ENWIN UTILITIES

September 17, 2008

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

Dear Ms. Walli:

Re: 2009 Cost of Service Rate Application
EB-2008-0227

Enclosed please find the 2009 Cost of Service Rate Application for *EnWin* Utilities Ltd. The Application is being submitted through the Board's web portal, in paper copy (2 copies) and on CD. All electronic copies are in searchable PDF format.

Yours very truly,

***EnWin* Utilities Ltd.**

Per: Andrew J. Sasso

From the Desk of Andrew J. Sasso, B.Comm., LL.B., Director, Regulatory Affairs
P.O. Box 1625, Stn "A", 787 Ouellette Avenue, Windsor, ON N9A 5T7
Tel: 519-255-2735 Fax: 519-973-7812 Email: regulatory@enwin.com

Schedule 1-1-1

Administration

Index

INDEX

Exhibit	Tab	Schedule	Contents of Schedule
1 - Administrative Documents			
	1		**Administration**
		1	Index
		2	Application
		3	Distribution License
		4	Contact Information
		5	List of Specific Approvals Requested
		6	Draft Issues List
		7	Procedural Orders/Correspondence/Notices
		8	Accounting Orders
		9	Compliance with USofA
		10	Maps of Distribution System
		11	List of Neighbouring Utilities
		12	Explanation of Any Host or Embedded Distributors
		13	Utility Organizational Chart
		14	Corporate Entities Relationships Chart
		15	Planned Changes in Corporate or Operational Structure
		16	Status of Board Directives
		17	Company Policies - Service Charges

		18	Company Policies – Conditions of Service
		19	Changes in Policies
		20	List of Witnesses and their Curriculum Vitae
		21	2009 COS Information Filing Requirements
		A	Requested Information
	2		**Overview**
		1	Summary of the Application
		A	Service Quality Requirements and Reliability Indices
		2	Schedule of Overall Revenue Deficiency/Sufficiency
		3	Numerical Schedules Detailing the Causes of the Deficiency/Sufficiency
	3		**Finance**
		1	Audited Financial Statements (2007)
		2	Pro Forma Statements (2008 and 2009)
		3	Reconciliation Between Financial Statements and Financial Results Filed
		4	Proposed Accounting Treatment
		5	Rating Agency Reports
2 – Rate Base			
	1		**Overview**
		1	Rate Base Summary

		A	Kinectrics 4 kV Report
		B	Kinectrics 27.6 kV Report
		C	CTL Report
		D	PBS Report
		E	SJH Consulting Report
	2		**Gross Assets - Property, Plant & Equipment and Accumulated Depreciation**
		1	Continuity Statements
		2	Gross Assets Table
		3	Accumulated Depreciation Table
	3		**Capital Budget**
		1	System Expansions
		2	Planning and Budgeting Process
		3	Capitalization Policy
	4		**Allowance for Working Capital**
		1	Overview and Calculation by Account
3 - Operating Revenue			
	1	1	Summary of Operating Revenue
	2		**Throughput Revenue**
		1	Overview

	2	Weather Normalized Forecast Methodology (filed in confidence)
3		**Other Revenue**
	1	Description of Other Revenue Sources
	2	Specific Service Charges
4		**Revenue Sharing**
	1	Description of Revenue Sharing
5		**Retail Service Transmission Rates**
	1	Description of Retail Service Transmission Rates
	A	Calculation of Retail Service Transmission Rates
4 - Operating Costs		
1		**Overview**
	1	Summary of Operating Costs
2		**OM&A Costs**
	1	Overview
	2	Staffing and Employee Expenses
	3	Purchase of Services and Products
	A	2007 Purchased Services and Products – OM&A
	B	2007 Purchased Services and Products – Inventory
	C	2008 Purchased Services and Products to July 31 – OM&A

	D	2008 Purchased Services and Products to July 31 – Inventory
	E	EWU Purchasing Policy
	4	Shared Services
	A	Affiliate Report - Terms of Reference
	B	Affiliate Report
	5	Depreciation and Amortization
	6	Loss Adjustment Factor
	7	Property Taxes
3		**Income Tax and Ontario Capital Tax**
	1	Overview
	2	Tax Model

5 - Deferral And Variance Accounts

1	1	Description of Deferral and Variance Accounts
	2	Calculation of Balances by Account
	3	Calculation of Rate Riders
2	1	Smart Meter Rate Adder

6 – Cost of Capital and Rate of Return

1	1	Overview
	A	Detailed Calculation of Long Term Debt Rate

7 - Calculation of Revenue Deficiency or Surplus

1	1	Calculation of Revenue Deficiency
	A	Revenue Deficiency Chart

8 – Cost Allocation

1	1	Cost Allocation Overview
	A	Cost Allocation Report
	2	Allocation Factors to Customer Classifications

9 – LRAM

1	1	Recovery of LRAM and SSM
	A	CDM Load Impacts by Class and Program
	B	Foregone Revenue by Class and Program
	C	SSM Amounts by Class and Program
	D	LRAM/SSM Rate Riders Sought

10 - Rate Design

1	1	Rate Design Overview
	2	Rate Mitigation
	3	Transformer Ownership Allowance

4	Existing Rate Schedules
5	Proposed Rate Schedules
6	Reconciliation of Rate Class Revenue to total Revenue Requirement
7	Calculation of Differences Between Revenue and Allocated Cost Under Current Rates and Proposed Rates by Customer Class
8	Explanation of Non-Cost Factors to Rate Design
9	Revenue/Cost Ratios for Historic Year and Test Year
10	Rate Impacts
A	Detailed Calculation of Proposed Rate Impacts
11	Customer Eligibility Criteria

Schedule 1-1-2

Administration

Application

ONTARIO ENERGY BOARD

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 EnWin Utilities Ltd. for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2009.

APPLICATION

1. The Applicant is EWU Utilities Ltd. ("EWU"). EWU is a licensed electricity distributor operating pursuant to license ED-2002-0527. EWU distributes electricity to approximately 85,000 customers within the corporate boundaries of the City of Windsor, Ontario.

2. EWU hereby applies to the Ontario Energy Board (the "Board") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended, (the "OEB Act") approving just and reasonable rates for the distribution of electricity based on a 2009 test year.

3. Specifically, EWU hereby applies for an order or orders granting approval of:

   a. EWU's forecasted 2009 base distribution revenue requirement of $51,791,751;

   b. Distribution rates that will allow EWU to recover its forecasted 2009 base distribution revenue requirement;

   c. Specific service charges and retail service charges;

   d. Retail service transmission charges;

   e. Disposition of deferral and variance accounts 1508, 1518, 1525, 1548, 1562, 1563, 1574, 1580, 1582, 1584, 1586, 1588, 1590, and 1592;

   f. Rate riders that will allow EWU to dispose of the aforementioned deferral and variance accounts;

   g. An amended smart meter rate adder in the amount of $1.00;

   h. A rate of return in the amount of 7.40%;

i. EWU's proposal to adjust the cost allocation among customer classes over three years;

j. Recovery of $298,733.99 through the Lost Revenue Adjustment Mechanism ("LRAM") and $378,687.61 through the Shared Savings Mechanism ("SSM");

k. Rate riders that will allow EWU to recover of the aforementioned LRAM and SSM amounts; and,

l. EWU's existing rates being interim commencing May 1, 2009 until such implementation date as the Board approves for new rates.

4. As indicated by EWU's pre-filed evidence, EWU's 2009 base revenue requirement is forecasted to be $51,791,751. Based on current distribution rates and forecasted load, EWU forecasts a 2009 revenue deficiency of $7,127,306.

5. This Application is made in accordance with the Board's *Filing Requirements for Transmission and Distribution Applications* dated November 14, 2006 (the "Filing Requirements").

6. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

7. EWU requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

8. EWU requests that a copy of all documents filed with the Board in this proceeding be served on EWU and EWU's counsel, as follows:

The Applicant:

EnWin Utilities Ltd.
787 Ouellette Avenue
P.O. Box 1625, Stn. "A"
Windsor, ON N9A 5T7

Attention:

Mr. Andrew J. Sasso
Director, Regulatory Affairs
Telephone: (519) 255-2735
Facsimile: (519) 973-7812
E-mail: regulatory@enwin.com

The Applicant's Counsel:

Ogilvy Renault LLP
Suite 3800
Royal Bank Plaza, South Tower
200 Bay Street
P.O. Box 84
Toronto, Ontario M5J 2Z4

Attention:

Mr. Charles Keizer
Telephone: (416) 216-2342
Facsimile: (416) 216-3930
E-mail: ckeizer@ogilvyrenault.com

DATED at Windsor, Ontario, this 17th day of September, 2008.

ENWIN UTILITIES LTD.

Andrew J. Sasso

Schedule 1-1-3

Administration

Distribution Licence

Ontario Energy Board
P.O. Box 2319
27th. Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone; 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY E-MAIL

November 23, 2007

Mr. Andrew J. Sasso
Director, Regulatory Affairs
ENWIN Utilities Ltd.
787 Ouellette Ave., P.O. Box 1625, Station A
Windsor, ON N9A 5T7

Dear Mr. Sasso:

Re: Application for Amendment to Distribution Licence (ED-2002-0527)
Board File Number EB-2007-0783

The Board has today issued its decision and order in the above matter and an executed copy is enclosed.

Please direct any questions relating to this application to Irina Kuznetsova, Analyst, Market Operations, Licensing at +1 (416) 440-8138.

Yours truly,

Kirsten Walli
Board Secretary

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2007-0783

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

AND IN THE MATTER OF an application pursuant to section 74 of the *Ontario Energy Board Act, 1998* by ENWIN Utilities Ltd. to amend Electricity Distribution Licence ED-2002-0527.

By delegation, before: Jennifer Lea

DECISION AND ORDER

On October 1, 2007, ENWIN Utilities Ltd. filed an application with the Ontario Energy Board for an amendment to licence ED-2002-0527 pursuant to section 74 of the *Ontario Energy Board Act, 1998*. The Board has assigned the application file number EB-2007-0783

The need for the amendment arises from an amalgamation of two entities: ENWIN Powerlines Ltd. and ENWIN Utilities Ltd. On December 19, 2006, the Board issued a decision and order in which the Board granted ENWIN Powerlines Ltd.'s application for leave to amalgamate with ENWIN Utilities Ltd. The applicant requested that the name on the licence be changed to ENWIN Utilities Ltd. to reflect the accomplishment of the amalgamation. In addition sections 14.3 to 14.5 of the existing licence can be deleted as these sections refer to a service agreement which no longer exists.

I have proceeded to decide the application without a hearing pursuant to section 21(4)(b) of the Act since no other parties are adversely affected in a material way by the outcome of the proceeding, and the applicant has consented to disposing of the application without a hearing.

I find that it is in the public interest to grant the requested licence amendments.

IT IS ORDERED THAT:

The name on Electricity Distribution Licence ED-2002-0527 is amended to be ENWIN Utilities Ltd., and section 14 of the licence is amended to exclude the provisions relating to the previously existing service agreement. The amended licence is attached to this decision and order.

DATED at Toronto, November 23, 2007

ONTARIO ENERGY BOARD

Jennifer Lea
Special Advisor, Market Operations

Ontario

Electricity Distribution Licence

ED-2002-0527

ENWIN Utilities Ltd.

Valid Until

December 17, 2023

Jennifer Lea
Special Advisor, Market Operations
Ontario Energy Board
Date of Issuance: December 18, 2003
Date of Amendment: June 24, 2004
Date of Amendment: June 1, 2005
Date of Amendment: November 23, 2007

Ontario Energy Board
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Table of Contents **Page No.**

1	Definitions	1
2	Interpretation	2
3	Authorization	2
4	Obligation to Comply with Legislation, Regulations and Market Rules	2
5	Obligation to Comply with Codes	2
6	Obligation to Provide Non-discriminatory Access	3
7	Obligation to Connect	3
8	Obligation to Sell Electricity	3
9	Obligation to Maintain System Integrity	4
10	Market Power Mitigation Rebates	4
11	Distribution Rates	4
12	Separation of Business Activities	4
13	Expansion of Distribution System	4
14	Provision of Information to the Board	4
15	Restrictions on Provision of Information	4
16	Customer Complaint and Dispute Resolution	5
17	Term of Licence	5
18	Fees and Assessments	6
19	Communication	6

20 Copies of the Licence 6

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA 7
SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE 8
SCHEDULE 3 LIST OF CODE EXEMPTIONS 9
APPENDIX A MARKET POWER MITIGATION REBATES 10

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means EnWin Utilities Ltd.

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 *Obligation to Comply with Codes*

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on December 18, 2003 and expire on December 17, 2023. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The City of Windsor as of December 31, 2002.

2. Part of Lot 146, Concession 2, Geographical Township of Sandwich East, City of Windsor, County of Essex.

3. Part of Lots 145 and 146, Concession 1, geographical Township of Sandwich east, now part of the City of Windsor, County of Essex, Lots 1 through 74 inclusive as shown on plan 12M.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

Schedule 1-1-4

Administration

Contact Information

CONTACT INFORMATION

The Applicant:

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787 Ouellette Avenue
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Director, Regulatory Affairs
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E-mail: regulatory@enwin.com

The Applicant's Counsel:

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Toronto, Ontario M5J 2Z4

Attention:

Mr. Charles Keizer
ckeizer@ogilvyrenault.com
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Facsimile: (416) 216-3930
E-mail: ckeizer@ogilvyrenault.com

Schedule 1-1-5

Administration

List of Specific Approvals Requested

LIST OF SPECIFIC APPROVALS REQUESTED

EWU hereby applies for an order or orders granting approval of:

- EWU's forecasted 2009 base distribution revenue requirement of $51,791,751;
- Distribution rates that will allow EWU to recover its forecasted 2009 base distribution revenue requirement;
- Specific service charges and retail service charges;
- Retail service transmission charges;
- Disposition of deferral and variance accounts 1508, 1518, 1525, 1548, 1562, 1563, 1574, 1580, 1582, 1584, 1586, 1588, 1590, and 1592;
- Rate riders that will allow EWU to dispose of the aforementioned deferral and variance accounts;
- An amended smart meter rate adder in the amount of $1.00;
- A rate of return in the amount of 7.40%;
- EWU's proposal to adjust the cost allocation among customer classes over three years;
- Recovery of $298,733.99 through the Lost Revenue Adjustment Mechanism ("LRAM") and $378,687.61 through the Shared Savings Mechanism ("SSM");
- Rate riders that will allow EWU to recover of the aforementioned LRAM and SSM amounts; and,
- EWU's existing rates being interim commencing May 1, 2009 until such implementation date as the Board approves for new rates.

Schedule 1-1-6

Administration

Draft Issues List

DRAFT ISSUES LIST

1. Administrative Documents
    a. Further documents required
2. Rate Base for the test year
    a. Capital Expenditures 2007
    b. Capital Expenditures 2008
    c. Capital Expenditures 2009
    d. Capital Planning and Budgeting Process
    e. Capitalization Policy
    f. Working Capital Allowance
3. Operating Revenue for the test year
    a. Load Forecast Methodology
    b. Throughput Revenue
    c. Other Revenue
    d. Specific Service Charges
    e. Retail Service Transmission Rates
4. Operating Costs for the test year
    a. Operations, Maintenance & Administration
    b. Shared Services
    c. Depreciation and Amortization
    d. Loss Adjustment Factor
    e. Income Tax and Ontario Capital Tax
5. Deferral and Variance Accounts
    a. Recoverable Accounts
    b. Account Balances
    c. Calculation of Rate Riders
    d. Smart Meter Rate Adder
6. Cost of Capital and Rate of Return for the test year
    a. Capital Structure
    b. Cost of Debt
    c. Cost of Equity

7. Revenue Requirement for the test year

8. Cost Allocation

    a. Revenue-to-cost ratios in the test year
    b. Revenue-to-cost ratios following the test year

9. LRAM and SSM

    a. Recovery of LRAM
    b. Recovery of SSM

10. Rate Design

    a. Rate mitigation
    b. Class rate design
    c. Rate impacts in the test year

Schedule 1-1-7

Administration

Procedural Orders/
Correspondence/Notices

PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

Schedule 1-1-8

Administration

Accounting Orders

ACCOUNTING ORDERS

No accounting orders have been issued to EWU.

Schedule 1-1-9

Administration

Compliance with USofA

COMPLIANCE WITH THE USofA

EWU is in compliance with the Uniform System of Accounts.

Schedule 1-1-10

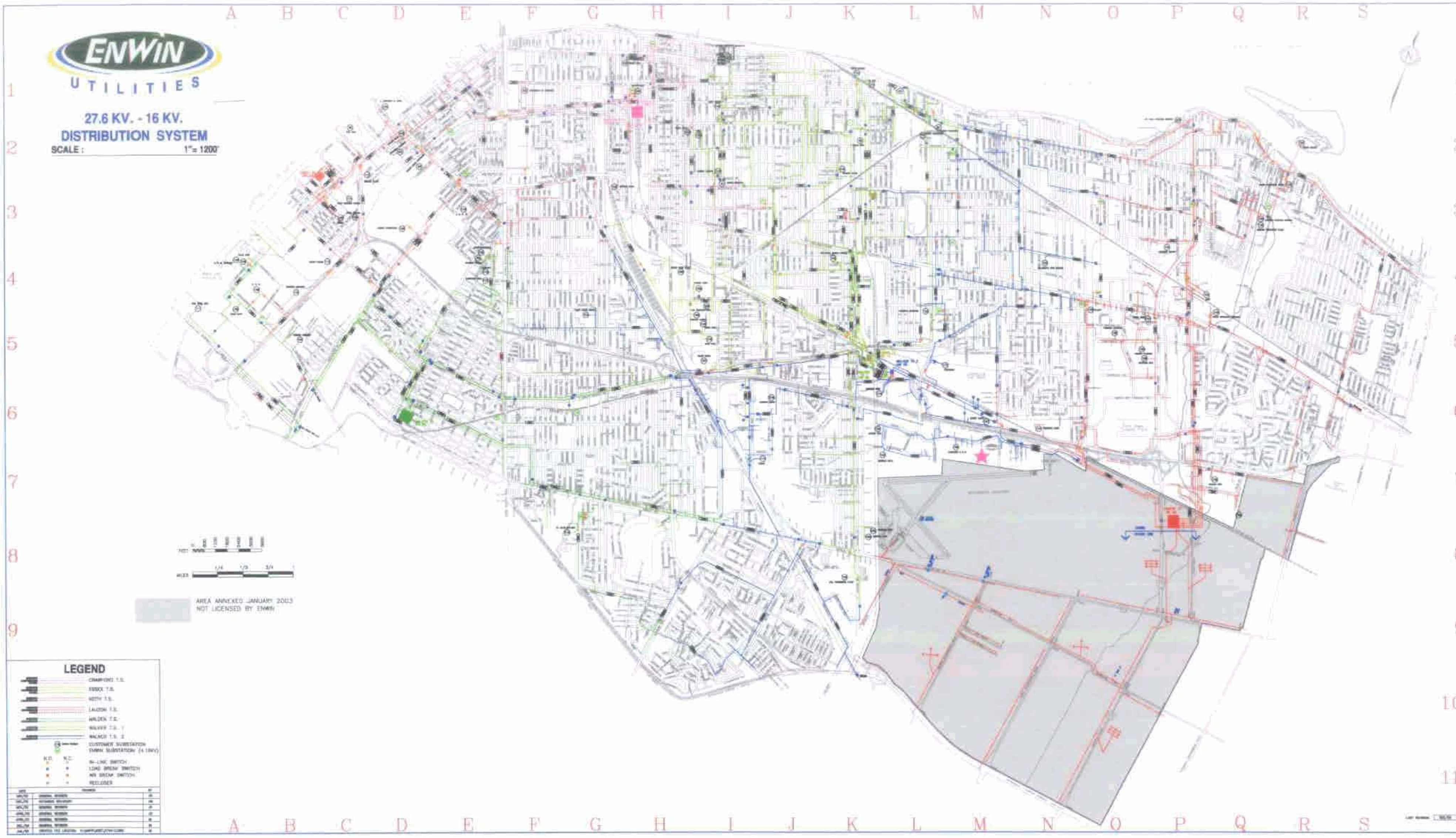
Administration

Maps of Distribution System

MAPS OF DISTRIBUTION SYSTEM

Maps that illustrate EWU's distribution service area follow.

ENWIN
UTILITIES
4.16 kV. - 2.4 kV.
DISTRIBUTION SYSTEM
SCALE : 1" = 1200'
A B C D E F G H I J K L M N O P Q R S
1 2 3 4 5 6 7 8 9 10 11
LEGEND
FEEDER NUMBER
MUC SUBSTATION
SWITCH NORMALLY CLOSED
SWITCH NORMALLY OPEN



ENWIN
UTILITIES
27.6 KV. - 16 KV.
DISTRIBUTION SYSTEM
SCALE : 1"= 1200'
A B C D E F G H I J K L M N O P Q R S
1 2 3 4 5 6 7 8 9 10 11
FEET
MILES
1/4 1/2 3/4 1
AREA ANNEXED JANUARY 2003
NOT LICENSED BY ENWIN
LEGEND
CRAWFORD T.S.
ESSEX T.S.
KEITH T.S.
LAUZON T.S.
WALDEN T.S.
WALKER T.S. 1
WALKER T.S. 2
CUSTOMER SUBSTATION
ENWIN SUBSTATION (4.16KV)
N.O.
N.C.
IN-LINE SWITCH
LOAD BREAK SWITCH
AIR BREAK SWITCH
RECLOSER

Schedule 1-1-11

Administration

List of Neighbouring Utilities

LIST OF NEIGHBOURING UTILITIES

North:	n/a
East:	Essex Powerlines Ltd., Hydro One Networks Inc.
South:	Essex Powerlines Ltd., Hydro One Networks Inc.
West:	Essex Powerlines Ltd., Hydro One Networks Inc.

Schedule 1-1-12

Administration

Explanation of Any Host or
Embedded Distributors

EXPLANATION OF ANY HOST OR EMBEDDED DISTRIBUTORS

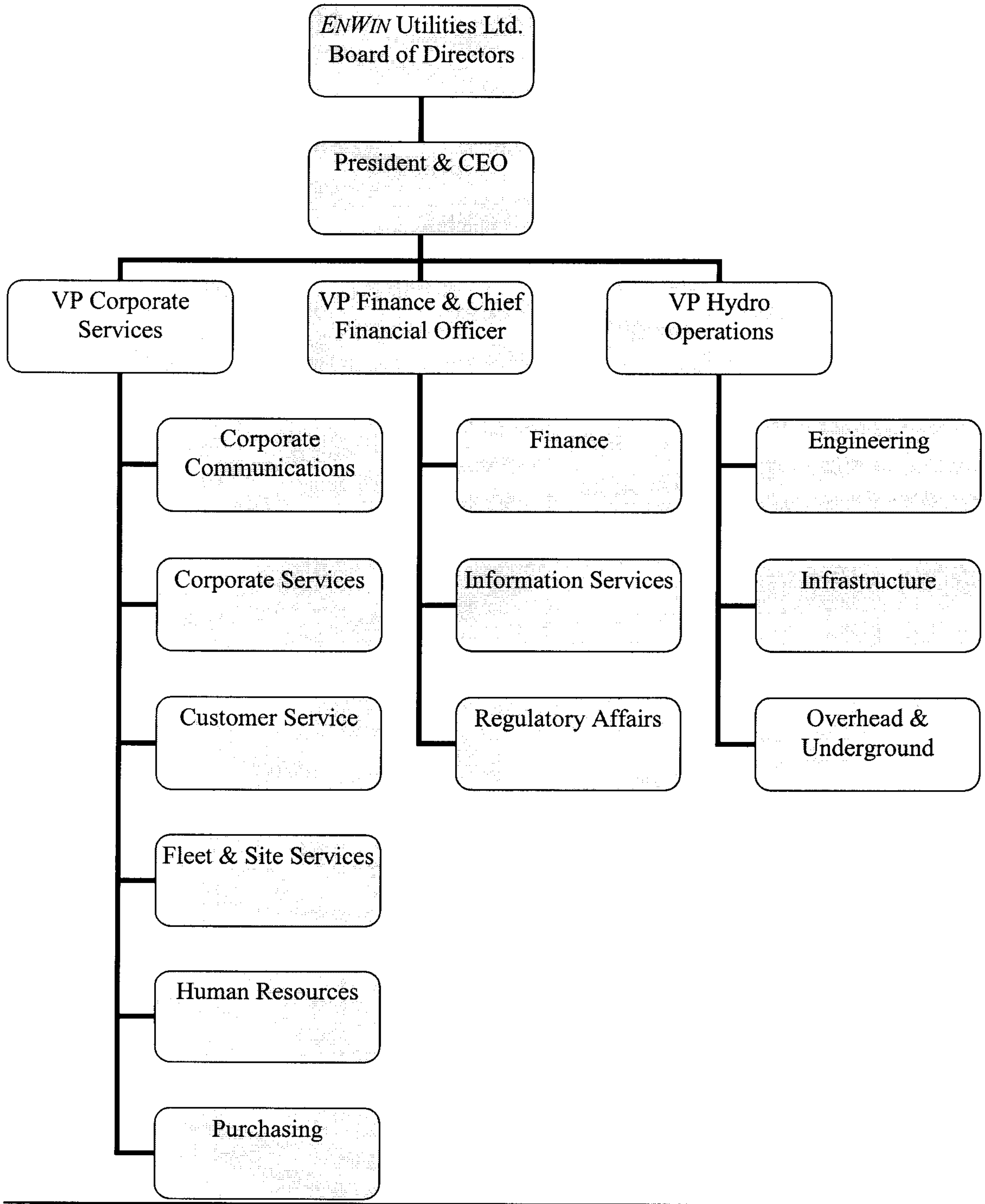
EWU has no embedded or host distributors.

Schedule 1-1-13

Administration

Utility Organizational Chart

UTILITY ORGANIZATIONAL CHART

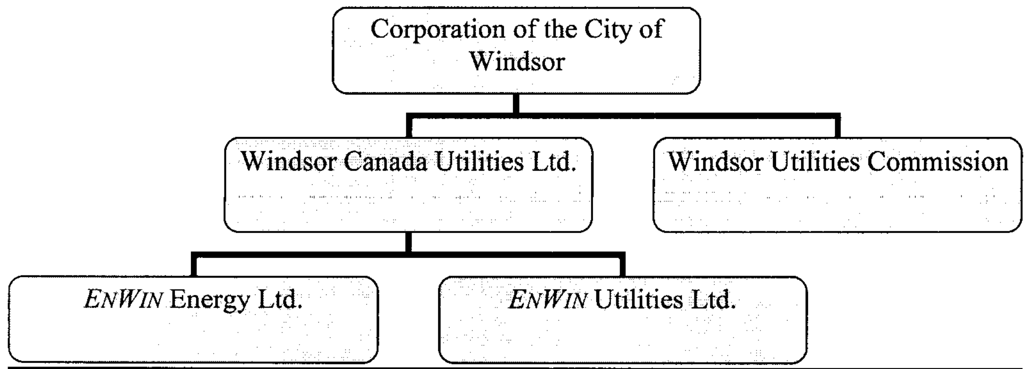


Schedule 1-1-14

Administration

Corporate Entities Relationships Chart

CORPORATE ENTITIES RELATIONSHIPS CHART



The Corporation of the City of Windsor (the "City") is a municipality in the Province of Ontario. The City is the sole shareholder of Windsor Canada Utilities Ltd. ("Windsor Canada") and the parent municipality of the Windsor Utilities Commission ("WUC").

The WUC is a municipal services board that provides water treatment and distribution services in the City.

Windsor Canada is the parent company and sole shareholder of *ENWIN* Utilities Ltd. ("EWU") and *ENWIN* Energy Ltd. ("EWE"). Windsor Canada holds 4 of 6 seats on the EWU Board of Directors. Windsor Canada and EWU share senior management services.

EWU is the Applicant and a local distribution company licensed and regulated by the Board. EWU provides senior management and corporate services to the WUC and EWE. EWU provides corporate services to the City.

EWE is an Ontario business corporation that is not regulated by the Board. EWE engages in electricity conservation and demand management activities on behalf of EWU. EWE engages in competitive activities, such as street lighting and sentinel lighting.

Schedule 1-1-15

Administration

Planned Changes in Corporate or
Operational Structure

PLANNED CHANGES IN CORPORATE OR OPERATIONAL STRUCTURE

There are no planned changes to the corporate or operational structure of EWU at this time.

Schedule 1-1-16

Administration

Status of Board Directives

STATUS OF BOARD DIRECTIVES

In the 2006 EDR (RP-2005-0020/EB-2005-0359), EWU's predecessor, *EnWin* Powerlines Ltd. ("Powerlines") entered into a Settlement Agreement, which was approved by the Board.

Arising from the affiliate transactions between Powerlines and an affiliated services company, the Intervenors sought, and Powerlines agreed to conduct a study and prepare a report related to affiliate costs and revenues (the "Affiliate Report"). The Affiliate Report shall be provided to the Board and the Intervenors. The framework for the report was settled on as follows:

> *"The Applicant will undertake a tender process for the selection of a consultant who will prepare the Affiliate Report. The Applicant will contact the Intervenors in the EDR Application and seek from them input into the issues the Intervenors would like addressed in the Affiliate Report. The Applicant will consider, but will not be required to adopt, the Intervenors' suggestions."*

The Affiliate Report was prepared by BDR North America and is attached at Exhibit 4, Tab 2, Schedule 4, in satisfaction of the only outstanding undertaking to or directive from the Board.

Schedule 1-1-17

Administration

Company Policies - Service Charges

COMPANY POLICIES - SERVICE CHARGES

EWU currently uses the following service charges, all of which have been previously approved by the Board. In this Application, EWU proposes to amend the "Disconnect/Reconnect Charge - At Meter After Hours" charge, as set out at Exhibit 3, Tab 3, Schedule 2.

Specific Service Charges

Customer Administration		
Arrears certificate	$	15.00
Pulling post dated cheques	$	15.00
Easement Letter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Dispute test residential	$	50.00
Dispute test commercial self contained – MC	$	105.00
Dispute test commercial TT-MC	$	180.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	65.00
Service layout – residential	$	110.00
Service layout – commercial	$	150.00
Overtime locate	$	60.00
Disposal of concrete poles	$	95.00
Missed service appointment	$	65.00
Service call – customer owned equipment	$	30.00
Same day open trench	$	170.00
Scheduled day open trench	$	100.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

Schedule 1-1-18

Administration

Company Policies
- Conditions of Service

COMPANY POLICIES – CONDITIONS OF SERVICE

EWU's Conditions of Service are accessible at:

http://www.enwin.com/customerservice/conditions_of_service.cfm

Schedule 1-1-19

Administration

Changes in Policies

CHANGES IN POLICIES

EWU's Specific Service Charges were approved by the Board in the 2008 Electricity Distribution Rate Order, EB-2007-0894. EWU is seeking to amend the rate applicable to one of those Specific Service Charges as set out at Exhibit 3, Tab 3, Schedule 2.

EWU's Retail Service Charges were approved by the Board in the 2008 Electricity Distribution Rate Order, EB-2007-0894. No changes to these charges have been made, nor are any sought.

EWU's Conditions of Service were filed with the Board in June 2007. No changes to these Conditions of Service have been made, nor are any sought.

Schedule 1-1-20

Administration

List of Witnesses and their
Curriculum Vitae

LIST OF WITNESSES AND THEIR CURRICULUM VITAE

Information will be provided at a later date.

Schedule 1-1-21

Administration

2009 COS
Information Filing Requirements

2009 COS INFORMATION FILING REQUIREMENTS

The Board requested particular information on September 4, 2008. The information sought is enclosed as Attachment A.

Attachment A

Revenue Requirement

1. Request: The most recent board approved revenue requirement from a cost of service application. In most cases this will be from your Board Decision for 2006 rates.

   The most recent Board approved revenue requirement provided in EWU's 2006 Electricity Distribution Rate Decision ((RP-2005-0020/EB-2005-0359) was in the amount of $49,524,982.

2. Request: The revenue requirement requested in 2009 using the same cost elements as was used to represent the number in the 2006 decision.

2006 Approved EDR (including LU-3TS and LU-FA Model)

Service Revenue Requirement	
Return on Rate Base ($157,885,140 + $24,964,954)	$13,673,299
Distribution Expenses	$32,116,413
Income Taxes (PILS)	$814,881
Total Service Revenue Requirement	**$46,604,593**
Transformer Allowance	$1,866,055
Smart Meters	$270,385
Regulatory Asset Recovery	$783,949
Revenue Offsets	-$3,078,717

2009 COS

Service Revenue Requirement	
Return on Rate Base ($201,034,177)	$14,868,316
Distribution Expenses	$36,770,084
Income Taxes (PILS)	$2,597,154
Total Service Revenue Requirement	**$54,235,554**
Transformer Allowance	$1,409,726
Smart Meters	$1,016,562
Variance Accounts	-$2,063,807
LRAM/SSM	$338,711
Revenue Offsets	-$2,443,803

Bill Impact - Delivery Charges

3. Request: The percentage change in the delivery line charges. This is inclusive of fixed charges, variable charges, rate riders and retail transmission rates.

Residential - 1,000 kWh	2008 Bill				2009 Bill			Impact	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$8.66			$13.45		
Distribution	kWh	1,000	$0.0211	$21.10	1,000	$0.0189	$18.90		
Sub Total Distribution				$29.76			$32.35		
Deferral/Variance	kWh				1,000	$0.0001	$0.10		
LRAM/SSM Rate Rider	kWh				1,000	$0.0003	$0.30		
Transmission - Network	kWh	1,039	$0.0051	$5.30	1,038	$0.0057	$5.91		
Transmission - Line & Transf. Connection	kWh	1,039	$0.0039	$4.05	1,038	$0.0041	$4.25		
Delivery Line Charges				**$39.11**			**$42.91**	**$3.80**	**9.72%**

General Service < 50 kW - 2,000 kWh	2008 Bill				2009 Bill			Impact	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$24.38			$27.13		
Distribution	kWh	2,000	$0.0155	$31.00	2,000	$0.0168	$33.60		
Sub Total Distribution				$55.38			$60.73		
Deferral/Variance	kWh				2,000	-$0.0007	-$1.40		
LRAM/SSM Rate Rider	kWh				2,000	$0.0000	$0.00		
Transmission - Network	kWh	2,078	$0.0047	$9.77	2,075	$0.0052	$10.79		
Transmission - Line & Transf. Connection	kWh	2,078	$0.0036	$7.48	2,075	$0.0038	$7.89		
Delivery Line Charges				**$72.63**			**$78.01**	**$5.38**	**7.41%**

Bill Impact – Total Bill

4. Request: The actual dollar per month change that customers will see in their bill associated with your cost of service application.

Residential - 1,000 kWh	2008 Bill				2009 Bill			Impact	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$8.66			$13.45		
Distribution	kWh	1,000	$0.0211	$21.10	1,000	$0.0189	$18.90		
Sub Total Distribution				$29.76			$32.35		
Deferral/Variance	kWh				1,000	$0.0001	$0.10		
LRAM/SSM Rate Rider	kWh				1,000	$0.0003	$0.30		
Transmission - Network	kWh	1,039	$0.0051	$5.30	1,038	$0.0057	$5.91		
Transmission - Line & Transf. Connection	kWh	1,039	$0.0039	$4.05	1,038	$0.0041	$4.25		
Electricity Commodity	kWh	1,039	RPP	$55.90	1,038	RPP	$55.82		
Wholesale Market Service	kWh	1,039	$0.0052	$5.40	1,038	$0.0052	$5.40		
Rural Rate Protection	kWh	1,039	$0.0010	$1.04	1,038	$0.0010	$1.04		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
Total Bill Charges				**$108.45**			**$112.17**	**$3.72**	**3.43%**

General Service < 50 kW - 2,000 kWh	2008 Bill				2009 Bill			Impact	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$24.38			$27.13		
Distribution	kWh	2,000	$0.0155	$31.00	2,000	$0.0168	$33.60		
Sub Total Distribution				$55.38			$60.73		
Deferral/Variance	kWh				2,000	-$0.0007	-$1.40		
LRAM/SSM Rate Rider	kWh				2,000	$0.0000	$0.00		
Transmission - Network	kWh	2,078	$0.0047	$9.77	2,075	$0.0052	$10.79		
Transmission - Line & Transf.Connection	kWh	2,078	$0.0036	$7.48	2,075	$0.0038	$7.89		
Electricity Commodity	kWh	2,078	RPP	$115.85	2,075	RPP	$115.70		
Wholesale Market Service	kWh	2,078	$0.0052	$10.81	2,075	$0.0052	$10.79		
Rural Rate Protection	kWh	2,078	$0.0010	$2.08	2,075	$0.0010	$2.08		
Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
Total Bill Charges				**$215.37**			**$220.58**	**$5.21**	**2.42%**

Schedule 1-2-1

Overview

Summary of the Application

SUMMARY OF THE APPLICATION

1. OVERVIEW OF THE APPLICANT

EnWin Utilities Ltd. ("EWU") is a small-mid sized LDC with about 85,000 customers in the City of Windsor. EWU is the successor company resulting from a January 1, 2007 merger of *EnWin* Powerlines Ltd., the former LDC, and *EnWin* Utilities Ltd., the former services company ("Serve Co").

EWU has built a great deal of its infrastructure to support Large Use customers. In 2007, EWU had 10 Large Use customers and a ratio of 1 Large Use customer per 8,476 total customers. By comparison, Toronto had 1 Large Use customer per 13,876 total customers, Horizon had 1 Large Use customer per 17,530 total customers and Oshawa had 1 Large Use customer per 25,490 total customers. It is therefore not surprising that EWU operates a very densely powered distribution system. In 2007, about 36,231kWh were purchased per customer and the system reached a summer peak of 577,900kW. However, as a result of the declining production in Ontario by General Motors, Ford and Chrysler, all of which currently have operations in Windsor, EWU is facing significant load loss.

EWU's distribution system is about 64% overhead and 36% underground. Though EWU operates in an older municipality, its prudent, long-term investment policies have enabled EWU to maintain and continue to project smooth patterns for future investment in capital projects and O&M for the distribution system. The bulk of EWU's capital expenditures on the distribution system are driven by the need to sustain safety and reliability. While reliable and quality supplies of power are important for all customers, the sensitivity of industrial equipment to even small and brief interruptions to electricity service, make these particular important factors in the EWU service area. EWU's reliability indices demonstrated the success of current polices. Those indices are enclosed as Attachment A.

EWU's senior management and corporate services provide the necessary support to the LDC and also provide services to EWU's affiliates. These arrangements enable EWU customers to benefit from levels of expertise, experience, and service that would not otherwise be available at the current levels of cost. The cost sharing arrangements have been considered by industry expert BDR North America and found to be reasonable and appropriate. The strong performance of the front line staff in meeting the needs of electricity distribution customers is reflected in the high scores achieved in the service quality requirements. Those scores are also enclosed as Attachment A.

In preparing this, its first Cost of Service Rate Application, EWU has relied heavily on internal staff, but has also availed itself of external expertise. Those external experts have proved necessary to navigate many of the complex technical requirements of the filing. Most importantly, EWU retained Ogilvy Renault LLP as legal counsel and engaged Elenchus Research Associates as expert consultants. EWU used Elenchus Research Associates'

RateMaker 2009 Cost of Service and PILs models to assist with determining EWU's proposed rate base, proposed rates and other pertinent data for the 2009 test year.

2. TOTAL BILL IMPACT

The impacts of the orders sought in this Application on the total bill, including the impact of rates related to smart meters, LRAM/SSM (conservation programming impact), deferral and variance accounts, and provincial transmission are:

- \$3.72 or 3.4% for a residential customer consuming 1,000kWh of electricity in a month
- \$5.21 or 2.4% for a small commercial customer (GS<50) consuming 2,000kWh of electricity in a month

The cost of EWU's service to its customers and the resulting rates are set out in this Application. A summary of each exhibit within the Application follows.

3. ADMINISTRATIVE DOCUMENTS

As a result of the January 1, 2007 amalgamation, EWU's Distribution Licence, Organizational Chart and Corporate Entities Relationships Chart have been amended since EWU's 2006 EDR Application. Included in this Application are also rating agency reports from DBRS and Standard & Poor's, both of which verify the positive financial turnaround of EWU over the past several years.

4. RATE BASE

On a forward test-year basis, EWU proposes a rate base of $201,034,177, which is based on an average capital asset balance of $171,628,658 and a working capital allowance of $29,405,520. The working capital allowance is 15% of the eligible distribution expenses of $25,282,116 and power supply expenses of $170,754,681.

EWU's capital expenditures are increasingly geared to the need for so-called "smart grid" technology. EWU's belief is that the starting point for smart grid infrastructure is a safe and reliable system. Accordingly, EWU is proposing to spend $6,788,648 on Operations Sustainability projects in 2009. The largest of these is the 4kV Voltage Conversion Project that is simultaneously replacing old infrastructure and upgrading the capacity of the distribution system. In order to maximize the functionality and operation of the current system and develop a "smarter" grid, EWU is proposing $603,675 for Operations Enhancement projects in 2009. The largest project is $272,175 in SCADA Improvements that will enhance the two-way flow of information along EWU's physical infrastructure. Finally, EWU's Operations systems must respond to Externally-Driven requirements and $2,876,747 is planned for that purpose in 2009.

EWU is also proposing $1,055,205 in Administration Sustainability projects. These projects support the basic EWU facilities and administrative functionalities. For 2009, EWU proposes $659,160 for a Customer Service Contact Centre. This Administration Enhancement will enable EWU to meet the current needs of its customers and allow for an improved flow of information.

This is another "smart grid" characteristic that is increasing demand by customers. EWU is also proposing a Comprehensive Enterprise Resource Planning ("ERP") software suite that will start coming into use in 2009. To evaluate the options for replacing its software systems that are currently at or close to end-of-life, EWU retained SJH Consulting. The consultant's report is included in this Application. The report recommends EWU implement a Comprehensive ERP over a 2 year timeframe.

5. OPERATING REVENUE

In the 2006 EDR application, EWU relied upon the 2004 Hydro One weather-normalized average consumption ("NAC"). For its 2009 load forecast, EWU retained Elenchus Research Associates to perform a medium term weather normalized distribution system load forecast. That forecast utilizes monthly class-specific retail detail for the period January 2003 through December 2007. Elenchus' study is included in this Application. The study projects a decrease in weather normalized consumption from 2,989,147,280kWh in 2007 to 2,667,516,053kWh in 2009 (11% decrease), largely as a result of the significant economic decline of the automotive industry in Windsor.

Downward load risk is the primary basis upon which EWU is planning on bringing another cost of service application to the Board within 2 years (2011), rather than 4 years (2013) as would be the case according to the Board's Report of July 14 in respect of EB-2007-0673.

Also, EWU seeks an order adjusting one of its Specific Service Charges from $65 to $185. The adjusted amount is the Board's standard charge and would more accurately reflect EWU's costs associated with that service. EWU proposes to keep the remaining Specific Service Charges as they have been since the Board's 2006 rate order.

Finally, EWU proposes to adjust its Retail Service Transmission Rates to reflect the Board's recent Uniform Transmission Rates decision (EB-2008-0113).

6. OPERATING COSTS

EWU anticipates total OM&A expenses of $25,282,116 in 2009. These expenses generally remain level and increases tend to be smooth. Where variances in expense levels have arisen, EWU has included explanations. Whereas the Board's requirement is that explanations be provided for variances of about $367,701 or greater for EWU in the test year, in the interests of clarity and transparency, EWU has provided explanations of variances exceeding $50,000.

EWU mitigates costs through a number of mechanisms. One mechanism is extensively using RFP/RFQ purchasing procedures for external service and products. Another mechanism is by sharing the cost of services with its affiliates. EWU's shared services and corporate cost allocation methodology were the subject of an independent study by Paula Zarnett of BDR North America. BDR's study is included in this Application. The study found EWU's affiliate transfer pricing and corporate cost allocation methodology to be reasonable and appropriate.

Through capital and OM&A initiatives, EWU has improved the efficiency of its distribution system. EWU therefore seeks a downward adjustment of its loss factors. EWU proposes that the Total Loss Factor for <5,000kW customers should be 1.0377 for secondary metered and 1.0273 for primary metered.

In 2009, EWU anticipates property taxes of $518,858, Ontario Capital Tax of $418,577 and Payments in Lieu of Corporate Income Taxes of $2,178,557.

7. DEFERRAL AND VARIANCE ACCOUNTS

EWU seeks to dispose of many of its deferral and variance accounts, resulting in a credit of $4,065,736 to its customers.

EWU seeks an increase of its smart meter rate adder from $0.27 to $1.00 in order to offset rate shock as a result of the Province's Smart Meter Initiative.

8. COST OF CAPITAL AND RATE OF RETURN

EWU calculates a 2009 rate of return of 7.40%. EWU has come to this figure based on the deemed debt-to-equity structure of 4% short-term debt (at the regulated rate of 4.47%), 56% long-term debt (at the calculated rate of 6.77%), and 40% equity (at the regulated rate of 8.57%).

9. CALCULATION OF REVENUE DEFICIENCY

EWU calculates a 2009 service revenue requirement of $54,235,554. Through revenue offsets, EWU has reduced this requirement by $2,443,803. The base revenue requirement of $51,791,751 results in a revenue deficiency of $7,127,306.

10. CUSTOMER COST ALLOCATION

EWU retained John Todd of Elenchus Research Associates to update EWU's 2007 Customer Cost Allocation filing, which had been based on 2004 data. Elenchus Research Associates' report is included in this Application. For customers outside the Board's revenue-to-cost ranges, EWU proposes to move the customers 50% of the way to the range in the test year and the remaining 50% in equal increments in the following 2 years.

11. LRAM/SSM

EWU seeks rate riders to recover $298,734 through the Lost Revenue Adjustment Mechanism and $378,688 through the Shared Savings Mechanism. These amounts are related to the Board-approved conservation and demand management activities undertaken by EWU in connection with "third tranche" programs.

12. RATE DESIGN

EWU is mindful of the Board's ongoing proceeding in respect of rate design (EB-2007-0031). Accordingly, EWU proposes to modify the rate design for only one of its rate classes. This change will more closely align the rate structure with other distributors and in keeping with the Board's provision in EB-2007-0667.

As a as a result of the ongoing nature of the rate design consultation, EWU seeks to maintain its Standby rate on an interim basis and proposes to maintain its Standby rate in abeyance, pending the outcome of EB-2007-0031.

Attachment A

SERVICE QUALITY REQUIREMENTS: 2007

Indicators	Standards		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1. New Connections - Low Voltage	Within 5 Working Days,	Total	17	17	13	29	39	27	26	43	42	41	34	35	363
	90% or more	Total Within Goal	17	17	13	29	39	27	26	43	41	41	34	34	361
		% within Goal	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**97.62%**	**100.00%**	**100.00%**	**97.14%**	**99.45%**
2. New Connections - High Voltage	Within 10 Working Days	Total	1	0	0	0	0	0	0	1	0	1	0	0	3
	90% or more	Total Within Goal	1	0	0	0	0	0	0	1	0	1	0	0	3
		% within Goal	**100.00%**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**100.00%**	**n/a**	**100.00%**	**n/a**	**n/a**	**100.00%**
3. Underground Cable Locates	Within 5 Working Days	Total	195	169	269	305	447	375	294	335	342	378	342	189	3640
	90% or more	Total Within Goal	194	169	268	304	445	374	294	334	340	377	342	189	3630
		% within Goal	**99.49%**	**100.00%**	**99.63%**	**99.67%**	**99.55%**	**99.73%**	**100.00%**	**99.70%**	**99.42%**	**99.74%**	**100.00%**	**100.00%**	**99.73%**
4. Telephone Accessibility	Within 30 seconds,	Total	16976	15573	15156	14069	14585	13805	14434	17169	14723	15921	15400	10325	178136
	65% or More	Total Within Goal	7325	7125	9210	10795	12429	11254	10146	11064	10826	12224	11253	7723	121374
		% within Goal	**43.15%**	**45.75%**	**60.77%**	**76.73%**	**85.22%**	**81.52%**	**70.29%**	**64.44%**	**73.53%**	**76.78%**	**73.07%**	**74.80%**	**68.14%**
5. Appointments Met	90% or More	Total	18	7	29	16	17	8	8	11	10	19	11	10	164
		Total Within Goal	18	6	29	16	16	8	8	11	10	19	11	10	162
		% within Goal	**100.00%**	**85.71%**	**100.00%**	**100.00%**	**94.12%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**98.78%**
6. Written Response to Inquiries	Within 10 Working Days,	Total	2	2	1	1	1	2	1	1	1	2	2	1	17
	80% or More	Total Within Goal	2	2	1	1	1	2	1	1	1	2	2	1	17
		% within Goal	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
7. Emergency Responses - Urban	Onsite within 60 minutes,	Total	22	27	26	29	35	58	35	31	23	23	23	36	368
	80% or More	Total Within Goal	21	25	25	27	33	52	33	29	20	23	21	35	344
		% within Goal	**95.45%**	**92.59%**	**96.15%**	**93.10%**	**94.29%**	**89.66%**	**94.29%**	**93.55%**	**86.96%**	**100.00%**	**91.30%**	**97.22%**	**93.48%**
8 Emergency Response - Rural	Not Applicable to EWU	Total	0	0	0	0	0	0	0	0	0	0	0	0	0
		Total Within Goal	0	0	0	0	0	0	0	0	0	0	0	0	0
		% within Goal	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

RELIABILITY INDICES: 2007

Indicators	*Low Point of Range**	*High Point of Range**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
1. SAIDI	1.1953	2.6495	0.0475	0.1513	0.0341	0.0172	0.0979	0.2615	0.0908	0.2006	0.0340	0.1267	0.0337	0.0996	**1.1951**
2. SAIFI	2.2013	3.1541	0.1289	0.2520	0.0757	0.0884	0.1432	0.3981	0.2474	0.2928	0.0697	0.1157	0.0501	0.2476	**2.1097**
3. CAIDI	0.4424	0.8400	0.3684	0.6005	0.4501	0.1948	0.6835	0.6570	0.3672	0.6851	0.4881	1.0953	0.6734	0.4022	**0.5665**

* 3 YR RANGE (yr 2004 - 2006)

SERVICE QUALITY REQUIREMENTS: 2008

Indicators	Standards		Jan	Feb	Mar	Apr	May	Jun	YTD
1. New Connections - Low Voltage	Within 5 Working Days, 90% or more	Total	17	15	16	19	27	23	117
		Total Within Goal	17	15	16	19	27	23	117
		% within Goal	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
2. New Connections - High Voltage	Within 10 Working Days 90% or more	Total	0	0	1	0	0	0	1
		Total Within Goal	0	0	1	0	0	0	1
		% within Goal	**n/a**	**n/a**	**100.00%**	**n/a**	**n/a**	**n/a**	**100.00%**
3. Underground Cable Locates	Within 5 Working Days 90% or more	Total	268	217	246	495	466	443	2135
		Total Within Goal	268	217	241	490	466	441	2123
		% within Goal	**100.00%**	**100.00%**	**97.97%**	**98.99%**	**100.00%**	**99.55%**	**99.44%**
4. Telephone Accessibility	Within 30 seconds, 65% or More	Total	15633	12786	11537	14567	14348	13163	82034
		Total Within Goal	11989	10248	9272	10667	11333	11790	65300
		% within Goal	**76.69%**	**80.15%**	**80.37%**	**73.23%**	**78.99%**	**89.57%**	**79.60%**
5. Appointments Met	90% or More	Total	23	1	20	21	7	12	84
		Total Within Goal	23	1	20	21	7	12	84
		% within Goal	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
6. Written Response to Inquiries	Within 10 Working Days, 80% or More	Total	3	2	2	1	2	1	11
		Total Within Goal	3	2	2	1	2	1	11
		% within Goal	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**
7. Emergency Responses - Urban	Onsite within 60 minutes, 80% or More	Total	24	26	22	30	26	48	176
		Total Within Goal	24	26	22	30	24	47	173
		% within Goal	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**92.31%**	**97.92%**	**98.30%**
8. Emergency Response - Rural	Not Applicable to EWU	Total	0	0	0	0	0	0	0
		Total Within Goal	0	0	0	0	0	0	0
		% within Goal	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**

RELIABILITY INDICES: 2008

Indicators	Low Point of Range*	High Point of Range*	Jan	Feb	Mar	Apr	May	Jun
1. SAIDI	1.1951	2.6495	0.1921	0.0166	0.0378	0.0173	0.2509	0.1387
2. SAIFI	2.1097	3.1541	0.2151	0.0220	0.0186	0.0444	0.3316	0.4840
3. CAIDI	0.5665	0.8400	0.8931	0.7540	2.0332	0.3886	0.7566	0.2866

* 3 YR RANGE (yr 2005 - 2007)

Schedule 1-2-2

Overview

Schedule of Overall Revenue
Deficiency/Sufficiency

Revenue Sufficiency / Deficiency

		2009 Projection
Utility Income	*(see below)*	9,919,587
Utility Rate Base		201,034,177
Indicated Rate of Return		4.93%
Requested / Approved Rate of Return		7.40%
Sufficiency / (Deficiency) in Return		(2.46%)
Net Revenue Sufficiency / (Deficiency)		**-4,948,729**
Provision for PILs/Taxes		-2,178,577
Gross Revenue Sufficiency / (Deficiency)		**-7,127,306**
Deemed Overall Debt Rate		*6.61%*
Deemed Cost of Debt		*7,976,865*
Utility Income less Deemed Cost of Debt		*1,942,723*
Return On Deemed Equity		*2.42%*

UTILITY INCOME

Total Net Revenues	47,108,248
OM&A Expenses	24,768,258
Depreciation & Amortization	11,487,968
Taxes other than PILs / Income Taxes	513,858
Total Costs & Expenses	36,770,084
Utility Income before Income Taxes / PILs	10,338,164
PILs / Income Taxes	418,577
Utility Income	**9,919,587**

Schedule 1-2-3

Overview

Numerical Schedules Detailing the
Causes of the Deficiency/Sufficiency

Revenue Requirement Summary

Rate Base		
2008 ending Net Fixed Assets	168,311,618	
2009 ending Net Fixed Assets	174,945,697	
Average Net Fixed Assets		171,628,658
Working Capital Allowance Base	196,036,797	
Working Capital Allowance	15.0%	29,405,520
Rate Base		**201,034,177**
Return On Rate Base		
Deemed Short-Term Debt %	4.00%	8,041,367
Deemed Long-Term Debt %	56.00%	112,579,139
Deemed Equity %	40.00%	80,413,671
Short-Term Interest	4.47%	359,449
Long-Term Interest	6.77%	7,617,416
Return On Equity	8.57%	6,891,452
Return On Rate Base		**14,868,316**
Distribution Expenses & Taxes		
OM&A	25,282,116	
Amortization	11,487,968	
PILs/Taxes	2,597,154	**39,367,238**
Revenue Offsets		**-2,443,803**
Distribution Revenue Requirement		**51,791,751**
Distribution Revenue at Existing Rates	*44,664,445*	
Revenue Sufficiency (Deficiency)	***-7,127,306***	

Schedule 1-3-1

Finance

Audited Financial Statements (2007)

Financial Statements of

ENWIN UTILITIES LTD.

Year ended December 31, 2007

KPMG

KPMG LLP
Chartered Accountants
618 Greenwood Centre
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Windsor ON N8W 5K8

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AUDITORS' REPORT

To the Shareholder

We have audited the balance sheet of Enwin Utilities Ltd. as at December 31, 2007 and the statements of retained earnings, earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Windsor, Canada
February 29, 2008

ENWIN UTILITIES LTD.

Balance Sheet
(In thousands of dollars)

December 31, 2007, with comparative figures for 2006

		2007		2006 (Restated) (See note 2)
Assets				
Current assets:				
Term deposit	$	-	$	1,000
Accounts receivable		17,575		22,356
Unbilled revenue		18,452		15,877
Due from related party (note 7)		-		849
Inventories		2,220		2,656
Prepaid expenses		246		1,435
		38,493		44,173
Capital assets (note 4)		175,200		190,772
Work in progress		458		183
Future payments in lieu of income taxes (note 13)		15,713		6,773
		191,371		197,728
	$	229,864	$	241,901

	2007	2006
		(Restated) (See note 2)

Liabilities and Shareholder's Equity

	2007	2006
Current liabilities:		
Bank indebtedness (note 6)	$ 14,455	$ 30,112
Accounts payable and accrued liabilities	23,160	23,969
Due to related parties (note 7)	7,288	5,135
Payments in lieu of income taxes payable	1,834	1,838
Regulatory liabilities (note 5)	5,010	504
Deferred revenue	329	965
Current portion of customer deposits	813	1,115
Current portion of long term borrowings	3,074	2,903
	55,963	66,541
Long-term liabilities:		
Customer deposits	8,002	4,673
Deferred revenue	-	1,353
Vested sick leave	17	62
Long-term borrowings (note 8)	52,424	55,318
Employee future benefits (note 9)	31,504	29,927
	91,947	91,333
Shareholder's equity:		
Common shares (note 11)	62,008	76,818
Contributed capital	516	516
Retained earnings	19,430	6,693
	81,954	84,027
Contingencies and commitments (notes 14, 15 and 16)		
	$ 229,864	$ 241,901

See accompanying notes to financial statements.

