay	DBP	84,172 ✓	1,275 ✓	592	1,275	5,741	69/4.1				
5)	81,82 W	Lunenburg	DBP	197,528 147,990	7,351 ✓	3,391	8,168	36,998	69/12.4				
6)	6,7,8 C	Antigonish	DD	305,601	8,911 ✓	4,422	9,130	43,879	23/4.1				
7)		Total DD		$305,601	8,911	4,422	9,130	43,879					
8)		Total COD		$ -	6,624	3,456	7,704	43,688					
9)		Total DBP		$417,603	28,800	12,282	29,747	127,010					

NOVA SCOTIA POWER CORPORATION

SCHEDULE 34
PAGE 1 OF 2

Allocation Of Pole & Wire Investment

For The Year Ended March 31, 1978

Coincident Peak Responsibility

($000)

		Total Cost (1)	Primary Demand D-8 (2)	Primary Customers C-6 (3)	Secondary Demand D-6 (4)	Secondary Customers C-4 (5)
	Poles					
1)	Domestic	$45,757	$ 7,958	$21,362	$ 4,930	$11,507
2)	Gen. Conn. Load	1,376	93	796	58	429
3)	General	6,879	2,990	1,392	1,749	748
4)	General All Elec.	1,833	1,004	146	605	78
5)	General Large	268	268	-	-	-
6)	Industrial To 249 KVA	274	157	17	91	9
7)	Industrial 250-3,999 KVA	887	880	7	-	-
8)	Industrial Large	257	257	-	-	-
9)	Interruptible	-	-	-	-	-
10)	Municipal	228	228	-	-	-
11)	Unmetered	631	208	191	129	103
12)	Total Company	$58,390	$14,043	$23,911	$ 7,562	$12,874
	Wire					
13)	Domestic	$24,316	$ 4,758	$10,796	$ 2,947	$ 5,815
14)	Gen. Conn. Load	709	55	402	35	217
15)	General	3,915	1,788	703	1,046	378
16)	General All Elec.	1,076	600	74	362	40
17)	General Large	160	160	-	-	-
18)	Industrial To 249 KVA	160	94	8	54	4
19)	Industrial 250-3,999 KVA	531	527	4	-	-
20)	Industrial Large	154	154	-	-	-
21)	Interruptible	-	-	-	-	-
22)	Municipal	136	136	-	-	-
23)	Unmetered	350	124	97	77	52
24)	Total Company	$31,507	$ 8,396	$12,084	$ 4,521	$ 6,506

NOVA SCOTIA POWER CORPORATION

Allocation of Pole and Wire Investment

For the Year Ended March 31, 1978

Coincident Peak & Average & Non-Coincident Peak

($000)

		Total Cost (1)	Primary Demand D-14 (2)	Primary Customers C-6 (3)	Secondary Demand D-12 (4)	Secondary Customer C-4 (5)
	Pole					
1)	Domestic	$ 44,282	$ 6,985	$ 21,362	$ 4,428	$ 11,507
2)	Gen. Conn. Load	1,401	108	796	68	429
3)	General	7,660	3,453	1,392	2,067	748
4)	General All Elec.	2,149	1,191	146	734	78
5)	General Large	302	302	-	-	-
6)	Industrial to 249 KVA	308	177	17	105	9
7)	Industrial 250-3,999 KVA	1,038	1,031	7	-	-
8)	Industrial Large	274	274	-	-	-
9)	Interruptible	-	-	-	-	-
10)	Municipal	269	269	-	-	-
11)	Unmetered	707	253	191	160	103
12)	Total Company	$ 58,390	$ 14,043	$ 23,911	$ 7,562	$ 12,874
	Wire					
13)	Domestic	$ 23,434	$ 4,176	$ 10,796	$ 2,647	$ 5,815
14)	Gen. Conn. Load	725	65	402	41	217
15)	General	4,382	2,065	703	1,236	378
16)	General All Elec.	1,265	712	74	439	40
17)	General Large	180	180	-	-	-
18)	Industrial to 249 KVA	180	106	8	62	4
19)	Industrial 250-3999 KVA	620	616	4	-	-
20)	Industrial Large	164	164	-	-	-
21)	Interruptible	-	-	-	-	-
22)	Municipal	161	161	-	-	-
23)	Unmetered	396	151	97	96	52
24)	Total Company	$ 31,507	$ 8,396	$ 12,084	$ 4,521	$ 6,506

NOVA SCOTIA POWER CORPORATION

SCHEDULE 35

Analysis of Meters Investment

For the Year Ended March 31, 1978

		Customers (1)	Unit Meter Cost (2)	Total Cost (3)	Percent (4)	Allocated Meter Cost (5)
1)	Domestic	264,465	$ 34.00	$ 8,991,810	77.22	$ 7,378,898
2)	General Conn. Load	9,855	34.00	335,070	2.88	275,204
3)	General	17,215	111.00	1,910,865	16.41	1,568,088
4)	General All Electric	1,792	145.00	259,840	2.23	213,092
5)	General Large	3	657.00	1,971	.02	1,911
6)	Industrial to 249 KVA	218	145.00	31,610	.27	25,800
7)	Industrial 250-3,999 KVA	126	657.00	82,782	.71	67,845
8)	Industrial Large	14	1,338.00	18,732	.16	15,289
9)	Interruptible	6	1,338.00	8,028	.07	6,689
10)	Municipal	8	520.00	4,160	.03	2,867
11)	Unmetered	2,380	-	-	-	-
12)	Total	296,082		$11,644,868	100.00	$ 9,555,683

NOVA SCOTIA POWER CORPORATION

SCHEDULE 36

Revenue Analysis

For the Year Ended March 31, 1978

($000)

		Total (1)	Discounts Direct (2)	Sub-Total (3)	Percent of Total (4)	Other (5)	Total (6)
1)	Domestic	$ 75,885	$ 799	$ 76,684	38.38	$ 1,756	$ 78,440
2)	Gen. Conn. Load	2,227	20	2,297	1.15	53	2,350
3)	General	48,390	144	48,534	24.29	1,111	49,645
4)	Gen. All Electric	13,473	34	13,507	6.76	309	13,816
5)	Gen. Large	3,567	-	3,567	1.79	82	3,649
6)	Ind. to 249 KVA	1,634	2	1,636	.82	37	1,673
7)	Ind. to 250 - 3,999 KVA	10,589	(4)	10,585	5.30	242	10,827
8)	Ind. Large	26,783	229	27,012	13.52	619	27,631
9)	Interruptible	3,250	5	3,255	1.63	75	3,330
10)	Municipal	7,184	58	7,242	3.62	166	7,408
11)	Unmetered	5,479	3	5,482	2.74	125	5,607
12)	Total	$198,511	$ 1,290	$199,801	100.00	$ 4,575	$204,376
13)	Glace Bay Steam	$ 6,508					
14)	Tupper-Joint	17,952					
15)	Mersey	1,790					
16)	Total	$ 26,250					
17)	Discounts	$ 1,290					
18)	Point Tupper	$ 45					
19)	Grants	$ 3,000					
20)	Other	$ 1,575					
21)	Total	$ 4,575					
22)	Merchandise & Jobbing	$ 1,157					
23)	Total	$231,828					

NOVA SCOTIA POWER CORPORATION

SCHEDULE 37

Analysis of Operating Costs For Glace Bay
and Point Tupper Steam Sale and Mersey System
For The Year Ended March 31, 1978
($000)

		Total Company (1)	Glace Bay (2)	Point Tupper (3)	Mersey System (4)	Total (5)
	Production Fuel					
1)	Mersey System	$ 14	$ -	$ -	$ 13	$ 1
2)	Other Hydro	42	-	-	-	42
3)	Gas Turbines	607	-	-	-	607
4)	Pt. Tupper Unit 1	15,497	-	12,320	-	3,177
5)	Glace Bay	12,985	5,310	-	-	7,675
6)	Water Street	9,031	-	-	-	9,031
7)	Other Steam	55,903	-	-	-	55,903
8)	Total Fuel	$ 94,079	$ 5,310	$ 12,320	$ 13	$ 76,436
	Production Opr. Cost					
9)	Mersey	$ 751	$ -	$ -	$ 697	$ 54
10)	Other Hydro	2,156	-	-	-	2,156
11)	Gas Turbines	538	-	-	-	538
12)	Pt. Tupper Unit 1	4,234	-	3,058	-	1,176
13)	Glace Bay	4,479	2,342	-	-	2,137
14)	Water Street	4,434	-	-	-	4,434
15)	Other Steam	10,063	-	-	-	10,063
16)	Total Opr. Cost	$ 26,655	$ 2,342	$ 3,058	$ 697	$ 20,558
	Purchased Power					
17)	Purchased Power - Fuel	$ 1,064	$ -	$ -	$ -	$ 1,064
18)	Purchased Power - Other	3,393	-	-	-	3,393
19)	Total	$ 4,457	$ -	$ -	$ -	$ 4,457
20)	**Transmission Expense**	$ 2,708	$ -	$ -	$ -	$ 2,708
	Distribution Expense					
21)	Land	$ 1,067	$ -	$ -	$ -	$ 1,067
22)	Substations	1,896	-	-	-	1,896
23)	Overhead Lines	2,804	-	-	-	2,804
24)	U. G. Lines	204	-	-	-	204
25)	Line Transformers	866	-	-	-	866
26)	Services	1,284	-	-	-	1,284
27)	Meters	900	-	-	-	900
28)	Cust. Serv. & Contracts	1,044	-	-	-	1,044
29)	Cust. Premise	733	-	-	-	733
30)	Communications	507	-	-	-	507
31)	Street Light	1,618	-	-	-	1,618
32)	Total Distribution	$ 12,923	$ -	$ -	$ -	$ 12,923
	Customer Accounting					
33)	Billing	$ 3,258	$ -	$ -	$ -	$ 3,258
34)	Customer Service	1,095	-	-	-	1,095
35)	Credit & Collection	1,472	-	45	-	1,427
36)	Total Cust. Acct.	$ 5,825	$ -	$ 45	$ -	$ 5,780
37)	**Customer Relations & Information**	$ 755	$ -	$ -	$ -	$ 755
38)	**Administration & General**	$ 5,748	$ 353	$ 501	$ 342	$ 4,552
39)	**Depreciation Expense**	$ 21,085	$ 553	$ 472	$ 368	$ 19,692
40)	**Grants In Lieu of Taxes**	$ 3,623	$ -	$ -	$ -	$ 3,623
41)	**Total Cost**	$177,858	$ 8,558	$ 16,396	$ 1,420	$151,484

SCHEDULE 38

NOVA SCOTIA POWER CORPORATION

Classification of Operating Expense

For the Year Ended March 31, 1978

($000)

		Total Company (1)	Coincident Peak (2)	Peak and Average (3)	Class N.C. Peak (4)	Customer N.C. Peak (5)	Energy (6)	Customer (7)	Revenue (8)	Direct (9)	As Other (10)
	Production Expenses										
1)	Fuel	$ 94,079	$ -	$ -	$ -	$ -	$ 76,436	$ -	$ -	$ 17,643	$ -
2)	Steam Operations	23,210	17,810	17,810	17,810	-	-	-	-	5,400	-
3)	Hydro Operating	2,907	2,210	2,210	2,210	-	-	-	-	697	-
4)	Gas Turbine Operating	538	538	538	538	-	-	-	-	-	-
5)	Purchase Power - Fuel	1,064	-	-	-	-	1,064	-	-	-	-
6)	Purchase Power - Other	3,393	3,393	3,393	3,393	-	-	-	-	-	-
7)	Total	$125,191	$ 23,951	$ 23,951	$ 23,951	$ -	$ 77,500	$ -	$ -	$ 23,740	$ -
8)	**Transmission Expenses**	$ 2,708	$ 2,708	$ 2,708	$ 2,708	$ -	$ -	$ -	$ -	$ -	$ -
	Distribution Expenses										
9)	Land	$ 1,067	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,067
10)	Substations	1,895	-	-	-	-	-	-	-	-	1,895
11)	Overhead Lines	2,804	-	-	-	-	-	-	-	-	2,804
12)	U.G. Lines	204	-	-	-	-	-	-	-	-	204
13)	Line Transformers	866	-	-	866	866	-	-	-	-	-
14)	Services	1,284	-	-	-	-	-	1,284	-	-	-
15)	Meters	900	-	-	-	-	-	-	-	900	-
16)	Cust. Serv. & Contract	1,045	-	-	-	-	-	105	-	940	-
17)	Cust. Premise	733	-	-	-	-	-	73	-	660	-
18)	Communications	507	-	-	507	507	-	-	-	-	-
19)	Street Lights	1,618	-	-	-	-	-	-	-	1,618	-
20)	Total	$ 12,923	$ -	$ -	$ 1,373	$ 1,373	$ -	$ 1,462	$ -	$ 4,118	$ 5,970
	Customer Accounting										
21)	Billing	$ 3,258	$ -	$ -	$ -	$ -	$ -	$ 3,258	$ -	$ -	$ -
22)	Customer Service	1,095	-	-	-	-	-	789	-	306	-
23)	Credit & Collections	1,472	-	-	-	-	-	539	-	933	-
24)	Total	$ 5,825	$ -	$ -	$ -	$ -	$ -	$ 4,586	$ -	$ 1,239	$ -
25)	**Customer Relations & Information**	$ 755	$ -	$ -	$ -	$ -	$ -	$ 755	$ -	$ -	$ -
26)	**Administrative and General**	$ 5,748	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,196	$ 4,552
27)	**Depreciation**	$ 21,085	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,393	$ 19,692
28)	**Grants in Lieu of Taxes**	$ 3,623	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,623
29)	**Total Cost**	$177,858	$ 26,659	$ 26,659	$ 28,032	$ 1,373	$ 77,500	$ 6,803	$ -	$ 31,686	$ 33,837
30)	**Total Revenue**	$201,997	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$201,997	$ -

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1978

Coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Coun. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
	Production Costs													
1)	Fuel	$ 76,436	$ 27,807	$ 741	$ 15,746	$ 4,877	$ 1,781	$ 459	$ 4,647	$ 13,781	$ 2,049	$ 3,539	$ 1,009	E-2
2)	Operating	20,558	8,655	150	4,681	1,645	407	214	1,324	2,159	-	939	384	D-2
3)	Purchased Power - Fuel	1,064	387	10	219	68	25	6	65	192	29	49	14	E-2
4)	Purchased Power - Other	3,393	1,429	25	773	271	67	35	219	356	-	155	63	D-2
5)	Total Production	$101,451	$ 38,278	$ 926	$ 21,419	$ 6,861	$ 2,280	$ 714	$ 6,255	$ 16,488	$ 2,078	$ 4,682	$ 1,470	
6)	Transmission Operating Costs	$ 2,708	$ 1,140	$ 20	$ 616	$ 217	$ 54	$ 28	$ 174	$ 284	$ -	$ 124	$ 51	D-2
	Distribution Operating Costs													
7)	Land	$ 1,067	$ 775	$ 21	$ 145	$ 43	$ 9	$ 6	$ 31	$ 13	$ -	$ 12	$ 12	P-12
8)	Substations	1,896	987	12	377	132	42	20	149	78	2	71	26	P-17
9)	Overhead Lines	2,804	2,186	65	337	91	13	13	44	13	-	11	31	P-10
10)	U. G. Lines	204	159	5	24	7	1	1	3	1	-	1	2	P-10
11)	Line Transformers	866	565	7	200	69	-	10	-	-	-	-	15	D-6
12)	Services	1,284	917	34	298	31	-	4	-	-	-	-	-	C-11
13)	Meters	900	695	26	148	20	-	2	6	2	1	-	-	Schedule 35
14)	Customer Service & Contracts	1,044	940	35	62	6	-	1	-	-	-	-	-	Schedule 42
15)	Customer Premise	733	660	25	43	4	-	1	-	-	-	-	-	Schedule 43
16)	Communications	507	287	3	108	36	10	6	32	9	-	8	8	D-8
17)	Street Lights	1,618	-	-	-	-	-	-	-	-	-	-	1,618	Direct
18)	Total Distribution	$ 12,923	$ 8,171	$ 233	$ 1,742	$ 439	$ 75	$ 64	$ 265	$ 116	$ 3	$ 103	$ 1,712	
	Customer Accounting													
19)	Billing	$ 3,258	$ 2,262	$ 87	$ 755	$ 79	$ -	$ 9	$ 11	$ 1	$ 1	$ 1	$ 52	C-12
20)	Customer Service	1,095	784	30	233	26	-	3	5	1	-	-	13	Schedule 44
21)	Credit & Collection	1,427	777	27	213	54	-	5	-	347	-	-	4	Schedule 45
22)	Total Customer Accounting	$ 5,780	$ 3,823	$ 144	$ 1,201	$ 159	$ -	$ 17	$ 16	$ 349	$ 1	$ 1	$ 69	
23)	Customer Relations & Info.	$ 755	$ 674	$ 25	$ 44	$ 5	$ -	$ 1	$ -	$ -	$ -	$ -	$ 6	C-2
24)	Admin. & General	$ 4,552	$ 1,918	$ 50	$ 921	$ 283	$ 89	$ 30	$ 247	$ 635	$ 76	$ 181	$ 122	O-4
25)	Depreciation	$ 19,692	$ 9,931	$ 211	$ 4,029	$ 1,339	$ 299	$ 179	$ 984	$ 1,463	$ 2	$ 660	$ 595	P-14
26)	Grants in Lieu of Taxes	$ 3,623	$ 1,827	$ 39	$ 741	$ 246	$ 55	$ 33	$ 181	$ 269	$ -	$ 122	$ 110	P-14
27)	Total Cost	$151,484	$ 65,762	$ 1,648	$ 30,713	$ 9,549	$ 2,852	$ 1,066	$ 8,122	$ 19,604	$ 2,160	$ 5,873	$ 4,135	
28)	Total Revenue	$204,376	$ 78,440	$ 2,350	$ 49,645	$ 13,816	$ 3,649	$ 1,673	$ 10,827	$ 27,631	$ 3,330	$ 7,408	$ 5,607	Schedule 36
29)	Return	$ 52,892	$ 12,678	$ 702	$ 18,932	$ 4,267	$ 797	$ 607	$ 2,705	$ 8,027	$ 1,170	$ 1,535	$ 1,472	
30)	Rate of Return	8.55	4.10	10.63	14.97	10.17	8.33	10.92	8.69	16.76	223.28	7.33	8.00	
31)	Percentage of Average	100.00	47.95	124.33	175.09	118.95	97.43	127.22	101.64	196.02	2611.46	85.73	93.57	

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1978

Coincident Peak & Average Responsibility

($000)

