Kingston Hydro

November 15, 2010

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1E4

Dear Ms. Walli,

RE: Kingston Hydro Corporation
EB-2010-0136 Cost of Service Rate Application
Responses to School Energy Coalition (SEC) Interrogatories

Pursuant to the Board's Procedural Order No. 1, issued on October 12, 2010, please find attached Kingston Hydro Corporation responses to SEC interrogatories (dated October 29, 2010) for this rate proceeding which have been filed electronically through the Board's RESS filing system and emailed to intervenors listed in Appendix "A" of the Order.

Respectfully submitted,

J.A. Keech, President & CEO
Kingston Hydro Corporation

Copy: Andrew Taylor, Energy Law (by email)
School Energy Coalition, Jay Shepherd (by email)
Vulnerable Energy Consumers Coalition, Michael Buonaguro (by email)
Energy Probe Research Foundation, Randy Aiken (by email)

P.O. Box 790 Kingston, Ontario Canada K7L 4X7 **p.** 613.546.1181 www.kingstonhydro.com

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Kingston Hydro Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2011.

INTERROGATORIES
FROM
THE SCHOOL ENERGY COALITION

<u>Interrogatory #1</u>

Please confirm that there are 41 publicly-funded schools in the Applicant's franchise area. Please advise the number of schools in each of the GS<50 and GS>50 classes.

There are 38 publicly-funded schools in Kingston Hydro's franchise area. Of these 10 are GS>50 and the remaining 28 are GS<50.

<u>Interrogatory #2</u>

Ref: Ex. 1/2/1, Attach 2

With respect to the Annual Report:

a) P. 17. Please advise what steps, if any, the Applicant has taken to make its DG safety course available for use by other LDCs.

This course was developed by Utilities Kingston in partnership with St. Lawrence College. The college markets and delivers the course to LDCs across Ontario through its contract training department. Utilities Kingston, whose linepersons work on Kingston Hydro's system, helps St. Lawrence College keep the course up-to-date with current practice & evolving distributed generation connection standards. Kingston Hydro has no financial interest in the course.

St. Lawrence College has delivered the course to linepersons at the following LDCs:

- Guelph Hydro
- Haldimand County Hydro
- Sault Ste. Marie P.U.C.
- Hydro One Mississauga

Additional LDCs are booked to take the course in 2011.

b) P. 19. Please advise the average balance of the Applicant's funds held in the bank account of the City for each of 2009 (actual), 2010 (actual plus forecast), and 2011, forecast. Please advise the total amount of interest paid to the Applicant on those funds. Please calculate the amount of interest that would be paid on those funds at 7.25%. Please provide any agreements or other documentation with respect to this arrangement between the Applicant and the City.

Year	Average Balance	Actual Interest Paid	Interest Calculated at 7.25%
2009	$2,524,256	$21,933	$183,009
2010	$3,640,693	$18,150	$263,950
2011	$5,579,323	$17,050	$404,501

Actual interest paid by the City of Kingston to Kingston Hydro is calculated at a rate consistent with the rate the TD Bank pays on the City's general bank account. See Part c below for details on the agreement between the Applicant and the City.

c) ***Financials p. 15. Please confirm that the contract with the City is between Utilities Kingston and the City, not the Applicant and the City. If there is also a contract between the Applicant and the City, please provide a copy of that document and all amendments and supporting documents.***

Kingston Hydro has a verbal agreement with the City of Kingston that the City of Kingston will hold Kingston Hydro's cash funds in its bank account and pay interest to Kingston Hydro at the same rate that the City earns from the bank. The City deposits Kingston Hydro's revenues it collects in its bank account and conversely pays monies out of its bank account for Kingston Hydro expenses.

<u>Interrogatory #3</u>

Ref: Ex. 1/2/3, Attach 2

Please confirm that this is the organizational chart of the Applicant, not Utilities Kingston. If it is the latter, please provide the organizational chart of the Applicant.

This is not the organizational chart of the Applicant. It is the organizational chart of Utilities Kingston. The Applicant, Kingston Hydro has no employees.

The following chart shows the officers of Kingston Hydro Corporation.

<u>Interrogatory #4</u>

Ref: Ex. 1/2/3. Attach 3

With respect to the agreement with Utilities Kingston:

a) P. 7. Please provide a copy of the last review conducted by Serviceco under clause 9(b) of the agreement.

Management undertakes a review prior to the yearly self-certification. These reviews are not documented.

b) P. 16. Please provide the names and positions of the signatories for each of the parties.

The names and positions of the signatories for each of the parties are as follows:

1425446 Ontario Limited, now Kingston Hydro Corporation

J. A. Keech	President and CEO (at the time of signing and current)
Denis Leger	Treasurer (at the time of signing)

1425445 Ontario Limited (operating as Utilities Kingston)

J. A. Keech	President and CEO (at the time of signing and current)
R.K. McConnachie	Treasurer (at the time of signing)

Interrogatory #5

Ref: Ex. 1/2/3, Attach 4, p. 3

Please provide the set of rates negotiated between the parties pursuant to section 4 of the agreement for each of the Historical, Bridge and Test Years. Please include all unit costs. Please provide all correspondence between the parties to the agreement containing offers or counter-offers with respect to such rates.

The rates negotiated between the parties at the time of incorporation were to be actual rates of cost incurred plus actual applicable overheads, with no mark up for profit. For unionized labour, there would be employer rates as noted in the applicable collective agreements. For new union personnel, the rates would be that paid to the employee and recorded in applicable compensation charts and employee contracts.

Other costs, for material, supplies and contracts, are paid directly by the Applicant.

<u>Interrogatory #6</u>

Ref: Ex. 1/2/3, Attach 5

With respect to the Financial Statements of Utilities Kingston:

a) ***P. 2. Please confirm that the revenues, expenses, assets and liabilities of Utilities Kingston relating to services provided to the Applicant are not considered to be for account of Utilities Kingston. Please explain the accounting principles being applied to non-reporting of these amounts in the audited financial statements of Utilities Kingston. Please advise whether Utilities Kingston is considered to be the beneficial owner of the business of supplying those services to the Applicant.***

The revenues and expenses of Utilities Kingston relating to services provided to the Applicant are not considered to be for account of Utilities Kingston. The assets and liabilities of Utilities Kingston do not relate to services provided to the Applicant with the exception of a portion of the "Employee future benefits recoverable" and "Employee future benefits payable".

The revenues and expenses related to work performed on behalf of the Applicant are not reported on the Statement of Earnings due to the fact that the revenues relate to recoveries from the Applicant for expenditures performed on behalf of the Applicant. Utilities Kingston does not profit or loss on the activities performed on behalf of the Applicant. Thus the amounts are not required to be reported on the Statement of Earnings.

Utilities Kingston is not considered to be the beneficial owner of the business of supplying those services to the Applicant because the risks and rewards of the business are borne by the Applicant, not by Utilities Kingston.

b) ***P. 2. Please advise whether the financial results of Utilities Kingston, including the revenues, expenses, assets and liabilities associated with services provided to the Applicant and to the other business areas, are included in the financial statements of the City.***

The financial results of Utilities Kingston, including the revenues, expenses, assets and liabilities associated with services provided to the Applicant and to the other business areas, are included in the financial statements of the City of Kingston on a modified equity basis.

The City of Kingston audited financial statements can be found at
http://www.cityofkingston.ca/residents/budget/audited.asp

c) ***P. 2. Please confirm that, at any given time, the Applicant is indebted to Utilities Kingston with respect to services performed and not yet paid. Please advise where that inter-company receivable is reported in these audited financial statements. Please advise whether at any time Utilities Kingston is indebted to the Applicant with respect to services paid for and not yet performed. If so, please advise where that inter-company payable is reported in the audited financial statements.***

Confirmed. The intercompany receivable is recorded through the intercompany receivable with the City of Kingston for both Kingston Hydro and Utilities Kingston. At no time is Utilities Kingston indebted to the Applicant with respect to services paid for by the Applicant but not yet performed.

d) ***P. 2. Please advise the extent, if any, to which the cash revenues of the Applicant are received by Utilities Kingston rather than the Applicant, and if so how the ownership of those funds is accounted for on receipt and subsequently. Please advise the extent to which the City is involved in those cash revenue receipts.***

Cash revenues of the Applicant are not received by Utilities Kingston. Revenues are recorded as receivable on the account of the Applicant when billed. The financial services department of the City of Kingston collects payment on behalf of the Applicant and credits the Applicant's account with the City of Kingston for the funds received.

e) ***P. 18. Please provide a breakdown of the $15,205,464 of salaries, wages and benefits and the $48,032,953 of materials, supplies and services reported for 2009, by function (similar to page 2 of the Applicant's financial statements), and by business area (i.e. with totals matching the "contract services recoveries" figures immediately above).***

Please see attached schedule.

School Energy Coalition: Question 6, part e)

	Salaries, wages and benefits	Materials, supplies and services	Total
Electric			
Distribution expenses, operation	1,486,463	453,588	1,940,050
Distribution expenses, maintenance	415,781	360,409	776,190
General and administrative	979,378	1,104,519	2,083,896
Community relations	30,680	170,006	200,686
Billing and collecting	172,995	261,273	434,268
Capital expenditures	585,511	3,037,596	3,623,107
Gas			
Distribution	757,261	425,910	1,183,171
Appliance rental	179,937	139,874	319,811
Customer service	133,374	146,199	279,573
General and administrative	615,070	733,857	1,348,927
Billing and collecting	127,486	133,840	261,326
Capital expenditures	213,717	2,306,118	2,519,835
Sewer			
Sewage collection	562,952	341,128	904,081
Pumping and treatment	1,634,778	4,015,353	5,650,131
Customer service	211,381	294,699	506,080
General and administrative	791,000	859,317	1,650,317
Billing and collecting	224,976	301,432	526,408
Capital expenditures	462,150	16,163,865	16,626,015
Water			
Distribution	1,833,434	1,591,175	3,424,609
Pumping and purification	1,265,649	2,047,241	3,312,890
Customer service	214,229	254,185	468,414
General and administrative	961,935	1,153,386	2,115,321
Billing and collecting	224,976	301,432	526,408
Capital expenditures	450,093	9,066,458	9,516,551
Recoverable work performed at cost	670,256	2,370,096	3,040,352
	15,205,464	48,032,953	63,238,417

<u>Interrogatory #7</u>

Please provide all correspondence or other documentation between the Applicant and the Board relating to the Applicant's organizational and affiliate structure and its compliance with the Affiliate Relationships Code.

Other than the annual certification statements as required by section 2.2 of the Electricity Reporting and Record Keeping Requirements which are now filed electronically and all of which have been affirmed, the only correspondence was a submission made by the applicant (formerly Kingston Electricity Distribution Limited) as part of EB-2007-0662 –consultation on amendments to the Affiliate Relationships Code.

KEDL
Kingston Electricity Distribution Limited

1211 John Counter Blvd. P.O. Box 790
Kingston, ON, Canada, K7L 4X7
Phone: 613.544.1181
Fax: 613.542.1463

March 10, 2008

Kristen Walli
Board Secretary, Ontario Energy Board
P.O. Box 2319, 2300 Yonge Street, Suite 2700
Toronto, ON, M4P 1E4

<u>OEB Reference # EB-2007-0662</u>

Dear Ms. Walli,

We would like to thank the Ontario Energy Board (OEB) for the opportunity to comment on the Revised Proposed Amendments to the Affiliate Relationships Code (ARC) released on February 11. Kingston Electricity Distribution Limited (KEDL) supports the purposes of the ARC as outlined in section 1.1 of the code, and is committed to working with its municipally owned affiliates in accordance with the provisions of the ARC.

KEDL recommends that the definition of definition of "Energy Services Provider" should <u>not</u> be modified to include metering or billing for electricity or natural gas services.

In Kingston, an affiliate company, Utilities Kingston, provides metering and billing services both for KEDL's electricity distribution customers as well as for the City of Kingston's water, sewer and natural gas customers. In many cases, the customers in Kingston receive one utility bill for all of these services. Since the introduction of the ARC, sharing of information has been permitted for the purpose of billing (s. 2.6.2) and KEDL, the City and our customers have benefited from this relationship in both achieving cost savings and operational efficiency and improved convenience. Addition of metering and billing to the definition of "energy services provider" will prohibit the involvement of Utilities Kingston employees in the metering and billing of KEDL's customers due to section 2.2.3 interpreted as per Compliance Bulletin 200604.

Customer information that is metered and collected for electricity billing is essentially the same information that is collected for water, sewer and gas billing (i.e. hourly consumption data). Information systems infrastructure and metering and billing expertise that Utilities Kingston has in place for the City of Kingston's water, sewer, and natural gas, services has been applied to KEDL's electricity billing, creating significant economies of scale benefitting KEDL's ratepayers. To put the magnitude of these economies of scale in perspective, if the definition of "energy services provider" is to be modified to include metering and billing, KEDL's ratepayers would have to absorb an increase of $250,000 per year in postage costs alone, before taking into account the cost increases related to hiring additional staff so as to comply with s2.2.3 of the ARC. A further illustration is that Utilities Kingston employs meter readers that can capture readings for all four utility services in one trip. Should the OEB include metering and billing in the definition of energy services provider, these staff can no longer be shared, effectively doubling the number of trips needed to read meters in the City of Kingston and thereby doubling the financial costs and environmental footprint of meter reading activities.

KEDL does not believe that there will be any harm to ratepayers or to non-affiliated entities from the exclusion of metering and billing from the definition of energy services provider, as other provisions of the ARC that are applicable to all affiliates will still apply. Section 2.6 ensures that information made available to Utilities Kingston by KEDL will not provide it with any unfair advantage, and that access to KEDL information is non-discriminatory. The "Transfer Pricing" and "Outsourcing to an Affiliate" provisions of the ARC ensure that KEDL would have to undertake an independently evaluated competitive bidding process for all services provided by Utilities Kingston at least once every five years, ensuring that KEDL's ratepayers are receiving the best value and allowing competitors to openly bid for provision of these services. Utilities Kingston complies with the intent of the ARC by separately identifying the entities and amounts being billed for on all invoices, minimizing customer confusion.

Furthermore, the customer information collected and processed by Utilities Kingston is protected by both the *Municipal Freedom of Information and Protection of Privacy Act, RSO 1990* and the *Personal Information Protection and Electronic Documents Act* and therefore can only be used for the purpose for which it was collected, specifically for the purposes of billing for an individual commodity unless some other specific consent to use the information is granted by the individual. Section 2.2.2 of the ARC ensures that access to customer information and Utilities Kingston's information technology infrastructure is arranged so that only staff involved in metering and billing have access to customer information. Given compliance with these requirements, it would be impossible for Utilities Kingston to use the information to gain some sort of unfair competitive advantage in the marketing of other energy services.

Integrated metering and billing for water, sewer, natural gas, and electricity services is part of the City of Kingston's strategy for exercising its right to foster Conservation and Demand Management. It has enabled Kingston to be the first community to pilot the use of smart meters for electricity, water and natural gas utilities. This is a significant advantage as each of these utilities will benefit from the conservation incentive created by customers having access to hourly information regarding their consumption. It also permits the development of rate designs for gas and water that promote conservation of all three commodities. This creates significant potential for electricity conservation as water consumption in particular creates a large peak electricity load during the summer months. The proposed change to the Code definition of "Energy Services Provider" would make it difficult if not impossible for Kingston to pursue this unique initiative.

Kingston Electricity Distribution Limited is in a unique position as one of only two electricity distributors owned by municipalities that are also gas distributors. As outlined in section 36.8 of the Ontario Energy Board Act, these municipalities are recognized as unique. We hope that the board will take this fact into consideration in their upcoming deliberations. Regardless of the outcome of the current consultations, we look forward to working with the compliance office to demonstrate that KEDL can satisfy the purpose and intent of the ARC while continuing to provide the citizens of the City of Kingston and the affiliated and non-affiliated energy service providers who serve them the cost savings and convenience of consolidated billing for water, sewer, natural gas, electricity, and other energy services.

Thank you for your consideration,

Jim Keech
President & CEO

<u>Interrogatory #8</u>

Ref: Ex. 1/4/3

With respect to the Historical Financial Results:

a) ***P. 1. Please provide details of all of the adjustments to accounting information prior to the Test Year that are referred to on this page. Please advise the total impact on opening rate base of those adjustments.***

   The details of all of the adjustments to accounting information prior to the test year are outlined in *Attachment 1 of 2: 2005-2009 Reconciliation between OEB Filings and Application.* The total impact on the opening rate base of the adjustments is zero.

b) ***P. 2. Please provide a depreciation continuity table for the years 2005 through 2010, consistent with Ex. 4/7/1, Attach. 1, showing the depreciation and rate base before the adjustment for the half year rule.***

   Please see attached for depreciation continuity table.

Appendix 2-M, Depreciation and Amortization Expense 2005 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343			
1808	Buildings	440,638		440,638		440,638	50	0.02	8,813
1810	Leasehold Improvements			-		-			
1815	Transformer Station Equipment >50 kV			-		-			
1820	Substation Equipment	2,424,875		2,424,875	427,247	2,852,122	30	0.03	95,071
1825	Storage Battery Equipment			-		-			
1830	Poles, Towers & Fixtures	7,933,496		7,933,496	168,934	8,102,430	25	0.04	324,097
1835	OH Conductors & Devices	877,283		877,283	273,674	1,150,957	25	0.04	46,038
1840	UG Conduit	3,014,915		3,014,915	253,092	3,268,007	25	0.04	130,720
1845	UG Conductors & Devices	2,202,751		2,202,751	224,756	2,427,507	25	0.04	97,100
1850	Line Transformers	2,769,249		2,769,249	105,374	2,874,623	25	0.04	114,985
1855	Services (OH & UG)	1,454,942		1,454,942	115,338	1,570,280	25	0.04	62,811
1860	Meters	2,812,809		2,812,809	235,153	3,047,962	25	0.04	121,918
1861	Smart Meters			-		-			
1861	Smart Meters/Communication Systems			-		-			
1905	Land			-		-			
1906	Land Rights			-		-			
1908	Buildings & Fixtures			-		-			
1910	Leasehold Improvements	20,602		20,602	30,506	51,108	10	0.1	5,111
1915	Office Furniture & Equipment 10yr			-		-			
1915	Office Furniture & Equipment 5yr			-		-			
1920	Computer - Hardware			-	105,930	105,930	5	0.2	21,186
1921	Computer - Hardware post Mar 22/04			-		-			
1921	Computer - Hardware post Mar 19/07			-		-			
1925	Computer Software	102,762		102,762		102,762	5	0.2	20,552
1930	Transportation Equipment	25,887		25,887		25,887	5	0.2	5,177
1935	Stores Equipment			-		-			
1940	Tools, Shop & Garage Equipment	476,632		476,632	110,187	586,819	10	0.1	58,682
1945	Measurement & Testing Equipment			-		-			
1950	Power operated Equipment			-		-			
1955	Communications Equipment			-		-			
1960	Graphics Equipment			-		-			
1965	Water Heater Rental Units			-		-			
1970	Load Management Controls			-		-			
1975	Load Management Controls Utility Premises			-		-			
1980	System Supervisor Equipment	1,892,228		1,892,228	152,521	2,044,749	15	0.07	136,317
1985	Miscellaneous Fixed Assets			-		-			
1995	Contributions & Grants	(55,549)		(55,549)		(55,549)	25	0.04	(2,222)
				-		-			
				-		-			
	Total	26,590,863	-	26,590,863	2,202,712	28,793,575			1,246,357

Appendix 2-M, Depreciation and Amortization Expense 2006 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343			
1808	Buildings	440,638		440,638		440,638	50	0.02	8,813
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	2,852,122		2,852,122	9,946	2,862,068	30	0.03	95,402
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	8,102,430		8,102,430	458,197	8,560,627	25	0.04	342,425
1835	OH Conductors & Devices	1,150,957		1,150,957	290,917	1,441,874	25	0.04	57,675
1840	UG Conduit	3,268,007		3,268,007	604,057	3,872,064	25	0.04	154,883
1845	UG Conductors & Devices	2,427,507		2,427,507	519,512	2,947,019	25	0.04	117,881
1850	Line Transformers	2,874,623		2,874,623	74,670	2,949,293	25	0.04	117,972
1855	Services (OH & UG)	1,570,280		1,570,280	75,647	1,645,927	25	0.04	65,837
1860	Meters	3,047,962		3,047,962	311,299	3,359,261	25	0.04	134,370
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	51,108		51,108	193,885	244,993	10	0.10	24,499
1915	Office Furniture & Equipment 10yr	-		-		-	-		
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930		105,930	5	0.20	21,186
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	102,762		102,762	40,898	143,660	5	0.20	28,732
1930	Transportation Equipment	25,887		25,887	8,465	34,352	5	0.20	6,870
1935	Stores Equipment	-		-		-	-		
1940	Tools, Shop & Garage Equipment	586,819		586,819	72,679	659,498	10	0.10	65,950
1945	Measurement & Testing Equipment	-		-		-	-		
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-		-	-		
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,044,749		2,044,749	36,502	2,081,251	15	0.07	138,750
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(55,549)		(55,549)	(23,158)	(78,707)	25	0.04	(3,148)
		-		-		-	-		
		-		-		-	-		
	Total	28,793,575	-	28,793,575	2,673,516	31,467,091			1,378,097

Appendix 2-M, Depreciation and Amortization Expense 2007 (without half year rule)

Account	Description	Opening Balance	Less Fully Depreciated (1)	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense
		(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c) + (d) (2)	(f)	(g) = 1 / (f)	(h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	440,638		440,638	8,744	449,382	50	0.02	8,988
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	2,862,068		2,862,068	1,000,491	3,862,559	30	0.03	128,752
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	8,560,627		8,560,627	609,591	9,170,218	25	0.04	366,809
1835	OH Conductors & Devices	1,441,874		1,441,874	406,394	1,848,268	25	0.04	73,931
1840	UG Conduit	3,872,064		3,872,064	935,342	4,807,406	25	0.04	192,296
1845	UG Conductors & Devices	2,947,019		2,947,019	1,061,351	4,008,370	25	0.04	160,335
1850	Line Transformers	2,949,293		2,949,293	1,736	2,951,029	25	0.04	118,041
1855	Services (OH & UG)	1,645,927		1,645,927	70,452	1,716,379	25	0.04	68,655
1860	Meters	3,359,261		3,359,261	479,062	3,838,323	25	0.04	153,533
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	244,993		244,993	21,436	266,429	10	0.10	26,643
1915	Office Furniture & Equipment 10yr	-		-		-	-		
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930		105,930	5	0.20	21,186
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660		143,660		143,660	5	0.20	28,732
1930	Transportation Equipment	34,352		34,352	7,548	41,900	5	0.20	8,380
1935	Stores Equipment	-		-		-	-		
1940	Tools, Shop & Garage Equipment	659,498		659,498	15,489	674,987	10	0.10	67,499
1945	Measurement & Testing Equipment	-		-		-	-		
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-		-	-		
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,081,251		2,081,251	20,774	2,102,025	15	0.07	140,135
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(78,707)		(78,707)	(124,494)	(203,201)	25	0.04	(8,128)
		-		-		-	-		
		-		-		-	-		
	Total	31,467,091	-	31,467,091	4,513,916	35,981,007			1,555,786

Appendix 2-M, Depreciation and Amortization Expense 2008 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	449,382		449,382		449,382	50	0.02	8,988
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	3,862,559		3,862,559	535,166	4,397,725	30	0.03	146,591
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	9,170,218		9,170,218	745,865	9,916,083	25	0.04	396,643
1835	OH Conductors & Devices	1,848,268		1,848,268	522,253	2,370,521	25	0.04	94,821
1840	UG Conduit	4,807,406		4,807,406	271,535	5,078,941	25	0.04	203,158
1845	UG Conductors & Devices	4,008,370		4,008,370	202,636	4,211,006	25	0.04	168,440
1850	Line Transformers	2,951,029		2,951,029	161,849	3,112,878	25	0.04	124,515
1855	Services (OH & UG)	1,716,379		1,716,379		1,716,379	25	0.04	68,655
1860	Meters	3,838,323		3,838,323	335,946	4,174,269	25	0.04	166,971
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	266,429		266,429		266,429	10	0.10	26,643
1915	Office Furniture & Equipment 10yr	-		-		-	-		
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930		105,930	5	0.20	21,186
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660		143,660		143,660	5	0.20	28,732
1930	Transportation Equipment	41,900	24,880	17,020	11,055	28,075	5	0.20	5,615
1935	Stores Equipment	-		-		-	-		
1940	Tools, Shop & Garage Equipment	674,987		674,987	31,667	706,654	10	0.10	70,665
1945	Measurement & Testing Equipment	-		-		-	-		
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-		-	-		
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,102,025		2,102,025		2,102,025	15	0.07	140,135
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(203,201)		(203,201)	(298,831)	(502,032)	25	0.04	(20,081)
etc.		-		-		-	-		
		-		-		-	-		
	Total	35,981,007	24,880	35,956,127	2,519,141	38,475,268			1,651,677

Appendix 2-M, Depreciation and Amortization Expense 2009 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant	-		-	369,597	369,597	40	0.03	9,240
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	449,382		449,382	87,726	537,108	50	0.02	10,742
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	4,397,725		4,397,725	1,205,402	5,603,127	30	0.03	186,771
1825	Storage Battery Equipment	-				-	-		
1830	Poles, Towers & Fixtures	9,916,083		9,916,083	1,320,748	11,236,831	25	0.04	449,473
1835	OH Conductors & Devices	2,370,521		2,370,521	29,969	2,400,490	25	0.04	96,020
1840	UG Conduit	5,078,941		5,078,941	518,628	5,597,569	25	0.04	223,903
1845	UG Conductors & Devices	4,211,006		4,211,006	671,996	4,883,002	25	0.04	195,320
1850	Line Transformers	3,112,878		3,112,878	250,566	3,363,444	25	0.04	134,538
1855	Services (OH & UG)	1,716,379		1,716,379	62,850	1,779,229	25	0.04	71,169
1860	Meters	4,174,269		4,174,269	15,618	4,189,887	25	0.04	167,595
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	266,429		266,429	29,633	296,062	10	0.10	29,606
1915	Office Furniture & Equipment 10yr	-		-	1,887	1,887	10	0.10	189
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930	2,308	108,238	5	0.20	21,648
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660		143,660		143,660	5	0.20	28,732
1930	Transportation Equipment	52,955	25,887	27,068	20,362	47,430	5	0.20	9,486
1935	Stores Equipment	-		-	56,201	56,201	10	0.10	5,620
1940	Tools, Shop & Garage Equipment	706,654		706,654	35,705	742,359	10	0.10	74,236
1945	Measurement & Testing Equipment	-		-	36,629	36,629	10	0.10	3,663
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-	17,794	17,794	10	0.10	1,779
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,102,025		2,102,025	8,765	2,110,790	15	0.07	140,719
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(502,032)		(502,032)	(94,096)	(596,128)	25	0.04	(23,845)
etc.		-		-		-	-		
		-		-		-	-		
	Total	38,500,148	25,887	38,474,261	4,648,288	43,122,549			1,836,604

Appendix 2-M, Depreciation and Amortization Expense 2010 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant	369,597		369,597	609,000	978,597	40	0.03	24,465
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	537,108		537,108	25,000	562,108	50	0.02	11,242
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	5,603,127		5,603,127	60,000	5,663,127	30	0.03	188,771
1825	Storage Battery Equipment	-		-	-	-	-		
1830	Poles, Towers & Fixtures	11,236,831		11,236,831	207,000	11,443,831	25	0.04	457,753
1835	OH Conductors & Devices	2,400,490		2,400,490	678,000	3,078,490	25	0.04	123,140
1840	UG Conduit	5,597,569		5,597,569	1,370,000	6,967,569	25	0.04	278,703
1845	UG Conductors & Devices	4,883,002		4,883,002	611,000	5,494,002	25	0.04	219,760
1850	Line Transformers	3,363,444		3,363,444	100,000	3,463,444	25	0.04	138,538
1855	Services (OH & UG)	1,779,229		1,779,229	130,000	1,909,229	25	0.04	76,369
1860	Meters	4,189,887		4,189,887	263,000	4,452,887	25	0.04	178,115
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	296,062		296,062		296,062	10	0.10	29,606
1915	Office Furniture & Equipment 10yr	1,887		1,887		1,887	10	0.10	189
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	108,238	52,965	55,273		55,273	5	0.20	11,055
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660	102,762	40,898	205,000	245,898	5	0.20	49,180
1930	Transportation Equipment	73,317	25,887	47,430		47,430	5	0.20	9,486
1935	Stores Equipment	56,201		56,201		56,201	10	0.10	5,620
1940	Tools, Shop & Garage Equipment	742,359	218,543	523,816	90,000	613,816	10	0.10	61,382
1945	Measurement & Testing Equipment	36,629		36,629		36,629	10	0.10	3,663
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	17,794		17,794		17,794	10	0.10	1,779
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,110,790		2,110,790	98,000	2,208,790	15	0.07	147,253
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(596,128)		(596,128)		(596,128)	25	0.04	(23,845)
		-		-		-	-		
						-			
	Total	43,148,436	400,157	42,748,279	4,446,000	47,194,279			1,992,223

Appendix 2-M, Depreciation and Amortization Expense 2005 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343			
1808	Buildings	440,638		440,638		440,638	50	0.02	8,813
1810	Leasehold Improvements			-		-			
1815	Transformer Station Equipment >50 kV			-		-			
1820	Substation Equipment	2,424,875		2,424,875	427,247	2,852,122	30	0.03	95,071
1825	Storage Battery Equipment			-		-			
1830	Poles, Towers & Fixtures	7,933,496		7,933,496	168,934	8,102,430	25	0.04	324,097
1835	OH Conductors & Devices	877,283		877,283	273,674	1,150,957	25	0.04	46,038
1840	UG Conduit	3,014,915		3,014,915	253,092	3,268,007	25	0.04	130,720
1845	UG Conductors & Devices	2,202,751		2,202,751	224,756	2,427,507	25	0.04	97,100
1850	Line Transformers	2,769,249		2,769,249	105,374	2,874,623	25	0.04	114,985
1855	Services (OH & UG)	1,454,942		1,454,942	115,338	1,570,280	25	0.04	62,811
1860	Meters	2,812,809		2,812,809	235,153	3,047,962	25	0.04	121,918
1861	Smart Meters			-		-			
1861	Smart Meters/Communication Systems			-		-			
1905	Land			-		-			
1906	Land Rights			-		-			
1908	Buildings & Fixtures			-		-			
1910	Leasehold Improvements	20,602		20,602	30,506	51,108	10	0.1	5,111
1915	Office Furniture & Equipment 10yr			-		-			
1915	Office Furniture & Equipment 5yr			-		-			
1920	Computer - Hardware			-	105,930	105,930	5	0.2	21,186
1921	Computer - Hardware post Mar 22/04			-		-			
1921	Computer - Hardware post Mar 19/07			-		-			
1925	Computer Software	102,762		102,762		102,762	5	0.2	20,552
1930	Transportation Equipment	25,887		25,887		25,887	5	0.2	5,177
1935	Stores Equipment			-		-			
1940	Tools, Shop & Garage Equipment	476,632		476,632	110,187	586,819	10	0.1	58,682
1945	Measurement & Testing Equipment			-		-			
1950	Power operated Equipment			-		-			
1955	Communications Equipment			-		-			
1960	Graphics Equipment			-		-			
1965	Water Heater Rental Units			-		-			
1970	Load Management Controls			-		-			
1975	Load Management Controls Utility Premises			-		-			
1980	System Supervisor Equipment	1,892,228		1,892,228	152,521	2,044,749	15	0.07	136,317
1985	Miscellaneous Fixed Assets			-		-			
1995	Contributions & Grants	(55,549)		(55,549)		(55,549)	25	0.04	(2,222)
				-		-			
				-		-			
	Total	26,590,863	-	26,590,863	2,202,712	28,793,575			1,246,357

Appendix 2-M, Depreciation and Amortization Expense 2006 (without half year rule)