On behalf of the Board:

____________________ Director

____________________ Director

ENWIN UTILITIES LTD.

Statement of Retained Earnings
(In thousands of dollars)

Year ended December 31, 2007, with comparative figures for 2006

		2007		2006 (Restated) (See note 2)
Retained earnings (deficit), beginning of year	$	6,693	$	(4,256)
Net earnings for the year		15,737		12,949
Dividends declared		(3,000)		(2,000)
Retained earnings, end of year	$	19,430	$	6,693

See accompanying notes to financial statements.

ENWIN UTILITIES LTD.

Statement of Earnings
(In thousands of dollars)

Year ended December 31, 2007, with comparative figures for 2006

		2007		2006
				(Restated) (See note 2)
Revenue:				
Customer billing for electricity and services charges	$	227,635	$	224,755
Cost of electricity purchased		184,315		183,844
		43,320		40,911
Services provided to Windsor Utilities Commission (note 7)		8,614		7,318
Services provided to Enwin Energy Ltd. (note 7)		695		39
Maxess Networx		-		3,359
Other income from operations (note 18)		4,817		5,624
		57,446		57,251
Operating expenses		30,502		33,276
Earnings before the undernoted items and taxes		26,944		23,975
Amortization		10,985		12,346
Gain on sale of capital assets		(299)		(213)
Interest		5,172		5,679
Settlement of regulatory assets (liabilities) (notes 3 and 5)		-		(2,511)
		15,858		15,301
Earnings before taxes		11,086		8,674
Payments in lieu of taxes (note 13):				
Current		4,289		2,498
Future		(8,940)		(6,773)
		(4,651)		(4,275)
Net earnings for the year	$	15,737	$	12,949

See accompanying notes to financial statements.

ENWIN UTILITIES LTD.

Statement of Cash Flows
(In thousands of dollars)

Year ended December 31, 2007, with comparative figures for 2006

	2007	2006 (Restated) (See note 2)
Cash provided by (used in):		
Operations:		
Net earnings for the year	$ 15,737	$ 12,949
Add items not affecting cash:		
Amortization of capital assets	10,985	12,346
Change in employee future benefits	1,577	2,196
Gain on sale of capital assets	(299)	(213)
Future payments in lieu of income taxes	(8,940)	(6,773)
Change in work in progress	(275)	437
Change in customer deposits	3,027	380
Change in vested sick leave	(45)	3
Change in deferred revenue	(1,989)	(1,647)
Amortization of deferred debt issuance costs	180	179
Change in non-cash working capital (note 12)	3,018	(3,438)
	22,976	16,419
Financing:		
Decrease in bank indebtedness	(15,657)	(5,546)
Increase (decrease) in regulatory liabilities	4,506	(228)
Repayment of long-term borrowings	(2,903)	(2,742)
Due to related parties, net	3,002	(2,594)
Dividends declared	(3,000)	(2,000)
	(14,052)	(13,110)
Investments:		
Maturity of term deposit	1,000	-
Acquisition of capital assets	(10,307)	(12,569)
Proceeds on sale of capital assets	383	223
	(8,924)	(12,346)
Change in cash during the year	-	(9,037)
Cash, beginning of year	-	9,037
Cash, end of year	$ -	$ -

See accompanying notes to financial statements.

Enwin Utilities Ltd. is a local distribution company responsible for the transmission and distribution of electricity, as well as the service and maintenance of the City of Windsor's powerline infrastructure. Enwin Utilities Ltd. also provides billing, credit, financial and customer service on behalf of Enwin Enwin Energy Ltd., Windsor Utilities Commission ("the Commission") and the City of Windsor. Enwin Utilities Ltd. was formed on January 2, 2007 as a result of the amalgamation of the former Enwin Utilities Ltd. and Enwin Powerlines Ltd.

1. Significant accounting policies:

The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") including accounting guidelines prescribed by the Ontario Energy Board (the "OEB") in the Accounting Procedures Handbook (the "AP Handbook") for Electric Distribution Utilities. The significant accounting policies are summarized below.

In 2007, the Corporation adopted certain new accounting policies in order to comply with new CICA Handbook sections – see note 1(o).

a) Rate regulation:

The Corporation is regulated by the OEB under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity customers and for ensuring the distribution companies fulfill obligations to connect and service customers.

The economic impact of rate regulation is reported in these financial statements. Regulatory assets (liabilities) represent certain costs that may be recovered from (or refunded to) customers in future periods through the rate-making process. In its capacity to approve or fix rates, the OEB has specified the following regulatory treatments, which have resulted in accounting treatments that differ from GAAP for enterprises operating in a non-regulated environment:

(In thousands of dollars)

1. Significant accounting policies (continued):

Settlement variances:

The Corporation has deferred certain post-market opening retail settlement variances in accordance with Article 490 set out in the AP Handbook. The settlement variances relate primarily to service charges, non-competitive electricity charges, and power charges (note 5). The nature of the settlement variances is such that their balance shall change each reporting period-end date.

b) Inventories:

Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net market value, with cost determined on an average cost basis and market value determined on replacement cost basis.

c) Capital assets:

Capital assets are recorded at cost with cost being determined based on material, purchased services, internal labour and overhead as applicable.

Amortization is calculated on a straight-line basis over the estimated service lives of capital assets as follows:

Asset	Estimated service life
Buildings	50 years
Transformer station	40 years
Substation equipment	30 years
Distribution system - overhead	25 years
Distribution system - underground	25 years
Transformers	25 years
Meters	25 years
Services	25 years
Office equipment	10 years
Rolling stock	4 - 8 years
Computer hardware and software	3 - 5 years
Other equipment	8 - 20 years
Assets under capital lease	3 years

d) Work in progress:

Work in progress is recorded at cost with cost being determined based on material, purchased services, internal labour and overhead as applicable.

1. Significant accounting policies (continued):

e) Customer deposits:

Customer deposits include cash collections from customers, which are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their service. Customer deposits are also refundable to customers demonstrating an acceptable level of credit risk, as determined by the Corporation. Customer deposits also include refundable maintenance deposits from developers, deposits for recoverable work orders, and prudential deposits from retailers.

f) Employee future benefits:

The Corporation provides post employment benefits such as compensated sick leave and post retirement benefits such as life insurance, supplemental health and dental coverage for employees who retire from active employment.

The Corporation accrues its obligations under employee benefit plans and the related costs.

The cost of retirement benefits earned by employees is actuarially determined using the projected benefit method pro rated on service and management's best estimate of salary escalation, retirement ages of employees and expected health care costs.

The excess of net actuarial gains (losses) over 10% of the benefit obligation is amortized on a straight-line basis over the average remaining service period of the employees, which is eight years at December 31, 2007 (2006 – eight years). Settlement gains or losses are recognised in the year in which they arise.

g) Pension plan:

The Corporation provides a pension plan for its employees through the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The fund is a contributory defined benefit pension plan.

1. **Significant accounting policies (continued):**

h) Revenue recognition:

Revenue is recognized on the accrual basis and includes an estimate of unbilled revenue representing electricity consumed by customers since the date of each customer's last meter reading.

i) Deferred revenue:

Revenues collected through the Corporation's distribution rates, for the conservation and demand management program which have not yet been expended, are recorded as deferred revenue.

j) Vested sick leave:

Under the sick leave benefit plan, unused sick leave can accumulate and certain employees hired prior to January 1, 1977 may become entitled to a cash payment when they leave the Corporation's employment. The liability for those accumulated days, to the extent that they have vested and could be taken in cash by an employee upon termination, has been recorded.

k) Related party transactions:

Transactions with related parties are measured at the exchange amount, which is the amount of consideration paid or received as established and agreed to by the related parties.

Related parties include Enwin Energy Ltd., Windsor Utilities Commission and the Corporation of the City of Windsor.

l) Payments in lieu of taxes ("PILs"):

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) ("ITA") and the Ontario Corporations Tax Act ("OCTA").

Pursuant to the *Electricity Act, 1998*, the Corporation is required to make payments in lieu of corporate taxes to Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the ITA and the OCTA as modified by the *Electricity Act, 1998*, and related regulations.

1. **Significant accounting policies (continued):**

l) Payments in lieu of taxes ("PILs") (continued):

The Corporation provides for amounts in lieu of corporate income taxes using the asset and liability method. Under the asset and liability method, future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the date of enactment or substantive enactment. A valuation allowance is recorded against any future tax asset if it is more likely than not the asset will not be realized.

m) Long-lived assets:

Long-lived assets, including capital assets, are amortized over their useful lives. The Corporation periodically reviews the useful lives and the carrying values of its long-lived assets for continued appropriateness. The Corporation reviews for impairment long-lived assets (or asset groups) to be held and used whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. If the sum of the undiscounted expected future cash flows expected to result from the use and eventual disposition of an asset is less than its carrying amount, it is considered to be impaired. An impairment loss is measured at the amount by which the carrying amount of the asset exceeds its fair value. When quoted market prices are not available, the Corporation uses the expected future cash flows discounted at a rate commensurate with the risks associated with the recovery of the asset as an estimate of fair value.

1. **Significant accounting policies (continued):**

n) Use of estimates:

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of the financial statements. Certain estimates are also required as regulations, which will ultimately determine the actual results, have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Significant estimates subject to such estimates and assumptions include the carrying value of capital assets, future tax assets or liabilities, employee future benefits and valuation allowances for accounts receivable, inventories and future PILs. Due to these uncertainties, actual results reported in future periods may differ from those estimates.

o) Adoption of new CICA Handbook sections:

In 2007 the Corporation adopted new CICA Handbook *Section 3855 - Financial Instruments – Recognition and Measurement ("CICA 3855").* The Corporation also considered new Handbook *Sections 1530 – Comprehensive Income* and *3865 – Hedges*, and determined that they had no impact on the reported results or financial position in 2007.

CICA 3855 requires that transaction costs associated with the issue of debt should either be expensed as incurred, or should be deferred and offset against the carrying value of the related debt. If the costs are deferred, they should be amortized into income over the life of the related debt, using the effective interest method of amortization.

The Corporation has elected to defer and amortize transaction costs relating to debt issued in earlier years. Management has determined that the required change in amortization from straight-line to the effective interest method does not have a significant impact on the carrying value of the remaining deferred costs.

The adoption of CICA 3855 has no impact on net assets at January 1 or December 31, 2006 or on the reported results or cash flows for 2006. Debt issue costs have been offset against the related debt in the 2006 balance sheet to provide consistent presentation with the 2007 financial statements.

2. Restatement of 2006 financial statements:

As described above Enwin Utilities Ltd. and Enwin Powerlines Ltd. amalgamated January 2, 2007 to form Enwin Utilities Ltd. Until and including this date, both entities had been wholly-owned subsidiaries of Windsor Canada Utilities Ltd.

The 2006 financial statements have been restated to present the results and cash flows for the year, and the financial position at December 31, 2006, as if the amalgamation had taken place on December 31, 2005. Balances and transactions between the two predecessor entities which had previously been reported in 2006 have been eliminated in the presentation of the revised financial statements.

3. Electricity industry restructuring and regulation:

On October 30, 1998, the provincial government passed the Electricity Act and the Ontario Energy Board Act, collectively known as Bill 35, the Energy Competition Act, 1998. The Electricity Act established the framework for a competitive market for the sale of electricity in the Province of Ontario. The Ontario Energy Board Act gave the OEB the power to licence and regulate all market participants, and set transmission and distribution rates.

The electricity marketplace was deregulated on May 1, 2002 and electricity generators, electricity wholesalers and retailers began competing for customers. As mandated by the Energy Competition Act (Bill 35), a three-year phase-in (2001 to 2003) of the electricity distributors' commercial rate of return and provincial tax increases was implemented to smooth the impact on consumers of the transition of distributors from municipal electric utilities.

However, in response to volatile and rising electricity prices in 2002, the Province of Ontario enacted The Electricity Pricing, Conservation and Supply Act, 2002 (Bill 210). This new legislation, which was given Royal Assent on December 9, 2002, effectively froze distribution rates until 2007, and fixed the commodity price paid by low volume and designated customers at 4.3 cents per kilowatt-hour (kWh) retroactive to May 1, 2002.

3. Electricity industry restructuring and regulation (continued):

On December 18, 2003, Bill 210 was superseded and modified by Bill 4 when a newly elected provincial government passed the Ontario Energy Board Amendment Act (Electricity Pricing), 2003 which enabled further changes to the pricing of electricity in Ontario.

In June 2004, the provincial government introduced legislation to further restructure the electricity industry. On December 9, 2004, this new legislation, the Electricity Restructuring Act, 2004 (Bill 100) received Royal Assent. Bill 100 made amendments to the Electricity Act, and the OEB Act, 1998. The legislation deals primarily with supply and conservation, reassigns responsibilities to different entities, and lays out the roles and responsibilities for the new Ontario Power Authority (OPA). Additionally, the Independent Market Operation (IMO) was renamed the Independent Electricity System Operator (IESO) to better reflect its new role.

a) Electricity commodity pricing:

On April 1, 2004, Bill 4 removed the 4.3 cents commodity price freeze, and a two-tiered pricing regime was implemented for all customers who were eligible for the 4.3 cents commodity rate. The commodity price was fixed at 4.7 cents per kWh for the first 750 kWh of consumption per month and 5.5 cents per kWh for any incremental monthly consumption thereafter. This current two-tiered pricing regime remained in place until April 1, 2005 when the OEB instituted a regulated price plan ("RPP").

Under RPP, the existing two-tier structure was continued. From April 1, 2005 to October 31, 2005 the threshold was 750 kWh/month. From November 1, 2005 for non-residential RPP customers the threshold continued to be 750 kWh/month, but for residential customers, the first tier began to vary seasonally. The threshold has been set at 1,000 kWh/month from November 1 to April 30 (winter), and 600 kWh/month from May 1 to October 31 (summer). RPP pricing is set by the OEB. Prices are reviewed and may change every six months based on an updated OEB forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous period.

(In thousands of dollars)

3. Electricity industry restructuring and regulation (continued):

b) Recovery of regulatory assets (liabilities):

Bill 210 eliminated the ability of electricity distributors to recover a variety of costs incurred since their preparations for market opening. These costs were deemed to be "regulatory assets (liabilities)", and are reflected in the balance sheet in anticipation of their future recovery (or refund) via electricity distribution charges. Regulatory assets (liabilities) are stated after evaluation of amounts expected to be collected.

4. Capital assets:

			2007
	Cost	Accumulated amortization	Net book value
Land	$ 1,428	$ –	$ 1,428
Buildings	21,389	3,224	18,165
Transformer station	30,249	4,799	25,450
Substation equipment	2,335	959	1,376
Distribution system - overhead	64,665	20,730	43,935
Distribution system - underground	60,988	22,703	38,285
Transformers	44,851	14,906	29,945
Meters	7,675	2,811	4,864
Services	153	2	151
Office equipment	1,192	796	396
Rolling stock	2,347	2,037	310
Computer hardware and software	11,374	9,669	1,705
Other equipment	2,750	1,435	1,315
Assets under capital lease	4,277	4,257	20
Assets in progress	7,855	–	7,855
	$ 263,528	$ 88,328	$ 175,200

No amortization is taken on assets in progress until they are placed into use.

(In thousands of dollars)

4. Capital assets (continued):

	Cost	Accumulated amortization	2006 Net book value
Land	$ 1,518	$ –	$ 1,518
Buildings	21,269	2,794	18,475
Transformer station	30,169	3,974	26,195
Substation equipment	2,335	878	1,457
Distribution system - overhead	61,035	17,727	43,308
Distribution system - underground	60,516	19,825	40,691
Transformers	42,729	12,708	30,021
Meters	7,149	2,439	4,710
Office equipment	1,124	677	447
Rolling stock	2,588	2,283	305
Fibre optic network	15,128	5,704	9,424
Computer hardware and software	11,300	8,978	2,322
Other equipment	2,481	1,203	1,278
Assets under capital lease	4,277	4,225	52
Assets in progress	10,569	–	10,569
	$ 274,187	$ 83,415	$ 190,772

5. Regulatory assets (liabilities):

The "Electricity Pricing, Conservation and Supply Act, 2002" (Bill 210) deems certain costs and variance account balances to be accounted for as regulatory assets (liabilities) (note 1a).

The Ontario Energy Board Amendment Act, (Electricity Pricing), 2003 (Bill 4) allowed local distribution companies ("LDC's") to adjust their distribution rates to recover some of their regulatory assets, on an interim basis, over a four year period starting April 1, 2004.

On December 9, 2004, the OEB released its process for OEB review of the prudence of the total regulatory asset amounts claimed by electricity distributors. In 2006, the Corporation received approval for recovery of its 2004 regulatory assets/liabilities. Balances in these accounts have been updated to reflect this settlement.

(In thousands of dollars)

5. Regulatory assets (liabilities) (continued):

		2007		2006
Post-market opening retail settlement variances	$	(6,267)	$	(2,620)
Retail cost variances		193		194
Miscellaneous deferred debits		11		10
Smart Meters		(454)		(168)
Other regulatory assets		1,302		1,246
		(5,215)		(1,338)
Recovery of regulatory assets		247		1,062
Reserves		(42)		(228)
	$	(5,010)	$	(504)

6. Bank indebtedness:

The Corporation has a long-term agreement with a Canadian chartered bank for an available line of credit in the amount of $75,000. Interest charged on outstanding borrowings incurred by the Corporation is calculated at the bank's prime rate less .85% or bankers' acceptances plus 45 basis points.

The line of credit restricts the availability of the Corporation to lien assets.

7. Related party transactions:

a) Under a Management Services Agreement effective January 1, 2000, the Corporation provides certain finance, administration, human resource, management and other support services to the Commission. The total amount charged to the Commission for the year ended December 31, 2007 was $8,614 (2006 - $7,318).

b) Under a Management Services Agreement effective January 1, 2000, the Corporation provides certain finance, administration, human resource, management and other support services to Enwin Energy Ltd. The total amount charged to Enwin Energy Ltd. for the year ended December 31, 2007 was $695 (2006 - $39).

c) The Corporation provides sewer surcharge billing and collecting and street lighting maintenance for the City of Windsor for which it charges a fee. The total amount charged to the City of Windsor for the year ended December 31, 2007 was $2,778 (2006 - $2,100).

(In thousands of dollars)

7. Related party transactions (continued):

d) The Corporation collects and remits the sewer surcharge on behalf of the City of Windsor. The total amount owing to the City of Windsor at year-end relating to sewer surcharge was $4,029 (2006 - $3,064).

e) The amounts due from related party consists of:

	2007	2006
Due from Windsor Utilities Commission	$ –	$ 849

The amounts due to related parties consist of:

	2007	2006
Due to Enwin Energy Ltd.	$ 654	$ 71
Due to Windsor Utilities Commission	1,082	–
Due to Windsor Canada Utilities Ltd.	2,000	2,000
Due to the City of Windsor (net)	3,552	3,064
	$ 7,288	$ 5,135

The amount due to Windsor Canada Utilities Ltd. represents a dividend payable. Dividends declared during the year were $3,000, with $1,000 paid in the year.

The amount due to (from) the Commission bears interest at the Bank of Canada rate, while the amount due to Windsor Canada Utilities Ltd. and the City of Windsor are non-interest bearing. These amounts have no specified repayment terms.

f) On January 2, 2007, the Corporation sold the net assets of the telecommunication division to Enwin Energy Ltd., for a net purchase price of $14,810, which represented book value. The Corporation did not make a gain or loss on the sale. Consideration was received via a capital reduction from the Corporation's parent, Windsor Canada Utilities Ltd. (note 11).

(In thousands of dollars)

8. Long-term borrowings:

	2007	2006
Debentures payable (i)	$ 50,000	$ 50,000
Promissory note payable to City of Windsor (ii)	6,330	9,233
Less unamortized debt issuance costs	(832)	(1,012)
	55,498	58,221
Less current portion due	3,074	2,903
Total long-term borrowings	$ 52,424	$ 55,318

(i) In 2002, the Corporation, along with four other Ontario local distribution companies, entered into an agreement with Electricity Distributors Finance Corporation ('EDFIN"), whereby EDFIN acquired unsecured debentures in the amount of $175,000 from the participants. The Corporation's share of these debentures amounted to $50,000. EDFIN, in turn, issued unsecured debentures for these amounts to TD Securities Inc. who sold them to external investors. The Corporation must pay semi-annual payments of interest on February 15 and August 15 in each year until and including maturity on August 15, 2012. Principal repayment is due on maturity and interest will accrue on the outstanding principal amount on the basis of a rate of 6.45% per annum.

(ii) A promissory note payable to the City of Windsor dated December 20, 2001 is unsecured, due on demand and bears interest at 6% per annum payable quarterly. The note has scheduled principal repayments and matures in 2009. The City of Windsor has agreed to not demand repayments beyond the schedule set out in the note.

Scheduled principal repayments on long-term debt are as follows:

2008	3,074
2009	3,256
2010	–
2011	–
2012	50,000
	$ 56,330

(In thousands of dollars)

9. Employee future benefits:

The Corporation pays certain health, dental and life insurance benefits on behalf of its retired employees.

The Corporation measures its accrued benefit obligation for accounting purposes as at December 31 each year. A valuation date of December 31, 2005 has been used and the results have been extrapolated to December 31, 2007.

Information about the Corporation's defined benefit plan is as follows:

		2007		2006
Change in accrued benefit obligation:				
Accrued benefit obligation, beginning of year	$	29,927	$	27,731
Current service cost		1,060		1,038
Interest cost		1,780		1,710
Amortization of actuarial loss		258		322
Settlement gain		(246)		–
Benefits paid		(1,275)		(874)
Accrued benefit obligation, end of year	$	31,504	$	29,927
Funded status:				
Unfunded benefit obligation	$	(34,321)	$	(35,551)
Unamortized net actuarial loss		2,817		5,624
Amount recognized in the balance sheet:				
Accrued benefit liability	$	(31,504)	$	(29,927)

The significant actuarial assumptions adopted in measuring the Corporation's accrued benefit obligations are as follows:

	2007	2006
Discount rate	5.35%	5%
Rate of compensation increase	3%	3%
Medical trend rate:		
Initial	6%	7%
Ultimate	4%	4%
Year of ultimate level	2010	2010

ENWIN UTILITIES LTD.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2007

9. Employee future benefits (continued):

		2007		2006
Components of net periodic benefit cost:				
Current service cost	$	1,060	$	1,038
Interest cost		1,780		1,709
Amortization of actuarial loss		258		322
Settlement gain		(246)		–
Net periodic benefit costs	$	2,852	$	3,069

10. Pension plan:

The Corporation participates in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer plan, on behalf of its employees. The plan is a contributory defined benefit pension plan. In 2007, the contribution rates were 6.5% for employee's earnings below the year's maximum pensionable earnings and 9.6% thereafter. During 2007, the Corporation contributed $1,281 (2006 – $1,315) to the fund.

11. Share capital:

		2007		2006
Authorized:				
Unlimited common shares				
Issued:				
22,000 common shares	$	62,008	$	76,818

The MaXess Networx division was transferred effective January 2, 2007 from Enwin Utilities Ltd. to Enwin Energy Ltd. The net assets of the division were transferred in consideration for a promissory note of $14,810. This note was subsequently used in consideration for a share capital reduction by the Corporation's parent company, Windsor Canada Utilities Ltd.

(In thousands of dollars)

12. Cash flow information:

The change in non-cash working capital is as follows:

		2007		2006
Decrease (increase) in current assets:				
Accounts receivable	$	4,781	$	(4,005)
Unbilled revenue		(2,575)		4,879
Inventories		436		(274)
Prepaid expenses		1,189		(737)
		3,831		(137)
Increase (decrease) in current liabilities:				
Accounts payable and accrued liabilities		(809)		(5,061)
Payments in lieu of income taxes payable		(4)		1,760
		(813)		(3,301)
	$	3,018	$	(3,438)

Payments in lieu of income taxes and interest paid during the year amounted to $2,547 (2006 – $1,320) and $4,784 (2006 – $6,312) respectively. Total payments in lieu of taxes paid, life to date, amounted to $8,839.

(In thousands of dollars)

13. Payments in lieu of taxes:

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Corporation's future tax liabilities and assets are as follows:

	2007	2006
Future tax liabilities:		
Deferred debt issuance costs	$ 221	$ 247
Total future tax liabilities	$ 221	$ 247
Future tax assets:		
Capital assets	$ 10,787	$ 10,272
Employee future benefits	2,819	2,686
Intangible assets	2,323	2,763
Other	5	21
Total future tax assets before valuation allowance	15,934	15,742
Valuation allowance for future tax assets	–	(8,722)
Total future tax assets	15,934	7,020
Net future tax assets	$ 15,713	$ 6,773

14. Liability insurance:

The Corporation is a member of the Municipal Electrical Reciprocal Insurance Exchange ("MEARIE"), a self-insurance plan that pools the liability risks of all the Municipal Electric Utilities in Ontario. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE for the years in which the Corporation was a member.

To December 31, 2007, the Corporation has not been made aware of any additional assessments.

Participation in MEARIE covers a three-year underwriting period, which expires January 1, 2010. Notice to withdraw from MEARIE must be given six months prior the commencement of the next three-year underwriting term.

(In thousands of dollars)

15. Contingencies:

The Corporation is periodically subject to lawsuits in which it is the defendant. In the opinion of management, the ultimate resolution of any current lawsuit would not have a material effect on the financial position of the Corporation.

16. Commitments:

The Corporation is committed to minimum annual lease payments under various operating leases as follows:

2008	$	866
2009		845
2010		739
2011		598
2012 and thereafter		936
	$	3,984

17. Fair value of financial instruments:

The carrying values of accounts receivable, unbilled revenue, bank indebtedness, accounts payable and accrued liabilities and the promissory note, approximate fair value due to the short maturity of these instruments.

The fair value of customer deposits, deferred revenue and amounts due to related parties is not determinable due to the uncertainty of the repayment terms and/or the revenue recognition process.

The debentures payable have a fair value of $51,300 at December 31, 2007, based on market prices for similar debt.

Financial assets held by the Corporation expose it to credit risk. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets.

The Corporation earns its revenue from a broad base of customers located principally in Windsor. No single customer would account for revenue or an accounts receivable balance in excess of 10% of the respective reported balances.

ENWIN UTILITIES LTD.

Notes to Financial Statements (continued)
(In thousands of dollars)

Year ended December 31, 2007

18. Other income from operations:

		2007		2006
Change in occupancy	$	214	$	184
Late payment and collection charges		1,031		1,023
Other operating revenues		708		816
Services provided to others		–		1,036
Pole rental		444		436
Sale of scrap		397		193
Sewer surcharge billing and collecting		2,023		1,565
Finance income on lease		–		371
	$	4,817	$	5,624

Schedule 1-3-2

Finance

Pro Forma Statements (2008 and 2009)

Profit & Loss Variance Analysis

Account Grouping	2009 @ existing rates	2008 Projection
3000-Sales of Electricity	170,754,681	174,834,148
3050-Revenues From Services - Distribution	44,934,094	45,519,930
3100-Other Operating Revenues	1,854,838	1,840,794
3150-Other Income & Deductions	2,012,958	2,061,564
3200-Investment Income	84,000	84,000
3350-Power Supply Expenses	-170,754,681	-174,834,148
Net Revenues	48,885,890	49,506,288
3500-Distribution Expenses - Operation	2,284,473	2,237,577
3550-Distribution Expenses - Maintenance	2,953,609	2,873,040
3650-Billing and Collecting	1,283,494	1,284,475
3700-Community Relations	53,949	59,335
3800-Administrative and General Expenses	18,192,733	16,192,418
3950-Taxes Other Than Income Taxes	513,858	484,248
OM&A Expenses	25,282,116	23,131,093
3850-Amortization Expense	11,487,968	10,915,804
Earnings Before Interest & Taxes	12,115,806	15,459,391
3900-Interest Expense	5,390,821	5,402,822
Earnings Before Tax	6,724,985	10,056,569
4000-Income Taxes	418,577	3,601,172
Net Income excluding Extraordinary Items	6,306,408	6,455,396
4100-Extraordinary & Other Items	16,802	12,357
Net Income	**6,289,606**	**6,443,039**

Balance Sheet Trend

Account Grouping	2008 Projection	2009 @ existing rates
1050-Current Assets	41,253,339	41,082,503
1100-Inventory	2,500,000	2,500,000
1150-Non-Current Assets	16,464,888	16,314,030
1200-Other Assets and Deferred Charges	-4,877,974	-5,097,567
1300-Intangible Plant		
1450-Distribution Plant	232,006,192	242,274,369
1500-General Plant	46,828,628	56,252,438
1550-Other Capital Assets	-2,129,394	-2,587,501
1600-Accumulated Amortization	-99,965,403	-112,565,204
Total Assets	**232,080,276**	**238,173,068**
1650-Current Liabilities	55,981,435	54,675,845
1700-Non-Current Liabilities	41,701,346	42,810,122
1800-Long-Term Debt	50,000,000	50,000,000
Total Liabilities	147,682,781	147,485,967
1850-Shareholders' Equity	84,397,494	90,687,101
Total Liabilities & Shareholders' Equity	**232,080,275**	**238,173,068**

Schedule 1-3-3

Finance

Reconciliation Between Financial Statements and Financial Results Filed

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED

The reconciliation of EWU's net income presented in the audited financial statements and net income included in the Reporting and Record-Keeping Requirements filing for the year ended December 31, 2007 is presented below.

Net Income Included in RRR for year-ended December 31, 2007

	2007 Actual Net Income (in 000's)
Audited Financial Statements	$15,737
RRR (USofA Account 3046)	$15,737
Difference	$0

Schedule 1-3-4

Finance

Proposed Accounting Treatment

PROPOSED ACCOUNTING TREATMENT

EWU's accounting policies are those described in the notes to its 2007 financial statements at Exhibit 1, Tab 3, Schedule 1. EWU is not proposing any changes to these treatments, nor were there any changes in EWU's accounting policies for any period under review.

Schedule 1-3-5

Finance

Rating Agency Reports

Rating Report

Report Date:
November 16, 2007

Previous Report:
September 9, 2005

Insight beyond the rating.

Electricity Distributors Finance Corporation

Analysts

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The Company

EDFIN was incorporated for the purpose of providing Ontario electric distributors with efficient access to the debt capital markets. EDFIN will purchase debentures and other evidences of indebtedness issued by LDCs and sell to investors, by way of private placement, certificates evidencing undivided co-ownership interests in such debentures or evidences of indebtedness. EDFIN has no assets or liabilities. EDFIN is administered by the MEARIE Group, a Canadian insurance supplier dedicated to the electricity sector. The three (formerly five) participating LDCs in EDFIN are PowerStream Inc., Enwin Utilities Ltd. (formerly Enwin Powerlines Ltd.), and Barrie Hydro Distribution Inc.

Recent Actions

September 1, 2005

Confirmed

Rating

Debt	Rating	Rating Action	Trend
Series 2002-1 Certificates	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating on the Series 2002-1 Certificates (Certificates) issued by Electricity Distributors Finance Corporation (EDFIN) at A (low) with a Stable trend. The rating is based on the lowest-rated of the three participants, Enwin Utilities Ltd (formerly Enwin Powerlines Ltd.), rated A (low).

The Certificates represent undivided co-ownership interests in unsecured debentures issued by the three participating local distribution companies (LDC Participants), namely PowerStream Inc. (PowerStream), Enwin Utilities Ltd. (Enwin) and Barrie Hydro Distribution Inc. (Barrie Hydro) to EDFIN. The obligations of the individual LDC Participants is several and not joint, and each LDC Participant is liable only for its obligations and not for the obligations of any others. Default of the obligations to EDFIN of one LDC Participant will result in a proportionate default of the unsecured debentures issued by EDFIN. Therefore, the rating of the Certificates is based on the rating of the lowest rated LDC Participant, Enwin.

DBRS has confirmed the rating of Enwin at A (low) with a Stable trend. Enwin continues to maintain a reasonable financial profile, reflecting its improving balance sheet and credit metrics. However, DBRS expects Enwin's heightened capital expenditure profile for the period 2007 to 2010 to create an external financing requirement. While the increased leverage is expected to affect Enwin's credit metrics, leverage is expected to be within 60%, thus enabling Enwin to maintain adequate metrics to support a rating of A (low). (Continued on page 2.)

Rating Considerations

Strengths

(1) Low business risk owing to predominantly regulated electricity distribution operations
(2) Solid balance sheets and reasonable credit metrics
(3) Strong franchise areas and favourable customer mix

Challenges

(1) Low regulatory returns
(2) Earnings are sensitive to the volume of electricity sold
(3) Refinancing risk
(4) Political risk and regulatory uncertainty

Financial Information

For 12 months ended June 30, 2007 (Unaudited)	Underlying Utility Debentures ($ millions)	Rate Base ($ millions)	Total Debt-to-Capital	EBIT Interest Coverage (times)	Cash Flow-to-Debt	DBRS Issuer Rating
PowerStream Inc.	100	481	56.0%	3.07	20.4%	A
Enwin Utilities Ltd.*	50	165	56.5%	2.08	15.8%	A (low)
Barrie Hydro Distribution Inc.	25	108	36.0%	4.49	31.1%	A

* Enwin figures are as of Dec 31, 2006

Rating Rationale (Continued from page 1.)

The rating of PowerStream has been confirmed at "A" with a Stable trend, as PowerStream continues to benefit from a strong and improved financial profile. However it expects leverage to increase marginally to 60% by 2008 due to the increased capital expenditures resulting from the construction of a new head office and the installation of Smart Meters. Given the Company's stated policy of maintaining leverage at 60%, in line with the Ontario Energy Board (OEB) approved deemed capital structure, DBRS expects the credit metrics to remain at a level appropriate for an "A" rating.

The rating of Barrie Hydro is confirmed at "A" with Stable trend, based largely on its solid and improved financial profile. Over the 2008 to 2011 period, Barrie Hydro expects to spend an average of $15 million annually on capital expenditures of which roughly 35% will be on servicing growth within its franchise area. DBRS expects this prolonged and heightened capital expenditure profile to create a fairly manageable external financing need without affecting the strong credit metrics in any significant way.

Overall, the three LDC Participants continue to benefit from a low level of business risk stemming from their regulated electricity distribution operations, solid financial profile and strong franchise areas with a favourable customer mix. The rating confirmation on the three LDC Participants is also supported by the improving regulatory outlook in Ontario. Over the next three years, the OEB will be re-basing the rates with full-cost-of-service proceedings for all distributors in Ontario. Barrie Hydro is in the first group to go through the re-basing of rates for the 2008 rate year, with the 3rd Generation Incentive Rate Mechanism applied in succeeding years, up to the 2010 rate year. The re-basing year for PowerStream and Enwin will be announced at a later date. The regulatory framework beyond 2010 remains uncertain, but DBRS expects the OEB will maintain a reasonable regulatory framework that should likely include cost of service recovery, a market-based rate of return and a performance-based incentive mechanism.

For the three LDC Participants, cash flows over the medium term will depend largely on the re-basing of rates, the 3rd Generation Incentive Rate Mechanism, and load growth with their respective service area.

Political intervention still remains a risk, especially in light of rising electricity commodity prices and anticipated increases in transmission and distribution rates over the medium- to longer-term.

Rating Considerations Details

Strengths

(1) Almost all earnings and cash flows are generated from the LDC Participants' low-risk, regulated distribution operations. The LDC Participants' exposure to higher-risk non-regulated businesses continues to remain limited.

(2) The LDC Participants continue to maintain solid balance sheets and reasonable credit metrics. These ratios are acceptable for their current rating categories given the low business risk for the LDC Participants stemming from their regulated electricity distribution operations.

(3) The franchise areas of all three LDC Participants have experienced population growth over the past five years. Further, the customer load profiles of the LDC Participants are reasonably well-diversified, consisting predominately of a residential and small commercial customer base. This provides a relatively stable and predictable demand load year over year, with limited influence from economic cycles.

Challenges

(1) The approved ROE of 9.0% for 2007 is low and has been in decline in recent years primarily due to the low-interest rate environment. Lower ROEs have a negative impact on earnings and cash flows.

(2) Earnings and cash flow for electricity-distribution companies are partially dependent on the volume of electricity sold and, hence, revenue earned from electricity sales. Seasonality, economic cyclicality and year-over-year changes in weather patterns directly impact the volume of electricity sold and revenue earned from electricity sales. In addition, economic growth impacts customer and load growth. However, the LDC Participants' generally favourable customer mix helps mitigate these risks.

(3) The three LDC Participants' long-term debt with EDFIN totalling $175 million matures on August 15, 2012. This bullet maturity poses a refinancing risk, although DBRS notes that the LDC Participants' credit profile, coupled with stable cash flows generated from strong franchise area with favourable customer mix, moderates this risk.

(4) Political risk and regulatory uncertainty is a challenge generally for LDCs in Ontario. The most significant risk in the near term is the possibility of political intervention, such as the imposition of rate caps with the passing of Bill 210 in December 2002, should the cost of electricity to end-consumers rise too quickly. Higher prices will arise from (a) costs associated with new generation capacity being added within the province; (b) higher distribution costs following a re-basing during the 2008 to 2010 period; and (c) the recovery of approximately $4 billion in transmission upgrades in the province during the next ten years. Should prices increase too quickly, there is a risk that the government would intervene in the rate-setting process. DBRS considers this risk to be reasonably low. Furthermore, there is regulatory uncertainty arising from the OEB's decision on December 20, 2006 concerning the Cost of Capital, and the 2nd Generation Incentive Regulation, which is effective only until 2010. The OEB has not yet provided details on the regulatory framework after 2010.

Structure

Issuer:	Electricity Distributors Finance Corporation
Amount:	$175.0 million
Term:	10 years through August 15, 2012
Interest Rate:	4.45%; payable semi-annually
Amortization:	Bullet maturity
Security:	None
Deposited Securities:	Each debenture is a direct obligation of the LDC Participant that issued the debenture. The LDC Participants' obligations are several and not joint, and each LDC is liable only for its obligations, and not for the obligations of any other LDC Participants.
Ranking:	All ownership interests rank equally with respect to their rights pursuant to each underlying debenture. Each underlying debenture is a direct, unsecured obligation of the LDC that issued it, ranking pari passu with all other debentures and prescribed debt instruments of such LDC. However, the unsecured debentures rank senior to all debt in the form of promissory notes held by the municipal shareholders of each LDC Participant.
Redemption:	Each participating LDC has the right to redeem, in part or in whole, the debenture issued by it, at any time prior to the maturity date, at a price equal to the greater of: (1) par, and (2) the Canada Yield Price plus accrued and unpaid interest.
Key Covenants:	Each LDC will: (1) ensure that its funded obligations do not exceed 75% of its consolidated net worth; (2) not pledge its primary assets; (3) not enter into any sale and leaseback transaction exceeding 10% of its consolidated net worth; (4) not invest in energy retailing beyond 20% of its consolidated net worth.

Regulation

Regulatory Update

Electricity distribution operations in Ontario are regulated by the OEB under the Electricity Act, 1998 (the Electricity Act).

Currently, the LDCs operate under a performance-based incentive mechanism with a ROE of 9.0%, based on a forward looking cost-of-service for the mid-year rate decision. The OEB's deemed capital structure is 60%/40% for PowerStream and 55%/45% for Enwin and Barrie Hydro (the deemed capital structure is changing, see below).

The purchased power included in distribution rates is a flow through to consumers determined by the OEB based on a blend of fluctuating, fixed and capped prices paid to generators under the Regulated Price Plan (RPP). The RPP is based on a forecast of expected costs over the next 12 months. If the cost of supplying electricity differs from what was forecast, the OEB may re-adjust electricity prices accordingly in the next price period, in order to true up the RPP prices with the prices paid to generators.

On December 20, 2006, the OEB issued a 2007 rate adjustment model (2nd Generation Incentive Regulation Model) and corresponding instructions to distributors for the purpose of adjusting distributor rates effective May 1, 2007. As a result, base distribution rates, exclusive of rate riders, will be adjusted formulaically to reflect an allowance for inflation subject to final determination by the OEB, and a fixed productivity offset of 1.0%. As such, no major financial impact for distributors, only a marginal increase in revenues is expected due to the inflation factor generally being slightly higher than the productivity factor.

The 2nd Generation Incentive Regulation will be in effect for the LDCs for a maximum of three years, until the 2010 rate year. In each of three subsequent years starting in 2008, one-third of the approximately 90 electricity distributors will have their distribution rates reviewed and reset by the OEB through a cost-of-service type of rate proceeding. LDCs rebased in 2008 will be subject to the 3rd Generation Incentive Rate Mechanism, applied in succeeding years up to the 2010 rate year. The two-thirds of LDCs that would not have gone through the re-basing process in 2008 will continue to have the 2nd Generation Incentive Regulation applied to their rates till they go the through the re-basing of rates in the following years, at which time the 3rd Generation Incentive Regulation will take effect. By 2010, all electricity distributors in Ontario would have undergone a re-basing of rates.

The OEB's December 20, 2006, decision also required that starting May 1, 2008, all distributors transition to a single deemed capital structure (60%/40%) over a three-year period. This will have no impact on PowerStream as its capital structure is already set at 60%/40%. However, Enwin and Barrie Hydro's regulated cash flow generation will be negatively affected by the decision, but the impact will be fairly modest.

The costs associated with the installation of Smart Meters is expected to be recovered through the imposition of a rate rider and the maintenance of a capital-variance account that will incorporate return-on-investment and amortization components, as well as an Operations Maintenance & Administration (OM&A) variance account that will reflect actual amounts spent plus carrying costs.

Rating

Debt	Rating	Rating Action	Trend
Series 2002-1 Certificates	A (low)	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Series 2002-1 Certificates	A (low)	A (low)	A (low)	A (low)	A (low)	A

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

The Company
Enwin Utilities Ltd. was created by the amalgamation of Enwin Powerlines Ltd., a regulated electricity distribution company, and Enwin Utilities Ltd., a management services company on January 1, 2007. The LDC serves approximately 85,000 customers in the Windsor service area. The newly amalgamated Enwin Utilities Ltd. is wholly-owned by Windsor Canada Utilities Ltd., which in turn is wholly-owned by the City of Windsor.

Enwin Utilities Ltd.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of Enwin Utilities Ltd. (formerly Enwin Powerlines Ltd.) at A (low) with a Stable trend. Enwin continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its reasonable financial profile and a strong record of cost containment.

On January 1, 2007, Enwin Powerlines Ltd., the regulated electricity distribution company, amalgamated with Enwin Utilities Ltd., the management services company, to create the new amalgamated entity, Enwin Utilities Ltd. (Enwin or the Company). Enwin Utilities Ltd. has assumed the EDFIN obligations. Given that the predecessor Enwin Utilities Ltd. did not have any debt on its balance sheet, the amalgamation should result in a slight improvement in the leverage of the amalgamated entity. Post-amalgamation, regulated activities are expected to comprise more than 90% of cash flows from operations.

Enwin continues to maintain a reasonable financial profile, reflecting its improving balance sheet and credit metrics. All credit metrics have improved from 2004 levels and continue to support the A (low) rating. The improved leverage is primarily attributable to positive free cash flows stemming from moderate dividend-payouts and relatively modest capital expenditures.

Enwin has significant exposure to large industrial customers, particularly the auto sector. Going forward, the downturn in the auto sector, especially the plant closure at Ford and many ancillary suppliers could pressure future cash flows. However, the Company anticipates that the relocation of some of the production from the closed Ford plant to other plants within Enwin's service area, the Windsor Casino expansion project and the opening of the Chrysler Paint Shop to somewhat mitigate the negative impacts. Enwin projects significantly heightened capital expenditures for 2007 to 2010, primarily due to the replacement of aging infrastructure, improving reliability and installation of Smart Meters. (Continued on page 6.)

Rating Considerations

Strengths
(1) Successful ongoing cost reduction program
(2) Expected efficiency improvement from amalgamation
(3) Strong financial profile

Challenges
(1) Managing the heightened capital expenditure profile
(2) Large exposure to industrial customers
(3) Low regulated returns
(4) Political and regulatory uncertainty

Financial Information

	For the year ended December 31				
	2006	2005	2004	2003	2002
EBIT interest coverage (times)	2.08	1.51	1.27	1.52	1.03
Total debt-to-capital	56.5%	63.0%	65.9%	64.5%	68.3%
Cash flow-to-total debt	15.8%	12.4%	9.7%	10.5%	5.7%
Operating cash flow ($ millions)	14.37	12.42	10.77	12.10	7.49
Net income before extras. ($ millions)	3.86	2.45	1.25	2.74	(0.23)
Operating margin	27.4%	21.2%	18.0%	23.0%	13.7%
Return on average equity	6.0%	4.2%	2.1%	4.4%	-0.4%
Electricity throughput (GWh)	3,128	3,339	3,173	3,235	3,386
Customer base	84,699	84,253	83,816	82,161	81,318

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Rating Rationale (Continued from page 5.)

DBRS expects the heightened capital expenditure profile combined with the amortizing promissory notes to create an external financing requirement of between $25 million to $30 million for the 2007 to 2010 period. While the increased leverage will affect the credit metrics of Enwin, the leverage is expected to be within 60%, thus enabling Enwin to maintain adequate credit metrics to sustain an A (low) rating. While cash flow from operations over the next two years will be primarily driven by population and load growth, cost savings as well as industrial demand, cash flows beyond 2008 will depend largely on the 2009 re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

Financial Profile and Outlook

	For the year ended December 31				
($ millions)	2006	2005	2004	2003	2002
EBITDA	21.41	17.66	16.03	17.84	13.07
EBIT	11.99	8.40	7.10	9.29	5.35
Interest Expense	5.76	5.57	5.57	6.13	5.17
Net income (before extras)	3.86	2.45	1.25	2.74	(0.23)
Depreciation	9.60	9.27	8.93	8.55	7.73
Other non-cash items	0.91	0.71	0.58	0.81	(0.01)
Cash Flow From Operations	14.37	12.42	10.77	12.10	7.49
Common dividends	(2.00)	(1.10)	-	-	-
Capex (net of capital contrib.)	(7.31)	(6.27)	(8.13)	(8.65)	(17.13)
Cash Flow Before Working Capital	5.05	5.06	2.64	3.45	(9.65)
Changes in working capital	(6.92)	2.47	(0.31)	(5.32)	(9.23)
Free Cash Flow	(1.87)	7.52	2.32	(1.87)	(18.88)
Adjusted for non-recurring non-cash	-	-	-	-	-
Share capital reduction	-	-	(1.10)	-	-
Other (investments)/dispositions	0.34	0.51	0.40	1.33	0.89
Settlement of regulatory assets/liabilities	2.51	-	-	-	
Increase in regulatory assets	(0.23)	5.59	4.13	1.57	(16.56)
Due to (from) related parties	7.87	(1.48)	-	-	
Net change in debt	(8.63)	(12.15)	(5.75)	(1.03)	34.54
Net Change in Cash	0.00	0.00	(0.00)	(0.00)	(0.00)

Key Financial Ratios	2006	2005	2004	2003	2002
Debt/capital	56.5%	63.0%	65.9%	64.5%	68.3%
EBITDA interest coverage	3.72	3.17	2.88	2.91	2.53
EBIT interest coverage	2.08	1.51	1.27	1.52	1.03
Cash flow-to-debt	15.8%	12.4%	9.7%	10.5%	5.7%
Return on Equity	6.0%	4.2%	2.1%	4.4%	-0.4%
Dividend payout	51.8%	44.9%	0.0%	0.0%	0.0%

Summary

- Enwin continues to maintain a reasonable financial profile, reflecting its improving balance sheet and credit metrics. Leverage, cash flow-to-debt and interest coverage ratios have improved from 2004 levels and continue to support the current rating.
- In F2006, the Company posted significantly increased operating results primarily due to increased distribution rates and operating cost containment.
- Positive free cash flow stemming from moderate dividend-payouts and relatively modest capital expenditures have been largely responsible for the significantly improved debt-to-capital ratio of 53.0% from the 2003 levels.
- The large swings in working capital are mainly due to timing differences in when the Company pays for, and is paid for, power costs.

Outlook

- Post amalgamation, regulated activities are expected to comprise more than 90% of cash flow from operations.
- Enwin has exposure to large industrial customers (approximately 30% of total load) which are largely tied to the auto sector. Therefore the economic outlook for the manufacturing sector will impact earnings.
- Earnings and cash flow from operations are expected to come under pressure largely due to the downturn in the auto sector. However, some economic mitigants (i.e., the Casino Windsor expansion and the opening of the Chrysler Paint Shop) are expected.
- Cash flows beyond 2008 will depend largely on the re-basing of rates and the 3rd Generation Incentive Mechanism as well as economic conditions.
- Enwin projects significantly increased capital expenditures for 2007 to 2010 primarily due to the replacement of aging infrastructure, improving reliability and installation of Smart Meters. While Enwin projects a capital expenditure of approximately $12 million for F2007, almost twice what it spent in F2006, annual capital expenditures from 2008 to 2010 are expected to average roughly $18 million. Smart Meter installations will comprise about 35% of the capital expenditure profile during the 2008 to 2010 period.
- DBRS expects the heightened capital expenditures, combined with the amortizing promissory notes to create a total external financing requirement of between $25 million to $30 million for the 2007 to 2010 period. While the increased leverage will affect the credit metrics of Enwin, leverage is expected to be within 60%, thus enabling Enwin to maintain adequate credit metrics to sustain the A (low) rating.

Long-Term Debt and Bank Lines

Summary

Enwin's long-term debt currently consists of the following:

- Senior unsecured debentures totalling $50 million issued to the Electricity Distributors Finance Corporation, maturing August 15, 2012.
- Amortising subordinate debt from the City of Windsor (promissory notes) totalling $9.233 million.

Enwin currently has an unsecured committed $75 million revolving term facility which is renewed annually.

- As at August 1, 2007, the Company was no longer required to post prudential with the IESO.

Outlook

The Company's liquidity position is reasonably strong, reflecting the $75 million credit facilities and stable cash flow from operations.

Working capital requirements and any short- to medium-term needs would be funded with the Company's revolver.

Income Statement	For the year ended December 31				
	2006	2005	2004	2003	2002
Gross distribution revenues	224.76	253.41	218.77	221.28	257.15
Power purchases	183.84	216.83	182.45	183.60	222.21
Net distribution revenues	40.91	36.57	36.33	37.68	34.94
Ancillary revenues	2.79	2.94	3.08	2.71	3.99
Net operating revenues	43.70	39.52	39.41	40.39	38.93
Expenses:					
Operating and maintenance	22.29	21.86	23.38	22.55	7.14
Services provided by related parties	-	-	-	-	18.19
Administrative and other operating	-	-	-	-	0.73
Depreciation	9.42	9.27	8.93	8.55	7.73
Total operating expenses	31.71	31.12	32.31	31.10	33.79
Operating income	11.99	8.40	7.10	9.29	5.14
Interest income	-	-	-	-	0.20
Earnings before interest & taxes (EBIT)	11.99	8.40	7.10	9.29	5.35
Interest expense	5.76	5.57	5.57	6.13	5.17
Non-cash financial charges	-	-	-	-	-
Net financial expense	5.76	5.57	5.57	6.13	5.17
Pre-tax income	6.24	2.83	1.53	3.16	0.18
Income taxes	2.38	0.38	0.28	0.42	0.41
Income before extraordinary items	3.86	2.45	1.25	2.74	(0.23)
Extraordinary items	9.42	0.07	(6.01)	(0.23)	(0.32)
Net Income	13.28	2.52	(4.75)	2.51	(0.56)

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Balance Sheet ($ millions)	As at December 31		
Assets	2006	2005	2004
Cash & short-term investments	-	-	-
A/R + unbilled revenue	35.9	35.2	33.0
Inventories	2.0	2.1	1.7
Regulatory assets	-	-	4.9
Other	0.1	8.7	6.3
Current Assets	38.0	46.1	45.8
Net fixed assets	152.4	145.7	148.7
Net investment in lease	-	8.6	9.0
Other assets	8.0	1.7	1.9
Total	198.4	202.0	205.4

	As at December 31		
Liabilities & Equity	2006	2005	2004
Short-term debt	34.7	40.6	48.9
A/P + accruals	19.9	27.7	24.3
Other Current Liab.	4	3	0
Current Liabilities	58.2	70.8	73.2
Customer deposits	0.5	0.8	1.0
Long-term debt	56.3	59.2	62.0
Other liabilities	13.4	12.5	12.0
Shareholders' equity	70.0	58.7	57.3
Total	198.4	202.0	205.4

	For the year ended December 31				
Ratios/Operating Stats	2006	2005	2004	2003	2002
Operating margin	27.4%	21.2%	18.0%	23.0%	13.2%
Pre-tax margin (bef. extras.)	14.3%	7.2%	3.9%	7.8%	0.5%
Return on avg. common equity	6.0%	4.2%	2.1%	4.4%	-0.4%
MWh sold/employee	10,825	11,594	11,840	11,233	11,139
Customers/employee	293	293	313	285	267
Oper. costs (1) /avg. customer ($)	265	263	283	278	326
Rate base — ($ millions)	165.4	165.4	161.3	161.3	161.3
Number of employees	289	288	268	288	304
Peak system demand (MW)	679	669	602	609	640
Electricity Throughputs					
Residential	683.5	740.0	675.0	684.0	666.8
General service	1,405.9	1,507.9	1,467.0	1,471.0	1,449.1
Large users	1,021.3	1,074.3	1,008.0	1,057.0	1,254.3
Street lighting	17.6	17.0	23.0	23.0	16.2
Total – (GWh)	3,128.3	3,339.2	3,173.0	3,235.0	3,386.3
Number of Customers					
Residential	76,407	75,921	75,107	73,512	72,501
General service	8,283	8,324	8,699	8,638	8,806
Large users	7	6	9	10	10
Street lighting	2	2	1	1	1
Total	84,699	84,253	83,816	82,161	81,318
Unit Revenues & Costs (cents per kWh throughputs)					
Average gross revenues	7.27	7.68	6.99	6.92	7.71
Power costs	5.88	6.49	5.75	5.68	6.56
Average net revenues	1.40	1.18	1.24	1.25	1.15
Variable costs (OM&A + PILS)	0.79	0.67	0.75	0.71	0.78
Fixed costs (deprec., int., gov't levies)	0.49	0.44	0.46	0.45	0.38
Total costs (excl. power costs)	1.27	1.11	1.20	1.16	1.16
Net margin	0.12	0.07	0.04	0.08	(0.01)

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

The Company
PowerStream Inc. was created in 2004 by the merger of three local distribution companies - Hydro Vaughan Distribution Inc., Markham Hydro Distribution Inc. and Richmond Hill Hydro Inc. PowerStream is 57% owned by the City of Vaughan and 43% by the Town of Markham. It is the fourth-largest electricity distribution company in Ontario, providing service to residential and business customers in the municipalities of Aurora, Markham, Richmond Hill and Vaughan. The Company serves approximately 232,000 customers in a service area of 640 square kilometers.

PowerStream Inc.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of PowerStream Inc. (PowerStream, or the Company) at "A" with a Stable trend. PowerStream continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its solid financial profile and a strong franchise area with a favourable customer mix.

The Company's financial metrics have steadily improved and continue to benefit from the growth in EBIT and earnings, which have trended upwards since the amalgamation in June 2004 (Hydro Vaughan, Markham Hydro and Richmond Hill Hydro). PowerStream had expected to achieve annual cost savings of $5 million to $7 million through synergies from the amalgamation, and reached this objective in both F2005 and F2006. Further, PowerStream's acquisition of Aurora Hydro in November 2005 has been earnings accretive and the Company has fully integrated Aurora Hydro into its operations, having completed all transitional issues pertaining to this acquisition. DBRS notes that PowerStream's management has been successful in steering the Company through the transitional challenges that were expected following the completion of the merger of three LDCs and the acquisition of Aurora Hydro within the last three years. PowerStream is expected to continue seeking additional growth opportunities through mergers/acquisitions. The Company currently has about 232,000 customers, and views a customer base in the 300,000-500,000 range to be optimal for a regulated distribution company. (Continued on page 12.)