		Total Company Less Steam & Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Costs													
1)	Fuel	$ 76,436	$ 27,807	$ 741	$ 15,746	$ 4,877	$ 1,781	$ 459	$ 4,647	$ 13,781	$ 2,049	$ 3,539	$ 1,009	E-2
2)	Operating	20,558	8,196	171	4,506	1,511	434	183	1,301	2,759	210	946	341	D-4
3)	Purchased Power - Fuel	1,064	387	10	219	68	25	6	65	192	29	49	14	E-2
4)	Purchased Power - Other	3,393	1,353	28	744	249	72	30	215	455	35	156	56	D-4
5)	Total Production	$101,451	$ 37,743	$ 950	$ 21,215	$ 6,705	$ 2,312	$ 678	$ 6,228	$ 17,187	$ 2,323	$ 4,690	$ 1,420	
6)	**Transmission Operating Costs**	$ 2,708	$ 1,080	$ 22	$ 594	$ 199	$ 57	$ 24	$ 171	$ 363	$ 28	$ 125	$ 45	D-4
	Distribution Operating Costs													
7)	Land	$ 1,067	$ 739	$ 22	$ 164	$ 50	$ 10	$ 7	$ 35	$ 13	$ -	$ 13	$ 14	P-13
8)	Substations	1,896	867	13	434	156	46	23	168	80	2	76	31	P-18
9)	Overhead Lines	2,801	2,112	66	375	107	15	15	52	14	-	13	35	P-11
10)	U. G. Lines	204	154	5	27	8	1	1	4	1	-	1	2	P-11
11)	Line Transformers	866	508	8	236	84	-	12	-	-	-	-	18	D-12
12)	Services	1,284	917	34	298	31	-	4	-	-	-	-	-	C-11
13)	Meters	900	695	26	148	20	-	2	6	2	1	-	-	Schedule 35
14)	Cust. Serv. & Contracts	1,044	940	35	62	6	-	1	-	-	-	-	-	Schedule 42
15)	Customer Premise	733	660	25	43	4	-	1	-	-	-	-	-	Schedule 43
16)	Communications	507	252	4	125	43	11	6	37	10	-	10	9	D-14
17)	Street Lighting	1,613	-	-	-	-	-	-	-	-	-	-	1,618	Direct
18)	Total Distribution	$ 12,923	$ 7,844	$ 238	$ 1,912	$ 509	$ 83	$ 72	$ 302	$ 120	$ 3	$ 113	$ 1,727	
	Customer Accounting													
19)	Billing	$ 3,253	$ 2,262	$ 87	$ 755	$ 79	$ -	$ 9	$ 11	$ 1	$ 1	$ 1	$ 52	C-12
20)	Customer Service	1,095	784	30	233	26	-	3	5	1	-	-	13	Schedule 44
21)	Credit & Collection	1,427	777	27	213	54	-	5	-	347	-	-	4	Schedule 45
22)	Total Customer Accounting	$ 5,780	$ 3,823	$ 144	$ 1,201	$ 159	$ -	$ 17	$ 16	$ 349	$ 1	$ 1	$ 69	
23)	**Customer Relations & Information**	$ 755	$ 674	$ 25	$ 44	$ 5	$ -	$ 1	$ -	$ -	$ -	$ -	$ 6	C-2
24)	**Admin. & General**	$ 4,552	$ 1,884	$ 51	$ 920	$ 279	$ 90	$ 29	$ 247	$ 664	$ 86	$ 182	$ 120	O-5
25)	**Depreciation**	$ 19,692	$ 9,568	$ 221	$ 4,078	$ 1,337	$ 313	$ 173	$ 994	$ 1,676	$ 75	$ 666	$ 591	P-15
26)	**Grants In Lieu of Taxes**	$ 3,623	$ 1,760	$ 41	$ 750	$ 246	$ 58	$ 32	$ 183	$ 308	$ 14	$ 122	$ 109	P-15
27)	**Total Cost**	$151,484	$ 64,376	$ 1,692	$ 30,714	$ 9,439	$ 2,913	$ 1,026	$ 8,141	$ 20,667	$ 2,530	$ 5,899	$ 4,087	
28)	**Total Revenue**	$204,376	$ 78,440	$ 2,350	$ 49,645	$ 13,816	$ 3,649	$ 1,673	$ 10,827	$ 27,631	$ 3,330	$ 7,408	$ 5,607	Schedule 36
29)	**Return**	$ 52,892	$ 14,064	$ 658	$ 18,931	$ 4,377	$ 736	$ 647	$ 2,686	$ 6,964	$ 800	$ 1,509	$ 1,520	
30)	**Rate of Return**	8.55	4.72	9.49	14.79	10.44	7.38	12.04	8.56	12.81	28.91	7.14	8.31	
31)	**Percentage of Average**	100.00	55.20	110.99	172.98	122.11	86.32	140.82	100.12	149.82	338.13	83.51	97.19	

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1978

Class Non-coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General-Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptable Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Costs													
1)	Fuel	$ 76,436	$ 27,807	$ 741	$ 15,746	$ 4,877	$ 1,781	$ 459	$ 4,647	$ 13,781	$ 2,049	$ 3,539	$ 1,009	E-2
2)	Operating	20,558	8,793	136	4,346	1,499	380	222	1,346	2,136	518	863	319	D-18
3)	Purchased Power-Fuel	1,064	387	10	219	68	25	6	65	192	29	49	14	E-2
4)	Purchased Power-Other	3,393	1,451	22	717	247	63	37	222	353	86	142	53	D-18
5)	Total Production	$101,451	$ 38,438	$ 909	$ 21,028	$ 6,691	$ 2,249	$ 724	$ 6,280	$ 16,462	$ 2,682	$ 4,593	$ 1,395	
6)	Transmission Operating Costs	$ 2,708	$ 1.158	$ 18	$ 573	$ 198	$ 50	$ 29	$ 177	$ 281	$ 68	$ 114	$ 42	D-18
	Distribution Operating Costs													
7)	Land	$ 1,067	$ 739	$ 22	$ 164	$ 50	$ 10	$ 7	$ 35	$ 13	$ -	$ 13	$ 14	P-13
8)	Substations	1,896	867	13	434	156	46	23	168	80	2	76	31	P-18
9)	Overhead Lines	2,804	2,112	66	375	107	15	15	52	14	-	13	35	P-11
10)	U. Ground Lines	204	154	5	27	8	1	1	4	1	-	1	2	P-11
11)	Line Transformers	866	508	8	236	84	-	12	-	-	-	-	18	D-12
12)	Services	1,284	917	34	298	31	-	4	-	-	-	-	-	C-11
13)	Meters	900	695	26	148	20	-	2	6	2	1	-	-	Schedule 35
14)	Cust. Serv & Contracts	1,044	940	35	62	6	-	1	-	-	-	-	-	Schedule 42
15)	Customer Premise	733	660	25	43	4	-	1	-	-	-	-	-	Schedule 43
16)	Communications	507	252	4	125	43	11	6	37	10	-	10	9	D-14
17)	St. Lighting	1,618	-	-	-	-	-	-	-	-	-	-	1,618	Direct
18)	Total Distribution	$ 12,923	$ 7,844	$ 238	$ 1,912	$ 509	$ 83	$ 72	$ 302	$ 120	$ 3	$ 113	$ 1,727	
	Customer Accounting													
19)	Billing	$ 3,258	$ 2,262	$ 87	$ 755	$ 79	$ -	$ 9	$ 11	$ 1	$ 1	$ 1	$ 52	C-12
20)	Customer Service	1,095	784	30	233	26	-	3	5	1	-	-	13	Schedule 44
21)	Credit & Collection	1,427	777	27	213	54	-	5	-	347	-	-	4	Schedule 45
22)	Total Customer Acc.	$ 5,780	$ 3,823	$ 144	$ 1,201	$ 159	$ -	$ 17	$ 16	$ 349	$ 1	$ 1	$ 69	
23)	Customer Relations & Information	$ 755	$ 674	$ 25	$ 44	$ 5	$ -	$ 1	$ -	$ -	$ -	$ -	$ 6	C-2
24)	Admin. & General	$ 4,552	$ 1,912	$ 49	$ 912	$ 279	$ 88	$ 31	$ 249	$ 634	$ 101	$ 178	$ 119	O-6
25)	Depreciation	$ 19,692	$ 9,818	$ 205	$ 3,921	$ 1,290	$ 286	$ 189	$ 1,016	$ 1,449	$ 341	$ 614	$ 563	P-16
26)	Grants in Lieu of Taxes	$ 3,623	$ 1,806	$ 38	$ 721	$ 237	$ 52	$ 35	$ 187	$ 267	$ 63	$ 113	$ 104	P-16
27)	Total Cost	$151,484	$ 65,473	$ 1,626	$ 30,312	$ 9,368	$ 2,808	$ 1,098	$ 8,227	$ 19,562	$ 3,259	$ 5,726	$ 4,025	
28)	Total Revenue	$204,376	$ 78,440	$ 2,350	$ 49,645	$ 13,816	$ 3,649	$ 1,673	$ 10,827	$ 27,631	$ 3,330	$ 7,408	$ 5,607	Schedule 36
29)	Return	$ 52,892	$ 12,967	$ 724	$ 19,333	$ 4,448	$ 841	$ 575	$ 2,600	$ 8,069	$ 71	$ 1,682	$ 1,582	
30)	Rate of Return	8.55	4.24	11.27	15.69	11.00	9.19	9.80	8.11	16.99	.65	8.60	9.08	
31)	Percentage of Average	100.00	49.59	131.81	183.51	128.65	107.48	114.62	94.85	198.71	7.60	100.58	106.20	

NOVA SCOTIA POWER CORPORATION

SCHEDULE 42

Allocation of Customer Service and Contracts

For the Year Ended March 31, 1978

($000)

		Direct (1)	Customers (2)	Percent (3)	Amount Allocated (4)	Total (5)
1)	Domestic	$ 940(1)	-	-	$ -	$ 940
2)	General Conn. Load	-	9,855	33.89	35	35
3)	General	-	17,215	59.20	62	62
4)	General All Electric	-	1,792	6.16	6	6
5)	Industrial To 249 KVA	-	218	.75	1	1
6)	Total	$ 940	29,080	100.00	$ 104	$ 1,044

(1) 90% Domestic

NOVA SCOTIA POWER CORPORATION

SCHEDULE 43

Allocation of Customer Premise Expense

For the Year Ended March 31, 1978

($000)

		Direct (1)	Customers (2)	Percent (3)	Amount Allocated (4)	Total (5)
1)	Domestic	$ 660(1)	-	-	$ -	$ 660
2)	General Conn. Load	-	9,855	33.89	25	25
3)	General	-	17,215	59.20	43	43
4)	General All Electric	-	1,792	6.16	4	4
5)	Industrial To 249 KVA	-	218	.75	1	1
6)	Total	$ 660	29,080	100.00	$ 73	$ 733

(1) 90% Domestic

NOVA SCOTIA POWER CORPORATION

SCHEDULE 44

Allocation of Customer Service Expense

For the Year Ended March 31, 1978

($000)

		Total Company Less Steam and Joint (1)	Meter Test (As Meters) (2)	Other C-12 (3)
1)	Domestic	$ 784	$ 236	$ 548
2)	General Conn. Load	30	9	21
3)	General	233	50	183
4)	General All Electric	26	7	19
5)	General Large	-	-	-
6)	Industrial to 249 KVA	3	1	2
7)	Industrial 250-3,999 KVA	5	2	3
8)	Industrial Large	1	1	-
9)	Interruptible	-	-	-
10)	Municipal	-	-	-
11)	Unmetered	13	-	13
12)	Total	$1,095	$ 306	$ 789

NOVA SCOTIA POWER CORPORATION SCHEDULE 45

Allocation of Credit & Collection Expense

For the Year Ended March 31, 1978

($000)

		Total (1)	Direct Bad Debts (2)	Other Bad Debts R-2 (3)	Collection Costs C-2 (4)
1)	Domestic	$ 777	$ -	$ 295	$ 482
2)	General Conn. Load	27	-	9	18
3)	General	213	-	182	31
4)	General All Electric	54	-	51	3
5)	General Large	-	-	-	-
6)	Industrial to 249 KVA	5	-	4	1
7)	Industrial 250-3,999 KVA	-	-	-	-
8)	Industrial Large	347	347	-	-
9)	Interruptible	-	-	-	-
10)	Municipal	-	-	-	-
11)	Unmetered	4	-	-	4
12)	Total	$1,427	$ 347	$ 541	$ 539

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) System Peak MW - 1977	993	411	7	219	85	18	7	59	123	-	47	17	
2) % Responsibility	100.00	41.39	0.71	22.05	8.56	1.81	0.71	5.94	12.39	-	4.73	1.71	D-1
2) System Peak MW - 1978	962	405	7	219	77	19	10	62	101	-	44	18	
4) % Responsibility	100.00	42.10	0.73	22.77	8.00	1.98	1.04	6.44	10.50	-	4.57	1.87	D-2
5) System Peak and Average - 1977	1,608	635	13	341	125	32	10	97	241	15	74	25	
6) % Responsibility	100.00	39.49	0.81	21.21	7.77	1.99	0.62	6.03	14.99	0.93	4.60	1.56	D-3
7) System Peak and Average - 1978	1,565	624	13	343	115	33	14	99	210	16	72	26	
8) % Responsibility	100.00	39.87	0.83	21.92	7.35	2.11	0.89	6.33	13.42	1.02	4.60	1.66	D-4
9) Customer Non-Coincident Demand Sec. - 1977	978,349	638,455	7,211	223,290	85,924	-	7,647	-	-	-	-	15,822	
10) % Responsibility	100.00	65.26	.74	22.82	8.78	-	.78	-	-	-	-	1.62	D-5
11) Customer Non-Coincident Demand Sec. - 1978	971,044	633,131	7,424	224,573	77,703	-	11,686	-	-	-	-	16,527	
12) % Responsibility	100.00	65.20	.77	23.13	8.00	-	1.20	-	-	-	-	1.70	D-6
13) Customer Non-Coincident Demand Pri. - 1977	1,162,016	661,439	7,471	245,080	91,319	21,012	8,743	68,493	20,344	-	21,724	16,391	
14) % Responsibility	100.00	56.92	0.64	21.09	7.86	1.81	0.75	5.90	1.75	-	1.87	1.41	D-7
15) Customer Non-Coincident Demand Pri. - 1978	1,151,946	652,758	7,654	245,220	82,403	22,047	12,865	72,175	21,093	-	18,692	17,039	
16) % Responsibility	100.00	56.67	.66	21.29	7.15	1.91	1.12	6.27	1.83	-	1.62	1.48	D-8
17) Customer Non-Coincident Demand DBPS - 1977	1,379,458	674,668	7,620	249,982	93,145	21,432	8,918	72,780	153,719	28,941	51,534	16,719	
18) % Responsibility	100.00	48.91	0.55	18.12	6.75	1.55	0.65	5.28	11.14	2.10	3.74	1.21	D-9
19) Customer Non-Coincident Demand DBPS - 1978	1,350,746	665,813	7,807	250,124	84,051	22,488	13,122	76,536	133,444	31,539	48,442	17,380	
20) % Responsibility	100.00	49.29	.58	18.52	6.22	1.66	.97	5.67	9.88	2.33	3.59	1.29	D-10
21) Class N.C. Demand Sec. - 1977	786,625	460,976	6,851	212,126	83,777	-	7,073	-	-	-	-	15,822	
22) % Responsibility	100.00	58.60	.87	26.97	10.65	-	.90	-	-	-	-	2.01	D-11
23) Class N.C. Demand Sec. - 1978	780,615	457,121	7,053	213,344	75,761	-	10,809	-	-	-	-	16,527	
24) % Responsibility	100.00	58.56	.90	27.33	9.71	-	1.38	-	-	-	-	2.12	D-12
25) Class N.C. Demand Pri. - 1977	952,787	477,571	7,098	232,826	89,037	19,436	8,087	63,356	17,802	-	21,182	16,392	
26) % Responsibility	100.00	50.13	.74	24.44	9.34	2.04	.85	6.65	1.87	-	2.22	1.72	D-13
27) Class N.C. Demand Pri. - 1978	947,441	471,292	7,272	232,959	80,343	20,393	11,900	69,561	18,457	-	18,225	17,039	
28) % Responsibility	100.00	49.74	.77	24.59	8.48	2.15	1.26	7.34	1.95	-	1.92	1.80	D-14
29) Class N.C. Demand DBPS - 1977	1,145,576	487,122	7,240	237,482	90,818	19,825	8,249	67,322	134,505	26,046	50,247	16,720	
30) % Responsibility	100.00	42.52	.63	20.73	7.93	1.73	.72	5.88	11.74	2.27	4.39	1.46	D-15
31) Class N.C. Demand DBPS - 1978	1,124,052	480,718	7,417	237,618	81,950	20,882	12,138	73,651	116,763	28,385	47,231	17,380	
32) % Responsibility	100.00	42.77	.66	21.14	7.29	1.85	1.08	6.55	10.39	2.52	4.20	1.55	D-16
33) Class N.C. Demand Gen. - 1977	1,175,358	499,787	7,428	243,656	93,179	20,340	8,463	69,072	138,002	26,723	51,553	17,153	
34) % Responsibility	100.00	42.52	.63	20.73	7.93	1.73	.72	5.88	11.74	2.27	4.39	1.46	D-17
35) Class N.C. Demand Gen. - 1978	1,153,279	493,217	7,610	243,796	84,081	21,342	12,454	75,566	119,799	29,123	48,459	17,832	
36) % Responsibility	100.00	42.77	.66	21.14	7.29	1.85	1.08	6.55	10.39	2.52	4.20	1.55	D-18

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1) MWH Gen. and Purchased - 1977	5,360,248	1,962,940	53,869	1,072,609	346,591	121,710	23,325	308,795	1,032,453	130,242	240,729	66,985	
2) % Responsibility	100.00	36.62	1.00	20.01	6.47	2.27	0.44	5.76	19.26	2.43	4.49	1.25	E-1
3) MWH Gen. and Purchased - 1978	5,280,003	1,920,889	51,449	1,087,430	337,065	123,193	31,907	321,103	951,746	141,260	244,223	69,738	
4) % Responsibility	100.00	36.38	0.97	20.60	6.38	2.33	0.60	6.08	18.03	2.68	4.63	1.32	E-2

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Customers - 1977	290,241	257,891	10,710	16,627	2,069	3	166	124	14	6	8	2,623	
2) Responsibility	100.00	88.86	3.69	5.73	0.71	-	0.06	0.04	.01	-	-	0.90	C-1
3) Customers - 1978	296,082	264,465	9,855	17,215	1,792	3	218	126	14	6	8	2,380	
4) % Responsibility	100.00	89.32	3.33	5.82	0.61	-	0.07	.04	.01	-	-	0.80	C-2
5) Customers Secondary - 1977	290,061	257,891	10,710	16,608	2,065	-	164	-	-	-	-	2,623	
6) % Responsibility	100.00	88.91	3.69	5.73	.71	-	.06	-	-	-	-	.90	C-3
7) Customers Secondary - 1978	295,900	264,465	9,855	17,196	1,788	-	216	-	-	-	-	2,380	
8) % Responsibility	100.00	89.38	3.33	5.81	.61	-	.07	-	-	-	-	.80	C-4
9) Customers Primary - 1977	290,175	257,891	10,710	16,627	2,069	3	166	82	2	-	2	2,623	
10) % Responsibility	100.00	88.88	3.69	5.73	.71	-	.06	.03	-	-	-	.90	C-5
11) Customers Primary - 1978	296,016	264,465	9,855	17,215	1,792	3	218	84	2	-	2	2,380	
12) % Responsibility	100.00	89.34	3.33	5.82	.61	-	.07	.03	-	-	-	.80	C-6
13) Customers DBPS - 1977	290,234	257,891	10,710	16,627	2,069	3	166	118	13	6	8	2,623	
14) % Responsibility	100.00	88.86	3.69	5.73	.71	-	.06	.04	.01	-	-	.90	C-7
15) Customers DBPS - 1978	296,075	264,465	9,855	17,215	1,792	3	218	120	13	6	8	2,380	
16) % Responsibility	100.00	89.32	3.33	5.82	.61	-	.07	.04	.01	-	-	.80	C-8
17) Weighted Secondary Customers - 1977	287,438	257,891	10,710	16,608	2,065	-	164	-	-	-	-	-	
18) Weighting Factor		1.00	1.00	5.0	5.0	-	5.0	-	-	-	-	-	
19) Weighted Total	362,786	257,891	10,710	83,040	10,325	-	820	-	-	-	-	-	
20) % Responsibility	100.00	71.09	2.95	22.88	2.85	-	0.23	-	-	-	-	-	C-9
21) Weighted Secondary Customers - 1978	293,550	264,465	9,885	17,196	1,788	-	216	-	-	-	-	-	
22) Weighting Factor		1.00	1.00	5.0	5.0	-	5.0	-	-	-	-	-	
23) Weighted Total	370,350	264,465	9,885	85,980	8,940	-	1,080	-	-	-	-	-	
24) % Responsibility	100.00	71.41	2.67	23.22	2.41	-	.29	-	-	-	-	-	C-11
25) Weighted Customers - 1977	289,701	257,891	10,170	16,627	2,069	3	166	124	14	6	8	2,623	
26) Weighting Factor		1.0	1.0	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	2.5	
27) Weighted Total	370,464	257,891	10,170	83,135	10,345	15	830	1,240	140	60	80	6,558	
28) % Responsibility	100.00	69.63	2.74	22.44	2.79	-	0.22	0.33	0.04	0.02	0.02	1.77	C-10
29) Weighted Customers - 1978	289,538	257,891	9,885	17,215	1,792	3	218	126	14	6	8	2,380	
30) Weighting Factor		1.00	1.00	5.0	5.3	5.3	5.0	10.0	10.0	10.0	10.0	2.5	
31) Weighted Total	371,406	257,891	9,885	86,075	8,960	15	1,090	1,260	140	60	80	5,950	
32) % Responsibility	100.00	69.44	2:66	23.18	2.41	-	.29	.34	.04	.02	.02	1.60	C-12