Account	Description	Opening Balance	Less Fully Depreciated (1)	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Rate	Depreciation Expense
		(a)	(b)	(c) = (a) - (b)	(d)	(e)=(c) + (d) (2)	(f)	(g) = 1 / (f)	(h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343			
1808	Buildings	440,638		440,638		440,638	50	0.02	8,813
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	2,852,122		2,852,122	9,946	2,862,068	30	0.03	95,402
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	8,102,430		8,102,430	458,197	8,560,627	25	0.04	342,425
1835	OH Conductors & Devices	1,150,957		1,150,957	290,917	1,441,874	25	0.04	57,675
1840	UG Conduit	3,268,007		3,268,007	604,057	3,872,064	25	0.04	154,883
1845	UG Conductors & Devices	2,427,507		2,427,507	519,512	2,947,019	25	0.04	117,881
1850	Line Transformers	2,874,623		2,874,623	74,670	2,949,293	25	0.04	117,972
1855	Services (OH & UG)	1,570,280		1,570,280	75,647	1,645,927	25	0.04	65,837
1860	Meters	3,047,962		3,047,962	311,299	3,359,261	25	0.04	134,370
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	51,108		51,108	193,885	244,993	10	0.10	24,499
1915	Office Furniture & Equipment 10yr	-		-		-	-		
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930		105,930	5	0.20	21,186
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	102,762		102,762	40,898	143,660	5	0.20	28,732
1930	Transportation Equipment	25,887		25,887	8,465	34,352	5	0.20	6,870
1935	Stores Equipment	-		-		-	-		
1940	Tools, Shop & Garage Equipment	586,819		586,819	72,679	659,498	10	0.10	65,950
1945	Measurement & Testing Equipment	-		-		-	-		
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-		-	-		
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,044,749		2,044,749	36,502	2,081,251	15	0.07	138,750
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(55,549)		(55,549)	(23,158)	(78,707)	25	0.04	(3,148)
		-		-		-	-		
		-		-		-	-		
	Total	28,793,575	-	28,793,575	2,673,516	31,467,091			1,378,097

Appendix 2-M, Depreciation and Amortization Expense 2007 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	440,638		440,638	8,744	449,382	50	0.02	8,988
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	2,862,068		2,862,068	1,000,491	3,862,559	30	0.03	128,752
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	8,560,627		8,560,627	609,591	9,170,218	25	0.04	366,809
1835	OH Conductors & Devices	1,441,874		1,441,874	406,394	1,848,268	25	0.04	73,931
1840	UG Conduit	3,872,064		3,872,064	935,342	4,807,406	25	0.04	192,296
1845	UG Conductors & Devices	2,947,019		2,947,019	1,061,351	4,008,370	25	0.04	160,335
1850	Line Transformers	2,949,293		2,949,293	1,736	2,951,029	25	0.04	118,041
1855	Services (OH & UG)	1,645,927		1,645,927	70,452	1,716,379	25	0.04	68,655
1860	Meters	3,359,261		3,359,261	479,062	3,838,323	25	0.04	153,533
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	244,993		244,993	21,436	266,429	10	0.10	26,643
1915	Office Furniture & Equipment 10yr	-		-		-	-		
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930		105,930	5	0.20	21,186
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660		143,660		143,660	5	0.20	28,732
1930	Transportation Equipment	34,352		34,352	7,548	41,900	5	0.20	8,380
1935	Stores Equipment	-		-		-	-		
1940	Tools, Shop & Garage Equipment	659,498		659,498	15,489	674,987	10	0.10	67,499
1945	Measurement & Testing Equipment	-		-		-	-		
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-		-	-		
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,081,251		2,081,251	20,774	2,102,025	15	0.07	140,135
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(78,707)		(78,707)	(124,494)	(203,201)	25	0.04	(8,128)
		-		-		-	-		
		-		-		-	-		
	Total	31,467,091	-	31,467,091	4,513,916	35,981,007			1,555,786

Appendix 2-M, Depreciation and Amortization Expense 2008 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant								
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	449,382		449,382		449,382	50	0.02	8,988
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	3,862,559		3,862,559	535,166	4,397,725	30	0.03	146,591
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	9,170,218		9,170,218	745,865	9,916,083	25	0.04	396,643
1835	OH Conductors & Devices	1,848,268		1,848,268	522,253	2,370,521	25	0.04	94,821
1840	UG Conduit	4,807,406		4,807,406	271,535	5,078,941	25	0.04	203,158
1845	UG Conductors & Devices	4,008,370		4,008,370	202,636	4,211,006	25	0.04	168,440
1850	Line Transformers	2,951,029		2,951,029	161,849	3,112,878	25	0.04	124,515
1855	Services (OH & UG)	1,716,379		1,716,379		1,716,379	25	0.04	68,655
1860	Meters	3,838,323		3,838,323	335,946	4,174,269	25	0.04	166,971
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	266,429		266,429		266,429	10	0.10	26,643
1915	Office Furniture & Equipment 10yr	-		-		-	-		
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930		105,930	5	0.20	21,186
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660		143,660		143,660	5	0.20	28,732
1930	Transportation Equipment	41,900	24,880	17,020	11,055	28,075	5	0.20	5,615
1935	Stores Equipment	-		-		-	-		
1940	Tools, Shop & Garage Equipment	674,987		674,987	31,667	706,654	10	0.10	70,665
1945	Measurement & Testing Equipment	-		-		-	-		
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-		-	-		
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,102,025		2,102,025		2,102,025	15	0.07	140,135
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(203,201)		(203,201)	(298,831)	(502,032)	25	0.04	(20,081)
etc.		-		-		-	-		
		-		-		-	-		
	Total	35,981,007	24,880	35,956,127	2,519,141	38,475,268			1,651,677

Appendix 2-M, Depreciation and Amortization Expense 2009 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated (1) (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) (2)	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant	-		-	369,597	369,597	40	0.03	9,240
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	449,382		449,382	87,726	537,108	50	0.02	10,742
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	4,397,725		4,397,725	1,205,402	5,603,127	30	0.03	186,771
1825	Storage Battery Equipment	-		-		-	-		
1830	Poles, Towers & Fixtures	9,916,083		9,916,083	1,320,748	11,236,831	25	0.04	449,473
1835	OH Conductors & Devices	2,370,521		2,370,521	29,969	2,400,490	25	0.04	96,020
1840	UG Conduit	5,078,941		5,078,941	518,628	5,597,569	25	0.04	223,903
1845	UG Conductors & Devices	4,211,006		4,211,006	671,996	4,883,002	25	0.04	195,320
1850	Line Transformers	3,112,878		3,112,878	250,566	3,363,444	25	0.04	134,538
1855	Services (OH & UG)	1,716,379		1,716,379	62,850	1,779,229	25	0.04	71,169
1860	Meters	4,174,269		4,174,269	15,618	4,189,887	25	0.04	167,595
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	266,429		266,429	29,633	296,062	10	0.10	29,606
1915	Office Furniture & Equipment 10yr	-		-	1,887	1,887	10	0.10	189
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	105,930		105,930	2,308	108,238	5	0.20	21,648
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660		143,660		143,660	5	0.20	28,732
1930	Transportation Equipment	52,955	25,887	27,068	20,362	47,430	5	0.20	9,486
1935	Stores Equipment	-		-	56,201	56,201	10	0.10	5,620
1940	Tools, Shop & Garage Equipment	706,654		706,654	35,705	742,359	10	0.10	74,236
1945	Measurement & Testing Equipment	-		-	36,629	36,629	10	0.10	3,663
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	-		-	17,794	17,794	10	0.10	1,779
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,102,025		2,102,025	8,765	2,110,790	15	0.07	140,719
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(502,032)		(502,032)	(94,096)	(596,128)	25	0.04	(23,845)
etc.		-		-		-	-		
		-		-		-	-		
	Total	38,500,148	25,887	38,474,261	4,648,288	43,122,549			1,836,604

Appendix 2-M, Depreciation and Amortization Expense 2010 (without half year rule)

Account	Description	Opening Balance (a)	Less Fully Depreciated [1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e)=(c) + (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)
1610	Miscellaneous Intangible Plant	369,597		369,597	609,000	978,597	40	0.03	24,465
1805	Land	197,343		197,343		197,343	-		
1808	Buildings	537,108		537,108	25,000	562,108	50	0.02	11,242
1810	Leasehold Improvements	-		-		-	-		
1815	Transformer Station Equipment >50 kV	-		-		-	-		
1820	Substation Equipment	5,603,127		5,603,127	60,000	5,663,127	30	0.03	188,771
1825	Storage Battery Equipment	-		-	-	-	-		
1830	Poles, Towers & Fixtures	11,236,831		11,236,831	207,000	11,443,831	25	0.04	457,753
1835	OH Conductors & Devices	2,400,490		2,400,490	678,000	3,078,490	25	0.04	123,140
1840	UG Conduit	5,597,569		5,597,569	1,370,000	6,967,569	25	0.04	278,703
1845	UG Conductors & Devices	4,883,002		4,883,002	611,000	5,494,002	25	0.04	219,760
1850	Line Transformers	3,363,444		3,363,444	100,000	3,463,444	25	0.04	138,538
1855	Services (OH & UG)	1,779,229		1,779,229	130,000	1,909,229	25	0.04	76,369
1860	Meters	4,189,887		4,189,887	263,000	4,452,887	25	0.04	178,115
1861	Smart Meters	-		-		-	-		
1861	Smart Meters/Communication Systems	-		-		-	-		
1905	Land	-		-		-	-		
1906	Land Rights	-		-		-	-		
1908	Buildings & Fixtures	-		-		-	-		
1910	Leasehold Improvements	296,062		296,062		296,062	10	0.10	29,606
1915	Office Furniture & Equipment 10yr	1,887		1,887		1,887	10	0.10	189
1915	Office Furniture & Equipment 5yr	-		-		-	-		
1920	Computer - Hardware	108,238	52,965	55,273		55,273	5	0.20	11,055
1921	Computer - Hardware post Mar 22/04	-		-		-	-		
1921	Computer - Hardware post Mar 19/07	-		-		-	-		
1925	Computer Software	143,660	102,762	40,898	205,000	245,898	5	0.20	49,180
1930	Transportation Equipment	73,317	25,887	47,430		47,430	5	0.20	9,486
1935	Stores Equipment	56,201		56,201		56,201	10	0.10	5,620
1940	Tools, Shop & Garage Equipment	742,359	218,543	523,816	90,000	613,816	10	0.10	61,382
1945	Measurement & Testing Equipment	36,629		36,629		36,629	10	0.10	3,663
1950	Power operated Equipment	-		-		-	-		
1955	Communications Equipment	17,794		17,794		17,794	10	0.10	1,779
1960	Graphics Equipment	-		-		-	-		
1965	Water Heater Rental Units	-		-		-	-		
1970	Load Management Controls	-		-		-	-		
1975	Load Management Controls Utility Premises	-		-		-	-		
1980	System Supervisor Equipment	2,110,790		2,110,790	98,000	2,208,790	15	0.07	147,253
1985	Miscellaneous Fixed Assets	-		-		-	-		
1995	Contributions & Grants	(596,128)		(596,128)		(596,128)	25	0.04	(23,845)
		-		-		-	-		
						-			
	Total	43,148,436	400,157	42,748,279	4,446,000	47,194,279			1,992,223

Interrogatory #9
Ref: Ex. 1/4/5

Please provide a copy of the approved 2010-2014 financial plan.

Please find attached a copy of the 2010-2014 financial plan.

Kingston Hydro Corporation

Balance sheet

	Audited 2009	Bridge Year 2010	Test Year 2011	Forecast 2012	Forecast 2013	Forecast 2014
Assets						
Current assets:						
Cash	2,340,508	1	1	1	1	1
Due from City of Kingston	1,857,450	4,347,565	3,471,416	3,071,527	3,229,406	3,194,199
Accounts and billed receivables	5,634,426	6,500,000	6,500,000	6,500,000	6,500,000	6,500,000
Unbilled revenue	6,585,137	6,600,000	7,000,000	7,049,000	7,098,343	7,148,031
Future Tax Asset	2,192,400	2,192,400	2,192,400	2,192,400	2,192,400	2,192,400
Inventory	1,125,725	1,125,725	1,125,725	1,200,000	1,200,000	1,200,000
Prepaid expense	102,278	102,278	102,278	75,000	75,000	75,000
	19,837,924	20,867,969	20,391,820	20,087,928	20,295,150	20,309,631
Deferred charges						
Incorporation costs	17,820	634	0	0	0	0
Regulatory assets - Smart Meters	1,182,504	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
	1,200,324	6,000,634	6,000,000	6,000,000	6,000,000	6,000,000
Capital assets:						
Cost	43,408,590	47,852,590	52,298,590	56,998,590	61,698,590	66,698,590
Accumulated depreciation	(15,712,977)	(17,633,588)	(19,711,016)	(22,116,320)	(24,640,862)	(27,311,812)
	27,695,613	30,219,002	32,587,574	34,882,270	37,057,728	39,386,778
Note receivable from Utilities Kingston	250,000	0	0	0	0	0
Total assets	48,983,861	57,087,605	58,979,394	60,970,198	63,352,878	65,696,410
Liabilities and Shareholder's Equity						
Current liabilities						
Bank loan, TD	2,512,334	418,461	502,078	577,437	659,323	750,447
Accounts payable & accruals	10,781,968	11,000,000	11,000,000	11,000,000	11,000,000	11,000,000
Regulatory liabilities	2,353,950	1,000,000	500,000	0	0	0
Long --term debt						
Note payable to City of Kingston	10,880,619	10,880,619	10,880,619	10,880,619	10,880,619	10,880,619
Capital Loan - TD Bank Existing 10 year	2,588,121	2,338,669	1,813,609	1,457,565	1,085,736	720,434
Capital Loan - Smart Meters		6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Capital Loan - TD Bank - 2009 Capex		2,181,585	2,109,785	2,034,431	1,955,349	1,872,352
Capital Loan - TD Bank - 2010 Capex		2,520,943	2,437,974	2,350,898	2,259,514	2,163,606
Capital Loan - TD Bank - 2011 Capex			2,100,168	2,029,340	1,954,888	1,876,626
Capital Loan - TD Bank - 2012 Capex				1,918,683	1,860,272	1,798,258
Capital Loan - TD Bank - 2013 Capex					2,115,426	2,054,297
Capital Loan - TD Bank - 2014 Capex						2,409,196
Employee future benefits	1,174,887	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Total liabilities	30,291,879	37,540,277	38,544,233	39,448,974	40,971,125	42,725,836
Shareholder's equity						
Common shares	12,380,617	12,380,619	12,380,619	12,380,619	12,380,620	12,380,620
Contributed Surplus	2,477,763	2,477,763	2,477,763	2,477,763	2,477,763	2,477,763
Retained earnings	4,083,602	4,688,946	5,576,779	6,662,842	7,523,370	8,112,190
less Dividends paid	(250,000)	0	0	0	0	0
Total equity	18,691,982	19,547,328	20,435,161	21,521,224	22,381,753	22,970,573
Total Liabilities and Shareholder's Equity	48,983,861	57,087,605	58,979,394	60,970,198	63,352,878	65,696,410

Kingston Hydro Corporation
Statement of Cash Flows

	Audited	Bridge	Test	Forecast	Forecast	Forecast
Year Ended December 31	2009	2010	2011	2012	2013	2014
Operations						
Net earnings	$1,165,075	$855,344	$887,833	$1,086,064	$860,528	$588,820
Items not involving cash						
Future Income Taxes	36,950					
Depreciation and amortization	2,086,472	1,937,797	2,077,428	2,405,304	2,524,542	2,670,950
	3,288,497	2,793,141	2,965,261	3,491,368	3,385,070	3,259,770
Change in non-cash operating working capital	572,562	(9,298,853)	(23,851)	(196,109)	(207,222)	(14,481)
Net change in cash from operations	3,861,059	(6,505,712)	2,941,410	3,295,259	3,177,848	3,245,288
Financing						
Note receivable from Utilities Kingston	250,000	250,000	0	0	0	0
Bank loan, operating	(487,666)	(2,093,873)	83,617	75,359	81,886	91,125
Capital Loan - TD Bank - 2009 Capex	0	2,181,585	(71,800)	(75,354)	(79,083)	(82,996)
Capital Loan - TD Bank Existing 10 year	2,588,121	(249,452)	(525,060)	(356,044)	(371,830)	(365,302)
Smart Meter Loan	0	6,000,000				
Capital Loan - TD Bank - 2010 Capital		2,520,943	(82,969)	(87,075)	(91,385)	(95,907)
Capital Loan - TD Bank - 2011 Capital	0	0	2,100,168	(70,828)	(74,452)	(78,261)
Capital Loan - TD Bank - 2012 Capital				1,918,683	(58,411)	(62,014)
Capital Loan - TD Bank - 2013 Capital					2,115,426	(61,128)
Capital Loan - TD Bank - 2014 Capital						2,409,196
Dividends paid	(250,000)	0	0	0	0	0
Net change in cash from financing	2,100,455	8,609,203	1,503,956	1,404,741	1,522,151	1,754,712
Investments						
Purchase of capital assets	(3,641,040)	(4,443,998)	(4,445,366)	(4,700,000)	(4,699,999)	(5,000,000)
Incorporation costs						
Net change in cash from investments	(3,641,040)	(4,443,998)	(4,445,366)	(4,700,000)	(4,699,999)	(5,000,000)
Change in cash and cash equivalents	2,320,474	(2,340,507)	(0)	0	0	(0)
Cash & cash equivalents, beginning of year	20,034	2,340,508	1	1	1	1
Cash & cash equivalents, end of year	2,340,508	1	1	1	1	1

Kingston Hydro Corporation

Statement of Earnings

Year ended	Audited 2009	Bridge 2010	Test 2011	Forecast 2012	Forecast 2013	Forecast 2014
Sale of power	53,948,337	55,000,000	$ 55,000,000	$ 55,000,000	$ 55,000,000	$ 55,000,000
Cost of power	53,948,337	55,000,000	55,000,000	55,000,000	55,000,000	55,000,000
	-	-	0	0	0	0
Local distribution revenue	9,606,109	9,606,109	11,268,703	12,100,000	12,184,700	12,269,993
Other revenue:	843,468	843,468	624,096	624,000	624,000	624,000
	10,449,577	10,449,577	11,892,799	12,724,000	12,808,700	12,893,993
Operating expenses:						
Contracted services	5,435,090	6,221,029	7,113,501	7,256,000	7,401,000	7,549,000
Earnings before interest, depreciation and taxes	5,014,487	4,228,548	4,779,298	5,468,000	5,407,700	5,344,993
Interest on bank loans	(8,347)	245,754	675,628	801,222	939,242	1,100,105
Interest on long term debt - City of Kingston	788,800	788,800	788,845	788,845	788,845	788,845
Depreciation and amortization	2,086,472	1,937,797	2,077,428	2,405,304	2,524,542	2,670,950
Ontario Capital Tax	33,135	16,568	0	0	0	0
	2,900,060	2,988,919	3,541,901	3,995,371	4,252,629	4,559,900
Net earnings before Incomes taxes	2,114,427	1,239,629	1,237,397	1,472,629	1,155,071	785,093
Income tax	949,352	384,285	349,565	386,565	294,543	196,273
Net earnings	1,165,075	$ 855,344	$ 887,833	$ 1,086,064	$ 860,528	$ 588,820

Interrogatory #10
Ref: Ex. 1/4/10, Attach 1

Please confirm that the Applicant is seeking an average rate increase of 35.3% based on the size of the deficiency relative to the revenue at current rates.

Please refer to VECC IR #8 a) response.

Kingston Hydro does not understand what is meant by an average rate increase, but we do confirm that based on the size of the deficiency, the proposed revenue requirement is a 27.8% increase from current Board-approved revenue requirement.

<u>Interrogatory #11</u>

Ref: Ex. 2/1/1

With respect to the Rate Base History:

a) P. 3. Please provide the calculations supporting the Applicant's ranking as lowest in its cohort in rates. Please provide that comparison between the members of the cohort for each rate class, with supporting calculations.

The information provided was obtained from:
http://www.oeb.gov.on.ca/OEB/_Documents/2010EDR/bill_impacts_2010.pdf.
The Applicant has no further comparisons to provide other than the summary provided on the attached schedule.

b) P. 4. Please provide the calculations supporting the figures of $971 of fixed assets per customer, as well as $1,219, and $1,434. Please calculate the Applicant's fixed assets per customer for the Test Year based on the Application, with supporting calculations.

The information provided was obtained from the *2008 Yearbook of Electricity Distributors* published by the Ontario Energy Board on September 10, 2009. Please see attached documents illustrating the figures noted in the application. As requested, following is the calculation of fixed assets per customer:

Gross Assets		
	Exhibit 2 Tab 3 Schedule 3 Attachment 1	$ 52,107,435
Accumulated Amortization		
	Exhibit 2 Tab 3 Schedule 3 Attachment 1	$ (18,004,715)
Net Fixed Assets		$ 34,102,720
Number of customers (Residential, General Service and Large Use)		
	Exhibit 3 Tab 1 Schedule 1 Attachment 1	26,977
Net Fixed Asset per customer Test Year 2011		**$ 1,264.14**

c) ***Please provide any reports between 1995 and 2008 to management, to Utilities Kingston, or to the City detailing the under investment in capital assets taking place during this period, the consequences of that under investments, and/or the deteriorating condition of the electricity distribution system.***

The following reports have relevance to the question and have been provided as noted below:

- Great Lakes Acres Limited Electric System Study – 1997
- Toronto Hydro Assessment of the Electrical Distribution System for the City of Kingston – 1998
- J.T. Watson & Associates Engineering Report on Electrical Vaults (provided at Exhibit 2 Tab 7 Schedule 1 Attachment 2)

Comparison of Kingston Hydro Rates to our Cohorts ***APPENDIX B***
Residential Customer using 800kWh per month
Prices include Smart Meter charge of $1 plus transmission rates paid to Hydro One of $6
Companies in bold are scheduled to re-base in 2011

Welland Hydro-Electric System Corp.	$ 36.86
Festival Hydro Inc.	$ 36.73
Bluewater Power Distribution Corporation	$ 36.64
Erie Thames Powerlines Corporation	$ 36.10
Woodstock Hydro Services Inc.	$ 35.85
Essex Powerlines Corporation	$ 35.75
Westario Power Inc.	$ 34.02
Niagara Falls Hydro Inc.	$ 33.95
Chatham-Kent Hydro Inc.	$ 32.85
St. Thomas Energy Inc.	$ 32.42
COLLUS Power Corp.	$ 30.97
Peterborough Distribution Incorporated	$ 30.78
E.L.K. Energy Inc.	$ 30.22
Wasaga Distribution Inc.	$ 29.59
Kingston Hydro Corporation	$ 27.13

Individual Electricity Distributors For the year ended December 31, 2008 (Alphabetically Listed)	Kingston Hydro Corporation	Bluewater Power Distribution Corporation	COLLUS Power Corp.	Chatham-Kent Hydro Inc.	E.L.K. Energy Inc.	Erie Thames Powerlines Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Niagara Peninsula Energy Inc.	Peterborough Distribution Incorporated	St. Thomas Energy Inc.	Wasaga Distribution Inc.	Welland Hydro-Electric System Corp.	Westario Power Inc.	Woodstock Hydro Services Inc.	AVERAGE OF 15 COHORTS
Net Fixed Assets per Customer	$ 971	$ 1,075	$ 832	$ 1,447	$ 812	$ 1,227	$ 1,117	$ 1,645	$ 2,200	$ 1,358	$ 1,194	$ 740	$ 952	$ 1,372	$ 1,340	$ 1,219

Individual Electricity Distributors For the year ended December 31, 2008 (Alphabetically Listed)																
	Kingston Hydro Corporation	Bluewater Power Distribution Corporation	COLLUS Power Corp.	Chatham-Kent Hydro Inc.	E.L.K. Energy Inc.	Erie Thames Powerlines Corporation	Essex Powerlines Corporation	Festival Hydro Inc.	Niagara Peninsula Energy Inc.	Peterborough Distribution Incorporated	St. Thomas Energy Inc.	Wasaga Distribution Inc.	Welland Hydro-Electric System Corp.	Westario Power Inc.	Woodstock Hydro Services Inc.
Net Fixed Assets per Customer	$ 971	$ 1,075	$ 832	$ 1,447	$ 812	$ 1,227	$ 1,117	$ 1,645	$ 2,200	$ 1,358	$ 1,194	$ 740	$ 952	$ 1,372	$ 1,340
	Port Colborne Hydro Inc	PowerStream Inc.	Renfrew Hydro Inc.	Rideau St. Lawrence Distribution Inc.	Sioux Lookout Hydro Inc.	Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Hydro-Electric System Limited	Veridian Connections Inc.	Waterloo North Hydro Inc.	Whitby Hydro Electric Corporation	Atikokan Hydro Inc.	Barrie Hydro Distribution Inc.	Brant County Power Inc.	Brantford Power Inc.
Net Fixed Assets per Customer	$ 1,064	$ 1,957	$ 988	$ 658	$ 1,805	$ 1,256	$ 847	$ 2,709	$ 1,291	$ 1,955	$ 1,570	$ 1,158	$ 1,867	$ 1,984	$ 1,557
	Burlington Hydro Inc	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc.-Fort Erie	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Clinton Power Corporation	Cooperative Hydro Embrun Inc.	ENWIN Utilities Ltd.	Eastern Ontario Power Inc.	Enersource Hydro Mississauga Inc.	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	Frances Power Corporation	Grand Valley Energy Inc.
Net Fixed Assets per Customer	$ 1,311	$ 1,671	$ 2,394	$ 1,068	$ 664	-	$ 978	$ 2,057	$ 3,050	$ 2,269	$ 1,637	$ 1,166	$ 1,331	$ 745	$ 508
	Great Lakes Power Ltd.	Greater Sudbury Hydro Inc.	Grimsby Power Incorporated	Regional Hydro Distribution Corporation	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Power Distribution Company Limited	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro Ottawa Limited	Hydro Distribution Systems Limited
Net Fixed Assets per Customer	$ 5,601	$ 1,347	$ 1,109	$ 834	$ 1,770	$ 1,577	$ 1,443	$ 357	$ 1,319	$ 351	$ 352	$ 2,371	$ 3,578	$ 1,696	$ 1,206
	Kenora Hydro Electric Corporation Ltd	London Hydro Inc.	Middlesex Power Distribution Corporation	Midland Power Utility Corporation	Milton Hydro Distribution Inc.	Newbury Power Inc.	Newmarket - Tay Power Distribution Ltd.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.	Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Power Distribution Corporation	Oshawa PUC Networks Inc.
Net Fixed Assets per Customer	$ 1,406	$ 1,289	$ 1,117	$ 1,183	$ 1,522	-	$ 1,534	$ 2,488	$ 2,264	$ 1,290	$ 620	$ 1,763	$ 1,290	$ 1,241	$ 977
	Ottawa River Power Corporation	PUC Distribution Inc.	Parry Sound Power Corporation	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Perth Power Inc.	AVERAGE ALL								
Net Fixed Assets per Customer	$ 788	$ 1,141	$ 1,189	$ 1,299	$ 965	-	$ 1,434								

The Public Utility Commission
of the City of Kingston

Electric System Study

Final Report Phase I

February 1997

Great Lakes Acres Limited

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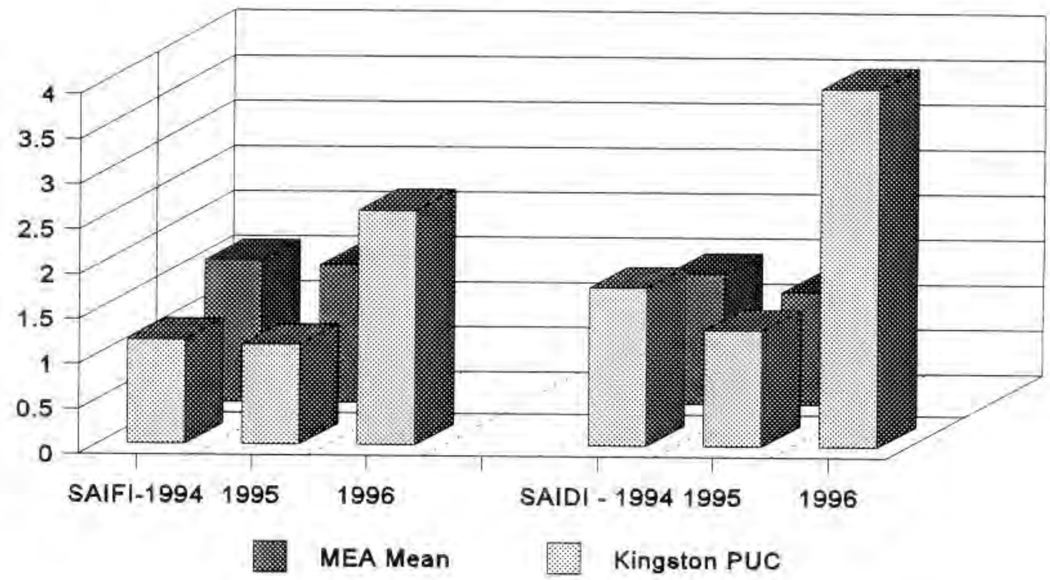
Executive Summary

Executive Summary

This report summarizes the findings of an assessment of Kingston PUC's power distribution system, carried out by Great Lakes Acres (GLA) during Phase 1 of a two phase engineering study. The objective of the study is to implement short term and long term system upgrades that would result in improvements in system reliability, power quality, public and employee safety and reduce overall operating costs by increasing system operating efficiency.



The reliability indices on Kingston PUC's distribution system along with the mean values of reliability indices for Municipal Electric Association (MEA) member utilities are shown above. As indicated, the Kingston PUC's reliability indices during 1994 and 1995 were quite comparable to the mean MEA values. However, during 1996, both the average outage duration and average number of customers affected per outage for Kingston PUC have increased significantly, resulting in considerable worsening of the reliability indices. (The reliability indices for the MEA utilities for 1996 were not available at the time of writing of this report.)

The distribution system design in overhead and underground service areas was reviewed and found to be generally consistent with the needs of urban service areas. The design incorporates adequate equipment redundancy to cope with equipment failures and should result in high reliability levels. The only bottlenecks in system design are the oil-insulated switches on the underground distribution system that cannot be used for load break operations and lack of back-up feeds for some single phase overhead branch circuits installed in radial configuration. A program to remedy both of these deficiencies is already under way.

The most significant improvements in reliability are expected to result from implementation of a scheduled program to monitor and manage the preventative maintenance of distribution equipment. Based on the value of customer outage costs, optimum reliability targets for the distribution system should be established. The system reliability performance should be monitored and measured against these targets and frequency of equipment maintenance adjusted as a function of the reliability performance.

Equitable distribution of load among different feeders and balancing of the load on different phases is also recommended, as it would eliminate outages caused by feeder overloads. It would also help reduce load losses.

For successful operation of an electric distribution utility in a deregulated and competitive environment, it would be necessary to take advantage of every available opportunity to reduce operating costs without compromising quality of service. Some long range system improvement initiatives that are expected to reduce overall system operating costs include distribution automation through SCADA, demand side management, integration of common utility functions and sharing of common infrastructure facilities. A strategically planned program for a gradual upgrade of system voltage and replacement of PILC cables with dry insulated cables is also expected to reduce system operating costs in the long run. Detailed economic and financial feasibility studies are recommended to be carried out to verify cost effectiveness of each of these initiatives.

Introduction

1 Introduction

This report summarizes the findings of an assessment of Kingston PUC's power distribution system, carried out by Great Lakes Acres (GLA) during Phase 1 of a two phase engineering study. The objective of the study is to implement short term and long term system upgrades that would result in improvements in system reliability, power quality, public and employee safety and operating efficiency.

The following specific items are included in this Phase 1 report:

- recommendations for reliability improvements;
- a conceptual plan for long range system upgrades;
- a commentary on recommended partnerships/possible integration of functions with the Queen's University and surrounding Ontario Hydro retail Systems;
- recommendations for improvements in preventative maintenance program;
- assessment of the ongoing program for replacement of underground switches;
- detailed scope of work for Phase 2.

Distribution System Reliability

2 Distribution System Reliability

Detailed data on system outages encountered on the distribution system from January 01, 1994 to November 15, 1996 was thoroughly examined in an attempt to compare the system reliability with other comparable electric utilities and to establish the underlying causes of most frequent system outages.

The following reliability indices were calculated for the calender years of 1994, 1995 and 1996:

- System Average Interruption Frequency Index (SAIFI);
- System Average Interruption Duration Index (SAIDI);
- Customer Average Interruption Duration Index (CAIDI).

SAIFI is a measure of the average number of interruptions per customer and is calculated with help of the following formula, by taking into account all planned and unplanned outages of longer than one minute duration:

$$SAIFI = \frac{Total\ Customer\ Interruptions}{Total\ Customers\ Served}$$

SAIDI is an indication of the system restoration speed after an outage and is calculated with help of the following formula:

$$SAIDI = \frac{Total\ Customer\ Hours\ of\ Interruptions}{Total\ Customers\ Served}$$

CAIDI is a measure of the average duration of each interruption during the year and is calculated with help of the following formula:

$$CAIDI = \frac{Total\ Customer\ hours\ of\ Interruptions}{Total\ Customer\ Interruptions}$$

2.1 Comparison of Reliability Indices with Other Utilities

The calculated values of SAIFI, SAIDI and CAIDI for the Kingston PUC distribution system during the calendar years of 1994, 1995 and 1996, along with the mean values of reliability indices for medium and large size municipal electric utilities of Ontario, are listed in Table 2.1. A graphic comparison of SAIFI, SAIDI and CAIDI values during different years, is presented in Figure 2.1, Figure 2.2, and Figure 2.3, respectively.