Rating Considerations

Strengths

(1) Growth oriented franchise area: PowerStream expects a revenue growth of 2% to 4.6% over the next five years.
(2) Past experiences with merger, acquisition, and transition provide PowerStream with an advantage in future M&A transactions.
(3) Strong financial profile

Challenges

(1) Managing heightened capital expenditures
(2) Low regulated returns
(3) Political and regulatory uncertainty
(4) Identifying suitable M&A opportunities and managing transition.

Financial Information

	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended	
	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003P	2002P
EBIT interest coverage (times)	3.07	2.90	2.27	2.10	3.08	2.97
Total debt-to-capital (1)	56.0%	56.4%	57.9%	59.7%	51.5%	54.0%
Cash flow-to-total debt (1)	20.4%	19.9%	17.5%	n/a	21.0%	19.1%
Operating cash flow ($ millions)	51.6	49.5	43.0	24.0	50.0	45.4
Net income ($ millions)	21.5	19.5	14.6	7.7	21.2	18.3
Operating margin	42.8%	40.6%	39.7%	n/a	45.5%	42.2%
Return on average equity	11.0%	10.5%	8.4%	n/a	9.9%	18.1%
Electricity throughput (GWh)	6,810	6,743	6,800	6,019	5,920	5,733
Customer base	232,230	228,518	219,816	197,167	190,250	181,071

P = pro forma (consolidation of Richmond Hill Hydro, Hydro Vaughan, and Markham Hydro).
n/a = not applicable. n.a. = not available.
(1) Includes subordinate debt (promissory notes to shareholders).

Rating Rationale (Continued from page 11.)

The Company posted a free cash flow deficit in F2006 primarily due to significantly heightened capital expenditures, with the deficit primarily funded with cash. The ongoing construction of a new head office, and transformer station expansion project contributed to the large swing in capital expenditures for F2006.

Prior to July 2007, PowerStream had four sets of rates in effect, one for each municipality it served. In July 2007, OEB approved PowerStream's application to harmonize its rates. The rate harmonization resulted in a modest rate increase of 0.1%.

The Company expects its leverage to increase to 60% by 2008 due to increased capital expenditures resulting from the construction of the new head office and the installation of Smart Meters. However, given the Company's stated policy of maintaining leverage at 60%, in line with the OEB approved deemed capital structure, DBRS expects the credit metrics will remain at a level appropriate for an "A" rating. While cash flow from operations over the next two years will be primarily driven by population and load growth as well as cost savings, cash flows beyond 2008 will depend largely on the 2009 re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

Financial Profile and Outlook

	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended
($ millions)	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005 (1)	Dec. 31, 2004	Dec. 31, 2003P
EBITDA	80.25	75.73	69.90	39.34	72.67
EBIT	51.6	47.2	43.8	24.5	48.7
Interest Expense	16.8	16.3	19.3	11.7	15.8
Net income (before extras)	21.5	19.5	14.6	7.7	21.2
Depreciation	30.2	30.0	27.6	15.8	27.7
Other non-cash items	(0.0)	(0.0)	0.9	0.5	1.0
Cash Flow From Operations	51.6	49.5	43.0	24.0	50.0
Common dividends	(4.7)	(6.6)	-	-	-
Capital expenditures	(55.1)	(57.8)	(26.0)	(14.7)	(21.6)
Cash Flow Before Working Capital	(8.3)	(14.9)	17.1	9.3	28.3
Changes in working capital	(6.7)	(20.2)	31.2	(18.7)	12.3
Free Cash Flow	(14.9)	(35.1)	48.2	(9.4)	40.6
Other (investments)/dispositions	4.6	9.6	7.8	0.9	(16.3)
Acquisition of Aurora Hydro	-	-	(30.0)	-	-
(Increase in)/recovery of regulatory assets	15.7	(0.8)	2.6	7.4	8.8
Net change in equity	-	-	6.8	-	-
Net change in debt	6.1	2.1	-	(25.0)	(3.0)
Other financing	0.9	(5.9)	(29.3)	1.6	(0.4)
Net Change in Cash	12.4	(30.0)	6.02	(24.4)	29.8
Key Financial Ratios					
Total debt-to-capital (2)	56.0%	56.4%	57.9%	59.7%	51.5%
EBITDA interest coverage	4.77	4.65	3.62	3.37	4.59
EBIT interest coverage	3.07	2.90	2.27	2.10	3.08
Cash flow-to-total debt (2)	20.4%	19.9%	17.5%	9.8%	21.0%
Return on Equity	11.0%	10.5%	8.4%	n/a	9.9%
Dividend payout	22.1%	33.6%	0.0%	0.0%	0.0%

P = pro forma (consolidation of Richmond Hill Hydro, Hydro Vaughan, and Markham Hydro).

(1) The F2005 financials include the financial results of Aurora Hydro for the 2 months period ending Dec. 31, 2005.

(2) Includes subordinate debt (promissory notes to shareholders).

Summary

- PowerStream continues to maintain a strong financial profile, reflecting its solid balance sheet and credit metrics.

- Cash flow-to-debt and interest coverage ratios have improved from 2005 levels and continue to support the "A" rating.

- A moderate dividend-payout ratio is primarily responsible for the moderately improved debt-to-capital ratio of 56.0%. The Company expects to maintain a minimum dividend payout ratio of 50%, once a leverage of 60% is achieved.

- In F2006, the Company posted a free cash flow deficit primarily due to significantly heightened capital expenditures, funded primarily with cash. The capital budget that was not completed in F2005 was spent in F2006 along with the full F2006 capital budget. The capital expenditures for F2006 were focussed on head office construction, a transformer station expansion project, and a web-based system implementation. The large swings in working capital are mainly due to timing differences in when the Company pays for, and is paid for, power costs.

- Regulated operations account for almost all the cash flow from operations.

Outlook

- Cash flow from operations is expected to increase moderately, along with earnings in 2007 due to the modest rate increase approved by the OEB and the customer growth within the service area.

- While growth in cash flow from operations over the next two years will be primarily driven by population and load growth, cash flows beyond 2008 will depend largely on the re-basing of rates and the 3rd Generation Incentive Mechanism. However, the Company's regulated electricity distribution operations, together with its strong franchise area, are expected to provide a high degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

- PowerStream projects significantly increased capital expenditures for 2007 and 2008, primarily due to the continued construction of its head office, and the installation of Smart Meters. In order to fund its increased capital expenditure program, it expects its leverage to increase to 60% by 2008. Additional debt of approximately $16 million ($8 million in both 2007 and 2008) is expected to be incurred due to the deferral of interest payments on the Notes Payable to the shareholders, which would be added to the principal balance.
  - The OEB has approved some initial funding for the installation of Smart Meters. The remainder of the costs associated with the installations is expected to be recovered through future rate riders.
  - Given the Company's stated financial policy of maintaining leverage at 60% in line with the OEB approved deemed capital structure, DBRS expects the credit metrics to remain at a level appropriate to support the "A" rating.

Long-Term Debt and Bank Lines

Summary

PowerStream's long-term debt currently consists of the following:

- Senior unsecured debentures totalling $100 million issued to the Electricity Distributors Finance Corporation, maturing August 15, 2012.
- Subordinate debt to shareholders (promissory notes) totalling $146.1 million.
  - $78.2 million held by the City of Vaughan; and
  - $67.9 million held by the Town of Markham.

The two promissory notes are repayable 90 days following demand by the City or the Town, no earlier than January 1, 2008. These notes have been classified as long term by PowerStream as it is not the intent of the City or the Town to demand repayment within the next year.

- The interest on these promissory notes was deferred for eight quarters commencing October 1, 2006 for five years.

PowerStream currently has access to the following unsecured bank-credit facility:

- $125 million revolving demand facility for a term of 5 years, renewable annually.

As at December 31, 2006, the Company had utilized $22 million to provide the IESO with a letter of credit for prudential support.

Outlook

The Company's liquidity position is strong, reflecting the fairly modest utilization of the credit facility, stable cash flow from operations, zero short-term obligations, and a reasonable cash position.

Working capital requirements and any short- to medium-term needs would be funded with the Company's operating line.

Income Statement	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended
($ thousands)	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003P
Gross electricity revenues	595.7	581.2	592.2	289.6	484.8
Power purchases	486.1	475.7	491.3	235.7	377.7
Net distribution revenues	109.6	105.5	100.9	53.9	107.1
Ancillary revenues	10.8	10.7	9.3	7.0	-
Contribution from Richmond Hill Hydro Inc.	-	-	-	-	-
Net operating revenues	120.4	116.2	110.2	61.0	107.1
Expenses					
Operating and maintenance	16.9	16.1	15.9	6.7	12.5
General and administration	21.2	22.3	22.3	13.6	19.6
Municipal and property taxes	2.1	2.1	2.1	1.3	2.3
Depreciation & amortization	28.7	28.5	26.1	14.9	24.0
Total operating expenses	68.9	69.0	66.4	36.5	58.4
Operating income	51.6	47.2	43.8	24.5	48.7
Other (income)/expense	-	-	-	-	-
Earnings before interest & taxes (EBIT)	51.6	47.2	43.8	24.5	48.7
Interest expense	16.8	16.3	19.3	11.7	15.8
Non-cash financial charges	-	-	-	-	-
Net interest expense	16.8	16.3	19.3	11.7	15.8
Pre-tax income	34.7	30.9	24.5	12.8	32.9
Income taxes/PILS	13.3	11.5	9.9	5.1	11.7
Net income	21.5	19.5	14.6	7.7	21.2

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Balance Sheet ($ millions)	Unaudited As at Jun. 30	As at December 31	
Assets	2007	2006	2005
Cash & short-term investments	18.5	4.5	41.7
A/R & unbilled revenue	110.1	114.5	99.8
Inventories	7.4	5.4	5.8
Other	0.9	0.6	0.5
Current Assets	136.9	124.9	147.8
Net fixed assets	414.1	404.8	376.8
Regulatory assets	-	-	-
Other assets	14.6	16.0	17.6
Goodwill & other assets	33.0	33.0	33.0
Total	598.5	578.7	575.2

	Unaudited As at Jun. 30	As at December 31	
Liabilities & Equity	2007	2006	2005
Short-term debt	-	-	-
A/P & accruals	98.5	100.3	111.8
Other	3.7	2.4	3.0
Current Liabilities	102.3	102.6	114.9
Customer deposits	11.6	12.7	13.4
Long-term debt	252.2	248.2	246.1
Regulatory liabilities	24.3	14.6	15.3
Other liabilities	9.9	8.5	6.2
Shareholders' equity	198.3	192.2	179.3
Total	598.5	578.7	575.2

	Unaudited 12 months ended	12 months ended		Jun. 1, 2004, to	12 months ended
Ratios/Operating Stats	Jun. 30, 2007	Dec. 31, 2006	Dec. 31, 2005	Dec. 31, 2004	Dec. 31, 2003P
Operating margin	42.8%	40.6%	39.7%	40.1%	45.5%
Pre-tax margin	28.9%	26.6%	22.2%	21.0%	30.7%
Return on avg. common equity	11.0%	10.5%	8.4%	4.0%	9.9%
MWh sold/employee	18,405	19,102	19,597	15,966	n.a.
Customers/employee	628	647	633	523	n.a.
Oper. costs/avg. customer ($)	165	171	183	105	n.a.
Rate base	481	468	443	417	417.0
Number of employees	370	353	347	377	n.a.
Peak system demand (MW)	1,577	1,577	1,485	1,240	n.a.
Electricity Throughputs					
Total – (GWh)	6,810	6,743	6,800	6,019	5,920
Number of Customers					
Residential	203,909	200,794	192,706	172,636	166,230
General service	28,268	27,671	27,075	24,500	23,989
Large users	4	6	7	5	5
Street lighting	49	47	28	26	26
Total	232,230	228,518	219,816	197,167	190,250
Unit Revenues & Costs (cents per kWh throughputs)					
Average gross revenues	8.91	8.78	8.85	4.93	8.19
Power costs	7.14	7.05	7.23	3.92	6.38
Average net revenues	1.77	1.72	1.62	1.01	1.81
Variable costs (OM&A + PILS)	0.75	0.74	0.71	0.42	0.74
Fixed costs (deprec., int., gov't levies)	0.70	0.70	0.70	0.46	0.71
Total costs (excl. power costs)	1.45	1.43	1.41	0.88	1.45
Net margin	0.32	0.29	0.21	0.13	0.36

P = pro forma (consolidation of Richmond Hill Hydro, Hydro Vaughan, and Markham Hydro).
n.a. = not available.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Issuer Rating	A	A	A	A (low)	N/R	N/R

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

The Company
Barrie Hydro Distribution Inc. is a regulated electricity distribution company with approximately 68,000 customers in the municipalities of Barrie, Bradford West Gwillimbury, New Tecumseth, Penetanguishene and Thornton. It is wholly-owned by Barrie Hydro Holdings Inc. which in turn is owned by the City of Barrie. Barrie Hydro Holdings Inc. also wholly owns a non-regulated energy services company; Barrie Hydro Energy Services Inc. Barrie Hydro Distribution Inc. comprises more than 95% of assets and revenues of Barrie Hydro Holdings Inc.

Barrie Hydro Distribution Inc.

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating Rationale

DBRS has confirmed the rating of Barrie Hydro Distribution Inc. (Barrie Hydro or the Company) at "A" with a Stable trend. Barrie Hydro continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its strong financial profile and a growth oriented franchise area with a favourable customer mix.

The Company's financial metrics have steadily improved and continue to benefit from the growth in EBIT and earnings, which have trended upwards since F2004 largely due to both distribution rate increases and population growth. While debt levels have remained stable since F2003, leverage has decreased primarily due to retained earnings growth stemming from historically modest dividend payments.

In F2006, the Company undertook a number of capital projects focussed on both improving reliability and servicing growth that resulted in significantly increased capital expenditures. This resulted in a fairly modest free cash flow deficit that was funded with cash balances. (Continued on page 17.)

Rating Considerations

Strengths

(1) Growth oriented franchise area: the city of Barrie's population grew by almost 20% over the past five years. Future population growth is expected to be robust.
(2) Significantly lower leverage relative to peers provides for financial flexibility.
(3) Strong financial profile

Challenges

(1) Managing the heightened capital expenditures.
(2) Low regulated returns
(3) Refinancing risk
(4) Political and regulatory uncertainty

Financial Information

	Unaudited 12 months ended Jun 30, 2007	For the year ended December 31 2006	2005	2004	2003
EBIT interest coverage (times)	4.49	4.08	3.95	3.48	3.26
Total debt-to-capital	36.0%	37.9%	38.8%	40.0%	40.4%
Cash flow-to-total debt	31.1%	27.6%	27.5%	23.5%	27.7%
Operating cash flow ($ millions)	14.0	13.1	13.2	11.3	12.9
Net income before extras. ($ millions)	5.1	4.5	5.8	4.3	6.5
Operating margin	43.3%	40.5%	44.8%	39.8%	39.2%
Return on average equity	6.5%	5.8%	7.8%	6.1%	9.9%
Electricity throughput (GWh)	1,590	1,560	1,564	1,474	1,419
Customer base	67,416	67,211	65,800	63,973	61,597

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Rating Rationale (Continued from page 16.)

Over the 2008 to 2011 period, Barrie Hydro expects to spend an average of $15 million annually to maintain reliability and service growth. Roughly 35% of the capital expenditure during this period is expected to be spent on growth related projects while Smart Meter installations are expected to account for 20% of the total capital budget. DBRS expects this prolonged and heightened capital expenditure profile to create a very modest external financing need without affecting the strong credit metrics in any significant way.
Barrie Hydro's promissory notes held by the City of Barrie in the amount of $20 million mature on December 31, 2007. The Company expects the notes to be either extended by the City or refinanced with an external long-term facility. Given Barrie Hydro's strong financial profile, DBRS does not expect any refinancing issues.

Barrie Hydro is in the first group to go through the re-basing of rates for the 2008 rate year, with the 3rd Generation Incentive Rate Mechanism applied in succeeding years, up to the 2010 rate year. Hence, cash flow from operations in the medium term will largely hinge on the re-basing proceedings as well as population and load growth in its service territory. However, the Company's regulated electricity distribution operations, together with its strong growth oriented franchise area with favourable customer mix, is expected to provide a reasonable degree of certainty to revenues and stability to consolidated earnings and cash flow over the longer term.

Financial Profile and Outlook

	Unaudited 12 months ended	For the year ended December 31			
($ millions)	Jun 30, 2007	2006	2005	2004	2003
EBITDA	23.35	21.59	21.28	18.36	17.49
EBIT	14.61	13.16	14.03	11.45	11.14
Interest Expense	3.25	3.23	3.56	3.29	3.41
Net income (before extras)	5.08	4.49	5.78	4.26	6.51
Depreciation	8.74	8.43	7.25	6.91	6.35
Other non-cash items	0.18	0.17	0.22	0.11	0.08
Cash Flow From Operations	14.01	13.09	13.25	11.28	12.94
Common dividends	(2.09)	(3.10)	(1.28)	(1.10)	-
Capital expenditures	(15.17)	(12.16)	(7.47)	(13.40)	(9.97)
Cash Flow Before Working Capital	(3.25)	(2.17)	4.50	(3.21)	2.97
Changes in working capital	0.18	(8.57)	3.58	2.03	3.82
Free Cash Flow	(3.06)	(10.75)	8.08	(1.18)	6.79
Other (investments)/dispositions	2.94	0.16	0.57	(0.20)	0.05
Customer deposits	1.59	0.34	(1.86)	0.87	1.41
(Increase in)/recovery of regulatory assets	3.56	3.52	1.31	1.72	(1.14)
Deferrred charges	(0.31)	(0.31)	-	(0.48)	
Net change in equity	-	-	-	-	-
Net change in debt	-	-	-	-	(0.15)
Net Change in Cash	4.71	(7.04)	8.09	0.74	6.96
Key Financial Ratios					
Total debt-to-capital	36.0%	37.9%	38.8%	40.0%	40.4%
EBITDA interest coverage	7.18	6.69	5.98	5.59	5.13
EBIT interest coverage	4.49	4.08	3.95	3.48	3.26
Cash flow-to-total debt	31.1%	27.6%	27.5%	23.5%	27.7%
Return on Equity	6.5%	5.8%	7.8%	6.1%	9.9%
Dividend payout	41.0%	69.1%	22.1%	25.8%	0.0%

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Summary

- Barrie Hydro continues to maintain a strong financial profile, reflecting its solid balance sheet and credit metrics. Cash flow-to-debt and interest coverage ratios have improved from 2003 levels and continue to support the current rating. While debt levels have remained stable since 2003, leverage decreased primarily due to historically modest dividend payments, the exception being F2006 where the company paid $3.1 million in dividends.

- The modest free cash flow deficit (before working capital) in F2006 was largely due to increased capital expenditure. The Company undertook a number of projects to both improve reliability and service growth within its service area. The deficit was primarily funded with cash.

- The low ROE levels are reflective of the low actual leverage Barrie Hydro carries, compared to the 55% approved by OEB, resulting in an under-earning on a portion of invested equity. While Barrie Hydro continues to maintain very strong credit metrics for the current rating, it is limited by its modest size of asset and rate base, and limited access to the capital markets.

Outlook

- Cash flow from operations, along with earnings is expected to experience modest growth in F2007 largely due to customer growth. Over the past four years, the customer base grew by an average 3.2% annually.

- Given that Barrie Hydro is to go through re-basing for the 2008 rate year, earnings and cash flow from operations beyond 2008 will largely depend on the outcome of the re-basing proceedings as well as customer base growth. Over the 2008 to 2011 period, Barrie Hydro expects to spend an average of $15 million annually to maintain reliability, prepare for growth and install Smart Meters. Growth related capital expenditure is expected to account for roughly one-third of the total spending while Smart Meter installation will account for 20% during the 2008 to 2011 period.

- The heightened future capital expenditure profile is expected to create a small external financing need, which would marginally impact credit metrics.
  - Along with external financing, the ratios will weaken marginally, but DBRS expects the credit metrics to stay well within the "A" rating.

Long-Term Debt and Bank Lines

Summary

Barrie Hydro's long-term debt consists of the following:

- Senior unsecured debentures totalling $25 million issued to the Electricity Distributors Finance Corporation, maturing August 15, 2012.
- Subordinate debt to the City of Barrie (promissory notes) totalling $20 million maturing on December 31, 2007. This debt has not been classified as short-term as it is expected to be renewed or refinanced through another long-term debt facility. The City of Barrie renewed this debt in January 1, 2006.

Barrie Hydro currently has a $10 million unsecured bank line, which was fully available as at June 30, 2007.

Outlook

The Company's liquidity position is strong, reflecting the fully available credit facility, stable cash flow from operations, zero short-term obligations and a significant cash position.

Working capital requirements and any short- to medium-term needs would be funded with the Company's operating line.

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Income Statement	Unaudited 12 months ended	For the year ended December 31			
($ millions)	Jun 30, 2007	2006	2005	2004	2003
Gross distribution revenues	142.46	138.78	146.84	123.21	104.11
Power purchases	112.30	110.24	119.06	97.78	78.62
Net distribution revenues	30.16	28.54	27.78	25.42	25.49
Ancillary revenues	3.59	3.95	3.55	3.34	2.90
Net operating revenues	33.75	32.48	31.33	28.77	28.39
Expenses					
Operating and maintenance	3.32	3.80	3.37	4.10	4.69
General and administration	7.08	7.08	6.69	6.30	6.22
Municipal and property taxes	-	-	-	-	-
Depreciation & amortization	8.74	8.43	7.25	6.91	6.35
Total operating expenses	19.15	19.32	17.30	17.32	17.25
Operating income	14.61	13.16	14.03	11.45	11.14
Other (income)/expense	-	-	-	-	-
Earnings before interest & taxes (EBIT)	14.61	13.16	14.03	11.45	11.14
Interest expense	3.25	3.23	3.56	3.29	3.41
Non-cash financial charges	-	-	-	-	-
Other financial (income)/expense	-	-	-	-	-
Net interest expense	3.25	3.23	3.56	3.29	3.41
Pre-tax income	11.36	9.94	10.48	8.16	7.73
Income taxes/PILS	6.27	5.45	4.70	3.90	1.21
Income before extraordinary items	5.08	4.49	5.78	4.26	6.51
Extraordinary items	-	-	-	-	-
Net Income	5.08	4.49	5.78	4.26	6.51

Balance Sheet	Unaudited As at	As at Dec. 31			Unaudited As at	As at Dec. 31	
($ millions)							
Assets	Jun. 30, 2007	2006	2005	**Liabilities & Equity**	Jun. 30, 2007	2006	2005
Cash & short-term. investments	7.7	2.2	9.2	Short-term debt	-	-	-
A/R & unbilled revenue	25.1	25.2	23.6	A/P + accruals	23.6	17.7	23.4
Inventories	2.9	1.6	1.2	Customer deposits	20.2	4.3	4.9
Goodwill and other assets	0.6	0.7	0.4	**Current Liabilities**	43.9	22.0	28.4
Current Assets	36.3	29.7	34.4	Customer deposits	2.6	2.6	2.4
Net fixed assets	128.5	124.7	119.2	Long-term debt	45.0	45.0	45.0
Regulatory assets	-	-	1.9	Regulatory & Other liabilities	3.8	17.9	14.3
Other assets	10.5	10.7	10.6	Shareholders' equity	80.0	77.6	76.0
Total	175.3	165.1	166.1	**Total**	175.3	165.1	166.1

Electricity Distributors Finance Corporation

Report Date:
November 16, 2007

Ratios/Operating Stats	Unaudited 12 months ended Jun. 30, 2007	2006	2005	2004	2003
		For the year ended December 31			
Operating margin	43.3%	40.5%	44.8%	39.8%	39.2%
Pre-tax margin (bef. extras.)	15.1%	13.8%	18.4%	14.8%	22.9%
Return on avg. common equity	6.5%	5.8%	7.8%	6.1%	9.9%
MWh sold/employee	14,324	13,688	13,485	12,706	12,556
Customers/employee	607	590	567	551	545
Oper. costs /avg. customer ($)	155	164	155	166	180
Rate base – ($ millions)	108	108	108	108	108
Number of employees	111	114	116	116	113
Peak system demand (MW)	341.9	313.0	304.0	274.9	283.8
Electricity Throughputs					
Total – (GWh)	1,590.0	1,560.4	1,564.3	1,473.9	1,418.8
Number of Customers					
Residential	60,830	60,659	59,174	57,473	55,195
General service	6,579	6,545	6,619	6,493	6,395
Large users	-	-	-	-	-
Street lighting	7	7	7	7	7
Total	67,416	67,211	65,800	63,973	61,597
Unit Revenues & Costs (cents per kWh throughputs)					
Average gross distribution revenues	9.19	9.15	9.61	8.59	7.54
Power costs	7.06	7.07	7.61	6.63	5.54
Average net distribution revenues	2.12	2.08	2.00	1.95	2.00
Variable costs (OM&A + PILS)	1.05	1.05	0.94	0.97	0.85
Fixed costs (deprec., int., gov't levies)	0.75	0.75	0.69	0.69	0.69
Total costs (excl power costs)	1.80	1.79	1.63	1.66	1.54
Net margin	0.32	0.29	0.37	0.29	0.46

n.a.=not available

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable

Rating History

	Current	2006	2005	2004	2003	2002
Issuer Rating	A	A	A	A	A	A

Note:
All figures are in Canadian dollars unless otherwise noted.

STANDARD & POOR'S

RATINGSDIRECT®

August 20, 2008

Electricity Distributors Finance Corp.

Primary Credit Analyst:
Nicole Martin, Toronto (1) 416-507-2560; nicole_martin@standardandpoors.com

Table Of Contents

Major Rating Factors

Rationale

Electricity Distributors Finance Corp.

Major Rating Factors

Strengths:
- Stable, regulated cash flows
- Limited exposure to commodity price and volume risk
- Low-risk monopoly electricity network businesses

Weaknesses:
- Intermediate financial risk profiles of entities supporting the debentures

None

Rationale

The rating on the senior unsecured debt of Electricity Distributors Finance Corp. (EDFIN) reflects the risk profile of the least creditworthy participant. EDFIN is a special-purpose corporation that acts as a financial conduit for participating local distribution companies (LDCs) in the Province of Ontario (AA/Stable/A-1+). The company itself has no assets or liabilities. The debt rating on EDFIN's C$175 million, 6.45% unsecured debentures series 2002-1 outstanding reflects the least creditworthy participant supporting the debentures, since the EDFIN structure does not provide for pooled credit support. Each LDC is liable only for its obligations within the structure and has no liability for the obligations of any of the other participants. All three have fairly similar credit risk profiles. Three utility holding companies service the EDFIN debt obligation: Barrie Hydro Distribution Inc. (C$25 million), EnWin Utilities Ltd. (C$50 million), and PowerStream Inc. (C$100 million). The debt matures Aug. 15, 2012.

All three LDCs enjoy excellent business risk profiles that are supported by stable, regulated cash flows from a monopoly franchise. Offsetting these strengths are intermediate financial risk profiles of varying strength. Although the debt rating necessarily reflects the risk profile of the least creditworthy participant, the differences between the three are not sufficient to affect the rating outcome. This has not always been the case, and could change. Some participants are exploring mergers with, or acquisitions of, other Ontario LDCs. A largely debt-financed transaction or change in financial policy by any one of the three companies could affect the rating.

Cash flow to service the EDFIN debt comes almost entirely from regulated electricity distribution activities and is stable and predictable. The Ontario Energy Board's regulatory framework supports the LDCs' cash flow stability, allowing for the recovery of prudent costs and the opportunity to earn a modest return. Regulatory cost recovery is generally predictable and timeliness is improving. The current environment limits the LDCs' exposure to commodity risk. Although the LDC must bill electricity customers for the commodity delivered, the cost is a flow through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements. Net distribution revenues are subject to modest volumetric risk due to weather. There is no near-term expectation of energy policy or electricity market framework initiatives that would affect the regulatory environment or LDC credit quality.

Each LDC's monopoly position in its service franchise and the asset-intensive and essential nature of electricity distribution limit competitive risk. The electricity distribution business also carries relatively low operating risk, and all three participants exhibit average operational efficiency and reliability.

The intermediate financial risk profiles of all EDFIN participants are relatively stable. Nevertheless, balance-sheet and cash-flow strength vary amongst the participants, largely due to differing financial policies. Barrie Hydro and EnWin Utilities retain much stronger balance sheets than Powerstream. Standard & Poor's Ratings Services believes the weakest adjusted funds from operations (AFFO) interest coverage ratio in the group could achieve 3.0x in 2008. We project AFFO-to-average total debt to exceed 15% in the same period. Interest and debt coverages vary among the participants. By 2009, the regulator will have phased in a deemed capital structure of 60% debt and 40% equity for all LDCs, which will have a negative-but-manageable impact on cash flow for EnWin Utilities and Barrie Hydro Distribution. For these two, the regulator previously used a deemed 45% common equity component in the capital structure for tariff-setting purposes. Powerstream's actual capital structure is aligned with its regulatory deemed equity layer of 40%.

Accounting

The EDFIN participants prepare audited consolidated financial statements (fiscal year ended Dec. 31) and unaudited quarterly statements in accordance with Canadian GAAP. No participant has power purchase agreement commitments or material operating leases. A third party provides pensions, and costs are expensed and recovered through rates. In its analysis, Standard & Poor's has made a material adjustment to Enwin Utilities' reported debt of C$70 million, reflecting about C$20 million in postretirement benefit obligations. We expect the cost of these obligations will be recovered through regulated rates.

Table 1

Electricity Distributors Finance Corp.--Peer Comparison*

Industry Sector: Electric Utility

	--Average of past three fiscal years--				
(Mil. C$)	**Barrie Hydro Distribution Inc.¶**	**Powerstream Inc.¶**	**Enwin Utilities Ltd.¶**	**Chatham Kent Energy Inc.**	**London Hydro Inc.**
Rating as of Aug. 20, 2008	A	A	A	A/Stable/--	A/Positive/--
Revenues	146.9	602.8	241.5	97.2	338.2
Net income from continuing operations	5.4	18.4	9.7	2.9	6.0
Funds from operations (FFO)	13.7	46.1	15.6	7.1	16.0
Capital expenditures	11.4	47.8	9.1	6.0	16.8
Cash and short-term investments	5.2	22.4	0.0	9.2	22.6
Debt	46.7	259.5	100.2	26.4	76.8
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	78.4	191.6	70.2	32.6	123.4
Debt and equity	125.1	451.2	170.4	58.9	200.2
Adjusted ratios					
EBIT interest coverage (x)	4.1	2.4	2.0	3.7	2.9
FFO interest coverage (x)	4.9	2.9	3.1	4.8	4.0
FFO/debt (%)	29.4	17.7	15.6	26.8	20.9
Discretionary cash flow/debt (%)	(3.5)	0.8	3.7	(3.3)	(6.6)
Net cash flow/capex (%)	97.2	88.5	149.6	101.1	83.5
Total debt/debt plus equity (%)	37.3	57.5	58.8	44.7	38.4
Return on common equity (%)	7.0	8.9	14.6	9.2	4.9

Table 1

Electricity Distributors Finance Corp.--Peer Comparison*(cont.)					
Common dividend payout ratio (unadjusted; %)	39.4	32.8	21.0	34.2	33.1

*Fully adjusted (including postretirement obligations). ¶Rating reflects debt rating on the senior unsecured debt of Electricity Distributors Finance Corp.

Table 2

Powerstream Inc.--Financial Summary*

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--			
(Mil. C$)	**2007**	**2006**	**2005**	**2004**
Revenues	614.8	591.9	601.5	296.6
Net income from continuing operations	21.1	19.5	14.6	7.7
Funds from operations (FFO)	46.3	48.9	42.9	24.2
Capital expenditures	59.6	57.5	26.2	15.2
Cash and short-term investments	23.6	3.4	40.1	35.3
Debt	261.8	255.1	261.7	282.0
Preferred stock	0.0	0.0	0.0	0.0
Equity	207.5	190.3	177.1	164.0
Debt and equity	469.3	445.4	438.8	446.0
Adjusted ratios				
EBIT interest coverage (x)	2.4	2.7	2.2	2.1
FFO interest coverage (x)	2.5	3.5	2.8	2.6
FFO/debt (%)	17.7	19.2	16.4	8.6
Discretionary cash flow/debt (%)	(2.4)	(13.9)	18.3	(3.4)
Net cash flow/capex (%)	69.8	73.6	163.7	159.5
Debt/debt and equity (%)	55.8	57.3	59.6	63.2
Return on common equity (%)	8.8	9.8	8.0	4.6
Common dividend payout ratio (unadjusted; %)	22.4	33.6	46.6	0.0

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Powerstream Inc. Reported Amounts With Standard & Poor's Adjusted Amounts*

	--Fiscal year ended Dec. 31, 2007--								
Powerstream Inc. reported amounts (mil. C$)	**Debt**	**Shareholders' equity**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	253.2	209.2	79.1	79.1	49.4	18.3	60.9	60.9	60.8
Standard & Poor's adjustments									
Operating leases	2.3	N/A	1.2	0.1	0.1	0.1	1.0	1.0	2.3
Postretirement benefit obligations	6.3	(1.7)	0.8	0.8	0.8	0.5	(0.4)	(0.4)	N/A

Table 3

Reconciliation Of Powerstream Inc. Reported Amounts With Standard & Poor's Adjusted Amounts*(cont.)									
Capitalized interest	N/A	N/A	N/A	N/A	N/A	3.5	(3.5)	(3.5)	(3.5)
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	4.1	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(11.8)	N/A
Total adjustments	8.6	(1.7)	2.0	1.0	5.0	4.1	(2.8)	(14.6)	(1.2)
Standard & Poor's adjusted amounts	**Debt**	**Equity**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	261.8	207.5	81.1	80.1	54.5	22.3	58.2	46.3	59.6

*Powerstream Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. D&A--Depreciation and amortization. N/A--Not applicable.

Table 4

Enwin Utilities Ltd. -- Financial Summary*

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2007**	**2006**	**2005**	**2004**	**2003**
Revenues	241.8	227.2	255.4	220.9	223.6
Net income from continuing operations	15.7	10.8	2.5	1.2	2.5
Funds from operations (FFO)	19.5	13.5	14.0	16.4	11.8
Capital expenditures	12.4	7.8	7.1	8.2	8.7
Cash and short-term investments	0.0	0.0	0.0	0.0	0.0
Debt	93.7	99.5	107.4	118.6	122.3
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	82.0	70.0	58.7	57.3	63.1
Debt and equity	175.7	169.5	166.1	175.9	185.4
Adjusted ratios					
EBIT interest coverage (x)	2.5	2.0	1.4	1.2	1.5
FFO interest coverage (x)	3.4	2.9	3.0	3.5	2.5
FFO/debt (%)	20.8	13.5	13.0	13.8	9.7
Discretionary cash flow/debt (%)	7.6	(2.4)	6.1	6.1	(1.8)
Net cash flow/capex (%)	133.1	147.5	180.5	199.4	136.5
Debt/debt and equity (%)	53.4	58.7	64.7	67.4	65.9
Return on common equity (%)	20.7	16.7	4.3	2.1	4.1
Common dividend payout ratio (unadjusted; %)	19.1	18.6	43.7	0.0	0.0

*Fully adjusted (including postretirement obligations). Enwin Utilities Ltd. and Enwin Powerlines Ltd. amalgamated Jan 2, 2007, to form Enwin Utilities Ltd.

Table 5

Reconciliation Of Enwin Utilities Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts*

	--Fiscal year ended Dec. 31, 2007--							
Enwin Utilities Ltd. reported amounts (mil. C$)	**Debt**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Capital expenditures**
Reported	70.0	26.9	26.9	16.0	5.2	23.0	23.0	10.3
Standard & Poor's adjustments								
Operating leases	3.3	0.7	0.2	0.2	0.2	0.5	0.5	2.1
Postretirement benefit obligations	20.5	1.8	1.8	1.8	1.8	(1.0)	(1.0)	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	(3.0)	N/A
Total adjustments	23.8	2.5	2.0	2.0	1.9	(0.5)	(3.5)	2.1
Standard & Poor's adjusted amounts	**Debt**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**	**Capital expenditures**
Adjusted	93.7	29.4	28.9	17.9	7.1	22.5	19.5	12.4

*Enwin Utilities Ltd. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. D&A--Depreciation and amortization. N/A--Not applicable.

Table 6

Barrie Hydro Distribution Inc.--Financial Summary*

Industry Sector: Electric Utility

	--Fiscal year ended Dec. 31--				
(Mil. C$)	**2007**	**2006**	**2005**	**2004**	**2003**
Revenues	147.5	142.7	150.4	126.5	105.7
Net income from continuing operations	5.8	4.5	5.8	4.3	6.5
Funds from operations (FFO)	15.0	13.0	13.2	11.2	12.8
Capital expenditures	13.9	12.2	8.1	14.1	11.1
Cash and short-term investments	4.3	2.2	9.2	1.1	0.4
Debt	46.7	46.7	46.6	46.5	46.7
Preferred stock	0.0	0.0	0.0	0.0	0.0
Equity	81.8	77.6	76.0	72.0	68.9
Debt and equity	128.5	124.3	122.5	118.5	115.5
Adjusted ratios					
EBIT interest coverage (x)	4.3	4.0	3.9	3.5	3.3
FFO interest coverage (x)	5.4	4.8	4.6	4.3	4.7
FFO/debt (%)	32.1	27.9	28.3	24.1	27.4
Discretionary cash flow/debt (%)	(3.4)	(23.2)	16.2	(4.1)	11.7
Net cash flow/capex (%)	86.1	81.5	139.8	72.0	114.9
Debt/debt and equity (%)	36.4	37.6	38.0	39.2	40.4
Return on common equity (%)	7.3	5.8	7.8	6.1	9.9

Table 6

Barrie Hydro Distribution Inc.--Financial Summary*(cont.)					
Common dividend payout ratio (unadjusted; %)	27.6	64.6	31.7	25.8	0.0

*Fully adjusted (including postretirement obligations).

Table 7

Reconciliation Of Barrie Hydro Distribution Inc. Reported Amounts With Standard & Poor's Adjusted Amounts*

	--Fiscal year ended Dec. 31, 2007--						
Barrie Hydro Distribution Inc. reported amounts (mil. C$)	**Debt**	**Operating income (before D&A)**	**Operating income (before D&A)**	**Operating income (after D&A)**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**
Reported	45.1	23.6	23.6	14.6	3.3	15.4	15.4
Standard & Poor's adjustments							
Postretirement benefit obligations	1.7	0.1	0.1	0.1	0.1	(0.0)	(0.0)
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	(0.3)
Total adjustments	1.7	0.1	0.1	0.1	0.1	(0.0)	(0.4)
Standard & Poor's adjusted amounts	**Debt**	**Operating income (before D&A)**	**EBITDA**	**EBIT**	**Interest expense**	**Cash flow from operations**	**Funds from operations**
Adjusted	46.7	23.7	23.7	14.7	3.4	15.3	15.0

*Barrie Hydro Distribution Inc. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. D&A--Depreciation and amortization. N/A--Not applicable.

Ratings Detail (As Of August 20, 2008)*	
Electricity Distributors Finance Corp	
Senior Unsecured (1 Issue)	A
Related Entities	
Windsor (City of)	
Issuer Credit Rating	AA/Stable/--
Senior Unsecured (1 Issue)	AA
York (Regional Municipality of)	
Issuer Credit Rating	AAA/Stable/--
Senior Unsecured (11 Issues)	AAA

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

The McGraw·Hill Companies

Schedule 2-1-1

Overview

Rate Base Summary

RATE BASE SUMMARY

1. RATE BASE OVERVIEW 2
2. GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT 3
2.1 Continuity Statements 3
2.2 Gross Assets Table 3
2.3 Variance Analysis 3
2.3.1 2008 vs. 2009 3
2.3.2 2007 vs. 2008 5
3. CAPITAL EXPENDITURES 6
3.1 Capital Expenditures Overview 6
3.2 Operation Expenditures by Project 9
3.2.1 Externally Driven 9
3.2.2 Infrastructure 17
3.3 Administration Expenditures by Project 42
3.3.1 Administration Sustainability 42
3.3.2 Administration Enhancement 50
3.3.3 Comprehensive ERP 59
4 AMORTIZATION/ACCUMULATED DEPRECIATION 62
5 SYSTEM EXPANSION 62
6 CAPITAL EXPENDITURE PLANNING AND BUDGETING PROCESS 63
7 CAPITALIZATION POLICY 63
8 WORKING CAPITAL ALLOWANCE 63

1. RATE BASE OVERVIEW

EWU's forecasted utility rate base for the 2009 Test Year is $201,034,177. The utility rate base underlying the Test Year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. The following table provides a numerical summary of EWU's rate base:

Table 2-1-1 A – Summary of Rate Base

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
Net Capital Assets in Service:					
Opening Balance		141,893,703	147,431,592	167,345,008	168,311,618
Ending Balance		147,431,592	167,345,008	168,311,618	174,945,697
Average Balance	155,058,892	144,662,648	157,388,300	167,828,313	171,628,658
Working Capital Allowance *(see below)*	31,450,564	30,918,537	30,834,827	29,694,786	29,405,520
Total Rate Base	186,509,456	175,581,184	188,223,127	197,523,099	201,034,177

Expenses for Working Capital

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection
Eligible Distribution Expenses:					
3500-Distribution Expenses – Operation	1,604,003	2,161,244	2,326,928	2,237,577	2,284,473
3550-Distribution Expenses – Maintenance	1,931,319	2,100,012	2,143,136	2,873,040	2,953,609
3650-Billing and Collecting	510,143	395,737	1,243,284	1,284,475	1,283,494
3700-Community Relations	10,857	38,570	43,602	59,335	53,949
3800-Administrative and General Expenses	18,629,649	17,034,636	14,444,327	16,192,418	18,192,733
3950-Taxes Other Than Income Taxes	142,542	549,034	1,049,408	484,248	513,858
Total Eligible Distribution Expenses	22,828,513	22,279,233	21,250,685	23,131,093	25,282,116
3350-Power Supply Expenses	186,841,914	183,844,344	184,314,828	174,834,148	170,754,681
Total Expenses for Working Capital	209,670,427	206,123,577	205,565,513	197,965,241	196,036,797
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	31,450,564	30,918,537	30.834,827	29,694,786	29,405,520

For the years 2007-2009, Exhibit 2, Tab 2, Schedule 1 provides the following on an account basis:

- the opening and closing NBV of EWU's fixed assets;
- the fixed asset additions and disposals;
- annual depreciation; and

- proof of continuity.

The components of EWU's rate base are discussed below.

2. GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT

2.1 Continuity Statements

For the Continuity Statements, please see Exhibit 2, Tab 2, Schedule 1.

2.2 Gross Assets Table

For the Gross Asset Tables, please see Exhibit 2, Tab 2, Schedule 2.

2.3 Variance Analysis

The variance each year is reflective of additions only. The filing guidelines require a materiality threshold of 1% of net fixed assets which equals approximately $1,683,116. EWU has used a more stringent threshold and has explained variances of $1,000,000.

2.3.1 2008 vs. 2009

Capital expenditure by account as follows:

<u>1830 – Poles, Towers and Fixtures: $4,162,088</u>

The projects driving these additions are the following:

- 4kV Conversion
- 28kV Pole Replacement
- New Services

These projects are described further below at Exhibit 2, Tab 1, Schedule 1, pages 19, 22 and 9 respectively.

1840 – Underground Conduit: $1,475,000

The projects driving these additions are the following:

- 4kV Conversion
- Manhole Reconstruction
- Replacement of End-of-Life Equipment on Customer Property
- Subdivision Re-Cabling
- New Services

These projects are further described at Exhibit 2, Tab 1, Schedule 1, pages 19, 29, 30, 23 and 9, respectively.

1850 – Line Transformers: $2,588,746

The major projects driving these additions are the following:

- 4kV Conversion
- New Services
- Subdivision Re-Cabling

These projects are further described below at Exhibit 2, Tab 1, Schedule 1, pages 19, 9 and 23, respectively.

1855 – Services: $1,120,360

The major projects driving these additions are the following:

- 4kV Conversion
- New Services

These projects are further described at Exhibit 2, Tab 1, Schedule 1, pages 19 and 9, respectively.

<u>1925 – Computer Software: $7,438,667</u>

The major projects driving these additions are the following:

- Comprehensive ERP
- Customer Service

These projects are further described at Exhibit 2, Tab 1, Schedule 1, pages 58 and 50, respectively.

2.3.2 2007 vs. 2008

Capital expenditures by account are as follows:

<u>1830 – Poles, Towers and Fixtures: $4,210,183</u>

The major projects driving these additions are the following:

- 4kV Conversion
- New Services

These projects are described further at Exhibit 2, Tab 1, Schedule 1, pages 19 and 9, respectively.

<u>1840 – Underground Conduit: $1,389,535</u>

The major projects driving these additions are the following:

- Subdivision Re-Cabling
- Padmounted Switchgear Replacements
- Manhole Reconstruction

- New Services
- Replacement of End-of-Life Equipment on Customer Property

The projects are described further at Exhibit 2, Tab 1, Schedule 1, pages 23, 33, 29, 10 and 30, respectively.

<u>1850 – Line Transformer: $3,261,373</u>

The major projects driving these additions are the following:

- 4kV Conversion
- Replacement of End-of-Life Equipment on Customer Property
- New Services
- Subdivision Re-Cabling

These projects are further described at Exhibit 2, Tab 1, Schedule 1, pages 19, 30, 9 and 23, respectively.

<u>1855 – Services: $1,114,623</u>

The major projects driving these additions are the following:

- 4kV Conversion
- New Services

These projects are further described at Exhibit 2, Tab 1, Schedule 1, pages 19 and 9, respectively.

3. CAPITAL EXPENDITURES

3.1 Capital Expenditures Overview

Based on the Filing Guidelines, EWU is required to provide descriptions of all capital projects that exceed approximately $1,683,116 (1% of net fixed assets). EWU's descriptions satisfy that requirement. Moreover, for transparency and clarity, EWU provides descriptions for more than 95% of total capital expenditures.

In order to assist the Board, EWU has set out descriptions of capital projects that fall below the materiality threshold. The year under which each capital expenditure is described corresponds with the in-service date of each capital expenditure. All capital work completed by EWU and described in this section of its evidence is subject to the Capitalization Policy set out at Exhibit 2, Tab 3, Schedule 3, Planning and Budgeting Policy set out at Exhibit 2, Tab 3, Schedule 2, and Purchasing Policy set out at Exhibit 4, Tab 2, Schedule 3.

EWU's capital expenditures are categorized under two general headings: (i) Operation expenditures; and (ii) Administration expenditures. EWU's Operation expenditures can be categorized further under two sub-headings: (i) Externally-Driven expenditures; and (ii) Infrastructure expenditures that includes Operations Sustainability and Operations Enhancement work. The following table 2-1-1 B illustrates how these expenditures contribute to EWU's Operation expenditures. Administration expenditures can be categorized under: (i) Administration Sustainability; (ii) Administration Enhancements; and (iii) Comprehensive ERP. Table 2-1-1 B below provides total year over year expenditures on a project basis. It further provides total dollar and percentage variances on a project basis. The project headings set out in Table 2-1-1 B correspond to the headings set out below at pages 10 to 60.

1 *Table 2-1-1 B – Rate Base Additions Summary*

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test	Cross
	2007	$	%	2008	$	%	2009	Reference
Externally Driven	**1,316,077**	**1,173,146**	**89%**	**2,489,223**	**387,524**	**16%**	**2,876,747**	3.2.1
New Services	990,227	1,439,621	145%	2,429,849	(4,982)	0%	2,424,867	3.2.1.1
IESO Wholesale Meters	325,850	(266,476)	-82%	59,374	392,506	661%	451,880	3.2.1.2
Operations Sustainability	**5,327,625**	**1,965,031**	**37%**	**7,292,656**	**(504,008)**	**-7%**	**6,788,648**	3.2.1.2
4kV Voltage Conversion Program	4,693,458	669,746	14%	5,363,204	(424,556)	-8%	4,938,648	(a)
27.6kV Pole Replacement Program	17,463	32,537	186%	50,000	800,000	1600%	850,000	(b)
Subdivision Re-Cabling	0	684,300	100%	684,300	(284,300)	-42%	400,000	(c)
Emergency Replacement Program	402,825	(167,825)	-42%	235,000	0	100%	235,000	(d)
PCB Contaminated Transformer Replacement Program	19,946	12,054	60%	32,000	(32,000)	-100%	0	(e)
Manhole Reconstruction/Reinforcement Program	0	87,708	100%	87,708	112,292	128%	200,000	(f)
Replacement of End-of-Life Equipment on Customer Property	0	651,944	100%	651,944	(651,944)	-100%	0	(g)
Other Distribution Plant	193,934	(5,434)	-3%	188,500	(23,500)	-12%	165,000	(h)
Operations Enhancement	**592,224**	**(9,846)**	**-2%**	**582,378**	**21,297**	**4%**	**603,675**	3.2.2.2
Padmounted Switchgear Replacements	0	107,240	100%	107,240	42,760	40%	150,000	(a)
Pole-Top Recloser Program	372,067	(372,067)	-100%	0	0	0%	0	(b)
Single-Phase Line Protection	0	15,000	100%	15,000	0	0%	15,000	(c)
SCADA Improvements	220,157	(115,446)	-52%	104,711	167,464	160%	272,175	(d)
Transformer Station Upgrades	0	355,427	100%	355,427	(188,927)	-53%	166,500	(e)
Operations Total	**7,235,927**	**3,128,331**	**43%**	**10,364,257**	**(95,187)**	**-1%**	**10,269,070**	
Sustainability	**398,820**	**680,904**	**171%**	**1,079,724**	**(24,519)**	**-2%**	**1,055,205**	3.3.1
Information Technology	86,806	205,118	236%	291,924	198,731	68%	490,655	3.3.1.1
Site Services	215,779	388,221	180%	604,000	(164,300)	-27%	439,700	3.3.1.2
Fleet Support	14,634	12,866	88%	27,500	39,500	144%	67,000	3.3.1.3
Other	81,601	74,699	92%	156,300	(98,450)	-63%	57,850	3.3.1.4
Enhancements	**-**	**1,161,370**	**100%**	**1,161,370**	**(502,210)**	**-43%**	**659,160**	3.3.2
Customer Service	0	679,925	100%	679,925	(20,765)	-3%	659,160	3.3.2.1
Fleet Operations	0	181,445	100%	181,445	(181,445)	-100%	0	3.3.2.2
Financial Reporting Software	0	300,000	100%	300,000	(300,000)	-100%	0	3.3.2.3
ERP Systems	**-**	**-**	**100%**	**-**	**7,250,445**	**100%**	**7,250,445**	3.3.3
Comprehensive ERP	0	0	100%	0	7,250,445	100%	7,250,445	
Administration Total	**398,820**	**1,842,274**	**462%**	**2,241,094**	**6,723,716**	**300%**	**8,964,810**	
GRAND TOTAL	**7,634,747**	**4,970,605**	**65%**	**12,605,351**	**6,628,529**	**53%**	**19,233,880**	

2

3.2 Operation Expenditures by Project

3.2.1 Externally Driven

Table 2-1-1 C – Externally Driven Projects

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Externally Driven	1,316,077	1,173,146	89%	2,489,223	387,524	16%	2,876,747

Externally driven projects are non-discretionary expenditures. These include: (i) customer connections, municipal roadwork and relocation of plant ("New Services"); and (ii) IESO wholesale metering. These categories of expenditures have in common the fact that they are all based upon requirements in the Distribution System Code, the Transmission System Code or the IESO Market Rules. This work is required under these Codes and Rules and is not optional for EWU.

3.2.1.1 New Services

EWU does not undertake plant expansions in anticipation of future growth, but rather builds plant when it is necessary to do so to accommodate connection requests from customers. When such requests are received, a planner/scheduler works with the engineering group to develop a plan for serving the new load that is the most cost and resource effective. EWU utilizes an economic model, as required by the Distribution System Code and as set out in the EWU Conditions of Service, to determine what amount of customer contribution is required for the expansion. Where required based upon the economic model, EWU collects contributions from customers and applies those contributions to offset the capital costs of the new plant. Whether the customers are required to contribute to capital expansions or not, servicing alternatives are reviewed with the customer to ensure that the needs of the customer are met.

The following table demonstrates EWU's net spending on New Services.

Table 2-1-1 D – New Services

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
New Services	990,227	1,439,621	145%	2,429,849	(4,982)	0%	2,424,867

2007 Expenditures for New Services

The following table demonstrates EWU's net spending on New Services for 2007.

		2007	
	AMOUNT	CONTRIBUTED CAPITAL	TOTAL
TOTAL	**2,329,042**	**(1,338,815)**	**990,227**

EWU's net spending on New Services in 2007 was unusually low due to two large connection projects that were fully paid for by capital contributions. Of the approximately $2.3 million gross spent on New Services in 2007, approximately $1.3 million was recovered by EWU through customer capital contributions. These capital contributions primarily arose from the VACIS project and the Casino Expansion project[1], both of which had no impact on EWU's rate base in 2007. Of the $990,227 being added to rate base in 2007, approximately $972,000 was incurred for new service connections, metering and relocation of plant and $17,000 represents road work.

New Services connection work in 2007 was made up of a collection of 346 connection projects city wide.

2008 Forecasted Expenditures for New Services

Relocated distribution plant located along public road rights-of-way is subject to external contributions per the Public Service Works on Highways Act ("PSWHA"), but only to the extent

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[1] VACIS Project

In 2007, EWU recovered $760,000 in capital contributions in respect to the VACIS project.

For this project, the Government of Canada and Canadian Pacific Railway ("CPR"), entered into a joint venture to secure a 7.5-km CPR rail corridor from Walker Road in Windsor to the U.S. border. This involved the installation of a Vehicle and Cargo Inspection System ("VACIS"), a state-of-the-art security system designed to scan the contents of freight cars and containers as trains pass by.

In order to x-ray the rail cars before allowing them to cross the border, the trains were required to slow down significantly. The railroad tracks intersect the municipal road at Walker Road. The installation of the VACIS system would result in significant traffic delays. To alleviate the traffic delays associated with these slow moving rail cars, substantial road work was required at the intersection of Walker Rd. and Grand Marais Road East. This roadwork involved the installation of an underpass very close to a Hydro One owned transformer station, Essex TS, which is a major source of electrical power for the rate payers of Windsor and naturally impacted a significant number of trunk feeders in EWU's distribution system by requiring them to be relocated.

The costs of this project will be fully recovered from the federal government and will not affect EWU's rate base.

Casino Project

In 2007 EWU recovered $365,000 in capital contributions in respect of the Casino Project. There was no impact on 2007 rate base caused by this project.

The Windsor Casino planned to expand. To facilitate this expansion, EWU was required to make capital improvements to its infrastructure to free up the necessary capacity by reconfiguring circuits and feeders on the system (by pushing load from one feeder to another), reconductoring portions of line.

of 50% of the labour and trucking costs. Requests to relocate infrastructure by parties other than the City of Windsor do not fall under the PSWHA and are 100% funded by the requester. The requester and EWU will complete a comprehensive review of acceptable servicing alternatives and will jointly develop the project plans.

The following table demonstrates EWU's net spending on New Services for 2008.

		2008	
	AMOUNT	CONTRIBUTED CAPITAL	TOTAL
TOTAL	**2,918,924**	**(489,076)**	**2,429,848**

EWU has budgeted $2,918,924 for New Services in 2008. As illustrated by the table above, EWU forecasts that $2,429,848 will be added to rate base for these new services. A breakdown of the forecasted 2008 net expenditures for New Services is as follows:

- Overhead line, cable and transformer work for the construction of a new arena is forecasted at $392,000.

- Load transfer and transformer work on 7th Concession is forecasted at $112,000. The work at 7th Concession is being completed to ensure compliance with the Distribution System Code requirements related to load transfer.

- All City road projects are forecast based upon known projects planned for 2008 which total $812,104. This total is broken down as follows:

- Walker/Parkdale road widening ($158,704 addition to rate base net of capital contribution)
- Tecumseh road widening at Jefferson ($553,875 addition to rate base net of capital contribution)
- Howard and North Talbot intersection improvements ($99,525 addition to rate base net of capital contribution).

The balance of the net budgeted amount for New Services is forecasted based on historical expenditures.