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors
For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Coincident Peak Poles & Wire - 1977	79,135	61,514	2,003	9,386	2,834	358	261	1,175	345	-	369	890	
2) % Responsibility	100.00	77.73	2.53	11.86	3.58	0.45	0.33	1.49	0.44	-	0.47	1.12	P-1
3) Coincident Peak Poles & Wire - 1978	89,897	70,073	2,085	10,794	2,909	428	434	1,418	411	-	364	981	
4) % Responsibility	100.00	77.95	2.32	12.01	3.23	0.48	0.48	1.58	0.46	-	0.40	1.09	P-10
5) Class Non-Coincident Peak & Average Poles & Wire -1977	79,135	59,467	2,038	10,489	3,323	403	293	1,323	369	-	438	992	
6) % Responsibility	100.00	75.15	2.58	13.25	4.20	0.51	0.37	1.67	0.47	-	0.55	1.25	P-2
7) Class Non-Coincident Peak & Avg. Poles & Wire-1978	89,897	67,716	2,126	12,042	3,414	482	488	1,658	438	-	430	1,103	
8) % Responsibility	100.00	75.33	2.36	13.39	3.80	0.54	0.54	1.84	0.49	-	0.48	1.23	P-11
9) Coincident Peak Substations Poles & Wire -1977	102,076	73,465	2,137	13,886	4,583	842	427	2,923	1,299	19	1,309	1,186	
10) % Responsibility	100.00	71.97	2.09	13.60	4.49	0.83	0.42	2.87	1.27	0.02	1.28	1.16	P-3
11) Coincident Peak Substations Poles & Wire -1978	113,081	82,153	2,226	15,401	4,529	935	681	3,244	1,362	18	1,235	1,297	
12) % Responsibility	100.00	72.65	1.97	13.62	4.00	0.83	0.60	2.87	1.20	0.02	1.09	1.15	P-12
13) Class Non-Coincident Peak & Avg. Subs., Poles & Wire-1977	103,099	69,993	2,193	15,692	5,383	935	480	3,228	1,348	19	1,475	1,353	
14) % Responsibility	100.00	68.56	2.15	15.37	5.27	0.92	0.47	3.16	1.32	0.02	1.44	1.32	P-4
15) Class Non-Coincident Peak & Avg. Subs., Poles & Wire-1978	112,081	78,319	2,290	17,353	5,317	1,041	765	3,712	1,415	18	1,364	1,487	
16) % Responsibility	100.00	69.26	2.02	15.35	4.70	0.92	0.68	3.28	1.25	0.02	1.21	1.31	P-13
17) Coincident Peak P.T.D. - 1977	415,392	215,985	4,970	80,341	29,102	5,383	2,475	17,888	32,157	26	13,121	13,944	
18) % Responsibility	100.00	51.99	1.20	19.34	7.00	1.30	0.60	4.30	7.74	0.01	3.16	3.36	P-5
19) Coincident Peak P.T.D. - 1978	580,779	292,910	6,218	118,808	39,502	8,848	5,274	29,051	43,142	25	19,441	17,560	
20) % Responsibility	100.00	50.43	1.07	20.46	6.80	1.52	0.91	5.00	7.43	0.01	3.35	3.02	P-14
21) Coincident Peak & Avg. P.T.D. - 1977	415,392	206,638	5,272	81,626	28,821	5,852	2,381	18,390	37,556	1,939	13,004	13,913	
22) % Responsibility	100.00	49.74	1.27	19.65	6.94	1.41	0.57	4.43	9.04	0.47	3.13	3.35	P-6
23) Coincident Peak & Avg. P.T.D. - 1978	580,779	282,180	6,535	120,294	39,454	9,236	5,097	29,308	49,404	2,194	19,640	17,437	
24) % Responsibility	100.00	48.59	1.12	20.71	6.79	1.59	0.88	5.05	8.51	0.38	3.38	3.00	P-15
25) Class Non-Coincident P.T.D. 1977	415,392	213,130	4,867	80,023	28,359	5,282	2,541	17,833	31,860	5,668	12,227	13,602	
26) % Responsibility	100.00	51.31	1.17	19.27	6.83	1.27	0.61	4.29	7.67	1.37	2.94	3.27	P-7
27) Class Non-Coincident P.T.D. - 1978	580,779	289,581	6,043	115,625	38,016	8,443	5,575	29,979	42,760	10,037	18,108	16,612	
28) % Responsibility	100.00	49.86	1.04	19.91	6.55	1.45	0.96	5.16	7.36	1.73	3.12	2.86	P-16
29) Coincident Peak Substations - 1977	22,941	11,951	134	4,500	1,749	484	166	1,748	954	19	940	296	
30) % Responsibility	100.00	52.10	0.58	19.62	7.62	2.11	0.72	7.62	4.16	0.08	4.10	1.29	P-8
31) Coincident Peak Substations - 1978	23,184	12,080	141	4,607	1,620	507	247	1,826	951	18	871	316	
32) % Responsibility	100.00	52.10	.61	19.87	6.99	2.19	1.06	7.88	4.10	.08	3.76	1.36	P-17
33) Class Non-Coincident Peak & Avg. Substations -1977	22,941	10,526	155	5,203	2,060	532	187	1,905	979	19	1,014	361	
34) % Responsibility	100.00	45.88	.68	22.68	8.98	2.32	.82	8.30	4.27	.08	4.42	1.57	P-9
35) Class Non-Coincident Peak & Avg. Substations -1978	23,184	10,603	164	5,311	1,903	559	277	2,054	977	18	934	364	
36) % Responsibility	100.00	45.73	.71	22.91	8.21	2.41	1.19	8.86	4.21	.08	4.03	1.66	P-18

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Coincident Peak O. & M. - 1977	$ 42,055	$21,755	$ 563	$ 8,196	$2,738	$ 514	$ 235	$1,719	$ 3,151	$ 3	$1,274	$1,907	
2) % Responsibility	100.00	51.73	1.34	19.49	6.51	1.22	.56	4.09	7.49	.01	3.03	4.53	0-1
3) Coincident Peak O. & M. - 1978	$123,617	$52,086	$1,348	$25,022	$7,681	$2,409	$ 824	$6,710	$17,237	$ 2,082	$4,910	$3,308	
4) % Responsibility	100.00	42.14	1.09	20.24	6.21	1.95	.67	5.43	13.94	1.68	3.97	2.68	0-4
5) Coincident Peak & Average O. & M. - 1977	$ 42,055	$20,980	$ 593	$ 8,156	$2,620	$ 565	$ 218	$1,762	$ 3,791	$ 232	$1,253	$1,885	
6) % Responsibility	100.00	49.89	1.41	19.39	6.23	1.34	.52	4.19	9.02	.55	2.98	4.48	0-2
7) Coincident Peak & Average O. & M. - 1978	$123,617	$51,164	$1,379	$24,966	$7,577	$2,452	$ 792	$6,717	$18,019	$ 2,355	$4,929	$3,267	
8) % Responsibility	100.00	41.39	1.12	20.20	6.13	1.98	.64	5.43	14.58	1.90	3.99	2.64	0-5
9) Class Non-Coincident Peak O. & M. - 1977	$ 42,055	$21,724	$ 548	$ 8,039	$2,657	$ 501	$ 240	$1,726	$ 2,997	$ 560	$1,202	$1,861	
10) % Responsibility	100.00	51.66	1.30	19.12	6.32	1.19	.57	4.10	7.13	1.33	2.86	4.42	0-3
11) Class Non-Coincident Peak O. & M. - 1978	$123,617	$51,937	$1,334	$24,758	$7,562	$2,382	$ 843	$6,775	$17,212	$2,754	$ 4,821	$3,239	
12) % Responsibility	100.00	42.01	1.08	20.03	6.12	1.93	.68	5.48	13.92	2.23	3.90	2.62	0-6

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Secondary Customer/Revenue - 1977	$ 141,659	$ 75,885	$ 2,277	$ 48,390	$13,473	$ -	$1,634	$ -	$ -	$ -	$ -	$ -	
2) % Responsibility	100.00	53.57	1.61	34.16	9.51	-	1.15	-	-	-	-	-	R-1
3) Secondary Customer/Revenue - 1978	$ 141,564	$ 77,108	$ 2,293	$ 47,582	$13,394	$ -	$1,187	$ -	$ -	$ -	$ -	$ -	
4) % Responsibility	100.00	54.47	1.62	33.61	9.46	-	.84	-	-	-	-	-	R-2
5) Discount Revenue - 1978	$1,293,894	$798,951	$19,796	$144,107	$34,283	$1,735	$ -	$ -	$228,837	$ 4,558	$58,530	$ 3,097	R-3
6) % Responsibility	100.00	61.75	1.53	11.14	2.65	.13	-	-	17.69	.35	4.52	.24	

SCHEDULE 1

NOVA SCOTIA POWER CORPORATION

Cost of Service Study Summaries

For the Years Ended March 31, 1977 and 1978

Percentage Relationship of Class Return to Average Return

	Total Company Less Steam And Joint (1)	Domestic (2)	General Comm. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)
Year Ended March 31, 1977												
1) Coincident Peak	100.00	59.0	99.3	161.5	101.4	115.4	125.7	104.5	190.9	4,796.8	105.5	78.8
2) Coincident Peak and Average	100.00	65.0	88.6	158.9	105.1	99.1	136.4	99.5	150.6	326.2	107.6	79.9
3) Class Non Coincident Peak	100.00	60.2	104.0	163.4	106.4	119.6	121.1	104.6	195.6	66.1	118.4	83.4
Year Ended March 31, 1978												
4) Coincident Peak	100.00	48.0	124.3	175.1	119.0	97.4	127.7	101.6	196.0	2,611.5	85.7	93.6
5) Coincident Peak and Average	100.00	55.2	111.0	173.0	122.1	86.3	140.8	100.1	149.8	388.1	83.5	97.2
6) Class Non Coincident Peak	100.00	49.6	131.8	183.5	128.7	107.5	114.6	94.9	198.7	7.6	100.6	106.2

SCHEDULE 2

NOVA SCOTIA POWER CORPORATION

Load Analysis

For the Years Ending March 31, 1977 and 1978

	Class	Customers Served (1)	MWH Sales (2)	Losses (3)	MWH Generated & Purchased (4)	Non Diversified Class L.F. at Dec KW (5)	Non Diversified Class KW Demand December (6)	Class Coincident Factor (7)	Diversified Class Load Factor (8)	Diversified Class KW Demand (9)	System Coincidence Factor (10)	Coincident KW Demand (11)	Losses (12)	System Coincident KW Demand (13)
	1977													
1)	Domestic	257,891	1,771,621	10.8	1,962,940	32.50	622,276	.722	45.01	449,294	.825	370,668	10.8	410,700
2)	Gen. Serv. Connt. Load	10,710	48,618	10.8	53,869	78.97	7,028	.950	83.12	6,677	.900	6,009	10.8	6,658
3)	Gen. Serv. Demand	16,627	968,059	10.8	1,072,609	47.86	230,906	.950	50.37	219,361	.900	197,425	10.8	218,747
4)	Gen. Serv. All Electric	2,069	314,226	10.3	346,591	41.72	85,969	.975	42.79	83,820	.925	77,534	10.3	85,519
5)	Gen. Serv. Large	3	111,661	9.0	121,710	62.85	20,282	.925	67.94	18,761	.875	16,416	9.0	17,893
6)	Industrial to 249 KVA	166	21,399	9.0	23,325	29.63	8,245	.925	32.02	7,627	.875	6,674	9.0	7,274
7)	Industrial 250-3,999 KVA	124	286,452	7.8	308,795	48.11	67,969	.925	52.01	62,871	.875	55,012	7.8	59,303
8)	Industrial Large	14	985,165	4.8	1,032,453	71.88	157,558	.875	81.57	137,863	.850	117,184	4.8	122,808
9)	Interruptible	6	124,277	4.8	130,242	50.00	28,373	.900	55.56	25,536	-	-	-	-
10)	Bowaters Mersey	1	200,000	4.8	209,600	54.39	41,979	1.000	54.39	41,979	.900	37,781	4.8	39,959
11)	A.E.C.L. Pt. Tupper	1	148,961	4.8	156,111	70.56	24,100	.975	72.37	23,498	.975	22,911	4.8	24,011
12)	Municipal	8	229,703	4.8	240,729	52.68	49,770	.975	54.04	48,526	.925	44,887	4.8	47,042
13)	Unmetered	2,623	60,456	10.8	66,985	44.75	15,421	1.000	44.75	15,421	1.000	15,421	10.8	17,086
14)	N.B.E.P.C.	1	1,659	4.8	1,739	-	-	-	-	-	-	-	-	-
15)	Total	290,244	5,272,257	8.638	5,727,698		1,359,876			1,141,234		967,922	9.252	1,057,000
	1978													
16)	Domestic	264,465	1,741,588	10.3	1,920,889	32.20	617,087	.722	44.62	445,537	.825	367,568	10.3	405,427
17)	Gen. Serv. Connt. Load	9,855	46,645	10.3	51,449	73.58	7,236	.950	77.46	6,874	.900	6,187	10.3	6,824
18)	Gen. Serv. Demand	17,215	985,884	10.3	1,087,430	48.48	232,156	.950	51.03	220,548	.900	198,493	10.3	218,938
19)	Gen. Serv. All Electric	1,792	307,822	9.5	337,065	45.08	77,956	.975	46.23	76,007	.925	70,307	9.5	76,986
20)	Gen. Serv. Large	3	113,542	8.5	123,193	60.61	21,384	.925	58.81	19,780	.875	17,308	8.5	18,779
21)	Industrial to 249 KVA	218	29,407	8.5	31,907	27.56	12,182	.925	26.74	11,268	.875	9,860	8.5	10,698
22)	Industrial 250-3,999 KVA	126	299,816	7.1	321,103	47.69	71,762	.925	46.28	66,380	.875	58,082	7.1	62,206
23)	Industrial Large	14	912,508	4.3	951,746	80.01	130,193	.875	82.07	113,919	.850	96,831	4.3	100,995
24)	Interruptible	6	135,436	4.3	141,260	50.00	30,921	.900	49.86	27,829	-	-	-	-
25)	Bowaters Mersey	1	200,000	4.3	208,600	56.37	42,240	.975	49.80	41,184	.900	37,066	4.3	38,659
26)	A.E.C.L. Pt. Tupper	1	163,691	4.3	170,730	77.86	24,000	.925	75.55	22,200	.975	21,645	4.3	22,576
27)	Municipal	8	234,154	4.3	244,223	56.96	46,930	.975	-	45,757	.925	42,325	4.3	44,145
28)	Unmetered	2,380	63,226	10.3	69,738	44.80	16,108	1.000	-	16,108	1.000	16,108	10.3	17,767
29)	N.B.E.P.C.	1	2,163	4.3	2,256	-	-	-	-	-	-	-	-	-
30)	Total	296,085	5,235,882	8.131	5,661,589		1,330,155			1,113,391		941,780		1,024,000

NOVA SCOTIA POWER CORPORATION

SCHEDULE 3

Analysis Of MWH Sold And Generated

For The Years Ended March 31, 1977 And 1978

		Year Ended March 31, 1977		Year Ended March 31, 1978	
		MWH Sales (1)	MWH Generation (2)	MWH Sales (3)	MWH Generation (4)
1)	Domestic	1,771,621	1,962,940	1,741,588	1,920,889
2)	Gen. Conn Load	48,618	53,869	46,645	51,449
3)	General	968,059	1,072,609	985,884	1,087,430
4)	General All Electric	314,226	346,591	307,822	337,065
5)	General Large	111,661	121,710	113,542	123,193
6)	Industrial To 249 KVA	21,399	23,325	29,407	31,907
7)	Industrial 250 - 3,999 KVA	286,452	308,795	299,816	321,103
8)	Industrial Large	985,165	1,032,453	912,508	951,746
9)	Interruptible	124,277	130,242	135,436	141,260
10)	Municipal	229,703	240,729	234,154	244,223
11)	Unmetered	60,456	66,985	63,226	69,738
12)	Sub-Total	4,921,637	5,360,248	4,870,028	5,280,003
13)	AECL Pt. Tupper	148,961	156,111	163,691	170,730
14)	Bowaters Mersey	200,000	209,600	200,000	208,600
15)	N.B.E.P.C.	1,659	1,739	2,163	2,256
16)	Total	5,272,257	5,727,698	5,235,882	5,661,589