Although the reliability indices for Kingston PUC during the years of 1994 and 1995 are quite comparable to mean values for Ontario utilities, the SAIFI and SAIDI values during the year 1996 on Kingston PUC's distribution system show a significant increase from the previous years. There was no increase in the number of outages during 1996, however, average outage duration and the average number of customers affected per outage increased considerably. The following factors contributed to the increased SAIFI and SAIDI values during the year 1996:

- an outage on Ontario Hydro's system that affected approximately one half of the total customers;

- a number of substation outages during 1996, affecting a large number of customers;

- a more accurate and detailed recording of system outages during the year 1996, which may not have been the case during previous years.

A month by month breakdown of system outages is provided in Table 2.2 and is displayed in Figure 2.4.

Table 2.1
Kingston PUC
Reliability Data

Year	1994	1995	1996(Prorated)
Total Number of Customers	26000	26000	26000
No. Outages	175	258	242
No. of Customer-Outages	30060	28905	67922
No. of Customer Outage hours	45763	33536	103513
SAIFI	1.16	1.11	2.61
SAIDI	1.76	1.29	3.98
CAIDI	1.52	1.16	1.52

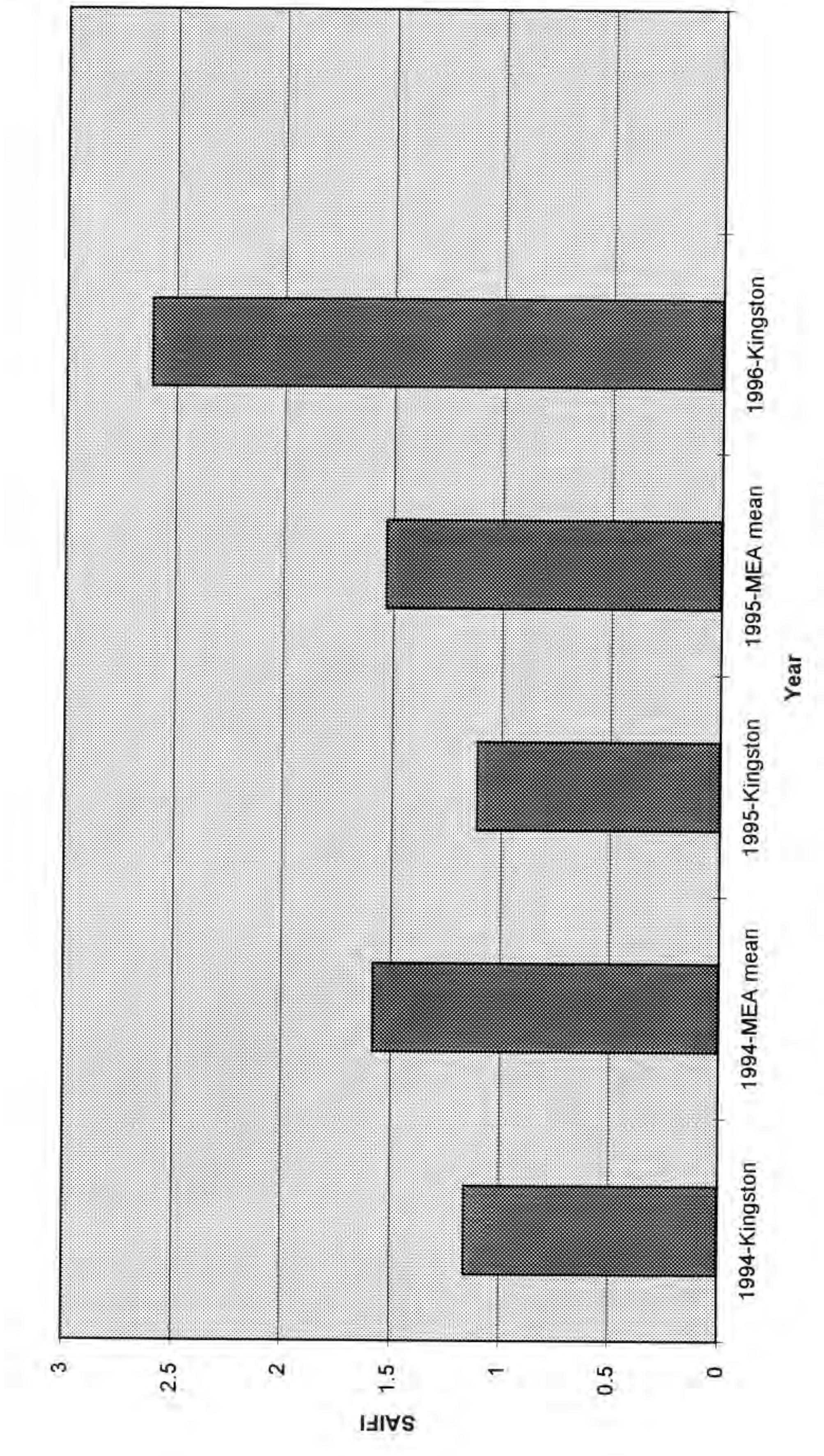


Figure 2.1 Comparison of Reliability Index - SAIFI

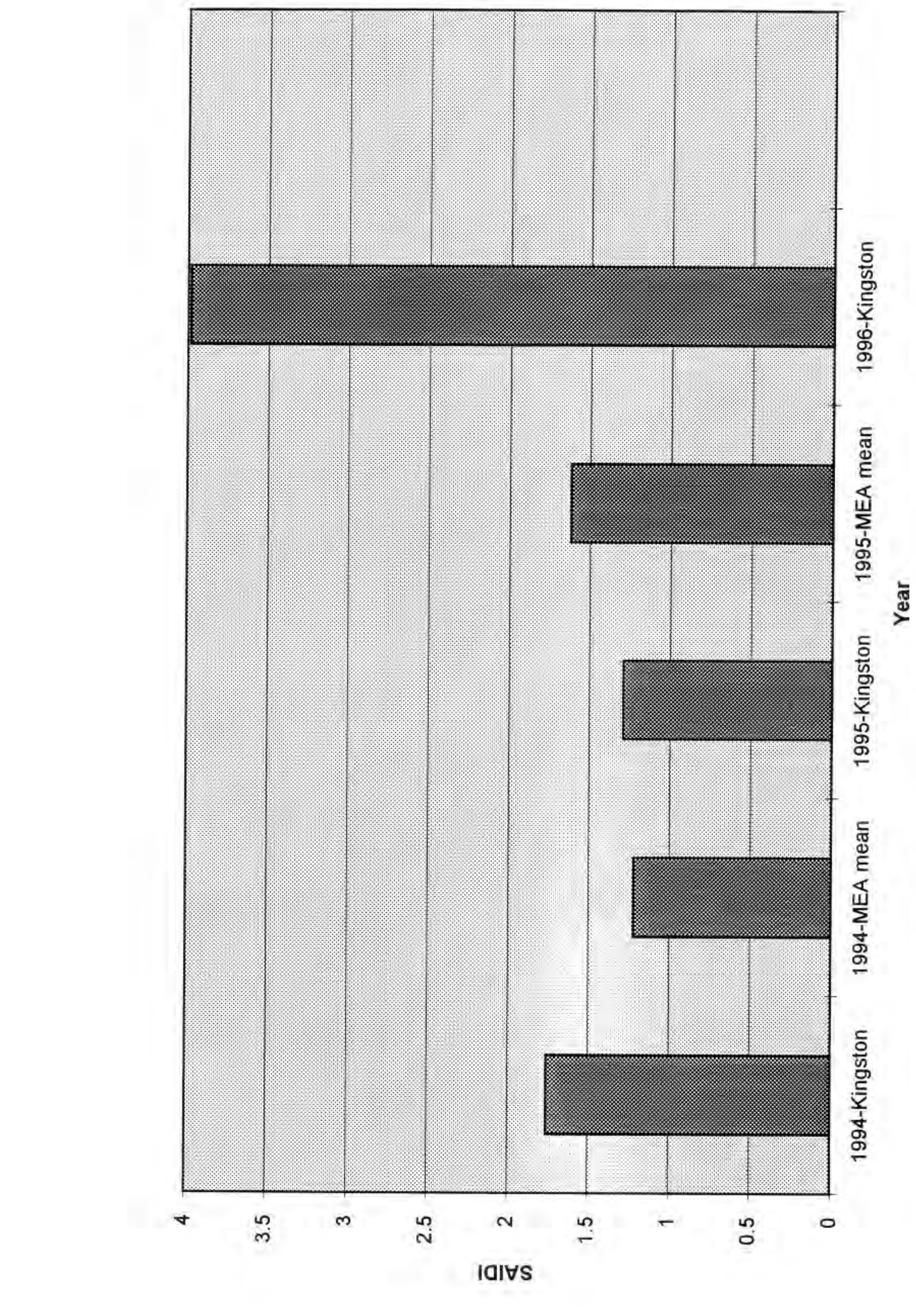


Figure 2.2 Comparison of Reliability Index - SAIDI

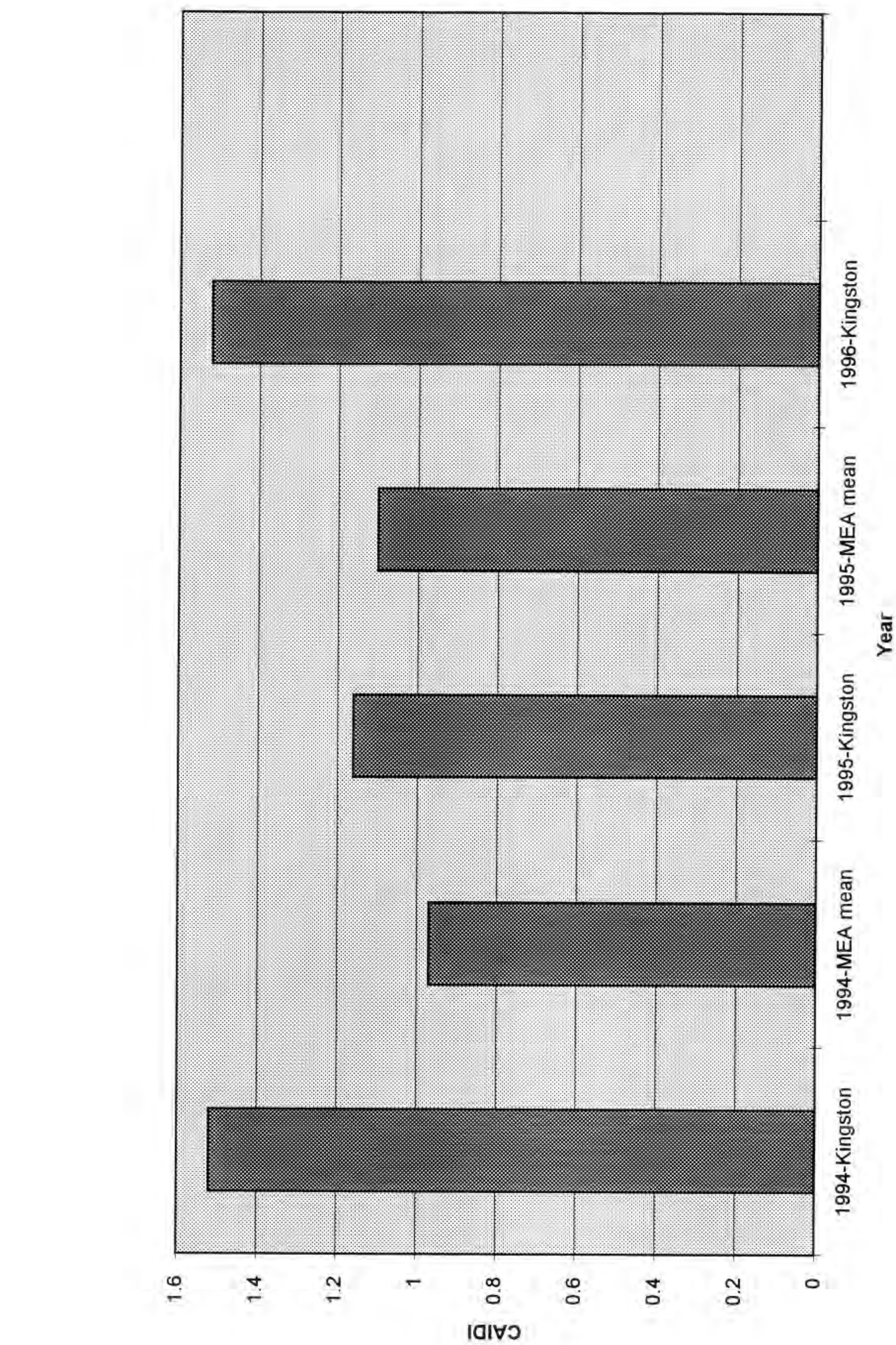


Figure2.3 Comparison of Reliability Index - CAIDI

Table 2.2
Kingston PUC
Seasonal Outage Variations

Month	Number of Outages During the Month		
	1994	1995	1996
January	23	20	57
February	19	16	30
March	23	39	27
April	14	11	6
May	9	12	11
June	15	14	7
July	22	36	27
August	13	15	11
September	7	18	17
October	5	23	11
November	23	37	
December	7	17	
Yearly Total	180	258	204

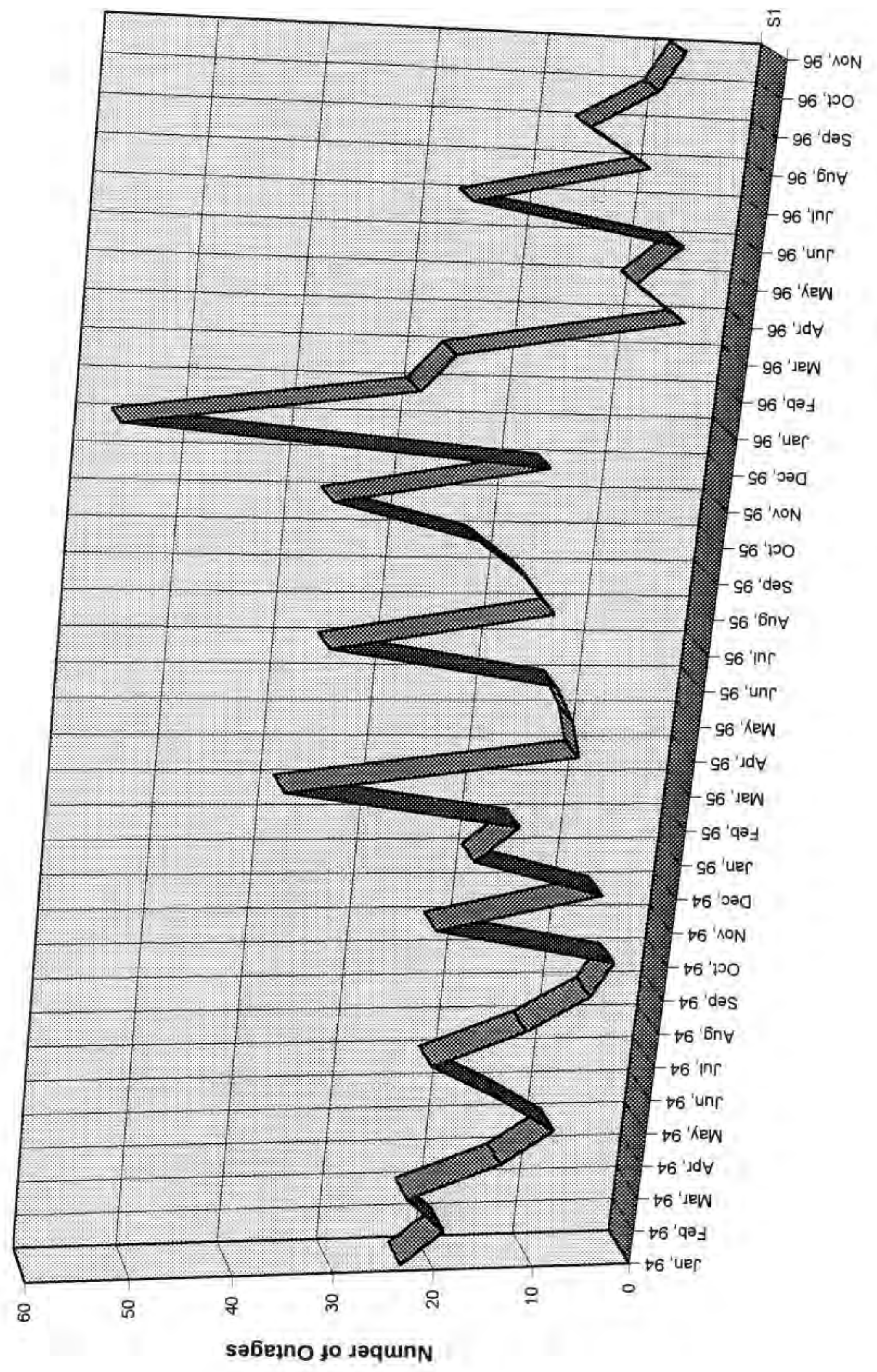


Figure 2.4 System Outage Distribution

2.2 Outage Distribution Among Different Service Areas

Figure 2.5 provides a breakdown of the system outages among service areas of different substations. As indicated, Substation # 8, #6, #11, #2, #3, #10 and #4 show considerably higher outage incidence. These service areas are supplied from an aging distribution system installed in predominantly overhead configuration, which in the absence of a scheduled preventative maintenance program would be expected to experience higher than normal frequency of outages.

A circuit by circuit breakdown of system outages for different substations is provided in Appendix A. As indicated, the outage frequency on some feeders is considerably higher than the others.

2.3 Causes of System Outages

The bar graph in Figure 2.6 provides a breakdown by cause, of system outages experienced over the past three years. A close examination of Figure 2.6 reveals the following information:

(a) Approximately 40% of the outages are attributable to causes that would be affected by the absence of a scheduled preventative maintenance program, such as, phase to phase contact among overhead line conductors during a wind storm, tree limbs or branches blown into conductors, broken cross arms, burned drop leads, etc.;

The cause of another 18% of outages was listed as unknown. Many of these outages may also have been due to temporary faults on overhead lines, caused by excessive sag or lack of a tree-trimming program.

(b) Approximately 13% of the outages were required for carrying out planned work on single phase radial branch circuits. To avoid such outages, alternative (back-up) supply means in form of a loop feeder configuration would be required.

(c) Over 14% of the outages were due to overload conditions on feeders during contingency operating conditions or during cold load pick up. It would be possible to prevent such outages through equal distribution of load among different feeders and balancing of load among three phases.

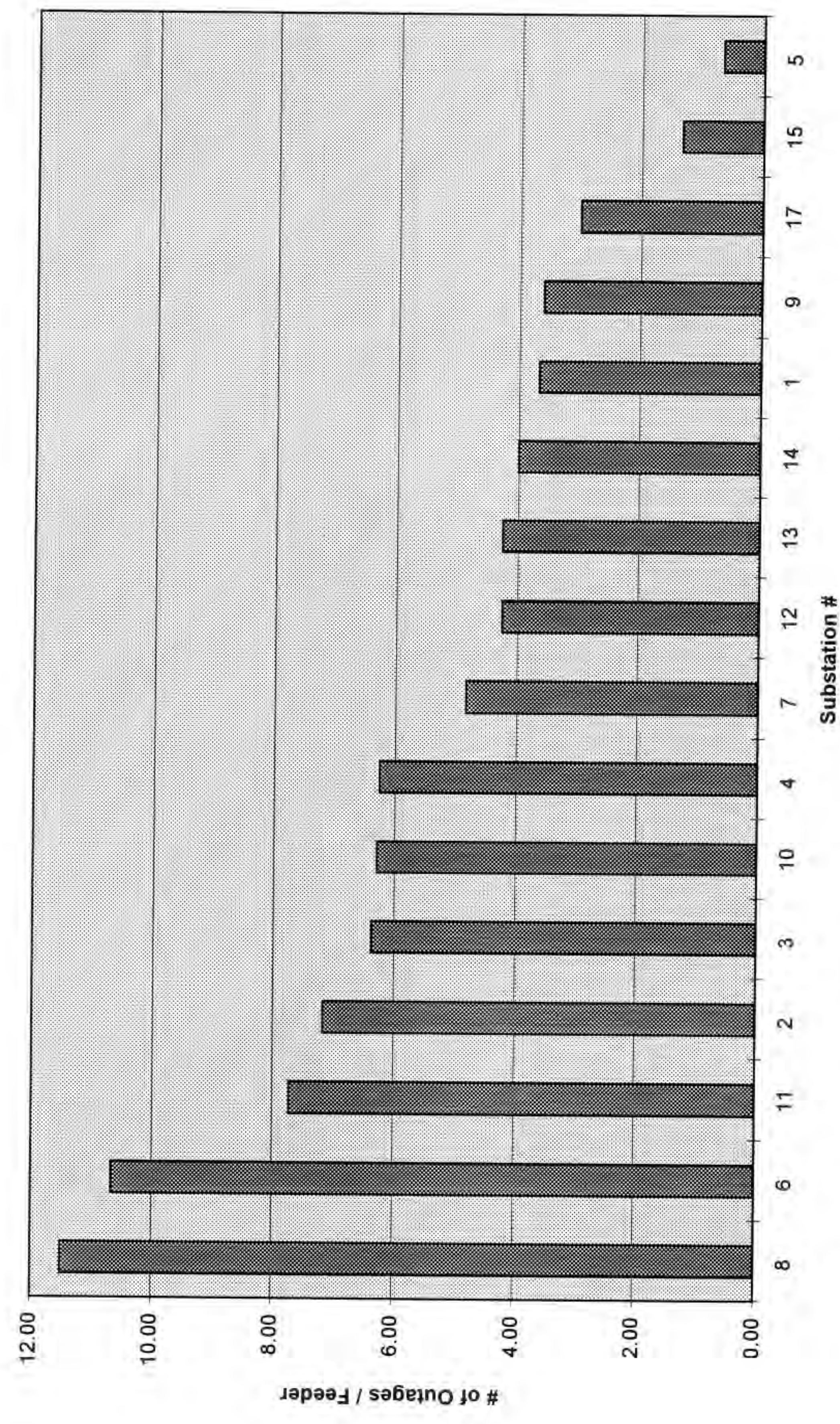


Figure 2.5 Outage Frequency in Different Service Areas

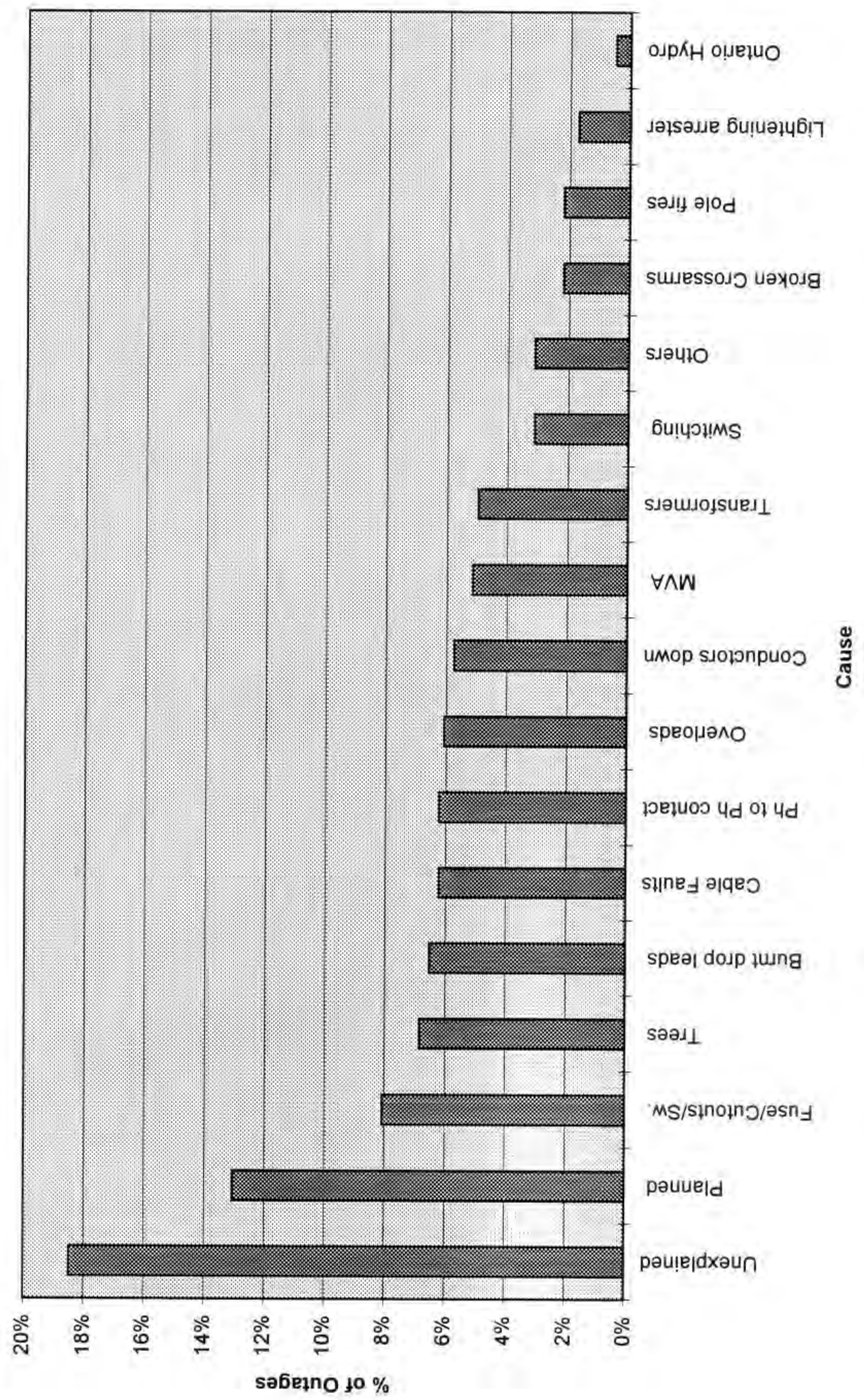


Figure 2.6 Causes of System Outages

(d) Approximately 6% of the outages were caused by cable faults on underground distribution system. 3% of the outages were necessary to carry out switching of the oil insulated switches, that cannot be operated as load break devices.

2.4 Review of System Design

The service area at Kingston PUC is supplied from 3-phase, 4 wire, multi-grounded distribution feeders energized at 4160 V and fed from 16 different substations. Each substation is supplied at 44-kV and except for a few recently commissioned stations which are not yet fully developed, each station has provision of a dual incoming 44-kV feed and dual step-down transformer arrangement, with full redundancy. On the 4-kV bus, by-pass switches are provided.

Two of the substations, #1 and #9, supply underground feeders, installed in a duct manhole system. The underground feeders are installed in a loop configuration and during a fault on an underground cable, faulted cable sections can be isolated and power restored to the distribution transformers from back-up feeders by manually operating disconnect switches installed in underground vaults. Unfortunately, a majority of the vault-mounted disconnect switches are of an old vintage and their ability to successfully and safely interrupt load current is in doubt. This uncertainty has necessitated a significant change in operating procedures. The switches are no longer used for interrupting load current but are used to isolate deenergized cable circuits, after opening of the substation circuit breaker. This procedure adversely affects the system reliability indices.

Aside from the service areas supplied from #1 and #9 substations, the remainder of the service area is supplied from predominantly overhead distribution feeders. The overhead feeders also employ a loop configuration and during a permanent fault on a feeder, the supply can be switched to an adjacent feeder. There are also some single phase branch circuits that are supplied in a radial configuration without backup.

All of the substation breakers have provision for SCADA control. No reclosers or SCADA controlled disconnects are provided on the feeders. The feeder lengths are relatively short however, and anticipated improvements from automation of on-line disconnect switches is expected to be marginal. In a few selected locations, where the feeder lengths are longer than average, it may be cost effective to install SCADA controlled switching devices at the normally open points. A SCADA interface with fault indicators is also expected to reduce restoration times after an outage and improve system reliability.

The distribution system design is generally consistent with the needs of an urban service area and should result in very high reliability levels. The major bottleneck in the distribution system are the oil-insulated disconnect switches on underground system that cannot be used for carrying out load break operations and the radial branch circuits supplied from the overhead system. A program to remedy both of these deficiencies is already in progress.

2.5 Feeder Loading

The summer and winter peak loads on distribution feeders during 1995 and 1996 are presented in Table 2.3. Although the feeders are generally quite lightly loaded, there are significant seasonal variations in load. There are also substantial variations in load from normal operating conditions to contingency operating conditions.

Some of the system outages caused by feeder trips during cold load pick up should be avoidable through transfer of loads from heavily loaded feeders to lightly loaded feeders. On some feeders, load balance also needs to be carried out among different phases.