Relative to 2007, 2008 net expenditures for New Services is forecasted to increase by approximately $1.4 million. Based upon EWU's experience, 2007 was an anomaly with respect to the level of capital contributions such as the VACIS and Casino projects footnoted above. Net capital spending on New Services is forecasted to be more consistent with historic net investment in New Services.

2009 Forecasted Expenditures for New Services

		2009	
	AMOUNT	CONTRIBUTED CAPITAL	TOTAL
TOTAL	**2,973,942**	**(549,076)**	**2,424,866**

EWU forecasts the same level of spending for New Services in 2009 as it did in 2008. EWU does not expect city road projects to vary significantly from that of 2008 in 2009. This forecast is based upon recent historical experience. Notwithstanding that labour and material costs will continue to rise, because of the economic slow down in EWU's service territory, EWU believes it is reasonable to hold costs in this category constant.

3.2.1.2 IESO Wholesale Meters

Table 2-1-1 E – IESO Wholesale Meters

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
IESO Wholesale Meters	325,850	(266,476)	-82%	59,374	392,506	661%	451,880

<u>2007 Expenditures for IESO Wholesale Metering Compliance</u>

IESO wholesale metering expenditures relate to replacement for wholesale revenue meters. A wholesale revenue metering point is defined as a point used to account for the electricity conveyed, through or out of the IESO-controlled grid. A wholesale revenue metering point is typically comprised of current and voltage transformers, a primary meter, an alternate meter, and associated communications equipment.

Historically, Hydro One has owned and maintained these revenue meters throughout the province. This responsibility has been transferred to meter market participants ("MMP"). EWU is a MMP. When the Hydro One meter seal expires, the MMP for the metering installation is required to make alternative arrangements as set out in Chapter 6 of the IESO Market Rules (the "Market Rules").

The Market Rules required owners of metering installations on the date of market opening to continue acting as meter service provider until the expiry of the first meter seal in the metering installation. There was one EWU metering installation located in Hydro One's Walker I transformer station that fell into this transitional obligation. In 2007, the first meter seal expired on the metering installation, ending Hydro One's obligation to continue acting as EWU's meter service provider. Since Hydro One was no longer EWU's meter service provider, it required EWU to remove its metering installation from its transformer station.

There are six feeders leaving the Walker I transformer station that supply EWU. EWU's power was historically metered at the bus in the station by the one metering installation. However, in order to meter EWU's wholesale power outside of the Walker I transformer station (i.e. beyond the bus), each of the six feeders had to be individually metered. Therefore, EWU was required to install six wholesale metering installations outside the station, one for each feeder leaving the station.

The re-located metering installations were in-service in 2007. A break-down of the $298,000 expenditure on this project is as follows:

	2007
Labour	$85,000
Material	$185,000
Trucking	$7,000
Contracted Services	$21,000
Total	**$298,000**

A total of $27,850 was spent on EWU owned municipal transformer stations related to Chrysler and General Motors. This spending relates to seals on the meters that expired in 2007 and were replaced in accordance with Measurement Canada requirements. EWU is required by the Electricity and Gas Inspection Act to upgrade or replace meters once the seal has expired.

<u>2008 Forecasted Expenditures for IESO Wholesale Metering Compliance</u>

Hydro One is in the process of rebuilding its Essex transformer station. EWU will be supplied from this station by 6 feeders. Hydro One has agreed to allow EWU to place its metering installation inside the transformer station at the bus. Therefore, unlike at the Walker I transformer station where metering installations are required for each feeder leaving the station, EWU will only require one metering installation inside the Essex station to meter all power supplied to EWU from that station. The forecasted cost for the metering installation in the Essex station is $59,374. This forecasted cost relates only to materials, since installation will be performed by Hydro One at its own cost.

2009 Forecasted Expenditures for IESO Wholesale Metering Compliance

$451,880 is forecasted in relation to the metering installation in Hydro One's Malden transformer station. The seal expires on this installation in 2010 and the installation will have to be moved from the station as in the case of the Walker I transformer station described above. However, a number of seals on EWU metering installations at other Hydro One transformer stations are expiring in 2010. As a result, EWU will not have the manpower to complete all of these 2010 expirations in 2010. To manage limited labour resources, this project was moved forward to 2009. This enables EWU to use its own internal labour force to complete this project and avoid incremental costs in 2010 associated with contracting out to alleviate limited labour resources at that time. The estimated amount for this project is as follows:

	2009
Labour	$141,018
Material	$264,480
Trucking	$25,582
Contracted Services	$20,800
Total	**$451,880**

3.2.2 Infrastructure

Infrastructure expenditures generally pertain to plant replacement at end-of-life, expenditures to increase reliability, expenditures for minimization of outages and expenditures for safety of the public and workers.

To improve system operating reliability a utility must:

- design feeders to operate efficiently and reliably;
- analyze outage data using reliability statistics to track and identify areas for improvement;
- limit the number of incidents and avoid major incidents; and
- limit the consequences of major incidents when they do occur.

An unplanned customer outage is generally caused by a fault on the utility system. 80% of the outages experienced are due to factors beyond EWU's control (e.g. loss of supply from Hydro One, extreme weather conditions, motor vehicle accidents, animal contact). Although the number of faults that occur on the system directly impact the reliability indices and may be outside the control of EWU, the effectiveness of the protective equipment can help minimize the impact of the outage on customers by limiting the number of customers affected or reducing the total outage time.

EWU's infrastructure expenditures have been categorized according to: (i) Operation Sustainability expenditures; and (ii) Operation Enhancement expenditures for the purposes of this evidence. Sustainability Expenditures are geared towards maintaining the reliability of the distribution system, improving the safety of workers and the general public and protecting the environment. Operation Enhancement expenditures pertain to minimizing impacts to customers resulting from outages. The following table numerically illustrates the infrastructure expenditures:

Table 2-1-1 F – Operation Infrastructure

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Operation Infrastructure	5,919,850	1,955,185	33%	7,875,034	(482,711)	-6%	7,392,323

Within the Operation Infrastructure category, Enhancement expenditures from 2007 to 2009 are forecasted to remain relatively constant. Sustainability expenditures are forecasted to increase from 2007 to 2008, and then decrease in 2009. Project descriptions for both Operation Sustainability and Operation Enhancement expenditures are set out in their respective sections below.

3.2.2.1 Operation Sustainability

Table 2-1-1 G – Operation Sustainability

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Operation Sustainability	5,327,625	1,965,031	37%	7,292,656	(504,008)	-7%	6,788,648

As mentioned above, Operation Sustainability are geared towards maintaining the reliability of the distribution system, improving the safety of workers and the general public and protecting the environment. The specific Operation Sustainability projects for 2007 to 2009 are described below.

a) 4kV Conversion Program

Table 2-1-1 H – 4kV Conversion

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
4kV Conversion Program	4,693,458	669,746	14%	5,363,204	(424,556)	-8%	4,938,648

Currently, approximately 16% of EWU's customers are supplied from old 4.16 kV facilities ("4 kV"). Since the 1970's, EWU has been slowly converting and replacing its 4 kV system with 27.6 kV. All major new load growth on the system since the 1970's has been added to the 27.6 kV system so as not to overload the 4 kV system.

The average age of EWU's existing 4 kV distribution infrastructure is 35 to 45 years. EWU's 4 kV system is approaching end-of-life. EWU could rebuild its 4 kV system at 4 kV, however, the cost of doing so would be greater than converting the existing 4 kV facilities to 27.6 kV. EWU completed a comprehensive evaluation of its 4 kV distribution system in May 2004 (the "EWU Report"). This evaluation concluded that for reliability and safety reasons it would be prudent to rebuild the system through a planned conversion program from 4 kV to 27.6 kV.

Conversion involves the decommissioning of 4 kV substations and the replacement of 4 kV distribution infrastructure with 27.6 kV distribution infrastructure. There are many reasons for EWU to proactively convert its old 4 kV system to 27.6 kV. Compared to 4 kV distribution, 27.6 kV distribution results in reduced line losses and reduced transformer losses (due to the elimination of the intermediate 4 kV substations). In addition, 27.6 kV also eliminates the large maintenance costs and eventual replacement costs associated with the maintenance of the old 4 kV substations. Other benefits of conversion include improvements in reliability, customer satisfaction, reduced potential environmental impacts from PCB contamination, and reductions in inventory.

EWU considered the alternative of reactively replacing sections of the 4 kV system as they fail instead of proactively engaging in a replacement program. This alternative was not accepted by EWU. The drawback of this alternative is increased customer outage times and frequency as well as substantially increased construction inefficiencies. In the event of a major storm, major portions of the distribution system would be at risk of collapse, which would result in long power outages. As well, EWU currently has 11 substations that convert power from 27.6 kV down to 4 kV that range in age from 40 to 70 years. These substations will need to be rebuilt in the near future at a significant cost. By converting EWU's 4 kV system to 27.6 kV, the need for these substations will be eliminated and rebuilding costs will be avoided.

EWU commissioned Kinetrics to review the validity of the assumptions and recommendations in the EWU Report. On April 28, 2005, Kinectrics provided a report, attached to this evidence as Attachment A (the "Kinectrics Report"). The Kinectrics Report concluded, as recommended in the EWU Report, that the best course of action would be to replace the 4 kV system with a 27.6 kV system.

EWU's expenditures on this program from 2007 to 2009 (actual and forecasted) on a feeder basis are set out in the following table:

4kV Conversion			Total
2007			
	RCF	64,394	
	42F3	90,181	
	51F2, 51F3	345,624	
	51F1	285,084	
	53F1, 62F4	1,787,559	
	56F1, 56F2, 56F3	1,572,134	
	59F1, 22F8	134,433	
	59F4	85,895	
	59F5	46,036	
	64F1	41,478	
	64F2	85,384	
	64F3, 53F4	155,257	
			4,693,458
2008			
	52F1	837,608	
	52F3	1,020,105	
	55F1	738,700	
	55F3	784,300	
	59F3	873,425	
	59F1	382,603	
	64F2	726,463	
			5,363,204
2009			
	42F2	617,331	
	42F4	617,331	
	42F5	617,331	
	54F2	617,331	
	54F3	617,331	
	54F4	617,331	
	54F5	617,331	
	67F1	617,331	
			4,938,648

b) 27.6 kV Pole Replacement Program

Table 2-1-1 I – 27.6 kV Pole Replacement

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
27.6kV Pole Replacement Program	17,463	32,537	186%	50,000	800,000	1600%	850,000

EWU started using 27.6 kV facilities in the 1970's. Therefore, portions of EWU's 27.6 kV system is approximately 40 years old.

Kinetrics was engaged by EWU to conduct a system analysis with respect to the condition of EWU is 27.6 kV system and provide recommendations on capital investment. On September 11, 2007 Kinectrics provided the report that is attached to this evidence as Attachment B (the "Kinectrics 27.6 kV Report"). The Kinectrics 27.6 kV Report identified that, generally, EWU's 27.6 kV system is in good condition. However, approximately 3000 poles in the 27.6 kV system are in poor condition and should be replaced.

EWU plans to replace approximately 160 poles in 2009 that have reached end-of-life. Of the $850,000 budget for 2009, $800,000 is estimated to be spent on pole replacements (160 poles x $5,000/pole = $800,000).

In addition to the pole replacements, certain work must be performed to replace old porcelain insulators on the 27.6 kV system. Insulator replacements have been on-going on the EWU system since the late 1980's. The work involves the replacement of porcelain insulators with polymer style insulators. The older style porcelain insulators are prone to fracture resulting in downed power lines and increased electrical hazard to employees and the public. The plan for porcelain insulator replacements is as follows:

- $17,463 in 2007;
- $50,000 in 2008 (budgeted based on approximately 200-250 insulators); and
- $50,000 in 2009 (budgeted based on approximately 200-250 insulators).

The replacement of porcelain insulators has been included in the 27.6 kV Pole Replacement Program description because this work is typically carried out in conjunction with pole replacements in order to reduce costs and to efficiently use resources.

c) Subdivision Re-Cabling

Table 2-1-1 J – Subdivision Re-Cabling

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Subdivision Re-Cabling	0	684,300	100%	684,300	(284,300)	-42%	400,000

In EWU's experience, direct buried underground primary cables installed during the 1970's have a 30-year life expectancy. EWU re-cabled most subdivisions of this era during the 1990's. However, two smaller subdivisions were not completed at that time and require re-cabling - Langlois Court and Borelli subdivisions. The primary cables that serve these subdivisions were installed in the 1970's. In the past two years, there have been 8 cable failures in these subdivisions. Depending on the location of a cable failure, more than 200 customers could lose power. Due to a recent increase in cable failures in those subdivisions, samples of cables from the Langlois Court subdivision were sent to a testing agency, Cable Technology Laboratories (The report dated September 18, 2006 is set out here as Attachment C (the "CTL Report"). The samples were subjected to the following tests by CTL:

- Visual examination of cable components

- Visual examination of the failure
- Evaluation of the bonding strength between the insulation and insulation shield
- Examination for gross imperfections in the insulation system of the failed section
- Evaluation of the nature of the extruded layers: plain PE or XLPE insulation; thermosetting or thermoplastic insulation shield
- Hot creep/set test to establish if the insulation was sufficiently cross-linked
- Measurement of the volume resistivity of the semiconducting shields, at ambient and elevated temperatures
- Dimensional analysis
- Microscopic examination of the insulation system for voids, contaminants, protrusions, and other abnormalities
- Water tree count tests.

Based on the results of these tests, CTL advised that EWU should replace these cables. Specifically, the CTL Report stated the following at page 9:

"The above-described condition of the insulation together with the fact that this cable has experienced two failures at different locations, in a short time, indicates that the cable apparently is approaching the end of its useful service life. According to CTL's experience it is not worth to rejuvenate unjacketed cables. Therefore, it appears advisable to schedule the replacement of this cable "

The cost of repairing a failure of direct buried underground primary cable ranges between $2,000 and $5,000 per incident. Therefore, it is expected that this capital project will eliminate or reduce these costs.

All materials and services for this project will be procured via EWU's purchasing policy as described in Exhibit 4, Tab 2, Schedule 3. EWU crews will provide the labour and trucking associated with the installation and connection of the high voltage cables, associated connections and transformers.

Both subdivisions were originally scheduled for re-build in 2007. However, due to the volume of work associated with the Walker Rd. VACIS underpass construction and the Casino expansion projects, EWU deferred these rebuilds to 2008 and 2009, respectively. 2009 will be the final year of this project.

2008 Forecasted Expenditures for Subdivision Re-cabling

EWU is scheduled to replace the buried underground primary cables that serve the Langlois Court subdivision commencing in September 2008 at a forecasted expense of $684,300, with completion expected by November 2008. The cost of this expenditure includes the replacement of eight transformers that have reached end-of-life. A breakdown of the cost for this expenditure is as follows:

	2008
Labour	$147,000
Material	$189,100
Trucking	$18,200
Contracted Services	$330,000
Total	**$684,300**

2009 Forecasted Expenditures for Subdivision Re-cabling

EWU plans to commence the rebuild of the Borelli subdivision in May 2009 at a forecasted expense of $400,000, with completion by August 2009. A breakdown of the cost for this expenditure is as follows:

	2009
Labour	$86,709
Material	$133,956
Trucking	$9,922
Contracted Services	$169,413
Total	**$400,000**

d) Emergency Replacement Program

Table 2-1-1 K – Emergency Replacement

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Emergency Replacement Program	402,825	(167,825)	-42%	235,000	0	100%	235,000

This investment involves replacing failed equipment on an emergency basis in order to secure reliability or safety. Equipment failures are difficult to predict, but must be addressed quickly because they generally result in customer interruptions or present safety risks. This program predominantly involves the emergency replacement of cable and transformers. Based upon historical experience, EWU spends approximately $235,000 annually for the emergency replacement of defective underground cable ($100,000), overhead transformers ($100,000) and underground transformers ($35,000) due to infrastructure failure.

<u>2007 Expenditures for Emergency Replacement Program</u>

EWU's emergency component replacements in 2007 were unusually high relative to historic expenditures. The expenditures in 2007 were as follows:

- Approximately $138,000 was spent in 2007 replacing sections of failed 4kV primary cable located in the downtown core of Windsor. These cables were all older than 50 years old.

- Approximately $99,000 was spent replacing 20 failed and overloaded pole mounted transformers.
- Approximately $22,000 was spent to replace four broken poles.
- Approximately $144,000 was spent replacing three failed padmounted transformers ($76,000), and six submersible distribution transformers ($68,000).

<u>2008 and 2009 Forecasted Expenditures for Emergency Replacement Program</u>

Although emergency component replacement was higher than usual in 2007, EWU forecasts that its 2008 and 2009 expenditures will be more in-line with historic expenditures. EWU spends approximately $235,000 annually for the replacement of defective underground cable ($100,000), overhead transformers ($100,000) and infrastructure failure ($35,000).

e) PCB Contaminated Transformer Replacement Program

Table 2-1-1 L – PCB Contaminated Transformer Replacement

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
PCB Contaminated Transformer Replacement Program	19,946	12,054	60%	32,000	(32,000)	-100%	0

In 2001, EWU hired K-Line Maintenance & Construction to inspect every overhead transformer in the City of Windsor and record its nameplate data including its date of manufacture. All transformers in EWU's system that were manufactured before 1985 also had an oil sample taken from the tank for PCB testing. The samples were sent to PSC Analytical Services in London, Ontario to be tested for PCB contamination. Any transformers that tested greater than or equal to 50ppm were to be replaced or decontaminated through a capital program completed by EWU in 2001 (the "2001 PCB Program").

In 2007, EWU conducted an audit of the 2001 PCB Program. At that time it was discovered that the 2001 PCB Program was not entirely complete. In the fourth quarter of 2007, EWU analyzed the data to ensure that:

1. All transformers in the system were inspected;
2. All transformers manufactured prior to 1980 were sampled; and
3. All transformers that sampled greater than or equal to 50ppm were replaced.

Three transformers were replaced in 2007 at a total cost of $19,946. It has since been determined that eight additional transformers require replacement in 2008. Based upon historical average costs for PCB transformer replacements, $4,000 per transformer was used for estimating the 2008 expenditures.

f) Manhole Reconstruction/Reinforcement Program

Table 2-1-1 M – Manhole Reconstruction

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Manhole Reconstruction/ Reinforcement Program	0	87,708	100%	87,708	112,292	128%	200,000

In 2005, it became apparent to EWU that a number of cable chambers (i.e. manholes) along Erie Street were significantly aged. These manholes showed signs of structural weakness, which posed a safety risk to the public. In 2005, EWU engaged P.B.S. Engineering Inc. ("P.B.S."), a third-party engineering consultant, to inspect and provide recommendations related to these manholes. P.B.S. prepared a report that recommended the systematic repair, refurbishment and rebuild of 13 manholes on Erie Street at an estimated cost of over $100,000 (the "PBS Report"). This report is attached to this schedule at Attachment D.

<u>2008 Forecasted Expenditures for Manhole Reconstruction</u>

Based on the P.B.S. Report, EWU commenced design work in respect of the manholes in 2007.

$87,708 is budgeted to complete the reconstruction/reinforcement of the manholes on Erie Street identified by the P.B.S. Report.

<u>2009 Forecasted Expenditures for Manhole Reconstruction</u>

As part of EWU's 2008 asset management program, EWU will inspect the remaining manholes in Windsor (in excess of 400) to identify structural deficiencies that will require repair, refurbishment or replacement. Based on the results of the findings of P.B.S. in regard to manholes on Erie Street, it is expected that a number of manholes throughout EWU's system have structural deficiencies, similar to those on Erie Street. Accordingly, EWU has budgeted $200,000 in 2009 to repair, refurbish or replace deficient manholes.

g) Replacement of End-of-Life Equipment on Customer Property

Table 2-1-1 N – Replacement of End-of-Life Equipment

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Replacement of End-of-Life Equipment on Customer Property	0	651,944	100%	651,944	(651,944)	-100%	0

2008 Forecasted Expenditures for Replacement of End of Life Equipment on Customer Property

EWU owns cables and transformers that are located inside apartment buildings and housing developments. In some cases, this equipment is over 30 years old and approaching end of useful life. In this circumstance, aged equipment may pose a fire/safety risk to customer property and tenants. EWU has identified the following customer properties containing EWU equipment that is approaching end of life that must be removed and replaced:

- St. Mike Apartments, 1445 Ouelette Avenue
- Shoreline Towers, 8575 Riverside Drive East
- Bayview Towers, 8591 Riverside Drive East
- Madrid Apartments, 8950 Wyandotte Street East
- Windsor Housing Development, downtown Windsor

The replacement facilities will be located outside apartment buildings. A breakdown of the forecasted cost is as follows:

	Cable ($)	**Transformer ($)**	**Total ($)**
St. Mike Apartments	8,000	25,896	33,896
Shoreline Towers	75,600	43,664	119,264
Bayview Towers	13,900	44,964	58,864
Madrid Apartments	19,700	24,220	43,920
Windsor Housing Development	256,000	140,000	396,000
Total	**373,200**	**278,744**	**651,944**

h) Other Distribution Plant

Table 2-1-1 O – Other Distribution Plant

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Other Distribution Plant	193,934	(5,434)	-3%	188,500	(23,500)	-12%	165,000

This category pertains to tools and equipment in 7 operational departments, as well as other miscellaneous distribution plant expenditures. Expenditures in this category include: Furniture, Tools (valued at more than $1,000 each, examples are battery powered crimpers, cutters, ratchets), safety equipment (traffic signs, gas detectors, explosion blankets, etc.), software licences for CAD (Computer Aided Design for the drafting department). Some of this amount accounts for improvements in ergonomics and safety features that require replacement.

2007 Expenditures for Other Distribution Plant

Approximately $151,900 was spent for tools and safety equipment in 2007. Approximately $80,000 of this amount is in respect of the purchase of an infra-red camera for preventative maintenance thermal scanning.

Approximately $42,000 was spent on rebuilding four line trailers for the overhead department. These custom trailers were no longer road worthy and needed to be completely overhauled.

These are needed to haul tools, equipment and materials required to maintain and construct the distribution system.

<u>2008 Forecasted Expenditures for Other Distribution Plant</u>

$145,000 has been budgeted for tools and safety equipment, and approximately $43,000 is budgeted to replace a cable trailer for the underground department. This particular trailer is more than 20 years old and must be replaced for safety reasons. It is used by the underground department to haul large reels of underground primary cable for field installation and its replacement was supported by a health and safety initiative.

<u>2009 Forecasted Expenditures for Other Distribution Plant</u>

$130,000 is forecasted to be spent in 2009 for tools and safety equipment. $35,000 is budgeted for the replacement/refurbishment of another overhead department Line Trailer.

3.2.2.2 Operation Enhancement

Table 2-1-1 P – Operation Enhancement

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Operation Enhancement	592,224	(9,845)	-2%	582,378	21,297	4%	603,675

It is impossible to build a fault-free distribution system. Even with good anti-outage design and construction, equipment degrades and eventually fails. For faults of this nature, the primary goal is to sectionalize feeders to reduce customer outages and efficiently deploy staff.

Operation Enhancement Expenditures focus on response to failures and minimizing the impacts to customers resulting from outages. EWU's projects that fit within this category of investment are described below.

a) Padmounted Switchgear Replacements

Table 2-1-1 Q – Padmounted Switchgear Replacements

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Padmounted Switchgear Replacements	0	107,240	-100%	107,240	42,760	40%	150,000

EWU's system uses both live-front and dead-front style padmounted switchgear. Live-front padmounted switchgear is used by EWU in residential subdivisions. This type of switchgear has exposed electrical contacts housed in a secured metal cabinet. It is susceptible to dirt and moisture build-up on the insulating components which may result in "flashovers" (i.e. sparks) that cause short circuits and power outages. Since 2001, the switchgear at the Banwell subdivision has experienced 9 flashovers resulting in 5,165 customer hours of power interruption. Since 2002, the switchgear at the Forest Glade subdivision has experienced 3 flashovers resulting in 3,517 customer hours of power interruption. These are the worst performing switching units in EWU's distribution system. Therefore, these switching units are scheduled for strategic replacement with newer 'dead-front' units. These newer style switches will eliminate flashovers and also offer the added benefits of being monitored and controlled remotely through the SCADA network. As with other SCADA controlled devices in the distribution system, the automation will allow for improved system reliability resulting from the ability to remotely monitor and efficiently dispatch response crews.

<u>2008 Forecasted Expenditures for Padmounted Switchgear Replacements</u>

The switchgear at the Banwell subdivision is planned to be replaced in 2008 at an estimated cost of $107,240. As mentioned above, this particular switch has experienced several flashovers that have affected reliability of service for this subdivision, as well as the customers served by the feeders connected to this switch.

<u>2009 Forecasted Expenditures for Padmounted Switchgear Replacements</u>

In 2009, EWU plans to replace a switching unit that serves the Forest Glade subdivision which, as described above, has also experienced several flashover incidents that have affected reliability of service. Through a competitive bidding process in 2008, it was discovered the $107,240 (the 2008 budget amount) did not sufficiently cover all the costs associated with the switchgear replacements. As such, the budget for 2009 has been adjusted upward to $150,000.

b) Pole-Top Recloser Program

Table 2-1-1 R – Pole Top Recloser

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Pole Top Recloser Program	372,067	(372,067)	-100%	0	0	0%	0

The average age of EWU's distribution infrastructure is 30 to 40 years old. Because the average life of distribution infrastructure is approximately 40 to 50 years, as EWU's infrastructure continues to age, the probability of equipment failure increases. In 2004, EWU, through internal studies, identified the need to improve outage reliability statistics. As part of a broader strategy to improve outage reliability statistics, EWU began a 4 year pole-top recloser program.

The improvement of EWU's reliability is extremely important to EWU. EWU has a number of large customers whose businesses are sensitive to power quality issues. The economy of Windsor depends on these customers. Therefore, in order to retain EWU's large customers, it is imperative that EWU addresses its system reliability issues.

One of the explanations for EWU's low outage reliability statistics was that EWU did not have a looped recloser scheme, similar to other utilities in Ontario (e.g. Burlington Hydro and Festival Hydro). A looped recloser scheme will automatically restore power to a part of a feeder after a fault condition has occurred that results in a power outage. The use of pole-mounted reclosures in a looped configuration can expedite power restoration initiatives and improve reliability statistics while reducing operating and maintenance costs.

Based on an internal analysis by EWU, it was determined that:

- Relative to other alternatives for improving reliability, implementing a closed-loop recloser scheme is the most economic alternative for improving reliability;
- Reliability can be improved by 10%; and
- Outage costs to EWU's large industrial customers can by reduced by $1.1 million/year.

Other benefits of a closed-loop recloser scheme include:

- The potential to be used not only for reliability improvements, but also for fast load shedding and restoration during emergencies; and

- Improved customer service regarding supply voltage inquiries/complaints.

Since reclosers will be installed at the ends of the feeders, EWU staff can better obtain power quality information, which will enhance the ability of EWU to address customer supply complaints such as low voltage problems due to long feeder lengths and load changes. The availability of real time information from the reclosers will allow EWU to proactively deal with low voltage problems.

2007 Expenditures for Pole-Top Reclosers

2007 was the final year of EWU's four year Pole-Top Recloser Program. This investment pertains to 10 reclosers at the following locations:

- 56M3-RC-56M5 Location: 3rd PS Tecumseh on W.S. Lauzon Pkwy.
- 55M5-RC-55M23 Location: George, 3PN. Franklin.
- 25M10-RC-55M2 Location: 2 PW Marentette on Shepherd.
- 15M8-RC-15M11 Location: Ouellette, 6 PS of Eugenie (in Staples's Parking area).
- 25M13-RC-55M24 Location: South Cameron, 5 PS Arcadia (1 PN 25M13-55M24 LI).
- 23M2-RC-24M6 Location: 2 PE Ambassador on Malden.
- 55M26-RC-56M2 Location: 1 PW Pillette on Rhodes.
- 55M22-RC-56M2 Location: 2 PE Jefferson on Coronation.
- 55M23-RC-56M1 Location: 1 PE Victor on Wyandotte.
- 56M7-56M8 Location: 1 PS of Riverside Dr on the ES of Riverdale.

c) Single-Phase Line Protection

Table 2-1-1 S – Single-Phase Line Protection

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Single Phase Line Protection	0	15,000	100%	15,000	0	0%	15,000

Some of the older sections of EWU's system do not have fuses between line taps and circuits. In these circumstances, an outage on a line tap can cause an outage of an entire circuit. In order to prevent such unnecessary outages on circuits, EWU has embarked on a multi-year program to install fused taps. This program is inexpensive relative to the benefits received from additional reliability.

<u>2008 and 2009 Forecasted Expenditures on Single-Phase Line Protection</u>

In each of 2008 and 2009 EWU will spend $15,000 on installation of fuse taps.

d) SCADA Improvements

Table 2-1-1 T – SCADA Improvements

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
SCADA Improvements	220,157	(115,446)	-52%	104,711	167,464	160%	272,175

In each of the years from 2007 to 2009, EWU has and will make investments in its SCADA system. These investments generally pertain to: (i) security measures; (ii) network analysis tools; and (iii) remote monitoring of field devices such as switchgear and faulted circuit indicators. In regard to security, EWU has implemented measures to protect its distribution system from cyber-attack, which could potentially interrupt power supply to the entire City of Windsor. Cyber-attack is a real threat, as demonstrated by the comprehensive critical infrastructure protection standards adopted by the North American Electric Reliability Corporation ("NERC"). [2]

2007 Expenditures for SCADA Improvements

Approximately $60,000 was spent on the acquisition and installation of network analysis software which will help the EWU system planning department analyze the distribution system, address customer power quality concerns, optimize the placement of switching devices, improve upon the coordination of protective devices, all with a view towards improved system reliability.

Approximately $160,000 encompassed new SCADA servers and a firewall. The original computer servers had reached the end of their useful life as hard drives were starting to fail and the software versions were no longer supported and had to be replaced or upgraded.

2008 Forecasted Expenditures for SCADA Improvements

$11,500 is budgeted for the installation of SCADA monitored Faulted Circuit Indicators ("FCI's"). Installation of FCI's help improve system reliability by assisting EWU Systems Control Operations in pinpointing trouble areas during outages. This allows operators to dispatch staff more efficiently by reducing patrol requirements. This functionality will minimize the duration of outages experienced by customers.

$58,000 is budgeted for security improvements to the SCADA system which include the installation of firewalls, servers, switches, personal computer cages within the office

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[2] More information on NERC's critical infrastructure protection standards are at www.nerc.com.

environment and door alarm contacts on a variety of field devices. These door contacts will alert the control room operators if someone is tampering with certain field devices.

$35,000 has been budgeted to continue with a multi-year program to expand the SCADA control of switchgear located in the downtown core to provide improved reliability to the customers of EWU.

2009 Forecasted Expenditures for SCADA Improvements

$12,000 is budgeted for the installation of FCI's to help improve system reliability by pinpointing trouble areas during outages and dispatching staff more efficiently.

$25,000 has been budgeted for cyber security enhancements.

$35,000 has been budgeted to continue with a multi-year program to expand the SCADA control of switchgear located in the downtown core to provide improved reliability to customers.

$100,000 is budgeted to continue with Phase II of a multi-year program directed at the creation of a Geographic Information System ("GIS") for EWU. Phase I started in 2007 in conjunction with the installation of network analysis software described above by generating maps and reports using a core database for the 4kV and 27.6kV distribution feeders. Phase II involves the data capture and record creation/validation of the low voltage distribution elements.

The purpose of EWU's GIS is to help ensure that the accurate, timely display of assets and their relationships with one another is conveyed to users. In turn, those responsible for maintaining or monitoring these assets in the field will be provided with the most reliable information on which to base decisions influencing system operation. Front line staff will also be provided with important, quality information, to be conveyed to customers more effectively.

$100,000 is budgeted for Control Room upgrades. The upgrades include the acquisition and installation of video screens and computer systems required for an advance notice display system. These tools will allow the system control operators to better use computer technology to help facilitate the operation of EWU's distribution system. This technology was not previously available for use by EWU's system control operators as the EWU system maps have been paper based. With the introduction of the GIS system, EWU can plan to move away from paper based maps to electronic ones.

e) Transformer Station Upgrades

Table 2-1-1 U – Transformer Station Upgrades

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Transformer Station Upgrades	0	355,427	100%	355,427	(188,927)	-53%	166,500

EWU has budgeted $355,427 in 2008 and $166,500 in 2009 for a number of projects related to upgrading its transformer stations.

<u>2008 Forecasted Expenditures for Transformer Station Upgrades</u>

$81,000 is related to cyber and physical security measures such as the installation of video cameras and magnetic door controls for site security. These measures prevent attacks to the critical infrastructure used to maintain and control the distribution system.

$75,000 is related to battery bank replacements as the batteries used for tele-protection have reached the end-of-life.

$200,000 is to upgrade the protective relays from an old electromechanical type to microprocessor based relays. The existing relays are twenty-years old and EWU is unable to acquire spare parts or replacements for them. In addition to the end-of-life issue, the microprocessor based relays require less maintenance, are more reliable and provide greater functionality for operating the distribution system.

2009 Forecasted Expenditures for Transformer Station Upgrades

A miscellaneous capital replacement amount of $72,500 is budgeted in total for five transformer stations and eleven sub-stations to cover any unexpected capital expenditures. This amount is based upon EWU's experience over the past three years where minor equipment failures requiring replacement have been encountered.

$94,000 has been budgeted for the replacement of the testing equipment required to maintain EWU's transformer stations. The existing test kit is greater than twenty years old and in addition to it becoming more difficult and expensive to maintain, it does not offer the functionality nor provide the operational efficiency newer test kits provide. It will be used to maintain the protective relaying equipment at the five transformer stations and eleven substations.

3.3 Administration Expenditures by Project

3.3.1 Administration Sustainability

Projects undertaken under this category include projects related to information technology, site services and fleet support. These projects are required to sustain current levels of service and performance in these areas.

Table 2-1-1 V – Administration Sustainability

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Administration Sustainability	398,820	680,904	171%	1,079,724	(24,519)	-2%	1,055,205

3.3.1.1 Information Technology – Hardware and Operating System Software

Table 2-1-1 W – Information Technology

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Information Technology	86,806	205,118	236%	291,924	198,731	68%	490,655

These amounts relate to EWU's IT operating system and related equipment. The operating system software controls the hardware; controls input, output and storage; and handles interaction with application programs. This capital work is different from the work proposed as part of the Comprehensive ERP Project described at Section 3.3.3 below.

EWU notes that industry practices generally dictate the replacement of computer hardware and software every 3-5 years. EWU has adopted a replacement schedule of about five years for most of its administration IT infrastructure. In order to ensure continuity of operations, evaluations of infrastructure and related architecture are regularly undertaken as a routine business process as well as on a per-complaint basis. Where the functionality of an asset has deteriorated and it is not economical to repair the asset, replacement occurs. In most cases, a combination of higher maintenance costs and new technology make it beneficial to replace this equipment at the five year point. At times, it is no longer possible, cost-effective or in the operational interests of EWU to repair the asset. It is more cost-effective to replace the assets. EWU also considers whether an identical asset will still have a life expectancy of at least three years or whether technological changes or altered business requirements make replacement unnecessary or imprudent. If the functionality is still required and the expenditure is prudent, EWU examines other procurement options, including upgrades.

<u>2007 Expenditures for Information Technology</u>

In 2007 EWU spent \$43,394 as part of its ongoing laptop and desktop computer replacement program. This equipment is generally replaced every 3-5 years. EWU spent an additional \$43,412 for network security upgrades and communication equipment.

<u>2008 and 2009 Forecasted Expenditures for Information Technology</u>

In 2008-2009, many of EWU's IT assets will be at the end of their life-expectancies and are accordingly scheduled for replacement. For 2008, of the \$291,924 forecast to be spent on information technology, \$193,000 relates to the acquisition of new servers and operating system software. For 2009 of the \$490,655 spent on information technology, \$418,000 relates to the acquisition of new servers and operating systems software. The remaining amounts for this category relate to the acquisition of desktop computers, laptops, and miscellaneous accessories, such as wiring and cables.

3.3.1.2 Site Services

Table 2-1-1 X – Site Services

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Site Services	215,779	388,221	180%	604,000	(164,300)	-27%	439,700

EWU operates a head office at 787 Ouellette Avenue in downtown Windsor, which was built in the 1950's. EWU also operates an Operations Centre at 4545 Rhodes Drive near the centre of Windsor, which was built in 2000. These projects are as a result of the needs of an aging head office and the ongoing needs of both buildings, with respect to security and conservation. The building at Rhodes Drive contains all of the operational fleet, tools and inventory for EWU. The facility at Ouellette Avenue houses the administrative services of EWU including the finance department and call centre.

<u>2007 Expenditures for Site Services</u>

In 2007 EWU engaged in over 20 miscellaneous projects that ranged in cost from under $1,500 to $60,616. The types of projects included within this area ranged from renovation of a handicapped washroom to relocating a yard fence.

2008 and 2009 Forecasted Expenditures for Site Services

The only projects within this category that are budgeted to be completed at an amount greater than $60,000 in 2008 and 2009 are a chiller/hot water unit in 2008 ($250,000) and high efficiency condensing boilers in 2009 ($130,000). Both of these projects are located at the Rhodes Drive building.

The chiller/hot water system is used in the Rhodes Drive building for air conditioning. The system currently in place is 9 years old, must be rebuilt every 20,000 hours and is already experiencing failures that require the coils to be replaced. To replace the coils would cost approximately $350,000. Given that cost, EWU is proposing to replace the chiller in 2008. The system that is proposed to be purchased by EWU will be far more energy efficient than the current system and has a payback period of 7.3 years. The proposed system will be able to function for 75,000 hours before being rebuilt. EWU anticipates that the proposed chiller would last for approximately 20 years.

Also in the Rhodes Drive building, there is a need for work to be conducted on the boilers in 2009. There are 2 boilers in the building that are suffering from cracked heat exchangers. The cost to repair the heat exchanger is comparable to replacement of the boiler.

There are over 20 remaining projects in each year, all of which are discrete and range in cost from between $2,000 - $60,000.

These projects include infrastructure upgrades for security control and access systems to ensure employee and public safety as well as the replacement and upgrades to the buildings' equipment.

As a result of these site services projects, the buildings will be safer, more secure, more energy efficient, and sustainable facilities for EWU's employees and equipment.

3.3.1.3 Fleet Support

Table 2-1-1 Y – Fleet Support

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Fleet Support	14,634	12,866	88%	27,500	39,500	144%	67,000

These projects replace and upgrade fleet support assets and the various garage equipment and tools required to maintain EWU's fleet of vehicles.

2007 Expenditures for Fleet Support

The only Fleet support expenditure in 2007 was the purchase of a vehicle hoist in the garage to allow for efficient maintenance of fleet vehicles.

2008 Forecasted Expenditures for Fleet Support

An automotive scan tool project and a vehicle Radio Frequency ("RF") data acquisition system project are forecast for 2008. These projects are to be phased in over 2008 and 2009. RF will target maintenance by analyzing information about fleet vehicles including engine hours, idling time, etc. The automotive scan tool will track the parts and equipment for vehicles in order to monitor equipment age and maintenance history. $16,000 of the $27,500 total in 2008 is in relation to these two projects.

2009 Forecasted Expenditures for Fleet Support

Upgrades to the drive clean testing equipment (emissions test), automotive scan tools and various garage equipment and tools are scheduled for 2009. These initiatives provide an opportunity to improve fuel efficiency as well as ensure compliance with the Ministry of Transportation's guidelines.

The amount of automotive scan tool upgrade and RF data acquisition system are forecasted to be $6,000 and $7,500, respectively. The drive-clean testing equipment is forecasted to be $35,000. EWU has carried out an assessment of providing diagnostic testing tools in-house as opposed to outsourcing those services. The conclusion is that it is more economic to purchase the diagnostic testing equipment. The remaining projects include clutch removal and installation, portable hydraulic power pack, mobile service cart, and miscellaneous tools, which have project values in the range of $3,000 to $5,500.

3.3.1.4 Other Administration

Table 2-1-1 Z – Other Administration

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Other Administration	81,601	74,699	92%	156,300	(98,450)	-63%	57,850

On a periodic basis, EWU management evaluates the condition of office furniture, workstations and similarly small value assets that support general administrative work.

<u>2007 Expenditures for Other Administration</u>

EWU's meter reading hand held equipment will no longer be supported by the vendor. Therefore EWU has spent $24,600 to replace meter reading hand helds.

EWU also spent $53,641 on office equipment.

<u>2008 Forecasted Expenditures for Other Administration</u>

Because of the lack of vendor support as stated above, EWU has budgeted $30,000 for the purchase of additional meter reading hand helds. EWU plans to spend $120,800 on office equipment.

This cost for office equipment is unusually high as a result of the establishment of a project management office. Approximately $60,000 is budgeted for start-up infrastructure, including desks, tables, chairs, and office set-up. The project management office has been implemented in order to provide a centralized resource to improve programme management through shared resources and best practices. The objective is to manage projects more efficiently and streamline related processes.

<u>2009 Forecasted Expenditures for Other Administration</u>

Because of lack of vendor as stated above, EWU has budgeted $32,000 for the purchase of additional meter reading hand helds. The remainder of 2009 is $24,859 for low-cost assets that support general administrative work.

3.3.2 Administration Enhancement

Administration enhancement projects are capital projects that provide for new capital assets that improve EWU's administration and its service to its customers. For 2008 and 2009, these projects relate to Customer Service, Fleet Operations and Financial Reporting Software.

Table 2-1-1 AA – Administration Enhancement

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Administration Enhancement	0	1,161,370	100%	1,161,370	(502,210)	-43%	659,160

3.3.2.1 Customer Service

Table 2-1-1 BB – Customer Service

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Customer Service	0	679,925	100%	679,925	(20,765)	-3%	659,160

There is one project to be phased in over 2008 and 2009 relating to customer service to provide for a Contact Centre and VOIP application. For 2008, the costs of in-use assets are forecasted to be $679,925. In 2009, the costs of in-use assets are forecasted to be $659,160.

In late 2006 and early 2007, the EWU IT and Customer Service departments undertook a process to begin exploring various means of upgrading its telephone system. This was primarily driven from a need to provide a higher degree of service for the EWU customer base. The outcome of that assessment is the implementation of a Contact Centre and VOIP application (collectively the

"Contact Centre"), beginning in 2008. Among the needs that the Contract Centre is to address are:

- The telephony infrastructure is reaching "end of life" and the current provider is dropping support and maintenance for some components beginning in 2008. Many of the remaining components are anticipated to become "non-serviced" over the coming years.

- Despite relatively static customer numbers, the volume of customer calls has been steadily increasing over the past few years. The volume of inbound calls increased 63% from 2004 to 2006. This elevated level of calls is expected to be sustained, if not increase further as a result of the adverse economic environment within the City of Windsor. Increasingly, these calls are credit related. Credit activity also increases the need for lengthier calls and outbound calls.

- Increased service levels are being mandated by the OEB through the Distribution System Code's Service Quality Requirements. These requirements necessitate excellent call answer times and the ability to accurately track and report these times and other performance indicators tied to communications with customers. The current telephone system does not provide for this functionality. To track all of this information or to be able to have the same scheduling functionality would require the addition of another staff member.

- EWU has studied customer preferences for contacting the Call Centre and has observed heavier volumes of calls early in the morning, lunch, and late afternoon. This indicates an interest from customers for extended service hours. The Contact Centre permits an extension of service hours through self-serve functionality. This permits EWU to provide higher levels of service to its customer base, extending availability to the customer over more days and more hours within each day. This could be accomplished by the acquisition of additional evening or night time staff. However, the costs associated with such staff (salary, benefits, etc.) would outweigh the costs to implement this program.

- The telephone system is a key component within EWU's Disaster and Recovery plan. The current system requires improvements to better meet these requirements. For example, outbound calls of a broadcast nature would permit messages to be conveyed to both customers and employees in the event of a disaster or localized emergency. This also permits EWU to continue on-going operations if a disaster strikes. The Call Centre may be relocated from a technological perspective.

- EWU requires additional telephone functions such as Call Recording to monitor service quality issues and, in some cases, for legal protection. The current phone system does not provide this level of functionality.

This project will build the existing infrastructure into an integrated networked telephone system. The Contact Centre product provides the basis for Call Recording, Interactive Voice Response ("IVR") with Speech Recognition for customer contact automation, and an Outbound Dialer service for EWU. By building the system into a single, networked solution, software and licenses are shared between the two EWU sites (Ouellette and Rhodes), eliminating the need to purchase duplicate software.

IVR allows the "automation" of select customer interactions, allowing customers to interact with EWU 24/7/365, thereby improving productivity by reducing the need for agents to handle this activity. This would allow EWU to shift staff from high volume, repetitious, unsophisticated work to more value–added customer care.

The outbound dialer will be used, in conjunction with the IVR, to allow EWU to automate calling its customers. This feature provides for a variety of customer contact options such as delivery of "credit" reminders and planned and unplanned outage messages. Much of this can be scheduled after hours when probabilities are highest that someone is home and the contact is successful.

3.3.2.2 Fleet Operations

Table 2-1-1 CC – Fleet Operations

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Fleet Operations	0	181,445	100%	181,445	(181,445)	-100%	0

In 2008, these costs are associated with the implementation and installation of Digital GPS mobile radios, and includes the radios, licenses and software for the entire fleet. As part of improving field operations, enhancements will be made to Fleet Operations through the installation of Digital GPS mobile radios.

In 2003, EWU moved voice communications to an analogue trunk radio system. The operating agreement for this radio system was a 5 year term expiring the summer of 2008. The new digital radio units include GPS. These new digital radios would operate on the existing trunk radio network. The radio GPS and Text Message is a licensed feature that can be added to each radio and the licence can be transferred between radios as required. This would allow EWU to tailor each of the radios to meet its needs and minimize the monthly service fees.

The GPS feature will aid in improved productivity, efficiency and safety by:

- Ensuring vehicle/crew closest to the customer / service request /emergency is redirected to the site in order to appropriately address concerns;
- Assist in minimizing travel time and reducing full consumption by ensuring vehicles take the most direct route to and from the job site;
- Availability of an emergency button for alerting dispatcher of problem and pinpoints exact location of crews;
- Reducing fuel consumption and monitoring of power take off systems (relates to hydraulic use of bucket operations); and

- Monitoring of truck and field staff utilization and engine idling hours.

The Digital GPS mobile radios will allow for status messaging. Status messaging allows crews to indicate their job status (e.g. "arrived", "working", "job completed") with very user-friendly technology that in turn allows supervisors and data recording staff to monitor, through the interconnected GPS, what is happening and where, in real-time. This will enable EWU to track numerous mandatory Service Quality Requirements in the Distribution System Code. EWU would not otherwise be able to provide this information in an accurate, cost-effective manner. This will allow EWU to meet the requirements of the Code with a high level of reliability.

GPS and Status messages are electronically logged and archived in the server. This data can be retrieved and put into a report as required.

3.3.2.3 Financial Reporting Software

Table 2-1-1 DD – Financial Reporting Software

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Financial Reporting Software	0	300,000	100%	300,000	(300,000)	-100%	0

2008 forecasted expenditures include an enhancement expenditure of $300,000 for the purchase (installation and implementation) of financial reporting software. This tool will improve reporting capabilities to all departments, management, executive, and EWU's stakeholders, including its customers. EWU's current financial reporting is primarily performed using internally developed Microsoft Excel files. It is a labour-intensive, inefficient, low work-value activity. It is an activity that, by its very nature, must be replicated every time unique reports need to be created for planning or tracking purposes. Preparing reports is presently a task that demands extensive data entry and formatting time, resulting in less time that can be dedicated to higher-order work, such as analysis.

EWU's existing reporting systems are very manual and time consuming. Multiple data sources are queried from the different systems and manually entered into Excel to monitor, track and report information. For example, to produce monthly financial management reports, several queries and data sources must be reviewed to deliver reports that are accurate and reflect the current financial state of the business. This manual extrapolation of data increases the risk of errors and business decisions being recommended on inaccurate or out of date information. Extensive manual effort is also required to validate and ensure the accuracy of the data presented. The existing reports are limited in their reporting capabilities as they are difficult to modify.

By contrast, financial reporting using the new software tool would allow EWU to shift personnel to higher-order functions. The software is a part of a Business Intelligence ("BI") Platform that simplifies the deployment and management of BI tools, reports and analytics. This platform would enable the finance department, managers, executive and other employees to access to real-time information that is consistent with all relevant data sources. This would improve EWU's capacity to make timely decisions that have regard to the pertinent data sources.

This platform would overlay EWU's current IT infrastructure. That is, it can extract data from Maximo, PeopleSoft Financials, PeopleSoft HR, and any combination thereof to generate reports. The software performs this function without the significant manual effort that characterizes current report-making. In addition to having functionality with EWU's current IT infrastructure, the tool that has been selected is capable of performing the same data extraction and report-making functionality with Comprehensive ERP systems offered by multiple vendors. This reporting software would further enhance the functionality of EWU's Comprehensive ERP.

By implementing financial reporting software, some of the benefits for EWU include:

- Data integrity and validity of reporting, creating opportunities for proactive resolutions;
- Efficiencies in reporting and improved response/reaction times to events;
- Time savings in reconciling timing difference between systems;
- Efficiencies arising from reduced manual work allow for additional analysis and better business decisions; and
- Improved strategic planning and strategy execution.

The financial reporting tool will empower user groups. This solution allows for business users to easily develop reports that will be extracted from the same data source/warehouse. This implementation will be initiated in the finance department, but has great potential to be used by other departments that depend on financial information, such as asset management, project management, procurement, and customer service. Through implementation, EWU will develop a data warehouse that will ensure consistency of data quality and data used for reporting. This data warehouse is a best practice for organizations seeking to better manage data. Data quality will enable EWU to develop improved policies in respect of data integrity across the various databases that feed into the reporting software. This will enhance staff's ability to produce reports that accurately represent EWU's business. Better reports are expected to result in faster decision making and business performance optimization.

3.3.3 Comprehensive ERP

Table 2-1-1 EE – Comprehensive ERP

Description	Actual	Variance 07-08		Bridge	Variance 08-09		Test
	2007	$	%	2008	$	%	2009
Comprehensive ERP	0	0	0%	0	7,250,445	100%	7,250,445

<u>Assessment of IT Infrastructure</u>

In May 2007, EWU began the process of evaluating its IT infrastructure. The focus was on the SPL (CIS), PeopleSoft (Finance and HR) and Maximo (Asset Management) systems. This process was led by the executive management group and was extended to involve the majority of managerial, supervisory and other non-unionized personnel. Through numerous discussion and evaluation sessions, EWU pinpointed hundreds of deficiencies with its IT infrastructure. In some cases these deficiencies were the result of a lack of ongoing system support by the original vendors. In other cases, there were major deficiencies in respect of the lack of integration among systems. In still other cases, the systems, many of which were implemented at least four years ago, could not perform the functions demanded by current or foreseeable near-term business and regulatory requirements. The severity of the deficiencies ranged from those related to fundamental business operations to foregone efficiencies.

Because of the specialized and quickly evolving field of IT infrastructure, EWU retained the services of SJH Consulting. EWU retained SJH Consulting to evaluate the findings of EWU's initial investigation, perform additional investigations and analysis as necessary, and to ultimately recommend a solution to the IT infrastructure deficiencies.

With EWU providing the background information, SJH Consulting developed a report in respect of EWU's current IT infrastructure. That report recommended that EWU resolve its IT infrastructure deficiencies by procuring and implementing a Comprehensive ERP. An analysis of the deficiencies in EWU's IT infrastructure underlying these recommendations are set out in detail in the SJH Consulting report. A copy of the report is enclosed at Attachment E.

<u>Assessment of Report</u>

EWU has considered the report and adopts its findings. SJH Consulting has assisted EWU in projecting not only when expenditures would occur, but also when systems within the Comprehensive ERP would be in-service and therefore eligible to be added into rate base as set out in Table 2-1-1 FF below.

Table 2-1-1 FF – Comprehensive ERP – Timing of In-Service

Cost Element	Total Cost	Total incl. 2009 (Test Year)	Total incl. 2010
Software Licence	$ 1,300,000	$ 1,300,000	$ -
RFP Process	$ 200,000	$ 200,000	$ -
Implementation Costs	$ 13,600,000	$ 5,018,667	$ 8,589,333
Project Management Costs	$ 700,000	$ 500,000	$ 200,000
Hardware Costs	$ 231,778	$ 231,778	
Total	$ 16,031,778	$ 7,250,445	$ 8,789,333

Based on the features of a Comprehensive ERP, EWU understands that the benefits of the system to EWU will range from the equivalent of $5,145,000 to $8,654,000 over 5 years. These figures are based on the low-range of industry averages, not on a detailed audit of EWU.

The position of EWU is that the Comprehensive ERP will provide the best dollars-for-value business proposition for EWU and its ratepayers.

<u>Action Plan</u>

Implementation of the Comprehensive ERP is scheduled to begin in 2009. At this stage, implementation is expected to occur over the course of 2 years. Currently, it is expected that the Finance and Human Resources systems will be addressed in 2009. The remaining systems (e.g. CIS, Work and Asset Management) will be implemented in 2010.

Vendors that offer Comprehensive ERP systems that exhibit the characteristics identified in SJH Consulting's report will be requested to submit proposals. System implementers that have a history of providing Comprehensive ERP implementation in the utility sector will be requested to submit proposals. It is anticipated that the bids will have been received and reviewed and that the necessary licences will be procured and system implementers retained by year end.

Based on the particular Comprehensive ERP selected and the particular system implementer selected, EWU will promptly update this Application to reflect the more precise cost and timing of cost estimates for this initiative.

Approval Sought

Based on the report by SJH Consulting which justifies EWU procuring a Comprehensive ERP and based on the implementation schedule developed by SJH Consulting, EWU anticipates $7,250,445 becoming eligible for rate base in the 2009 test year. EWU accordingly requests that the Board approve the addition of $7,250,445 into EWU's rate base for the 2009 test year.

4 AMORTIZATION/ACCUMULATED DEPRECIATION

For EWU's Accumulated Depreciation Table, please see Exhibit 2, Tab 2, Schedule 3.

5 SYSTEM EXPANSION

For EWU's System Expansion plan, please see Exhibit 2, Tab 3, Schedule 1.

6 CAPITAL EXPENDITURE PLANNING AND BUDGETING PROCESS

For the EWU Planning and Budgeting Process to Exhibit 2, Tab 3, Schedule 2.

7 CAPITALIZATION POLICY

For EWU's Capitalization Policy, please see Exhibit 2, Tab 3, Schedule 3.

8 WORKING CAPITAL ALLOWANCE

For discussion of EWU's Working Capital Allowance, please see Exhibit 2, Tab 4, Schedule 1.

Attachment A

KINECTRICS

Review of ENWIN Evaluation of 4.16 kV Capital Rebuild Program

Kinectrics Report: 11846-010-RA-0001-R00

April 28, 2005

Client Purchase Order: EWPWR 06045

Ray Piercy
Senior Engineer
Distribution Systems

PRIVATE INFORMATION

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Review of ENWIN Evaluation of 4.16 kV Capital Rebuild Program

Kinectrics Report: 11846-010-RA-0001-R00

April 28, 2005

Client Purchase Order: EWPWR 06045

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Dated: June 28/05

DISCLAIMER

REVISIONS

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TABLE OF CONTENTS

PAGE

1. CONCLUSIONS AND RECOMMENDATIONS 1

1.1 Conclusions 1

1.2 Recommendations 2

2. INTRODUCTION AND BACKGROUND 3

3. RESULTS OF REVIEW 3

3.1 Completeness 3
3.1.1 Identification of Issues 3
3.1.2 Establishing the Need for Capital Spending 4
3.1.3 Identification of Options 4
3.1.4 Analysis of Costs and Benefits of Each Option 5
3.1.5 Decision with Rationale 5

3.2 Accuracy of Analysis 5
3.2.1 Substation Transformer Failure Rate 5
3.2.2 Condition Assessment of the 4.16 kV Infrastructure 6
3.2.3 Analysis of Costs of Capital Replacement and Maintenance 6
3.2.4 Prioritizing the Infrastructure to Rebuild 6

3.3 Accuracy of Conclusions 7

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Review of ENWIN Evaluation of 4.16 kV Capital Rebuild Program

1. CONCLUSIONS AND RECOMMENDATIONS

1.1 Conclusions

1. The condition assessment of ENWIN's 4.16 kV infrastructure discussed in the document entitled "Evaluation of 4.16 kV Capital Rebuild Program", has been performed competently and the conclusion that the 4.16 kV system is reaching its end-of-life is clearly correct.