SCHEDULE 4

NOVA SCOTIA POWER CORPORATION

Determination Of Customer Non-Coincident KW By Voltage Level

For The Years Ended March 31, 1977 And 1978

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible (10)	Municipal (11)	Unmetered (12)
	Year Ended March 31, 1977												
1)	Non Coin. KW Secondary	953,557	622,276	7,028	217,632	83,747	-	7,453	-	-	-	-	15,421
2)	Losses 2.6%	24,792	16,179	183	5,658	2,177	-	194	-	-	-	-	401
3)	Sub-Total	978,349	638,455	7,211	223,290	85,924	-	7,647	-	-	-	-	15,822
4)	Non Coin. KW Primary	1,121,639	638,455	7,211	236,564	88,146	20,282	8,439	66,113	19,637	-	20,970	15,822
5)	Losses 3.6%	40,377	22,984	260	8,516	3,173	730	304	2,380	707	-	754	569
6)	Sub-Total	1,162,016	661,439	7,471	245,080	91,319	21,012	8,743	68,493	20,344	-	21,724	16,391
7)	Non Coin. KW DBPS	1,352,410	661,439	7,471	245,080	91,319	21,012	8,743	71,353	150,705	28,373	50,524	16,391
8)	Losses 2.0%	27,048	13,229	149	4,902	1,826	420	175	1,427	3,014	568	1,010	328
9)	Sub-Total	1,379,458	674,668	7,620	249,982	93,145	21,432	8,918	72,780	153,719	28,941	51,534	16,719
10)	Total at Trans. Level	1,379,458	674,668	7,620	249,982	93,145	21,432	8,918	72,780	153,719	28,941	51,534	16,719
	Year Ended March 31, 1978												
11)	Non Coin. KW Secondary	946,437	617,087	7,236	218,882	75,734	-	11,390	-	-	-	-	16,108
12)	Losses 2.6%	24,607	16,044	188	5,691	1,969	-	296	-	-	-	-	419
13)	Sub-Total	971,044	633,131	7,424	224,573	77,703	-	11,686	-	-	-	-	16,527
14)	Non Coin. KW Primary	1,117,310	633,131	7,424	237,847	79,925	21,384	12,478	70,005	20,459	-	18,130	16,527
15)	Losses 3.1%	34,636	19,627	230	7,373	2,478	663	387	2,170	634	-	562	512
16)	Sub-Total	1,151,946	652,758	7,654	245,220	82,403	22,047	12,865	72,175	21,093	-	18,692	17,039
17)	Non Coin. KW DBPS	1,324,261	652,758	7,654	245,220	82,403	22,047	12,865	75,035	130,827	30,921	47,492	17,039
18)	Losses 2.0%	26,485	13,055	153	4,904	1,648	441	257	1,501	2,617	618	950	341
19)	Sub-Total	1,350,746	665,813	7,807	250,124	84,051	22,488	13,122	76,536	133,444	31,539	48,442	17,380
20)	Total At Trans. Level	1,350,746	665,813	7,807	250,124	84,051	22,488	13,122	76,536	133,444	31,539	48,442	17,380

NOVA SCOTIA POWER CORPORATION

SCHEDULE 7

Analysis of Working Capital

Glace Bay Steam Sales, Point Tupper Steam and Electric Sales

and Bowaters Mersey Electric Sales

For the Year Ended March 31, 1977

($000)

		Total Company (1)	Glace Bay (2)	Point Tupper (3)	Mersey System (4)	Total (5)
	Cash					
1)	Fuel	$ 4,719	$ 576	$ 407	$ -	$ 3,736
2)	Purch. Power	129	-	-	-	129
3)	Labour	2,573	139	96	45	2,293
4)	Other	2,869	89	195	28	2,557
5)	Sub-Total	$ 10,290	$ 804	$ 698	$ 73	$ 8,715
	Deduct:					
6)	Consumer Deposits	$(732)	$ -	$ -	$ -	$(732)
7)	Fed. Coal Subvention	(823)	-	-	-	(823)
8)	Prov. for Non-DB Losses	(716)	-	-	-	(716)
9)	C&RR Bowaters	(650)	-	-	(650)	-
10)	Ref. Cap. Cont.	(44)	-	-	-	(44)
11)	Total Deduct	$(2,965)	$ -	$ -	$(650)	$(2,315)
12)	Net Cashwork-Capital	$ 7,325	$ 804	$ 698	$(577)	$ 6,400
	Mat. & Supp. Inventory					
13)	Fuel	$ 4,126	$ 346	$ 106	$ -	$ 3,674
14)	Linestores	11,054	-	-	-	11,054
15)	Thermal	-	-	-	-	-
16)	Mobile Serv.	-	-	-	-	-
17)	Trans & Subst.	-	-	-	-	-
18)	Total Mat. & Supp.	$ 15,180	$ 346	$ 106	$ -	$ 14,728
19)	Total Work Capital	$ 22,505	$ 1,150	$ 804	$(577)	$ 21,128

NOVA SCOTIA POWER CORPORATION

Classification of Plant In Service

For the Year Ended March 31, 1977

($000)

		Total Company (1)	Coincident Peak (2)	Peak and Average (3)	Class N.C. Peak (4)	Customer N.C. Peak (5)	Energy (6)	Customer (7)	Revenue (8)	Direct (9)	As Other (10)
	Production										
1)	Steam Other	$ 95,627	$ 95,627	$ 95,627	$ 95,627	$ -	$ -	$ -	$ -	$ -	$ -
2)	Mersey System	4,638	450	-	450	-	-	-	-	4,188	-
3)	Other Hydro	19,227	19,227	-	19,227	-	-	-	-	-	-
4)	Gas Turbine	23,189	23,189	-	23,189	-	-	-	-	-	-
5)	Pt. Tupper	14,424	5,682	5,682	5,682	-	-	-	-	8,742	-
6)	Glace Bay	24,996	10,820	10,820	10,820	-	-	-	-	14,176	-
7)	Water Street	18,956	18,956	18,956	18,956	-	-	-	-	-	-
8)	Total	$201,057	$173,951	$131,085	$173,951	$ -	$ -	$ -	$ -	$ 27,106	$ -
	Transmission Plant										
9)	Sub-Stations	$ 26,362	$ 26,362	$ 26,362	$ 26,362	$ -	$ -	$ -	$ -	$ -	$ -
10)	All Other	48,206	48,206	48,206	48,206	-	-	-	-	-	-
11)	Total	$ 74,568	$ 74,568	$ 74,568	$ 74,568	$ -	$ -	$ -	$ -	$ -	$ -
	Distribution Plant										
12)	Land	$ 2,505	$ -	$ -	$ 2,505	$ 2,505	$ -	$ -	$ -	$ -	$ -
13)	Sub-Stations	23,115	-	-	20,996	20,996	-	-	-	2,119	-
14)	Poles	51,376	-	-	19,008	19,008	-	32,368	-	-	-
15)	Wire-OH	27,759	-	-	11,382	11,382	-	16,377	-	-	-
16)	Underground	4,246	-	-	-	-	-	-	-	-	4,246
17)	Line Transformers	26,562	-	-	26,562	26,562	-	-	-	-	-
18)	Services	14,217	-	-	-	-	-	14,217	-	-	-
19)	Meters	9,200	-	-	-	-	-	-	-	9,200	-
20)	Other	67	-	-	-	-	-	-	-	-	67
21)	Street Lighting	8,000	-	-	-	-	-	-	-	8,000	-
22)	Total	$167,047	$ -	$ -	$ 80,453	$ 80,453	$ -	$ 62,962	$ -	$ 19,319	$ 4,313
23)	General Intangible & Future Use	$ 5,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,945
	Working Capital										
24)	Cash - Fuel	$ 3,042	$ -	$ -	$ -	$ -	$ 3,042	$ -	$ -	$ -	$ -
25)	Cash - Other	3,358	-	-	-	-	-	-	-	-	3,358
26)	Mat. & Supp. - Fuel	3,674	-	-	-	-	3,674	-	-	-	-
27)	Mat. & Supp. - Other	11,054	-	-	-	-	-	-	-	-	11,054
28)	Total	$ 21,128	$ -	$ -	$ -	$ -	$ 6,716	$ -	$ -	$ -	$ 14,412
	CWIP										
29)	Production-Hydro	$ 81,434	$ 81,434	$ -	$ 81,434	$ -	$ -	$ -	$ -	$ -	$ -
30)	Production-Steam	11,661	11,661	11,661	11,661	-	-	-	-	-	-
31)	Transmission	7,005	7,005	7,005	7,005	-	-	-	-	-	-
32)	Distribution	5,035	-	-	-	-	-	-	-	-	5,035
33)	General	2,750	-	-	-	-	-	-	-	-	2,750
34)	Total	$107,885	$100,100	$ 18,666	$100,100	$ -	$ -	$ -	$ -	$ -	$ 7,785
35)	**Total Plant**	$577,630	$348,619	$224,319	$429,072	$ 80,453	$ 6,716	$ 62,962	$ -	$ 46,425	$ 32,455

SCHEDULE 8
Page 2 of 4

NOVA SCOTIA POWER CORPORATION

Analysis of Distribution Substation Costs

For the Year Ended March 31, 1977

		Distribution Bulk Power (1)	Dist. Ded. Bulk Power (2)	Dist. Cust. Owned B. P. (3)	Distribution General (4)	Dist. Ded. General (5)	Dist. Cust. Owned Gen. (6)	Total Cost (7)
1)	Total Cost	$21,020,700	$1,411,823	$32,319	$6.518,929	$1,499,408	$33,344	$30,516,523
2)	AECL Pt. Tupper	-	(230,205)	-	-	-	-	-
3)	Bayers Rd.	-	-	-	19,397	(19,397)	-	-
4)	Reserve Mines	-	-	-	29,286	(29,286)	-	-
5)	Sydney Mines	-	-	-	115,901	(115,901)	-	-
6)	Canadian Liquid Air	-	-	-	14,688	(14,688)	-	-
7)	Total Dist. Substations	$21,020,700	$1,181,618	$32,319	$6,698,201	$1,320,136	$33,344	$30,286,318
8)	Total Net Dist. Substations	$15,922,562	$ 895,041	$24,481	$5,073,690	$ 999,964	$25,257	$22,940,995
9)	Municipal		$ 316,322			$ 231,484		
10)	Interruptible			$10,677		$ 7,856		
11)	Industrial to 249 KVA		$ 2,272			$ 6,666		
12)	Ind. 250 To 3,999 KVA		$ 123,511	$ 826		$ 359,244	$25,257	
13)	Industrial Large		$ 452,936	$12,978		$ 120,606		
14)	General					$ 71,505		
15)	General All Electric					$ 98,770		
16)	General Large					$ 103,833		

NOVA SCOTIA POWER CORPORATION

SCHEDULE 8
PAGE 3 OF 4

Analysis of Pole Investment

For the Year Ended March 31, 1977

($000)

		Total Cost (1)	Primary Demand (2)	Primary Customer (3)	Secondary Demand (4)	Secondary Customer (5)
1)	Total Net Pole Cost 1977	$51,376				
2)	Primary Only 30%	$15,412	$ 5,702	$ 9,710	$ -	$ -
3)	50% Joint Primary	17,982	6,653	11,329	-	-
4)	50% Joint Secondary	17,982	-	-	6,653	11,329
5)	Total	$51,376	$ 12,355	$ 21,039	$ 6,653	$11,329

Demand Cost 37%

Customer Cost 63%

NOVA SCOTIA POWER CORPORATION

Analysis of Wire Investment

For the Year Ended March 31, 1977

($000)

		Total Cost (1)	Primary Demand (2)	Primary Customer (3)	Secondary Demand (4)	Secondary Customer (5)
1)	Total Net Cost 1977	$27,759				
2)	Primary Only 30%	$ 8,327	$ 3,414	$ 4,913	$ -	$ -
3)	50% Joint Primary	9,716	3,984	5,732	-	-
4)	50% Joint Secondary	9,716	-	-	3,984	5,732
5)	Total	$27,759	$ 7,398	$10,645	$ 3,984	$ 5,732

Demand Cost 41%

Customer Cost 59%

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For the Year Ended March 31, 1977

Coincident Peak Responsibility

($000)

		Total Co. Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Allocation Factors (13)
1)	Production Plant	$173,951	$ 71,998	$ 1,235	$ 38,356	$ 14,890	$ 3,148	$ 1,235	$ 10,333	$ 21,553	$ -	$ 8,228	$ 2,975	D-1
2)	Transmission Plant	$ 74,568	$ 30,864	$ 529	$ 16,442	$ 6,383	$ 1,350	$ 529	$ 4,430	$ 9,239	$ -	$ 3,527	$ 1,275	D-1
	Distribution Plant													
3)	Land	$ 2,505	$ 1,803	$ 52	$ 341	$ 112	$ 21	$ 11	$ 72	$ 31	$ 1	$ 32	$ 29	P-3
4)	Substations	22,941	11,951	134	4,500	1,749	484	166	1,748	954	19	940	296	Sched. 12 Pg 1
5)	Poles	51,376	40,146	1,322	5,979	1,785	224	165	735	216	-	231	573	Sched. 14 Pg 1
6)	Wire - O. H.	27,759	21,368	681	3,407	1,049	134	96	440	129	-	138	317	Sched. 14 Pg 1
7)	Underground	4,246	3,300	107	504	152	19	14	63	19	-	20	48	P-1
8)	Line Transformers	26,562	17,334	197	6,062	2,332	-	207	-	-	-	-	430	D-3
9)	Services	14,217	10,107	419	3,253	405	-	33	-	-	-	-	-	C-9
10)	Meters	9,200	7,066	293	1,488	242	2	19	65	15	6	4	-	Sched. 15
11)	Other	67	48	1	9	3	1	-	2	1	-	1	1	P-3
12)	Street Lighting	8,000	-	-	-	-	-	-	-	-	-	-	8,000	Direct
13)	Total	$166,873	$113,123	$ 3,206	$ 25,543	$ 7,829	$ 885	$ 711	$ 3,125	$ 1,365	$ 26	$ 1,366	$ 9,694	
14)	General, Intangible & Future Use	$ 5,945	$ 3,091	$ 71	$ 1,150	$ 416	$ 77	$ 36	$ 256	$ 460	$ 1	$ 188	$ 199	P-5
15)	Total Plant in Service	$421,337	$219,076	$ 5,041	$ 81,491	$ 29,518	$ 5,460	$ 2,511	$ 18,144	$ 32,617	$ 27	$ 13,309	$ 14,143	
	Working Capital													
16)	Cash-Fuel	$ 3,042	$ 1,114	$ 30	$ 609	$ 197	$ 69	$ 13	$ 175	$ 586	$ 74	$ 137	$ 38	E-1
17)	Cash	3,358	1,737	45	654	219	41	19	137	252	-	102	152	O-1
18)	Mat. & Supp. - Fuel	3,674	1,345	37	735	238	83	16	212	708	89	165	46	E-1
19)	Mat. & Supp. - Other	11,054	5,747	133	2,138	774	144	66	475	856	1	349	371	P-5
20)	Total	$ 21,128	$ 9,943	$ 245	$ 4,136	$ 1,428	$ 337	$ 114	$ 999	$ 2,402	$ 164	$ 753	$ 607	
21)	Total Rate Base	$442,465	$229,019	$ 5,286	$ 85,627	$ 30,946	$ 5,797	$ 2,625	$ 19,143	$ 35,019	$ 191	$ 14,062	$ 14,750	

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base For The Year Ended March 31, 1977

Coincident Peak and Average Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Plant													
1)	Steam	$131,085	$ 51,765	$ 1,062	$ 27,803	$ 10,185	$ 2,609	$ 813	$ 7,904	$ 19,650	$ 1,219	$ 6,030	$ 2,045	D-3
2)	Hydro	19,677	8,144	140	4,339	1,684	356	140	1,169	2,438	-	931	336	D-1
3)	Gas Turbine	23,189	9,598	165	5,113	1,985	420	165	1,377	2,873	-	1,097	396	D-1
4)	Total	$173,951	$ 69,507	$ 1,367	$ 37,255	$ 13,854	$ 3,385	$ 1,118	$ 10,450	$ 24,961	$ 1,219	$ 8,058	$ 2,777	
5)	**Transmission Plant**	$ 74,568	$ 29,447	$ 604	$ 15,816	$ 5,794	$ 1,484	$ 462	$ 4,496	$ 11,178	$ 694	$ 3,430	$ 1,163	D-3
	Distribution Plant													
6)	Land	$ 2,505	$ 1,717	$ 54	$ 385	$ 132	$ 23	$ 12	$ 79	$ 33	$ 1	$ 36	$ 33	P-4
7)	Substations	22,941	10,526	155	5,203	2,060	532	187	1,905	979	19	1,014	361	Sched. 12 Pg. 2
8)	Poles	51,376	38,866	1,343	6,669	2,091	252	185	828	231	-	274	637	Sched. 14 Pg. 2
9)	Wire-O.H.	27,759	20,601	695	3,820	1,232	151	108	495	138	-	164	355	Sched. 14 Pg. 2
10)	Underground	4,246	3,190	110	563	178	22	16	71	20	-	23	53	P-2
11)	Line Transformers	26,562	15,565	231	7,164	2,829	-	239	-	-	-	-	534	D-11
12)	Services	14,217	10,107	419	3,253	405	-	33	-	-	-	-	-	C-9
13)	Meters	9,200	7,066	293	1,488	242	2	19	65	15	6	4	-	Schedule 15
14)	Other	67	46	1	10	4	1	2	1	1	-	1	-	P-4
15)	Street Lighting	8,000	-	-	-	-	-	-	-	-	-	-	8,000	Direct
16)	Total	$166,873	$107,684	$ 3,301	$ 28,555	$ 9,173	$ 983	$ 801	$ 3,444	$ 1,417	$ 26	$ 1,516	$ 9,973	
17)	**Gen., Intan, and Future Plant**	$ 5,945	$ 2,957	$ 76	$ 1,168	$ 413	$ 84	$ 34	$ 263	$ 537	$ 28	$ 186	$ 199	P-6
18)	**Total Plant In Service**	$421,337	$209,595	$ 5,348	$ 82,794	$ 29,234	$ 5,936	$ 2,415	$ 18,653	$ 38,093	$ 1,967	$ 13,190	$ 14,112	
	Working Capital													
19)	Cash Fuel	$ 3,042	$ 1,114	$ 30	$ 609	$ 197	$ 69	$ 13	$ 175	$ 586	$ 74	$ 137	$ 38	E-1
20)	Cash-Other	3,358	1,675	47	651	209	45	18	141	303	18	100	151	O-2
21)	Mat. & Supp.-Fuel	3,674	1,345	37	735	238	83	16	212	708	89	165	46	E-1
22)	Mat. & Supp.-Other	11,054	5,499	140	2,172	767	156	63	490	999	52	346	370	P-6
23)	Total	$ 21,128	$ 9,633	$ 254	$ 4,167	$ 1,411	$ 353	$ 110	$ 1,018	$ 2,596	$ 233	$ 748	$ 605	
24)	**Total Rate Base**	$442,465	$219,228	$ 5,602	$ 86,961	$ 30,645	$ 6,289	$ 2,525	$ 19,671	$ 40,689	$ 2,200	$ 13,938	$ 14,717	

SCHEDULE 11

NOVA SCOTIA POWER CORPORATION

Allocation of Rate Base

For The Year Ending March 31, 1977

Class Non-Coincident Responsibility

($000)

		Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Industrial Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1)	Production Plant	$173,951	$ 73,807	$ 1,096	$ 36,025	$ 13,429	$ 3,009	$ 1,218	$ 10,072	$ 21,309	$ 3,949	$ 7,497	$ 2,540	D-17
2)	Transmission Plant	$ 74,568	$ 31,639	$ 470	$ 15,443	$ 5,757	$ 1,290	$ 522	$ 4,317	$ 9,134	$ 1,693	$ 3,214	$ 1,089	D-17
	Distribution Plant													
3)	Land	$ 2,505	$ 1,717	$ 54	$ 385	$ 132	$ 23	$ 12	$ 79	$ 33	$ 1	$ 36	$ 33	P-4
4)	Substations	22,941	10,526	155	5,203	2,060	532	187	1,905	979	19	1,014	361	Sched 12 Pg 2
5)	Poles	51,376	38,866	1,343	6,669	2,091	252	185	828	231	-	274	637	Sched 14 Pg 2
6)	Wire - O.H.	27,759	20,601	695	3,820	1,232	151	108	495	138	-	164	355	Sched 14 Pg 2
7)	Underground	4,246	3,190	110	563	178	22	16	71	20	-	23	53	P-2
8)	Line Transformers	26,562	15,565	231	7,164	2,829	-	239	-	-	-	-	534	D-11
9)	Services	14,217	10,107	419	3,253	405	-	33	-	-	-	-	-	C-9
10)	Meters	9,200	7,066	293	1,488	242	2	19	65	15	6	4	-	Sched 15
11)	Other	67	46	1	10	4	1	2	1	1	-	1	-	P-4
12)	Street Lighting	8,000	-	-	-	-	-	-	-	-	-	-	8,000	Direct
13)	Total	$166,873	$107,684	$ 3,301	$ 28,555	$ 9,173	$ 983	$ 801	$ 3,444	$ 1,417	$ 26	$ 1,516	$ 9,973	
14)	General Intangible & Future Use	$ 5,945	$ 3,050	$ 70	$ 1,146	$ 406	$ 76	$ 36	$ 255	$ 456	$ 81	$ 175	$ 194	P-7
15)	Total Plant In Service	$421,337	$216,180	$ 4,937	$ 81,169	$ 28,765	$ 5,358	$ 2,577	$ 18,088	$ 32,316	$ 5,749	$ 12,402	$ 13,796	
	Working Capital													
16)	Cash - Fuel	$ 3,042	$ 1,114	$ 30	$ 609	$ 197	$ 69	$ 13	$ 175	$ 586	$ 74	$ 137	$ 38	E-1
17)	Cash - Other	3,358	1,735	43	642	212	40	19	138	239	45	96	149	O-3
18)	Mat. & Supp. - Fuel	3,674	1,345	37	735	238	83	16	212	708	89	165	46	E-1
19)	Mat. & Supp. - Other	11,054	5,672	129	2,130	755	140	67	474	848	152	325	362	P-7
20)	Total	$ 21,128	$ 9,866	$ 239	$ 4,116	$ 1,402	$ 332	$ 115	$ 999	$ 2,381	$ 360	$ 723	$ 595	
21)	Total Rate Base	$442,465	$226,046	$ 5,176	$ 85,285	$ 30,167	$ 5,690	$ 2,692	$ 19,087	$ 34,697	$ 6,109	$ 13,125	$ 14,391	

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NOVA SCOTIA POWER CORPORATION

Allocation of Distribution Substation Costs

For the Year Ended March 31, 1977

Coincident Peak Responsibility

	Total Company Less Steam And Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Allocation Factor (13)
1) Distribution Bulk Power	$15,922,562	$ 9,063,122	$ 101,905	$3,358,068	$1,251,514	$ 288,198	$ 119,419	$ 939,431	$ 278,645	$ -	$ 297,752	$ 224,508	D-7
2) Distr. Bulk Power Dedicated	895,041	-	-	-	-	-	2,272	123,511	452,936	-	316,322	-	Sched 8 Pg 2
3) Distr. Customer Owned Bulk Power	24,481	-	-	-	-	-	-	826	12,978	10,677	-	-	Sched 8 Pg 2
4) Dist. General	5,073,690	2,887,944	32,472	1,070,041	398,792	91,834	38,053	299,348	88,789	-	94,878	71,539	D-7
5) Distr. Dedicated General	999,964	-	-	71,505	98,770	103,833	6,666	359,244	120,606	7,856	231,484	-	Sched 8 Pg 2
6) Distr. Cust. Owned General	25,257	-	-	-	-	-	-	25,257	-	-	-	-	Sched 8 Pg 2
7) Total Allocation Cost	$22,940,995	$11,951,066	$ 134,377	$4,499,614	$1,749,076	$ 483,865	$ 166,410	$1,747,617	$ 953,954	$ 18,533	$ 940,436	$ 296,047	

Note: Allocations done on Customer Non-Coincident for this study.

NOVA SCOTIA POWER CORPORATION

Allocation of Distribution Substation Costs

For the Year Ended March 31, 1977

Peak and Average and Class Non-Coincident Peak Responsibility

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Allocation Factor (13)
1) Distribution Bulk Power	$15,922,562	$ 7,981,981	$ 117,827	$3,891,474	$1,487,167	$ 324,820	$ 135,342	$1,058,850	$ 297,752	$ -	$ 353,481	$ 273,868	D-13
2) Distr. Bulk Power Dedicated	895,041	-	-	-	-	-	2,272	123,511	452,936	-	316,322	-	Sched 8 Pg 2
3) Distr. Customer Owned Bulk Power	24,481	-	-	-	-	-	-	826	12,978	10,677	-	-	Sched 8 Pg 2
4) Distr. General	5,073,690	2,543,441	37,545	1,240,010	473,883	103,503	43,126	337,400	94,878	-	112,636	87,268	D-13
5) Distr. Dedicated General	999,964	-	-	71,505	98,770	103,833	6,666	359,244	120,606	7,856	231,484	-	Sched 8 Pg 2
6) Distr. Cust. Owned General	25,257	-	-	-	-	-	-	25,257	-	-	-	-	Sched 8 Pg 2
7) Total Allocated Cost	$22,940,995	$10,525,422	$ 155,372	$5,202,989	$2,059,820	$ 532,156	$ 187,406	$1,905,088	$ 979,150	$ 18,533	$1,013,923	$ 361,136	

Note: Allocations done on Class Non-Coincident for these studies.

SCHEDULE 13 & 33
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NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - General Service

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	37 H	Police Station	DD	$25,202					23/.6	148	79	154	983
2)	33 H	Bank of Montreal	DD	13,170					23/.6	720	250	780	2,887
3)	49 H	N. S. Hospital	DD	9,607					23/4.1	648	311	684	3,752
4)	63 H	Holiday Inn	DD	7,361					23/.2	264	81	336	1,474
5)	69 H	D.O.T. Marine Service	DD	4,002					23/.6	560	230	864	3,061
6)	47 H	Naval Arm	COD						23	1,152	171	1,152	2,787
7)	53 H	Bedford Magazine	COD						23	558	213	596	1,626
8)	45 H	Osborne Head	COD						23	120	57	120	583
9)	50 C	D.O.T. Pt. Hastings	COD						23 KV	104	42	106	322
10)	50-51 H	CFB Shearwater	COD		2,052	930	2,340	11,010	23 KV				
11)	12 H	Statacona	COD		1,404	573	1,404	7,806	23 KV	1,620	722	1,680	8,300
12)	25 H	Royal Bank	DD	24,253						756	258	900	3,404
13)	46 V	Stevens Lumber	DD	10,805						114	3	144	86
14)	41 V	Minas Basin Mill	COD							200	25	208	206
15)	58 V	Greenwood	COD							2,240	1,106	2,320	11,040
16)	59 V	Greenwood Shopping	COD							134	59	185	765
17)	74 V	Cornwallis Base	COD							2,000	996	2,160	11,389
18)	51 W	Bowater Mill	DBP							1	0	1	0
19)	60 W	I.M. Matheson	COD							100	21	192	209
20)		Total DD		$94,400	3,210	1,212	3,862	15,647					
21)		Total COD			10,064	4,915	12,463	97,743					
22)		Total DBP			1		1						

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - General - All Electric

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	38 H	Citadel Inn	DD	$ 25,202					23/.6	438	182	451	2,284
2)	29 H	Law Courts	DD	21,345					23/.6	1,040	316	1,080	4,543
3)	36 H	Young Street	DD	30,567					23/.6	528	162	552	2,384
4)	74 S	Keltic Lodge	DD	53,279					23/.6	216	74	368	1,245
5)		Total DP		$130,393						2,222	734	2,451	10,456

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - General Large

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	11 H	Dock Yard	COD	Cust.	5,054	1,752	5,054	22,346	23 KV				
2)	28 H	Scotia Square	DD	$137,079	10,476	5,618	11,016	56,027	23/.6				
3)	24,27,30 31,32 H	Dalhousie	COD	Cust.	4,752	2,576	4,752	30,144	23 KV				
4)		Total DD		$137,079	10,476	5,618	11,016	56,027					
5)		Total COD			9,806	4,328	9,806	52,490					

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Industrial to 249KVA

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	44 C	Bd. of Ed. Little River	DBP	$3,000					69/.6	603	5	612	847
2)	24 N	C. E. Harrisons Mill	DD	8,801	189	30	205	291	24/.6				
3)		Total DD		$8,801	189	30	205	291					
4)		Total DBP		$3,000	603	5	612	847		603	5	612	847

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Industrial 250-3,999 KVA

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	18 C	Canso Seafoods	DD	$ 2,000	1,584	746	1,584	8,046	23 KV	1,562	634	1,642	8,910
2)	60 C	Evans Coal	DD	5,402	252	30	252	269	25/2.3	280	26	320	352
3)	13 C	Georgia Pacific 6B	DBPD	17,473					69/.6	320	62	336	652
4)	45 C	Georgia Pacific	DD	17,472					25/.6	512	32	512	308
5)	43 C	Dept. of Environment	DBPD	6,228					69/.6	696	271	960	4,031
6)	90 W	C.O.T.C. - (Tellstake)	DD	176,265	684	344	869	4,207	24/4.16	653	344	970	4,192
7)	114 H	National Gypsum	DD	36,016					23/2.3	960	112	1,480	2,146
8)	102 H	Pockwock Pumps	DBPD						69/4.16	1,280	752	1,840	7,116
9)	13 H	Halifax Shipyard	COD	-	2,304	1,064	2,376	8,988	23	2,560	776	2,640	7,396
10)	66 N	River Herbert Coal	DD	9,004	261	49	270	586	23/2.4	297	43	306	514
11)	18 N	Enheat - Rolling Mill #4	COBP	1,091	749	143	916	1,432	69				
12)	59 N	Maritime Steel	COD	-	713	113	745	985	24	1,044	118	1,158	1,318
13)	63 N	Thorborn Mine	COD		551	95	616	239	23	551	115	583	1341
14)	23 N	Christy Crops	DD	10,805	97	54	97	750	24/.6				
15)	39 V	Fundy Gypsum - Hansport	COD	-	691	38	706	5,376	23	864	43	912	629
16)	37 V	Fundy Gypsum - W.	COD	-	1,044	188	1,116	2,440	23	1,040	64	1,680	2,928
17)	38 V	Fundy Gypsum - Man.	COD	-	576	146	648	1,660	23	720	154	800	2,140
18)	71 V	United Elastics	DD	14,254	691	131	763	2,173	23/.6	840	214	936	2,511
19)	23 V	DND Newport Corner	COD	-	846	574	972	7,439	23	1,200	708	1,280	9,840
20)	83-84 V	L.E. Shaw - Lantz	COD	-	1,123	379	1,253	3,966	23	1,368	271	1,392	4,023
21)	32-33 V	Dresser Minerals	COD	-	1,584	636	1,728	7,296	23	1,760	652	1,920	8,232
22)	18 H	National HB In Bd.	COD		1,584	284	2,304	4,272	23	2,080	332	2,560	4,092
23)	19 H	National HB Pin C.	COD		594	252	702	2,682	23	720	363	1,020	3,354
24)	26 H	Dover Mills	COD		792	399	846	4,413	23	1,020	361	1,020	4,571
25)	46 H	National Gypsum	COD		792	99	846	651	23	960	79	1,100	1,083
26)	66 H	Dart. Marine Ships	COD		828	222	900	2,560	23	760	172	1,200	2,630
27)	61 H	Moosehead	COD		742	307	821	3,770	23	880	294	960	3,738
28)	55 H	City of Dartmouth	DD	16,547	497	192	508	2,890	23/.6	456	209	504	2,828
29)	67 H	Hermie Electronics	DD	14,287	108	50	324	691	23/.6	152	17	192	216
30)	74 H	Maritime Paper	DD	10,237	547	300	619	3,073	23/.6	752	286	912	3,299
31)	71 H	Phillips Cables	DD	22,313	216	17	288	256	23/.6	136	16	304	199

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule-Industrial 250-3,999 KVA

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
32)	75 H	Sivaco Maritime	DD	$ 18,409	360	143	432	1,656	23/.6	600	184	640	1,904
33)	70 H	City of Dart.-Lake Major	DD	48,023	1,022	388	1,037	5,224	23/2.4	576	404	1,184	4,921
34)	80 H	Municipal Spraying-OP	DD	6,936	1,188	375	1,224	2,668	23/.6	1,560	372	1,560	2,319
35)	81 H	Municipal Spraying-Asphalt	DD	7,000					23/.6				
36)	82 H	Municipal Spraying-Crusher	DD	14,799		ONE BILL			23/.6				
37)	59 S	Kaizer Celestile Mine	DBPD	139,356	45	15	666	1,445	69/12.5				
38)	30 S	Kaizer	COBP		CLOSED DOWN - NOV 76				69/.6				
39)	34 S	Dev. Co. P.C.	COD	31,844	1,685	554	1,814	7,185	23	1,512	511	2,016	5,825
40)	61 V	Greenwood Base Airport	COD	-									
41)	63 S	National Sea Prod.	DD	44,499	648	204	774	2,732	23/.6				
42)	21 S	Devco Shops	COD	1,500	562	1,884	648	1,261	23	1,104	342	1,176	4,864
43)		1977 Portion			25,960	10,475	29,634	103,281					
44)		1978 Portion			3,391	1,229	4,615	14,253					
45)		Total			29,351	11,704	34,279	117,534					
46)		Total DD		$ 474,268	9,480	3,227	11,534	37,675					
47)		Total DBP		$ 186,758	2,111	1,100	3,488	13,244					
48)		Total COD		$ 33,344	17,011	7,234	19,041	65,183					
49)		Total COBP		$ 1,091	749	143	916	1,432					
				$ 731,791	29,351	11,704	34,279	117,534					

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Industrial Large

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	12,13,29 W	Dominion Textile	DBP	$113,176	3,607	1,431	3,607	17,702	69/.6	3,380	1,311	3,872	17,123
2)	26 S	Devco #26	DD	159,222	6,912	2,976	7,488	23,744	22/6.6	6,192	3,109	7,488	37,770
3)	8&9 S	Sysco	DBP	-	12,710	6,211	17,642	71,740	138/23	11,281	5,501	14,166	61,020
4)	80 S	Lingan Mine	DBP	7,884	6,696	1,836	6,696	20,652	69/6.9	6,372	2,058	7,020	24,636
5)	19 S	A.E.C.L. G.B.	COBP	17,132	20,430	13,398	20,430	134,988	69	4,500	2,814	15,818	72,366
6)	74 W	Michelin BW	DBP	73,055	6,054	3,435	6,513	43,597	138/12.5	6,468	3,692	6,738	46,401
7)	85 W	Masonite Canada	COT	-	7,560	3,480	7,776	41,232	69	5,400	2,688	8,856	37,332
8)	47 C	Nova Scotia Forest Ind.	DBP	-	40,352	18,980	46,051	257,426	138/13.8	29,688	15,641	38,062	227,485
9)	46 C	Gulf Oil - Pt. Tupper	COBP	-	8,511	4,922	8,983	51,586	138	7,920	4,767	9,180	56,557
10)	49 N	Michelin Granton	DBP	86,419	9,891	6,125	10,107	76,645	138/12.5	10,125	6,217	10,602	79,408
11)	52 N	Canso Chem.	DBP	317,424	17,412	11,914	20,067	149,554	69/13.8	17,958	12,943	18,662	148,016
12)	11 N	Canada Cement	COBP	-	4,698	2,097	13,860	25,794	69	6,642	1,872	6,642	27,396
13)		Total DD		$159,222	6,912	2,976	7,488	23,744		6,192	3,109	7,488	37,770
14)		Total DBP		$597,958	96,722	49,932	110,683	637,316		85,272	47,363	99,122	604,089
15)		Total COD		$ -	-	-	-	-		-	-	-	-
16)		Total COBP		$ 17,132	33,639	20,417	43,273	212,368		19,062	9,453	31,640	156,319
17)		Total COT		$ -	7,560	3,480	7,776	41,232		5,400	2,688	8,856	37,332
				$774,312	144,833	76,805	169,220	914,660		115,926	62,433	147,106	835,510

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Interruptible

	Subst. (1)	Customer (2)	Code (3)	Cost (4)	1977 Dec. KW (5)	1977 Dec. MWH (6)	1977 Annual KW (7)	1977 Annual MWH (8)	Voltage (9)	1978 Dec. KW (10)	1978 Dec. MWH (11)	1978 Annual KW (12)	1978 Annual MWH (13)
1)	8,9,47,48 V	Minas Basin	DD	$10,372		739		16,134	23 KV				
2)	53 N	Scott Paper	COBP	14,096		352		15,898			2		15
3)		Total DD		$10,372		739		16,134					
4)		Total COBP		$14,096		352		15,898					

NOVA SCOTIA POWER CORPORATION

Analysis of Dedicated Facilities

For the Years Ended March 31, 1977 and 1978

Rate Schedule - Municipal

					1977					1978			
	Subst. (1)	Customer (2)	Code (3)	Cost (4)	Dec. KW (5)	Dec. MWH (6)	Annual KW (7)	Annual MWH (8)	Voltage (9)	Dec. KW (10)	Dec. MWH (11)	Annual KW (12)	Annual MWH (13)
1)	52 V	Town of Berwick	DBP	$52,593	2,419	1,099	2,549	13,272	69/4.1				
2)	77 V	Conway (Digby C.P.B.)	DBP	83,310	17,755	7,200	17,755	70,999	69/12.4				
3)	53 V	Kentville	COD		6,624	3,456	7,704	43,688	23 KV				
4)	76 W	Mahome Bay	DBP	84,172	1,275	592	1,275	5,741	69/4.1				
5)	81,82 W	Lunenburg	DBP	197,528	7,351	3,391	8,168	36,998	69/12.4				
6)	6,7,8 C	Antigonish	DD	305,601	8,911	4,422	9,130	43,879	23/4.1				
7)		Total DP		$305,601	8,911	4,422	9,130	43,879					
8)		Total COD		$ -	6,624	3,456	7,704	43,688					
9)		Total DBP		$417,603	28,800	12,282	29,747	127,010					

NOVA SCOTIA POWER CORPORATION

SCHEDULE 14
PAGE 1 OF 2

Allocation of Pole and Wire Investment

For the Year Ended March 31, 1977

Coincident Peak Responsibility

($000)

		Total Cost (1)	Primary Demand D-7 (2)	Primary Customers C-5 (3)	Secondary Demand D-5 (4)	Secondary Customers C-3 (5)
	Poles					
1)	Domestic	$40,146	$ 7,032	$18,699	$ 4,342	$10,073
2)	General Conn. Load	1,322	79	776	49	418
3)	General	5,979	2,606	1,206	1,518	649
4)	General All Electric	1,785	971	150	584	80
5)	General Large	224	224	-	-	-
6)	Industrial to 249 KVA	165	93	13	52	7
7)	Industrial 250-3,999 KVA	735	729	6	-	-
8)	Industrial Large	216	216	-	-	-
9)	Interruptible	-	-	-	-	-
10)	Municipal	231	231	-	-	-
11)	Unmetered	573	174	189	108	102
12)	Total Company	$51,376	$12,355	$21,039	$ 6,653	$11,329
	Wire					
13)	Domestic	$21,368	$ 4,211	$ 9,461	$ 2,600	$ 5,096
14)	General Conn. Load	681	47	393	29	212
15)	General	3,407	1,560	610	909	328
16)	General All Electric	1,049	582	76	350	41
17)	General Large	134	134	-	-	-
18)	Industrial to 249 KVA	96	56	6	31	3
19)	Industrial 250-3,999 KVA	440	437	3	-	-
20)	Industrial Large	129	129	-	-	-
21)	Interruptible	-	-	-	-	-
22)	Municipal	138	138	-	-	-
23)	Unmetered	317	104	96	65	52
24)	Total Company	$27,759	$ 7,398	$10,645	$ 3,984	$ 5,732