Table 2.3
Kingston PUC
Seasonal Feeder Load Peaks

Feeder #	January 1995			July 1995			October 1995			January 1996			July 1996		
	R	W	B	R	W	B	R	W	B	R	W	B	R	W	B
102	180	250	180	210	220	200	180	190	160	365	375	380	260	250	270
103	160	200	195	220	200	215	160	170	170	200	195	200	190	190	190
104	250	270	245	155	180	140	150	170	150	340	340	370	235	220	225
105	185	180	180	240	240	250	110	110	130	100	90	110	115	115	130
106	280	270	275	260	255	255	180	200	190	265	250	260	240	240	230
107	230	210	200	210	200	170	150	150	130	210	200	170	180	170	150
108	150	160	155	50	50	50	60	70	90	265	170	240	40	40	40
109	250	270	245	250	260	250	200	220	210	260	280	255	230	245	225
110	30	130	120	10	50	50	30	270	330	20	370	370	70	260	280
111	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
112	285	275	285	280	285	290	190	190	190	275	265	270	240	240	240
113	130	140	130	50	70	50	20	90	50	120	130	130	50	80	60
201	130	150	196	150	155	195	0	0	0	300	300	325	340	325	320
202	0	0	0	0	0	0	0	0	0	0	0	0	75	45	55
203	78	30	45	55	35	25	75	30	45	85	40	40	60	35	30
204	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
205	240	222	205	125	125	110	170	160	145	265	230	205	185	230	175
206	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
207	115	215	185	105	165	145	100	150	150	115	205	180	185	250	240
208	120	115	145	95	100	125	90	90	75	90	110	110	50	65	100
301	10	10	20	130	220	160	120	190	140	170	210	160	170	210	140
302	165	210	200	120	170	130	10	10	10	220	120	190	100	20	80
303	140	170	90	110	120	140	140	140	190	150	180	190	145	165	130
304	100	90	50	110	125	140	120	130	120	320	200	400	160	210	230
305	140	140	130	80	100	100	80	110	100	320	310	315	80	100	100
306	10	10	10	0	0	0	140	110	160	230	150	250	150	130	160
307	315	265	390	180	155	215	310	290	320	210	100	200	140	90	120
308	280	180	230	215	140	175	190	140	180	255	180	215	205	140	170
401	190	140	160	140	120	120	140	120	120	170	140	180	220	260	250
402	130	260	280	120	140	160	120	160	160	130	260	270	120	170	170
403	0	0	0	0	0	0	160	100	100	0	0	0	0	0	0
404	270	250	280	265	240	265	220	200	230	270	265	300	245	225	250
405	210	245	270	120	120	110	280	260	320	285	260	310	100	100	60
406	100	80	20	40	40	40	20	20	20	90	60	60	0	0	0
407	250	255	210	195	295	160	150	130	150	250	260	210	170	160	150
408	230	240	295	180	170	215	160	160	200	230	250	300	170	180	210
409	190	220	215	255	270	265	200	220	200	200	210	200	220	240	210

Table 2.3 (Continued)
Kingston PUC
Seasonal Feeder Load Peaks

Feeder #	January 1995			July 1995			October 1995			January 1996			July 1996		
	R	W	B	R	W	B	R	W	B	R	W	B	R	W	B
5 - F1	45	59	30	35	35	30				55	65	30	40	50	20
5 - F2	54	45	58	55	45	55				60	50	75	55	55	65
5 - F3	70	80	60	60	72	60				65	75	60	60	74	58
5 - F4	0	0	0	0	0	0				0	0	0	0	0	0
604	320	255	280	205	170	190	230	220	180	310	265	240	270	265	265
605	220	180	170	110	110	120	200	150	150	270	160	190	140	120	140
606	100	100	100	120	130	130	130	130	130	140	140	140	120	120	120
607	150	200	170	140	160	130	150	150	130	150	230	180	160	160	140
608	150	120	345	100	100	150	OFF	OFF	OFF	260	150	330	120	100	140
609	270	210	280	150	100	160	250	260	240	350	245	350	160	120	170
701	325	215	210	210	190	190	220	190	190	280	210	210	240	190	190
702	325	275	295	225	205	220	190	160	180	295	250	270	225	240	255
703	190	170	110	110	110	60	130	110	90	340	310	300	170	140	120
704	200	145	200	120	110	130	120	110	140	165	125	190	110	110	110
705	145	140	140	90	20	100	100	10	80	210	170	160	50	60	50
706	220	185	255	210	200	220	210	190	240	110	100	120	280	280	340
804	345	455	340	220	280	180	230	340	200	340	485	340	210	290	180
805	50	50	50	140	220	80	0	0	0	50	80	50	50	60	80
806	200	310	405	200	250	250	150	200	250	170	270	370	180	180	220
807	330	330	375	190	240	240	270	200	250	310	320	380	290	465	320
808	220	300	300	150	210	210	280	200	200	240	290	300	200	230	200
809	270	170	260	210	140	160	390	200	250	380	310	400	260	160	240
901	375	345	330	220	190	170	300	280	260	400	400	400	20	30	20
902	245	275	125	160	185	160	200	250	170	280	335	210	155	170	145
903	170	160	205	105	95	120	310	230	280	390	310	390	340	240	320
904	315	295	345	270	260	290	260	250	270	305	280	310	230	220	230
905	105	100	100	110	100	100	190	170	170	200	170	170	190	160	170
906	200	210	210	185	200	200	200	210	210	215	220	220	40	50	80
907	240	255	250	225	240	230	220	230	230	220	220	220	265	280	270
908	220	215	220	190	180	190	220	210	230	215	205	210	210	200	210
909	230	220	220	200	190	190	120	120	110	160	160	150	140	130	120
910	115	109	110	261	225	237	147	139	142	122	119	117	261	246	250

Table 2.3 (Continued)
Kingston PUC
Seasonal Feeder Load Peaks

Feeder #	January 1995			July 1995			October 1995			January 1996			July 1996		
	R	W	B	R	W	B	R	W	B	R	W	B	R	W	B
1002	135	130	145	100	160	115	70	40	80	145	140	145	80	60	90
1003	285	310	255	170	165	145	170	190	160	270	320	270	180	210	170
1004	260	205	265	300	240	280	150	110	130	270	200	265	145	100	135
1005	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1006	160	150	150	110	90	70	130	100	100	160	155	150	120	105	110
1007	300	300	285	10	175	130	170	200	170	300	300	300	170	205	145
1008	140	50	70	125	30	50	120	40	40	160	80	90	120	40	40
1009	195	225	205	155	170	155	270	250	280	205	170	210	155	150	155
1102	220	200	220	130	135	135	130	120	140	210	185	235	260	230	250
1103	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1104	235	240	240	140	130	130	150	140	140	265	245	265	260	240	230
1105	225	265	300	135	160	160	140	170	170	200	245	275	365	385	385
1106	260	315	270	175	210	200	170	210	190	240	300	250	295	285	345
1107	260	260	250	130	120	110	140	130	130	300	270	260	210	150	160
1108	245	270	285	110	120	130	120	130	150	235	265	290	140	125	170
1109	205	220	210	170	160	160	110	110	100	195	240	205	0	0	0
1201	80	150	250	80	100	150	50	100	180	290	330	425	OFF LINE		
1202	20	100	100	10	80	80	10	10	20	20	140	120	FOR SCADA		
1203	180	50	150	30	30	30	50	20	30	150	40	150	EQUIPMENT		
1204	80	60	80	80	40	50	30	20	30	60	50	60	INSTALLATION		
1205	95	50	100	145	125	100	10	10	50	300	350	110			
1206	200	145	220	110	70	130	110	50	110	205	160	220			
1207	20	115	190	20	40	50	10	90	90	295	295	300			
1208	150	80	115	100	40	80	100	10	90	205	120	130			
1301	195	180	285	280	235	285	210	210	240	200	180	285	235	220	270
1302	400	400	340	230	175	180	210	140	100	330	205	165	305	275	265
1303	265	400	290	255	200	130	270	260	260	355	300	220	215	195	230
1304	315	290	290	225	195	175	240	230	200	265	250	220	150	115	110
1401	15	14	13										13	13	15
1402	340	320	340										290	230	290
1403	140	155	100										70	90	80
1501	60	100	110	10	10	10	10	10	10	50	90	100	40	90	90
1502	255	60	130	120	115	90	150	50	80	250	60	130	190	110	100
1503	10	10	10	10	10	10	10	10	10	50	20	20	40	20	20
1504	0	0	0				0	0	0	0	0	0	0	0	0
1701	125	125	130										120	140	145
1702	18	16	18										20	18	20
1703	170	150	180										140	130	140

2.6 Recommendations for Reliability Improvements

The power system reliability can be improved through implementation of several different initiatives, such as underground installation of distribution systems, incorporation of equipment redundancy in design, reduction in feeder lengths, distribution automation and implementation of proactive preventative maintenance programs. All reliability improvement initiatives require capital investment and result in an increase in utility's costs.

Improvements in supply system reliability, however, result in direct and indirect savings to utility's customers, through avoidance of the following customer costs associated with power outages:

- direct customer losses or damages arising from an actual failure of power supply, i.e., loss of sales during a power outage for a retail store, loss of production or damage to work in progress for an industrial customer, expenses of eating out for a residential customer due to unavailability of kitchen appliances;

- direct customer costs incurred in undertaking steps to offset the impact of anticipated power outages, i.e., acquiring backup power supply equipment;

- indirect costs incurred as a result of power outages by parties other than the electricity customer, i.e., costs associated with shutdown of an industrial assembly line caused by unavailability of parts or raw materials from another plant that is unable to operate due to a power outage;

- intangible costs associated with customer annoyance or inconvenience that do not result in readily identifiable customer costs but interrupt customer enjoyment of many benefits of electricity, i.e., inability to enjoy a favourite TV program.

Over the recent years, through initiatives sponsored by Canadian Electricity Association (CEA), methods for integrating the value of reliability benefits to utility's customers to optimize overall total costs during planning and design of distribution systems have been developed. As indicated in Figure 2.7, the optimum level of reliability for the specific customer mix supplied from the utility's distribution system can be determined through value based planning techniques. The optimum reliability levels thus determined can be used as reliability targets and the system performance can be measured against these.

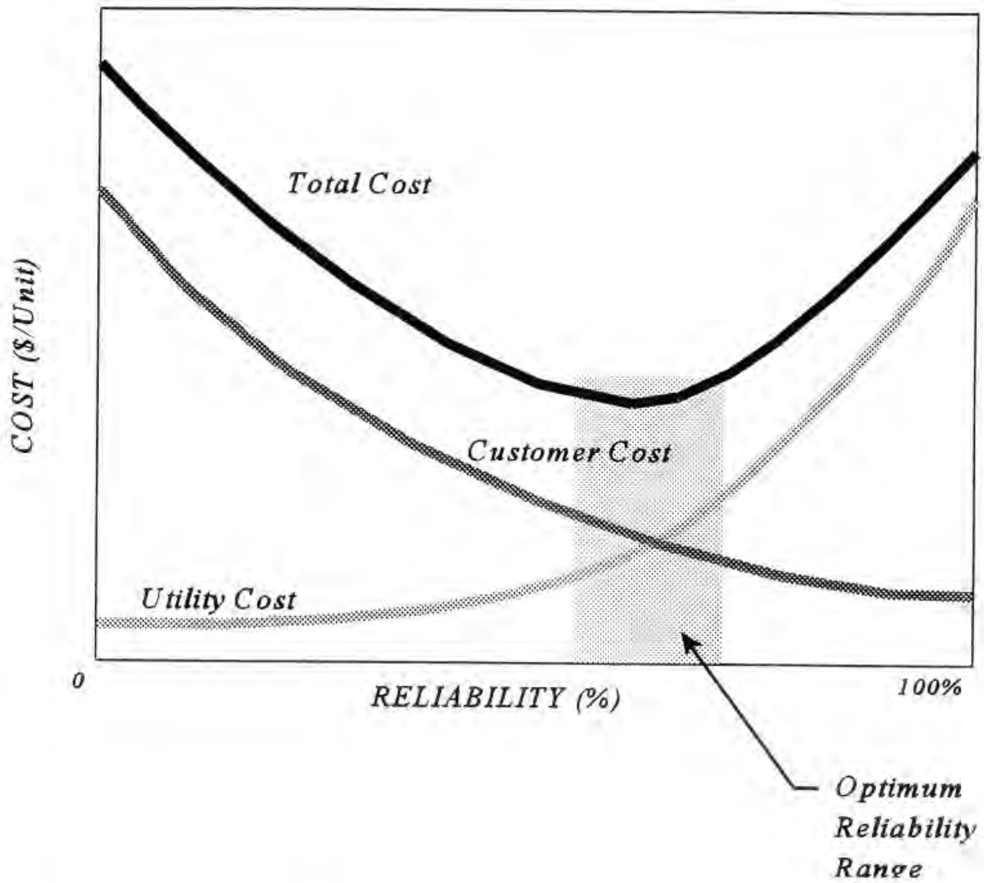


Figure 2.7 Optimum Reliability Levels

The following remedial tasks are expected to provide cost effective means of reducing system outages and improving distribution system reliability

2.6.1 Preventative Maintenance Program

A scheduled program is recommended to be adopted to monitor and manage the preventative maintenance of distribution equipment. Based on the value of customer outage costs, optimum reliability targets for the distribution system should be established. Actual system reliability performance should be monitored and measured against these targets. The frequency of equipment maintenance should be adjusted as a function of measured reliability performance. A number of maintenance software packages are commercially available to facilitate scheduling and record keeping of maintenance functions.

It is expected that the outages caused by malfunctioning substation equipment that affect a large number of customers and have a significant impact on system reliability can be reduced through implementation of a substation equipment maintenance program. Many of the outages caused by excessive sag on distribution lines or low clearance from tree branches can be eliminated through a scheduled distribution system monitoring and maintenance program. The use of Infrared Thermography which is being successfully used by Kingston PUC on the 44-kV system, should be extended to the 4-kV distribution system. Specific recommendations for a maintenance program are described in Section 5.

2.6.2 Load Break Switches

The underground distribution system supplied from Substation #1 and Substation #9 employs paper insulated lead covered (PILC) cables. The splices and terminations on PILC cables are not easily disconnectable during restoration of power supply, following a cable fault on this system. The faulty cable sections can be isolated only through operation of the underground disconnect switches. The existing oil insulated underground switches on the distribution system are however not suitable for load-break operations.

A program to replace these disconnect switches with load break switches has recently been started and should be continued. Specific recommendations on disconnect switch replacement program are provided in Section 6.

2.6.3 Feeder Loads

The peak seasonal loading on the feeders tabulated in Table 2.4 is marginally higher and should be lowered through transfer of load to adjacent feeders. This would eliminate the possibility of feeder circuit breakers tripping under overload conditions during contingency operating conditions or during cold load pick up.

Table 2.4 Feeders with Higher than Average Loads

Substation #1	Substation #2	Substation #3	Substation #4
Feeder 102 Feeder 104	Feeder 201	Feeder 304 Feeder 305 Feeder 307	Feeder 404 Feeder 405
Substation #6	**Substation #7**	**Substation #8**	**Substation #9**
Feeder 604 Feeder 608 Feeder 609	Feeder 701 Feeder 702 Feeder 703	Feeder 804 Feeder 807 Feeder 809	Feeder 901 Feeder 903 Feeder 904
Substation #10	**Substation #11**	**Substation #12**	**Substation #13**
Feeder 1003 Feeder 1004	Feeder 1105 Feeder 1106	Feeder 1205	Feeder 1302

2.6.4 Distribution Automation/ Use of SCADA System

Many retail utilities in Ontario have adopted 13-kV and 25-kV voltages over the recent years. Higher distribution voltages generally result in fewer substations, lower load losses and savings in both capital and operating costs. Higher distribution voltage levels, however, due to longer average lengths of distribution feeders, result in worsening of reliability. In order to offset the effect of longer distribution feeders, many utilities have implemented distribution automation initiatives such as the use of mid-feeder reclosers or SCADA controlled switches.

In case of Kingston PUC's distribution system, the operating voltage is 4,160 V and the feeder lengths are relatively short. Anticipated improvements from automation of on-line disconnect switches are expected to be marginal. In a few selected locations, where feeder lengths are longer than average, it may be cost effective to employ SCADA controlled switches at the normally open points on primary distribution feeders. An on-line SCADA interface with fault indicators is also expected to be cost effective in reducing response time to system outages and thus improving system reliability.

2.6.5 Back up Feeds for Radial Single Phase Taps

The on-going program to provide back-up feed in form of a loop configuration for long radial single phase branch circuits supplying a significant number of customers should be continued.

Long Range System Improvements

3 Long Range System Improvements

Based on preliminary assessment of the Kingston PUC's distribution system during Phase 1, the following initiatives are expected to result in improvements in system reliability, power quality, safety and operating efficiencies:

- voltage upgrade;
- loss reduction/power factor correction;
- implementation of an AM/FM/GIS system;
- distribution automation through SCADA system;
- demand management;
- review of underground cable specifications.

In order to establish their cost effectiveness, a detailed economic and financial feasibility study into each of these initiatives would be necessary.

3.1 Voltage Upgrade

The town of Kingston with approximately 26,000 customers and a peak demand of 165 MW is served from distribution feeders energized at 4,160 Volt. The service area, spread over approximately 30 square kilometers, is presently supplied from a total of 16 substations.

If the distribution system were to be rebuilt again to supply the above service area, a distribution voltage of 13.8-kV or 27.6-kV is expected to be more economical than the existing system voltage of 4.16-kV. A majority of the savings at a higher operating voltage are expected to come from the significantly reduced number of substations and feeder circuit breakers, that would be necessary. The voltage conversion program, by reducing feeder loading, is also expected to help improve system power factor and reduce losses.

A comparison of the required number of substations and feeder positions to supply the existing load at different voltage levels is provided in Table 3.1. As indicated in Table 3.1, the entire service area can be supplied from a total of three transformer stations and 12 primary feeders, energized at 27.6-kV.

Table 3.1
System Voltage Vs Number of Substations

System Nominal Voltage (kV)	4.16	13.8	27.6
Peak Service Area Demand (MW)	130	130	130
Diversity Factor	0.9	0.9	0.9
Average Feeder Current (A)	300	300	300
Average Feeder Demand (MW)	2.16	7.16	14.32
Number of Feeders per Substation	4	4	4
Average Load per Substation (MW)	8.64	28.65	57.30
Number of Required Substations	17	5	3

Although the capital costs of the existing 4-kV substations can be treated as sunk costs, some of the substation equipment will have to replaced over the next 10 to 15 years. A strategically planned voltage upgrade program is expected to reduce the capital spending for substation rebuild program and reduce the operating and maintenance costs associated with substation equipment. However, in order to fully utilize the existing investments in 4-kV system and to minimize over all long run costs the voltage upgrade program would have to be implemented gradually over the next 15 to 20 years.

With a majority of electric utilities in North America opting for higher distribution voltages, the 4-kV systems are becoming virtually obsolete. In the future, as the demand for 4-kV rated equipment gradually vanishes, there would be fewer and fewer equipment vendors available to supply the 4-kV rated equipment. As a result, the equipment costs are expected to rise, due to lack of competition among equipment vendors.

A detailed financial and economic feasibility study for implementation of a long range voltage upgrade program is recommended to be carried out.

3.2 Loss Reduction/ Power Factor Correction

Although the loads on distribution feeders at Kingston PUC are generally light, a detailed load flow analysis is expected to reveal selected service areas where power factor improvement and loss reduction initiatives would help reduce overall life cycle costs. It is therefore recommended that detailed investigations into loss reduction and power factor improvement initiatives be carried out in conjunction with the feasibility studies into voltage upgrade. The entire distribution system should be modelled into one of the commercially available load flow programs. Optimum feeder loads, transformer loads, watt and var. flows should be determined and the need for implementing power factor correction measures should be studied. Power factor correction not only reduces losses but helps reduce peak system loads resulting in energy purchase costs as well as deferring the need for costly system upgrades.

3.3 Expanding the Role of AM/FM/GIS Systems

With the development of PC based automated mapping, facilities management and geographic information systems (AM/FM/GIS) over the recent years, the cost benefit ratios for implementation of such systems have become very attractive. There are many low cost software packages commercially available with the ability of improving operating efficiencies of distribution system planning, design, construction and operating functions. A number of software packages can be integrated with SCADA systems and can perform on-line load management, automated switching operations, trouble crew dispatch during system outages or assist in steering of preventative maintenance programs.

It is recommended that practical options for expanding the role of existing AM/FM/GIS System in optimizing various distribution system operation functions be identified and implemented.

3.4 Distribution Automation through SCADA System

Due to a distribution voltage level of 4-kV being employed at Kingston PUC, the primary feeders are relatively short in length. Each of the feeders has full SCADA interface at the substation for monitoring of load, opening and reclosing of the feeder circuit breakers.

Many utilities that operate their distribution systems at 13.8-kV or 27.6-kV levels, have adopted automation initiatives involving SCADA controlled disconnect switches or automatic reclosers installed on excessively long feeders. Due to considerably short feeder lengths such automation initiatives are not expected to be cost effective on Kingston PUC's distribution system.

However, in a few selected locations with longer than average feeder lengths, distribution automation initiatives may be justifiable. A SCADA interface with fault indicators is expected to be cost effective in improving reliability. Use of SCADA controlled distribution automation functions for demand side management may also be justifiable. It is recommended a detailed cost benefit analysis for SCADA controlled distribution automation initiatives be carried out.

3.5 Demand Side Management

In order for an electric utility to successfully compete in a deregulated environment, it would become essential to take advantage of every available opportunity to reduce operating costs, without sacrificing quality of service. Since a significant portion of a distribution utility's operating costs are related to wholesale power purchase, any load and demand management initiatives would go a long way in reducing operating costs.

A detailed investigation into load and demand management, in cooperation with some of the large utility customers, such as the Queens University, is recommended to be carried out including feasibility studies for installation of peak shaving generation.

3.6 Review of Underground Cable Specifications

The underground distribution system supplied from Substation #1 and Substation #9 employs paper insulated lead covered (PILC) cables. Aside from Kingston PUC, two other major utilities in Ontario, Ottawa Hydro and Toronto Hydro also continue to use PILC cables on their distribution systems, extensively. Although the PILC cables generally provide a long service life, their overall life cycle costs are expected to be higher compared with dry insulation cables, due to higher cable procurement costs and higher splicing and termination costs. The useful life of cable splices and terminations is dependent upon the quality of workmanship and requires highly skilled trades persons and cooperative weather. Kingston PUC does have fully trained and skilled staff available to install and repair PILC cables.

Over the recent years, significant improvements have occurred in the design and manufacture of dry insulation cables, which have resulted in tree retardant cross linked polyethylene (TRXLPE) and ethyl propyl rubber (EPR) insulations being adopted as a standard for distribution cables by an increasing number of utilities. Due to the shrinking demand for PILC cables, many cable manufacturers are abandoning PILC manufacturing lines and the procurement costs of these cables are expected to even increase further in the future.

A cost/benefit analysis for gradual and systematic replacement of the PILC cables with dry insulation cables is recommended to be carried out.

3.7 Asbestos Coverings on PILC Cables

Distribution cables within manholes and vaults are commonly covered with fire retardant tapes to restrict spread of fire from a faulted cable circuit to cables of other circuits. The fire retardant tapes, in the past, were virtually always made of asbestos containing materials. Due to the potential health hazards associated with asbestos, fire retardant tapes of non-asbestos materials have become available over the past several years and a number of utilities have undertaken programs for removal of asbestos containing cable coverings.

The PILC cables on Kingston PUC's distribution system are covered with asbestos based fire retardant tapes, in manholes and vaults. Services of private contractors are utilized to handle the asbestos coverings when needed. This work procedure arrangement may slow down response times to repair and restore power during a major fault on the underground distribution system. It is recommended that the asbestos tapes be permanently removed and replaced with non-asbestos fire retardant tapes.

Opportunities for Integration of Utility Functions

4 Opportunities for Integration of Utility Functions

As previously indicated, for successful operation of an electric distribution utility in a deregulated and competitive environment, it would be necessary to take advantage of every available opportunity to reduce costs without compromising quality of service. It is expected that the operating costs can be reduced through integration of some common utility functions and sharing of common infrastructure facilities.

Kingston PUC is responsible for distribution of gas, water and electricity within the town of Kingston, which already provides opportunities for integration of some common utility functions such as records and drawings management, locating underground facilities to allow excavations, metering, billing, revenue collection and other customer service functions. There may be some additional opportunities for further integration and sharing of common functions and facilities with the telephone/TV cable utilities.

Queens University is the largest utility customer with an underground distribution system very similar in design to the underground distribution system supplied from #1 and #9 substations. There would be opportunities for both the Queens university and the Kingston PUC to reduce operating costs, through a merger of their distribution systems. The savings should result through elimination of duplication in spare equipment and parts inventories as well as operating and maintenance staff functions. A detailed investigation into feasibility of such a merger is being carried out by the Kingston PUC under a separate contract.

In view of the report of the Advisory Committee on Competition in Ontario's Electricity System, the provincial government may adopt policies for merger of municipally owned electric utilities and Ontario Hydro retail jurisdictions. There would certainly be opportunities for reducing operating costs through sharing of resources with neighboring municipalities or Ontario Hydro retail jurisdictions. However, before undertaking any detailed feasibility studies on practical merger options, it would be prudent to wait for the provincial government to finalize and announce its policy on Ontario's electricity system.

Preventative Maintenance Program

5 Preventative Maintenance Program

A well planned preventative maintenance program not only helps improve power quality, system reliability and public safety, but it also often helps reduce overall operating costs by eliminating costly equipment damage and the need for emergency repairs.

The distribution equipment maintenance programs generally consist of two separate tasks:

- equipment inspections and monitoring;
- equipment maintenance.

The equipment inspection and monitoring activities are used to identify potential hazards that could impact public or employee safety or result in equipment damage or a system outage. The reports of equipment inspection and monitoring activities are used as a trigger for carrying out preventative maintenance with the objective of rectifying potential hazards or extending equipment life or for replacement of aging equipment.

The Canadian utilities spend between 2% to 10% of their operating and maintenance budgets on equipment inspections and monitoring activities. The frequency of monitoring activities vary considerably from one utility to another. The following frequencies are commonly employed by Canadian utilities for monitoring of various distribution equipment items:

- once every six months;
- once every year;
- once every three years;
- once every five years;
- once every ten years;
- never, only after a breakdown.

5.1 Recommended Maintenance/ Monitoring Schedule

It is recommended that the frequency of distribution equipment maintenance be monitored and adjusted on an on-going basis to meet the reliability targets. The following maintenance/monitoring schedule is recommended for different categories of distribution equipment items as the initial benchmark.

5.1.1 Overhead Feeder Equipment

(a) Poles / Wood Cross arms

Visual Inspections (Once every six years)
Bore Tests (Only where pole integrity in doubt)
Hammer Tests (Only where pole integrity in doubt)

(b) Conductors, Splices and Connectors

Infrared Thermography (Once every six years)
Visual Inspections (Once every six years)
Tree trimming (as required, depending on tree types in different service areas)
Monitor Failure Rate (On-going)

(c) Insulators and Hardware

Visual Inspections (Once every six years)

(d) Fuse Cutouts

Infrared Thermography (Once every two years)
Visual Inspections (Once every two years)
Operational Tests (Once every two years)

(e) Disconnect Switches

Infrared Thermography (Once every two years)
Visual Inspections (Once every two years)
Operational Tests (Once every two years)

(f) Surge Arresters

Visual Inspections (Once every two years)
Infrared Thermography (Once every two years)
Monitoring of failure rate (On-going)

(g) Transformers

Visual Inspections (Once every two years)
Infrared Thermography (Once every two years)
Monitoring of failure rate (Once every two years)

Oil tests (Once every six years - On transformers 20 years or older)
Insulation tests (Only in case of trouble)
Electrical tests (Only in case of trouble)

5.1.2 Underground Feeder Equipment

(a) Cables

Visual inspections (Once every six years)
Failure rate monitoring (On-going)
Microscopic examination (Only where cable integrity in doubt)
Insulation tests (Only where cable integrity in doubt)

(b) Elbows, Splices, Connectors, Terminations

Visual inspections (Once every two years)
Failure rate monitoring (Once every two years)
Infrared thermography (Once every two years)

(c) Disconnect Switches

Visual inspections (Once every two years)
Infrared thermography (Once every two years)
Operational tests (Once every two years)
Failure rate monitoring (On-going)

(d) Transformers

Visual Inspections (Once every two years)
Infrared Thermography (Once every two years)
Monitoring of failure rate (Once every two years)
Oil tests (Once every six years - On transformers 36 years or older)
Insulation tests (Only in case of trouble)
Electrical tests (Only in case of trouble)

5.1.3 Substation Equipment

(a) Power Transformers

Oil tests (Once every two years)
OLTC count (Twice a year)
Visual inspections (Twice a year)

Insulation tests (Once every six years)
Electrical tests (Once every six years)

(b) Circuit Breakers/Reclosers

Visual inspections (Twice a year)
Operations count (Twice a year)
Operational tests (Once every two years)
Oil tests (Once every two years)
Insulation tests (Once every four years)
Electrical tests (Once every four years)

(c) Voltage Regulators/OLTC's

Visual inspections (Twice a year)
Operations Count (Twice a year)
Oil tests (Once every two years)
Insulation tests (Once every four years)
Electrical tests (Once every four years)

(d) Shunt Capacitors

Visual inspections (Twice a year)
Infrared thermography (Once every year)
Electrical tests (Once every four years)
Insulation tests (Once every four years)
Oil tests (Once every four years)

(e) Disconnect Switches, By-pass Switches, Isolators

Visual inspections (Twice a year)
Infrared thermography (Once every year)
Operations tests (Once every four years)

(f) Surge Arresters

Visual inspections (Twice a year)
Operations count (Twice a year)
Failure rate monitoring (On-going)
Electrical tests (Only in case of trouble)

(g) Power Fuses

Visual inspections (Twice a year)
Infrared thermography (Once every year)

(h) Control Batteries, Battery Chargers

Visual inspections (Twice a year)
Specific Gravity Test (Once every year)
Electrical Tests (Once every four years)

5.2 Equipment Check Lists

The following items are recommended to be included in the check list during equipment inspections and monitoring activities.

5.2.1 Overhead Feeder Equipment

(a) Poles/Wood Cross Arms

1. Record pole number, circuit number and date of installation.
2. Check for plumb/square.
3. Expose the pole below ground line and check for signs of wood decay.
4. Check for surface damage.
5. Inspect pole guys.
6. Inspect pole grounds for continuity, where applicable.
7. List corrective action required, if any.

(b) Conductors, Splices and Connectors

1. Record span number, circuit number.
2. Check for excessive sag or tension.
3. Check for clearances from ground or tree branches.
4. Check for hot spots.
5. Check for conductor strand damage from birdcaging.
6. Check for foreign objects entangled in lines.
7. List corrective action required, if any.

(c) Insulators and Hardware

1. Record pole number, circuit number.
2. Check for missing, damaged, rusted hardware.

3. Check for broken, cracked, chipped, flashed-over insulators.
4. Check for dust deposit on insulator surface.
5. List corrective action required, if any.

(d) Fuse Cutouts

1. Record cutout number, circuit number and date of installation.
2. Look for missing, damaged, rusted hardware.
3. Verify fuse cartridge current rating.
4. Operate the cutout and look for smooth hook stick operation.
5. Examine contacts for wear or damage from arcing.
6. Check for hot spots with help of Infrared Thermography with the cutout closed.
7. Inspect pole grounds for continuity, where applicable.
8. List corrective action required, if any.

(e) Disconnect Switches

1. Record disconnect switch number, circuit number and date of installation.
2. Look for missing, damaged, rusted hardware.
3. Verify fuse cartridge current rating.
4. Operate the disconnect switch and look for smooth hook stick operation.
5. Examine contacts for wear or damage from arcing.
6. Check for hot spots with help of Infrared Thermography with the cutout closed.
7. Inspect pole grounds for continuity, where applicable.
8. List corrective action required, if any.

(f) Surge Arresters

1. Record surge arrester number, circuit number and date of installation.
2. Look for missing, damaged, rusted hardware.
3. Check for broken, cracked, chipped, flashed-over insulators.
4. Check for hot spots with help of Infrared Thermography.
5. Inspect surge arrester grounds for continuity.
6. List corrective action required, if any.

(g) Transformers

1. Record transformer number, circuit number and date of installation.
2. Record transformer nameplate rating.
3. Look for missing, damaged, rusted hardware.
4. Check condition of transformer tank, look for signs of rust.
5. Check oil level and look for oil leaks.
6. Estimate transformer load, by counting number of services supplied.
7. Check and record maximum transformer temperature.
8. Check for hot spots with help of Infrared Thermography.
9. List corrective action required, if any.

5.2.2 Underground Feeder Equipment

(a) Cables

1. Record circuit number, cable size, installation date.

2. Check if the cables are properly trained and supported.

3. Check if the cables are subjected to frequent flooding.

4. On selected samples remove the fire-retardant tape and inspect lead shield for possible cracks or bulging out. (Bulging out of the shield indicates oil migration from the opposite end).

5. List Corrective action required, if any.

(b) Cable Splices and Terminations

1. Record circuit number, cable size, installation date.
2. Check if the splices/terminations are properly supported.
3. Check if the splices are racked high to protect from flooding.

4. Look for insulating oil or compound leaks from terminations, splices.
5. Look for possible cracks or bulging out of the housing.
6. Check for hot spots with help of Infrared Thermography.
7. List corrective action required, if any.

(c) Disconnect Switches

1. Record disconnect switch number, circuit number and date of installation.
2. Check for damage or rust to switch tank
3. Look for oil leaks from the cable glands.
4. Operate the switch and verify smooth operation.
5. Check for hot spots with help of Infrared Thermography with the cutout closed.
6. List corrective action required, if any.

(d) Transformers

1. Record transformer number, circuit number and date of installation.
2. Record transformer nameplate rating.
3. Check condition of transformer tank, look for signs of rust.
4. Check oil level and look for oil leaks.
5. Estimate transformer load, by counting number of services supplied.
6. Check and record maximum transformer temperature.
7. Check for hot spots with help of Infrared Thermography.
8. List corrective action required, if any.

5.2.3 Substation Equipment

(a) Power Transformers

(a-1) Visual Inspections

1. Record transformer number, circuit number and date of installation.
2. Record transformer nameplate rating.
3. Check condition of transformer tank, look for signs of rust.
4. Check oil level and look for oil leaks.
5. Check and record maximum transformer temperature.
6. Check for hot spots with help of Infrared Thermography.

7. Check and record OLTC operation count.
8. Check the condition of Silica gel in breather pipes, where applicable.
9. Check and clean transformer bushings.
10. List corrective action required, if any.

(a-2) Insulation Tests

1. Carry out and record results of dc insulation resistance tests.
2. Carry out and record results of dielectric breakdown test.
3. Carry out and record results of applied voltage test.

(a-3) Insulating Oil Tests

1. Examine and record visual aspects, color and turbidity.
2. Test for and record water content.
3. Test for and record dissolved gas content.
4. Test for and record interfacial tension.
5. Examine and record results of combustible gas analysis.
6. Test for record neutralization number.
7. Test for and record the insulation power factor.

(a-4) Electrical Tests

1. Carry out and record the results of turns ratio test.
2. Carry out and record the results of excitation current test.
3. Carry out and record the results of winding resistance measurement.
4. Test the operation of OLTC.
5. Test the operation of cooling fans.

(b) Circuit Breakers/Reclosers

(b-1) Visual Inspections

1. Record circuit breaker number, circuit number and date of installation.
2. Record circuit breaker nameplate rating.
3. Check and record operations counter reading.
4. Inspect gaskets, tank liners, air diaphragms, bushings, as applicable.
5. Inspect contacts for wear and damage from arcing.
6. Inspect contact springs and other springs in close and trip mechanism.
7. Check and clean bushings, if applicable.
8. Check and replace indicating light bulbs where necessary.

(b-2) Insulation Tests

1. Carry out and record results of meggar test, phase-to-phase and phase-to-ground.

2. Carry out and record results of Hi-pot test, phase-to-phase and phase-to-ground.

(b-3) Electrical Tests

1. Test and record the contact resistance.
2. Test the operation of anti-pump and trip-free circuit.
3. Carry out and record the results of winding resistance measurement.
4. Test the operation of reclose and lockout relay.
5. Check close and trip operation from local controls and remote.
6. Check the operation of auxiliary switches.
7. Check and record the control voltages.
8. Calibrate the protective relays and test for trip currents.
9. Retorque busbar connections, where applicable.
10. Follow manufacturers instructions.