2. A capital replacement program is a key element in any utility's plan to maintain reliability at the lowest long term cost. The present capital replacement program at ENWIN is not excessive compared to other utilities. ENWIN's present capital replacement program is well below the value of the annual depreciation of the equipment, which means that the asset base upon which financial returns can be earned is being slowly reduced.

3. The conclusion that the best course of action would be to replace the 4.16 kV system with a 27.6 kV system over 15 years, is reasonably justified and most likely correct. It is in agreement with Kinectrics engineering judgement based on experience. It is well supported by the general discussion of issues in the report. The cost and risk analysis presented in the report in support of this conclusion could be improved by inclusion of all the options and comparison of their present value, annual capital requirements, and safety, reliability and risk.

4. The ENWIN report does not establish that the capital replacement expenditures being recommended are less expensive in the long term than the increased maintenance that would be required at lower levels of capital replacement. There are no projections in the report for the cost of maintenance under different levels of capital spending.

1.2 Recommendations

1. Further cost analyses would be useful on the "do nothing but maintenance" and "delay capital replacement until the rate freeze is over" options. They could be compared to the three optional rates of capital replacement on the basis of present value of costs and benefits, cash flow, risk of major failure, safety and predicted reliability. This would be useful because the report as it stands now does not document why these options were rejected. Kinectrics could assist with this analysis as part of a more thorough review.

2. The substation transformer failure data at ENWIN could be used to produce a failure probability curve that is more applicable to ENWIN substation transformers than the manufacturer data used in the report. Kinectrics could assist with this analysis as part of a more thorough review.

3. An addition should be made to the report to include some coverage of the option of rebuilding at 4.16kV to rule out this option.

4. Further condition assessment considering factors such as prior utilization, maintenance history, quality of initial product, and installation might be considered if information is available on these additional parameters. This analysis would improve the evaluation of the risk of failure. Kinectrics could assist with this analysis as part of a more thorough review.

5. Clarification would be useful on the assessment of losses in the report. It would be helpful to state in the notes to Table 2 that the loss estimate includes losses in station transformers, primary lines, distribution transformers and secondary lines if this is the case. In the fifth paragraph of the presidents summary where it is stated that conversion will reduce losses by 97% it would be helpful to state what losses are included.

6. The overall presentation of the report could be improved by expanded use of visual summaries such as graphs and charts. For example, a present value chart of the costs and benefits of the different options in spending on maintenance/capital would be useful.

2. INTRODUCTION AND BACKGROUND

At the request of ENWIN Powerlines, Kinectrics Inc. has conducted a brief independent review of ENWIN's internal evaluation of their 4.16 kV capital rebuild program. The capital rebuild program was described in ENWIN's document "Evaluation of 4.16 kV Capital Rebuild Program", prepared by Tom Kosnik, Steven Bastounas, Zhiqiang Liu, Marvio Vinhaes, and dated May 12, 2004. The scope of this review by Kinectrics included an assessment of the general accuracy of ENWIN's analysis and conclusions and an evaluation of the completeness in the discussion of issues. This initial review by Kinectrics was however limited to a commentary on these issues, as opposed to conducting any further analysis. A more detailed assessment of particular aspects of the plan could be conducted by Kinectrics at ENWIN's discretion.

3. RESULTS OF REVIEW

3.1 Completeness

In an evaluation of a capital spending plan the following elements should be addressed:

1. Identification of Issues that have impact on, or will be affected by the capital program
2. Establishing the need for capital spending
3. Identification of Options
4. Analysis of costs and benefits of each option
5. Decision with rationale

3.1.1 Identification of Issues

The ENWIN report identifies the following issues:

1. Capital spending is under pressure to be reduced because of the rate freeze
2. Capital spending is still worthwhile to maximize the asset base available for rate making in 2006
3. The 4.16 kV infrastructure is old, 75%-100% of expected life
4. Present capital replacement spending is only 60% of depreciation
5. Present cost of borrowing is quite low
6. Reduced capital replacement would lead to poorer reliability, increased maintenance, customer dissatisfaction and perhaps fewer jobs in local industry
7. Delaying or slowing capital replacement programs increases the risk of failure nonlinearly
8. Losses are lower in 27.6 kV systems, especially since no substation needed, and higher levels of government are asking for lower energy consumption by everyone
9. Risk of failure must be based on condition assessment as well as on prior reliability indices.
10. As 4.16 kV is converted there is a loss of system redundancy, so a slow rate of conversion increases the risk
11. Improving reliability is an opportunity to increase private investment in the local economy
12. Decreasing capital spending temporarily will create layoffs of staff and trouble re-hiring/training, and staff layoffs could increase restoration times after outages
13. If reliability decreases it leads to increased scrutiny and pressure, as in Kingston
14. load growth will require a new substation by 2009
15. Delaying capital spending could lead to liability issues for EWP and its directors

All of the identified issues are relevant to the evaluation of the capital rebuild program. The detailed discussion of these issues that is in the ENWIN report will not be repeated here. The main thrust of the argument is squarely in line with analysis performed at other utilities since most of these issues are not unique to ENWIN.

The Enwin report does not discuss the following issues that may be relevant:

A. The issue of safety is addressed, but two points are missing. Firstly, older plant sometimes creates hazards when it fails, so capital replacement usually increases safety, both for utility personnel and the general public. Secondly, the higher voltage at 27.6 kV is inherently less safe than 4 kV (higher fault currents lead to higher step and touch potentials near tree branch contacts and faults). This is not discussed in the report, however the safety of 27.6 kV systems is recognized by the industry to be adequate and so perhaps it does not need to be.
B. The report does not explicitly compare the cost of rebuilding at 4.16 kV with the cost of rebuilding at 27.6 kV. An option that is not discussed is to rebuild at 4.16 KV. This would achieve many of the benefits discussed, but would also cost more because of the cost of substations. This option was probably rejected early in the decision process because of this and was therefore left out of the report. As a result the report apparently confuses the benefits of capital replacement with the benefits of conversion, lumping them together. However, once the rebuild at 4.16 kV option is rejected then the benefits of both capital replacement and conversion can be lumped together as is done in the report.
C. The report does not mention that the reliability of 27.6 kV systems can often be lower than 4.16 kV systems because the circuits are generally longer and the higher voltage is more sensitive to animal and tree branch outages. Avoiding this requires careful design of the 27.6 kV system, often not building the least expensive system.

3.1.2 Establishing the Need for Capital Spending

This is an issue identified in the previous section. In fact it is dealt with by nine of the fourteen identified issues. One issue that is not dealt with in the ENWIN report concerning the need for capital spending is to establish that the capital replacement expenditures being recommended are less expensive in the long term than the increased maintenance that would be required at lower levels of capital replacement. The cost of maintenance is mentioned but there are no projections in the report for the cost of maintenance under different levels of capital spending. Of course, the increased risk of failure that occurs even with increased maintenance, may be considered to be the overriding factor. In this case the relative cost of increased maintenance could be a minor issue.

3.1.3 Identification of Options

The options identified in the report are "do nothing" and three levels of capital replacement spending. The option of rebuilding at 4.16 kV is not considered. That is probably because it would clearly be more expensive than rebuilding at 27.6 kV and so was rejected early in the decision process. The cost to rebuild lines at 27.6 kV is only marginally more than at 4.16 kV and the cost of the substations required to reduce the voltage to 4.16 kV would certainly make the 4.16 kV option more expensive.

Another option that is not clearly identified is to delay capital spending for two years until the rate freeze is expected to be lifted and then increase spending substantially to make up for the delay resulting in the same 15 year replacement period. Some of the ramifications of this option are discussed, such as staff layoffs and the difficulty of obtaining contract workers (issue12 above), increased risk of failure (issue 7 above) and decreased customer satisfaction and private investment in the local economy (issue 6 above). However, the delay option is not addressed clearly with costs identified and reasons given for rejection.

3.1.4 Analysis of Costs and Benefits of Each Option

The costs and benefits of the three levels of capital replacement (10,15, and 20 year plans) are covered in detail in the report. The "do nothing" option is not explicitly costed, but it is discussed in general and it is clear that the expected costs of this option would be much higher than the others.

3.1.5 Decision with Rationale

The choice between the three rates of capital replacement is clearly presented in the ENWIN report. As mentioned above the "do nothing" option, rebuilding at 4.16 kV, and the option to delay capital spending until the rate freeze is lifted were not clearly summarized.

3.2 Accuracy of Analysis

The main analysis in the report relate to the following:

1. The failure rate of substation transformers and the probability of survival beyond N years
2. The condition assessment of the 4.16 kV infrastructure
3. The analysis of costs of capital replacement and maintenance
4. Prioritizing the infrastructure to rebuild

3.2.1 Substation Transformer Failure Rate

The substation transformer failure rate has been estimated on the basis of data from a transformer manufacturer (Figure 2 in the report). This data looks generally reasonable, although the failure rates at ages beyond 50 years in Figure 2 are rising perhaps faster than the experience of other utilities in Ontario would suggest. It is very difficult to assess failure probability of very old transformers because it depends heavily on the past loading and maintenance history. For very old transformers the failure rate will not correlate well with age, in other words it is the opinion of Kinectrics that the curves in Figure 2 are not accurate for older transformers. They should flatten out rather than continue to rise if the transformer thermal life has not been used up.

In the analysis that produced "Table 1 Probability of Transformer Survival" the graph in figure 2 was extrapolated to transformer ages beyond 60 years. This produced an extremely low probability of survival for transformers over 60 years old. This does not appear to be consistent with the actual survival rate of old transformers at Enwin in recent years. The values in table 1 indicate that there should have been many more substation transformer failures in the last 10 years at Enwin. It appears that the extrapolation procedure used was overly pessimistic.

3.2.2 Condition Assessment of the 4.16 kV Infrastructure

The condition assessment that has been conducted on station transformers (based on oil tests and visual inspection), station structures (based on visual inspection), wood poles (based on testing program), distribution transformers (based on age and loading), and conductors (based on age) appears to have been conducted in a complete and competent manner. There is no reason to doubt the conclusion that the 4.16 kV infrastructure is reaching the end of its life.

One criticism that might be raised is that the oil test results presented in the report did not include trends in the results. It is often the trend that is most indicative of a problem rather than the absolute values.

3.2.3 Analysis of Costs of Capital Replacement and Maintenance

The cost of losses and maintenance on the 4.16 kV system was tabulated in Table 2. It was not clear whether the transformer losses in column three included just the substation transformers or also included the distribution transformers. Since the losses on distribution transformers at 27.6 kV were never mentioned in the report it might be assumed that all distribution transformer losses were assumed to be the same at 4.16 kV and 27.6 kV and were therefore not included in the comparison. Although distribution transformer losses can be specified over a wide range depending on the cost of the transformer, generally speaking the losses on 27.6 kV distribution transformers will be higher than those in 4.16 kV distribution transformers.

The cost of losses expected on 27.6 kV lines were also not included in the analysis. The report states that these losses are 2.25% of the losses on 4.16 kV lines and so they were probably thought to be negligible in the comparison. However, the line loss on a distribution system depends on the size of conductor chosen and this in turn depends on a large number of factors, such as mechanical strength, voltage drop, fault current capability, and relative cost. The voltage level by itself is not a dominant factor in the line loss.

Neither of the above points have a substantial impact on the analysis of the report since the report fails to compare the costs of staying with the 4.16 kV system and the three plans for different rates of capital replacement. The report should have a clear cost comparison between the present value and the annual budgets for the "do nothing but maintenance" option, the "delay capital replacement until the rate freeze in over" option, and the three capital replacement options.

The capital spending survey in Appendix G is used in the report to suggest that the rate of capital spending at Enwin is less than the average of other utilities and therefore should be increased. A careful review of appendix G does not support this conclusion. There are differences between the utilities in the survey that could affect the appropriate level of capital spending. For example the higher levels of spending tend to be at the smaller utilities so there may be an economy of scale operating here. Two of the three utilities with higher capital spending do not have any 4.16 kV distribution. The analysis by comparison of capital spending per customer at ENWIN to the average of five other utilities is too simplistic.

3.2.4 Prioritizing the Infrastructure to Rebuild

The analysis in support of the prioritization of substations and lines to rebuild appears to be complete and as accurate as this type of analysis can be.

The risk analysis used in the prioritization is of relative risk. It is effective in comparing one station or line against another. However, it does not establish absolute values of risk. The only absolute risk analysis concerns the substation transformers, and this is based on the manufacturer data which does not appear to be typical of ENWIN's past experience.

There appears to be no quantitative numerical analysis in the report to support the overall conclusion of a 50% chance of major infrastructure failure in the next five years, rather than say 40% or 60%. The report does contain a qualitative analysis that can be used to conclude that major infrastructure failure is "likely". The report also contains a quantitative numerical analysis for individual station transformers, but not a quantitative assessment of the overall risk of "a major infrastructure failure". However, if a more complete quantitative risk analysis was conducted, which would take considerable time and expense, it is the opinion of Kinectrics that the conclusions of the report would be confirmed.

3.3 Accuracy of Conclusions

The ENWIN report draws the following conclusions:

1. Costs and risks of three different rates of conversion
2. Major infrastructure failure is very likely (50%) within five years if nothing is done
3. 15 year plan is best because it gives tolerable levels of risk and can be done with existing staff levels and it has a smooth capital expenditure scheme.
4. Rebuilding requires several other tasks that should be done anyway, prioritize pole replacement, optimize feeder loading and losses, standardize construction methods.

As was discussed in section 3.2, the weakest conclusions relate to the risk of failure in the next few years (conclusions 1 and 2 in the above list). However, a more accurate risk analysis would be expensive and time consuming and may not change the overall conclusion that the 15 year capital replacement program is most appropriate.

The rationale for selecting the 15 year capital replacement program is clear. In the opinion of Kinectrics this is a good conclusion based on the available analysis and discussion of the issues.

The secondary benefits of the replacement program listed in conclusion 4 are correct. However, the pole replacement prioritization could be done as part of routine maintenance and does not require a conversion program.

RJP:rjp

Attachment B

KINECTRICS

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

Kinectrics Inc. Report No.: K-013638-010-RA-0001-R00

September 11, 2007

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CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

Kinectrics Inc. Report No.: K-013638-010-RA-0001-R00

September 11, 2007

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Dated: Tuesday, September 11, 2007

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and ENWIN Utilities, PO 11308, April 2, 2007..

REVISIONS

Revision Number	Date	Comments	Approved

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

Kinectrics Inc. Report No.: K-013638-010-RA-0001-R00

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Ray Piercy
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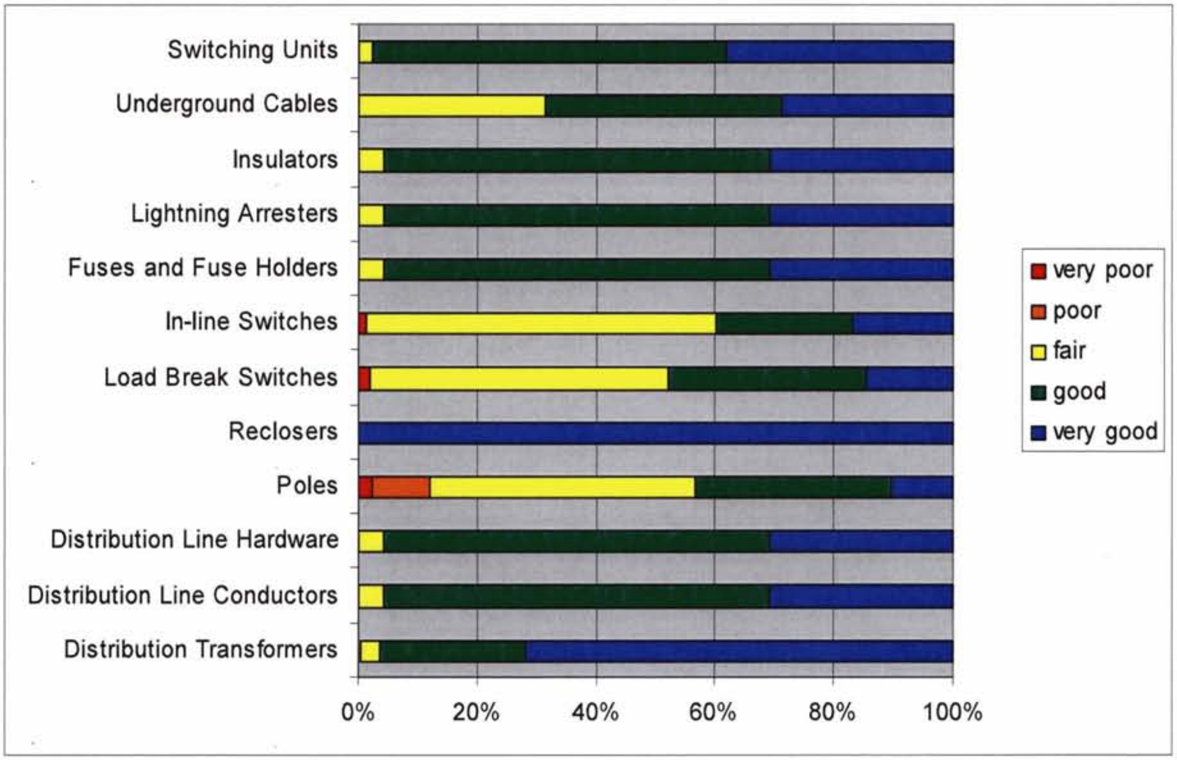
EXECUTIVE SUMMARY

This report contains the results of an asset condition assessment and capital replacement plan for the 27.6 kV distribution assets of Enwin Utilities. It is based upon information provided by ENWIN and upon visual inspections and analysis conducted by Kinectrics. The analysis calculated health indices for the twelve major types of component. The health indices can be used as an over all indication of condition and as a basis for estimating the remaining life of components and predicting a required capital replacement plan. The resulting recommended replacement plan identifies the annual capital budget that will be required to maintain the system. If capital spending is below the required level, the condition of the equipment will slowly degrade and increasing customer interruptions and decreased safety can be expected.

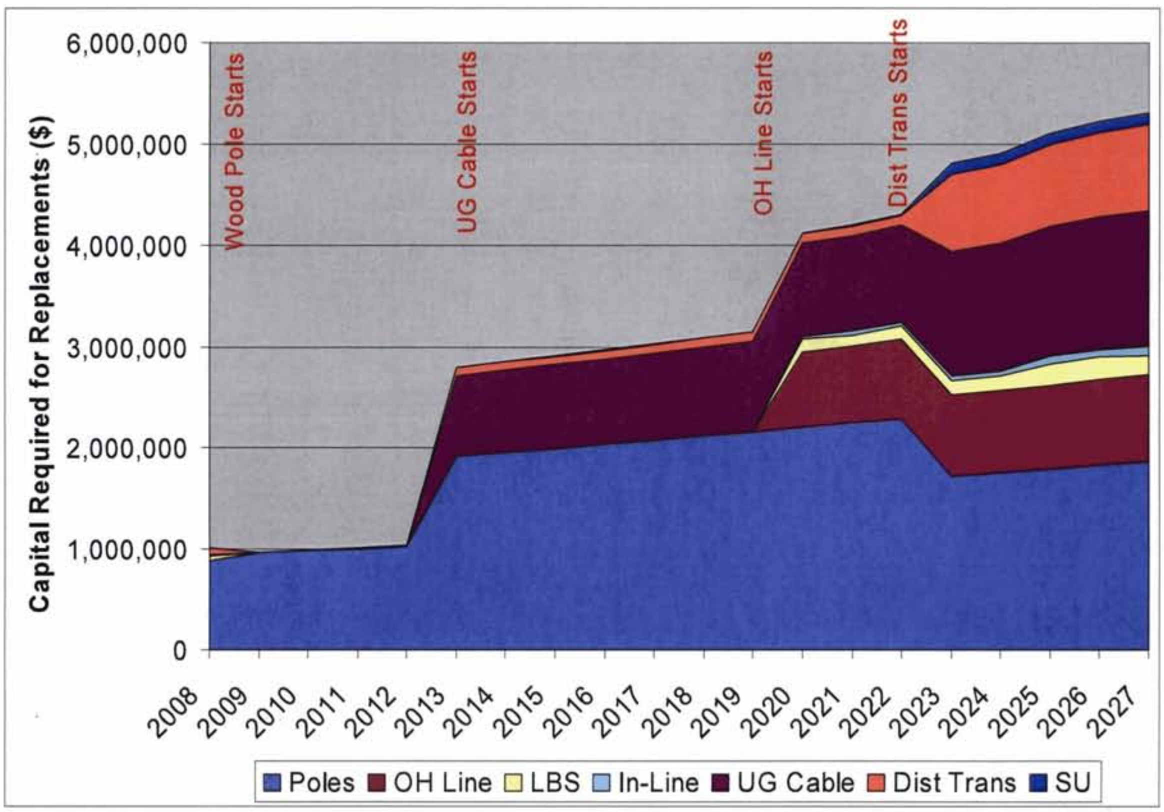


The overall asset condition at ENWIN Utilities is good. The health index results are shown in the following figure. They show that the assets are generally in good condition. Approximately 15% of the poles are in poor condition and need to be replaced. In addition there are a few switches in need of replacement.

The condition monitoring program at ENWIN includes a pole grading program. Recommendations for improving the condition monitoring program of this and other assets are included in the report.

Overall spending on maintenance is at the low end of the range of other utilities in southern Ontario, at $44 in O&M per year per customer and $90 in capital replacement per year per customer. Recent capital replacement programs have reduced overtime and maintenance costs, but capital spending may need to be increased in the future to maintain the system in the present good condition. At the present time, capital spending is only 83% of the annual depreciation.

The following figure shows the recommended capital plan for equipment replacement based on the health indices. It shows that the priority in the near future should be to replace the wood poles that are in poor condition. It also shows that the required capital will increase in about five years as the underground cable will start to need replacement. The further increase in fifteen years will be driven by the need to replace the older overhead lines.



The required replacements over the next twenty years have been grouped by geographic area to identify which areas of the city will require the most work in which years.

TABLE OF CONTENTS

PAGE

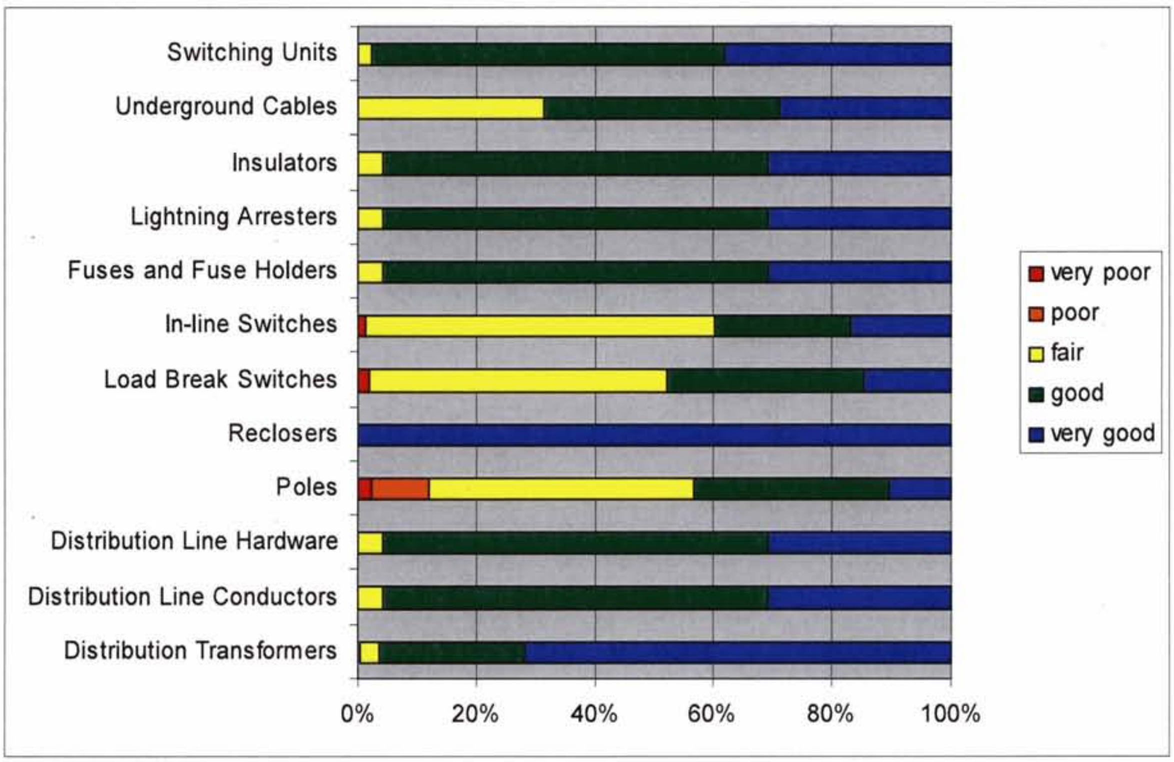
DISCLAIMER ii
1 CONCLUSIONS AND RECOMMENDATIONS 1
2 INTRODUCTION 5
3 DOCUMENTATION AND INFORMATION 6
3.1 Sources Of Information 6
3.2 Field Visits 6
3.3 Interviews 7
4 ASSET POPULATIONS 8
5 HEALTH INDEX METHODOLOGY 9
6 ASSET CONDITION ASSESSMENT 12
6.1 Distribution Transformers 12
6.2 Distribution Line Conductors 15
6.3 Distribution Line Hardware 17
6.4 Poles 18
6.5 Reclosers 21
6.6 Load Break Switches 24
6.7 In-Line Switches 26
6.8 Fuse Holders 28
6.9 Lightning Arresters 29
6.10 Insulators 30
6.11 Underground Cables 31
6.12 Switching Units 33
6.13 Civil Infrastructure 35
6.14 Mobile Unit Substations 35
7 REVIEW OF RELIABILITY STATISTICS 36
8 REVIEW OF CAPITAL AND MAINTENANCE BUDGETS 39
9 CAPITAL EXPENDITURE PLAN FOR POWER SYSTEM EQUIPMENT REPLACEMENT AT END OF LIFE 40
10 DEVELOPMENT OF RECOMMENDATIONS 42
10.1 Review Of Asset Condition Monitoring Program 42
10.2 Pole Replacement Program 43
10.3 Wood Pole Preservation Program 44
10.4 Completely Self Protected (Csp) Transformer Replacement Program 45
11 GEOGRAPHIC DISTRIBUTION OF EQUIPMENT REPLACEMENT 45
12 APPENDIX A Information Requirements for Asset Condition Assessment 53
13 APPENDIX B Photographs from Visual Inspections 56
14 APPENDIX C Asset Condition Information from Staff Interviews 61

KINECTRICS

CONDITION ASSESSMENT FOR ENWIN UTILITIES' 27.6 kV ASSETS

1 CONCLUSIONS AND RECOMMENDATIONS

1. The overall asset condition at ENWIN Utilities is very good. The Health Index results are shown in the following figure. They show that the assets are generally n good condition. Approximately 15% of the poles a4re in poor condition and need to be replaced. In addition there are a few switches in need of replacement.



2. The condition monitoring program at ENWIN includes a pole grading program. The following table summarizes the recommended additions to the condition monitoring program.

Asset Type	Available Parameters	Recommended Parameters
Distribution Transformers	age*, loading*	age visual
Distribution Line Conductors	line age, visual*	visual tensile strength
Distribution Line Hardware	line age, visual*	
Poles	rating, line age*, visual*	
Reclosers	age	maintenance cost failure rate
Load Break Switches	line age, visual*	age visual maintenance cost failure rate
In-line Switches	line age, visual*	age visual failure rate
Fuses and Fuse Holders	line age, visual*	
Lightning Arresters	line age,	
Insulators	line age, visual*	age*
Underground Cables	age	failure rate VLF breakdown
Switching Units	age	visual maintenance cost, failure rate
Civil Infrastructure (concrete pads, vaults, ducts)	visual	
Mobile Substations	age	oil breakdown oil moisture oil furan

* not available for individual units, only as a distribution or sample of the population

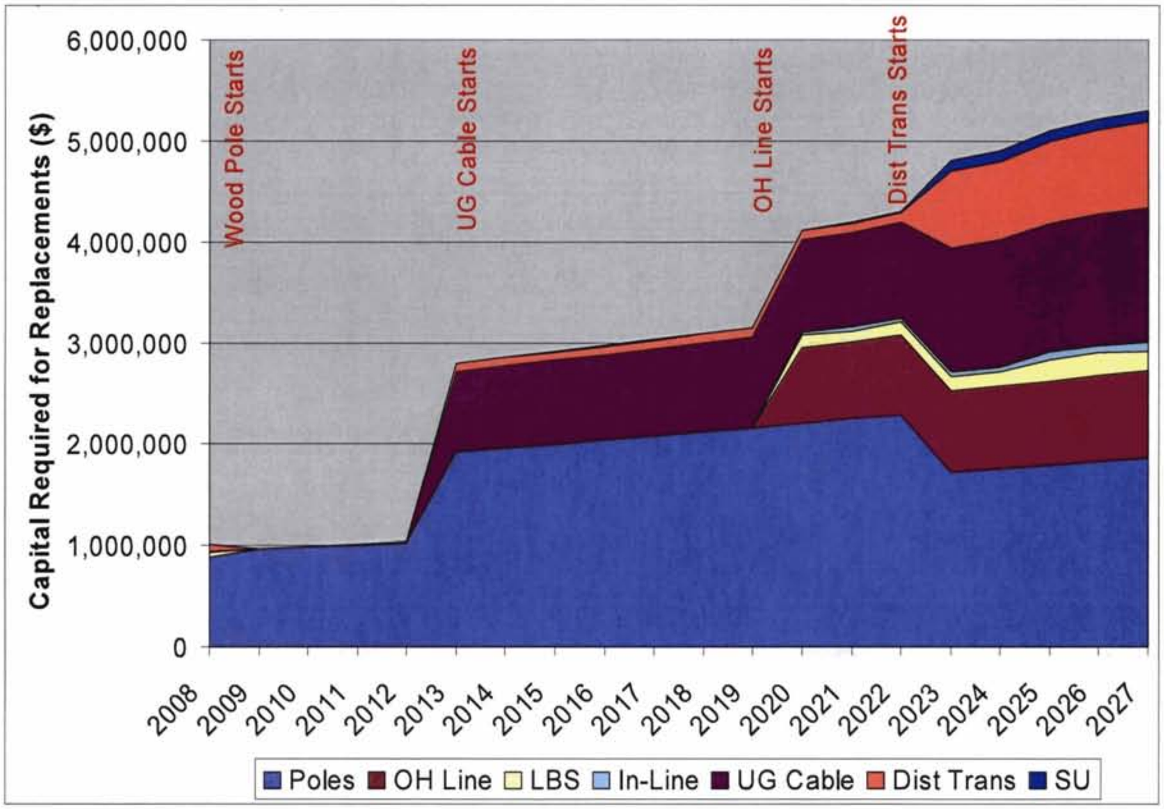
It is recommended that the routine visual inspections assign a condition grade to the inspected component, such as 1 – Excellent (like new), 2 – Good (no visible problems), 3 – Fair (some evidence of degradation), 4 – Poor (obvious problems, near end of life), and 5 – Bad (needs priority replacement).

The expensive tests (tensile strength for overhead conductor and very low frequency (VLF) breakdown for underground cables) are only recommended for use on components at least 80% through their expected life, or on components experiencing a higher than normal failure rate, to determine if condition is the problem. They should not be done more frequently than every five years.

3. It is recommended that ENWIN Utilities replace the poles, distribution transformers, and the rest of the OH line equipment independently, rather than rebuild a section of line replacing all components, whenever this independent replacement is operationally feasible. This recommendation is based on the difference in condition that was found

between these groups of assets. The poles are generally in worse condition than the conductors and transformers and will reach their end of life first.

4. Overall spending on maintenance is at the low end of the range of best practices in the industry, at $44 in O&M per year per customer and $90 in capital replacement per year per customer. Recent capital replacement programs have reduced overtime and maintenance costs, but capital spending may need to be increased in the future to maintain the system in the present good condition. At the present time, capital spending is only 83% of the annual depreciation. The following figure shows the recommended plan.



5. The required replacements over the next twenty years have been grouped, in the report Tables 26 to 32 , by geographic area to identify which areas of the city will require the most work in which years.

6. It is recommended that ENWIN continue the existing targeted replacement programs that are not yet complete, for all assets that will not be made redundant as part of the voltage conversion program. Examples are: porcelain insulators with wood pins, non-tree-retardant UG cable, Dominion disconnect switches.

7. It is recommended that ENWIN change the present policy of replacing wood poles only when they fail. The replacement of wood poles only in response to failure and not based on condition can result in large unplanned capital expenditures. A wood pole is subjected to widely varying loading. A weak pole can go for years without failing because it does not experience a stress close to its design stress. However, if they are not replaced, gradually many poles would be in this condition and then when a large stress comes (a big wind or ice storm) it will fail a large portion of the system all at once.

In addition the CEA standard mandates pole replacement when the design load factor is one or less, because falling lines are a public safety hazard.

If individual pole replacement is adopted it is recommended that Enwin investigate the use of pole re-enforcement and re-treatment with preservatives to delay replacement.

8. It is recommended that ENWIN collect data on end of life for components in their service conditions to further refine this parameter in future analysis.

9. It is recommended that ENWIN consider using a single data base to record condition data. This reduces the cost of asset condition monitoring and most utilities are moving toward this practice. The data recorded needs to be several grades of condition rather than the OK/notOK that is used in maintenance data bases.

10. It is recommended that ENWIN continue to monitor the secondary breaker operation rate in CSP transformers. No planned replacement program is necessary until operation rate increases and becomes a significant operational expense or drain on manpower.

2 INTRODUCTION

As part of their asset management program Enwin Utilities has requested an assessment of the present condition of their 27.6 kV power distribution system infrastructure and a business plan for the strategic replacement of distribution assets to maintain a reliable 27.6 kV system. Together with the regular maintenance program, the result of this assessment will ensure that the equipment will provide optimal service life and that the capital equipment replacement rate is adequate to ensure that there are no large unexpected increased capital requirements in future years.

This report deals with the findings of the asset condition assessment and the equipment replacement capital planning process. The report provides an assessment of the present condition of the assets, an evaluation of the life expectancy identified by geographic region, a review of the asset management program at ENWIN benchmarking it against "best practice" in the industry, and a year by year plan for asset replacement extending out to twenty years.

The assessment has been restricted to the 27.6 kV power system equipment, excluding the substations, land, buildings, office equipment, tools and maintenance vehicles.

3 DOCUMENTATION AND INFORMATION

3.1 Sources Of Information

Requests were made for the detailed information listed in Appendix A of this report. The following summarizes key documentation that was made available by ENWIN Utilities:

- present loading of circuits
- number of wood poles, switches, automated switches, distribution transformers, km of overhead line and underground cable
- age distribution of most assets
- condition grade of poles
- reliability indices
- capital expenditure budget
- book value of capital costs
-

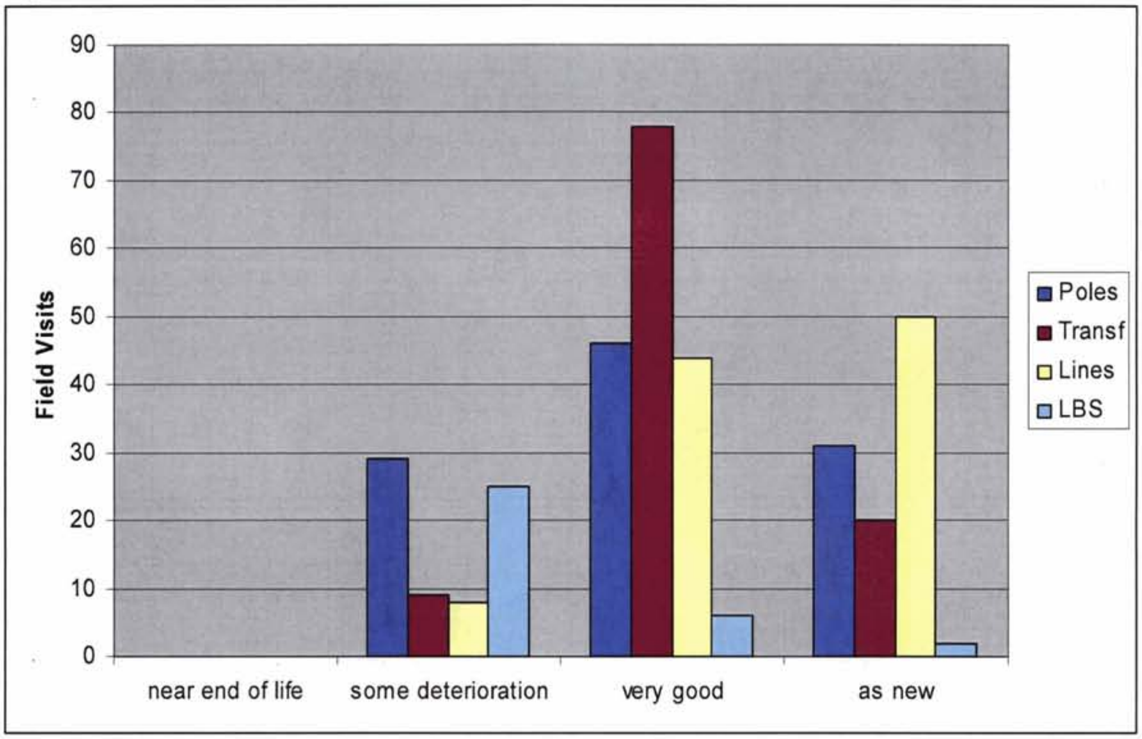
When ages of lines were not available, ENWIN provided an estimate made by experienced staff. This age was recorded on a paper map.

3.2 Field Visits

Field visits to ENWIN Utilities were conducted in May 2007. A sample of 116 locations on the overhead distribution lines were inspected and evaluated. The information obtained in the field visits has been incorporated into the asset condition assessment in report section 3.2. Pictures illustrating the condition of assets are presented in Appendix B. This visual inspection "audit" was used to confirm the asset condition based on age data.

The following figure summarizes the results of the field visits. This figure cannot be used to draw conclusions about the condition of the equipment because a visual inspection is often a poor indicator when used alone.

Figure 1 Results of Field Visits



3.3 Interviews

Additional information utilized in this review was received verbally from interviews with ENWIN Utilities staff. Interviews were conducted with the following staff: Tom Kosnik, Val Ward, Nimal Weeratunga, Doug Collins, Jim St Louis, Shawn Filice.

Information was solicited in each of the interviews on the historical condition, present condition, maintenance activity, and future issues for Enwin Utilities on both Overhead and Underground systems. The notable issues related to asset condition and management are detailed in Appendix C. The information has provided insight into a number of asset issues that were not readily apparent from site inspection and documentation.

In general, it was noted that Enwin is aware of the impact of most asset issues and is taking systematic steps to solve problems as they arise. There have been several targeted replacement programs in the past 20 years, non-tree-retardant UG cable direct buried, lighting arresters, porcelain insulators, and distribution transformers (for overloads and PCB). Squirrel guards, covered conductor and reclosers have been added to improve reliability. The result of these replacement programs is that these assets are in very good condition and the required maintenance has been decreasing. The general strategy has been to spend money on capital replacements and minimize maintenance spending and overtime costs.

The condition of assets is generally thought to be good now, but the ACA is being done to ensure that in the future reliability continues to be good and there are no catastrophic failures or unplanned for, large, increases in capital requirements.

Condition data has not been collected and stored in a common data base. The exception is that there has been an ongoing pole inspection program resulting in a data base with a condition grade on every pole. The inspections have been done by station maintenance staff, who have been trained, but lack experience. As a result some of the individual condition grades are incorrect. Equipment replacements have been done in response to failure rather than based on condition.

Infra-red scans are conducted each year.

The maximum age of the 27.6 kV system assets should be 38 years.

The areas of worst OH asset condition are in the downtown core and some of the back lot single phase lines. Wood poles, in-line switches, underground vaults and some pad mounted switching units are in poor condition. There is no condition monitoring of in-line switches, beyond infra-red scans, and no maintenance is done. This is in contrast to the load break switches that are operated once per year. This area could be improved. Poles are run to failure unless they are on major streets. Most of the poles on major streets are concrete. Underground vault maintenance is considered adequate, with every vault being inspected every year. The switching units that are in poor condition are poor because of moisture build up, and they urgently require maintenance.

The main causes of outages are tree and animal contact, not equipment failures.

There are some old 4/0 copper conductors, but there have been no problems with them.

4 ASSET POPULATIONS

The following assets were included in the condition assessment and capital plan:

Asset Type	Population	Available Condition Parameters
Distribution Transformers	7881	age*, loading*
Distribution Line Conductors	1266 conductor km	line age, visual*
Distribution Line Hardware		line age, visual*
Poles	19666	rating, line age*, visual*
Reclosers	33	age
Load Break Switches	207	line age, visual*
In-line Switches	115	line age, visual*
Fuses and Fuse Holders		line age, visual*
Lightning Arresters		line age,
Insulators		line age, visual*
Underground Cables	576 conductor km	age
Switching Units	176	age
Civil Infrastructure (concrete pads, vaults, ducts)	462 vaults/manholes	visual
Mobile Substations	3	age

* not available for individual units, only as a distribution or sample of the population

5 HEALTH INDEX METHODOLOGY

The condition of the 27.6 kV system assets has been assessed by calculating a health index for each group of assets. A health index is a number between 0 and 100 that indicates the overall condition of the asset, as it relates to its ability to perform its intended function. The index is intended to give a general overview of the asset condition related to its end of life. It is not an indication of whether maintenance is required. Maintenance programs require more detailed information and information on different condition parameters. For example, the contacts of a switch may be in poor condition and need to be maintained, but that will not result in a low health index because it does not relate tot the end of life of the switch.

The health index is based on a set of parameters that indicate the condition of an asset. Each asset type can have a different set of condition parameters. A set of condition parameters was selected for each type of asset at ENWIN. The set was chosen based on the available data provided by ENWIN. The two most common parameters are age and a condition grade based on a visual inspection. For some assets with high populations, such as fuses or line hardware, the age of individual assets was not available and the age of the line itself was used as a surrogate, with all the assets on the line assumed to have the same age.

The Health Index has been calculated with the following equation:

$$HI = \frac{\Sigma (F_i \times W_i)}{\text{Max Score}} \times 100$$

where:

- HI is the health index (0-100, 0=bad 100=good)
- F_i is the health index factor for the ith condition parameter
- W_i is the weight of the ith parameter
- Σ is the sum over all i condition parameters
- Max Score is the sum if all factors are at the maximum value

The condition parameters and health index factors have been defined in seven steps. The seven steps were selected to match the existing condition grades in data for poles.

If there are one or more condition factors that are considered to be more relevant than the others they are weighted higher (2 or 3). If they are much more relevant, and can indicate end of life all on their own, then the health index is divided by two if the relevant condition factor has a value of 1, and by five if the value is 0. This eliminates masking of poor condition by good values in the less relevant parameters.

The health index is designed so that a value of less than 50% indicates that replacement should be considered and planned for and a value of less than 30% indicates the asset should be replaced as soon as possible. The health index essentially indicates remaining strength, assuming an original design safety factor of 2. So if a pole has a design load of 50 kN and a design load factor of 2, its original strength would be 100 kN. At a health index of 50% it would have 50 kN remaining strength, and should be planned for replacement in the next five years or so. At a health index of 30% its remaining strength would be 30 kN which is well below the design load, indicating that replacement should be a priority.

Table 1 Interpretation of the Health Index

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

The different rates of degradation for different components is handled by altering the "Expected Lifetime" column. The expected lifetime used in this project has been based on industry experience. It is recommended that ENWIN collect data on end of life for components in their service conditions to further refine this parameter in future analysis.

The following example will illustrate the health index calculation method. Poles will be used as the example. There are three condition parameters available for poles, a pole rating from the individual pole inspection program (0 – good to 6 – bad), the age of the line, and a condition grade based on a visual inspection of a sample of poles. Each of the parameters are divided into seven ranges, such as age >10 and <20 years, and each range is assigned a "factor" value. The details for every range of all three condition parameters are provided in Table 7 on page 15. Taking age as an example, the age range "<10 years" is assigned a factor value of 6, indicating the maximum good condition. The age range ">10 <20" is assigned a factor value of 5, indicating slightly worse condition. All the factor values must be high for good condition and low for poor condition because they are used directly in the equation for health index where a high health index is defined as good condition. The factor values for the pole condition ratings are therefore the reverse of the condition ratings, so that a pole rating of 0 (indicating good condition), becomes a factor value of 6 (indicating good condition).

The health index is a weighted average of the three factor values. The equation for health index is:

$$HI = [F_1 \times W_1 + F_2 \times W_2 + F_3 \times W_3] / \text{max score} \times 100$$

where F_1 is the pole rating condition factor
W_1 is the pole rating factor weight (= 3)
F_2 is the age condition factor
W_2 is the age factor weight (=1)
F_3 is the visual condition factor
W_3 is the visual condition factor weight (=1)

max score = 6X3 + 6X1 + 6X1 (= 30)

The weights are chosen using engineering judgment. In this case the individual pole rating was considered to be a better indication of condition than the other two condition parameters.

The following table illustrates the health index calculation for a few different combinations of Condition, Age and Visual Condition factors. The "Condition Rating" factor is the rating from the individual pole inspection program.

Table 2 Example Health Index Calculations

A	B	C	D	E	F	G
Condition Rating Factor	Condition Weight	Age Factor	Age Weight	Visual Factor	Visual Weight	Health Index (A*B + C*D + E*F)/max max=6*3 + 6*1 + 6*1 =30
1	3	0	1	1	1	13
6	3	6	1	6	1	100
4	3	4	1	3	1	63
1	3	4	1	1	1	26
3	3	3	1	3	1	50

The health index for each pole is calculated individually. The poles are then grouped into five ranges of health index <30, 30-50, 50-70, 70-85, >85 as in Table 1 above. The poles were divided into geographic regions, based on the secondary map areas, and the number of poles in each health index range was calculated for each geographic area. These numbers were then used to generate the plan for required replacement capital in each geographic area.

6 ASSET CONDITION ASSESSMENT

6.1 Distribution Transformers

Table 3 Distribution Transformer Health Index Formulation

Condition Parameter	**Weight**
Age	1
Loading	1
Visual Inspection	0
Age (years)	**Health Index Factor**
<10	6
>10 <30	5
>30 <40	4
>40 <45	3
>45 <50	2
>50 <60	1
>60	0
Loading (peak as % of rating)	**Health Index Factor**
<100	6
>100 <110	5
>110 <120	4
>120 <130	3
>130 <150	2
>150 <170	1
>170	0
Max Score = 12	

The visual inspection parameter has been weighted as zero, for distribution transformers only, effectively removing it from the assessment, because it is available on only 102 of the 7,882 distribution transformers and it is not as good an indicator of condition as the age and the loading. Some utilities have a detailed visual inspection of every distribution transformer as part of their condition monitoring system. Condition parameters such as bushing condition (contamination, cracks, chips), tank corrosion, and paint, are graded on a scale from 1 to 5 and the grades are recorded electronically in a data base. This is a "better" condition monitoring system but the cost may not be justified. Very few distribution transformers fail because of conditions that can be detected by the visual inspection.

The Health Index Factors for loading are non-linear in their relation to the load level because loading has a non-linear effect on transformer condition, increasing quickly above 100% load.

The condition parameters for distribution transformers are available only as frequency distributions over the entire population, not as specific values for individual units. It was therefore not possible to calculate a health index value for individual units or for geographic areas.

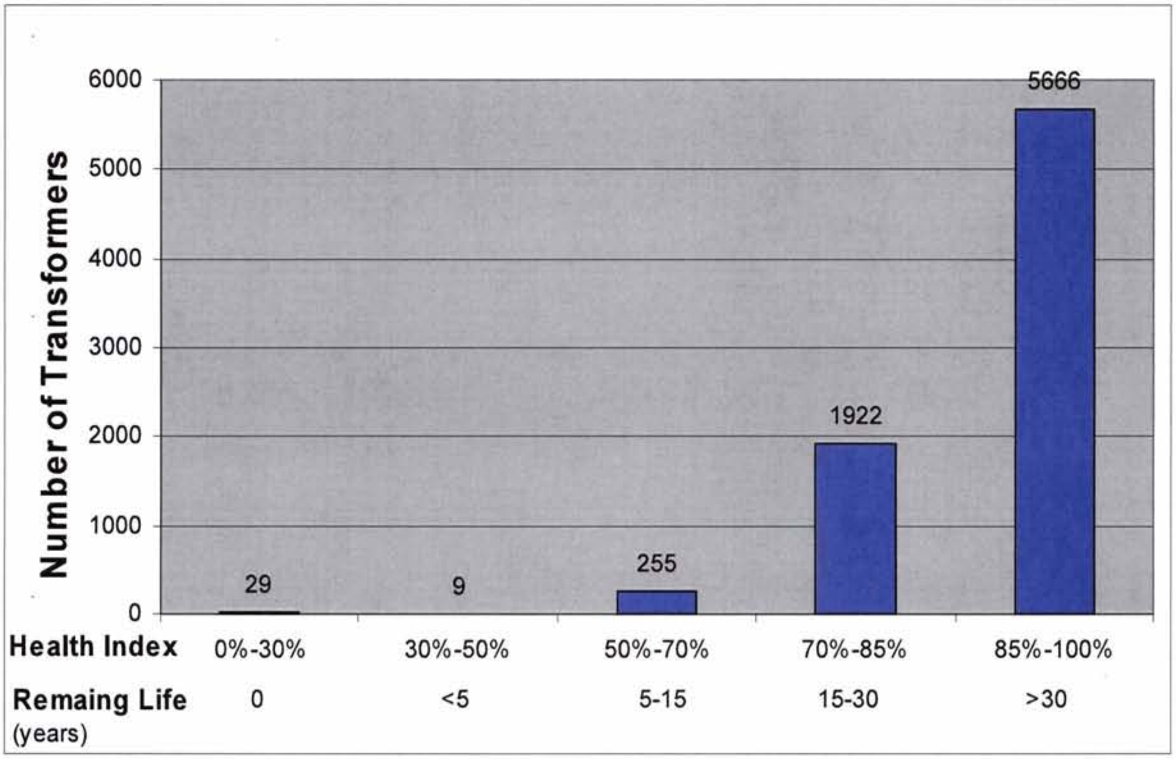
Better indicators of transformer condition, such as furan content of the insulating oil, are not economical to apply to distribution transformers.

The present set of condition parameters available at ENWIN is consistent with industry "best practices".

Table 4 Distribution Transformer health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 2 Distribution Transformer Health Index Results



The good condition of distribution transformers indicated by the health index has been confirmed by the interviews with staff and the visual inspections. Many replacements have been made due to load growth and voltage upgrading.

6.2 Distribution Line Conductors

Table 5 OH Conductor Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

The visual condition parameters use fewer levels of health index factor because the quality of the input data and its relationship to condition does not warrant more detailed analysis.

The loading was available only for the section nearest the station. Since the data is being analyzed by geographic area, this level of load detail was not sufficient to be used in the quantitative analysis. The load data indicates that in general the lines are not overloaded. Only 20% have peak loads in excess of the line rating and no circuits have average peak loads above the line rating.

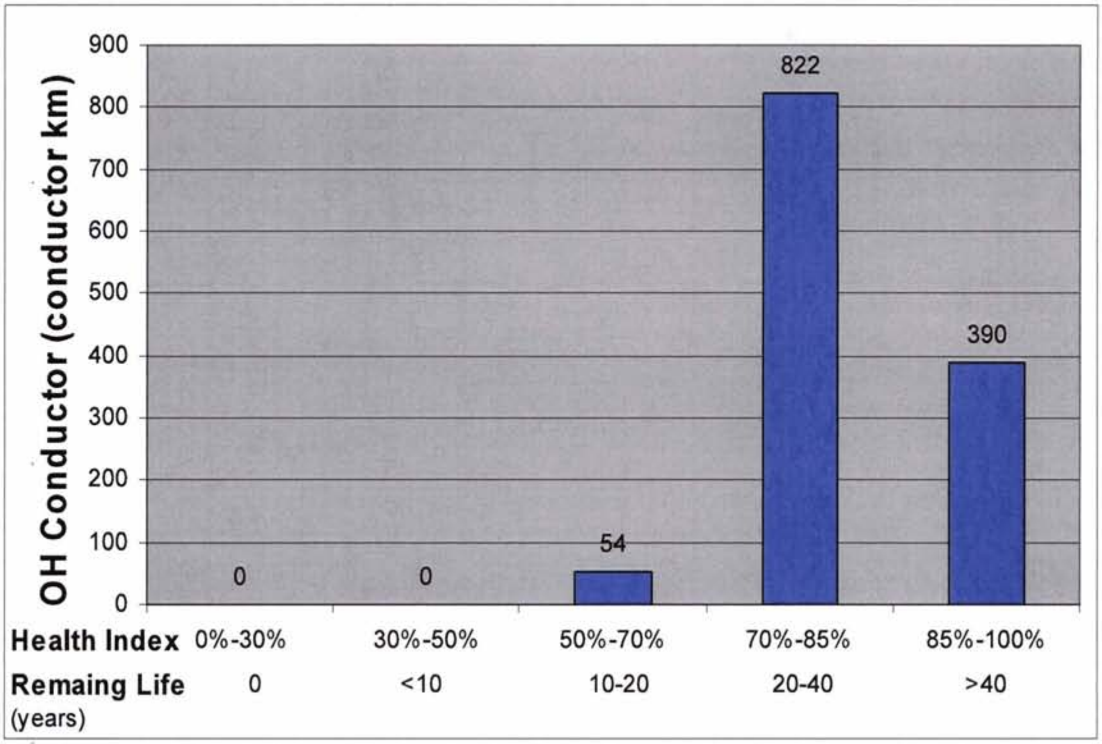
The age was available only from an estimate of the year the line was constructed. However, the accuracy of this should be acceptable because conductor replacements are rare.

Better condition parameters are tensile strength and torsional ductility, but these must be measured on samples removed from the line. The expense of these tests can only be justified if conductor failure rate contributes significantly to safety hazards or reliability problems. It is recommended that ENWIN monitor failure rate and age of conductors.

Table 6 **OH Conductor Health Index Interpretation**

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 40 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 20-40 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 10 – 20 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 10 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 3 OH Conductor Health Index Results



The good condition indicated by the health index for overhead conductor has been confirmed by the interviews with staff. There have been very few problems experienced, even with very old copper conductor.

6.3 Distribution Line Hardware

Table 7 OH Line Hardware Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

Distribution line hardware includes standoff brackets, braces, clamps and guys.

The health index for distribution line hardware is the same as the health index calculated for overhead conductors, because the age and visual condition data available are the same. There are no other condition parameters that can be used cost effectively to monitor the condition of line hardware.

The present set of condition parameters available at ENWIN is consistent with industry "best practices".

6.4 Poles

Table 8 Poles Health Index Formulation

Condition Parameter	**Weight**
Pole Rating	3
Line Age	1
Visual Inspection	1
Pole Rating (0 – 6)	**Health Index Factor**
0	6
1	6
2	5
3	4
4	3
5	2
6	1
Line Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <45	2
>45 <50	1
>50	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 30	

The poles had been previously classified in condition ratings based on an individual pole inspection program. This assessment is considered to be more accurate than using the age of the line or the visual inspection of a small sample of poles. The weighting has been set accordingly.