NOVA SCOTIA POWER CORPORATION

SCHEDULE 14
PAGE 2 OF 2

Allocation of Pole and Wire Investment

For the Year Ended March 31, 1977

Coincident Peak and Average and Non-Coincident

($000)

		Total Cost (1)	Primary Demand D-13 (2)	Primary Customers C-5 (3)	Secondary Demand D-11 (4)	Secondary Customers C-3 (4)
	Poles					
1)	Domestic	$38,866	$ 6,194	$18,700	$ 3,899	$10,073
2)	Gen. Conn. Load	1,343	91	776	58	418
3)	General	6,669	3,020	1,206	1,794	649
4)	General All Electric	2,091	1,154	149	708	80
5)	General Large	252	252	-	-	-
6)	Industrial to 249 KVA	185	105	13	60	7
7)	Industrial 250-3,999 KVA	828	822	6	-	-
8)	Industrial Large	231	231	-	-	-
9)	Interruptible	-	-	-	-	-
10)	Municipal	274	274	-	-	-
11)	Unmetered	637	212	189	134	102
12)	Total Company	$51,376	$12,355	$21,039	$ 6,653	$11,329
	Wire					
13)	Domestic	$20,601	$ 3,709	$ 9,461	$ 2,335	$ 5,096
14)	Gen. Conn. Load	695	55	393	35	212
15)	General	3,820	1,808	610	1,074	328
16)	General All Electric	1,232	691	76	424	41
17)	General Large	151	151	-	-	-
18)	Industrial to 249 KVA	108	63	6	36	3
19)	Industrial 250-3,999 KVA	495	492	3	-	-
20)	Industrial Large	138	138	-	-	-
22)	Interruptible	-	-	-	-	-
23)	Municipal	164	164	-	-	-
24)	Unmetered	355	127	96	80	52
25)	Total Company	$27,759	$ 7,398	$10,645	$ 3,984	$ 5,732

NOVA SCOTIA POWER CORPORATION

SCHEDULE 15

Analysis of Meter Investment

For the Year Ended March 31, 1977

		Customers (1)	Unit Meter Cost (2)	Total Cost (3)	Percent (4)	Allocated Meter Cost (5)
1)	Domestic	257,891	$ 34.00	$ 8,768,294	76.80	$7,065,783
2)	General Conn. Load	10,710	34.00	364,140	3.19	293,488
3)	General	16,627	111.00	1,845,597	16.17	1,487,678
4)	General All Electric	2,069	145.00	300,005	2.63	241,966
5)	General Large	3	657.00	1,971	0.02	1,840
6)	Industrial To 249 KVA	166	145.00	24,070	0.21	19,321
7)	Industrial 250-3,999 KVA	124	657.00	81,468	0.71	65,322
8)	Industrial Large	14	1,338.00	18,732	0.16	14,720
9)	Interruptible	6	1,338.00	8,028	0.07	6,440
10)	Municipal	8	520.00	4,160	0.04	3,680
11)	Unmetered	2,623	-	-	-	-
12)	Total	290,241		$11,416,465	100.00	$9,200,238

NOVA SCOTIA POWER CORPORATION

SCHEDULE 16

Revenue Analysis

For the Years Ended March 31, 1977

($000)

		Total (1)	Discounts R-3 (2)	Sub-Total (3)	Percent of Total (4)	Other (5)	Total (6)
1)	Domestic	$ 77,108	$ 842	$ 77,950	39.28	$ 2,610	$ 80,560
2)	Gen. Conn. Load	2,293	21	2,314	1.17	77	2,391
3)	General	47,582	152	47,734	24.05	1,598	49,332
4)	General All Electric	13,394	36	13,430	6.77	450	13,880
5)	General Large	3,275	2	3,277	1.65	110	3,387
6)	Ind. to 249 KVA	1,187	-	1,187	.60	40	1,227
7)	Ind. 250-3,999 KVA	9,467	-	9,467	4.77	317	9,784
8)	Ind. Large	27,319	241	27,560	13.89	923	28,483
9)	Interruptible	2,983	5	2,988	1.50	100	3,088
10)	Municipal	7,082	61	7,143	3.60	239	7,382
11)	Unmetered	5,390	3	5,393	2.72	180	5,573
12)	Total	$197,080	$ 1,363	$198,443	100.00	$ 6,644	$205,087
13)	Glace Bay - Steam	$ 8,300					
14)	Tupper - Joint	17,868					
15)	Mersey	1,476					
16)	Total	$ 27,644					
17)	Discounts	$ 1,363					
18)	Grants	$ 5,000					
19)	Other	1,644					
20)	Total	$ 6,644					
21)	Merchandise & Jobbing	$ 2,149					
22)	Total	$234,880					

NOVA SCOTIA POWER CORPORATION

SCHEDULE 17

Analysis Of Operating Cost For Glace Bay Steam,
And Point Tupper Steam And Electric And
Bowater Mersey Electric Sales
For The Year Ended March 31, 1977
($000)

		Total Company (1)	Glace Bay (2)	Point Tupper (3)	Bowater Mersey (4)	Total Other (5)
	Production Fuel					
1)	Mersey System	$ 14	$ -	$ -	$ 13	$ 1
2)	Other Hydro	39	-	-	-	39
3)	Gas Turbines	3,918	-	-	-	3,918
4)	Pt. Tupper Unit 1	6,986	-	6,456	-	530
5)	Glace Bay	17,407	9,143	-	-	8,264
6)	Water Street	4,288	-	-	-	4,288
7)	Other Steam	42,289	-	-	-	42,289
8)	Total Fuel	$ 74,941	$ 9,143	$ 6,456	$ 13	$ 59,329
	Production Opr. Cost					
9)	Mersey	$ 590	$ -	$ -	$ 478	$ 112
10)	Other Hydro	2,007	-	-	-	2,007
11)	Gas Turbines	472	-	-	-	472
12)	Pt. Tupper Unit 1	3,344	-	2,415	-	929
13)	Glace Bay	4,237	2,216	-	-	2,021
14)	Water Street	2,934	-	-	-	2,934
15)	Other Steam	10,560	-	-	-	10,560
16)	Total Opr. Cost	$ 24,144	$ 2,216	$ 2,415	$ 478	$ 19,035
17)	Purchased Power Fuel	$ 1,807	$ -	$ -	$ -	$ 1,807
18)	Purchased Power Other	$ 3,421	$ -	$ -	$ -	$ 3,421
19)	Transmission Expense	$ 2,051	$ -	$ -	$ -	$ 2,051
	Distribution Expense					
20)	Land	$ 1,135	$ -	$ -	$ -	$ 1,135
21)	Substations	1,872	-	-	-	1,872
22)	Overhead Lines	2,403	-	-	-	2,403
23)	U. G. Lines	133	-	-	-	133
24)	Line Transformers	812	-	-	-	812
25)	Services	1,249	-	-	-	1,249
26)	Meters	767	-	-	-	767
27)	Cust. Serv. & Contracts	926	-	-	-	926
28)	Cust. Premise	806	-	-	-	806
29)	Communications	502	-	-	-	502
30)	Street Lights	1,325	-	-	-	1,325
31)	Total Distribution	$ 11,930	$ -	$ -	$ -	$ 11,930
	Customer Accounting					
32)	Billing	$ 3,178	$ -	$ -	$ -	$ 3,178
33)	Customer Serv.	1,026	-	-	-	1,026
34)	Credit & Collection	868	-	-	-	868
35)	Total Cust. Acct.	$ 5,072	$ -	$ -	$ -	$ 5,072
36)	Customer Relations & Info.	$ 546	$ -	$ -	$ -	$ 546
37)	Administration & General	$ 4,978	$ 250	$ 636	$ 287	$ 3,805
38)	Depreciation Expense	$ 19,497	$ 553	$ 469	$ 396	$ 18,079
39)	Grants In Lieu Of Taxes	$ 2,954	$ -	$ -	$ -	$ 2,954
40)	Total Cost	$151,341	$ 12,162	$ 9,976	$ 1,174	$128,029

SCHEDULE 18

NOVA SCOTIA POWER CORPORATION

Classification Of Operating Cost

For The Year Ended March 31, 1977

($000)

		Total Company (1)	Coincident Peak (2)	Peak And Average (3)	Class N.C. Peak (4)	Customer N.C. Peak (5)	Energy (6)	Customer (7)	Revenue (8)	Direct (9)	As Other (10)
	Production Expenses										
1)	Fuel	$ 74,941	$ -	$ -	$ -	$ -	$ 59,329	$ -	$ -	$ 15,612	$ -
2)	Steam Operating	21,075	16,444	16,444	16,444	-	-	-	-	4,631	-
3)	Hydro Operating	2,597	2,119	-	2,119	-	-	-	-	478	-
4)	Gas Turbine Operating	472	472	-	472	-	-	-	-	-	-
5)	Purchase Power Fuel	1,807	-	-	-	-	1,807	-	-	-	-
6)	Purchase Power Other	3,421	3,421	3,421	3,421	-	-	-	-	-	-
7)	Total	$104,313	$ 22,456	$ 19,865	$ 22,456	$ -	$ 61,136	$ -	$ -	$ 20,721	$ -
8)	**Transmission Expenses**	$ 2,051	$ 2,051	$ 2,051	$ 2,051	$ -	$ -	$ -	$ -	$ -	$ -
	Distribution Expenses										
9)	Land	$ 1,135	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,135
10)	Substations	1,872	-	-	-	-	-	-	-	-	1,872
11)	Overhead Lines	2,403	-	-	-	-	-	-	-	-	2,403
12)	U.G. Lines	133	-	-	-	-	-	-	-	-	133
13)	Line Transformers	812	-	-	812	812	-	-	-	-	-
14)	Services	1,249	-	-	-	-	-	1,249	-	-	-
15)	Meters	767	-	-	-	-	-	-	-	767	-
16)	Cust. Serv. & Contracts	926	-	-	-	-	-	93	-	833	-
17)	Cust. Premise	806	-	-	-	-	-	81	-	725	-
18)	Communications	502	-	-	502	502	-	-	-	-	-
19)	Street Lights	1,325	-	-	-	-	-	-	-	1,325	-
20)	Total	$ 11,930	$ -	$ -	$ 1,314	$ 1,314	$ -	$ 1,423	$ -	$ 3,650	$ 5,543
	Customer Accounting										
21)	Billing	$ 3,178	$ -	$ -	$ -	$ -	$ -	$ 3,178	$ -	$ -	$ -
22)	Customer Service	1,026	-	-	-	-	-	710	-	316	-
23)	Credit & Collections	868	-	-	-	-	-	277	-	591	-
24)	Total	$ 5,072	$ -	$ -	$ -	$ -	$ -	$ 4,165	$ -	$ 907	$ -
25)	**Customer Relations & Info.**	$ 546	$ -	$ -	$ -	$ -	$ -	$ 546	$ -	$ -	$ -
26)	**Administrative & General**	$ 4,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,173	$ 3,805
27)	**Depreciation**	$ 19,497	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,418	$ 18,079
28)	**Grants In Lieu of Taxes**	$ 2,954	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,954
29)	**Total Cost**	$151,341	$ 24,507	$ 21,916	$ 25,821	$ 1,314	$ 61,136	$ 6,134	$ -	$ 27,869	$ 30,381
30)	**Total Revenue**	$202,440	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$202,440	$ -

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1977

Coincident Peak Responsiblity

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Comm. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Cost													
1)	Fuel	$ 59,329	$ 21,726	$ 593	$ 11,872	$ 3,838	$ 1,347	$ 261	$ 3,417	$ 11,427	$ 1,442	$ 2,664	$ 742	E-1
2)	Operating	19,035	7,879	135	4,197	1,629	345	135	1,131	2,358	-	900	326	D-1
3)	Purchased Power - Fuel	1,807	662	18	362	117	41	8	104	348	44	81	22	E-1
4)	Purchased Power - Other	3,421	1,416	24	754	293	62	24	203	424	-	162	59	D-1
5)	Total Production	$ 83,592	$ 31,683	$ 770	$ 17,185	$ 5,877	$ 1,795	$ 428	$ 4,855	$ 14,557	$ 1,486	$ 3,807	$ 1,149	
6)	Transmission Operating Cost	$ 2,051	$ 849	$ 15	$ 452	$ 175	$ 37	$ 15	$ 122	$ 254	$ -	$ 97	$ 35	D-1
	Distribution Operating Cost													
7)	Land	$ 1,135	$ 817	$ 24	$ 154	$ 51	$ 9	$ 5	$ 33	$ 14	$ -	$ 15	$ 13	P-3
8)	Substations	1,872	975	11	367	143	40	13	143	78	1	77	24	P-8
9)	Overhead Lines	2,403	1,868	61	285	86	11	8	36	10	-	11	27	P-1
10)	U. G. Lines	133	103	3	16	5	1	-	2	1	-	1	1	P-1
11)	Line Transformers	812	530	6	185	71	-	7	-	-	-	-	13	D-5
12)	Services	1,249	888	37	286	35	-	3	-	-	-	-	-	C-9
13)	Meters	767	589	24	124	20	-	2	5	1	1	1	-	Schedule 15
14)	Customer Service & Contracts	926	833	34	52	6	-	1	-	-	-	-	-	Schedule 22
15)	Customer Premise	806	725	29	46	6	-	-	-	-	-	-	-	Schedule 23
16)	Communications	502	286	3	106	39	9	4	30	9	-	9	7	D-7
17)	Street Light	1,325	-	-	-	-	-	-	-	-	-	-	1,325	Direct
18)	Total Distribution	$ 11,930	$ 7,614	$ 232	$ 1,621	$ 462	$ 70	$ 43	$ 249	$ 113	$ 2	$ 114	$ 1,410	
	Customer Accounting													
19)	Billing	$ 3,178	$ 2,213	$ 87	$ 713	$ 89	$ -	$ 7	$ 10	$ 1	$ 1	$ 1	$ 56	C-10
20)	Customer Service	1,026	737	30	210	28	-	3	4	1	-	-	13	Schedule 24
21)	Credit & Collection	868	562	20	218	58	-	7	-	-	-	-	3	Schedule 25
22)	Total Customer Accounting	$ 5,072	$ 3,512	$ 137	$ 1,141	$ 175	$ -	$ 17	$ 14	$ 2	$ 1	$ 1	$ 72	
23)	Customer Relations & Information	$ 546	$ 485	$ 20	$ 31	$ 4	$ -	$ 1	$ -	$ -	$ -	$ -	$ 5	C-1
24)	Administrative & General	$ 3,805	$ 1,968	$ 51	$ 742	$ 248	$ 46	$ 21	$ 156	$ 285	$ 1	$ 115	$ 172	O-1
25)	Depreciation	$ 18,079	$ 9,399	$ 217	$ 3,497	$ 1,266	$ 235	$ 109	$ 777	$ 1,399	$ 2	$ 571	$ 607	P-5
26)	Grants in Lieu of Taxes	$ 2,954	$ 1,536	$ 35	$ 571	$ 207	$ 39	$ 18	$ 127	$ 229	$ -	$ 93	$ 99	P-5
27)	Total Cost	$128,029	$ 57,046	$ 1,477	$ 25,240	$ 8,414	$ 2,222	$ 652	$ 6,300	$ 16,839	$ 1,492	$ 4,798	$ 3,549	
28)	Total Revenue	$205,087	$ 80,560	$ 2,391	$ 49,332	$ 13,880	$ 3,387	$ 1,227	$ 9,784	$ 28,483	$ 3,088	$ 7,382	$ 5,573	Schedule 16
29)	Return	$ 77,058	$ 23,514	$ 914	$ 24,092	$ 5,466	$ 1,165	$ 575	$ 3,484	$ 11,644	$ 1,596	$ 2,584	$ 2,024	
30)	Rate of Return	17.42	10.27	17.29	28.14	17.66	20.10	21.90	18.20	33.25	835.60	18.38	13.72	
31)	Percentage of Average	100.00	58.96	99.25	161.54	101.38	115.39	125.72	104.48	190.87	4,796.79	105.51	78.76	

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Cost

For the Year Ended March 31, 1977

Coincident Peak and Average

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Cost													
1)	Fuel	$ 59,329	$ 21,726	$ 593	$ 11,872	$ 3,838	$ 1,347	$ 261	$ 3,417	$ 11,427	$ 1,442	$ 2,664	$ 742	E-1
2)	Operating	19,035	7,517	154	4,037	1,479	379	118	1,148	2,853	177	876	297	D-3
3)	Purchased Power - Fuel	1,807	662	18	362	117	41	8	104	348	44	81	22	E-1
4)	Purchased Power - Other	3,421	1,351	28	726	266	68	21	206	513	32	157	53	D-3
5)	Total Production	$ 83,592	$ 31,256	$ 793	$ 16,997	$ 5,700	$ 1,835	$ 408	$ 4,875	$ 15,141	$ 1,695	$ 3,778	$ 1,114	
6)	Transmission Operating Cost	$ 2,051	$ 810	$ 17	$ 435	$ 159	$ 41	$ 13	$ 124	$ 307	$ 19	$ 94	$ 32	D-3
	Distribution Operating Cost													
7)	Land	$ 1,135	$ 778	$ 24	$ 175	$ 60	$ 11	$ 5	$ 36	$ 15	$ -	$ 16	$ 15	P-4
8)	Substations	1,872	859	13	425	168	43	15	155	80	2	83	29	P-9
9)	Overhead Lines	2,403	1,807	62	318	101	12	9	40	11	-	13	30	P-2
10)	U. G. Lines	133	99	3	18	6	1	2	1	-	-	1	2	P-2
11)	Line Transformers	812	476	7	219	87	-	7	-	-	-	-	16	D-11
12)	Services	1,249	887	37	286	36	-	3	-	-	-	-	-	C-9
13)	Meters	767	589	24	124	20	-	2	5	1	1	1	-	Schedule 15
14)	Customer Serv. & Cont.	926	833	34	52	6	-	1	-	-	-	-	-	Schedule 22
15)	Customer Premise	806	725	29	46	6	-	-	-	-	-	-	-	Schedule 23
16)	Communications	502	252	4	123	47	10	4	33	9	-	11	9	D-13
17)	Street Lights	1,325	-	-	-	-	-	-	-	-	-	-	1,325	Direct
18)	Total Distribution	$ 11,930	$ 7,305	$ 237	$ 1,786	$ 537	$ 77	$ 48	$ 270	$ 116	$ 3	$ 125	$ 1,426	
	Customer Accounting													
19)	Billing	$ 3,178	$ 2,213	$ 87	$ 713	$ 89	$ -	$ 7	$ 10	$ 1	$ 1	$ 1	$ 56	C-10
20)	Customer Service	1,026	737	30	210	28	-	3	4	1	-	-	13	Schedule 24
21)	Credit & Collection	868	562	20	218	58	-	7	-	-	-	-	3	Schedule 25
22)	Total Customer Accounting	$ 5,072	$ 3,512	$ 137	$ 1,141	$ 175	$ -	$ 17	$ 14	$ 2	$ 1	$ 1	$ 72	
23)	Customer Relations & Information	$ 546	$ 485	$ 20	$ 31	$ 4	$ -	$ 1	$ -	$ -	$ -	$ -	$ 5	C-1
24)	Administrative & General	$ 3,805	$ 1,898	$ 54	$ 738	$ 237	$ 51	$ 20	$ 160	$ 343	$ 21	$ 113	$ 170	O-2
25)	Depreciation	$ 18,079	$ 8,992	$ 230	$ 3,552	$ 1,255	$ 255	$ 103	$ 801	$ 1,634	$ 85	$ 566	$ 606	P-6
26)	Grants in Lieu of Taxes	$ 2,954	$ 1,469	$ 38	$ 580	$ 205	$ 42	$ 17	$ 131	$ 267	$ 14	$ 92	$ 99	P-6
27)	Total Cost	$128,029	$ 55,727	$ 1,526	$ 25,260	$ 8,272	$ 2,301	$ 627	$ 6,375	$ 17,810	$ 1,838	$ 4,769	$ 3,524	
28)	Total Revenue	$205,087	$ 80,560	$ 2,391	$ 49,332	$ 13,880	$ 3,387	$ 1,227	$ 9,784	$ 28,483	$ 3,088	$ 7,382	$ 5,573	Schedule 16
29)	Return	$ 77,058	$ 24,833	$ 865	$ 24,072	$ 5,608	$ 1,086	$ 600	$ 3,409	$ 10,673	$ 1,250	$ 2,613	$ 2,049	
30)	Rate of Return	17.42	11.33	15.44	27.68	18.30	17.27	23.76	17.33	26.23	56.82	18.75	13.92	
31)	Percentage of Average	100.00	65.04	88.63	158.90	105.05	99.14	136.40	99.48	150.57	326.18	107.64	79.91	