(c) Voltage Regulators/OLTC

(c-1) Visual Inspections

1. Record voltage regulator number, circuit number and date of installation.
2. Record voltage regulator nameplate rating.
3. Check and record operations counter reading.
4. Check condition of regulator tank, look for signs of rust.
5. Check oil level and look for oil leaks.
6. Check and record maximum temperature.
7. Check for hot spots with help of Infrared Thermography.
8. List corrective action required, if any.

(c-2) Electrical Tests

1. Untank and inspect moving contacts, stationary contacts, electrical connections, tightness of bolts.

2. Test the operation of regulator controls and record the bandwidth volts during voltage raise operation.

3. Test and operation of regulator controls and record the bandwidth volts during voltage lower operation.

(d) Disconnect Switches, By-pass Switches, Isolators

1. Record disconnect switch number, circuit number and date of installation.
2. Look for missing, damaged, rusted hardware.
3. Verify fuse cartridge current rating.
4. Operate the disconnect switch and look for smooth hook stick operation.
5. Examine contacts for wear or damage from arcing.
6. Check for hot spots with help of Infrared Thermography with the cutout closed.
7. Inspect equipment grounds for continuity.
8. List corrective action required, if any.

(e) Surge Arresters

1. Record surge arrester number, circuit number and date of installation.
2. Look for missing, damaged, rusted hardware.
3. Check for broken, cracked, chipped, flashed-over insulators.
4. Check for hot spots with help of Infrared Thermography.
5. Inspect surge arrester grounds for continuity, where applicable.
6. Check for surge arrester damage by inspecting arrester isolator condition.
7. List corrective action required, if any.

(f) Power Fuses

1. Record fuse number, circuit number and date of installation.
2. Verify fuse cartridge current rating.
3. Check for hot spots with help of Infrared Thermography.
4. List corrective action required, if any.

(g) Control Batteries and Chargers

(g-1) Visual Inspections

1. Check and record the electrolyte levels.
2. Check for corrosion of terminals.
3. Check for cracks in battery cells.

4. Test for and record the electrolyte specific gravity.
5. List corrective action required, if any.

(g-2) Electrical Tests

1. Test and record battery bank voltage.

2. Test the operation of ground fault alarm.

3. Test the operation of low voltage alarm.

4. In case of nickel cadmium batteries, carry out deep discharge and recharge of the battery.

5. Test the battery charger operation, under fast charge and trickle charge.

Oil Switch Replacement Program

6 Oil Switch Replacement Program

6.1 Background

The underground primary distribution system supplying service areas of #1 and #9 substations employs paper insulated, lead covered (PILC) cables. The terminations and splices on PILC cables are not easily disconnect able. In order to provide convenient means of isolation and disconnection of cables from energized system during a planned or unplanned system outage, disconnect switches have been provided in the design. There are a total of 27 disconnect switches installed in below grade vaults.

These switches with a design interrupting rating of 400 A, were manufactured by G&W and employ an oil-insulated, 3-pole, 4-way, double-throw design. The single line diagram for a typical load break switch is shown in Figure 6.1. As indicated, switch ways #1 and #3 are used to loop through the primary feeders. Switch way #2 is fused and is used to supply distribution transformers. Switch way #4 is employed for back-up feeders or for supplying additional distribution transformers where necessitated by load growth. The double throw, dual bus arrangement is intended to provide convenient means of grounding any of the circuits connected to the disconnect switch.

Unfortunately, the existing disconnect switches are of an old vintage and employ an obsolete design that does not use toggles or mechanical springs in the switch closing mechanism. As a result, the closing speed of switch blades is highly variable. Because of their obsolete design and old age , the ability of these disconnect switches to successfully and safely break or make load current is in doubt. This uncertainty, along with their oil insulated design and installation in confined spaces has necessitated a significant change in operating procedures to ensure operator safety. The switches are no longer used for interrupting load current but are used only to isolate de-energized cable circuits, after opening of the substation circuit breaker.

This procedure results in unnecessary customer outages and defeats the purpose of load break switches in the design. A program to replace the existing switches, with new switches capable of performing load break operation has recently been adopted by Kingston PUC. Under this program, the first two switches of oil-insulated design are currently being purchased from G&W.

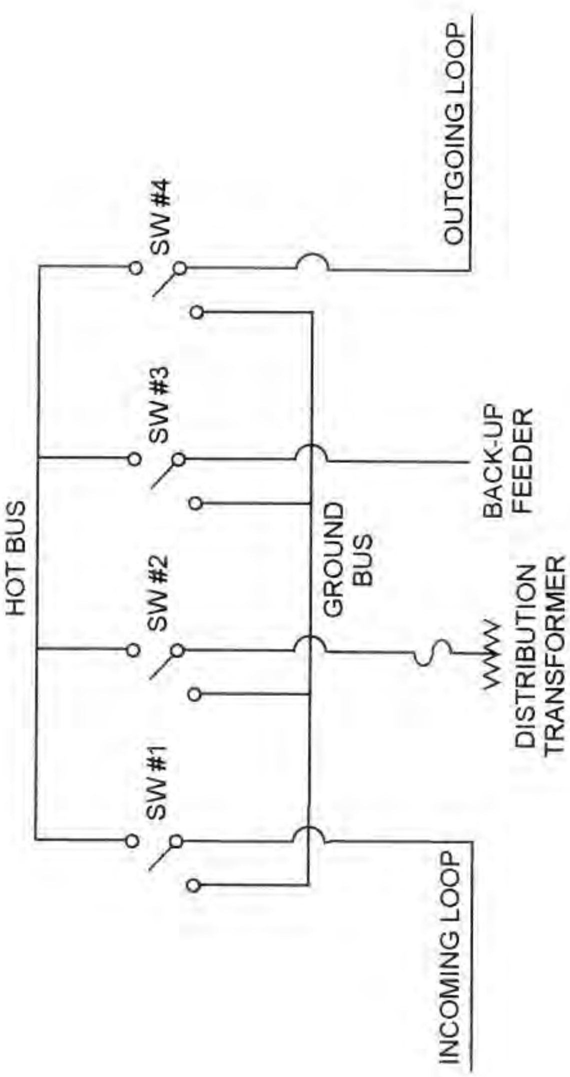


Figure 6.1 Single Diagram for Oil-insulated Disconnect Switch

6.2 Available Options for Replacement Switchgear

The underground distribution switchgear suitable for load break operations, is available in several different design options. Each option, as described below, has its own advantages and drawbacks depending on the application.

6.2.1 Design Options Based on Switch Installation Location

The underground distribution switchgear can be purchased in either metal enclosed design for above-grade, pad-mount installations or in submersible design suitable for below grade vault installations.

The pad mounted switchgear generally offers the advantages of lower purchase price, lower operating and maintenance costs, longer life and ease of access for operation. However this design can be employed only in locations where above-grade space for pad-mounted installations is readily available. For the service areas supplied from substation #1 and #9, space for pad-mounted switchgear installation is not available and the switchgear must be installed in below grade vaults. Therefore, submersible switchgear design is the only practical option.

6.2.2 Design Options Based on Type of Switchgear Insulation

The following design options are available based on the switchgear insulation type:

- air insulated;
- oil insulated;
- SF-6 insulated.

The air insulated switchgear designs, due to their larger dimensions are generally suitable for pad-mounted applications. For vault installations, where compact designs are desirable due to available space limitations, oil-insulated and SF-6 insulated designs are the only practical options.

The SF-6 insulated switchgear design have become very popular over the recent years, as the SF-6 gas has proven to be an excellent insulation and arc quenching medium. SF-6 gas in a non-toxic and non-flammable gas. The only health hazards associated with SF-6 design are the small amounts of arcing by-products in form of a powder, which are considered toxic. However since the SF-6 switches employ a sealed design, the possibility of an operator contact with these arcing by-products is rather remote.

The oil insulated switch design employs mineral insulating oil for insulation and arc quenching. Although oil-insulated disconnect switches have been successfully employed by electric utilities for many years, their major drawback is the flammability of insulating oil and environmental spills.

6.2.3 Design Options Based on Type of Cable Terminations

Most modern switchgear designs, including the SF-6 disconnect switches are equipped with terminating bushings suitable for quick connect and disconnect of dry insulated cables. The PILC cables, that require pot-head type terminations cannot be directly connected to this type of switchgear design. In order to connect PILC cables to SF-6 insulated switchgear would require the use of transition splices.

For termination of PILC cables directly on to switchgear, pot-head type terminations are required, which are still available in oil-insulated designs from some vendors.

6.3 Design Selection

Based on the site specific limitations of below grade installations and the requirements for compatibility with PILC cable terminations, there is only one practical design option available - use of oil insulated, submersible design, with the following features:

Continuous and load break rating:	400 A or higher
Close and hold, momentary 10 cycle rating:	20 kA or higher
Nominal Voltage:	4160 V or higher

Four way, dual bus switching, with provision for grounding
Current limiting fuses for transformer protection
Provision for remote switch operation
Contact viewing windows

It is recommended that the decision for selection of replacement switchgear be made after a review of the distribution cable specifications, as described in Section 3.5 and the feasibility study for voltage conversion program. If it is decided to adopt dry insulation cables for future installations or a voltage upgrade program is adopted, there may be merit in adopting SF-6 switchgear design.

Work Plan for Phase 2

7 Work Plan for Phase 2

In order to determine cost effectiveness of each of the system improvement initiatives proposed in Section 3, the work plan for Phase 2 is recommended to include detailed economic and financial feasibility studies into the following tasks:

- distribution system voltage upgrade;
- power factor and load loss optimizations;
- expanding the role of AM/FM/GIS system;
- distribution automation through SCADA system;
- demand management;
- review of underground cable specifications.

The proposed work plan for undertaking each of the above tasks is briefly described below, in point form.

7.1 Distribution System Voltage Upgrade

7.1.1 Life Cycle Costs for 4.16-kV Distribution System

- Carry out small area load growth forecasts for Kingston PUC's service areas.

- Determine quantities and age profile of equipment installed on the existing 4.16-kV distribution system.

- Establish present worth of life cycle capital investments necessary to cope with the load growth and replacement of aging distribution equipment.

- Establish present worth of life cycle equipment maintenance costs.

- Carry out load flow analysis, calculate system losses and operating costs.

- Calculate present worth of total life cycle costs for 4-kV distribution system.

7.1.2 Life Cycle Costs for 27.6-kV Distribution System

- Prepare a phased implementation plan for conversion to 27.6-kV system.

- Establish present worth of life cycle capital investments necessary for voltage conversion program.

- Establish present worth of life cycle equipment maintenance costs.

- Carry out load flow analysis, calculate system losses and operating costs.
- Calculate present worth of total life cycle costs for 27.6-kV distribution system.
- Verify economic feasibility of voltage upgrade program.
- Verify cash flow requirements and establish financial feasibility.

7.2 Power Factor and Load Loss Optimizations

- Based on the optimum system voltage selected during the previous task, establish the Watt/VAR. flow and calculate present worth of life cycle losses.
- Identify practical options for power factor improvements and loss reduction and establish capital investments for their implementation.
- Recalculate system losses and their present worth during the life cycle, after implementation of loss reduction and power factor improvement initiatives.
- Determine economic and financial feasibility of loss reduction initiatives.

7.3 Expanding the Role of AM/FM/GIS System

- Identify additional useful applications of existing AM/FM/GIS system.
- Establish capital investments for implementation of these additional applications.
- Establish present worth of life cycle benefits.
- Determine economic and financial feasibility.

7.4 Distribution Automation Through SCADA System

- Establish customer outage damage functions for different customer classes, based on Canadian electric utilities outage survey data (CEA reports).
- Identify practical distribution automation initiatives for reliability improvements and establish capital investments for their implementation.

- Calculate quantitative improvements in reliability and determine present worth of life cycle value of customer benefits resulting from reliability improvements.

- Determine economic and financial feasibility of automation initiatives.

7.5 Load Demand Management

- Identify pratical options for reducing peak winter demand and peak summer demand.

- Establish capital investments for implementation of peak shaving initiatives.

- Calculate present worth of life cycle operating costs for peak shaving initiatives.

- Establish present worth of life cycle savings in bulk power purchase costs.

- Determine economic and financial feasibility of peak shaving initiatives.

7.6 Review of Underground Cable Specifications

- Establish quantities and remaining life of existing PILC cables.

- Establish future capital investments necessary to cope with the load growth and replacement of aging cables with PILC cables.

- Establish maintenance and operating costs of PILC cable network.

- Calculate present worth of life cycle costs for the PILC cable network.

- Prepare a phased implementation plan for conversion to dry insulation cables.

- Establish future capital investments for cable conversion.

- Establish operating and maintenance costs for dry insulation cables.

- Calculate present worth of life cycle costs for dry insulation cables.

- Compare the life cycle costs of dry insulation cables to those of PILC cable network and establish economic feasibility.

- Verify cash flow requirements and establish financial feasibility.

Conclusions and Recommendations

8 Conclusions and Recommendations

1. Based on the value of customer outage costs, optimum reliability targets for power supply system should be established. Actual system reliability should be monitored and measured against these targets and corrective action taken, as and when necessary.

2. A scheduled program is recommended to be adopted to monitor and manage the preventative maintenance of distribution system equipment. The equipment maintenance frequency should be adjusted as a function of the system reliability performance.

3. The replacement program for underground disconnect switches with load-break switchgear should continue. The specifications for replacement switchgear should be reviewed and finalized after the cable specifications for future installations have been selected.

4. The program to provide back-up feeds in form of a loop configuration for excessively circuits that are presently installed in radial configurations, should continue.

5. The load on distribution feeders should be rearranged to achieve equal load distribution among various feeders. The load should also be balanced among different phases.

6. It is expected that implementation of a planned and gradual voltage upgrade program over a long range would result in lower overall life cycle costs. A detailed feasibility study into a voltage conversion program is recommended to be carried out.

7. It is expected that loss reduction and power factor improvement initiatives in some selected areas would result in lower overall life cycle costs. A detailed feasibility study into practical loss reduction and power factor improvement initiatives is recommended.

8. It is expected that additional applications of the existing AM/FM/GIS system in optimizing distribution system operating functions, such as demand management, automated switching, trouble crew dispatch, steering of preventative maintenance program etc. would result in lower overall life cycle costs. A feasibility study into the role of AM/FM/GIS system in expanded applications is recommended to be carried out.

9. An on-line interface between the SCADA system and fault indicators is expected to be cost effective in improving power system reliability. A feasibility study is recommended to be carried out into additional distribution automation SCADA applications.

10. It is expected that demand management initiatives would result in lower overall life cycle costs. A detailed feasibility study into peak shaving initiatives through the use of SCADA system is recommended to be carried out.

11. It is expected that the use of dry insulated cables instead of PILC cables on underground distribution system would result in lower overall life cycle costs in the long run. A feasibility study into gradual replacement of PILC cables with dry insulated cables is recommended.

12. The asbestos coverings on PILC cables in underground manholes may expose the workers to possible health hazards. It is recommended to replace the asbestos coverings with asbestos-free fire retardant tapes.

13. It is expected that the distribution system operating costs can be reduced through integration of some common utility functions and sharing of common infrastructure facilities with the Queens University. A detailed investigation into feasibility of such a merger is being carried out by the Kingston PUC under a separate contract.