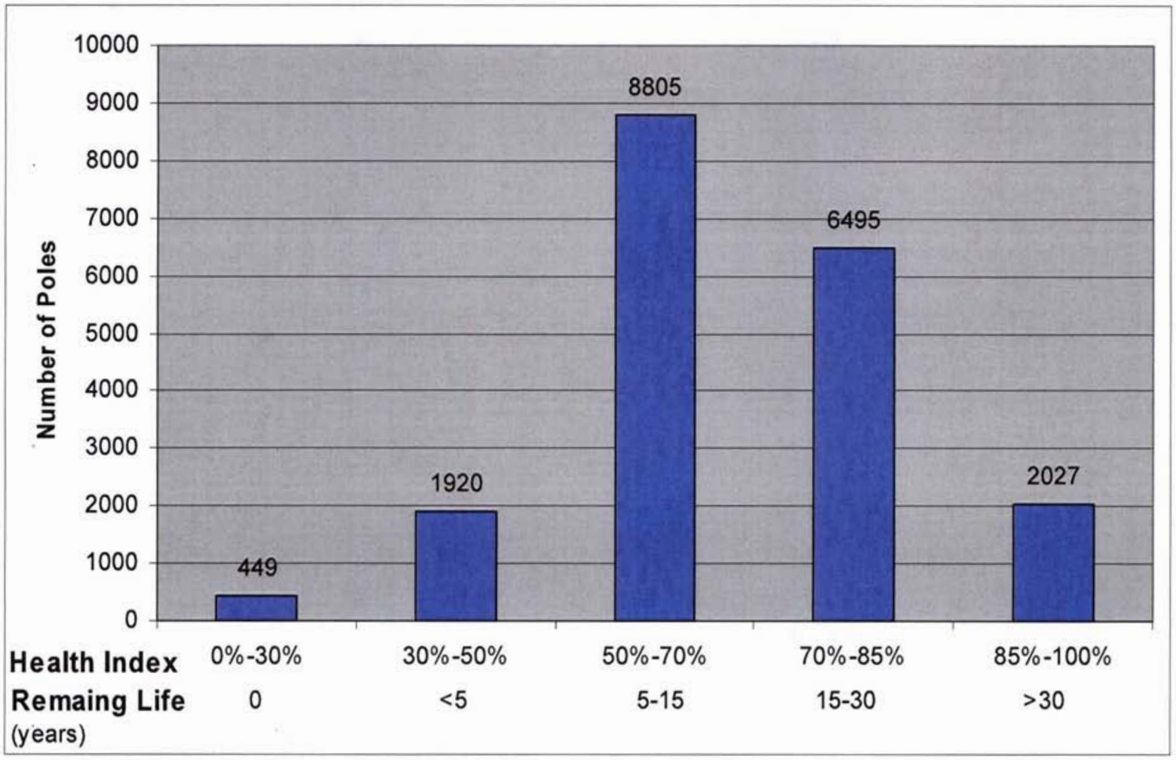
The health index factor for the pole condition rating provided by Enwin has been adjusted to reflect the fact that the Health Index is interpreted as 30% representing end-of-life, but the Enwin condition rating uses a value of 6 as end-of-life. This results in the health index factor being 6 for both Enwin condition ratings of 0 and 1. The health index factor of zero is not used.

The present set of condition parameters available at ENWIN is consistent with industry "best practices". However, the "pole rating" is not defined in relation to the remaining strength of the pole. Defining relative to remaining strength is a "best practice" because it allows the utility to demonstrate compliance with standard CSA C22.3 No1 which requires pole replacement when the strength decreases to the point that the load factor in the design strength calculation is less than one.

Table 9 Poles Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 4 Poles Health Index Results



The wide range of condition of wood poles indicated by the health index has been confirmed by the interviews with staff. Operations staff expressed a growing concern about the number of poles in very poor condition. A recommendation for a pole replacement program has been made in section 10 of this report.

6.5 Reclosers

Table 10 Reclosre Health Index Formulation

Condition Parameter	**Weight**
Age	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Max Score = 6	

The actual condition of an individual recloser depends heavily on its operating history. The condition degrades quickly with frequent operation and with high fault currents. Condition can be monitored more accurately by recording the number of operations and/or the interrupting I^2t, rather than just tracking age.

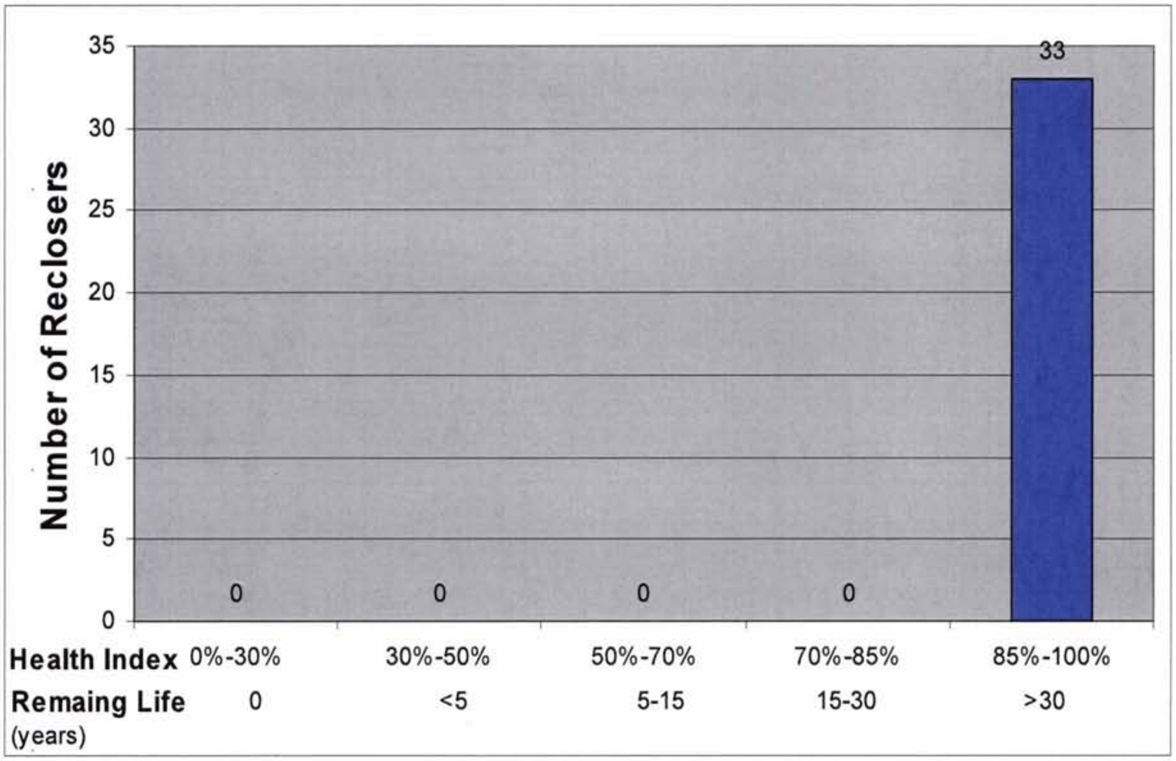
The age of reclosers was only available as an estimate, based on the warranty expiry date. However, the alternative of using the line age as an indication of recloser age was considered less accurate, since most of the reclosers have been added to the system recently.

It is recommended that in the future, ENWIN keep records of the age of individual reclosers and their operation count. Estimating I^2t from operations count can be accomplished by modeling the installation location of each recloser. The reclosers are maintenance free, sealed units so maintenance cost cannot be tracked against replacement cost to indicate end-of-life.

Table 11 Recloser Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 5 Recloser Health Index Results



The excellent condition of reclosers indicated by the health index has been confirmed by interviews with staff and visual inspection. Reclosers have only been installed in recent years in an effort to improve reliability. There have been some failures with units from a specific manufacturer, but these issues are being addressed under warranty with the manufacturer. They are not indicative of the overall condition of the reclosers.

6.6 Load Break Switches

Table 12 Load Break Switch Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

The actual age of individual load break switches was not available and so the age of the line was used as a surrogate.

The visual condition was available only for a sample of the population (33 of 207 units). Visual condition is a poor indicator of switch condition. The actual condition of an individual switch is better determined by contact resistance measurements, force required to operate, and infrared thermography. However, most of the degradation can be reversed through maintenance, such as replacing contacts, and lubricating linkages, so the condition is not a good indicator of remaining life.

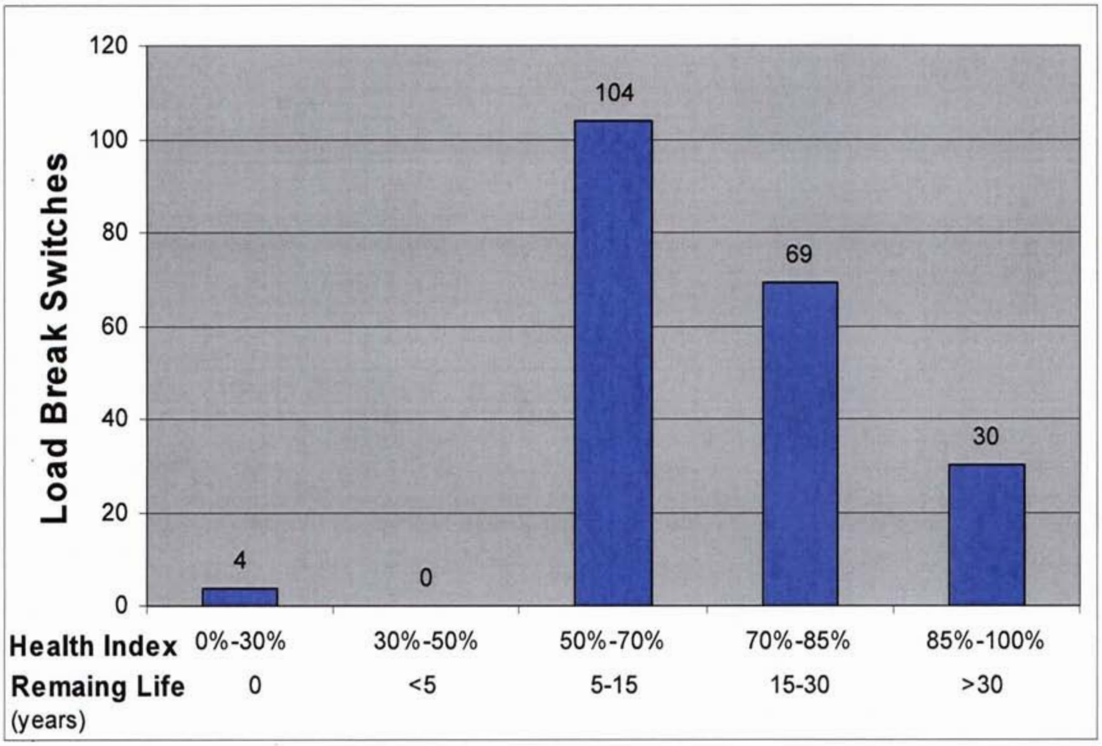
If the annual cost of maintenance was tracked, it could be compared to the replacement cost as an indicator of the economical end of life. Technically the life of the switch can be extended almost indefinitely by maintenance.

It is recommended that in the future, ENWIN keep records of the age of individual load break switches and their annual maintenance costs.

Table 13 Load Break Switch Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 6 Load Break Switch Health Index Results



The generally good condition of load break switches indicated by the health index has been conformed by interviews with staff. The switches are operated annually as part of the scheduled maintenance program and any deficiencies are repaired.

6.7 In-Line Switches

Table 14 In-line Switch Health Index Formulation

Condition Parameter	**Weight**
Line Age	3
Visual Inspection	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 24	

The actual age of individual in-line switches was not available and so the age of the line has been used as a surrogate.

Visual condition is a poor indicator of switch condition. The actual condition of an individual switch is better determined by contract resistance measurements, force required to operate, and infrared thermography. This level of condition monitoring is not recommended because of the high cost. Since most of the degradation can be reversed through maintenance, such as cleaning contacts and lubricating linkages, the condition of contacts is not a good indicator of remaining life. This leaves age as the best indicator of remaining life.

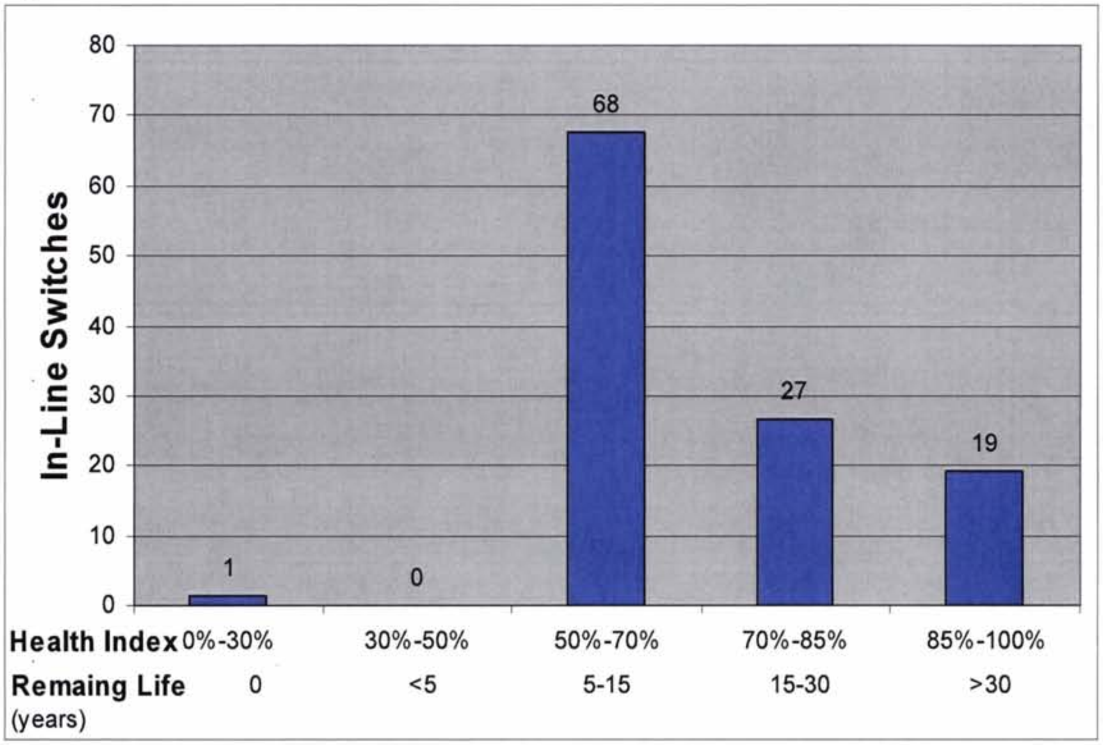
If the annual cost of maintenance was tracked, it could be compared to the replacement cost as an indicator of the economical end of life. Technically the life of the switch can be extended almost indefinitely by maintenance.

It is recommended that in the future, ENWIN keep records of the age of individual in-line switches and their annual maintenance costs.

Table 15 In-line Switch Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 7 In-line Switch Health Index Results



The good condition of in-line switches indicated by the health index has been confirmed by interviews with staff. There have been problems with some designs in the past, but these have been replaced with better designs.

6.8 Fuse Holders

Table 16 Fuse Holder Health Index Formulation

Condition Parameter	**Weight**
Line Age	2
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 18	

There was no data on any condition parameter for fuse holders. Condition can be determined by a combination of visual inspection and laboratory testing of a sample of fuse holders, but this is not recommended because of the low expected benefits compared to the high costs.

The end of life of a fuse holder is usually indicated by cracking of the insulator, or corrosion of the metal parts.

Actual age of individual fuse holders was not available and so the age of the line has been used as a surrogate. This makes the health index for fuses and fuse holders the same as the health index for overhead conductors. It is recognized that this will estimate a health index that is lower than would actually occur in the field because some fuse holders are replaced on an individual basis, not just as part of a line rebuild, and many have been installed at the start of laterals well after the line was built in an effort to improve reliability.

The present set of condition parameters available at ENWIN is consistent with industry "best practices".

6.9 Lightning Arresters

Table 17 Lightning Arrester Health Index Formulation

Condition Parameter	**Weight**
Line Age	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Max Score = 6	

Actual age of individual lightning arresters was not available and so the age of the line has been used as a surrogate. This makes the health index for lighting arresters the same as the health index for overhead conductors.

Visual inspection is not capable of detecting the condition of a lightning arrester, unless it has already failed and the disconnector has operated. There is no good condition indicator available for lighting arresters. They should be replaced if the disconnector has operated or the transformer is being replaced.

The present set of condition parameters available at ENWIN is consistent with industry "best practices".

6.10 Insulators

Table 18 Insulator Health Index Formulation

Condition Parameter	**Weight**
Line Age	2
Visual Inspection	1
Age (years)	**Health Index Factor**
<15	6
>15 <30	5
>30 <45	4
>45 <60	3
>60 <75	2
>75 <95	1
>95	0
Visual Condition	**Health Index Factor**
A (as new)	6
B (very good)	5
C (some deterioration)	3
D (near end of life)	1
Max Score = 18	

Actual age of individual insulators was not available and so the age of the line has been used as a surrogate. This makes the health index for insulators the same as the health index for overhead conductors.

The visual inspection can detect broken water sheds, and surface degradation of polymer materials. During the visual inspections conducted as part of this project the condition grade of the insulators was never different than the condition grade of the conductor and over all line.

It is recommended that ENWIN keep records of the age of insulators independently of the age of the line, since the recent insulator replacement program has resulted in some insulators being much newer than the line as a whole.

The present set of condition parameters available at ENWIN is consistent with industry "best practices".

6.11 Underground Cables

Table 19 UG Cable Health Index Formulation

Condition Parameter	**Weight**
Age	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Max Score = 6	

Age was the only condition parameter available for underground cables. Most of the cable ages were estimated by ENWIN staff. When age estimates were not available the age of overhead circuits in the same geographic area have been used.

The 40 year end of life assumed here applies to older types of polymer insulated cables. Modern cables with tree retardants and strand blocking are expected to last longer. PILC cables have much longer lifetimes, but individual cable type data was not available.

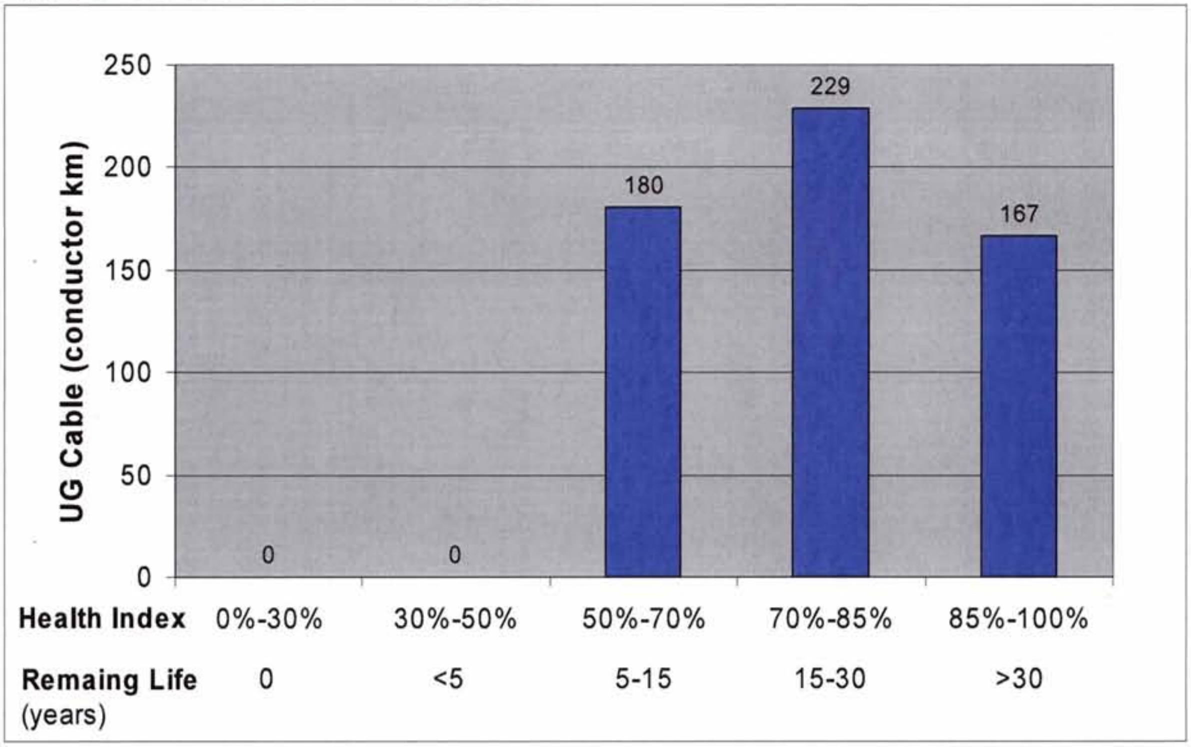
It is recommended that data on cable failure rate be tracked for different cable types, ages, and geographic areas as an indication of cable condition. Present overall failure rates at ENWIN indicate that the UG cables are presently in very good condition overall.

Very low frequency breakdown tests could also be done every few years, on cables older than 20 years, as an additional condition parameter.

Table 20 UG Cable Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 8 UG Cable Health Index Results



The overall good condition of underground cable indicated by the health index has been confirmed by interviews with staff and the low failure rate experienced. The staff interviews identified that there is a targeted replacement program to eliminate the direct buried XLPE cable, about 5% of the installed cable.

6.12 Switching Units

Table 21 Switching Unit Health Index Formulation

Condition Parameter	Weight
Age	1
Age (years)	**Health Index Factor**
<10	6
>10 <20	5
>20 <30	4
>30 <40	3
>40 <50	2
>50 <60	1
>60	0
Max Score = 6	

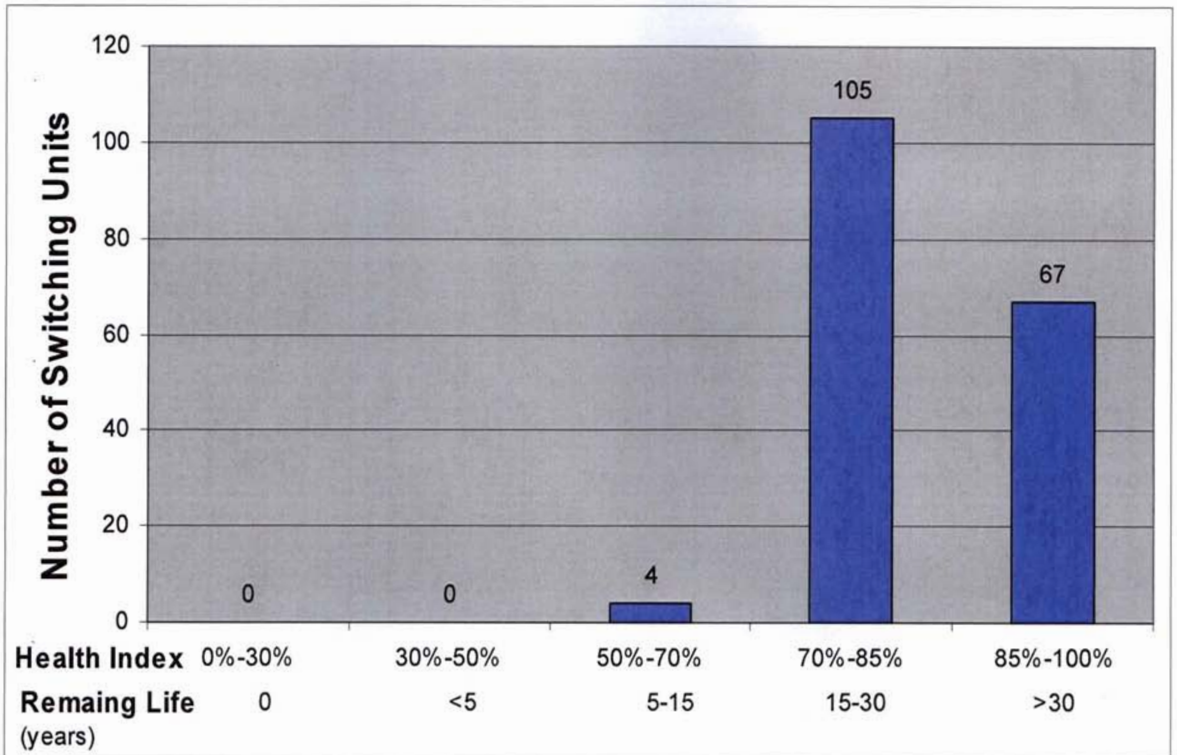
Age was the only condition parameter available for switching units, and only as a distribution based on a sample (113 of 176).

Some utilities have been experiencing high failure rates for switching units. The cabinets and contacts are rusting due to a moist environment and the insulators are becoming contaminated with road salt. A visual inspection has been found to be an effective monitoring technique and an insulator cleaning program can be implemented based on the condition. It is recommended that ENWIN in the future, record a condition grade for switching units based on a visual inspection.

Table 22 Switching Unit Health Index Interpretation

Health Index	Condition	Description	Expected Lifetime	Requirements
85 - 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 30 years	Normal maintenance
70 – 85	Good	Significant deterioration of some components	From 15-30 years	Normal maintenance
50 – 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 5 – 15 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 – 50	Poor	Widespread serious deterioration	Less than 5 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 – 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

Figure 9 Switching Unit Health Index Results



The overall good condition of switching units indicated by the health index has been confirmed by visual inspection of a sample of units and interviews with staff. However, the staff interviews did indicate that there are a few units that are experiencing the corrosion problem caused by moisture build up that other utilities are experiencing. If the recommended visual inspection grade is added to the condition monitoring program then health indices calculated in the future will be able to reflect this condition. The present health index analysis is missing these poor condition switches because a visual condition grade was not available on all units.

6.13 Civil Infrastructure

Civil infrastructure includes manholes, concrete pads, underground vaults and ducts.

Age was available for 171 manholes out of a population of 462, but all ages were 1967 and 1968, which was not considered to be representative. A separate project will be conducted on civil infrastructure condition. No health index was calculated as part of this project.

6.14 Mobile Unit Substations

There are three mobile unit substations. The only condition data that was available was age (41, 30 and 24 years). Since these units are only used sporadically, their expected life could be as high as 60 years if they are not overloaded when they are used. Based only on age they would all have a health index of 100%. However, age is not an adequate indicator of substation transformer condition.

A better indication of condition could be made by conducting regular oil tests, particularly furan content, water content, dielectric strength, and interfacial tension. It is recommended that ENWIN conduct these tests every five years.

7 REVIEW OF RELIABILITY STATISTICS

As a component of the asset condition assessment, a review of the reliability statistics provided by ENWIN Utilities was conducted. Reliability statistics are an indicator of the condition of assets, the effectiveness of maintenance, and often the existence of any operational issues.

Table 22 below provides the standard reliability indices utilized by power utilities, indicating the duration, frequency and customer impact of power outages. Data on the cause of outages, particularly the % caused by equipment failure, would be useful in determining the effectiveness of the maintenance program and the general condition of the assets but it was not available.

Table 23 Reliability Statistics

Index	Value (2006)	CEA Urban Utility Average
SAIFI	2.20	1.88
SAIDI	1.38	1.69
CAIDI	0.63	0.95

In general, all of the reliability indices are in the normal range for distribution companies of this size and customer mix, but significantly better than average. From the data provided, it was also noted that the variation in frequency of outages on a year-over-year basis was within the normal range. This better than average performance indicates that asset condition is not seriously affecting the reliability statistics, but comparisons are difficult because weather severity, animal populations, and power system design have large effects on the reliability statistics that are unrelated to asset condition.

Failure rate data was available for some of the asset types and is shown in Table 23. The failure rates being experienced are generally low compared with industry wide expectations. The exception is the reclosers, which are failing at a rate of 10% per year. This is extremely high, given that the reclosers are less than 5 years old. The problem is a specific problem with a particular manufacturer and is being addressed by the manufacturer.

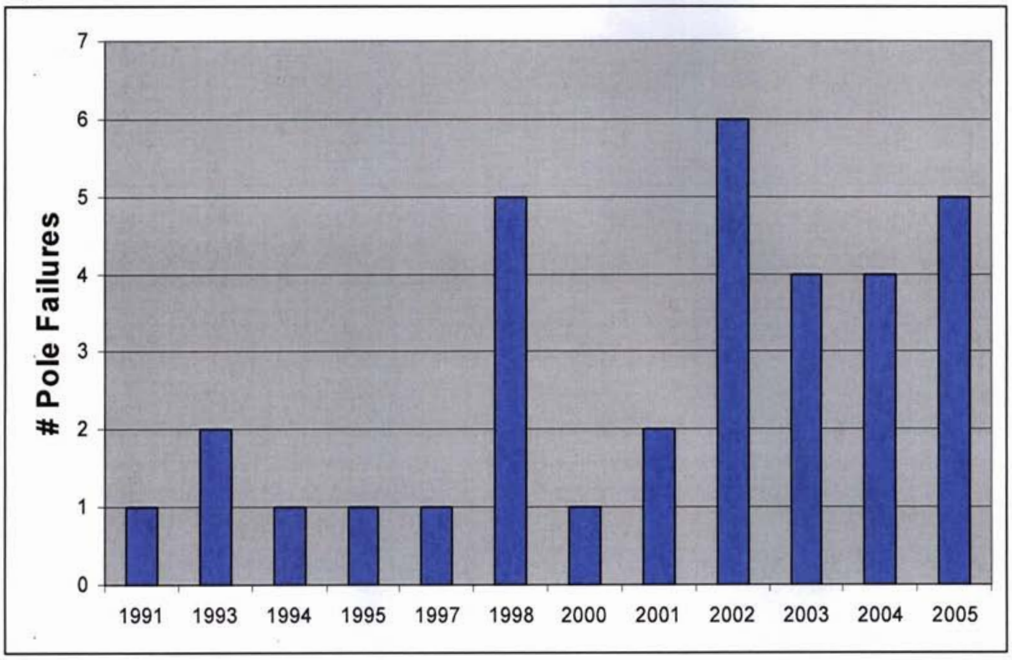
Table 24 Equipment Failures Rates

TYPE	2004	2005	2006
SWITCH		1	1
SU		1	1
RECLOSER		1	3
LI	1	1	1
CABLE		4	5
FUSE HOLDER		1	
LF	2		
ILS	1		
DS	1		
TAP	2		1

The cable failure rate is 5 per 576 conductor km or 0.9 per 100 km per year. Typical industry experience is 1 or 2 failures per 100 km per year.

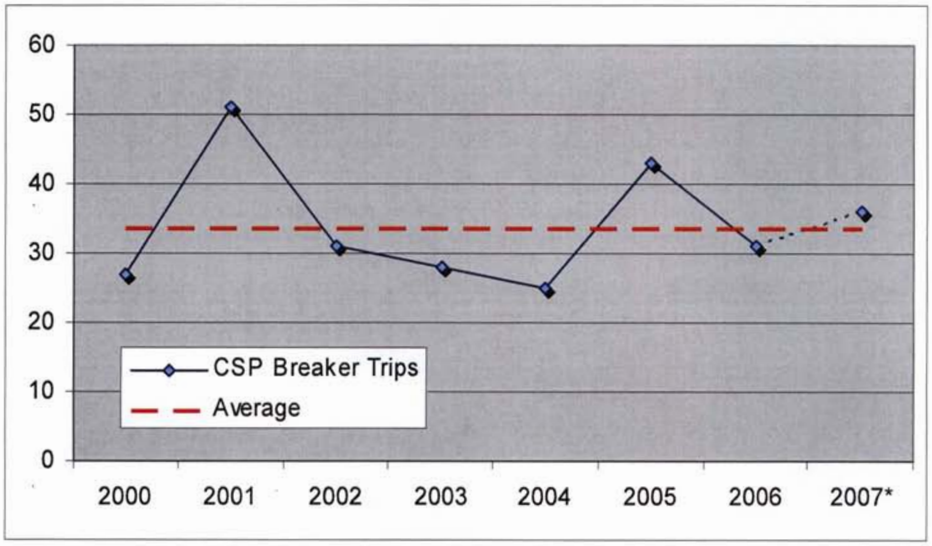
The trend in wood pole failures is shown in Figure 10. Concrete poles have experienced no failures. The failure rate of 5/19666 (0.02%) is low but the trend is increasing. This is an indication that wood pole condition is deteriorating and may require remedial action in the future.

Figure 10 Wood Pole Failure Trend



The trend in secondary breaker trips in completely self protected (CSP) transformers is shown in Figure 11. There is no increasing trend, indicating that the secondary breakers of the CSP transformers are not reaching end of life. There are 2454 CSP transformers installed on the system with an average operation rate of 33.7 per year, which is 1.3%. This operation rate is typical of the industry and also does not indicate end of life.

Figure 11 Trend in CSP Transformer Breaker Trips



* The 2007 value has been estimated by doubling the number of trips from January to July 31 2007 (18).

These reliability and failure rate figures are consistent with the generally good condition found in the health index calculation.

8 REVIEW OF CAPITAL AND MAINTENANCE BUDGETS

As part of the asset condition assessment, the capital and maintenance budgets of ENWIN Utilities were reviewed to ascertain that they were reasonable in light of the asset populations and ongoing maintenance activity.

Table 24 provides a summary of the capital and maintenance budget information. The figures include all distribution equipment including 4.16 kV since separate figures for the 27.6 kV system were not available. The following paragraphs provide some observations on the budget and comments.

Table 25 Summary of Maintenance and Capital Budgets

	ENWIN	Typical[2]
Historic Cost (k$)	189,000	
Net Capital Assets, NBV (k$)	149,000	
Capital Replacement Budget (k$)	7,630	
O&M Budget (k$)	3,380	
Annual Depreciation (k$)	9,203	
Capital Replacement as % of Depreciation	82.9	100 - 140
O&M as % of Capital Replacement	44	45-55
Historic cost /customer ($)[1]	2,230	1,000 - 4,000
Capital Replacement per customer ($)[1]	90	80 - 160
O&M cost per customer($)[1]	40	45 - 65

Note[1] Based on 84,600 customers
All cost are for distribution equipment only, excluding meters, fleet, tools, computers, buildings, land.
Note [2] The "typical" values are taken from annual reports of major utilities in Southern Ontario.

The Enwin figures were provided by their financial department and are as of Dec 31 2006.

Most of the comparison figures for ENWIN Utilities are within the range expected. This indicates that the cost of purchasing and maintaining the systems are similar to other utilities in southern Ontario.

One exception is the size of the equipment replacement budget compared to the annual depreciation. Previous studies have indicated that a typical utility of the size and type of ENWIN Utilities would have a capital replacement budget between 100 and 140% of the annual depreciation of equipment. At ENWIN the capital replacement budget is considerably lower than this. The capital expenditure budget is 7.6 million dollars per year, which is 83% of the 9.2 million dollars depreciation. This could indicate that equipment is not being replaced at a sustainable rate, and that it may need to be increased in the future. However, the capital replacement per customer is in the middle of the range. The 82% may be low because the annual depreciation is high due to higher than average capital expenditures in the previous 25 years. Other utilities may have more fully depreciated systems.

The other metric that is out of the usual range is the O&M cost per customer, which is a bit low. Based on the interviews with staff, this is likely due to a strategy that has recently reduced O&M by focusing on replacement of equipment. Given the low capital replacement budget at the present time, this situation is probably not sustainable. In the future either capital expenditure or O&M, or both, will have to rise.

9 CAPITAL EXPENDITURE PLAN FOR POWER SYSTEM EQUIPMENT REPLACEMENT AT END OF LIFE

Based on information provided by ENWIN Utilities an estimate of the capital plan, for 27.6 kV distribution equipment replacement, was prepared for the next 20 years. The estimated capital plan provides an indication of the likely capital expenditures for equipment replacement. These estimates were done on the basis of the health indexes and the interpretation tables presented in section 5. The capital costs are the dollars required in the year of replacement (not present value). An inflation escalation factor of 2% per year has been included in the estimated costs.

Actual capital replacement requirements will likely be slightly higher than this plan because it does not include other reasons for capital replacement, such as road widening, load growth, equipment obsolescence and improving safety.

Another factor that can increase the capital requirement in any one year is the cost efficiency of replacing many components at once. Rather than replace individual conductors, insulators and hardware based on their condition, it is often cost effective to rebuild an entire line section all at once. This means that some components will be replaced before their end of life, but that the overall long-term cost will be minimized. This plan has been made assuming this efficient replacement strategy. The "OH Line" in Figure 11 includes conductor, insulators and hardware.

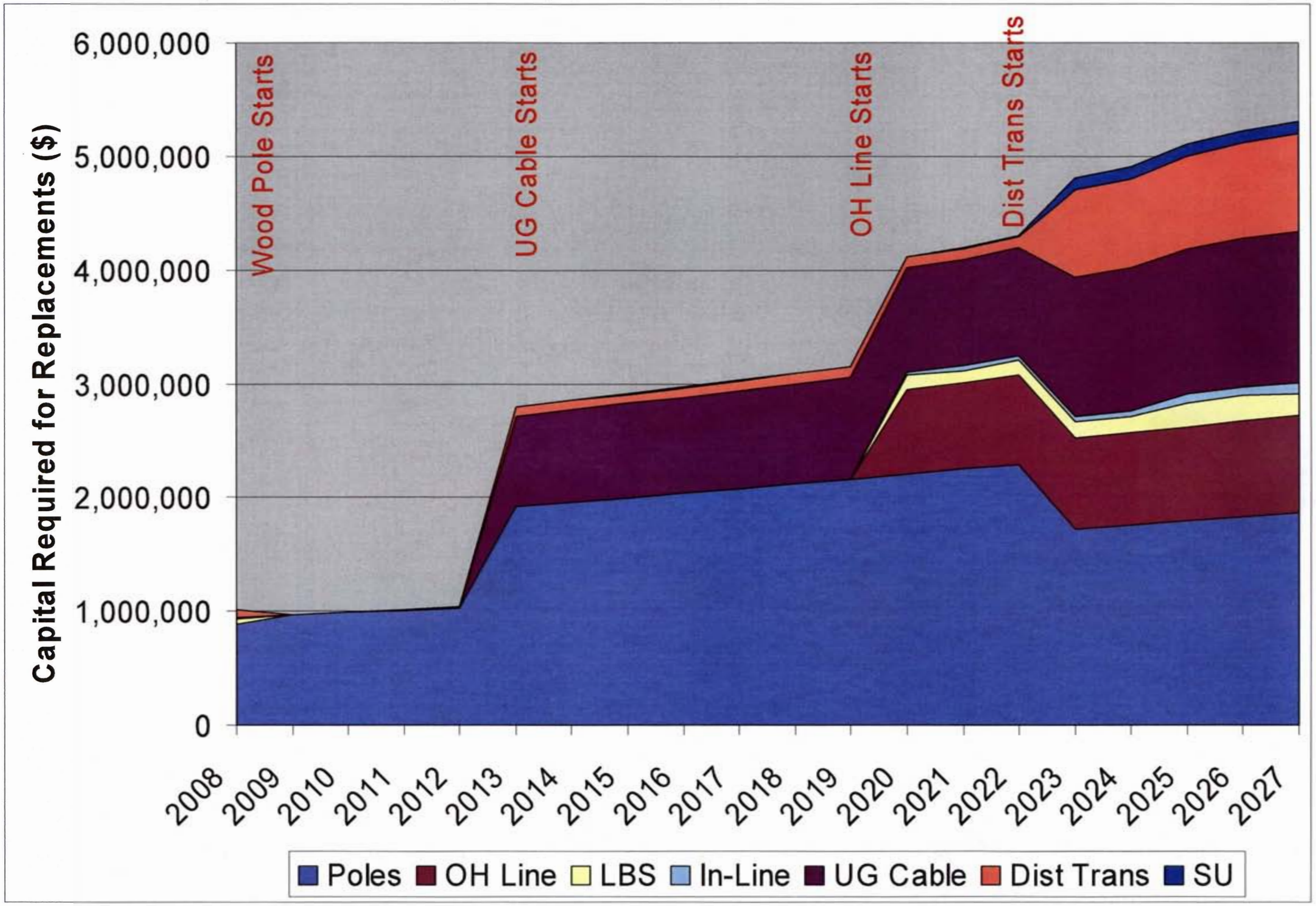
It is difficult to compare the plan in Figure 11 with the present capital spending of $6.1 million because the latter number includes the 4.16 kV and replacements for reasons other than end of life.

The figure shows that pole replacements should begin immediately and double after five years. Underground cable replacements should begin in about five years and continue at a steady rate. In 10-15 years the overhead lines will add significantly to the capital requirements and then in 15 years the distribution transformers will add a significant amount. The required expenditure on switches, although present, will be small in comparison

This plan needs to be combined with the other expected capital expenditures on 4 kV systems and substations to determine a smooth year to year level of capital expenditure. Some of the replacements may have to be moved up to earlier years to create a smooth plan.

It must be stressed that this plan only applies to aging power system equipment and does not include vehicles, tools, buildings, office equipment, or equipment needed for system growth.

Figure 12 Estimated Capital Plan for Power System Equipment Aging Only



10 DEVELOPMENT OF RECOMMENDATIONS

10.1 Review Of Asset Condition Monitoring Program

In comparing the condition monitoring parameters for which ENWIN could provide data with the industry "best practices" there are a few places were a change could be considered by ENWIN. The following table summarizes the available parameters used in section 6 and the recommendations discussed in section 6 for particular asset types.

Table 26 Summary of Recommended Condition Monitoring Parameters

Asset Type	Available Parameters	Recommended Parameters
Distribution Transformers	age*, loading*	age visual
Distribution Line Conductors	line age, visual*	visual tensile strength
Distribution Line Hardware	line age, visual*	
Poles	rating, line age*, visual*	
Reclosers	age	maintenance cost failure rate
Load Break Switches	line age, visual*	age visual maintenance cost failure rate
In-line Switches	line age, visual*	age visual failure rate
Fuses and Fuse Holders	line age, visual*	
Lightning Arresters	line age,	
Insulators	line age, visual*	age*
Underground Cables	age	failure rate VLF breakdown
Switching Units	age	visual maintenance cost, failure rate
Civil Infrastructure (concrete pads, vaults, ducts)	visual	
Mobile Substations	age	oil breakdown oil moisture oil furan

* not available for individual units, only as a distribution or sample of the population

If a parameter is only available as a sample (*) and it is recommended that it be obtained for individual units, then it is included in the "recommended" column without the "*".

It is recommended that the routine visual inspections assign a condition grade to the inspected component, such as 1 – Excellent (like new), 2 – Good (no visible problems), 3 – Fair (some evidence of degradation), 4 – Poor (obvious problems, near end of life), and 5 – Bad (needs priority replacement).

The “maintenance cost” parameter is the expected average annual maintenance cost of the component. It can be compared with the estimated replacement cost to decide when a repairable component has reached the end of its economical life and should be replaced rather than repaired. The exact value at which this occurs should be decided on the basis of lowest net present value which in turn depends on estimates of inflation and the return on capital investment. It is typically about 10%, i.e. when the expected annual maintenance cost is greater than 10% of the replacement cost then the component should be replaced rather than repaired.

The expensive tests (tensile strength for overhead conductor and very low frequency (VLF) breakdown for underground cables) are only recommended for use on components at least 80% through their expected life, or on components experiencing a higher than normal failure rate, to determine if condition is the problem. They should not be done more frequently than every five years.

Failure rate can be tracked to indicate the condition of a group of assets that are a similar age and experience similar service conditions. This is especially recommended for underground cables as it is an industry “best practice”.

It is recommended that Enwin consider defining their pole rating condition parameter in terms of the percentage of the original strength that is remaining. At present each of the levels (0-6) are not defined quantitatively. This make it difficult for Enwin to demonstrate that its pole management program is in compliance with CSA standard C22.3 No.1 Overhead Systems, which requires that poles be replaced when the load factor falls below 1. Typically this occurs at 50 to 66% of original strength. The use of percent remaining strength is standard practice for pole inspection contractors (such as Osmose).

It is recommended that ENWIN consider using a single data base to record condition data. This reduces the cost of asset condition monitoring and most utilities are moving toward this practice. The data recorded needs to be several grades of condition rather than the OK/notOK that is used in maintenance data bases. This represents a significant change to historical practices. When condition monitoring is not being done, and condition checks are only designed to determine if maintenance is required, then the simple OK/not OK information is all that is required. However, this two state information is not adequate for condition monitoring because it does not show gradual deterioration and so does not allow for planned replacement.

10.2 Pole Replacement Program

When a component on a distribution line fails it is always replaced in order to restore service. However, if components are replaced before failure, based on the condition of the component, there are two different strategies that can be employed. One involves replacing individual components one at a time as their condition becomes unacceptable. An alternative strategy is to wait until many components are in poor condition and then rebuild the entire line section replacing all components at once. The choice of strategy depends on a number of factors. Most utilities use a combination of these strategies.

The factors that affect the decision include:

- the relative condition of the different components (are they all degrading together)
- the risks associated with failure, including safety, reliability and cost risks
- the cost effectiveness of group replacement
- the availability of capital for group replacement

In the past Enwin has replaced transformers, lightning arresters, isolating switches and insulators on an individual basis based on condition or on failure rates of specific types of product or manufacturer. However, for poles the strategy at Enwin has been to not replace individual poles unless they failed, or would fail when climbed, and then to rebuild line sections and replace all poles at the same time. This strategy did not require a regular condition assessment of poles.

It is recommended that Enwin adjust its strategy to replace individual wood poles, rather than wait for many to be in poor condition and then rebuilding the line. This recommendation is based on the following rationale:

- the wood poles are in various condition states on most line sections (sometimes due to a partial replacement during voltage upgrading). This makes line rebuilds less cost effective.
- many poles in poor condition scattered throughout the service territory leave the utility exposed to the risk of lengthy restoration activity after a major storm.
- a regular condition assessment of all poles is now being performed at the request of the OEB so extra work is not needed to get the information on which to base individual pole replacement.
- the other components on a line section, such as transformers, insulators, arresters, conductors, are often in much better condition than the poles. This also makes line rebuilds less cost effective.
- Canadian standard C22.3 No. 1 Overhead Systems requires that when a pole's strength has been reduced so that the load factor is less than 1 it should be replaced

Line rebuild can still be recommended in areas where the majority of poles need replacing, or where the majority of other components, such as conductors, insulators, guy wires, anchors, fuse holders etc. need to be replaced.

10.3 Wood Pole Preservation Program

When wood poles are being replaced individually, rather than in groups as part of a line rebuild, the opportunity arises to reinforce and/or retreat individual poles. Most utilities find both of these activities to be cost effective. The decision to reinforce or retreat is always based on lowest long term cost, and often depends on the pricing that individual utilities can obtain from contracting companies.

Poles can be reinforced if they are weak only at certain spots, such as at wood pecker damage, or near the ground line where they often rot the most. The reinforcement can be made by steel trusses, at about $600 per pole or reinforced epoxy wraps at $1400 per pole. This will often extend the life of a pole worth $2000-$4000 by ten or twenty years.

Re-treatment with preservative is harder to evaluate on a cost basis. Once rot is well established re-treatment is not effective. When it will be effective is difficult to determine ahead of time, and the effectiveness is difficult to track after re-treatment.

It is recommended that Enwin investigate both of these options is if adopts a policy of replacing individual wood poles based on condition.

10.4 Completely Self Protected (CSP) Transformer Replacement Program

CSP transformers have been known to have problems with the secondary breaker tripping at too low a load level and causing an unnecessary outage. One of the staff interviews mentioned this issue. There is a potential for this problem to increase as the transformers age. The rate at which customer interruptions are caused by this should be monitored. If the rate becomes unacceptable then a planned replacement program may be necessary. At the present time only the monitoring of the interruption rate is recommended as there is no evidence to show that the rate is unacceptably high at the present time (see Figure 11).

11 GEOGRAPHIC DISTRIBUTION OF EQUIPMENT REPLACEMENT

The following tables show the actual number of components that need to be replaced in each geographic area of the city to make up the capital expenditure plan. Geographic areas are designated by the secondary map numbers. The green, yellow, and red backgrounds indicate increasing levels of replacement. These colours can be used to identify the geographic areas that will require the most work. The years have been grouped into five year groups because the health index end-of-life prediction is not accurate enough to support individual year resolution. This table is intended as a general planning tool. Actual replacements should be done on the basis of equipment condition at the time, not on this prediction.

Switches are not included in the table because they are a small component of the overall expenditure and their columns would be almost all zeros. Distribution transformers are not included because no geographic information was available on distribution transformer condition.

Table 27 Required Replacements by Geographic Area E - I

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
E-1	1	18	18	6	0	0	0	0	0	0	0	0
E-2	0	15	15	9	0	0	0	0	0	0	0	0
E-3	24	19	19	5	0	0	0	0	0	0	0	0
E-4	11	14	14	0	0	0	0	0	0	0	0	604
F-1	2	24	24	8	0	0	0	0	0	0	0	0
F-2	0	13	13	0	0	0	0	0	0	0	0	72
F-3	2	9	9	3	0	0	0	0	0	0	0	0
F-4	11	14	14	1	0	0	0	0	0	600	600	0
F-5	0	0	0	0	0	0	0	0	0	0	0	1800
F-6	5	31	31	5	0	0	0	0	0	3188	3188	0
F-7	5	6	6	0	0	0	0	0	0	1852	1852	926
F-8	6	19	19	22	0	0	0	0	0	0	0	0
G-1	1	40	40	17	0	0	0	0	0	783	783	0
G-2	31	35	35	26	0	0	0	0	0	0	0	0
G-3	0	12	12	19	0	0	0	0	0	0	0	0
G-4	4	8	8	39	0	0	0	0	0	0	0	0
G-5	2	16	16	13	0	0	0	0	0	0	0	0
G-6	14	32	32	1	0	0	0	0	0	0	0	0
G-7	24	52	52	18	0	0	0	0	0	0	0	0
H-1	12	33	33	26	0	0	2638	4397	0	428	428	0
H-2	24	29	29	8	0	0	0	0	0	428	428	0
H-3	19	55	55	14	0	0	0	0	0	300	300	0
H-4	35	47	47	29	0	0	0	0	0	0	0	1851
H-5	7	62	62	8	0	0	0	0	0	0	0	960
I-1	5	35	35	19	0	0	0	0	0	428	428	0
I-2	2	57	57	59	0	0	0	0	0	428	428	0
I-3	0	12	12	6	0	0	0	0	0	0	0	0
I-4	0	24	24	36	0	0	0	0	0	0	0	150

Table 28 Required Replacements by Geographic Area J - L

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
J-1	0	0	0	0	0	0	0	0	0	1229	1229	0
J-2	66	24	24	65	0	0	0	0	0	1229	1229	0
K-1	0	0	0	0	0	0	1512	2520	0	0	0	0
K-10	3	51	51	49	0	0	0	0	0	1710	1710	0
K-11	0	0	0	0	0	0	0	0	0	1206	1206	724
K-2	0	0	0	0	0	0	0	0	0	0	0	0
K-3	11	15	15	3	0	0	0	0	0	0	0	772
K-4	1	63	63	19	0	0	3043	5071	0	0	0	0
K-5	0	51	51	40	0	0	0	0	0	0	0	220
K-6	0	0	0	0	0	0	0	0	0	0	0	1561
K-7	0	0	0	0	0	0	0	0	0	0	0	2345
K-8	0	0	0	0	0	0	0	0	0	1826	1826	304
K-9	0	1	1	1	0	0	0	0	0	0	0	230
L-1	144	34	34	22	0	0	0	0	0	522	522	0
L-10	2	21	21	29	0	0	0	0	0	0	0	0
L-11	30	23	23	36	0	0	2108	3513	0	0	0	603
L-12	2	19	19	0	0	0	1354	2257	0	0	0	0
L-13	0	0	0	0	0	0	0	0	0	0	0	469
L-2	16	56	56	45	0	0	0	0	0	0	0	0
L-3	27	13	13	27	0	0	0	0	0	0	0	0
L-4	2	20	20	37	0	0	0	0	0	0	0	0
L-5	0	12	12	5	0	0	0	0	0	0	0	0
L-6	0	0	0	0	0	0	0	0	0	0	0	0
L-7	64	29	29	24	0	0	0	0	0	0	0	0
L-8	9	58	58	28	0	0	0	0	0	0	0	0
L-9	0	0	0	0	0	0	0	0	0	0	0	0

Table 29 Required Replacements by Geographic Area M - N

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
M-1	26	0	0	8	0	0	0	0	0	13463	13463	0
M-10	67	73	73	29	0	0	0	0	0	51	51	0
M-11	2	26	26	39	0	0	0	0	0	150	150	0
M-12	56	69	69	25	0	0	0	0	0	277	277	0
M-13	0	7	7	3	0	0	0	0	0	0	0	0
M-14	0	0	0	0	0	0	0	0	0	0	0	1304
M-15	0	0	0	0	0	0	0	0	0	0	0	990
M-2	0	0	0	0	0	0	0	0	0	5591	5591	0
M-3	0	0	0	0	0	0	0	0	0	113	113	0
M-4	0	0	0	0	0	0	0	0	0	113	113	0
M-5	0	0	0	0	0	0	0	0	0	113	113	0
M-6	0	0	0	0	0	0	0	0	0	113	113	0
M-7	2	32	32	5	0	0	0	0	0	0	0	0
M-8	2	70	70	28	0	0	0	0	0	0	0	0
M-9	20	49	49	28	0	0	0	0	0	51	51	0
N-1	0	0	0	0	0	0	0	0	0	12494	12494	0
N-10	3	13	13	11	0	0	0	0	0	0	0	252
N-11	0	19	19	12	0	0	0	0	0	0	0	0
N-12	0	78	78	48	0	0	0	0	0	130	130	0
N-13	0	1	1	7	0	0	0	0	0	0	0	4390
N-14	0	0	0	0	0	0	0	0	0	0	0	2969
N-2	16	51	51	26	0	0	0	0	0	7112	7112	0
N-3	37	63	63	28	0	0	0	0	0	713	713	0
N-4	0	0	0	0	0	0	0	0	0	0	0	0
N-5	0	0	0	0	0	0	0	0	0	284	284	0
N-6	9	39	39	34	0	0	0	0	0	113	113	0
N-7	20	43	43	37	0	0	0	0	0	300	300	0
N-8	18	11	11	8	0	0	0	0	0	1122	1122	0
N-9	9	20	20	26	0	0	0	0	0	0	0	3867

Table 30 Required Replacements by Geographic Area O - P

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
O-1	24	58	58	26	0	0	0	0	0	0	0	1776
O-10	2	18	18	2	0	0	0	0	0	0	0	0
O-11	0	29	29	0	0	0	0	0	0	0	0	933
O-12	97	36	36	6	0	0	0	0	0	0	0	3196
O-13	0	2	2	7	0	0	0	0	0	0	0	0
O-2	33	45	45	61	0	0	0	0	0	0	0	0
O-3	8	27	27	4	0	0	0	0	0	113	113	0
O-4	0	0	0	0	0	0	818	1363	0	113	113	0
O-5	38	80	80	10	0	0	0	0	0	0	0	0
O-6	40	54	54	39	0	0	0	0	0	0	0	0
O-7	4	25	25	5	0	0	0	0	0	2407	2407	267
O-8	22	44	44	20	0	0	0	0	0	0	0	2484
O-9	3	50	50	1	0	0	0	0	0	5863	5863	2932
P-1	0	0	0	1	0	0	0	0	0	0	0	0
P-2	0	0	0	0	0	0	0	0	0	0	0	0
P-10	2	11	11	24	0	0	0	0	0	0	0	533
P-11	22	83	83	17	0	0	0	0	0	0	0	0
P-12	0	3	3	37	0	0	0	0	0	0	0	0
P-13	0	0	0	0	0	0	0	0	0	0	0	0
P-3	0	1	1	6	0	0	0	0	0	0	0	0
P-4	19	26	26	55	0	0	0	0	0	852	852	0
P-5	14	44	44	37	0	0	0	0	0	0	0	0
P-6	33	51	51	67	0	0	0	0	0	0	0	0
P-7	11	16	16	9	0	0	0	0	0	652	652	1521
P-8	15	55	55	36	0	0	0	0	0	0	0	0
P-9	5	59	59	1	0	0	0	0	0	0	0	1575

Table 31 Required Replacements by Geographic Area Q - S

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
Q-1-2	0	0	0	0	0	0	0	0	0	0	0	0
Q-2	0	0	0	0	0	0	0	0	0	0	0	0
Q-3	6	47	47	50	0	0	0	0	0	0	0	0
Q-4	27	53	53	33	0	0	0	0	0	0	0	0
Q-5	52	47	47	84	0	0	0	0	0	0	0	0
Q-6	119	62	62	4	0	0	0	0	0	0	0	817
Q-7	20	33	33	36	0	0	0	0	0	0	0	0
Q-8	11	37	37	20	0	0	0	0	0	1488	1488	0
Q-9	2	16	16	51	0	0	0	0	0	879	879	0
R-1	0	0	0	0	0	0	0	0	0	950	950	0
R-2	76	60	60	87	0	0	0	0	0	52	52	0
R-4	47	97	97	26	0	0	0	0	0	899	899	0
R-5	14	78	78	72	0	0	0	0	0	0	0	1067
R-6	2	91	91	49	0	0	0	0	0	0	0	309
R-7	4	7	7	28	0	0	0	0	0	0	0	688
R-8	9	17	17	17	0	0	0	0	0	0	0	490
R-9	1	18	18	40	0	0	0	0	0	879	879	0
S-1	35	46	46	18	0	0	1165	1942	0	518	518	0
S-2	88	41	41	23	0	0	0	0	0	0	0	0
S-3	61	38	38	7	0	0	1354	2256	0	0	0	0
S-4	22	46	46	7	0	0	0	0	0	1055	1055	0
S-5	49	47	47	23	0	0	0	0	0	664	664	0
S-6	69	81	81	27	0	0	0	0	0	0	0	1092
S-7	0	28	28	44	0	0	0	0	0	0	0	3276
S-8	0	26	26	12	0	0	0	0	0	7086	7086	0
S-9	0	16	16	42	0	0	0	0	0	1527	1527	0

Table 32 Required Replacements by Geographic Area T- V

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
T-1	12	9	9	40	0	0	245	408	0	150	150	0
T-10	0	22	22	1	0	0	0	0	0	0	0	0
T-2	29	23	23	58	0	0	0	0	0	150	150	0
T-3	17	39	39	36	0	0	1873	3122	0	1818	1818	0
T-4	32	29	29	17	0	0	0	0	0	0	0	0
T-5	0	2	2	9	0	0	0	0	0	0	0	150
T-6	12	17	17	42	0	0	0	0	0	2287	2287	2287
T-7	6	23	23	46	0	0	0	0	0	0	0	750
T-8	0	0	0	0	0	0	0	0	0	0	0	0
T-9	9	17	17	4	0	0	0	0	0	0	0	0
U-1	53	62	62	10	0	0	0	0	0	0	0	300
U-10	10	39	39	18	0	0	0	0	0	0	0	0
U-2	30	28	28	48	0	0	0	0	0	0	0	0
U-3	0	52	52	48	0	0	0	0	0	175	175	0
U-4	21	30	30	24	0	0	0	0	0	470	470	0
U-5	0	11	11	23	0	0	0	0	0	0	0	0
U-6	11	28	28	17	0	0	0	0	0	0	0	0
U-7	7	10	10	9	0	0	0	0	0	0	0	5042
U-8	1	5	5	22	0	0	0	0	0	0	0	4853
U-9	0	12	12	0	0	0	0	0	0	0	0	0
V-1	6	29	29	38	0	0	0	0	0	0	0	0
V-2	4	13	13	61	0	0	0	0	0	300	300	0
V-3	2	25	25	47	0	0	0	0	0	400	400	400
V-4	0	0	0	0	0	0	0	0	0	0	0	5093
V-5	7	2	2	1	0	0	0	0	0	0	0	0
V-7	0	3	3	15	0	0	0	0	0	0	0	6026
V-8	0	0	0	0	0	0	0	0	0	0	0	11855
V-9	0	0	0	0	0	0	0	0	0	0	0	6250

Table 33 Required Replacements by Geographic Area W - Y

Component	Poles				OH Line (conductor m)				UG Cable (conductor m)			
Years	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20	0-5	5-10	10-15	15-20
Map												
W-1	0	4	4	0	0	0	0	0	0	0	0	0
W-2	43	21	21	16	0	0	0	0	0	0	0	2868
W-3	0	0	0	0	0	0	0	0	0	0	0	0
W-4	0	0	0	0	0	0	0	0	0	0	0	0
W-5	0	0	0	0	0	0	0	0	0	0	0	0
X-2	0	13	13	3	0	0	0	0	0	0	0	0
X-3	0	0	0	0	0	0	0	0	0	0	0	0
X-4	0	0	0	0	0	0	0	0	0	0	0	0
X-5	0	0	0	0	0	0	0	0	0	0	0	0
X-7	0	24	24	3	0	0	0	0	0	0	0	4898
X-8	1	6	6	0	0	0	0	0	0	0	0	5972
X-9	3	11	11	1	0	0	0	0	0	0	0	2236
Y-1	0	0	0	0	0	0	0	0	0	0	0	0
Y-2	4	12	12	6	0	0	0	0	0	0	0	600
Y-3	0	0	0	12	0	0	0	0	0	0	0	3179
Y-4	0	0	0	12	0	0	0	0	0	0	0	1488
Y-5	0	9	9	43	0	0	0	0	0	0	0	0
Y-6	0	0	0	0	0	0	0	0	0	0	0	0

12 APPENDIX A Information Requirements for Asset Condition Assessment

The following information is required to provide a basis for asset condition assessment. In some cases a priority level is identified. P1 indicates essential information. P2 indicates that estimation or exclusion of this information will affect the overall assessment by less than 20%.