NOVA SCOTIA POWER CORPORATION

Allocation of Operating Costs

For the Year Ended March 31, 1977

Class Non-Coincident Peak Responsibility

($000)

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
	Production Cost													
1)	Fuel	$ 59,329	$ 21,726	$ 593	$ 11,872	$ 3,838	$ 1,347	$ 261	$ 3,417	$ 11,427	$ 1,442	$ 2,664	$ 742	E-1
2)	Operating	19,035	8,094	120	3,946	1,509	329	137	1,119	2,235	432	836	278	D-17
3)	Purchased Power - Fuel	1,807	662	18	362	117	41	8	104	348	44	81	22	E-1
4)	Purchased Power - Other	3,421	1,455	21	709	271	59	25	201	402	78	150	50	D-17
5)	Total Production	$ 83,592	$ 31,937	$ 752	$ 16,889	$ 5,735	$ 1,776	$ 431	$ 4,841	$ 14,412	$ 1,996	$ 3,731	$ 1,092	
6)	**Transmission Operating Cost**	$ 2,051	$ 872	$ 13	$ 425	$ 163	$ 35	$ 15	$ 121	$ 241	$ 46	$ 90	$ 30	D-17
	Distribution Operating Cost													
7)	Land	$ 1,135	$ 778	$ 24	$ 175	$ 60	$ 11	$ 5	$ 36	$ 15	$ -	$ 16	$ 15	P-4
8)	Substations	1,872	859	13	425	168	43	15	155	80	2	83	29	P-9
9)	Overhead Lines	2,403	1,806	62	319	101	12	9	40	11	-	13	30	P-2
10)	U. G. Lines	133	100	3	18	5	1	-	2	1	-	1	2	P-2
11)	Line Transformers	812	476	7	219	87	-	7	-	-	-	-	16	D-11
12)	Services	1,249	888	37	286	35	-	3	-	-	-	-	-	C-9
13)	Meters	767	589	24	124	20	-	2	5	1	1	1	-	Schedule 15
14)	Customer Service & Contracts	926	833	34	52	6	1	-	-	-	-	-	-	Schedule 22
15)	Customer Premise	806	725	29	46	6	-	-	-	-	-	-	-	Schedule 23
16)	Communications	502	252	4	123	47	10	4	33	9	-	11	9	D-13
17)	Street Lights	1,325	-	-	-	-	-	-	-	-	-	-	1,325	Direct
18)	Total Distribution	$ 11,930	$ 7,306	$ 237	$ 1,787	$ 535	$ 78	$ 45	$ 271	$ 117	$ 3	$ 125	$ 1,426	
	Customer Accounting													
19)	Billing	$ 3,178	$ 2,213	$ 87	$ 713	$ 89	$ -	$ 7	$ 10	$ 1	$ 1	$ 1	$ 56	C-10
20)	Customer Service	1,026	737	30	210	28	-	3	4	1	-	-	13	Schedule 24
21)	Credit & Collection	868	562	20	218	58	-	7	-	-	-	-	3	Schedule 25
22)	Total Customer Accounting	$ 5,072	$ 3,512	$ 137	$ 1,141	$ 175	$ -	$ 17	$ 14	$ 2	$ 1	$ 1	$ 72	
23)	**Customer Relations & Information**	$ 546	$ 485	$ 20	$ 31	$ 4	$ -	$ 1	$ -	$ -	$ -	$ -	$ 5	C-1
24)	**Administrative & General**	$ 3,805	$ 1,966	$ 49	$ 727	$ 240	$ 45	$ 22	$ 156	$ 271	$ 51	$ 109	$ 169	O-3
25)	**Depreciation**	$ 18,079	$ 9,276	$ 211	$ 3,484	$ 1,235	$ 230	$ 110	$ 776	$ 1,387	$ 248	$ 531	$ 591	P-7
26)	**Grants in Lieu of Taxes**	$ 2,954	$ 1,516	$ 34	$ 569	$ 202	$ 37	$ 18	$ 127	$ 227	$ 40	$ 87	$ 97	P-7
27)	**Total Cost**	$128,029	$ 56,870	$ 1,453	$ 25,053	$ 8,289	$ 2,201	$ 659	$ 6,306	$ 16,657	$ 2,385	$ 4,674	$ 3,482	
28)	**Total Revenue**	$205,087	$ 80,560	$ 2,391	$ 49,332	$ 13,880	$ 3,387	$ 1,227	$ 9,784	$ 28,483	$ 3,088	$ 7,382	$ 5,573	Schedule 16
29)	**Return**	$ 77,058	$ 23,690	$ 938	$ 24,279	$ 5,591	$ 1,186	$ 568	$ 3,478	$ 11,826	$ 703	$ 2,708	$ 2,091	
30)	**Rate of Return**	17.42	10.48	18.12	28.47	18.53	20.84	21.10	18.22	34.08	11.51	20.63	14.53	
31)	**Percentage of Return**	100.00	60.16	104.02	163.43	106.37	119.63	121.13	104.59	195.64	66.07	118.43	83.41	

NOVA SCOTIA POWER CORPORATION

SCHEDULE 22

Allocation of Customer Service and Contracts

For the Year Ended March 31, 1977

($000)

		Direct (1)	Customers (2)	Percent (3)	Amount Allocated (4)	Total (5)
1)	Domestic	$ 833(1)	-	-	$ -	$ 833
2)	General Conn. Load	-	10,710	36.22	34	34
3)	General	-	16,627	56.22	52	52
4)	General All Electric	-	2,069	7.00	6	6
5)	Industrial to 249 KVA	-	166	0.56	1	1
6)	Total	$ 833	29,572	100.00	$ 93	$ 926

(1) 90% Domestic

NOVA SCOTIA POWER CORPORATION

SCHEDULE 23

Allocation of Customer Premise Expense

For the Year Ended March 31, 1977

($000)

		Direct (1)	Customers (2)	Percent (3)	Amount Allocated (4)	Total (5)
1)	Domestic	$ 725(1)	-	-	$ -	$ 725
2)	General Conn. Load	-	10,710	36.22	29	29
3)	General	-	16,627	56.22	46	46
4)	General All Electric	-	2,069	7.00	6	6
5)	Industrial 249 KVA	-	166	.56	-	-
6)	Totals	$ 725	29,572	100.00	$ 81	$ 806

(1) 90% Domestic

NOVA SCOTIA POWER CORPORATION SCHEDULE 24

Allocation of Customer Service Expense

For the Year Ended March 31, 1977

($000)

		Total Co. Less St. & Joint (1)	Meter Test (As Meters) (2)	Other C-10 (3)
1)	Domestic	$ 737	$ 243	$ 494
2)	General C.L.	30	10	20
3)	General	210	51	159
4)	General All Electric	28	8	20
5)	General Large	-	-	-
6)	Ind. to 249 KVA	3	1	2
7)	Ind. 250-3999 KVA	4	2	2
8)	Ind. Large	1	1	-
9)	Interruptible	-	-	-
10)	Municipal	-	-	-
11)	Unmetered	13	-	13
12)	Total	$ 1,026	$ 316	$ 710

NOVA SCOTIA POWER CORPORATION SCHEDULE 25

Allocation of Credit & Collection Expense

For the Year Ended March 31, 1977

($000)

		Total (1)	Direct Bad Debts (2)	Other Bad Debts R-1 (3)	Collection Costs C-1 (4)
1)	Domestic	$ 562	$ -	$ 316	$ 246
2)	General C.L.	20	-	10	10
3)	General	218	-	202	16
4)	General All Electric	58	-	56	2
5)	General Large	-	-	-	-
6)	Ind. to 249 KVA	7	-	7	-
7)	Ind. to 250-3,999 KVA	-	-	-	-
8)	Ind. Large	-	-	-	-
9)	Interruptible	-	-	-	-
10)	Municipal	-	-	-	-
11)	Unmetered	3	-	-	3
12)	Total	$ 868	$ -	$ 591	$ 277

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

		Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1)	System Peak MW - 1977	993	411	7	219	85	18	7	59	123	-	47	17	
2)	% Responsibility	100.00	41.39	0.71	22.05	8.56	1.81	0.71	5.94	12.39	-	4.73	1.71	D-1 ✓D
3)	System Peak MW - 1978	962	405	7	219	77	19	10	62	101	-	44	18	
4)	% Responsibility	100.00	42.10	0.73	22.77	8.00	1.98	1.04	6.44	10.50	-	4.57	1.87	D-2
5)	System Peak and Average - 1977	1,608	635	13	341	125	32	10	97	241	15	74	25	
6)	% Responsibility	100.00	39.49	0.81	21.21	7.77	1.99	0.62	6.03	14.99	0.93	4.60	1.56	D-3 ✓D
7)	System Peak and Average - 1978	1,565	624	13	343	115	33	14	99	210	16	72	26	
8)	% Responsibility	100.00	39.87	0.83	21.92	7.35	2.11	0.89	6.33	13.42	1.02	4.60	1.66	D-4
9)	Customer Non-Coincident Demand Sec. - 1977	978,349	638,455	7,211	223,290	85,924	-	7,647	-	-	-	-	15,822	
10)	% Responsibility	100.00	65.26	.74	22.82	8.78	-	.78	-	-	-	-	1.62	D-5
11)	Customer Non-Coincident Demand Sec. - 1978	971,044	633,131	7,424	224,573	77,703	-	11,686	-	-	-	-	16,527	
12)	% Responsibility	100.00	65.20	.77	23.13	8.00	-	1.20	-	-	-	-	1.70	D-6
13)	Customer Non-Coincident Demand Pri. - 1977	1,162,016	661,439	7,471	245,080	91,319	21,012	8,743	68,493	20,344	-	21,724	16,391	
14)	% Responsibility	100.00	56.92	0.64	21.09	7.86	1.81	0.75	5.90	1.75	-	1.87	1.41	D-7
15)	Customer Non-Coincident Demand Pri. - 1978	1,151,946	652,758	7,654	245,220	82,403	22,047	12,865	72,175	21,093	-	18,692	17,039	
16)	% Responsibility	100.00	56.67	.66	21.29	7.15	1.91	1.12	6.27	1.83	-	1.62	1.48	D-8
17)	Customer Non-Coincident Demand DBPS - 1977	1,379,458	674,668	7,620	249,982	93,145	21,432	8,918	72,780	153,719	28,941	51,534	16,719	
18)	% Responsibility	100.00	48.91	0.55	18.12	6.75	1.55	0.65	5.28	11.14	2.10	3.74	1.21	D-9
19)	Customer Non-Coincident Demand DBPS - 1978	1,350,746	665,813	7,807	250,124	84,051	22,488	13,122	76,536	133,444	31,539	48,442	17,380	
20)	% Responsibility	100.00	49.29	.58	18.52	6.22	1.66	.97	5.67	9.88	2.33	3.59	1.29	D-10
21)	Class N.C. Demand Sec. - 1977	786,625	460,976	6,851	212,126	83,777	-	7,073	-	-	-	-	15,822	
22)	% Responsibility	100.00	58.60	.87	26.97	10.65	-	.90	-	-	-	-	2.01	D-11 ✓D-
23)	Class N.C. Demand Sec. - 1978	780,615	457,121	7,053	213,344	75,761	-	10,809	-	-	-	-	16,527	
24)	% Responsibility	100.00	58.56	.90	27.33	9.71	-	1.38	-	-	-	-	2.12	D-12 X
25)	Class N.C. Demand Pri. - 1977	952,787	477,571	7,098	232,826	89,037	19,436	8,087	63,356	17,802	-	21,182	16,392	
26)	% Responsibility	100.00	50.13	.74	24.44	9.34	2.04	.85	6.65	1.87	-	2.22	1.72	D-13 ✓D
27)	Class N.C. Demand Pri. - 1978	947,441	471,292	7,272	232,959	80,343	20,393	11,900	69,561	18,457	-	18,225	17,039	
28)	% Responsibility	100.00	49.74	.77	24.59	8.48	2.15	1.26	7.34	1.95	-	1.92	1.80	D-14 X
29)	Class N.C. Demand DBPS - 1977	1,145,576	487,122	7,240	237,482	90,818	19,825	8,249	67,322	134,505	36,046	50,247	16,720	
30)	% Responsibility	100.00	42.52	.63	20.73	7.93	1.73	.72	5.88	11.74	2.27	4.39	1.46	D-15 ✓D.
31)	Class N.C. Demand DBPS - 1978	1,124,052	480,718	7,417	237,618	81,950	20,881	12,138	73,651	116,763	28,385	47,231	17,380	
32)	% Responsibility	100.00	42.77	.66	21.14	7.29	1.85	1.08	6.55	10.39	2.52	4.20	1.55	D-16
33)	Class N.C. Demand Gen. - 1977	1,175,358	499,787	7,428	243,656	93,179	20,340	8,463	69,072	138,002	26,723	51,553	17,155	
34)	% Responsibility	100.00	42.52	.63	20.73	7.93	1.73	.72	5.88	11.74	2.27	4.39	1.46	D-17 ✓D
35)	Class N.C. Demand Gen. - 1978	1,153,279	493,217	7,610	243,796	84,081	21,342	12,454	75,566	119,799	29,123	48,459	17,832	
36)	% Responsibility	100.00	42.77	.66	21.14	7.29	1.85	1.08	6.55	10.39	2.52	4.20	1.55	D-18

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NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1) MWH Gen. and Purchased - 1977	5,360,248	1,962,940	53,869	1,072,609	346,591	121,710	23,325	308,795	1,032,453	130,242	240,729	66,985	
2) % Responsibility	100.00	36.62	1.00	20.01	6.47	2.27	0.44	5.76	19.26	2.43	4.49	1.25	E-1 E-
3) MWH Gen. and Purchased - 1978	5,280,003	1,920,889	51,449	1,087,430	337,065	123,193	31,907	321,103	951,746	141,260	244,223	69,738	
4) % Responsibility	100.00	36.38	0.97	20.60	6.38	2.33	0.60	6.08	18.03	2.68	4.63	1.32	E-2

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factor (13)
1) Customers - 1977	290,241	257,891	10,710	16,627	2,069	3	166	124	14	6	8	2,623	
2) Responsibility	100.00	88.86	3.69	5.73	0.71	-	0.06	0.04	.01	-	-	0.90	C-1 ✓C
3) Customers - 1978	296,082	264,465	9,855	17,215	1,792	3	218	126	14	6	8	2,380	
4) % Responsibility	100.00	89.32	3.33	5.82	0.61	-	0.07	.04	.01	-	-	0.80	C-2
5) Customers Secondary - 1977	290,061	257,891	10,710	16,608	2,065	-	164	-	-	-	-	2,623	
6) % Responsibility	100.00	88.91	3.69	5.73	.71	-	.06	-	-	-	-	.90	C-3 ✓C
7) Customers Secondary - 1978	295,900	264,465	9,855	17,196	1,788	-	216	-	-	-	-	2,380	
8) % Responsibility	100.00	89.38	3.33	5.81	.61	-	.07	-	-	-	-	.80	C-4
9) Customers Primary - 1977	290,175	257,891	10,710	16,627	2,069	3	166	82	2	-	2	2,623	
10) % Responsibility	100.00	88.88	3.69	5.73	.71	-	.06	.03	-	-	-	.90	C-5 ✓C
11) Customers Primary - 1978	296,016	264,465	9,855	17,215	1,792	3	218	84	2	-	2	2,380	
12) % Responsibility	100.00	89.34	3.33	5.82	.61	-	.07	.03	-	-	-	.80	C-6
13) Customers DBPS - 1977	290,234	257,891	10,710	16,627	2,069	3	166	118	13	6	8	2,623	
14) % Responsibility	100.00	88.86	3.69	5.73	.71	-	.06	.04	.01	-	-	.90	C-7
15) Customers DBPS - 1978	296,075	264,465	9,855	17,215	1,792	3	218	120	13	6	8	2,380	
16) % Responsibility	100.00	89.32	3.33	5.82	.61	-	.07	.04	.01	-	-	.80	C-8
17) Weighted Secondary Customers - 1977	287,438	257,891	10,710	16,608	2,065	-	164	-	-	-	-	-	
18) Weighting Factor		1.00	1.00	5.0	5.0	-	5.0	-	-	-	-	-	
19) Weighted Total	362,786	257,891	10,710	83,040	10,325	-	820	-	-	-	-	-	
20) % Responsibility	100.00	71.09	2.95	22.88	2.85	-	0.23	-	-	-	-	-	C-[illegible]
21) Weighted Secondary Customers - 1978	293,550	264,465	9,885	17,196	1,788	-	216	-	-	-	-	-	
22) Weighting Factor		1.00	1.00	5.0	5.0	-	5.0	-	-	-	-	-	
23) Weighted Total	370,350	264,465	9,885	85,980	8,940	-	1,080	-	-	-	-	-	
24) % Responsibility	100.00	71.41	2.67	23.22	2.41	-	.29	-	-	-	-	-	C-[illegible] X
25) Weighted Customers - 1977	289,701	257,891	10,170	16,627	2,069	3	166	124	14	6	8	2,623	
26) Weighting Factor		1.0	1.0	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	2.5	
27) Weighted Total	370,464	257,891	10,170	83,135	10,345	15	830	1,240	140	60	80	6,558	
28) % Responsibility	100.00	69.63	2.74	22.44	2.79	-	0.22	0.33	0.04	0.02	0.02	1.77	C-[illegible] ✓C
29) Weighted Customers - 1978	289,538	257,891	9,885	17,215	1,792	3	218	126	14	6	[illegible]	2,380	
30) Weighting Factor		1.00	1.00	5.0	5.0	5.0	5.0	10.0	10.0	10.0	10.0	2.5	
31) Weighted Total	371,406	~~257,891~~	9,885	86,075	8,960	15	1,090	1,260	140	60	80	5,950	
32) % Responsibility	100.00	69.44	2.66	23.18	2.41	-	.29	.34	.04	.02	.02	1.60	C-[illegible] X