Appendix

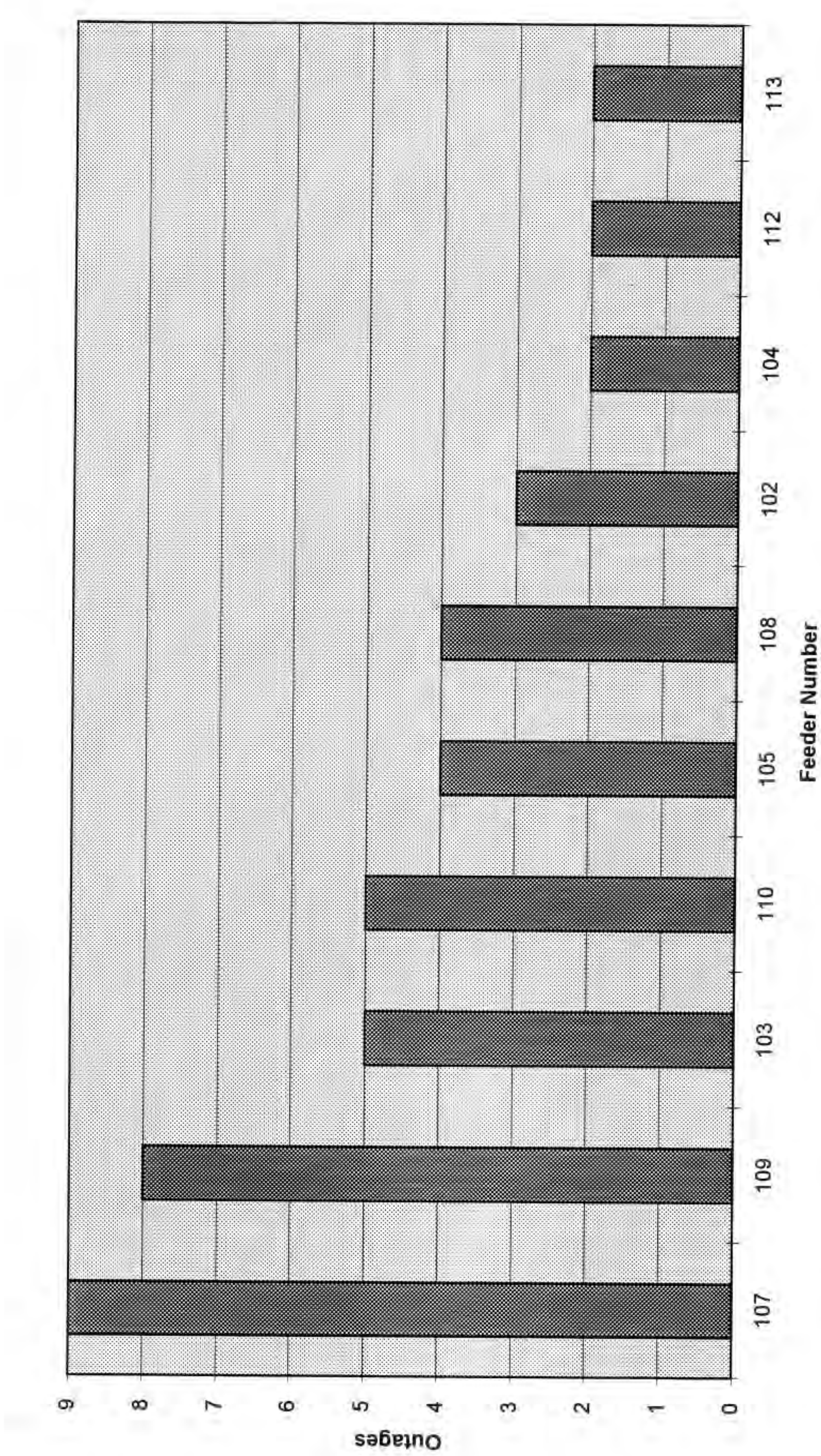


Figure A-1 Outage Distribution at Substation #1

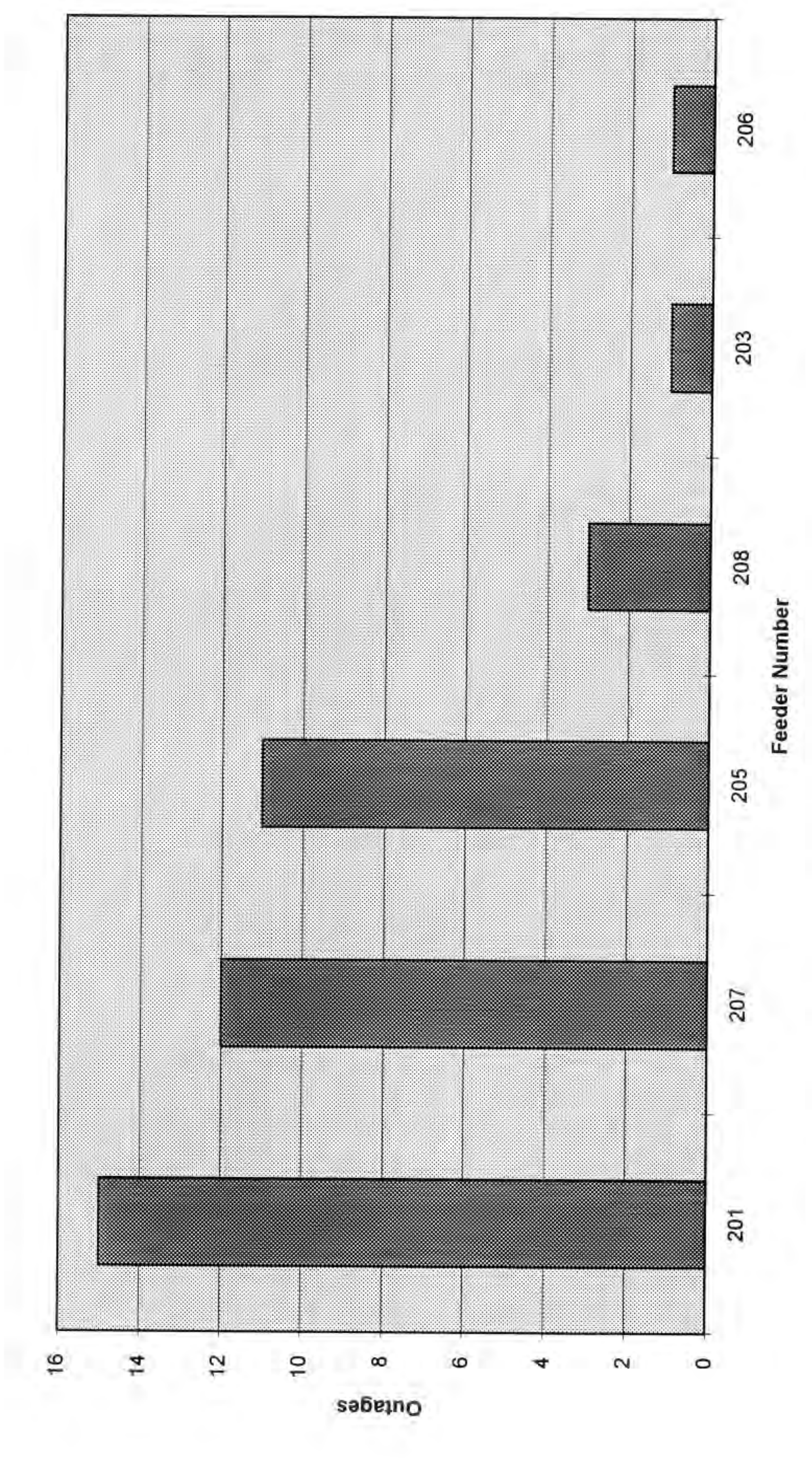


Figure A-2 Outage Distribution at Substation #2

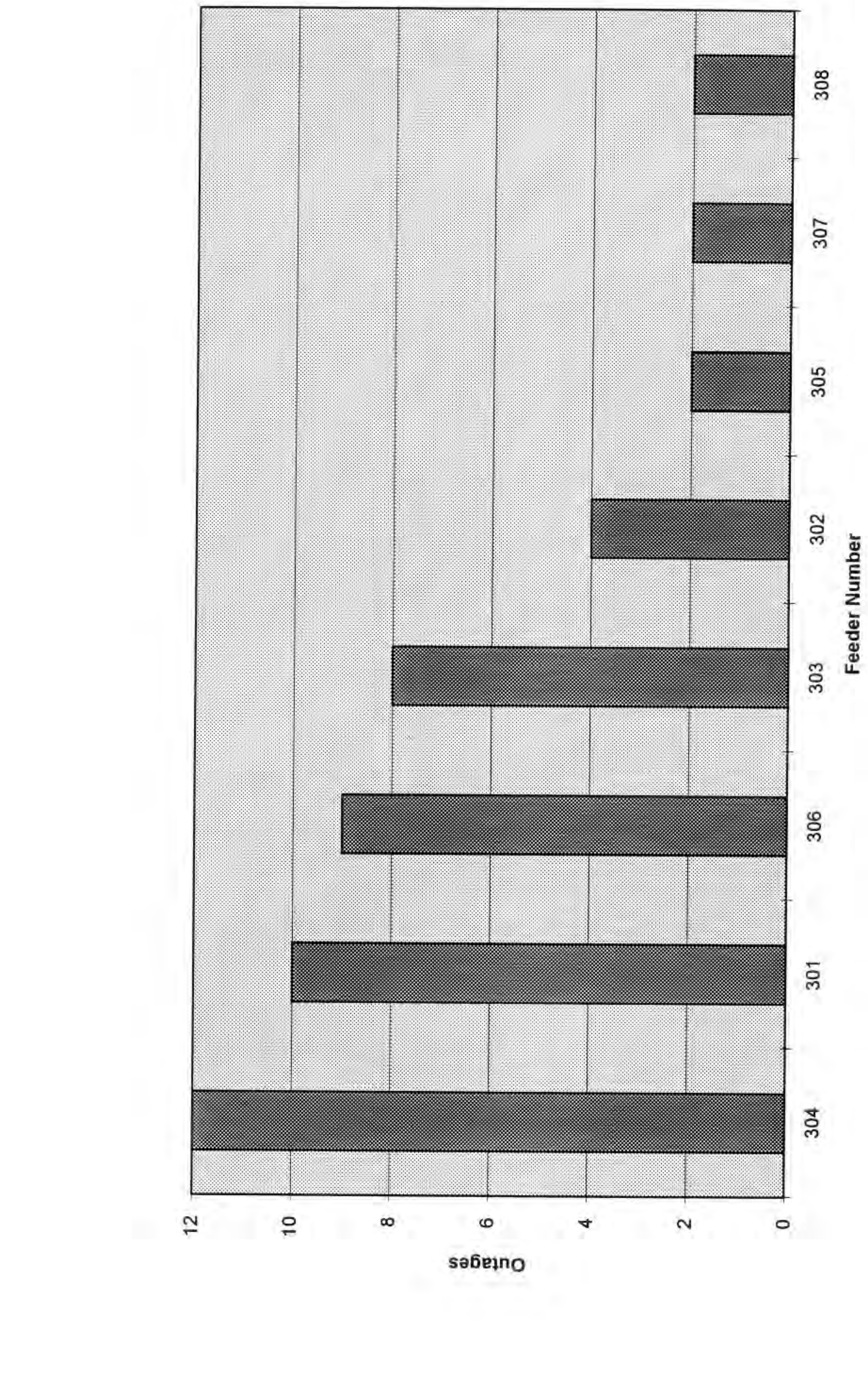


Figure A-3 Outage Distribution at Substation #3

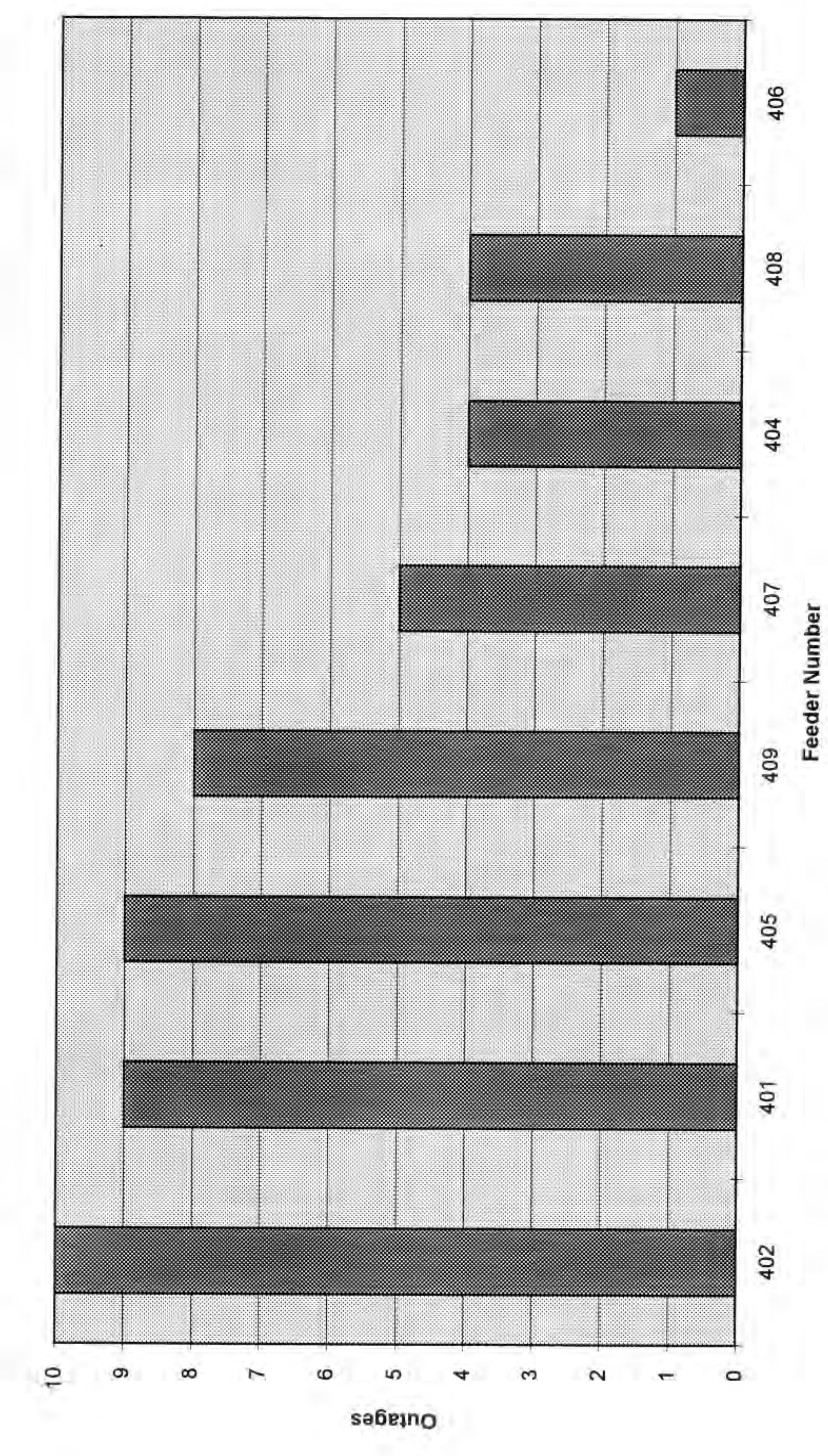


Figure A-4 Outage Distribution at Substation #4

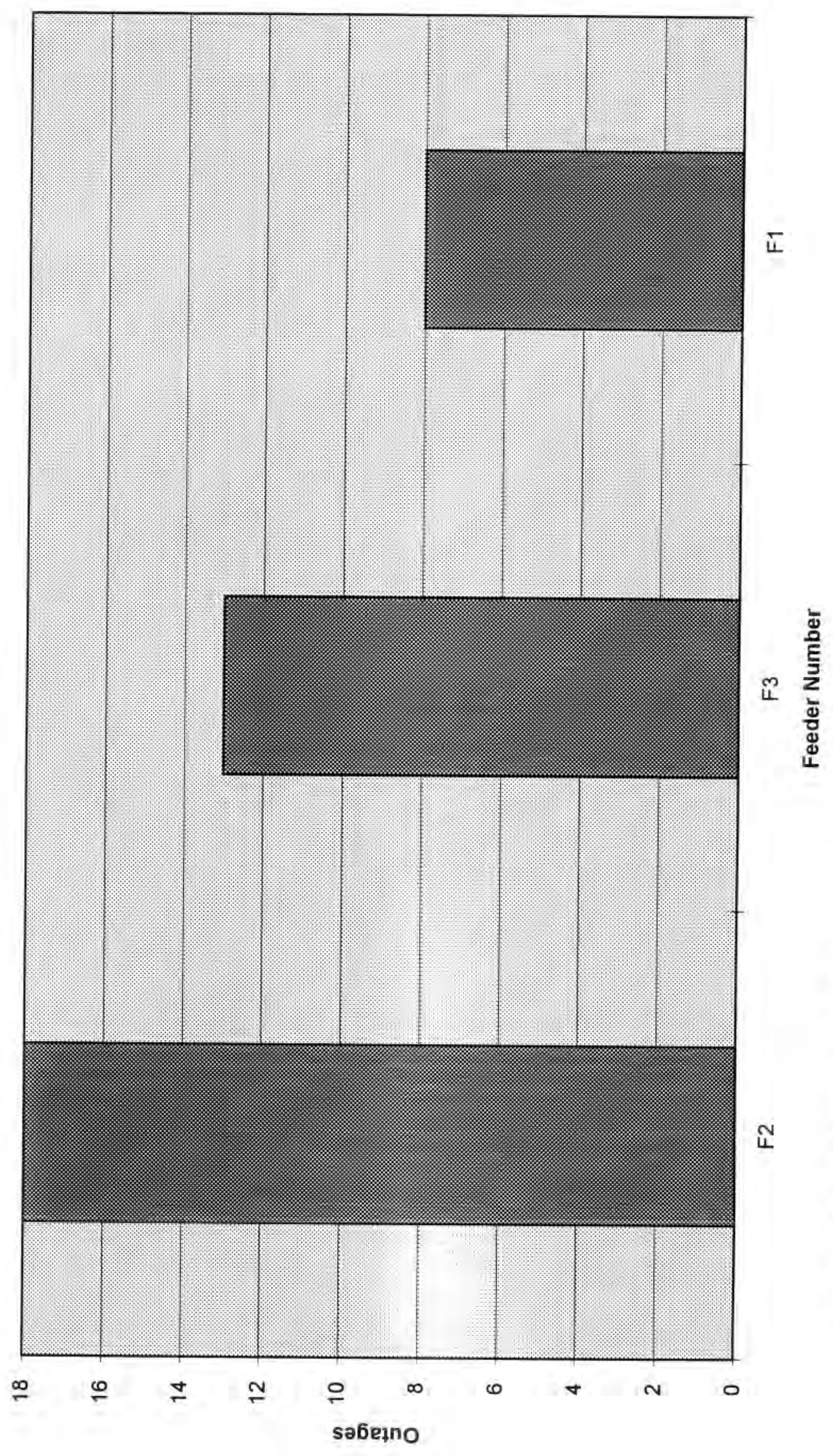


Figure A-5 Outage Distribution at Substation #5

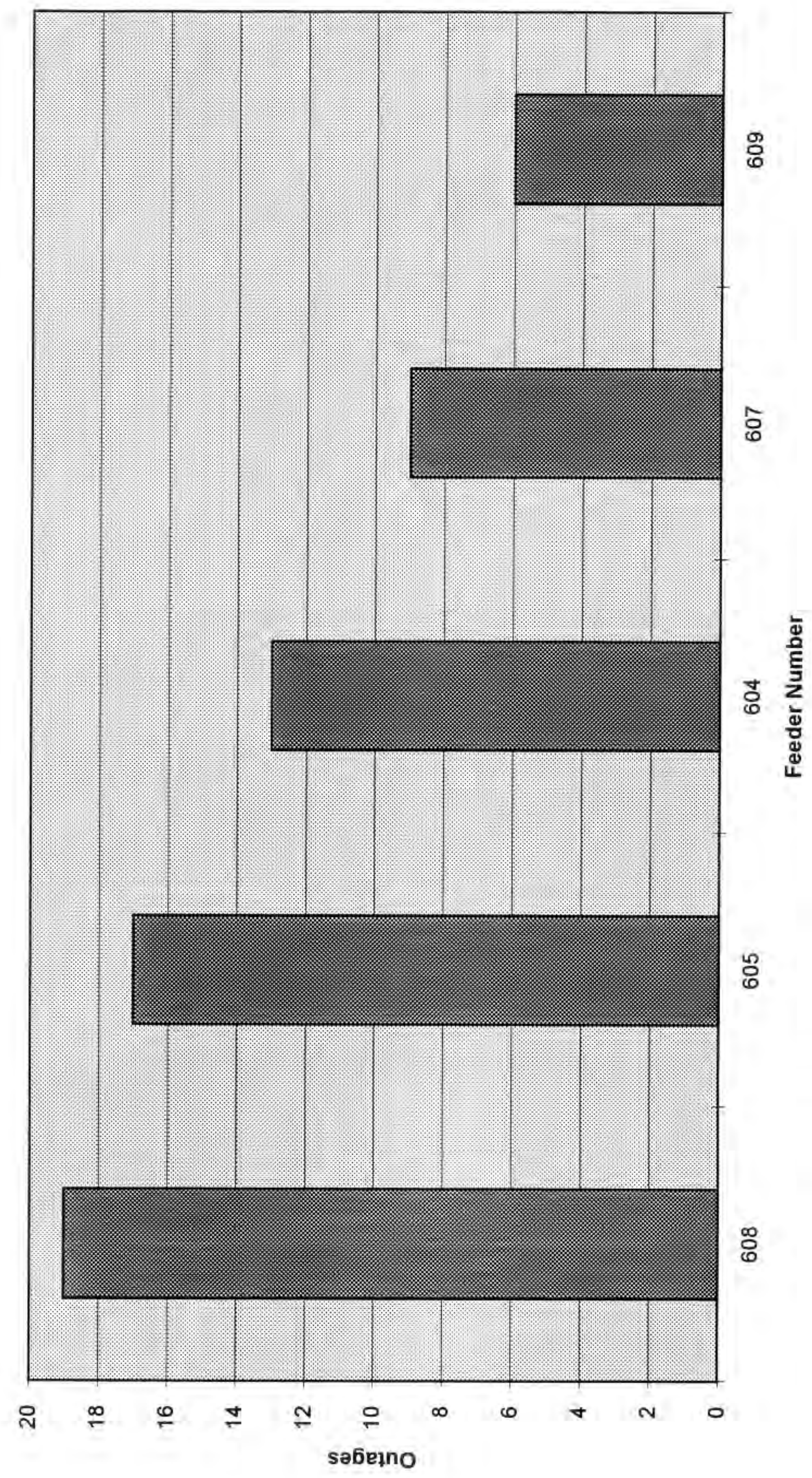


Figure A-6 Outage Distribution at Substation #6

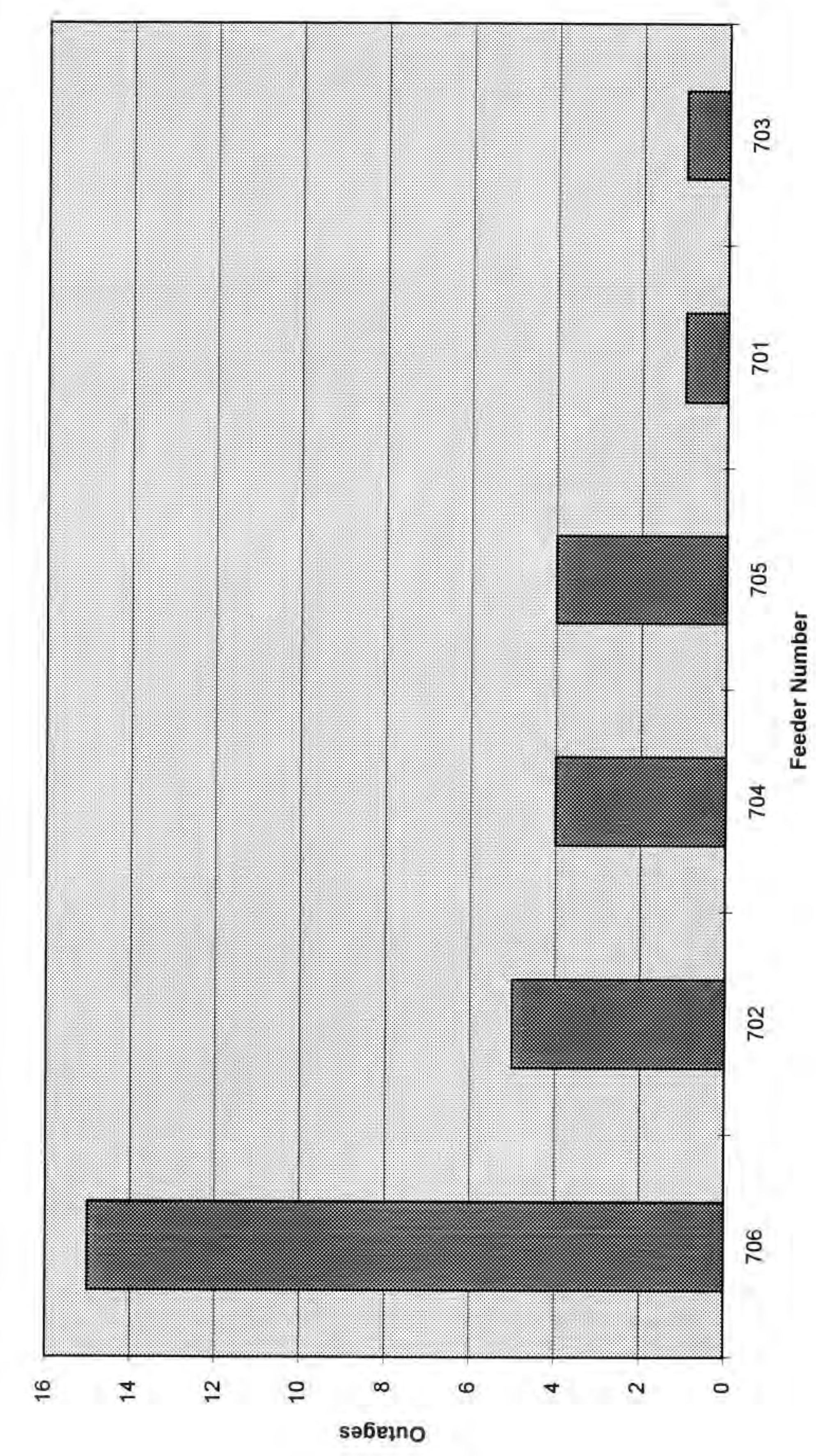


Figure A-7 Outage Distribution at Substation #7

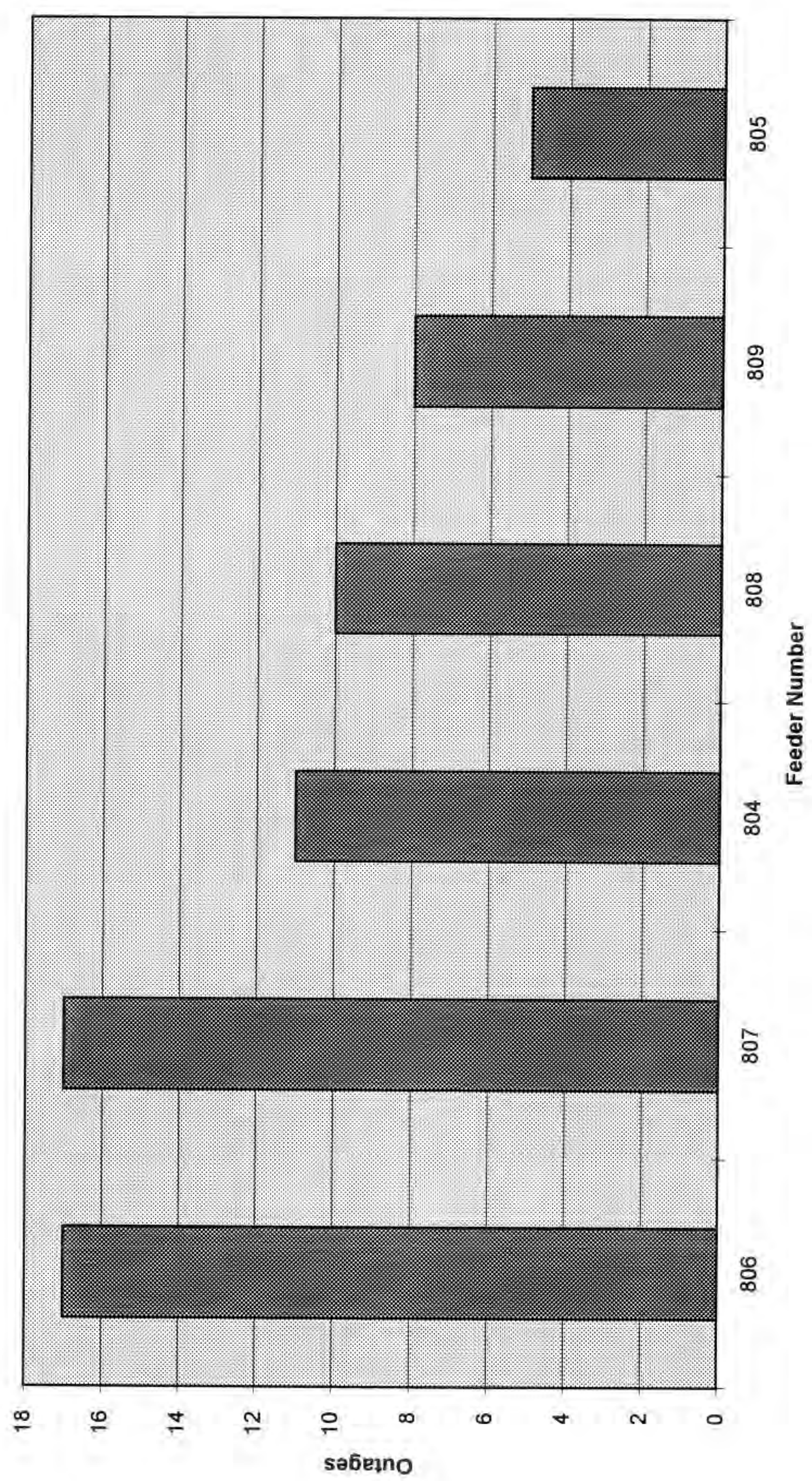


Figure A-8 Outage Distribution at Substation #8

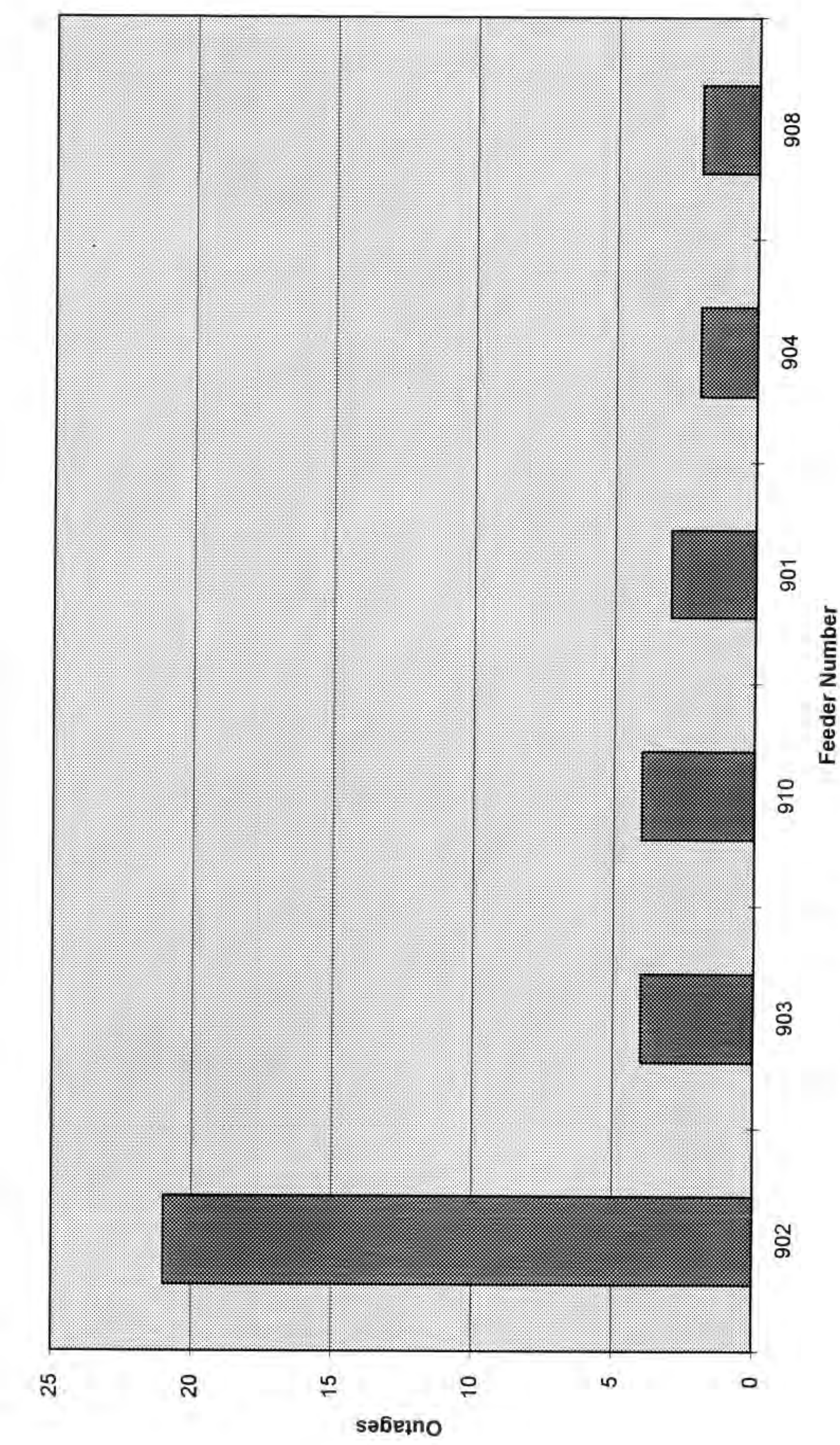


Figure A-9 Outage Distribution at Substation #9

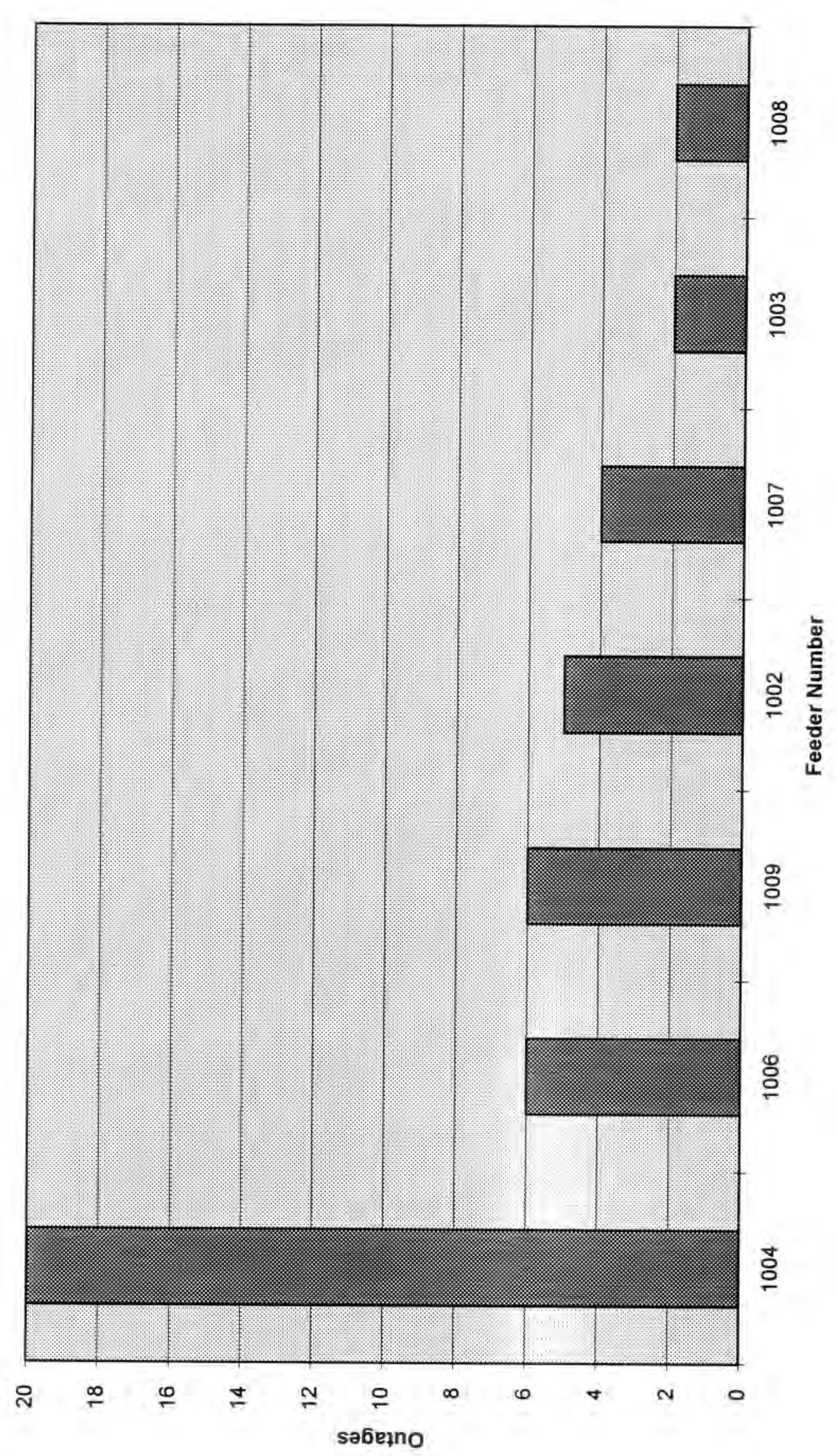


Figure A-10 Outage Distribution at Substation #10

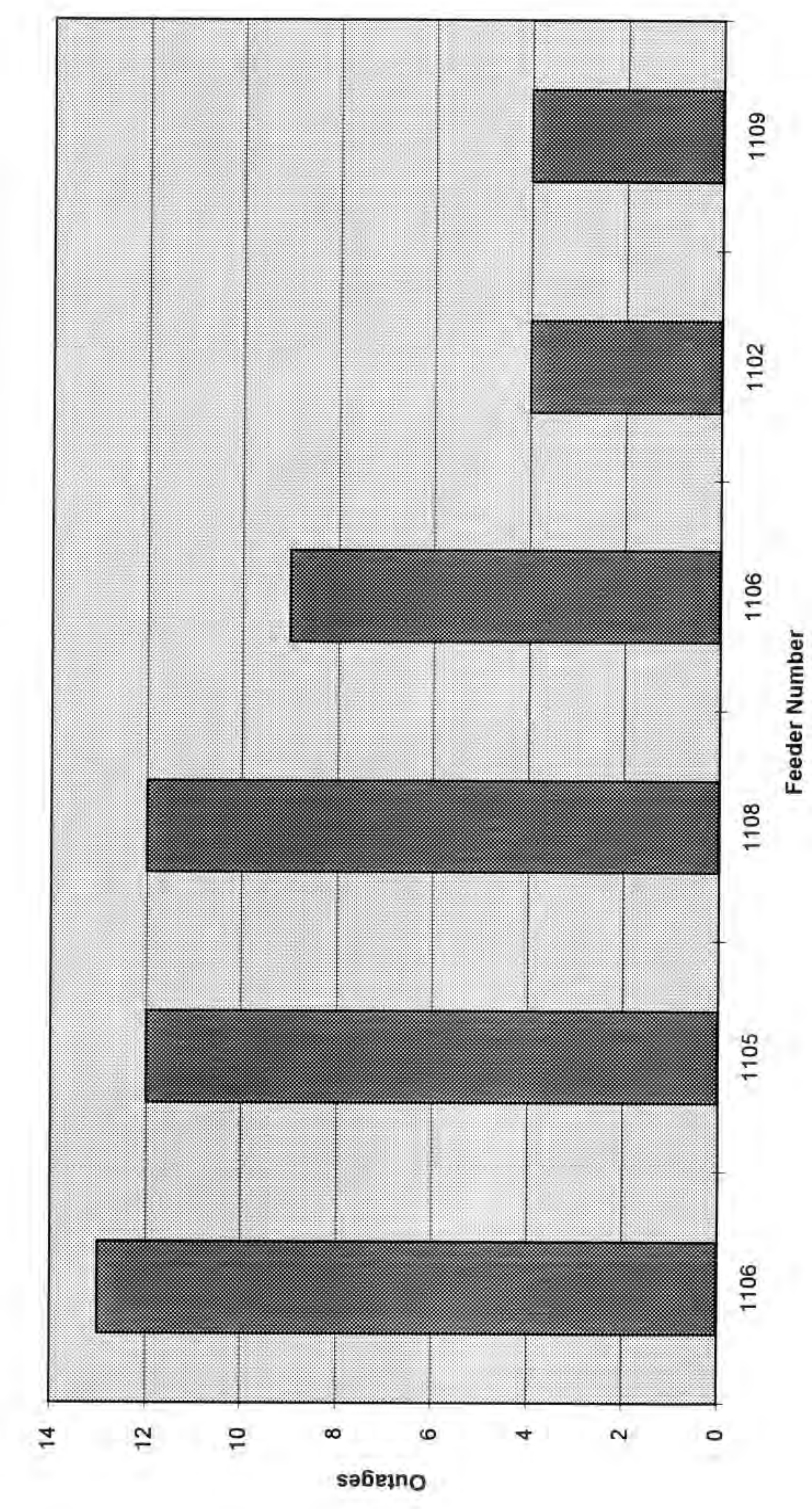


Figure A-11 Outage Distribution at Substation #11

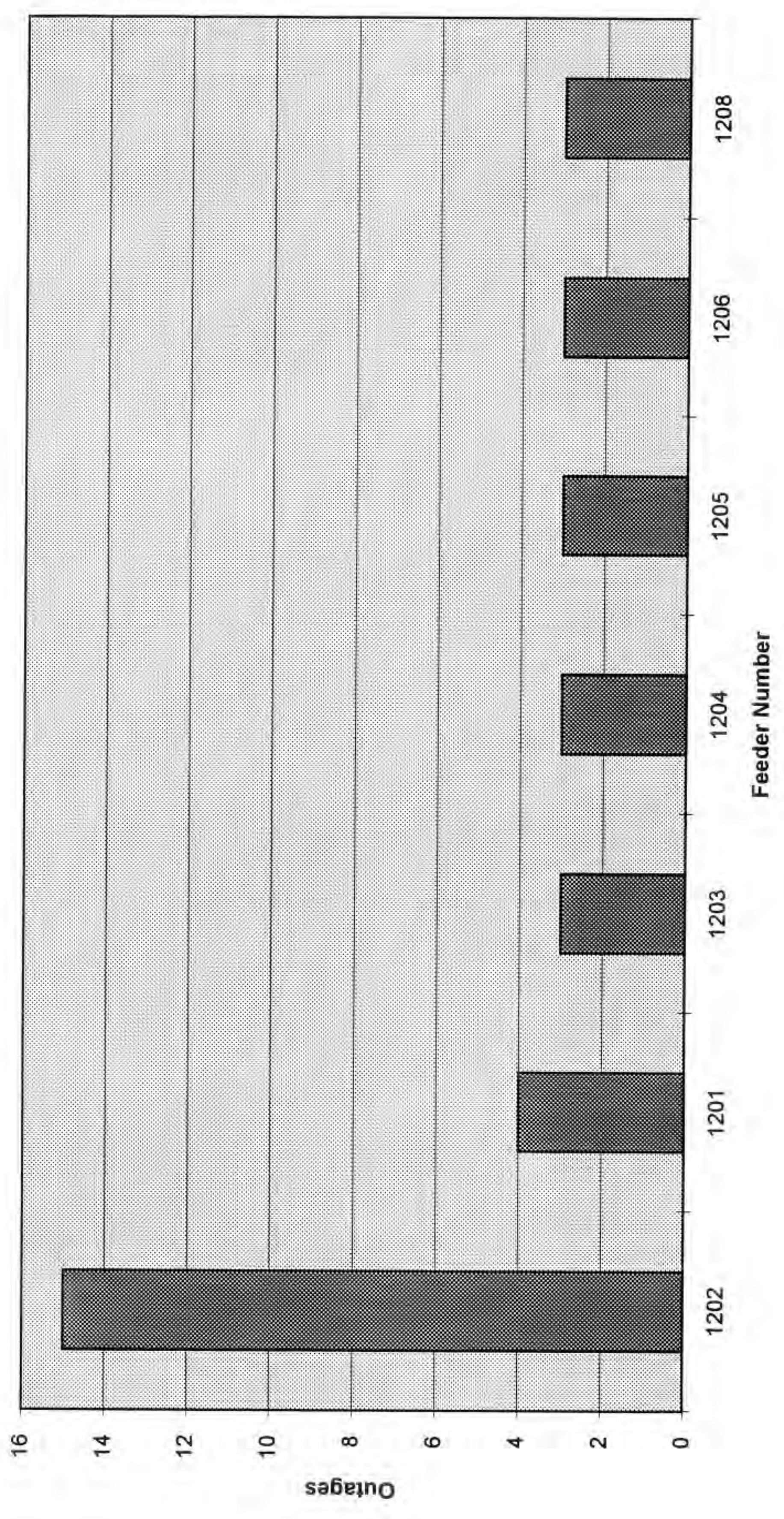


Figure A-12 Outage Distribution at Substation #12

Figure A-13 Outage Distribution at Substation #13

Figure A-14 Outage Distribution at Substation #14

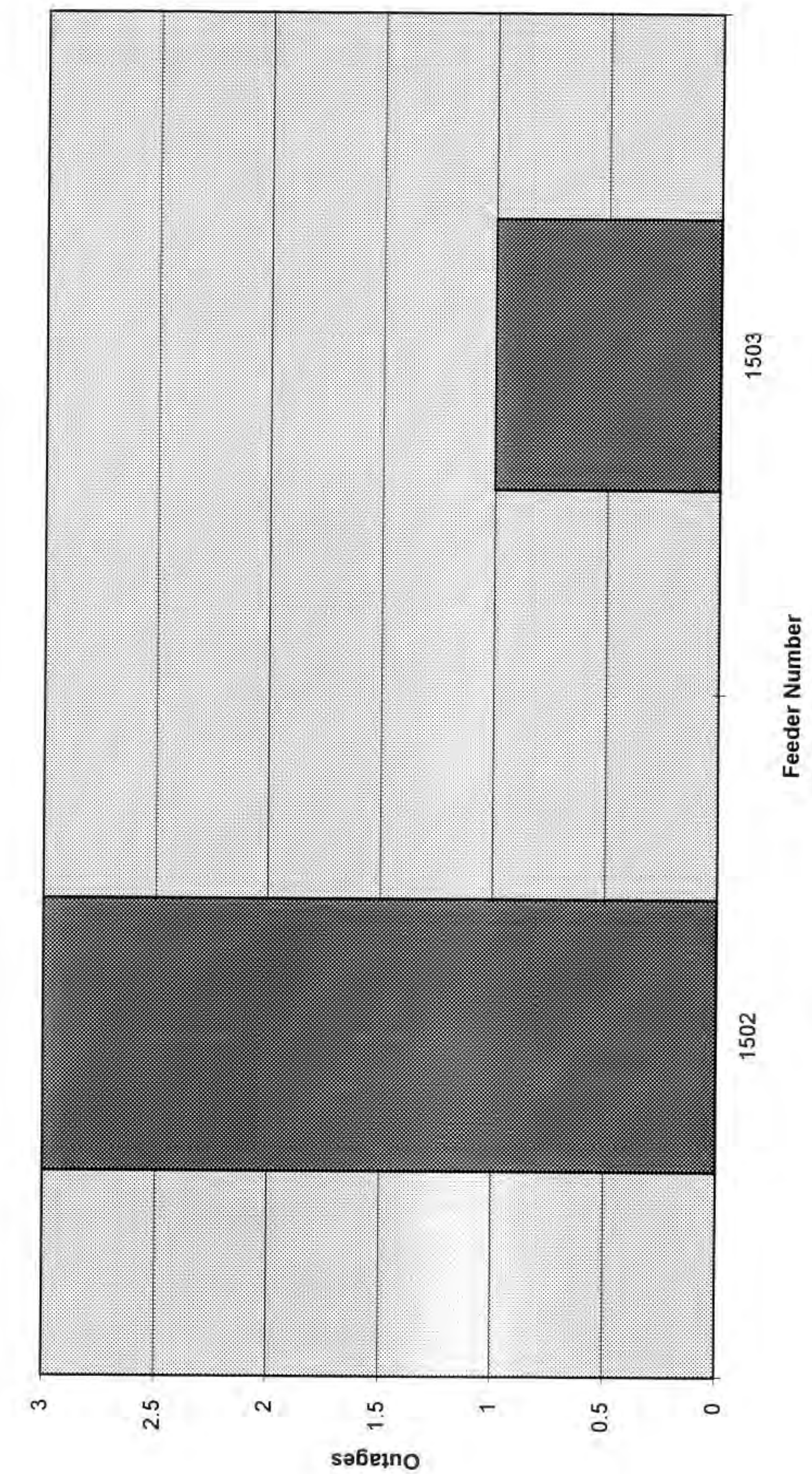


Figure A-15 Outage Distribution at Substation #15

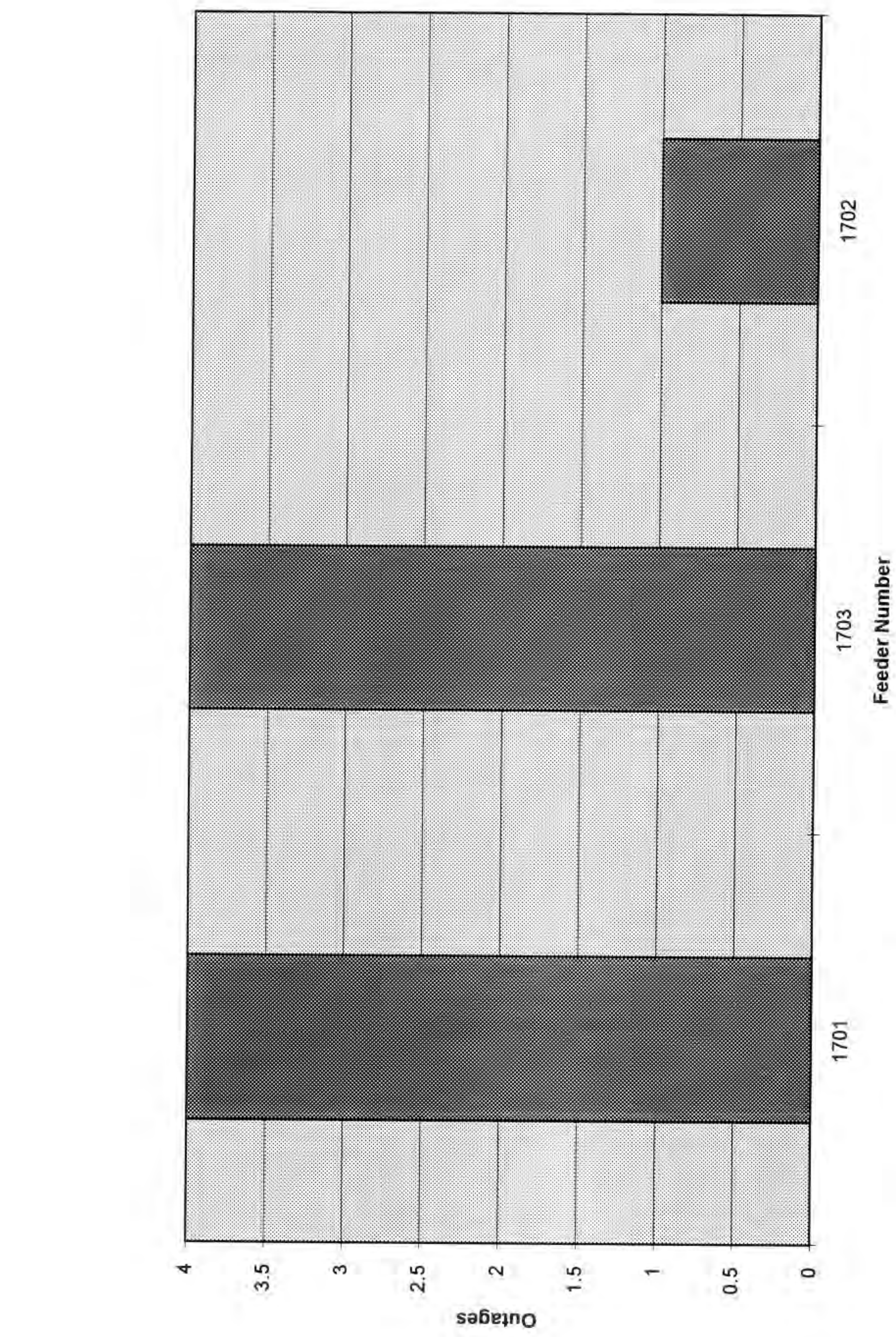


Figure A-16 Outage Distribution at Substation #17

AN ASSESSMENT

OF THE ELECTRICAL DISTRIBUTION SYSTEM

FOR THE CITY OF KINGSTON

Prepared by: R. Sironi, M Senkiw, D. George and B. Payne
of Toronto Hydro

January 23, 1998

REPORT SUMMARY

Following the exceptionally severe ice storm of January of 1998, a team of two engineering and two trade supervisors from Toronto Hydro was asked to make an assessment of the distribution system serving the City of Kingston. During the three-day on site review, the team focused on the following four specific areas:

- **review the short and long term effects resulting from the ice storm;**
- **recommend improvements to improve reliability;**
- **identify possible problems with integrating the electrical systems between the City of Kingston and the Township (an area currently serviced by Ontario Hydro);**
- **comment on the adequacy of the level of technical resources allocated to the electrical business of the new utility.**

The team visited many of Kingston's streets and selected 4 kV substations, consulted several Hydro crews participating in the restoration effort, and held several meetings with Jim Keech, General Manager of Kingston Utilities and Brian Doxtator, Director of Engineering of Belleville Utilities. Based on information gathered and the team's best engineering judgment a number of recommendations were presented to interested parties on January 19, 1998 to help Kingston Utilities' management in setting their objectives and priorities for the post-storm period. **Issues of greatest concern to the New City of Kingston must be decided upon in the final decision making process.**

KINGSTON CITY'S DISTRIBUTION SYSTEM

The Utility Division of the New City of Kingston owns and operates a 44 kV sub-transmission system and a 4 kV distribution system. Four 44 kV feeders emanate from the Frontenac T.S. on Division Street: four other 44 kV feeders originate from Gardiner

T.S. In turn, these feeders supply sixteen 4 kV municipal substations. These are spaced about one kilometer apart throughout the city. A cursory review of station peak loads indicates that there is ample capacity to handle future demand. However, the individual load profiles of substations and feeders were not assessed to identify particular areas that may not have excess capacity. The annual load growth rate has been modest (1% per year over the last ten years) and is projected to be less than 1% per year for the foreseeable future.

The 44 kV sub-transmission system is the backbone of the electric utility's system. The team found that this system was solidly built and well maintained. These lines, mainly located in the public road allowance, have adequate set-back from trees and were sufficiently robust to withstand even the extreme ice load conditions. In spite of the so called "ice storm of the century", the sub-transmission feeders suffered only minimum damage. All but one feeder were restored within one day; the last feeder within three days. The only serious damage was the failure of two poles due to the loss of guy wires. Inspection reports produced by experts from the Canadian Armed Forces (lead by Captain I.M. Tisdale, P. Eng.) indicated that outstanding repairs could be easily handled with minimum maintenance effort.

THE 4 kV DISTRIBUTION

About one hundred 4 kV feeders distribute power to the various streets. The 4 kV distribution system has been serving the City of Kingston relatively well for many years. However, by current standards the 4 kV system is inefficient and has gradually become outmoded. The overhead system has now been further weakened by the ice storm.

The City of Kingston encompasses an area of approximately 30 square kilometers. The downtown core and newer residential areas are supplied underground. Some portions of the system (both overhead and underground) are over fifty years old. In many areas, clearances on the overhead plant are not up to current standards. This increases the risk of "outages" and poses safety concerns for the line personnel. In recent years there have been serious accidents involving line personnel.

It is the understanding of the team that some reconstruction of the 4kV plant has been done, but that this was primarily driven by other City work. In the team's opinion, this level of reconstruction is insufficient and it can only lead to a progressive decrease in the level of reliability of the 4 kV system (i.e. more frequent power outages).

THE EFFECTS OF THE ICE STORM

The combination of a heavily treed environment, limited tree trimming, and the exceptional ice load were too onerous for large portions of the 4 kV system. At the peak of the ice storm up to 80 % of the 4 kV feeders were affected - i.e. 80% of the residences had no power. Linepersons from several utilities across Ontario took one full week to restore the 4 kV feeders to service. Increased reliability could be achieved by upgrading a good portion of the 4 kV plant. **It is the main recommendation of the team that an optimization study be conducted leading to a systematic rehabilitation including a partial replacement or relocation of the 4 kV plant.**

Information gathered through visits and interviews by the team includes the following key points:

- the majority of power outages (up to 80% of the system) were caused by tree branches falling down on power lines due to the exceptional coat of ice;
- the conductor size (#6 and #8 solid copper) used in many areas was insufficient to withstand the ice loads and downed tree branches;
- the integrity of wires was already weakened due to their age (old and brittle);

- many switch failures were reported during post-storm restoration; the failures were mechanically based due to age and conditions (i.e. lack of maintenance);
- the impression of local linepersons is that the appearance of the overhead plant has not changed (i.e. the line sags seem to be the same as before the ice storm);
- prior to the storm, the main focus of Kingston's utility personnel has been to provide service to customers by altering plant to fulfill immediate needs, without upgrading it to current industry standards in the course of their work;
- reconnection of the large number of downed services was made even more difficult by the lack of slack provided during the original service line installations;
- tree trimming and general line maintenance carried out during the past was clearly inadequate to minimize the extent of damage caused by the ice storm;
- the small section of an older type of spacer cable system sustained little or no damage.

Once all customers have been restored, the team suggests that **an aggressive short-term tree-trimming program** be initiated to remove those residual branches that are still damaged or otherwise pose a threat. This will reduce the risk of further outages in the event of further adverse weather conditions. The team also recommends **that infrared testing** be carried out for all of the overhead distribution system. **A visual inspection** may also identify obsolete and substandard components of the plant, such as undersized lines, broken conductor strands, obsolete switches, etc.

To determine the long term effect of the exceptional stress placed on the overhead lines by the ice (up to 3" in diameter), **conductor samples could be sent out for testing** to determine if ultimate tensile strength has been reduced (yield factor exceeded). Conductors would have experienced the greatest stress at their point of attachment. Suggested contacts regarding test facilities will be forwarded as soon as possible. Furthermore, the team will request that the **MEA review our industry's design practices via committee in light of the performance of plant in utilities affected by the ice storm.**

PLANT REHABILITATION AND/OR CONVERSION TO HIGHER DISTRIBUTION VOLTAGE

The rehabilitation should be part of an overall master plan, that includes an optimization study geared to minimizing system losses and reducing the number of feeders. Further reduction in losses and number of feeders could be achieved by converting the 4 kV system to a higher voltage. For instance, a 13.8 kV system has more than three times the load carrying capacity of a corresponding 4 kV system. As experienced by many utilities, conversion from 4 kV to 13.8 kV could reduce line losses by at least 2/3 and station maintenance costs by at least 50%. However, in the case of Kingston, the removal of one level of transformation (say by converting the T.S. to 27.6 kV) may not be feasible, nor economic.

It is therefore important that **the decision to convert or rehabilitate the aging plant be supported by an economic and reliability evaluation**. Some options that are typically employed by other utilities are discussed in this report. Whatever rehabilitation plan is eventually chosen, it is also extremely important that there be a commitment to see it through to conclusion. In any event, all new work should follow current industry standards and focus on an overall master plan (pole type and height, higher BIL insulation, higher cable rating, etc.).

To facilitate integration with future programs, the team recommends that for all work, consistent standards be applied to such things as clearances between different voltage lines, location of transformer on a pole, etc. A review of data collected from **a pole testing program** would help in setting priorities for an effective pole replacement program.

TREE TRIMMING FOR LINE CLEARANCE

Kingston's residents pride themselves on the beauty of their many trees and are sensitive to the utility's need to maintain adequate line clearances by trimming trees. One way to address this important issue is to locate pole lines away from trees wherever possible and control the species and location of subsequent tree planting. Where lines already run through trees, or where trees cannot be avoided, **"tree-proof" cable** has been relatively successful in reducing both the extent of tree trimming and outages. This system will tolerate intermittent brush contact with trees. However, the partial insulation of the conductor does not guarantee protection for people who contact the conductor. As a way to providing a further barrier to falling branches, **a spacer system** could be used. The grounded messenger wire (from which the three "tree-proof" cables are suspended) will help protect the cable from lightning damage and provide a significant level of additional mechanical strength to withstand ice loads, falling limbs and heavy winds.

THE REAR LOT

More than 25 % of the 4 kV overhead distribution plant is located in rear lots. Access to the plant by mechanized equipment is impossible and all work must be done by hand. Work methods and equipment used by modern linepersons no longer suit work activities required to maintain or upgrade rear lot plant. Over a period of time, vegetation growth seriously affects access to the plant and renders it vulnerable to outages. Restoration of power is greatly complicated and prolonged.

Some utilities are making a concerted **effort to recover all rear lot overhead plant,** replacing it with front lot - underground, or overhead, or some other hybrid variation on the theme. Where rear lot primary must exist (hopefully in the short term), limiting it to single-phase and ensuring that all "run offs" are fused will help control outages. A more effective measure would be to move all of the rear lot plant to the road allowance.

40' poles without crossarms are recommended, as are gray insulators, bare ACSR wire (where trees are not a potential problem), gray transformer and lashed secondaries. The use of the triangular line configuration will allow new lines to be strung on shorter poles than those needed for vertical line construction. Where trees are a potential problem "tree-proof" cable could be used.

UNDERGROUND OPTION

Typical costs to replace the existing 4 kV overhead plant with an underground 13.8 kV system in urban settings range from five to eight times those of a corresponding overhead system. The shallow bedrock (reportedly 2' to 6' deep), normally encountered in the Kingston area, is a major obstacle to construction of cable chambers and deep duct banks. **Soil data and trenching costs** should be determined before considering the undergrounding option in any specific area.

Typical **costs of undergrounding** weighted against reliability requirements need to be appreciated before considering such options. Costs to place all wires underground in a major urban arterial road, already congested by many other underground infrastructures, can exceed $4,000,000 per kilometer. For reference purpose, the team notes that former municipalities now part of the new City of Toronto have carried out a number of projects to remove their rear lot plants; each utility has installed different types of plants in the road allowance. Costs per kilometer of street vary depending on property frontage, house set-back and number of customers on a given street.

Orders of magnitude of costs per kilometer to relocate a three-phase circuit from a residential rear lot are as follows:

- $400,000 for overhead construction in the road allowance (former Etobicoke Hydro)
- $1,000,000 for partial underground - primary and transformer underground in the road allowance with easement for secondary cables to feed overhead services from shorter poles from the rear lot (former Toronto Hydro)
- $2,000,000 for total underground in the road allowance (former North York Hydro)

It is typical for municipalities to require that all **new subdivisions** be provided with an underground distribution system.

INTEGRATION OF THE ELECTRICAL SYSTEMS

While it is possible to integrate human resources in the operation of different systems, physical integration of two electrical systems is possible only when both systems have the same voltage. In the case of Kingston, the 44 kV sub-transmission system is common to both areas; 44 kV feeders from different T.S. stations (Ontario Hydro's Terminal Stations) can be used to supply or "back-up" all of the distribution substations, regardless of their distribution voltage.

The City of Kingston uses the 4 kV as their distribution voltage, while the Township uses 8.3 kV. Even though the two voltages are not compatible for mutual back-up purposes, this in itself does not present operational difficulties. In fact, it is not uncommon for a utility to have two or more voltage systems within their jurisdiction. In any case, as a result of the amalgamation there may be opportunities to optimize the electrical supply to certain customers that are close to former boundary lines.

The most important element in integrating two distribution voltages relates to staff (at the technical and trade level). At issue are: renegotiation of contracts, cross training to reach competence in different systems, integration of safety and administrative standards and procurement of necessary tools and equipment, including safety equipment.

TECHNICAL HUMAN RESOURCES

The annual expenditure level for capital projects carried out by the former Kingston PUC in the past few years (ranging from $600,000 to $2,800,000) is clearly inadequate to effect the recommended rehabilitation program. **Technical staffing** (already reduced by the voluntary exit program), **is extremely limited and appears "hard pressed"** to manage even the existing work plan. As in any business, expertise and commitment of utility personnel is key to providing dependable quality service to its customers. The need for continuous monitoring, planning, adjusting, upgrading, and expanding the electrical facilities requires specialized staff with an intimate knowledge of all aspects of the City's electrical system. Regardless of whether or not the recommended programs are implemented, the utility will require technical resource levels that are comparable to that of other similar size utilities.

SUMMARY OF RECOMMENDATIONS

A) IMMEDIATE TERM

1. **Initiate a short-term program to remove those branches that are still damaged.**
2. **Initiate a pole-testing program and prioritize pole replacement.**
3. **Carry out infrared inspection of the overhead plant to identify weak spots.**

B) LONGER TERM

1. **Secure expert inspection to identify obsolete and substandard components of the plant, such as undersized lines, obsolete switches, etc.**
2. **Secure adequate technical resources.**
3. **Carry out optimization study (losses, feeder loading, routing, etc.) and develop a master plan to rehabilitate substandard and obsolete plant, area by area.**
4. **Evaluate options and address safety and reliability issues related to the rear lot plant.**

5. **Standardize methods of construction (clearances between lines, location of transformers on a pole, terminations, etc.) and ensure adherence on all future work.**
6. **Establish a maintenance plan for all system components.**
7. **Revise specifications and purchase higher rated materials (poles, insulators, cables, etc.) to facilitate the phasing in of future programs.**
8. **Where tree trimming is a problem, consider replacing wires with "tree-proof" cable, or a more robust spacer system.**
9. **Determine soil characteristics and estimate costs when considering underground options.**
10. **Establish a policy to place all wires underground in new subdivisions.**

ACKNOWLEDGMENT

The team is very grateful for the warm hospitality and especially for the technical assistance provided by Brian Doxtator during such a difficult time. The team appreciated the opportunity given to provide input and trust that the recommendations made in this short time will assist management in setting their objectives and priorities for the post-storm period.

R. Sironi, P. Eng.

R. Sironi
Supervisor, Engineering/Design and Q.A

M. Senkiw
Supervisor, Design

D. George
Supervisor, Overhead Construction

B. Payne
Inspector, Construction

APPENDIX A

RELEVANT KEY POLICIES OF THE NEW CITY OF KINGSTON

Key Policy Issue #2

It is the policy of the City of Kingston that utility services will **demonstrate the highest standard of reliability**

More specifically, the document states: "To support the attraction of high tech business to the City, the Utility Department will demonstrate **reliability indicators that exceeded the industry standard and will explore options to minimize interruptions**

Key Policy Issue #5

Each of these utilities have current weaknesses that will have to be examined and addressed in the capital projects section of the business planning process. In **addition it will be necessary to address funding issues for these capital projects**. It may be necessary to increase rates, either across the board or in specific areas to strengthen deteriorating infrastructures.

- Continued systematic rebuilding of an aging transmission and distribution infrastructure.
- Completion and expansion of the installation of a SCADA system to allow quicker response to system problem outages.
- Building in redundancies to improve system reliability.
- Addressing the issues of "Safe Limits of Approach" existing on old infrastructure which create difficulties for our work force to work safely on live apparatus.

Key Policy Issue #6

It is the policy of the City of Kingston to **operate our Utility Systems in a matter that ensures the safety of our employees, citizens, and the environment**.

… Be it… electricity, if the proper policies procedures and qualified personnel are not in place at all times to ensure safe operation of these systems disastrous consequences can result.

APPENDIX B

STATISTICAL INFORMATION ABOUT THE CITY OF KINGSTON

• area	30 square kilometers
• number of customers	25,713
• system peak load	165 MW
• 44 kV customers	12

<u>Interrogatory #12</u>

Ref: Ex. 2/4/8, p. 1

Please provide, for each of the years 2005 through 2010, a description of the top five most urgent capital projects in the year that were not included in the capital budget because of the "top-down" approach to capital budgeting. Please advise, for each of those projects, when they were finally completed, and at what cost.

2005

- Transformer Vault 13
  Completed in 2007. Refer to Exhibit 2 Tab 4 Schedule 4 p15.
- Transformer Vault 2
  Completed in 2009. Refer to Exhibit 2 Tab 4 Schedule 2 p30.
- Transformer Vault 28
  Completed in 2009. Refer to Exhibit 2 Tab 4 Schedule 2 p32.
- Transformer Vault 12 and Circuit 103
  To be completed in 2010. Refer to Exhibit 2 Tab 4 Schedule 7 p60.
- Deteriorated Poles throughout distribution system.
  Numerous individual poles identified were completed successive years.

2006

- Same as 2005

2007

- Transformer Vault 10
  To be completed in 2010. Refer to Exhibit 2 Tab 4 Schedule 7 p63.
- Transformer Vault 2
  Completed in 2009. Refer to Exhibit 2 Tab 4 Schedule 2 p30.
- Transformer Vault 28
  Completed in 2009. Refer to Exhibit 2 Tab 4 Schedule 2 p32.
- Transformer Vault 12 and Circuit 103
  To be completed in 2010. Refer to Exhibit 2 Tab 4 Schedule 7 p60.
- Deteriorated Poles throughout distribution system.
  Numerous individual poles identified were completed successive years.

2008

- Same as 2007

2009

- Transformer Vault 10
  To be completed in 2010. Refer to Exhibit 2 Tab 4 Schedule 7 p63.
- Transformer Vault 12 and Circuit 103
  To be completed in 2010. Refer to Exhibit 2 Tab 4 Schedule 7 p60.
- Transformer Vault 7
  To be completed in 2011. Refer to Exhibit 2 Tab 4 Schedule 7 p12.
- Substation No.11 Circuit Breakers
  To be completed in 2011. Refer to Exhibit 2 Tab 4 Schedule 7 p4.
- Deteriorated Poles throughout distribution system.
  Numerous individual poles identified.

2010

- Transformer Vault 7
  To be completed in 2011. Refer to Exhibit 2 Tab 4 Schedule 7 p12.
- Substation No.11 Circuit Breakers
  To be completed in 2011. Refer to Exhibit 2 Tab 4 Schedule 7 p4.
- Substation No.8 Transformer
  To be completed in 2011. Refer to Exhibit 2 Tab 4 Schedule 7 p10.
- Westdale
  To be completed in 2011. Refer to Exhibit 2 Tab 4 Schedule 7 p20.
- Deteriorated Poles throughout distribution system.
  Numerous individual poles identified.

Interrogatory #13

Ref: Ex. 3/1/1, p. 2

Please provide an updated 2010 forecast for GS>50 identifying customer numbers and demand to date, and forecast for the balance of the year. Please provide on an actual and weather-normalized basis.

An updated kWh forecast using the most recent chartered bank forecasts for employment growth was provided in response to Energy Probe #12 (h). From that same forecast update, the corresponding demand and customer counts for the GS>50 class are displayed in the table below.

Updated GS>50 Forecast Using Most Recent Employment Growth		
Year	kW	Customers
2010F	711,803	347
2011F	701,859	347

2010 year to date demand and customers are displayed in the table below.

GS>50 Class Actual Consumption and Customers, Jan-Oct 2010		
Billed kW	Cust (Oct 2010)	Cust (Avg)
644,845	340	348

Interrogatory #14
Ref: Ex. 4/1/1, p. 1

Please provide details on the reductions in personnel and costs for the electricity distribution activities at the time of the municipal amalgamation.

It is difficult to say exactly how many employees the electric operations was reduced by during the amalgamation. There was a voluntary exit package (VEP) offered in 1997 for full-time employees and employees were encouraged to take the package. In total, 47 employees of the former Public Utilities Commission (PUC) took advantage of the VEP. Of these 47, one was 100% allocated to the electric department and another 11 would have worked a portion of their time for the electric department.

At the time of incorporation in 2000, documents show there were 27 full-time and 16 shared employees for a full time equivalent of 35 employees involved in the electric department as compared to 44 at the end of 2009.

Additional operating expenses for that period indicate a decline in personnel leading up to and following the amalgamation in 1998:

Year	Operating Expenses
1995	$5,353,000
1996	$5,185,000
1997	$4,636,000
1998	$5,373,000
1999	$4,208,000
2000	$4,513,000

Note – 1998 was the year of the ice storm and it has been estimated this event incurred operating expenses that year by approximately $1,000,000.

<u>Interrogatory #15</u>
Ref: Ex. 4/2/3

With respect to the Cost Drivers:

a) P. 8. Please provide a calculation showing, on a year by year basis and cumulatively, the amounts in years prior to 2008 coded to the capital program for pole replacements that should have been coded to OM&A for those years. Please calculate the impact on opening rate base of those errors.

The table below provides an estimate of the amount that would have been shifted from capital and that the net effect on the 2011 opening balance for rate base would be to reduce it by $342,992:

Description	2005	2006	2007	Impact on opening rate base
1830 - Poles Towers & Fixtures	(16,383)	(120,220)	(217,281)	
1835 - OH Conductors & Devices	(10,760)	(14,330)	(28,637)	
Total decrease in capital assets	(27,143)	(134,550)	(245,918)	(407,611)
2010 depreciation expense change	1,086	5,382	9,837	
2010 depreciation expense change	1,086	5,382	9,837	
2010 depreciation expense change	1,086	5,382	9,837	
2010 depreciation expense change	1,086	5,382	4,918	
2010 depreciation expense change	1,086	2,691		
2010 depreciation expense change	543			
Total decrease in accumulated depreciation	5,971	24,219	34,429	64,619
			Total	(342,992)

b) P. 12. Please confirm that the Warehouse fee was a cost recovery fee. Please advise what percentage of the $158,000 would otherwise have been capital, and what percentage OM&A. Please advise the amount included in opening rate base that represents amounts charged for this fee in prior years to capital projects.

The Warehouse fee was a cost-recovery based fee. 100% of the $156,000 is the amount that would have been charged (i.e. debited) to capital, with the corresponding credit to the OM&A account 5085. The amount included in the opening balance for rate base is $403,333.

c) ***P. 20. Please advise who pays the audit fees. If the audit fees are paid by the City or Utilities Kingston, and their auditing firm is the same as the Applicant's, please provide the retainer letters and fee quotes for the audits of both the Applicant and the payor, together with all correspondence with respect to changes between the initial quote and the final agreed amounts. Please provide all such correspondence dated after January 1, 2009, regardless of the audit year to which it relates.***

   Utilities Kingston pays the audit fees and then Kingston Hydro reimburses Utilities Kingston. Please find attached a copy of the final billing for Kingston Hydro for its 2008 and 2009 audit. These billings were consistent with the fee quotes received. As described in the response to Board staff interrogatory #17, we were advised orally by the auditor that IFRS would increase audit fees. There was no accompanying correspondence.

Emailed AIP June 2/09

KPMG

Invoice No.	:	43443733
Reference	:	CA047-11768908
Client	:	60114106

May 29, 2009

KPMG LLP
Suite 400
863 Princess Street
Kingston ON K7L 5N4

Telephone : (613) 549-1550
Telefax : (613) 549-6349

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact : Len Anderson
Telephone : 613-541-7327

Kingston Hydro Corporation
Attention: Mr. Randy Murphy
1211 John Counter Blvd.
Kingston, ON K7L 4X7

Elect - 740405 - 001 - 6480000 . 78200

For professional services rendered with respect to the following:

- Audit and preparation of financial statements for Kingston Hydro Corporation for the fiscal year ended December 31, 2008.
- Preparation of Audit Findings Report, Management Letter and Independence Letter.
- Preparation of PIL returns and provisions.
- Attendance at Board Meetings.
- Disbursement costs.

T2
4$200.

Our fee (As per engagement letter dated December 10, 2008)	$ 35,200.00
• Additional procedures relating to retailer transactions and confirmation reconciliations.	700.00
	35,900.00
• Less interim billing (net of GST) of December 23, 2008.	(17,000.00)
	18,900.00
GST	945.00
Balance due (this invoice only)	**$ 19,845.00**

Payment is due upon receipt

Remittance Advice

Cheque Payments to:
KPMG LLP
Accounting Service Centre
Suite 1100 University Centre
393 University Avenue
Toronto ON M5G 2N9
Please return remittance advice with cheque.

Canadian Dollar Wire Payments to:
KPMG LLP
Bank: TD Canada Trust
55 King St West
Toronto ON M5K 1A2
Branch 10252 Account 0938281
Swift Code TDOMCATTTOR
Email EFT payment details to kpmg-ar@kpmg.ca
Please indicate invoice number.

KN Hydro Corporation
May 29, 2009

Invoice No.	:	43443733
Reference	:	CA047-11768908
Client	:	60114106
Amount	:	$19,845.00

KPMG

Invoice No.	:	43709239
Reference	:	CA048-11910122
Client	:	60114106

April 23, 2010

KPMG LLP
115 King Street South 2nd Floor
Waterloo, Ontario
N2J 5A3

Attention: Mr. Randy Murphy
Manager of Finance
Kingston Hydro Corporation
1211 John Counter Blvd PO Box 790
KINGSTON, ON K7L 4X7

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact	:	Matthew Betik
Telephone	:	(519) 747-8245
Fax	:	(519) 747-8268
Email	:	mbetik@kpmg.ca

Final Billing

Professional fees for services rendered in connection with the following:

- Audit of the financial statements of Kingston Hydro Corporation for the year-ended December 31, 2009 including preparation of corporate income tax returns for the same period

	$	36,300.00
Less interim billings		(25,000.00)
		11,300.00
GST		565.00
	$	**11,865.00**

Elect

Payment is due upon receipt

Remittance Advice

Cheque Payments to:
KPMG LLP, T4348
P. O. Box 4348, Station A
Toronto, ON M5W 7A6
Please return remittance advice with cheque.

Canadian Dollar Wire Payments to
KPMG LLP
Bank: TD Canada Trust
55 King St. West
Toronto, ON M5K 1A2
Branch 10252 Account 0938281
Swift Code TDOMCATTTOR
Email EFT payment details to kpmg-ar@kpmg.ca
Please indicate invoice number.

Invoice No.	:	43709239
Reference	:	CA048-11910122
Client	:	60114106
Amount	:	$11,865.00

<u>Interrogatory #16</u>

Ref: Ex. 4/3/1 With respect to the Variance Analysis:

a) ***P. 6. Please provide a detailed explanation of the 260% increase in pole replacement work planned for the Test year. Please explain why that is an OM&A expense.***

   The Applicant submits that the explanation for the increase is set out in Exhibit 4/Tab 3/Schedule 1/p6. The 260% is the increase amount over the year 2006. It is an OM&A expense because some of the work that is performed related to the replacement of the deteriorated poles is considered to be an operational expense in accordance with the OEB Accounting Procedures Handbook.

b) ***P. 6. Please explain how the $160,000 in A/C 5020 relates to the $140,000 amount in A/C 5120, and where those adjustments appear in other accounts, either capital or operating.***

   The $160,000 in A/C 5020 does not directly relate to the $140,000 amount in A/C 5120. The 160,000 increase in account 5020 is attributable to what would have been coded (incorrectly) in the past to capital accounts 1830 and 1835, with amounts estimated at approximately $112,000 and $48,000 respectively from those accounts.

c) ***P. 9. Please confirm that, with the adjustments in the last paragraph, the correct increase in A/C 5615 is $280,561.***

   Yes that is correct.

<u>Interrogatory #17</u>

Ref: Ex. 4/4/1

With respect to Employee Costs:

a) Please provide a table similar to Table 1 showing full FTEs for all employees of the City providing services to the Applicant, and break down those FTEs into the FTEs allocated to the Applicant (through Utilities Kingston), and the FTEs allocated to other activities of the City including other activities of Utilities Kingston.

Service	City of Kingston FTE	Allocated to Kingston Hydro	Allocated to other Utilities Kingston business
Information Systems Services	31.0	1.4	4.6
Client Services	19.0	2.4	7.9
Payroll Services	11.0	0.5	1.7
Financial Services	26.0	1.0	3.3
Legal Services	8.0	0.1	0.3
Communications	9.0	0.3	0.8

b) Please provide a table similar to Table 1 showing full FTEs for all employees of Utilities Kingston providing services to the Applicant, and break down those FTEs between the FTEs allocated to the Applicant and the FTEs allocated to each of the other business areas of Utilities Kingston.

Please find attached a Table similar to table 1 showing full FTEs for all employees of Utilities Kingston.

c) Please provide a table similar to Table 1 showing full FTEs for all employees of the Applicant (if any), and break down those FTEs between the FTEs allocated to the Applicant, and the FTEs allocated to the provision of services to any related entity.

The Applicant has no employees.

d) ***P. 2. Please confirm that the Applicant is proposing to increase FTEs by 57.2% over the five year period ending in the Test Year. Please disaggregate the increase in FTEs into the numbers of:***

Confirmed.

i) ***additional persons hired solely to provide services to the Applicant,***

From 2006-2011 there will have been 10 FTEs hired solely to provide services to the Applicant.

ii) ***additional persons hired to provide services to the Applicant as well as other activities of Utilities Kingston or the City, and***

From 2006-2011 there have been 5.9 FTEEs allocated to the Applicant based on 22 people hired to provide services to the Applicant as well as to provide other services for Utilities Kingston.

iii) ***re-allocations of the time spent by existing persons working for the City or Utilities Kingston.***

From 2006 to 2011, there has been 6.27 FTEE reallocated to the Applicant based on re-allocations of the time spent by existing persons working for Utilities Kingston.

e) ***P. 3. Please confirm that the Applicant is proposing to increase Total Compensation by 73.3% over the five year period ending in the Test Year.***

Confirmed.