1. **Maps and Diagrams**
    - Geographic map of system
    - Geographic line and station locations
    - System single line diagrams

2. **Asset Listings, Populations, Inventories, Lengths etc**
    - number, size, of voltage regulators (P1)
    - number, V and I ratings of breakers/reclosers (P1)
    - number and rating of controlled switches (P1)
    - number of manual 3 phase switches (P2)
    - number of manual 1 phase switches (P2)
    - km of overhead 3 phase line by conductor size and type(P1)
    - km of overhead 1 phase line by conductor size and type(P1)
    - insulators by voltage class and material (porcelain, polymer)
    - km of underground 3 phase line (P1) for each cable type and size (ie jacketed\unjacketed, encapsulated jacked, XLPE, tree-retardant TRXLPE) (P2)
    - km of underground 1 phase line (P1) for each cable type and size (P2)
    - km of cable in duct and km of direct buried
    - number of polemounted, padmounted, submersible distribution transformers (P1) for each kVA size (P2)
    - number and type of arresters (polymer, porcelain, gapped, ZnO), cutouts, CLFs
    - number and size of line capacitor banks
    - number of wood poles of various species and treatments (P2)
    - number of concrete poles (P2)
    - number of direct buried steel poles (P2)
    - underground vaults

3. **Age of major assets and age-distribution of minor assets**
    - voltage regulators (P1)
    - breakers/reclosers (distribution P1) (individually P2)
    - controlled switches (distribution P1) (individually P2)
    - manual switches (distribution P1) (individually P2)
    - overhead line (distribution P1) (individually P2)
    - underground line (distribution P1) (individually P2) by cable type (P2)
    - distribution transformers (distribution P1) (individually P2)
    - wood poles (distribution P1) (individually P2)
    - arresters, cutouts, capacitors
    - concrete poles (distribution P1) (individually P2)
    - direct buried steel poles (distribution P1) (individually P2)

- underground vaults

4. Reliability Statistics

- SAIFI, SAIDI, CAIDI for entire system (P2)
- SAIFI, SAIDI, CAIDI for local areas (P2)
- SAIFI, SAIDI, CAIDI for individual circuits (P2)
- SAIFI, SAIDI, CAIDI for individual cable sections, number of splices
- Number of failures, outages, and outage minutes per year by cause of failure (P2)
- Particular reliability issues with individual customers

5. Operation history of major assets and historic operation distribution of minor assets

(operation history is the peak and average loading for transformers, # operations per year for regulators, breakers/reclosers and switches)

- voltage regulators (P2)
- breakers/reclosers (distribution P2)
- controlled switches (distribution P2)
- manual switches (distribution P2)
- overhead line (distribution P1) (individually P2)
- underground line (distribution P1) (individually P2) by cable type (P2)
- distribution transformers (distribution P2)

6. Information on Known Issues

- Elimination of PCB from the system?
- Use of non-tree-retardant cable
- Padmount transformers with drywell canisters
- Porcelain gapped arrester population and failures
- Bolted as opposed to wedge ground connectors
- Loadbreak elbows with aluminum and copper connections and aluminum threaded eye
- Inline switches with polymer insulators prone to failure
- Cable terminations and splices

7. Maintenance Records

- voltage regulators
    i. list of maintenance performed and dates (P2)
- breakers/reclosers
    i. number maintained each year (P2)
- *controlled switches*
    i. number maintained each year (P2)
- wood pole inspections, testing, and replacement program
- line grounding inspections and maintenance
- inspection program description

i. type of inspection and frequency (P1)

8. Design Standards and Purchasing Specs

- Overhead and underground design standards and purchasing specs

9. Financial Information

- Any existing book value of assets (and depreciation method used)
- purchase price and date for major assets
- replacement cost for major assets or asset groups
- annual capital replacement budget
- itemized annual maintenance budget

13 APPENDIX B Photographs from Visual Inspections

Figure 12 illustrates an old pole with new insulators and hardware. The pole will reach the end of its life before the insulator and hardware do.

Figure 13 Old Pole with New Insulators

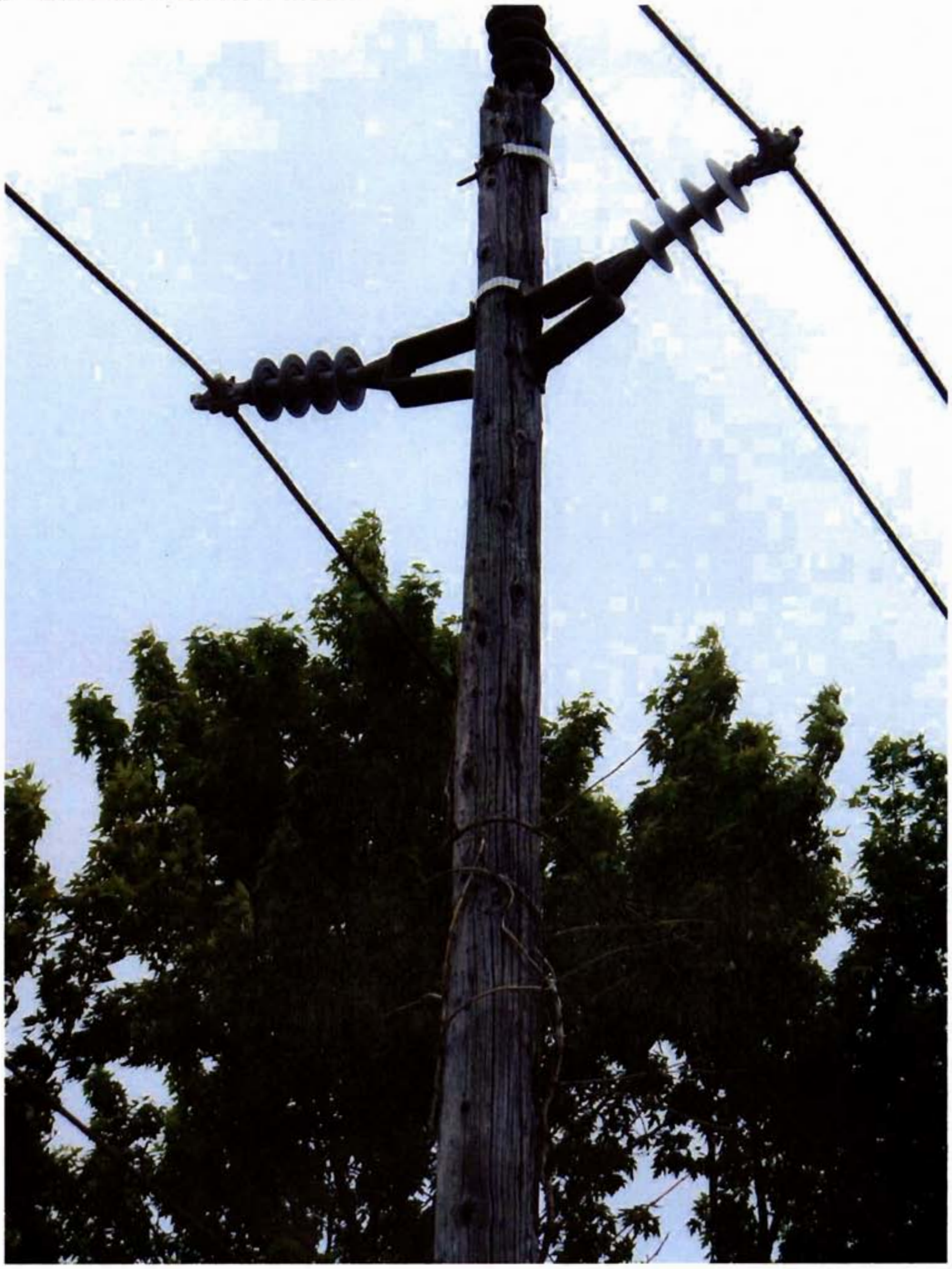


Figure 13 illustrates a problem with back lot lines. The poles in this picture are in good condition but they are inadequately guyed.

Figure 14 Leaning Poles on Back Lot Line

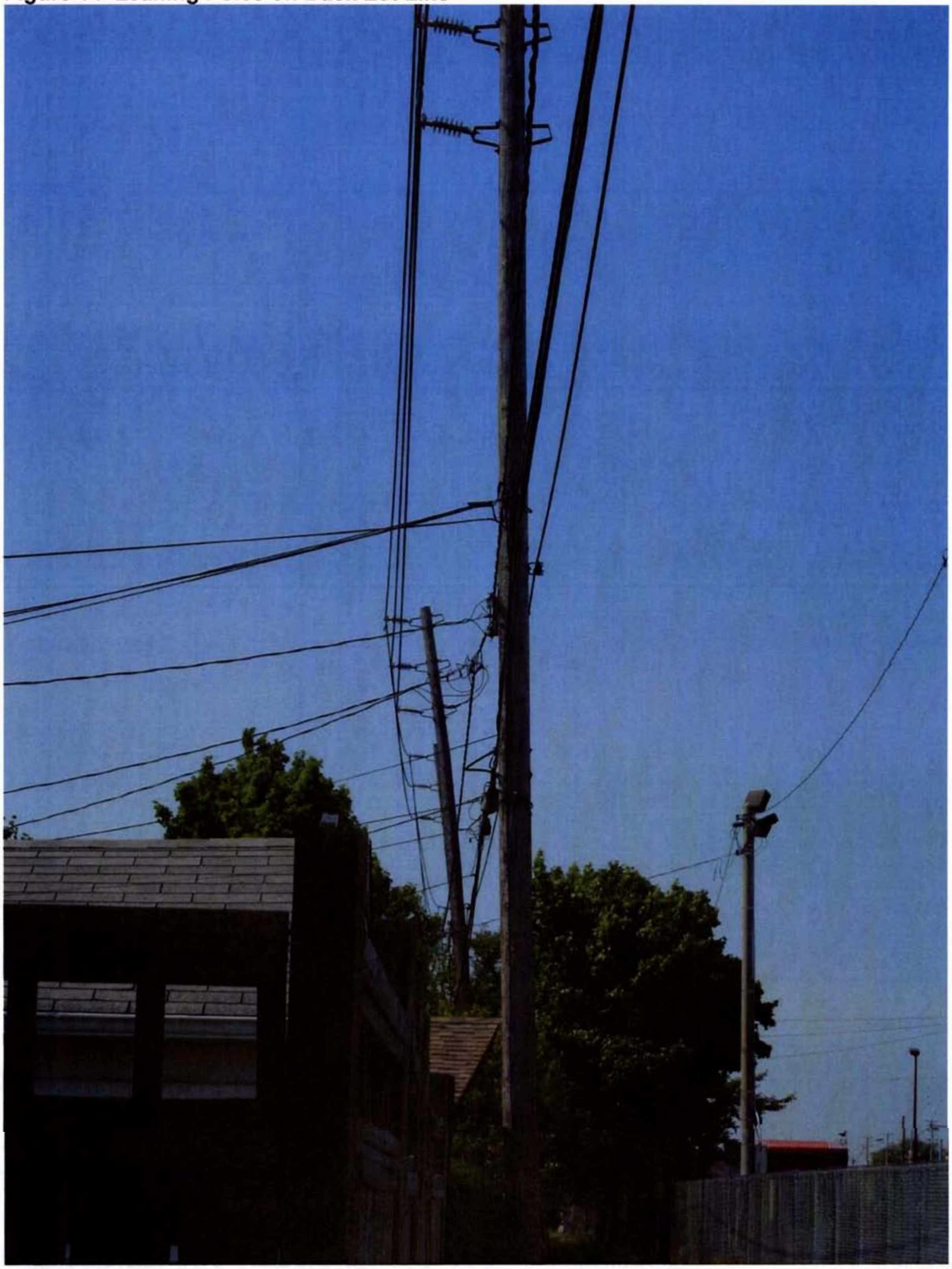


Figure 14 illustrates a concrete pole in poor condition. Water can corrode the exposed rebar and also freeze in the interior of the concrete, cracking the pole and weakening it.

Figure 15 Concrete Pole with Exposed Aggregate

Figure 15 illustrates a conductor that may be in poor condition, but the close splices and the separation of the strands (bird caging) do not necessarily indicate poor mechanical strength. A tensile test is the only reliable condition indicator.

Figure 16 Conductor in Poor Condition

Figure 16 is an example of a transformer in fair condition. It shows signs of deterioration, but the deterioration is not extensive and does not affect its function. Even this small degree of deterioration is rare on the ENWIN system. The transformers are generally in good or excellent condition.

Figure 17 Transformer with Minor Rust

An example inspection form from a field visit is shown below.

Asset Condition Survey
Overhead Distribution

Voltage	27.6	101
Location	Riverside + Green Park	102
sec map	Y-2	

1.0 Remotely Operated Pole Mounted Load Break Switch

brand new
not in service

ID No.		105
	Circle ONLY one	106
1.1 Insulator Condition	A B C D N U	107
1.2 Mechanical Support Condition	A B C D N U	108
1.3 Signs of Over Heating?	A B C D N U	109
1.4 Contact Condition	A B C D N U	110
1.5 Operating Mechanism Condition	A B C D N U	111
1.6 Motor Operator and Control Condition	A B C D N U	112
1.7 Overall Condtion	A B C D N U	113

2 Manually Operated Pole Mounted Load Break Switch

ID No.		117
1.1 Insulator Condition	A B C D N U	118
1.2 Mechanical Support Condition	A B C D N U	119
1.3 Signs of Over Heating?	A B C D N U	120
1.4 Contact Condition	A B C D N U	121
1.5 Operating Mechanism Condition	A B C D N U	122
1.6 Overall Condtion	A B C D N U	123

3 Wood Pole

Location		125
ID No.		126
Age		127
1.1 Holes and Cracks ?	A B C D N U	128
1.2 Rot ?	A B C D N U	129
1.3 Cross arm Condition	A B C D N U	130
1.4 Overall Pole Condtion	A B C D N U	131
1.5 Pole Top Hardware	A B C D N U	
1.6 Guy and Anchor	A B C D N U	
1.7 Conductor	A B C D N U	
1.8 Insulators	A B C D N U	

3 Pole Mounted Transformer

4 pics

Location		133
ID No.		134
1.1 Tank Integrity	A B C D N U	135
1.2 Oil Leak	A B C D N U	136
1.3 Bushing Condition	A B C D N U	137
1.4 Electrical Connections	A B C D N U	138
1.5 Signs of Overheating?	A B C D N U	139
1.6 Overall Transformer Condition	A B C D N U	140

	Name	Date	
Inspector Name and Date	Ray Piercy	2007/05/ 14	145

(write any comments or concerns on the back of this form)

8/1/2007 Survey Form-1/1 Overhead Distribution VI Form.xls

14 APPENDIX C Asset Condition Information from Staff Interviews

Enwin staff were interviewed to determine the staff perceptions the asset condition and to obtain information about recent equipment replacement programs operational problems. The interviews were conducted April 10, 2007.

Interview with Val Ward - Line Supervisor

Pole condition sampling is horrendous. Sonic test has been used in the past but results were unreliable. They now use boring but results are still not good. A pole graded "OK" in 2004 and when they go to it now it breaks off. The inspections are done by their station maintenance staff, who have been trained, but lack experience.

Their line maintenance is typically done by rebuilding a section of line rather than by maintaining individual components.

In the downtown core the condition of overhead lines is generally poor, especially in areas O1, P1, Q1. Also along Walker Road from the river to Tecumseh Road is old 1/0 conductor. It is scheduled for replacement.

There are some older pin type insulators still near the university. The 27.6 kV switches on the high side of the 4 kV substations are often in poor condition.

All switches are operated once per year as part of standard maintenance program. (actually this is condition monitoring, not maintenance)

There has not been an epidemic of cracked cutouts, only a few isolated incidents.

There has been a problem in the past with in-line switches dropping the conductor, but now they use Ampac switches and have not had a problem. They are starting to use fused in-line switches.

The lightning arrester are 99% polymer.. Over 1000 scout arresters have been replaced in the last twenty years.

Lots of distribution transformers have been replaced. Many in 1988 which was a hot summer and many overloaded. Also many have been replaced as part of the PCB removal program. Many are also new because of the 4 kV conversion program. They convert about 400 poles per year, with 50-60 transformers. This has been going on since 1992.

They have had problems with the secondary breakers on Completely Self Protected (CSP) distribution transformers. They don not use CSP anymore, but there are still many in service.

Pole are run to failure unless they are on a critical circuit. Most of the poles along major streets are concrete. On the back lot lines there are hundreds of rotten poles.

There is an operational concern about how to rebuild 27.6 kV lines. (Nimal thinks just build higher, like a 4 kV conversion.)

The main causes of outages are trees and squirrels. Lots of back lot lines leads to the tree problem.

There is no condition monitoring of in-line switches and no maintenance done. This area could be improved.

The capital replacement program used to be good, but little is done now.

Interview with Nimal Weeratunga

The system is thought to be in good shape right now but the ACA is planning for the future. Work is expected to be needed in five to ten years. The idea is to prioritize areas for replacement.

There has been a problem with some of the new reclosers added to the system in recent years, to improve reliability. They seem to develop vacuum leaks.

The typical conductor life span is 50 years.

The lightning arrester replacement program has been completed.

The in-line switches are thought to be in poor condition.

Wood poles are in poor condition, with a fair amount needing replacement. Concrete poles are in good condition.

The underground cable spreadsheet has new cable included, but does not include single phase laterals.

Many underground vaults/manholes are in very poor condition. PILC and XLPE cables are in good condition.

Pad mounted transformers and pole mounted transformers are in good condition.

Should Enwin use a work order tracking system? They now track for substations, breakers, reclosers, load break switches. Is this the best level to get most of the benefit for the smallest cost (80/20 rule)?

There are no capacitors on 27.6 kV lines. They are all in the stations or on 4 kV lines.

The general strategy has been to use capital replacements rather than do a large amount of maintenance. Equipment is replaced in response to failure, not based on condition.

Infra red scans are contracted out and performed once per year.

The main causes of outrages are trees.

All maintenance is recorded digitally in the Maximo System. A system for tracking work orders is targeted for December 2007.

Interview with Tom Kosnik

The driver for the asset condition assessment is that the management board wants no surprises on budgets. A smooth year to year change is desired. The board also wants to avoid catastrophic failures.

The 27.6 kV system was started in 1970 so the maximum age should be 38 years.

There has been a 10 year replacement program for the old porcelain pin type insulators, replacing with polymer post style. There are still some old wood pin insulators on lines feeding old substations. (COMMENT , may not be worth replacing if 4 kV gone in a few years time)

The old Dominion isolation switches have largely been replaced in recent years.

Only 5% of underground cable now is direct buried. There is a targeted replacement program to replace it with cable in duct ($5M).

There was a large replacement program for distribution transformers in 1988-1990, based on overloading and in the early 2000's based on PCB removal.

There are no known problems with pad mounted transformers. All pad mounted transformers have under oil lightning arresters.

There have been high outage rates due to animal and tree contact in the past. They now use animal guards, covered conductor and a better inspection of tree trimming after the contractor is finished. This is part of a reliability centered program.

There has been an on-going replacement program for lightning arresters since the early 1990's replacing with polymer MOV arresters.

There is some concern about the condition of man holes.

The maintenance program is considered adequate, with no known problems. It uses time based maintenance.

Reclosers have been installed to improve reliability.

Targeted replacement programs have been successful in reducing overtime and maintenance staff level.

Interview with Doug Collins and Jim St Louis –Underground Department

Circuit 25M10 has experienced a large number of failures.

There have been problems with cable splices.

There are no problems with elbows, since 35 kV elbows are used and no load switching is done.

Ducts are all 5" PVC, with a very small amount of old fibre duct.

Vault maintenance is considered OK. Every vault is visited at least once a year.

Old 27.6 kV cable is XLPE, the only PILC is 4 kV. Old direct buried cable is a problem.

Switching units are only in fair condition. Corona can be heard and they have moisture build up. They need maintenance in a bad way. The old Vac-Pac switches have low gas levels.

The sides of the vaults are falling in on some submersible transformer vaults in the Little River Fountain Blue area.

The work order system is more than 20 years old.

Interview with Shawn Filice

The drives behind the ACA assessment are to increase the confidence of the board that the system is in good shape, not falling down. The results will be presented to the OEB.

There are some old 4/0 copper conductors but there have not been any problems. 556 is now standard.

There has been an insulator replacement program for 10 years, starting with the three phase lines. There are still some old insulators around college Ave and Cataraqui and Niagara. Insulators near the expressway are washed spring and fall.

There has been an arrester replacement program, replacing with Ohio Brass.

About 100 in-line switches are worthy of replacement.

Wood poles are in poor condition in areas converted from 4 kV where poles were not replaced.

A summer student was hired to inspect guys, especially bolted connections.

Non-tree retardant XLPE cable has been replaced in 1990's.

Some manholes are on poor shape, with chunks of concrete falling down.

Load break switches are not maintained, just operated every year.

Maintenance is time based, trees trimmed every three years, poles inspected every three years.

There is no specific database for condition information.

DISTRIBUTION

Mr. Shawn Filice	Enwin Utilities (5 copies)
S. Cress	Kinectrics Inc., KL206
R. Piercy	Kinectrics Inc., KL206

Attachment C

CABLE TECHNOLOGY LABORATORIES, INC.

REPORT

FAILURE ANALYSIS

OF A 28 KV XLPE INSULATED CABLE FROM FEEDER 15M11

INVESTIGATION PERFORMED FOR

ENWIN POWERLINES

Windsor, ON

Canada

Report No. 06-111	Main Investigators(s) V. Yaroslavskiy
Composed of 23 (twenty three) pages	
Order No. EWPWR 0000003340 dated 07/20/2006	Approved by: C. Katz
New Brunswick, September 18 of 2006	

625 Jersey Avenue – P.O. Box 707
New Brunswick, N.J. 08903

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Fax: (732) 846-5531

CABLE TECHNOLOGY LABORATORIES, INC.

REPORT

FAILURE ANALYSIS

OF A 28 KV XLPE INSULATED CABLE FROM FEEDER 15M11

CONTENTS

Item	Subject	Page
1.0	PURPOSE	1
2.0	BACKGROUND	1
3.0	SAMPLE DESCRIPTION	2
4.0	TESTS PERFORMED	3
5.0	TEST RESULTS	4
	5.1. Visual Examination	4
	5.2. Stripping Tension Test and Microscopic Examination of the Insulation – Insulation Shield Interface	4
	5.3. Examination for Gross Imperfections	5
	5.4. Evaluation of Nature of Extruded Layers	5
	5.5. Hot Creep/Set Test	6
	5.6. Volume Resistivity of Semiconducting Shields	6
	5.7. Dimensional Analysis	6
	5.8. Microscopic Examination	7
	5.9. Examination for the Presence of Water Trees	8
6.0	DISCUSSION	8
7.0	CONCLUSIONS	10
	Tables 1 through 5	11-12
	Figures 1 through 11	13-23

625 Jersey Avenue – P.O. Box 707
New Brunswick, N.J. 08903

Tel: (732) 846 -3133
Fax: (732) 846-5531

FAILURE ANALYSIS

OF A 28 KV XLPE INSULATED CABLE FROM FEEDER 15M11

1.0 PURPOSE

To report on the results of failure analysis performed on a section of 28 kV XLPE (Cross-Linked Polyethylene) insulated cable that failed in service in Enwin Powerlines feeder 15M11.

2.0 BACKGROUND

Subject cable is directly buried and operates in the Enwin's 28-kV distribution system. After it had failed in service (early in July 2006), a short section, containing the failure, was removed from the system during cable repair and submitted to Cable Technology Laboratories (CTL) for detailed analysis and possible assessment of the cable condition. Another failure took place recently on the same cable, at a different location.

3.0 SAMPLE DESCRIPTION

The cable submitted for analysis comprised two short sections, approximately 6 and 19 inches long (Figure 1). The shorter section contained the failure hole (Figure 2), at approximately 1¼ inches from one of the section ends. The relative position of the two sections in the feeder is not known. It is assumed that they were adjacent to each other. Neutral wires were not present.

It was learned during evaluations that the cable had a No. 1/0 AWG compact Al conductor, extruded conductor shield, 280 mils of XLPE insulation, and a thermoplastic extruded insulation shield. As indicated, the neutral wires had been removed from the sample prior to its arrival to CTL. A heavy deposit of dirt on the surface of the insulation shield (Figure 1) indicated the cable was unjacketed and directly buried.

The insulation shield imprint (if present on the short sections available) could not be read, so that the cable vintage and manufacturer were not established. Based on the design peculiarities, this cable apparently had been manufactured during the late 60's - mid 70's.

4.0 TESTS PERFORMED

The following evaluations were performed:

- Visual examination of cable components
- Visual examination of the failure
- Evaluation of the bonding strength between the insulation and insulation shield
- Examination for gross imperfections in the insulation system of the failed section
- Evaluation of the nature of the extruded layers: plain PE or XLPE insulation; thermosetting or thermoplastic insulation shield
- Hot creep/set test to establish if the insulation was sufficiently cross-linked
- Measurement of the volume resistivity of the semiconducting shields, at ambient and elevated temperatures
- Dimensional analysis
- Microscopic examination of the insulation system for voids, contaminants, protrusions, and other abnormalities
- Water tree count tests

5.0 TEST RESULTS

5.1 Visual Examination

The failure created a small hole and ruptured the insulation shield over approximately 1.5 inches. Upon removal of the insulation shield, a round hole (approximately ¼ inch diameter) in the insulation became visible. It was surrounded by darkened insulation, which extended approximately 2 inches longitudinally and 240° circumferentially. The darkening had been created by hot gases developed during the failure. The same gases separated the insulation shield from the insulation in this area.

When stripping the insulation shield, it was noted that the required stripping tension apparently varied along and around the cable. In addition, at some locations the shield adhered to the surface of the insulation so strongly that it could not be removed, leaving small pieces on the insulation surface (Figure 3).

5.2 Stripping Tension Test and Microscopic Examination of the Insulation – Insulation Shield Interface

Considering the above, stripping tension tests were performed on the longer section of cable; in contrast to two pulls required by the industry specifications, four pulls were performed. The results shown in Table No. 1 indicate that the adhesion was more or less uniform along the cable length, noticeably varying circumferentially. It was, however, well within the required limits in all areas tested.

Similar sticking "in-spots" of the insulation shield to the insulation was noted (Figure 4). When observed under a microscope, the outer surface of the insulation exhibited significant roughness (Figure 5). It was covered with micro-cavities, whose diameters ranged from a fraction of a mil to 7 mils.

5.3 Examination for Gross Imperfections

The short cable section, with the exposed insulation, was placed in hot oil, to make the insulation translucent. The bulk of the insulation as well as the interface between the conductor shield and insulation were examined for the presence of irregularities that could be seen with the naked eyes. None were found.

5.4 Evaluation of Nature of Extruded Layers

The nature of the extruded layers was established by placing the materials in an oven and observing their deformation. It was learned that the insulation shield was thermoplastic, while the insulation was cross-linked.

5.5 Hot Creep/Set Test

To establish if the insulation was sufficiently cross-linked, a hot creep/set test was performed on two samples of the insulation, removed from the inner part of the insulation wall of the longer cable section. The results shown in Table No. 2 indicate that the insulation was sufficiently crosslinked.

5.6 Volume Resistivity of Semiconducting Shields

Volume resistivity of the conductor and insulation shields was measured at room temperature and at elevated temperatures: 90 and 110 ^{o}C for the insulation shield, 90 and 130 ^{o}C for the conductor shield. The results are summarized in Table No. 3. The performance of both semiconducting shields was found well within the industry specification requirements for new cables.

5.7 Dimensional Analysis

Thickness of the extruded layers of the insulation system was measured on a cross-section of the cable. The results are shown in

Table No. 4. The dimensional characteristics of the insulation system were found within the specified limits.

5.8 Microscopic Examination

To perform microscopic examination of the insulation system for the presence of imperfections, 20 cross-sectional wafers, each approximately 25 mils thick, were cut from the long cable section. The first observation was of a halo in the insulation (Figure 6). The halo indicated that the cable insulation was saturated with moisture. Upon removing the sample from the wet installation environment, this moisture started vaporizing, creating transparent circles at the outside (well defined in Figure 6) and inside (to a lesser degree) of the insulation wall.

During microscopic examination no imperfections, whose dimensions exceeded the specification allowances, were found. At the same time, numerous small voids, with diameters between 1 and 2 mils, were located in the bulk of the insulation. An example of a void is shown in Figure 7.

5.9 Examination for the Presence of Water Trees

To evaluate if these voids were conducive to the deterioration of the insulation, selected wafers with voids were died in a methylene blue solution and examined under the microscope for the presence of water trees. No trees initiated by voids were noted.

In contrast, when an additional set of 20 wafers was died and examined, numerous large water trees, vented at the insulation – insulation shield interface, were found. Figures 8 and 9 give examples of such trees. A few bow-tie water trees were also found in the bulk of the insulation. These trees were not so dense and grew up to smaller sizes as compared to the vented trees (Figure 10). However, one case was found, where two bow-tie trees lined up and created a chain that bridged approximately half of the insulation wall thickness (Figure 11). The results of the water tree count test are shown in Table No. 5.

6.0 DISCUSSION

Subject cable operated in a wet environment, and its insulation was saturated with moisture (Figure 6). In combination with the rough outer surface of the insulation (Figure 5), it was conducive to the development of numerous relatively large water trees, vented at the insulation shield (Figures 7 and 8). In addition, bow-tie trees had developed in the bulk of the insulation (Figure 10). None of the water trees, found in the cable section examined, are expected to cause an immediate failure of the insulation. However, the tree density was relatively high (Table 5). Therefore, a more severe situation could be present in the cable at other locations, especially if several water trees lined up, creating a long chain of deteriorated areas (Figure 11).

Numerous small voids were found in the insulation (Figure 7). Due to their small size they were not conducive to the insulation deterioration. Nonetheless, if larger voids are present at different locations, they may participate in same.

The above-described condition of the insulation together with the fact that this cable has experienced two failures at different locations, in a short time, indicates that the cable apparently is approaching the end of its useful service life. According to CTL's experience it is not worth to rejuvenate unjacketed cables. Therefore, it appears advisable to schedule the replacement of this cable.

7.0 CONCLUSIONS

1. No manufacturing defects, which could be conducive to the cable failure, were found.
2. The insulation of subject cable is significantly deteriorated with water trees, which are especially dense and large at the interface between the insulation and insulation shield.
3. It appears reasonable to schedule the replacement of this cable.

Table No. 1

STRIPPING TENSION

Pull No.	Pulling Tension – lbf Minimum	Pulling Tension – lbf Maximum
1	15	17
2	9	9.5
3	14.5	15
4	10	10.5
AEIC Limits for new cable	≤ 3	≤ 24

Table No. 2

INSULATION HOT CREEP/SET TEST

Sample No.	Hot Creep Elongation - %	Hot Creep Set - %
1	69	-3
2	75	0
AEIC Limits	≤175	<10

Table No. 3

VOLUME RESISTIVITY OF SEMICONDUCTING SHIELDS

Insulation Shield		Conductor Shield	
Temp. °C	Volume Resistivity Ohm-m	Temp. °C	Volume Resistivity Ohm-m
110	20.8	130	0.5
90	0.6	90	1.1
25	0.2	25	0.3
AEIC Limits for new cable	≤500	-	≤1000

Table No. 4

DIMENSIONAL CHARACTERISTICS

Thickness - mils	Min.	Max.	Avg.
Conductor Shield	22	38	28
AEIC Limits	≥12	--	≥15
Insulation	270	293	280
AEIC Limits	≥252	-	≥280
Insulation Shield	37	43	40
AEIC Limits	≥24	≤50	≥30

Table No. 5

RESULTS OF TREE COUNT TEST

		<20 mils	20-40 mils	40-50 mils
Bow-tie trees	Number	0	3	2
	Volume examined, in^3	0.29	0.29	0.29
	Tree density, N/in^3	0	10	7
		20-30 mils	30-40 mils	40-70 mils
Vented trees at conductor shield surface	Number	0	0	0
	Surface examined, in^2	0.6	0.6	0.6
	Tree density, N/in^2	0	0	0
Vented trees at insulation shield surface	Number	32	17	9
	Surface examined, in^2	1.5	1.5	1.5
	Tree density, N/in^2	21	11	6

Figure 1: Sample as received.

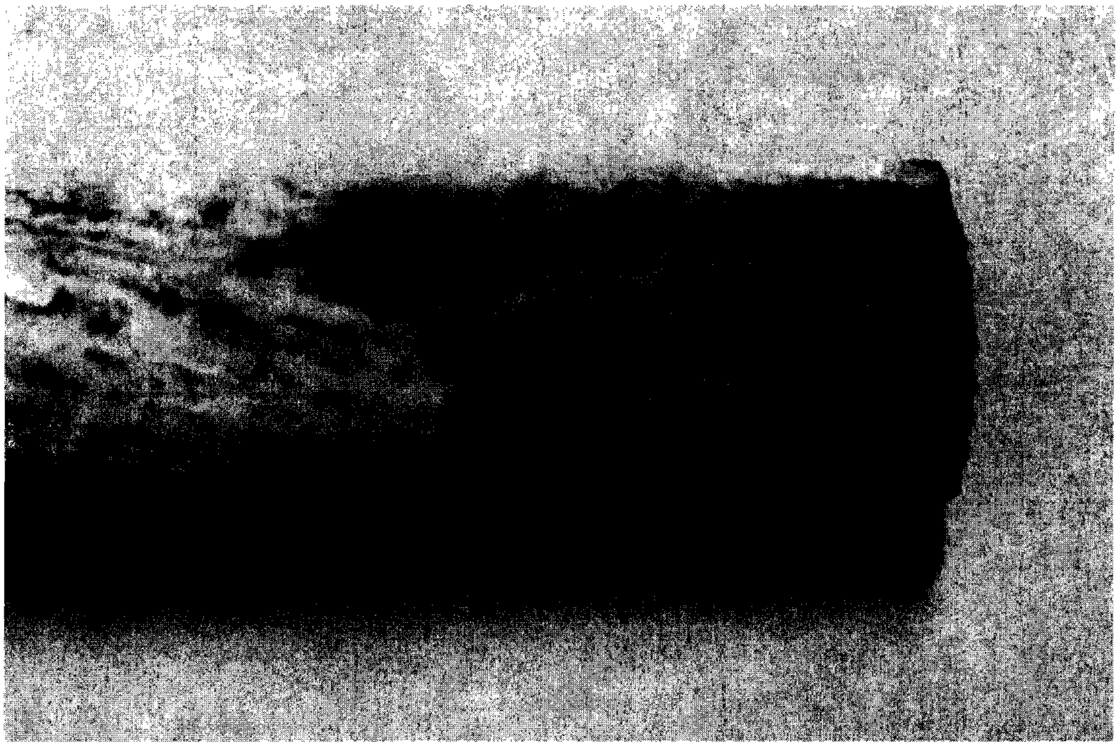


Figure 2: Close-up of the failure.

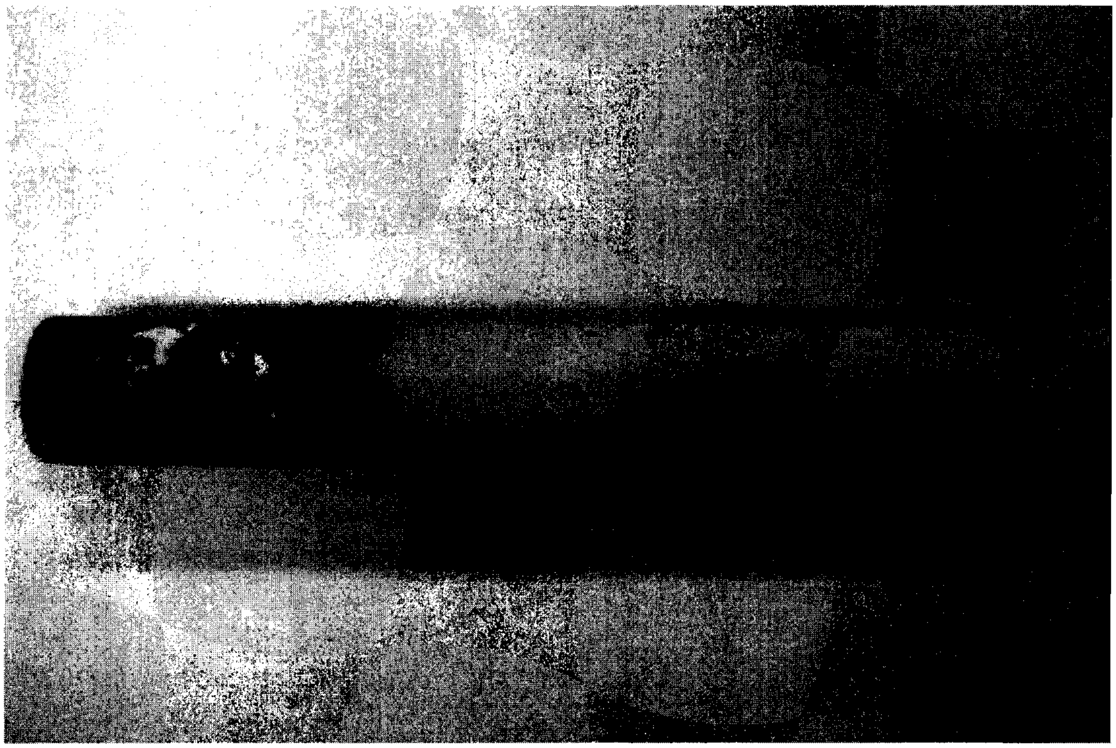


Figure 3: Failed cable section with removed insulation shield.

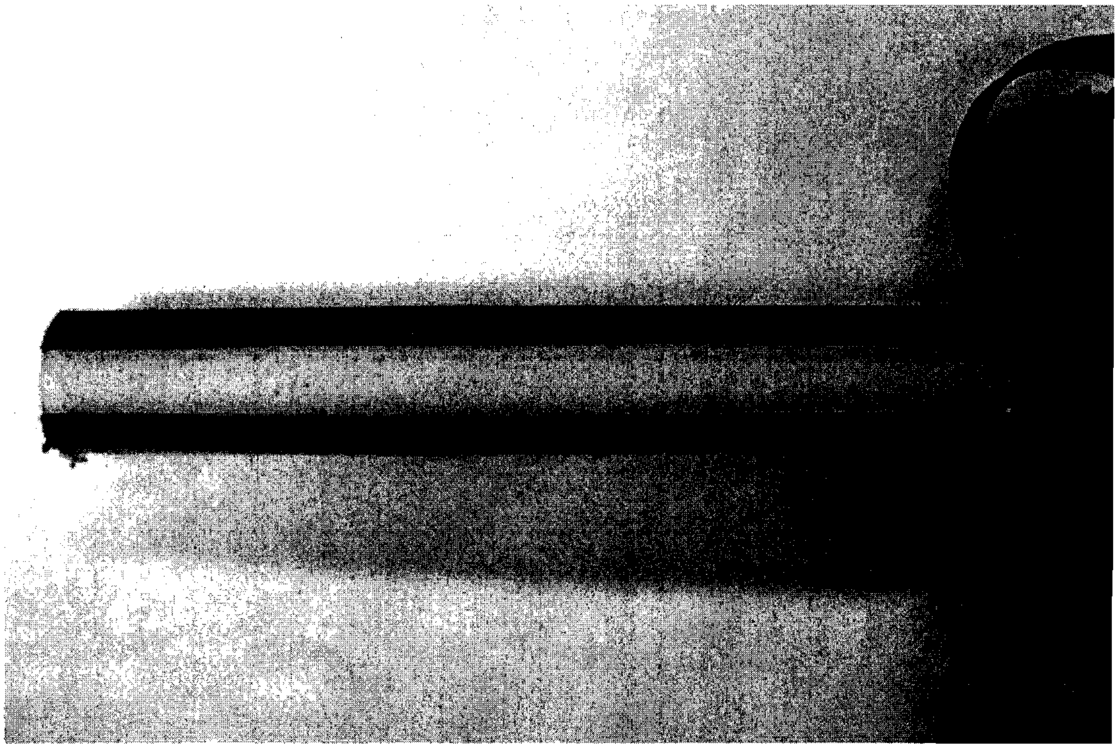


Figure 4: Small pieces of the semiconducting material remain sticking to the insulation surface after stripping the insulation shield.

Figure 5: Microphotograph of the insulation surface.

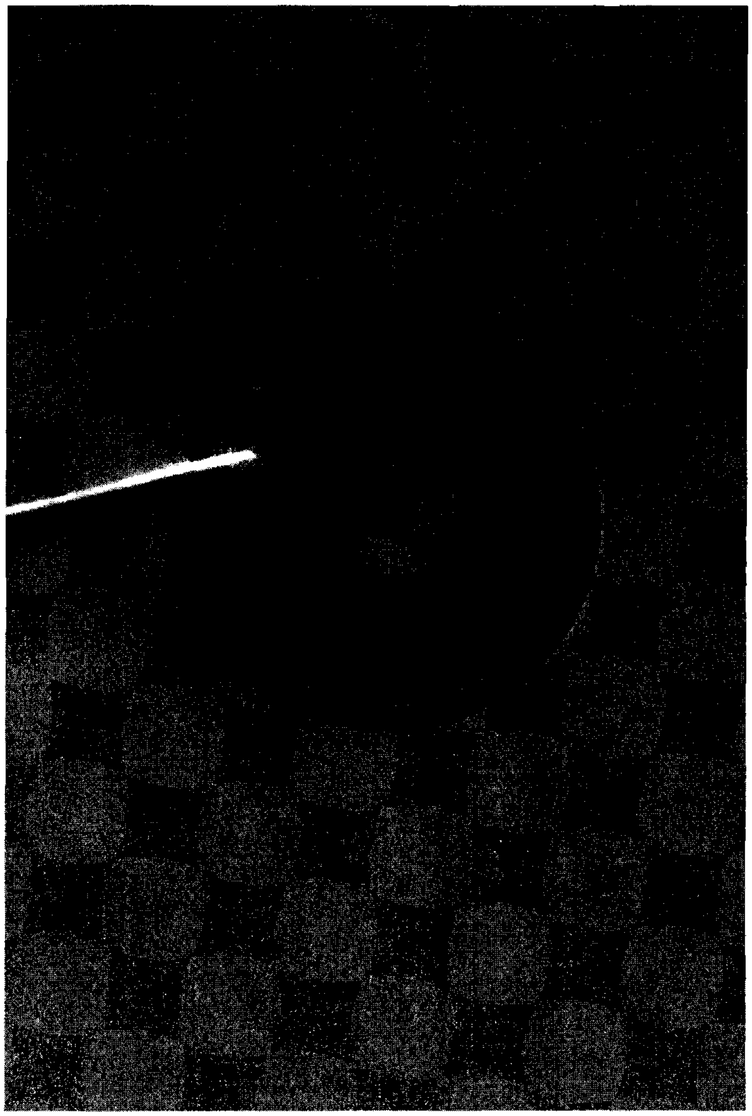


Figure 6: Moisture halo in the cable insulation.

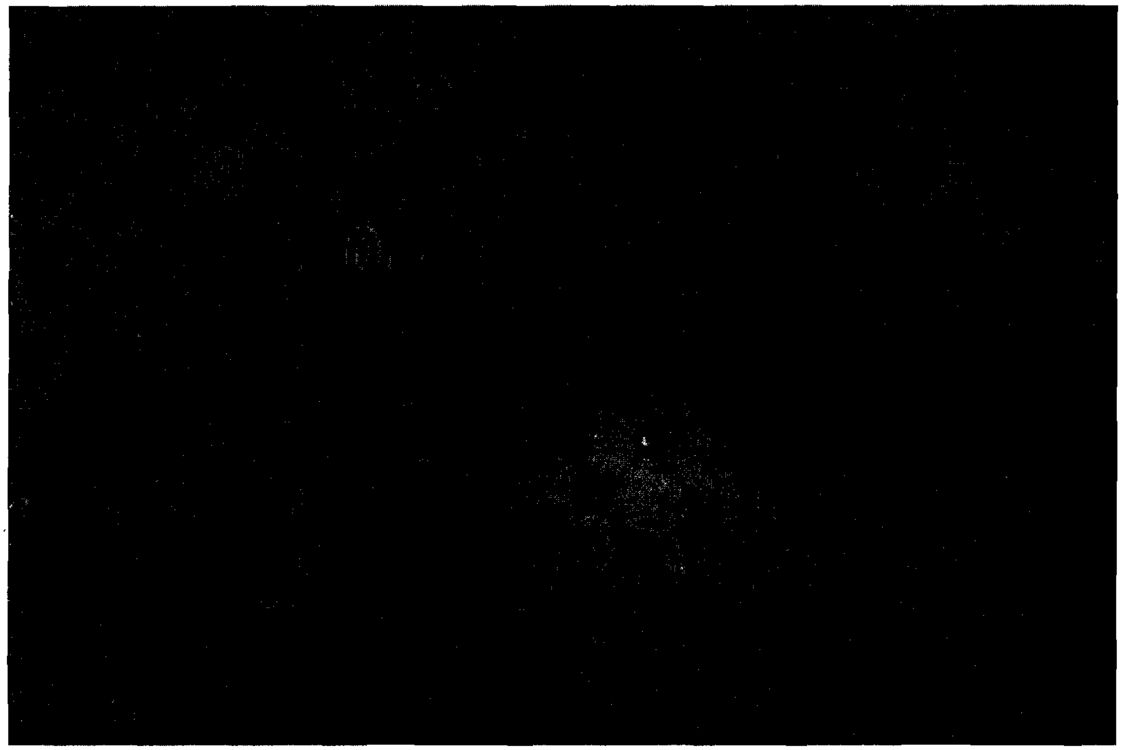


Figure 7: Void in the bulk of the insulation.

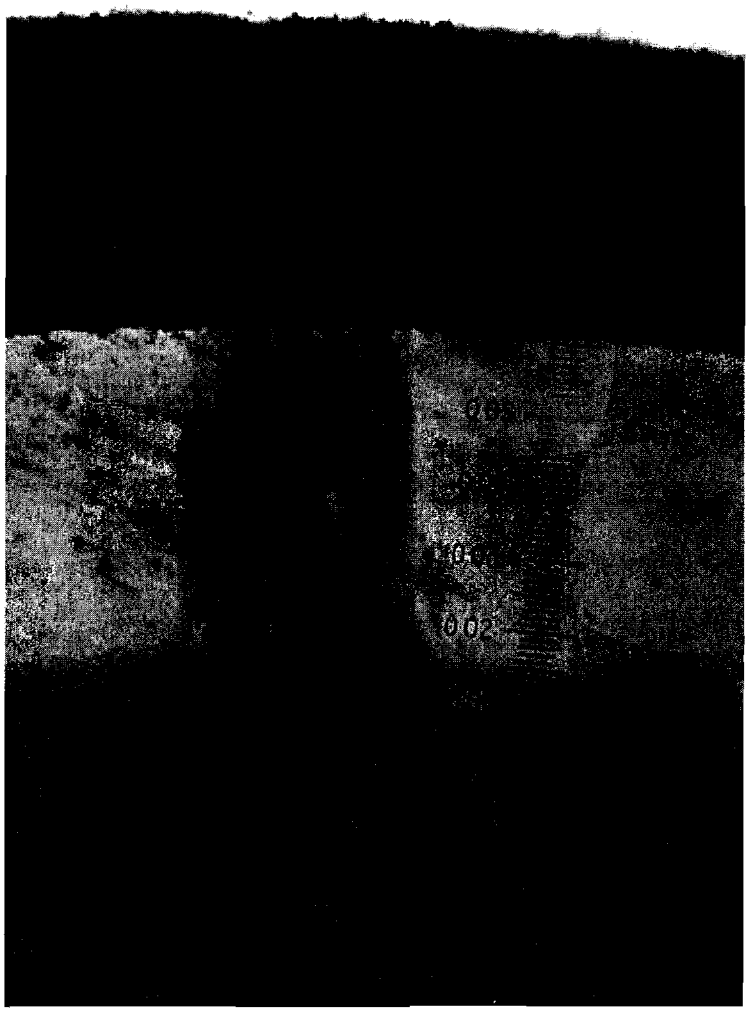


Figure 8: One of the largest water tree (approximately 60 mils long), vented from the insulation shield.

Figure 9: Numerous water trees growing from the rough interface between the insulation and insulation shield.

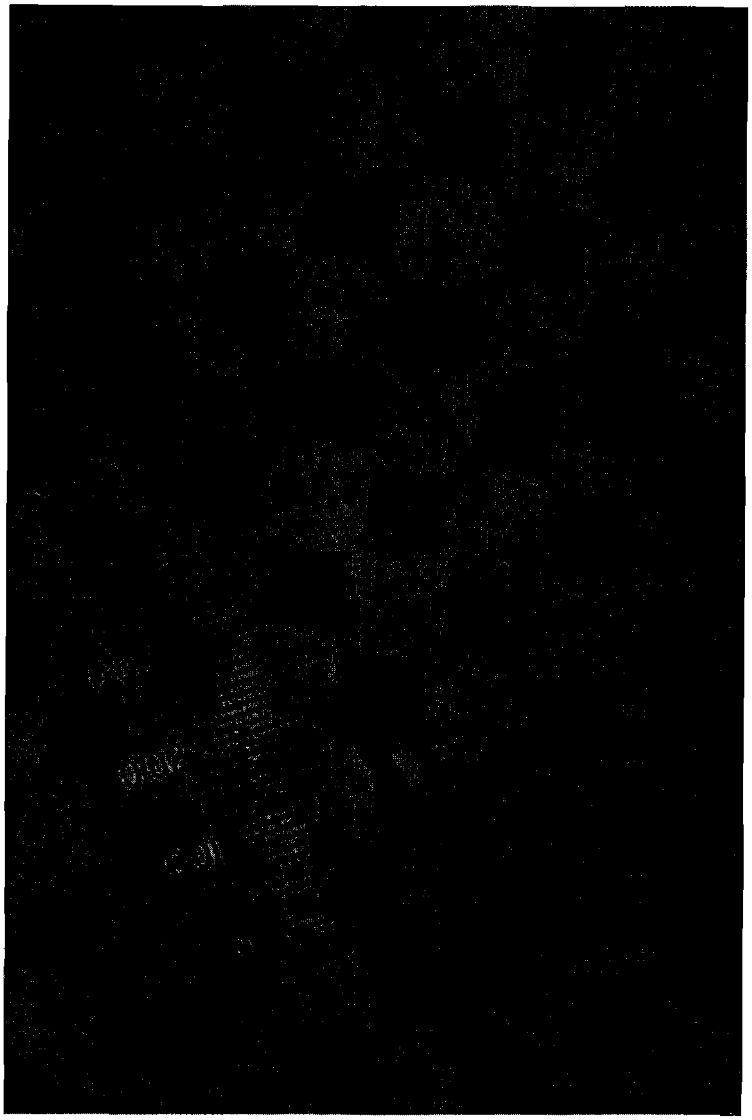


Figure 10: Typical bow-tie tree.

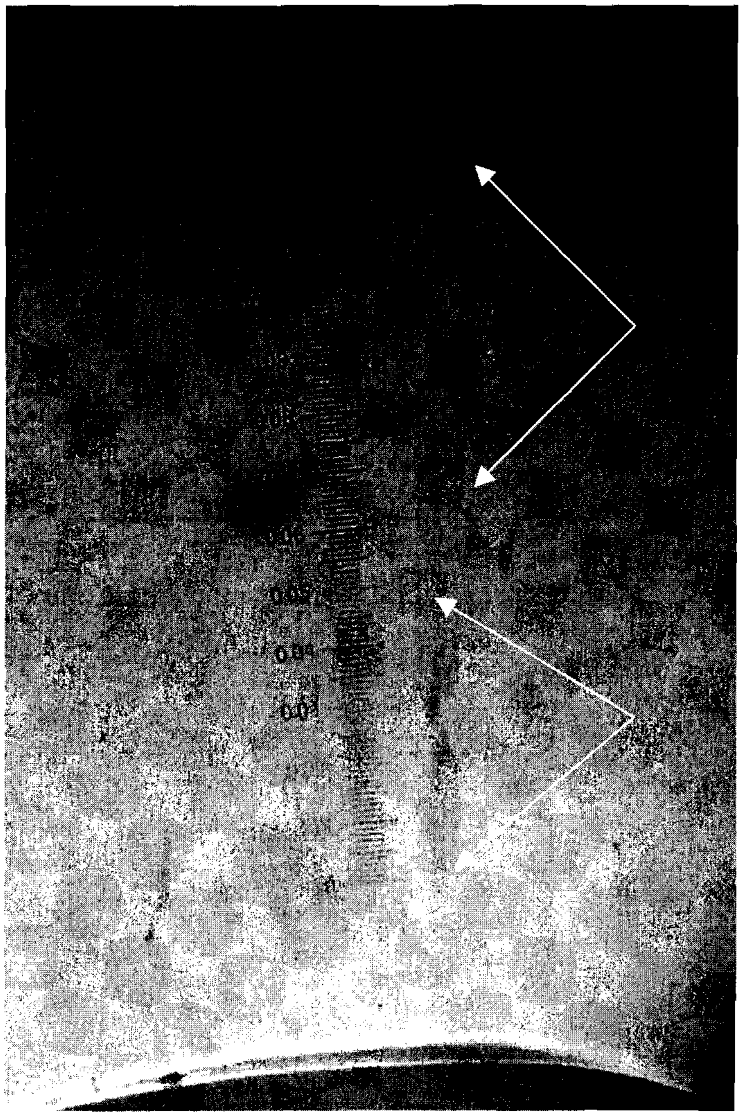


Figure 11: Bow-tie trees lined up in a chain in the insulation bulk.