264,465

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors
For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Coincident Peak Poles & Wire - 1977	79,135	61,514	2,003	9,386	2,834	358	261	1,175	345	-	369	890	
2) % Responsibility	100.00	77.73	2.53	11.86	3.58	0.45	0.33	1.49	0.44	-	0.47	1.12	P-1
3) Coincident Peak Poles & Wire - 1978	89,897	70,073	2,085	10,794	2,909	428	434	1,418	411	-	364	981	
4) % Responsibility	100.00	77.95	2.32	12.01	3.23	0.48	0.48	1.58	0.46	-	0.40	1.09	P-10
6) Class Non-Coincident Peak & Average Poles & Wire -1977	79,135 ✓	59,467	2,039	10,489	3,323	403	293	1,323	369	-	438	992	
6) % Responsibility	100.00	75.15	2.58	13.25	4.20	0.51	0.37	1.67	0.47	-	0.55	1.25	P-2 ✓P-1
7) Class Non-Coincident Peak & Avg. Poles & Wire-1978	89,897	67,716	2,125	12,042	3,414	482	488	1,658	438	-	430	1,103	
8) % Responsibility	100.00	75.33	2.36	13.39	3.80	0.54	0.54	1.84	0.49	-	0.48	1.23	P-11 X
9) Coincident Peak Substations Poles & Wire -1977	102,076	73,465	2,137	13,886	4,583	842	427	2,923	1,299	19	1,309	1,186	
10) % Responsibility	100.00	71.97	2.09	13.60	4.49	0.83	0.42	2.87	1.27	0.02	1.28	1.16	P-3
11) Coincident Peak Substations Poles & Wire -1978	113,081	82,153	2,226	15,401	4,529	935	681	3,244	1,362	18	1,235	1,297	
12) % Responsibility	100.00	72.65	1.97	13.62	4.00	0.83	0.60	2.87	1.20	0.02	1.09	1.15	P-12
13) Class Non-Coincident Peak & Avg. Subs., Poles & Wire-1977	103,099 102,076	69,993	2,193	15,692	5,383	935	480	3,228	1,348	19	1,475 1,452	1,353	
14) % Responsibility	100.00 ✓	68.56	2.15	15.37	5.27	0.92	0.47	3.16	1.32	0.02	1.44	1.32	P-4 ✓P-2
15) Class Non-Coincident Peak & Avg. Subs., Poles & Wire-1978	112,081	78,319	2,290	17,353	5,317	1,041	765	3,712	1,415	18	1,364	1,487	
16) % Responsibility	100.00	69.26	2.02	15.35	4.70	0.92	0.68	3.28	1.25	0.02	1.21	1.31	P-13 X
17) Coincident Peak P.T.D. - 1977	415,392	215,985	4,970	80,341	29,102	5,383	2,475	17,888	32,157	26	13,121	13,944	
18) % Responsibility	100.00	51.99	1.20	19.34	7.00	1.30	0.60	4.30	7.74	0.01	3.16	3.36	P-5
19) Coincident Peak P.T.D. - 1978	580,779	292,910	6,218	118,808	39,502	8,848	5,274	29,051	43,142	25	19,441	17,560	
20) % Responsibility	100.00	50.43	1.07	20.46	6.80	1.52	0.91	5.00	7.43	0.01	3.35	3.02	P-14
21) Coincident Peak & Avg. P.T.D. - 1977	415,392	206,638	5,272	81,626	28,821	5,852	2,381	18,390	37,556	1,939	13,004	13,913	
22) % Responsibility	100.00	49.74	1.27	19.65	6.94	1.41	0.57	4.43	9.04	0.47	3.13	3.35	P-6 P-3
23) Coincident Peak & Avg. P.T.D. - 1978	580,779	282,180	6,535	120,294	39,454	9,236	5,097	29,308	49,404	2,194	19,640	17,437	
24) % Responsibility	100.00	48.59	1.12	20.71	6.79	1.59	0.88	5.05	8.51	0.38	3.38	3.00	P-15 X
25) Class Non-Coincident P.T.D. 1977	415,392	213,130	4,867	80,023	28,359	5,282	2,541	17,833	31,860	5,668	12,227	13,602	
26) % Responsibility	100.00	51.31	1.17	19.27	6.83	1.27	0.61	4.29	7.67	1.37	2.94	3.27	P-7
27) Class Non-Coincident P.T.D. - 1978	580,779	289,581	6,043	115,625	38,016	8,443	5,575	29,979	42,760	10,037	18,108	16,612	
28) % Responsibility	100.00	49.86	1.04	19.91	6.55	1.45	0.96	5.16	7.36	1.73	3.12	2.86	P-16
29) Coincident Peak Substations - 1977	22,941	11,951	134	4,500	1,749	484	166	1,748	954	19	940	296	
30) % Responsibility	100.00	52.10	0.58	19.62	7.62	2.11	0.72	7.62	4.16	0.08	4.10	1.29	P-8
31) Coincident Peak Substations - 1978	23,184	12,080	141	4,607	1,620	507	247	1,826	951	18	871	316	
32) % Responsibility	100.00	52.10	.61	19.87	6.99	2.19	1.06	7.88	4.10	.08	3.76	1.36	P-[illegible]
33) Class Non-Coincident Peak & Avg. Substations -1977	22,941	10,526	155	5,203	2,060	532	187	1,905	979	19	1,014	361	
34) % Responsibility	100.00	45.88	.68	22.68	8.98	2.32	.82	8.30	4.27	.08	4.42	1.57	P-[illegible] ✓P-4
35) Class Non-Coincident Peak & Avg. Substations -1978	23,184	10,603	164	5,311	1,903	559	277	2,054	977	18	934	384	
36) % Responsibility	100.00	45.73	.71	22.91	8.21	2.41	1.19	8.86	4.21	.08	4.03	1.66	P-[illegible] X

NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors
For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Coincident Peak O. & M. - 1977	$ 42,055	$21,755	$ 563	$ 8,196	$2,738	$ 514	$ 235	$1,719	$ 3,151	$ 3	$1,274	$1,907	
2) % Responsibility	100.00	51.73	1.34	19.49	6.51	1.22	.56	4.09	7.49	.01	3.03	4.53	O-1
3) Coincident Peak O. & M. - 1978	$123,617	$52,086	$1,348	$25,022	$7,681	$2,409	$ 824	$6,710	$17,237	$ 2,082	$4,910	$3,308	
4) % Responsibility	100.00	42.14	1.09	20.24	6.21	1.95	.67	5.43	13.94	1.68	3.97	2.68	O-4
5) Coincident Peak & Average O. & M. - 1977	$ 42,055	$20,980	$ 593	$ 8,156	$2,620	$ 565	$ 218	$1,762	$ 3,791	$ 232	$1,253	$1,885	
6) % Responsibility	100.00	49.89	1.41	19.39	6.23	1.34	.52	4.19	9.02	.55	2.98	4.48	O-2
7) Coincident Peak & Average O. & M. - 1978	$123,617	$51,164	$1,379	$24,966	$7,577	$2,452	$ 792	$6,717	$18,019	$ 2,355	$4,929	$3,267	
8) % Responsibility	100.00	41.39	1.12	20.20	6.13	1.98	.64	5.43	14.58	1.90	3.99	2.64	O-5
9) Class Non-Coincident Peak O. & M. - 1977	$ 42,055	$21,724	$ 548	$ 8,039	$2,657	$ 501	$ 240	$1,726	$ 2,997	$ 560	$1,202	$1,861	
10) % Responsibility	100.00	51.66	1.30	19.12	6.32	1.19	.57	4.10	7.13	1.33	2.86	4.42	O-3
11) Class Non-Coincident Peak O. & M. - 1978	$123,617	$51,937	$1,334	$24,758	$7,562	$2,382	$ 843	$6,775	$17,212	$2,754	$ 4,821	$3,239	
12) % Responsibility	100.00	42.01	1.08	20.03	6.12	1.93	.68	5.48	13.92	2.23	3.90	2.62	O-6

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NOVA SCOTIA POWER CORPORATION

Determination of Allocation Factors

For the Years Ended March 31, 1977 & 1978

	Total Company Less Steam and Joint (1)	Domestic (2)	General Conn. Load (3)	General (4)	General All-Electric (5)	General Large (6)	Industrial To 249 KVA (7)	Industrial 250-3,999 KVA (8)	Industrial Large (9)	Interruptible Service (10)	Municipal (11)	Unmetered (12)	Factors (13)
1) Secondary Customer/Revenue - 1977	$ 141,659	$ 75,885	$ 2,277	$ 48,390	$13,473	$ -	$1,634	$ -	$ -	$ -	$ -	$ -	
2) % Responsibility	100.00	53.57	1.61	34.16	9.51	-	1.15	-	-	-	-	-	R-1 R-1
3) Secondary Customer/Revenue - 1978	$ 141,564	$ 77,108	$ 2,293	$ 47,582	$13,394	$ -	$1,187	$ -	$ -	$ -	$ -	$ -	
4) % Responsibility	100.00	54.47	1.62	33.61	9.46	-	.84	-	-	-	-	-	R-2
5) Discount Revenue - 1978	$1,293,894	$798,951	$19,796	$144,107	$34,283	$1,735	$ -	$ -	$228,837	$ 4,558	$58,530	$ 3,097	R-3
6) % Responsibility	100.00	61.75	1.53	11.14	2.65	.13	-	-	17.69	.35	4.52	.24	

Request IR-184:

With regard to CA IR-75,

(a) Please explain how, if at all, distribution poles and wires require land and easements.

(b) Please provide a list of all locations at which NSPI owns land or easements for distribution poles or wires.

Response IR-184

(a) Property in Nova Scotia, for the most part, is held by deed. In some cases, the property owner includes various levels of government. NSPI requires a grant of easement by the owner, or owners, to install, replace or repair equipment (such as distribution poles and wires) in order to avoid a trespass situation. NSPI easements are granted in perpetuity.

(b) NSPI has not prepared the requested information for this Proceeding. NSPI requires land or easements at many locations of poles and wires. A master list of the location of all poles and wires is not maintained by NSPI.

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Request IR-185:

Does NSPI agree that all land and easements associated with distribution are required for substations, rather than poles and wires? If not, provide the evidence that land and land rights are required for distribution poles and wires.

Response IR-185

Nova Scotia Power does not agree. Easements are required in order for Nova Scotia Power to place any Nova Scotia Power equipment, such as poles and any other transmission or distribution equipment, on the real property of a third party. Placing equipment on a third party's real property without permission is considered a trespass under the law.

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Request IR-186:

CA IR-77 asked "how land, easements and surveys used for generation and transmission are treated in the Cost of Service Study." The response refers to land functionalized in the accounting system as transmission or general plant, but not generation.

(a) Please explain whether the accounting system functionalizes some land, easements and surveys as generation plant, and if so, whether those costs are included in the generation plant accounts.

(b) Please provide the total amount of land functionalized in the accounting system in general plant.

Response IR-186

(a) Land associated with generation plant is included in the generation plant accounts.

(b) The total amount of land included within generation plant is $9,064,745.

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Request IR-187:

CA IR-83 asked for the "basis and supporting documents and computations for the estimates by month and class in Exhibit 9A." CA IR-84 requested "the basis and supporting documents and computations for the estimates of class non-coincident kW demand in Exhibit 9B." The responses refer to some text in the 1995 COSS, to the electronic version of Exhibit 9A and 9B, and to an input sheet that contains essentially the same data as Exhibit 9A. Neither response provides the derivation of the various peaks and loss factors.

(a) Please provide the derivation of each and every value in "Input Data Two" in Multeese IR-1 Attachment 1.

(b) Please provide the date and hour for the forecast monthly coincident peak load for each month in "Input Data Two" in Multeese IR-1 Attachment 1, or for the historical month that was the basis of forecast.

(c) Please provide the historical data used to project these values for 2012.

(d) If any of the historical or projected values are estimated using load-research data, please provide the load-research data and analyses used in that estimation.

(e) Please provide the line-loss studies or analyses used to estimate losses by class for energy and coincident peak.

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Response IR-187

(a) Please refer to NPB IR-116. It contains the estimates for sales and losses by hour for the test year. From this file, all of the values in the **"**Input Data Two**"** are selected.

(b) Please find the time and date of the monthly system peak for the test year forecast.

Test Year Forecast Date	Hour	Hourly Demand MW
YY-01-21	1900	2308
YY-02-05	1800	2291
YY-03-18	0900	2033
YY-04-03	0900	1840
YY-05-02	0900	1630
YY-06-23	1300	1502
YY-07-15	1600	1591
YY-08-11	1800	1585
YY-09-24	2100	1498
YY-10-22	2000	1645
YY-11-23	1800	1880
YY-12-19	1800	2232

(c) Please find the actual time and date of the monthly system peak from the base data year (2008).

Actual Peak Date from historical base year : 2008	Hourly Demand MW
21-Jan-08 19:00	2192
11-Feb-08 19:00	1975
18-Mar-08 9:00	1991
3-Apr-08 9:00	1792
2-May-08 9:00	1597
23-Jun-08 13:00	1512
25-Jul-08 12:00	1592
7-Aug-08 12:00	1558
23-Sep-08 21:00	1519
23-Oct-08 9:00	1647
24-Nov-08 18:00	1868
19-Dec-08 18:00	2059

(d) Interval load data from meters is used to record energy patterns. Load research class curves are stratified representative samples of a population. They provide the energy and demand information for the particular rate class or stratum (subdivision of a class depending on a particular attribute) that is being defined. The curves provide information on hourly loads used to enable the analysis of historical and forecast demand peaks and energy usage.

Census curves:

These are curves where all the entire population of a particular class is included as contributors to the curve. Each individual customer's hourly load shape is summed to provide the resulting class load profile of 8760 values (8784 hours in a leap year).

NSPI's census class curves:

- Large General
- Large Industrial
- Large Industrial Interruptible Rider
- Generation Replacement/Load Following
- Bowater
- NewPage

Sample Curves:

These are curves where stratified samples of the population are used as contributors to the curve. The sample was designed to be representative of the entire population.

NSPI's sample class curves:

- Residential
- General Demand
- Medium Industrial
- Small Industrial
- Small General

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Please find attached the hourly meter data from both sample and census rate classes used to develop the test year estimation. Attachments 1 to 15 (filed electronically) are the load research metered data.

(e) The line loss estimates are developed by allocating the difference between the net system requirement (generation) curve and the sum of the class load shapes. The allocation procedures involve assessing an allocation of the monthly energy losses based upon typical service voltage for customers within that class. Generally, customers served at the highest voltages incur the lowest losses because they are served from the most efficient parts of the grid. Customers served at lower voltages often generally have more transformers and higher line losses. A series of equations with linear and square terms are used to balance to the monthly losses and provide an hourly losses solution by rate class similar to previous filings and analysis.

The hourly net system requirement curve is attached. See Attachment 16, filed electronically.

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Request IR-188:

The response to CA IR-85 provides NSPI's estimate of the time and date of the non-coincident peak load for each class for 2008. "Input Data Two" in Multeese IR-1 Attachment 1 provides NSPI's estimate of the monthly non-coincident peak load for each class and monthly coincident-peak contribution for each class in 2012. Yet the response to a request for the "all load research studies relied upon by the Company in developing the load-based allocators for its COS study" consisted of a reference back to the text of the 1993 COSS, which contains no load-research studies.

(a) **If the response to CA IR-85 and the data in "Input Data Two" in Multeese IR-1 Attachment 1 are based on load-research data, please provide the load-research studies.**

(b) **If NSPI derived the response to CA IR-85 and the data in "Input Data Two" in Multeese IR-1 Attachment 1 without any load data, please explain how that was done and provide all supporting computations, analyses and work papers.**

Response IR-188

(a) The data for "input data two" is provided in CA IR-187. The load research data from which it was developed is attached with CA IR-187 (c) and (d).

(b) The load research data as mentioned in part (a) has been provided.

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Request IR-189:

The response to CA IR-85 states that "historical hourly load profiles for each class…are scaled to the forecast class energy sales and the maximum hourly demands are selected from the resulting load shapes."

(a) Please provide these computations.

(b) Please explain whether the scaling process scales load in each hour using the forecast change in monthly class energy sales or annual class energy sales.

(c) Please explain whether the forecast maximum hourly demand for each class and month is always the historical maximum hourly demand times the ratio of forecast to historical sales, and if not, why.

Response IR-189:

(a) The worksheet containing the hourly sales and losses is provided in response to NPB IR-116 Attachment 1.

(b) The load research sample is designed for analysis of the winter peaks and load, some summer seasonal effects may not be represented. It is for this reason the hourly load shapes are scaled to monthly values instead of annual.

(c) In general, the mentioned load shape characteristics are preserved in the scaling process and the forecast maximum is the ratio of forecast to historical values. Exceptions may be seen due to factors such as customer shutdowns, inter-class migration, or correction for weather events.

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Request IR-190:

Please provide actually weekly coincident peak loads for January 2009 through June 2011.

Response IR-190:

The following table shows the maximum hourly system load for each week of 2009 to June 2011

Week Number	2009 Peak MW	2010 Peak MW	2011 Peak MW
1	1888	1872	1619
2	1861	1902	1977
3	2086	2011	1899
4	1923	1982	1982
5	2075	1991	2168
6	1943	2114	2042
7	2019	1885	1990
8	1958	1833	2024
9	1866	1858	1938
10	1928	1856	2018
11	1771	1708	1850
12	1698	1633	1853
13	1788	1775	1809
14	1611	1720	1717
15	1569	1505	1669
16	1537	1628	1649
17	1535	1655	1643
18	1510	1475	1549
19	1529	1364	1561
20	1511	1489	1544
21	1492	1463	1627
22	1492	1407	1471
23	1491	1540	1438
24	1366	1396	1429
25	1333	1412	1548
26	1379	1464	1455
27	1368	1450	1466
28	1388	1580	1500
29	1412	1563	
30	1546	1600	
31	1521	1516	

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32	1515	1537	
33	1518	1507	
34	1586	1606	
35	1529	1530	
36	1434	1598	
37	1317	1493	
38	1407	1510	
39	1414	1466	
40	1429	1528	
41	1518	1476	
42	1669	1548	
43	1629	1579	
44	1685	1626	
45	1824	1695	
46	1659	1610	
47	1752	1673	
48	1694	1761	
49	1802	1859	
50	2077	1959	
51	2092	1839	
52	2044	1930	
53	2066	1731	

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Request IR-191:

Please provide forecast weekly coincident peak loads for July 2011 through December 2012.

Response IR-191:

NSPI does not forecast a weekly load. However system peaks can be extracted from the forecast hourly load profiles used for other purposes. A forecast of weekly maximum hourly loads for the requested period is shown in table below.

Week Number	2011F Peak MW	2012F Peak MW
1		2208
2		1895
3		2063
4		2308
5		2110
6		2291
7		1962
8		1939
9		1917
10		1902
11		1841
12		2033
13		1912
14		1840
15		1722
16		1692
17		1679
18		1630
19		1509
20		1597
21		1586
22		1483
23		1170
24		1138
25		1168
26	1457	1502

Week Number	2011F Peak MW	2012F Peak MW
27	1426	1462
28	1467	1505
29	1545	1591
30	1489	1516
31	1458	1509
32	1462	1509
33	1518	1585
34	1467	1513
35	1491	1539
36	1432	1473
37	1427	1453
38	1441	1493
39	1465	1498
40	1440	1465
41	1508	1537
42	1484	1493
43	1599	1645
44	1524	1557
45	1676	1695
46	1668	1685
47	1826	1847
48	1834	1880
49	1848	1883
50	2076	2132
51	2191	2232
52	2075	2135
53	1905	1959