	Last Rebasing Year 2006			Historical Year 2009			Bridge Year 2010			Test Year 2011		
	Utilities Kingston	Kingston Hydro	Non-Kingston Hydro	Utilities Kingston	Kingston Hydro	Non-Kingston Hydro	Utilities Kingston	Kingston Hydro	Non-Kingston Hydro	Utilities Kingston	Kingston Hydro	Non-Kingston Hydro
Number of Employees (FTEs including Part-Time)												
Non-Union	31.00	7.07	23.93	41.00	10.04	30.96	43.00	11.30	31.70	49.00	14.45	34.55
Union	162.00	31.67	130.33	177.00	33.75	143.25	181.00	36.87	144.13	188.00	46.46	141.54
Total	193.00	38.74	154.26	218.00	43.79	174.21	224.00	48.17	175.83	237.00	60.91	176.09
Total Salary and Wages												
Non-Union	2,360,206	562,508	1,797,698	3,354,174	807,901	2,546,274	3,611,849	874,964	2,736,884	4,153,402	1,122,838	3,030,564
Union	7,927,726	1,610,585	6,317,141	8,727,663	1,956,217	6,771,445	9,895,958	2,257,169	7,638,789	10,527,694	2,699,814	7,827,880
Total	10,287,931	2,173,093	8,114,838	12,081,837	2,764,118	9,317,719	13,507,807	3,132,133	10,375,674	14,681,096	3,822,652	10,858,444
Current Benefits												
Non-Union	450,794	104,488	346,306	688,968	154,864	534,104	798,591	195,812	602,779	813,241	226,135	587,106
Union	1,644,090	333,249	1,310,841	1,861,550	454,918	1,406,632	2,572,502	571,557	2,000,945	2,476,176	656,559	1,819,617
Total	2,094,884	437,737	1,657,147	2,550,518	609,782	1,940,736	3,371,092	767,368	2,603,724	3,289,418	882,694	2,406,724
Accrued Pension and Post-Retirement Benefits												
Non-Union	506,144	163,935	342,209	674,610	230,730	443,880	703,817	254,710	449,107	818,010	324,136	493,874
Union	2,645,011	734,345	1,910,666	2,912,342	775,612	2,136,730	2,962,580	831,077	2,131,503	3,138,486	1,051,750	2,086,736
Total	3,151,155	898,280	2,252,875	3,586,952	1,006,342	2,580,610	3,666,397	1,085,787	2,580,610	3,956,496	1,375,886	2,580,610
Total Benefits (Current and Accrued)												
Non-Union	956,938	268,423	688,515	1,363,578	385,594	977,985	1,502,408	450,522	1,051,886	1,631,251	550,271	1,080,980
Union	4,289,101	1,067,594	3,221,507	4,773,892	1,230,530	3,543,362	5,535,081	1,402,633	4,132,448	5,614,663	1,708,309	3,906,353
Total	5,246,039	1,336,017	3,910,022	6,137,470	1,616,124	4,521,346	7,037,489	1,853,155	5,184,334	7,245,914	2,258,580	4,987,334
Total Compensation (Salary, Wages and Benefits)												
Non-Union	3,317,144	830,931	2,486,213	4,717,753	1,193,494	3,524,258	5,114,256	1,325,486	3,788,770	5,784,653	1,673,109	4,111,544
Union	12,216,827	2,678,179	9,538,648	13,501,554	3,186,747	10,314,807	15,431,039	3,659,802	11,771,237	16,142,356	4,408,123	11,734,233
Total	15,533,970	3,509,110	12,024,860	18,219,307	4,380,242	13,839,065	20,545,296	4,985,288	15,560,008	21,927,010	6,081,232	15,845,777
Compensation - Average Yearly Base Wages												
Non-Union	76,136	79,532	75,123	81,809	80,470	82,243	83,996	77,410	86,345	84,763	77,702	87,717
Union	48,937	50,861	48,470	49,309	57,954	47,272	54,674	61,218	53,000	55,998	58,109	55,306
Total	53,305	56,094	52,605	55,421	63,116	53,487	60,303	65,017	59,011	61,946	62,757	61,665
Compensation - Average Yearly Overtime												
Non-Union												
Union	3,395	1,569	1,826	3,986	3,510	476	3,047	2,411	637	3,139	2,051	1,088
Total	3,395	1,569	1,826	3,986	3,510	476	3,047	2,411	637	3,139	2,051	1,088
Compensation - Average Yearly Benefits												
Non-Union	30,869	37,952	28,772	33,258	38,407	31,588	34,940	39,859	33,186	33,291	38,080	31,288
Union	26,476	33,714	24,718	26,971	36,455	24,736	30,581	38,042	28,672	29,865	36,768	27,599
Total	27,182	34,487	25,347	28,154	38,903	25,954	31,417	38,468	29,486	30,573	37,079	28,323
Total Compensation	15,533,970	3,509,109	12,024,861	18,219,307	4,380,242	13,839,065	20,545,296	4,985,288	15,560,008	21,927,010	6,081,232	15,845,777
Total Compensation Charged to OM&A	13,914,208	2,946,843	10,967,365	16,488,039	3,822,678	12,665,361	18,039,765	3,964,712	14,075,053	19,668,685	4,938,635	14,730,050
Total Compensation Capitalized	1,619,762	562,266	1,057,496	1,731,268	557,563	1,173,705	2,505,531	1,020,577	1,484,954	2,258,324	1,142,598	1,115,726

<u>Interrogatory #18</u>

Ref: Ex. 4/5/1, p. 18

With respect to the Fleet Services:

a) Please provide the full calculations supporting the amount and unit prices for the usage fees for each of the Historical, Bridge and Test Years.

Vehicle #	Description	2009 Rate	2010 Rate	2011 Rate
009	UT - 2001 Ford Mini Van	10.5	10.5	5.25
016	UT - 1991 Ford 5 TON	27.3	27.3	13.65
017	UT - 1991 Ford 1 TON	18.9	18.9	9.45
027	UT - 1992 Ford 5 TON	27.3	27.3	13.65
038	UT - 1995 Ford 5 TON	27.3	27.3	13.65
042	CC - GMC Van	18.9	18.9	9.45
043	CC - GMC Van	18.9	18.9	9.45
044	UT - 2008 Ford F450	27.3	27.3	13.65
055	UT-2003 Ford F250 Truck	10.5	10.5	5.25
056	UT-2003 Ford F250 Truck	10.5	10.5	5.25
057	UT - 1998 Freightliner 8 TON	27.3	27.3	13.65
058	UT-2004 FL Bucket Truck	27.3	27.3	13.65
069	UT - 1997 Freightliner 8 TON	27.3	27.3	13.65
075	UT - 2005 GMC Cargo Van	10.5	10.5	5.25
083	UT - 2001 Ford MINI VAN	10.5	10.5	5.25
093	UT - 2004 E350 Cube Van	10.5	10.5	5.25
094	UT - 1997 Freightliner 5 TON	27.3	27.3	13.65
106	UT-2005 Freightliner	16.8	16.8	8.4

The vehicle rates were originally based on the Ministry of Transportation Chargeback Ontario Standard specifications for each type of equipment. The rates are adjusted each year to reflect the change in costs for materials due to inflation, fuel costs or other factors.

b) Please provide the agreement between the City and Utilities Kingston with respect to Fleet Services. Please provide the amendment to the agreement, or other documentation, setting out the change in the usage fees and the responsibility for capital replacements. Please provide all presentations made to the Board of Directors of the Applicant or Utilities Kingston, or City Council or any of its committees, dealing with this change.

The agreement for fleet services is included in the agreement provided at Exhibit 1 Tab 2 Schedule 3 Attachment 4. There has been no written change to this agreement. Utilities Kingston and the City of Kingston met on May 25, 2010 to discuss fleet services for Kingston

Hydro and agreed on the change noted in the application effective January 1, 2011. There is no other documentation regarding the decision to change the relationship to provide maintenance services only. As noted in the application, the rate charged prior to 2011 included the cost of capital replacements to which the City will utilize for the benefit of Kingston Hydro.

c) ***Please provide the full calculation of the $2.4 million credit. Please explain why, with the change as of January 1, 2010, the City did not simply refund the $2.4 overpayment to the Applicant. Please confirm that the current intention is that the vehicles purchased with the $2.4 million overpayment will be owned by the City, and provided to Utilities Kingston at the new usage fees, i.e. excluding capital costs.***

The change is planned to be effective January 1, 2011. The amount in the utility equipment reserve fund as at December 31, 2009 was $6.7 million. Based on an analysis of hours used by all utility vehicles, it was determined that Kingston Hydro vehicle usage was 36% of the total usage. Therefore it was determined that 36% of the amount in the utility equipment reserve fund, or $2.4 million should be earmarked for the benefit of Kingston Hydro.

The Applicant confirms that the current intention is that the vehicles purchased with the $2.4 million overpayment will be owned by the City, and provided to Utilities Kingston at the new usage fees, i.e. excluding capital costs.

Interrogatory #19

Ref: Ex. 5/1/1, Attach. 3

Please provide a copy of the promissory note evidencing the indebtedness to the City, together with any loan agreement, security document, negative covenants, or other supporting documents.

A copy of the Certificate of Passing of Resolution evidencing the indebtedness to the City has been provided at Exhibit 5 Tab 1 Schedule Attachment 3.

<u>Interrogatory #20</u>

Ref: Ex. 8/2/1, Attach 1

Please confirm that, if the fixed charge for GS>50 is set at half the current rate (i.e. $117.05 per month), the variable charge based on the revenue requirement requested would be $3.5119/kW.

Confirmed.

Interrogatory #21

Please provide all presentations, reports and other materials provided to the Board of Directors with respect to approval of the 2011 budgets for OM&A and capital, including any supporting documents. Please provide any update materials where any budgets have been changed since their first approval.

Please find attached a presentation given to the Kingston Hydro Board of Directors on July 12, 2010. After the presentation and discussion, the Kingston Hydro Board of Directors then considered and approved the recommendation included in the attached Report # KH10-10. There have been no updates provided to the Board of Directors with respect to budgets since July 12, 2010.

Kingston Hydro

2011 Electricity Rate Application

12 July 2010

Kingston Hydro

Role of the Ontario Energy Board

- 1. (1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
- **1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.**
- 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
- 3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
- 4. To facilitate the implementation of a smart grid in Ontario.
- 5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1

Kingston Hydro

Role of the Ontario Energy Board

- The process
  - Preparation of application
  - Public notice in local paper
  - Declaration of intervenors
  - Interrogatories – Board staff, intervenors
  - Settlement conference
  - Written or oral hearing
  - Decision of the Board and rate order issued

Kingston Hydro

Rate Making Process

- May 1, 2006 – Cost of Service (based on Dec. 31, 2004 audited)
- May 1, 2007, 2008, 2009, 2010 – Incentive Rate Mechanism IRM (based on GDP IPI minus 1% ~ plus or minus other adjustments……)

Kingston Hydro

2006 Cost of Service

- Last Cost of Service Adjustment
- Based on December 31, 2004 audited financial statements
- 1.5 year lag
- Based on 50/50 Debt/Equity Ratio

Kingston Hydro

2006 Cost of Service

- Rates set based on predetermined allowable return on debt and equity
- Debt – 6.57%
- Equity – 9.00%
- Allowable return – 7.79% (50/50)
- 7.79% on "Rate Base"

Kingston Hydro

2006 Rate Base

- Gross Historical Cost of Capital Assets minus Accumulated Depreciation (Average of beginning of 2004 and ending of 2004)
- Add 15% of annual operating expenses

Kingston Hydro

2006 Rate Base

- Capital Assets - $19.5 million
- Plus 15% of Working Capital - $8.3 million
- $27.8 million
- Deemed return - $2,164,000

Kingston Hydro

2006 Revenue

- Required Net Income - $2,200,000
- Total OPEX - $7,200,000
- Revenue Requirement - $9,400,000
- But …$2,164,000 is taxable; so add $917,000
- Total Revenue Requirement $10.3 million

Kingston Hydro

2006 Distribution Revenue

- Total Revenue Required - $10.3 million
- Specific Service Charges - $500,000
- Rate Revenue Required - $9.8 million

Kingston Hydro

Revenue Allocation

- Revenue allocated based "Cost Allocation" estimating the percentage that each class of customers should contribute to the rate revenue requirement.

Kingston Hydro

Allocation of $9.8 million

- Residential - $5.2 million (22,553)
- GS<50 - $1.8 million (3,351)
- GS>50 - $2.3 million (411)
- Large Users - $0.3 million (3)
- Unmetered - $50,000 (159)
- Street Lights - $100,000 (5,019)

Kingston Hydro

Fixed vs. Variable

- Revenue requirement for each class is split into fixed vs. variable
- On average 48% variable and 52% fixed charges

Kingston Hydro

Fixed vs. variable

- Fixed monthly charge is then calculated as fixed dollars required divided by number of customers divided by 12
- Variable charge is calculated as variable dollars required divided by total kWh per year

Kingston Hydro

IRMs – adjusting COS Rates

- 2007 – 1.9% minus 1% = 0.9%
- 2008 – 2.1% minus 1% = 1.1%
  - – debt/equity and PILs adjustment
- 2009 – 2.3% minus 1% = 1.3%
  - – debt/equity and PILs adjustment

Kingston Hydro

IRMs – adjusting COS rates

- 2010 – 1.3% minus 1% = 0.3%
  - – debt/equity and PILs adjustment
- 2008-2010 – rates decreased 1.2% for the debt/equity change from 50/50 to 60/40

Kingston Hydro

2006 – 2010 Residential

- From 2007 to 2010 residential rates contributing to net revenue increased a total of 2.4% or 0.6% per year
- At the same time PILs adjustments decreased distribution revenue but also decreased PILs payable – net income effect of Nil.

Kingston Hydro

Where are we now?

Comparison of Kingston Hydro Rates to our Cohorts
Residential Customer using 800kWh per month
Prices include Smart Meter charge of $1 plus transmission rates paid to Hydro One of $6
Companies in bold are scheduled to re-base in 2011

Kingston Hydro

Festival Hydro Inc.	$ 36.73
Bluewater Power Distribution Corporation	$ 36.64
Erie Thames Powerlines Corporation	$ 36.10
Woodstock Hydro Services Inc.	$ 35.85
Essex Powerlines Corporation	$ 35.75
Westario Power Inc.	$ 34.02
Niagara Falls Hydro Inc.	$ 33.95
Chatham-Kent Hydro Inc.	$ 32.85
St. Thomas Energy Inc.	$ 32.42
COLLUS Power Corp.	$ 30.97
Peterborough Distribution Incorporated	$ 30.78
E.L.K. Energy Inc.	$ 30.22
Wasaga Distribution Inc.	$ 29.59
Kingston Hydro Corporation	$ 27.13
Average (excluding Kingston)	$ 33.77
Median (excluding Kingston)	$ 33.98
Percent increase to obtain Average	24%
Percent increase to obtain Median	25%
Effect on overall bill	6-8%

Kingston Hydro

2011 Rate application

- Rate Base is increasing from $27.8 million to $42.3 million – HOW?
- Net capital assets increased from $19.5 million to $32.8 million (2004-2011)
- Working Capital Allowance increased from $8.3 million to $9.5 million

Kingston Hydro

2011 Debt/Equity Returns

- Deemed Return is now based on 60/40 debt equity split
- Allowable return on debt is 5.41% based on KHC's actual debt rates
- Allowable return on equity is 9.85% deemed per OEB
- Deemed return of 7.19%

Kingston Hydro

2011 Rate Application

- Deemed Return of $3,028,000
- Total OPEX - $9,100,000
- Revenue Requirement - $12,100,000
- But $3,028,000 is taxable; so add $647,000
- Total Revenue Requirement $12.7 million

Kingston Hydro

2011 Rate Application

- Total Revenue Required - $12.7 million
- Specific Service charges - $624,000
- Rate Revenue Required - $12.1 million

Kingston Hydro

Allocation of $12.1 million

Customer Class Name	Cost Allocation	Existing Rates	Rate Application
Residential	7,505,837	6,665,093	6,664,066
General Service Less Than 50 kW	1,761,833	2,297,505	2,116,429
General Service 50 to 4,999 kW	2,388,494	2,554,951	2,819,691
Large Use	289,323	412,564	332,792
Unmetered Scattered Load	65,665	58,317	60,401
Street Lighting	101,127	123,849	118,900
TOTAL	12,112,279	12,112,279	12,112,279

Kingston Hydro

Distribution Rate Impacts

kWh's		2010 BILL			2011 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge		1	$10.12	$10.12	1	$13.40	$13.40	$3.28	32.4%
Distribution	kWh	800	$0.0124	$9.92	800	$0.0149	$11.92	$2.00	20.2%
Smart Meter Adder		1	$1.0000	$1.00	1	$1.0000	$1.00		
GA Rider 2010	kWh		$0.0015			$0.0015			
GA Rider 2011	kWh								
Def/Var Acct Rider 2010	kWh	800	($0.0031)	($2.48)	800	($0.0031)	($2.48)		
Def/Var Acct Rider 2011	kWh	800			800				
Distribution sub-total				**$18.56**			**$23.84**	**$5.28**	**28.4%**

Kingston Hydro

Total Bill Impact - Residential

Distribution sub-total				**$18.56**			**$23.84**	**$5.28**	**28.4%**
Electricity (Commodity)	kWh	830	RPP	$56.25	828	RPP	$56.07	($0.18)	(0.3%)
Transmission - Network	kWh	830	$0.0055	$4.61	828	$0.0054	$4.47	($0.14)	(3.0%)
Transmission - Connection	kWh	830	$0.0046	$3.84	828	$0.0047	$3.89	$0.05	1.3%
Wholesale Market Service	kWh	830	$0.0052	$4.32	828	$0.0052	$4.30	($0.02)	(0.5%)
Rural Rate Protection	kWh	830	$0.0013	$1.08	828	$0.0013	$1.08		
Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
Low Voltage Charges	kWh	800	$0.0002	$0.16	800	$0.0007	$0.56	$0.40	>100%
TOTAL BILL				**$94.42**			**$99.81**	**$5.39**	**5.7%**
Delivery Only				*$27.17*			*$32.76*	*$5.59*	*20.6%*

Kingston Hydro

Capital Program

Kingston Hydro

2010 Capital

Project	Area	$ Cap
Princess St. Reconstruction	Holiday Inn to King St.	$ 1,155,000
Princess St. Condition Assessment	King to Bagot	$ 25,000
Annual Pole Repairs/Rebuilds	Various	$ 1,015,000
Vaults	Various	$ 545,000
Annual Underground Cable Fault Repairs/Rebuilds	Various	$ 100,000
Barrie St. Underground Infrastructure	William to Princess	$ 176,000
Annual Services	Various	$ 60,000
Annual Substation Battery Replacement	Two Substations	$ 60,000
Hydro One Gardiner TS Expansion - Cost Overruns	Gardiner TS	$ 609,000
Maximo	Various	$ 125,000
CYME - 5kV Model	Various	$ 80,000
SCADA		$ 98,000
Meters		$ 263,000
Property & Equipment (Security, Analyzer, etc.)		$ 90,000
Annual RFP for Structural Engineering Services	Various	$ 20,000
Contingency		$ 25,000
	TOTAL	**$ 4,446,000**

Kingston Hydro

Poles: $1,015,000

Kingston Hydro

Poles

Kingston Hydro

Vaults: $545,000

Kingston Hydro

Barrie St: $176,000

Kingston Hydro

2011 Capital

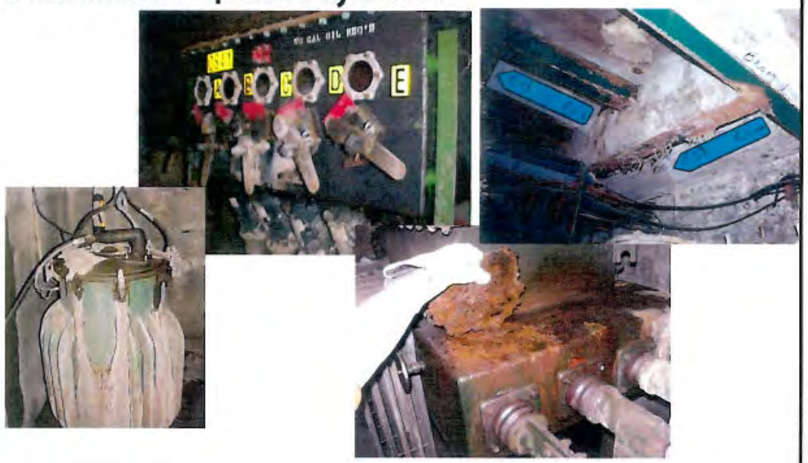
Project	Area	$ Cap
Annual Pole Repairs/Rebuilds	Various	$ 1,175,000
Substations	Notch Hill Rd	$ 1,176,000
Vaults		$ 392,000
Alfred Street	Earl to Princess	$ 549,000
Westdale	Westdale @ Princess	$ 171,000
Replace Poletrans	Fairway Hills	$ 110,000
Queen's Cogen - Gardiner TS Protection Upgrades		$ 40,000
Annual Underground Cable Fault Repairs/Rebuilds	Various	$ 200,000
Annual services	Various	$ 60,000
Annual Substation Battery Replacement	Two Substations	$ 60,000
Maximo	Various	$ 125,000
SCADA and 44kV Motorized Switch		$ 182,000
Meters		$ 100,000
Property & Equipment (Security, Analyzer, etc.)		$ 133,000
Annual RFP for Structural Engineering Services	Various	$ 20,000
Contingency		$ 20,000
	TOTAL	$ 4,513,000

Kingston Hydro

Substations: $1,176,000

Kingston Hydro

Vaults: $392,000



Kingston Hydro

Alfred St: $549,000

Kingston Hydro

Westdale Ave.: $171,000

Kingston Hydro

Replace Poletrans: $110,00

Kingston Hydro

Operating

Kingston Hydro

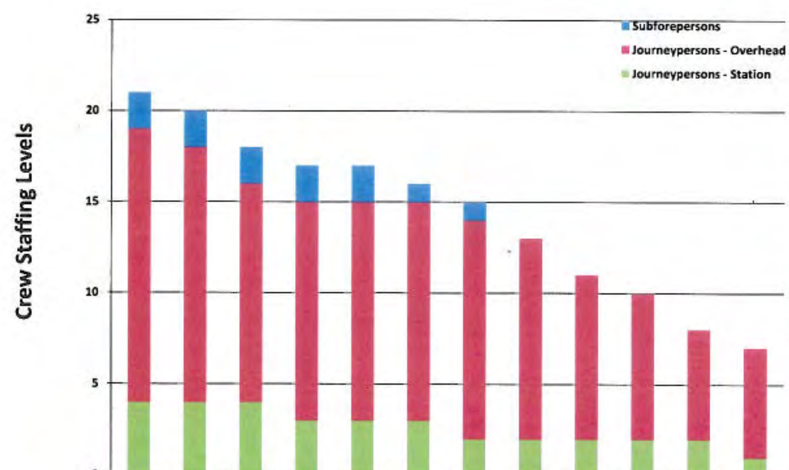
Operating

- Substation Maintenance Program
  - 2 FTE (theoretical)
  - 2x-4x longer
- Overhead/Underground Maintenance Program
  - Complete Development 2nd Qtr 2011
  - Implement 3rd Qtr 2011

Kingston Hydro

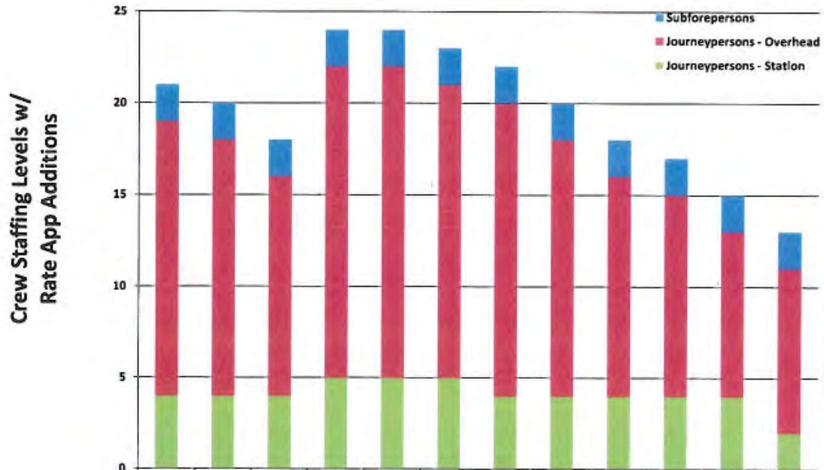
Staffing

Kingston Hydro



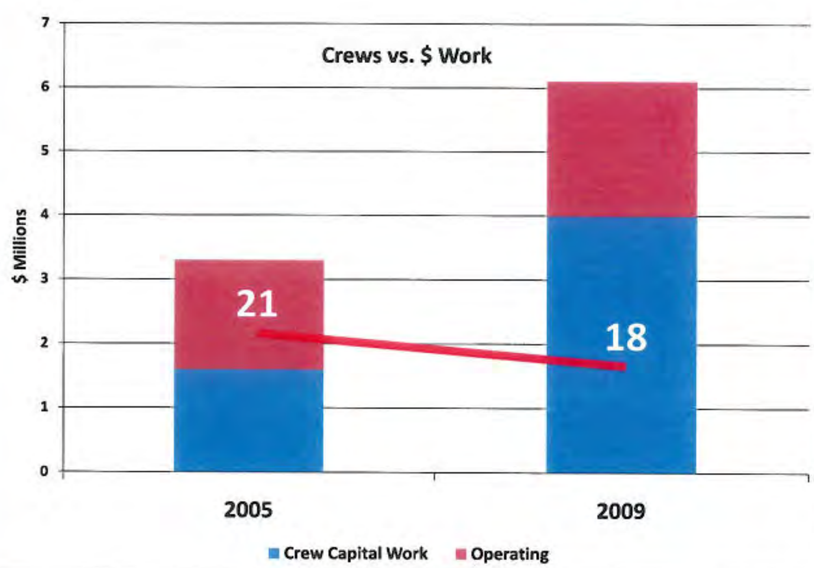
	2005	2007	2009	2011	2012	2013	2014	2015	2016	2017	2018	2019
Subforepersons	2	2	2	2	2	1	1	0	0	0	0	0
Journeypersons - Overhead	15	14	12	12	12	12	12	11	9	8	6	6
Journeypersons - Station	4	4	4	3	3	3	2	2	2	2	2	1

Kingston Hydro



	2005	2007	2009	2011	2012	2013	2014	2015	2016	2017	2018	2019
Subforepersons	2	2	2	2	2	2	2	2	2	2	2	2
Journeypersons - Overhead	15	14	12	17	17	16	16	14	12	11	9	9
Journeypersons - Station	4	4	4	5	5	5	4	4	4	4	4	2

Kingston Hydro



REPORT TO BOARD OF DIRECTORS
KINGSTON HYDRO CORPORATION

Kingston Hydro

MEETING NO. 2010-02 **Report KH10-10**

Subject:	Approval of the 2010 – 2014 Financial Plan
Date of Meeting:	July 12, 2010
From:	J. A. Keech, President & C.E.O, Kingston Hydro Corporation
Prepared By:	R. Murphy, Treasurer, Kingston Hydro Corporation

Recommendation

It is recommended that the Board approve expenditures of $55,000,000 to purchase electricity, $7,200,000 for Operating Expenditures, and $4,500,000 for Net Capital Expenditures for 2011

~And Further~

The Board approves in principal the 2010 to 2014 Financial Plan which will entail applying for maximum distribution rate increases and incurring total debt up to $31,000,000.

Purpose

Following is an analysis of the Financial Plan for the Company.

Financial Plan 2010 through 2014

Kingston Hydro's Financial Plan Summary for 2010 through 2014 is included in this report as Appendix A. The 2009 dollar figures are audited numbers while 2010-2014 are forecasted numbers.

The plan outlines an increased capital expenditure requirement that has resulted from the asset management analysis that was performed over the past 12 months. The analysis has resulted in significant capital replacement work that needs to be done over the next 6-8 years. In order to achieve this, the Company will be required to obtain additional financing. Consequently, distribution rates must increase in order for the Company to have the capability to service the debt that is required. Therefore we will be applying for a distribution rate increase effective May 1, 2011 which will result in an increase in a typical residential customer's monthly total bill of up to 10%.

This increase is not unexpected as the latest report from the OEB has Kingston Hydro's distribution rates rank 76th out of 82 reported distributors. Furthermore, we rank 15th lowest of our 15 cohorts in distribution rates. See Appendix B for a list of our Cohorts' Delivery rates.

In addition, based on the OEB reports, our operating costs per customer were \$182 per customer and ranked 13th out of 15 for 2007, 15% below the average of \$214 per customer. In 2008, our operating costs per customer were \$193 per customer and ranked 11th out of 15, 11% below the average of \$218 per customer. For 2009, our operating costs increased to \$197 per customer. Comparative data has not yet been released for 2009. For 2010 and 2011, operating costs per customer are projected to increase to \$226 and \$259 per customer.

The financial plan does not include any dividend payments to the City of Kingston as all after tax profits are projected to be reinvested into capital infrastructure.

The Company's affiliate, 1425445 Ontario Limited (o/a Utilities Kingston) will repay its loan to Kingston Hydro in the amount of \$250,000 in 2010.

Distribution Revenue

The 2010 distribution revenue is based on our approved 2006 rate application and rates in effect as of May 1, 2006 plus 2nd generation Incentive Regulation Mechanism adjustments for May 1, 2007, May 1, 2008 and May 1, 2009 and May 1, 2010. These revenues have also been adjusted for customer classification changes that have occurred since May 1, 2006.

The 2011 and 2012 distribution revenue is a preliminary estimate of our rebased revenues that we are hopeful of receiving effective May 1, 2011. These rebased revenues are based on the expected Rate Base of the Company, a regulated rate of return on the approved operating expenditures by the OEB.

Operating Expenditures

The following chart summarizes the actual audited operating expenses for 2003 through 2009 and the forecasted operating expenses for 2010 and 2011.

	Amount	Change
Audited 2003	\$5,399,000	
Audited 2004	\$5,451,000	1.0%
Audited 2005	\$5,348,000	-1.9%
Audited 2006	\$4,743,000	-11.3%
Audited 2007	\$4,928,000	5.2%
Audited 2008	\$5,333,000	8.2%
Audited 2009	\$5,435,000	1.9%
Forecast 2010	\$6,221,000	14.5%
Forecast 2011	\$7,150,000	14.9%

Kingston Hydro is projecting its 2010 and 2011 operating and maintenance expenses to increase from 2010. The main reasons for this increase are a 2 stage increase in our maintenance activities. In particular, maintenance activities on our substations need to increase in order to ensure continued reliability of our system and that are assets will remain in service for as long as we expect them to. In addition, we have a need to hire staff for succession planning purposes as outlined in the presentation to the Board at the meeting of July 12, 2010.

We believe that it is imperative that the required maintenance and operating activities be identified and included in our financial planning in order to have the best chance at getting the required revenue increase in 2011, which will be based on 2011 expected expenses.

Capital Budgets

The chart below summarizes the actual capital expenditures for 2005 through 2009 as well as the forecasted capital expenditures for 2010 and 2011. Please note that these expenditures are shown on a net basis. Any amount of customer funded work we do is in addition to this work but has minimal impact on the company's cash flow.

	Capital
2005 Audited (net)	$2,967,000
2006 Audited (net)	$2,502,000
2007 Audited (net)	$3,083,000
2008 Audited (net)	$3,757,000
2009 Audited (net)	$3,641,000
2010 Forecast (net)	$4,500,000
2011 Forecast (net)	$4,500,000

2010 and 2011 Infrastructure Investment

A detailed presentation will be presented to the Board regarding the work required for 2010 and 2011.

The asset management program also identifies theoretical spending levels associated with maintaining the optimum life of our assets in the distribution system. The following is a total of the spending levels by year required from our asset management analysis.

2010	**2011**	**2012**	**2013**	**2014**	**2015**
$5,363,598	$5,498,622	$16,372,122	$5,954,297	$7,879,315	$6,055,172

2016	**2017**	**2018**	**2019**
$4,216,941	2,703,622	2,703,622	2,703,622

As can be seen, the spending levels in the first 5-6 years are more developed and refined than those in the last 4-5 year period. Of note the major increase in projected spending for 2012 reflects the reconstruction of Municipal Substation No. 1. This has not been included in the rate application planning as it will require special consideration for rate making purposes.

Appendices

Appendix A: Kingston Hydro Corporation Financial Summary
Appendix B: Kingston Hydro Corporation Cohorts Delivery Rates

J. A. Keech President & C.E.O.
Kingston Hydro Corporation