Attachment D

P. B. S. ENGINEERING INC.

3200 ELECTRICITY DR., WINDSOR, ONTARIO N8W 5J1

PHONE (519) 945-1000 — — FAX (519) 974-7438

December 14, 2004

Enwin Powerlines,
4545 Rhodes Drive,
P.O. Box 1625,
Station "A",
Windsor, Ontario
N9A 5T7

Attention: Robert Spagnuolo, Distribution Engineer

Re: Erie Street Cable Chamber Structural Analysis - 2005

Attached is our report for the Erie Street Manhole Inspection - 2005.

If you have any questions, please do not hesitate to phone me.

Sincerely,

P. B. S. Engineering Inc.

Yves Poirier

Per: Yves Poirier, P.Eng.

Manhole Inspection Summary Sheets

Manhole No. 1 October 28, 2005

Summary / Repairs:

1 Brick walls in good condition with only a few minor hairline cracks that do not require repairs at this time. Concrete floor and roof in good condition.

2 Cable support brackets have moderate to severe corrosion and should be replaced within two years (27 brackets).

Estimated Cost of Repair (Item No. 2 Only)	$ 7,000.00
Estimated Cost of Engineering	$ 2,000.00
Total Cost of Work	**$ 9,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 2 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition.

2 The bottom of some cable support brackets have moderate corrosion but are acceptable.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 3 October 28, 2005

Summary / Repairs:

1 Brick walls in poor condition with significant areas of deterioration particularly at the top of the walls. There is evidence of previous concrete repairs on the west, and east walls. The floor of the manhole is in good condition.
The roof of the manhole is in very poor condition and needs immediate repair.
The walls can be repaired by pouring a concrete wall in front of the existing walls. The roof slab should be removed and replaced with a new concrete slab.

2 Cable support brackets have moderate to severe corrosion and should be replaced.

Estimated Cost of Repair (Item 1 and 2)	$ 18,000.00
Estimated Cost of Engineering	$ 4,000.00
Total Cost of Work	**$ 22,000.00** + GST

Recommended Date for Next Inspection: 10 years after reconstruction (2016)

Manhole Inspection Summary Sheets

Manhole No. 9 October 28, 2005

Summary / Repairs:

1 Brick walls in fair condition with some minor cracks that do not require repairs at this time. Concrete roof and floor in good condition.
2 Cable support brackets are in good condition.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 10 October 28, 2005

Summary / Repairs:

1 Concrete walls, roof and floor in good condition with only a few minor hairline cracks that do not require repairs at this time.
2 Cable support brackets have light corrosion and are acceptable.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 12 October 28, 2005

Summary / Repairs:

1 Brick walls in fair condition with some minor cracks that should be repaired when the roof slab is replaced. **The roof slab is in very poor condition and is presently shored with wooden posts to support it. The roof slab should be replaced immediately.**
2 The cable support bracket on the north wall has severe corrosion and should be replaced when the other repairs are done.

Estimated Cost of Repairs (Items 1 & 2)	$ 8,000.00
Estimated Cost of Engineering	$ 3,000.00
Total Cost of Work	**$ 11,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 13 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks in the roof slab at the chimney opening that do not require repairs at this time.
2 Cable support brackets are in good condition.

Recommended Date for Next Inspection: 5 years (2010)

Manhole Inspection Summary Sheets

Manhole No. 14 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition.
2 The galvanized cable support brackets have light to moderate corrosion but are acceptable. The plastic cable support brackets are in good condition.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 15 October 28, 2005

Summary / Repairs:

1 Brick walls in fair condition. In general, the top two to three courses of brick have moderate to severe deterioration. The tops of all walls are capped with approximately 9" of concrete. The top of the south wall has been pushed inward. There is also inward displacement of the east wall at the south end. The cracks in the walls should be repaired along with replacement of the deteriorated brick. at the top of the walls. The roof slab of the manhole shall be removed and replaced with a new concrete slab including application of traffic membrane.
2 Cable support brackets light corrosion and should be scraped and painted with Galvafroid paint. The steel lintels shall also be scraped and painted.

Estimated Cost of Repairs (Item 1& 2)	$ 12,000.00
Estimated Cost of Engineering	$ 3,000.00
Total Cost of Work	**$ 15,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 16 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks and a small area of exposed rebar, that do not require repairs at this time.
2 Cable support brackets are in good condition.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 17 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks that do not require repairs at this time. This manhole appeared to have been recently reconstructed.
2 Cable support brackets are in good condition with only one bracket having light corrosion.

Manhole Inspection Summary Sheets

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 18 October 28, 2005

Summary / Repairs:

1 Brick walls are in fair to poor condition with numerous cracks and areas of deterioration (loose mortar, spalled brick, cracks) that need to be repaired. The top 10" of each wall is concrete that is in good condition and appears to have been placed at the same time that the roof slab was replaced. The concrete floor and roof slabs are in good condition. The steel angle lintels above the ductbanks shall be scraped and painted with Galvafroid paint.

2 Cable support brackets are in good condition.

Estimated Cost of Repair (Item No. 1 Only) $ 5,000.00

Estimated Cost of Engineering $ 2,000.00

Total Cost of Work **$ 7,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 32 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks that do not require repairs at this time. Some brick around the chimney are loose and falling out and should be removed and replaced. This manhole appeared to have been recently reconstructed.

2 Cable support brackets were in good condition.

Estimated Cost of Repair (Item No. 1 Only) $ 1,000.00

Estimated Cost of Engineering $ 750.00

Total Cost of Work **$ 1,750.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 33 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks that do not require repairs at this time. As a preventative measure, we recommend repairing the minor amounts of exposed rebar and one spalled area on the roof and at the same time, repair the hairline cracks in the walls. Some brick around the chimney are loose and should be removed and replaced.

2 Two cable support brackets on the south wall have moderate corrosion and should be replaced when the concrete repairs are carried out.

Estimated Cost of Repair (Items 1 & 2) $ 2,000.00

Estimated Cost of Engineering $ 1,000.00

Manhole Inspection Summary Sheets

Total Cost of Work	**$ 3,000.00** + GST
Recommended Date for Next Inspection:	5 years (2010)

Manhole No. 34 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks that do not require repairs at this time. Some brick around the chimney are loose and should be removed and replaced.

2 Two cable support brackets on the north wall have severe corrosion on the bottom and should be replaced within two years.

Estimated Cost of Repair (Items 1 & 2)	$ 1,500.00
Estimated Cost of Engineering	$ 750.00
Total Cost of Work	**$ 2,250.00** + GST
Recommended Date for Next Inspection:	5 years (2010)

Manhole No. 225 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with a few hairline cracks on the east and west walls that do not require repairs at this time.

2 Cable support brackets are all in good condition.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 226 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks that do not require repairs at this time.

2 Cable support brackets have moderate to severe corrosion and should be replaced within two years (7 brackets).

Estimated Cost of Repair (Item No. 2 Only)	$ 1,500.00
Estimated Cost of Engineering	$ 750.00
Total Cost of Work	**$ 2,250.00** + GST
Recommended Date for Next Inspection:	5 years (2010)

Manhole No. 227 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with a few minor hairline cracks that do

not require repairs at this time.
2 Cable support brackets are in good condition.

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 228 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition except the west wall which has numerous cracks that should be repaired along with a few minor cracks on the north wall. The chimney has loose brick that should be removed and replaced.
2 Two cable support brackets on the south wall should be scraped and painted with Galvafroid paint.

Estimated Cost of Repair (Items 1 & 2)	$ 2,500.00
Estimated Cost of Engineering	$ 1,000.00
Total Cost of Work	**$ 3,500.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 229 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with a few minor cracks in the walls and localized areas of exposed rebar in the roof. These minor defects should be repaired now as a preventative measure.
2 Two cable support brackets have light corrosion and should be scraped and painted when the repairs in item #1 are carried out.

Estimated Cost of Repairs (Items 1 & 2)	$ 2,000.00
Estimated Cost of Engineering	$ 800.00
Total Cost of Work	**$ 2,800.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 230 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks that do not require repairs at this time.
2 Cable support brackets have light corrosion and are acceptable.

Recommended Date for Next Inspection: 5 years (2010)

Manhole Inspection Summary Sheets

Manhole No. 231 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with some minor cracks. The roof slab has a few localized areas of exposed rebar that should be repaired as a preventative measure. The wall cracks should also be repaired when the roof repairs are carried out.
2 Cable support brackets are in good condition.

Estimated Cost of Repair (Item No. 1 Only)	$ 2,000.00
Estimated Cost of Engineering	$ 800.00
Total Cost of Work	**$ 2,800.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 232 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition with some minor cracks. The roof slab has a few localized areas of exposed rebar that should be repaired as a preventative measure. The wall cracks should also be repaired when the roof repairs are carried out.
2 Cable support brackets have light to severe corrosion. Three should be replaced within two years.

Estimated Cost of Repairs (Items 1 & 2)	$ 3,000.00
Estimated Cost of Engineering	$ 1,200.00
Total Cost of Work	**$ 4,200.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 233 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition except for a few minor hairline cracks on the east and west walls and one 1/2" wide crack on the west wall. The 1/2" wide crack must be structurally repaired and at the same time, the other smaller cracks should also be repaired.
2 Two cable support brackets on the north wall have moderate corrosion and should be repaired when the repairs in item #1 are carried out.

Estimated Cost of Repairs (Item 1 &.2) $ 2,000.00

Manhole Inspection Summary Sheets

Estimated Cost of Engineering $ 1,000.00

Total Cost of Work **$ 3,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 234 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition except for a few minor hairline cracks and some 3/8" wide cracks on the east wall. The 3/8" wide cracks must be structurally repaired and at the same time, the other cracks should also be repaired.

2 Cable support brackets are in good condition.

Estimated Cost of Repair (Item No. 1 Only) $ 2,000.00

Estimated Cost of Engineering $ 1,000.00

Total Cost of Work **$ 3,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 235 October 28, 2005

Summary / Repairs:

1 Concrete walls, floor and roof in good condition except for some cracks particularly on the east and west walls, adjacent to the ductbank. These cracks shall be structurally repaired.

2 Cable support brackets are in good condition.

Estimated Cost of Repairs (Item No. 1 Only) $ 2,000.00

Estimated Cost of Engineering $ 1,000.00

Total Cost of Work **$ 3,000.00** + GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 236 October 28, 2005

Summary / Repairs:

1 Concrete walls and floor are in good condition with only a few minor cracks that do not require repairs at this time. The roof has some moderate rebar corrosion and spalled concrete, particularly around the chimney, that should be repaired as a preventative. measure. It appears that the old chimney hole was infilled and a new hole created. There is leakage occurring around the perimeter of the old chimney hole.

2 Cable support brackets have moderate corrosion and should be replaced within two years (6 brackets).

Estimated Cost of Repairs (Items 1 & 2) $ 3,000.00

Manhole Inspection Summary Sheets

Estimated Cost of Engineering	$ 1,000.00	
Total Cost of Work	**$ 4,000.00**	+ GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 237 October 28, 2005

Summary / Repairs:

1 Concrete walls and floor in good condition with a few cracks that should be structurally repaired. The roof slab is in poor condition with significant spalled concrete and exposed corroded rebar that shall be repaired.
2 Cable support brackets have light corrosion and should be scraped and painted with Galvafroid paint when the roof repairs are carried out.

Estimated Cost of Repairs (Items 1 & 2)	$ 7,000.00	
Estimated Cost of Engineering	$ 2,400.00	
Total Cost of Work	**$ 9,400.00**	+ GST

Recommended Date for Next Inspection: 5 years (2010)

Manhole No. 238 October 28, 2005

Summary / Repairs:

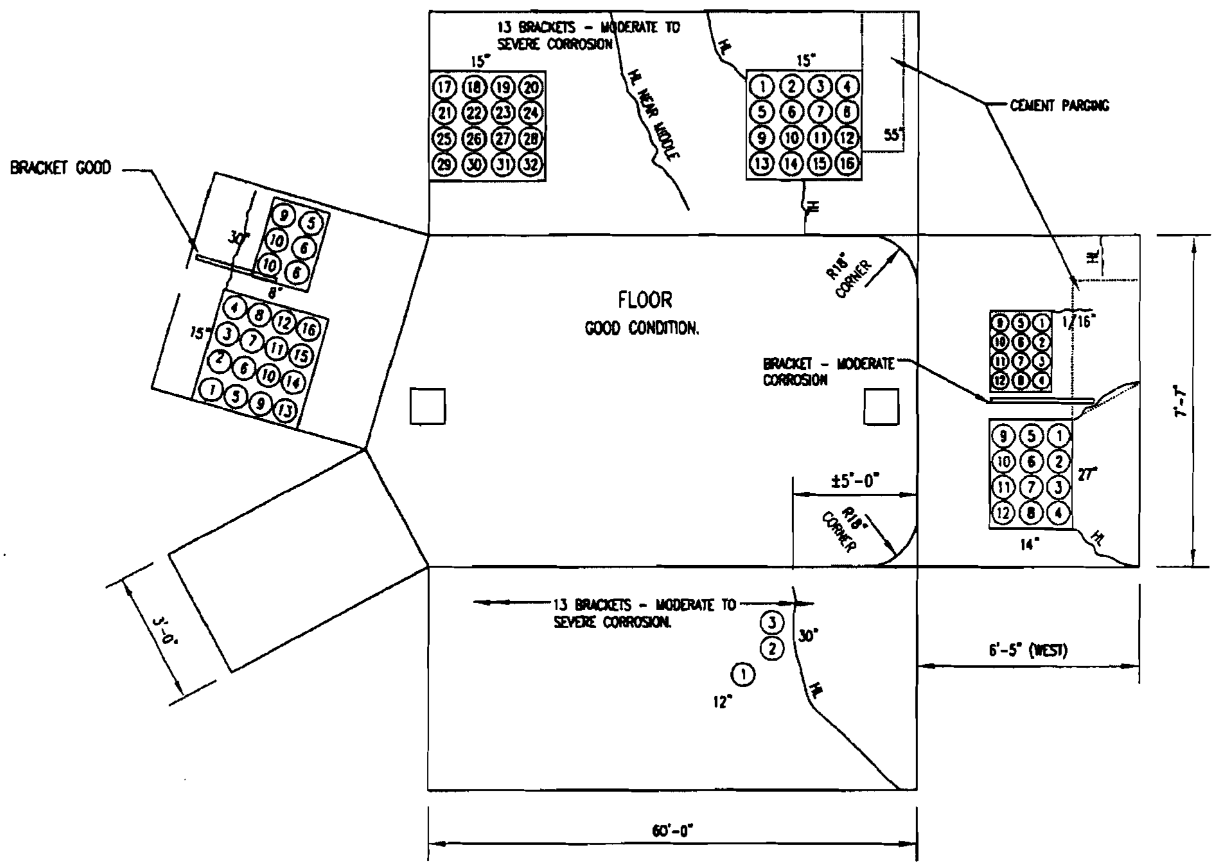
1 Concrete walls, floor and roof in good condition with only a few minor hairline cracks and spalled concrete around the chimney that do not require repairs at this time. Manhole appeared to have been recently reconstructed.
2 There were no cable support brackets in the manhole.

Recommended Date for Next Inspection: 5 years (2010)

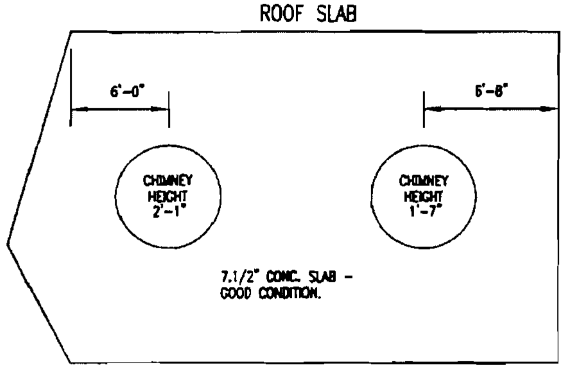
MANHOLE No. : 1

LOCATION: TUNNEL ON NORTH SIDE OF ERIE, IN FRONT OF SUB 22.
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

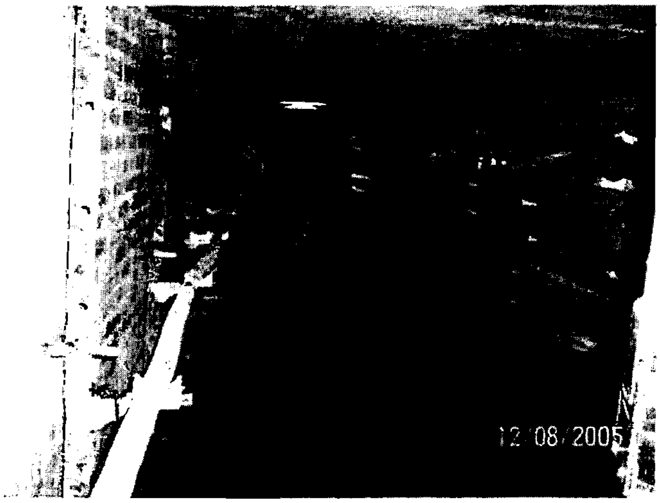
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



ROOF SLAB

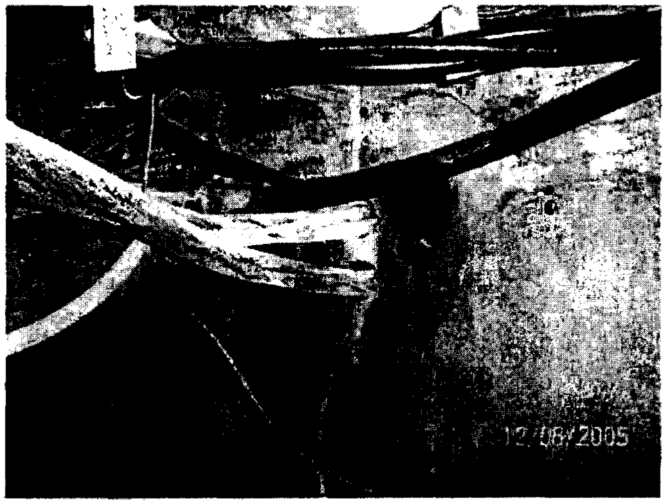


Manhole No. 1

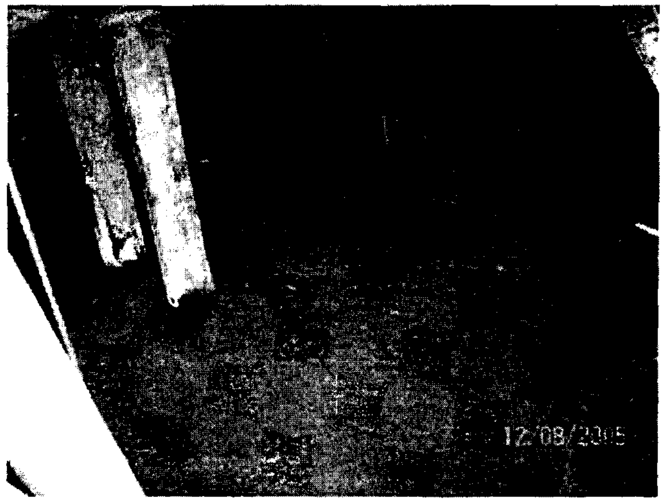


West Wall Looking East

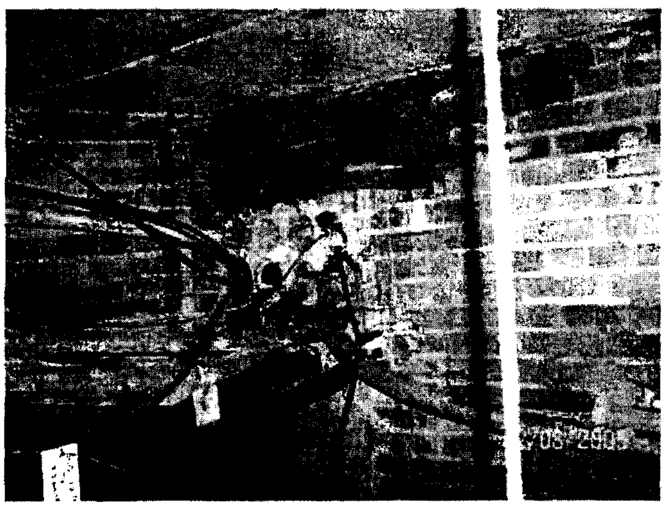

West Wall



West Wall



Floor (West)

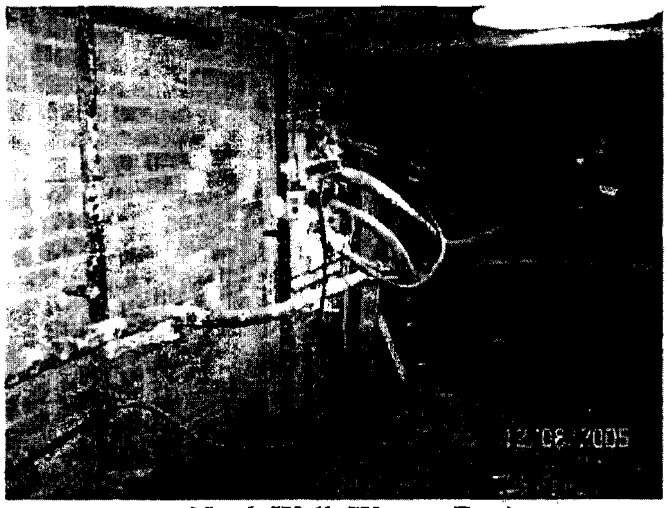

West Wall


North Wall (West to East)

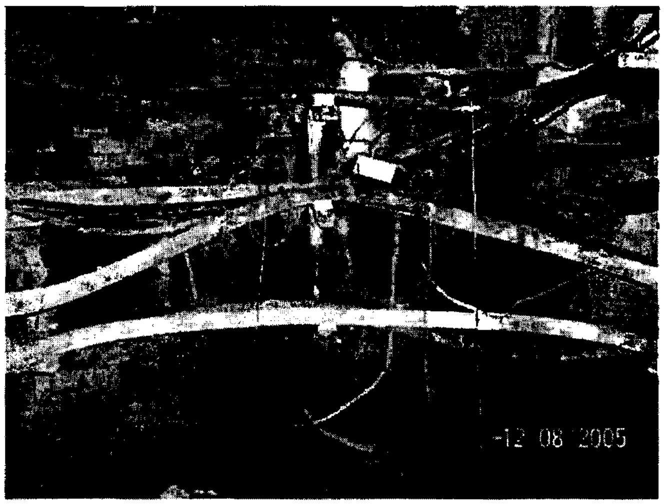
Manhole No. 1

North Wall (West to East)

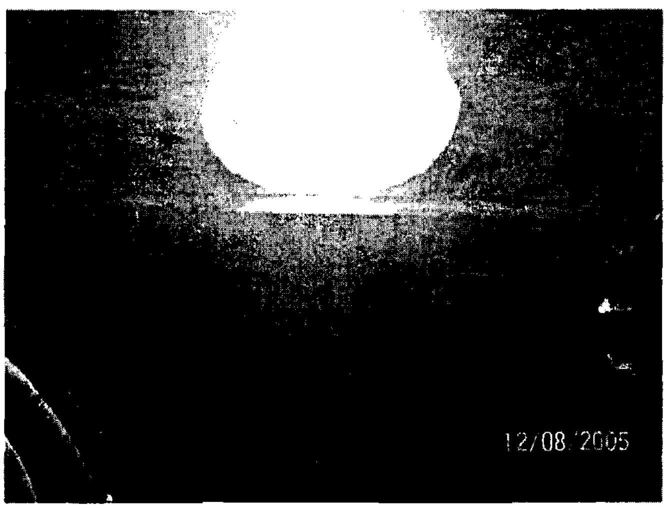
North Wall (West to East)



North Wall (West to East)



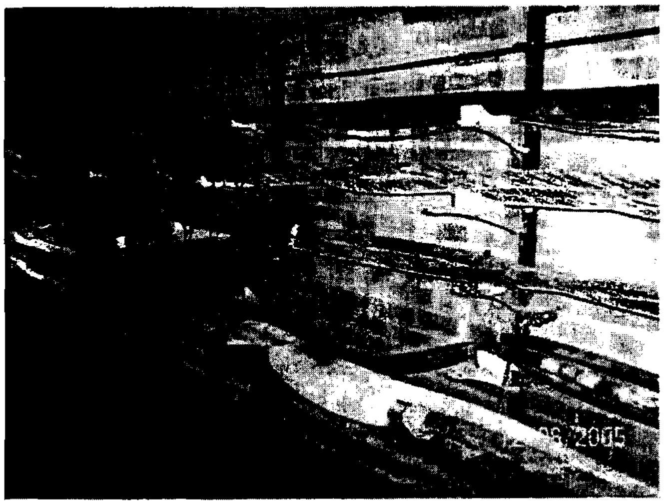
East Wall



Roof (East)

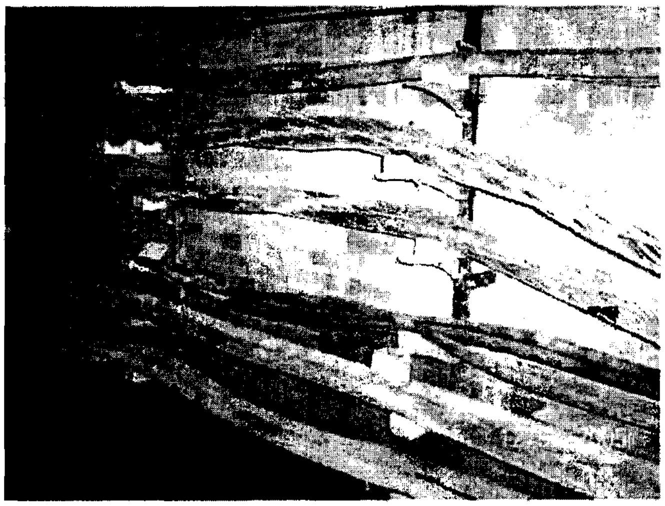

South Wall (East to West)

Manhole No. 1

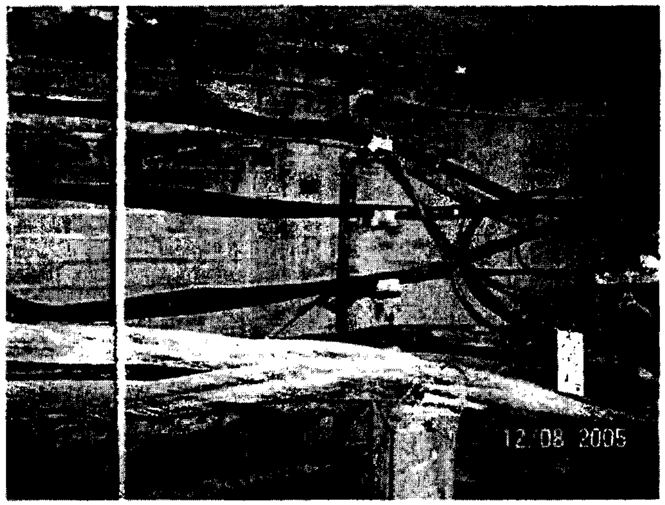


South Wall (East to West)

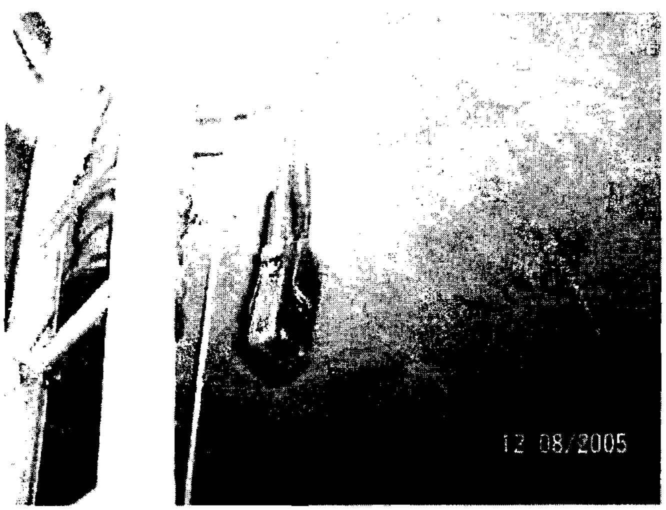
South Wall (East to West)



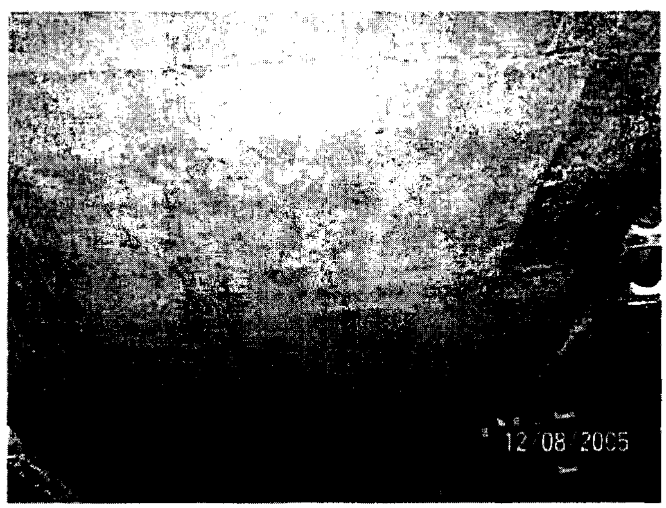
South Wall (East to West)



South Wall (East to West)

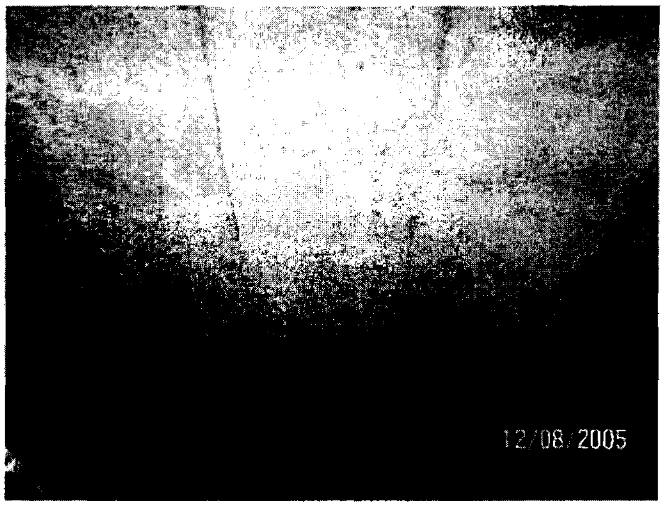


Roof (West to East)

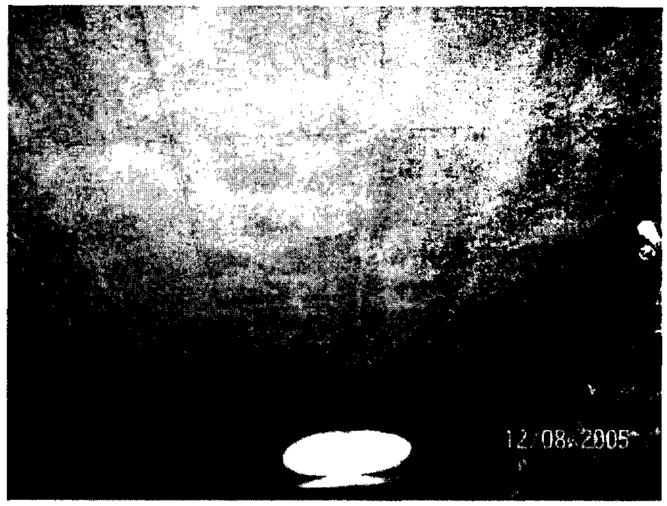


Roof (West to East)

Manhole No. 1

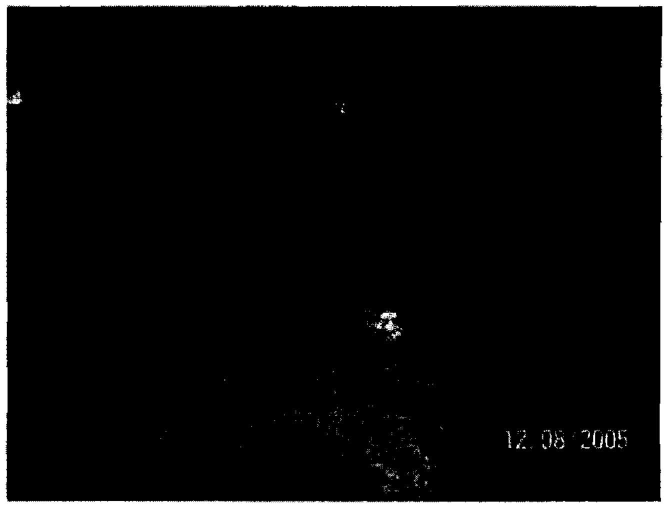


Roof (West to East)

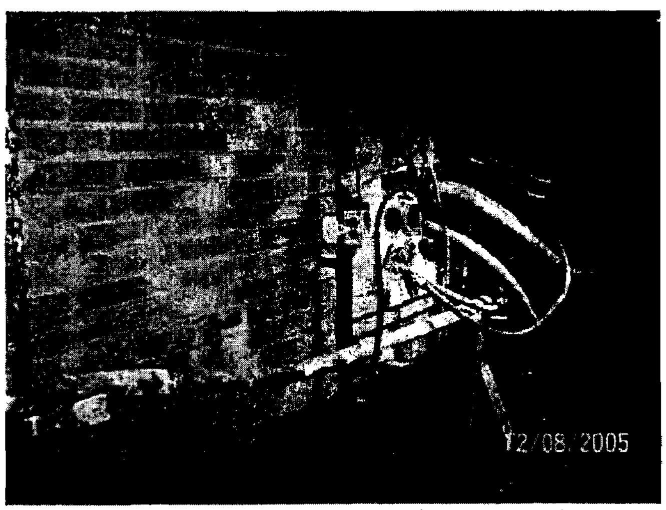


Roof (West to East)

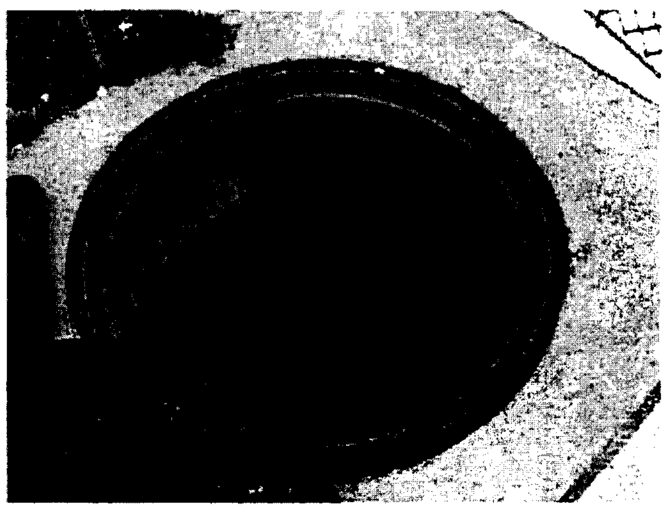
Floor



Floor



South Wall (West End)


Chimney (East)

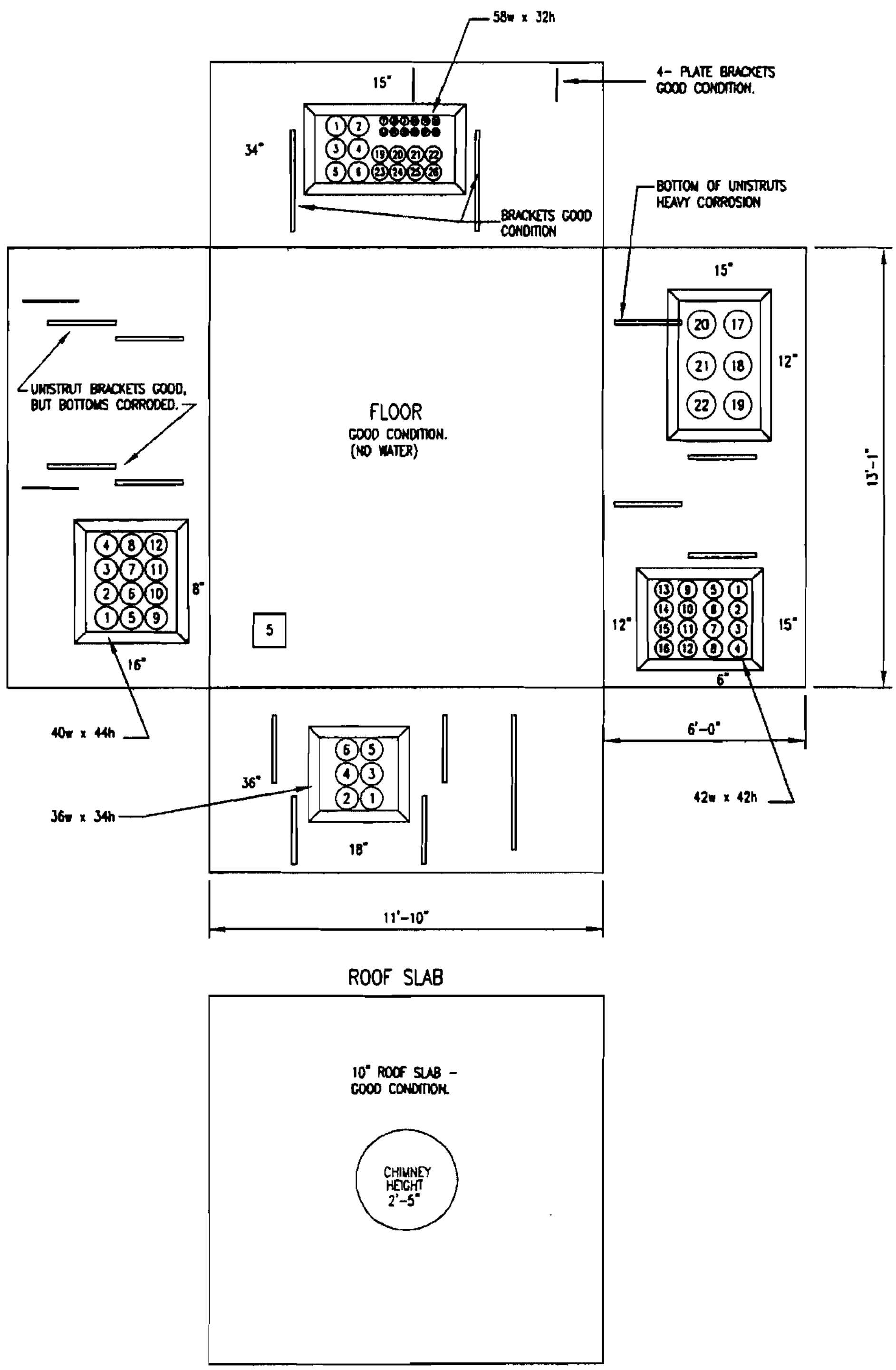
Manhole No. 1

Chimney (West)

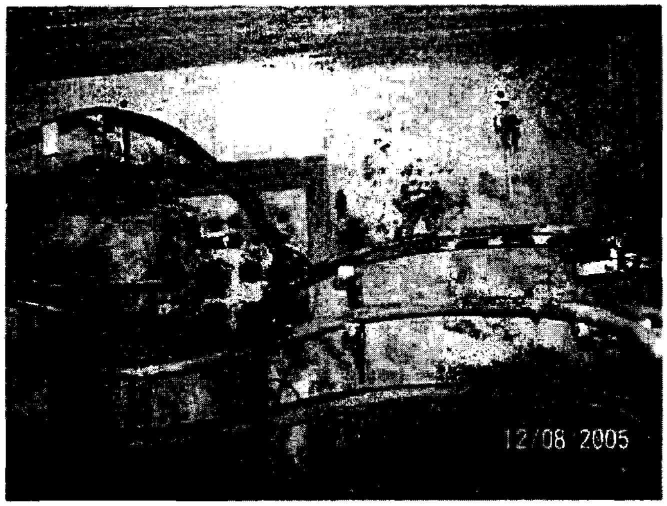
MANHOLE No. : 2

LOCATION: NORTHEAST CORNER OF McDOUGALL & ERIE
OVERALL CONDITION: GOOD.

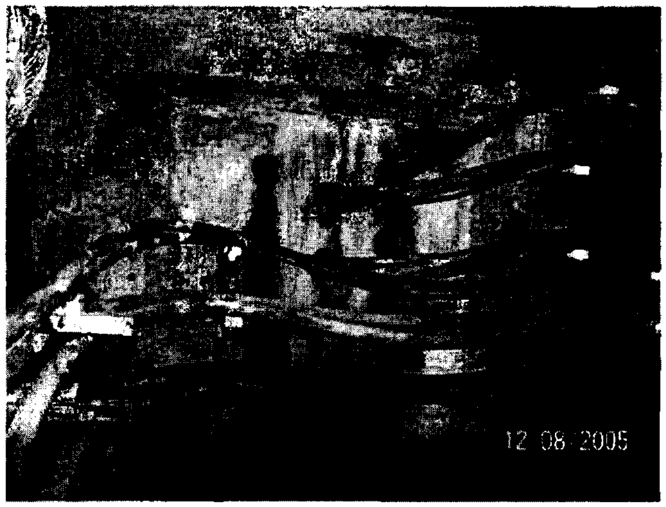
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



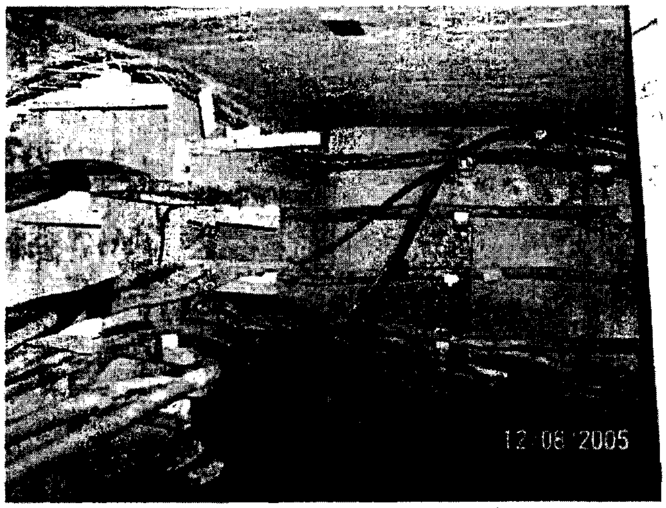
Manhole No. 2



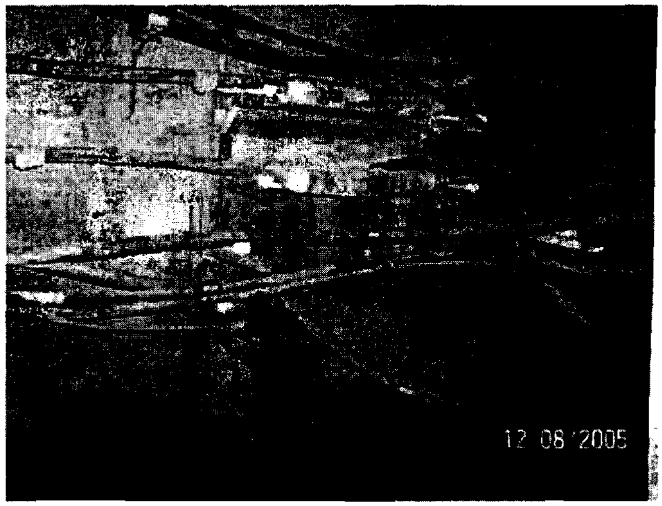
West Wall



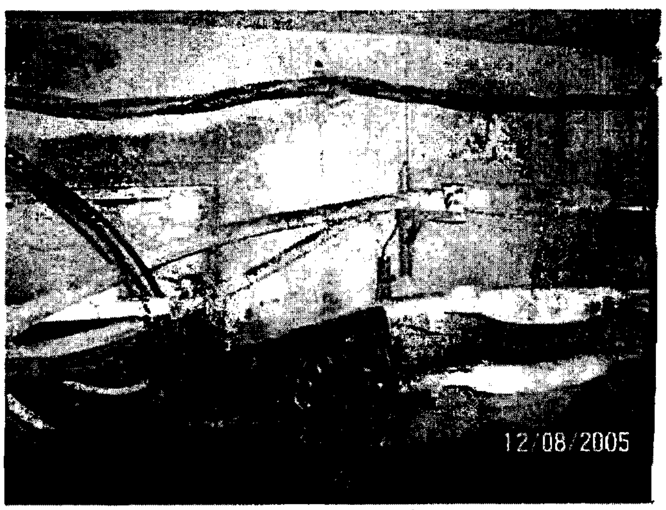
North Wall



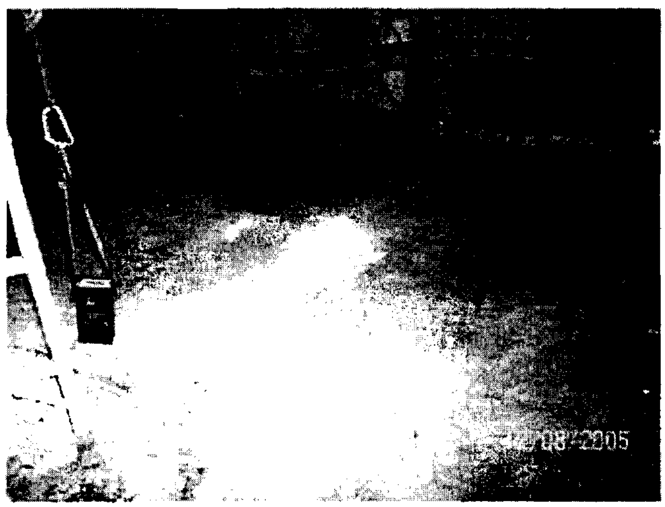
East Wall (North)



East Wall



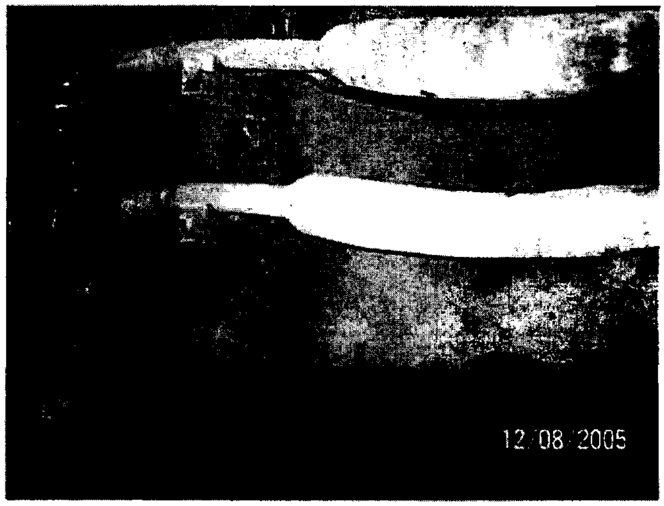
South Wall



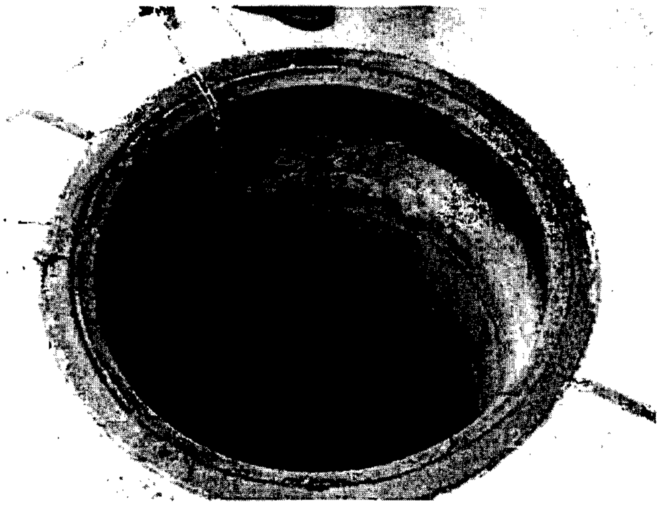
Floor

Manhole No. 2

Roof



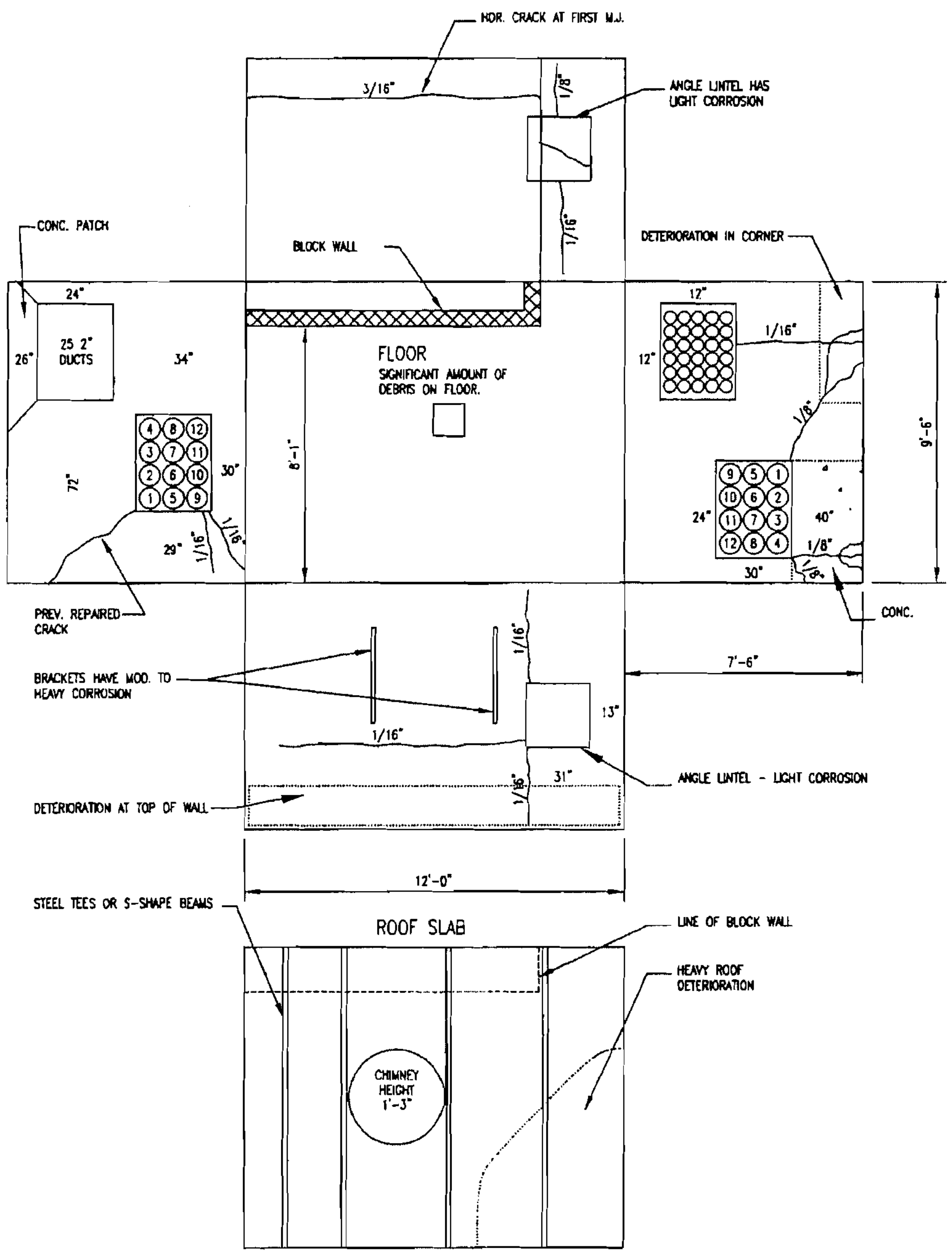
South Unistrut Bracket


Chimney

MANHOLE No. : 3

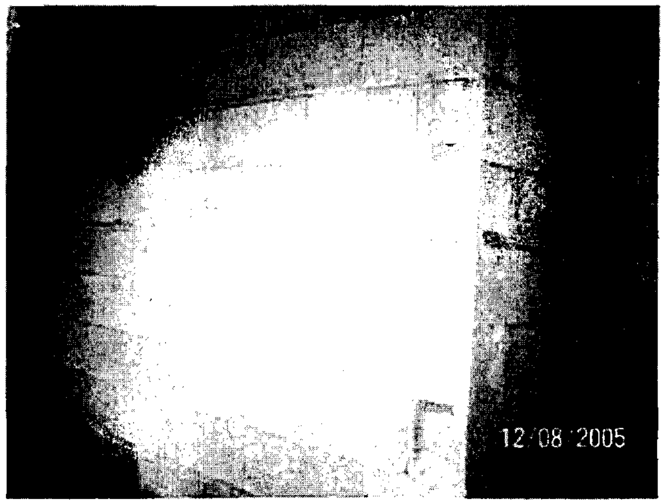
LOCATION: NORTHWEST CORNER OF DOUGALL & ERIE
OVERALL CONDITION: WALLS: POOR, ROOF: VERY POOR.
REMARKS: MANHOLE HAS BRICK WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



Manhole No. 3

West Wall

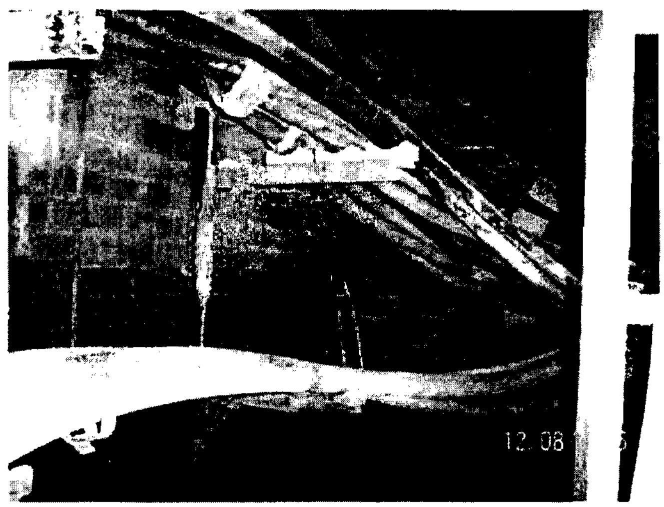


North Wall

Northeast Corner

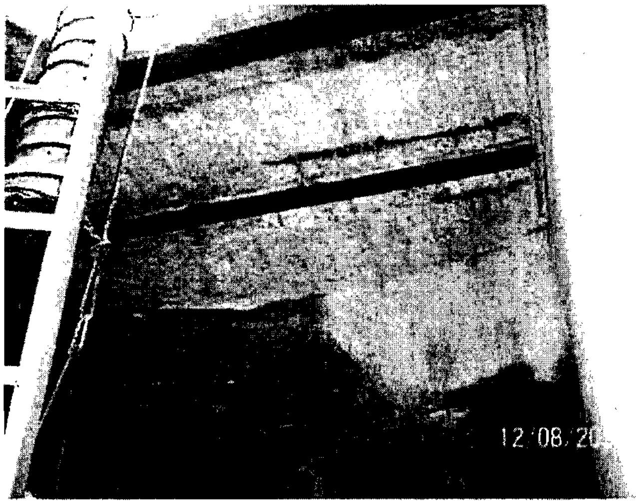
East Wall

South Wall

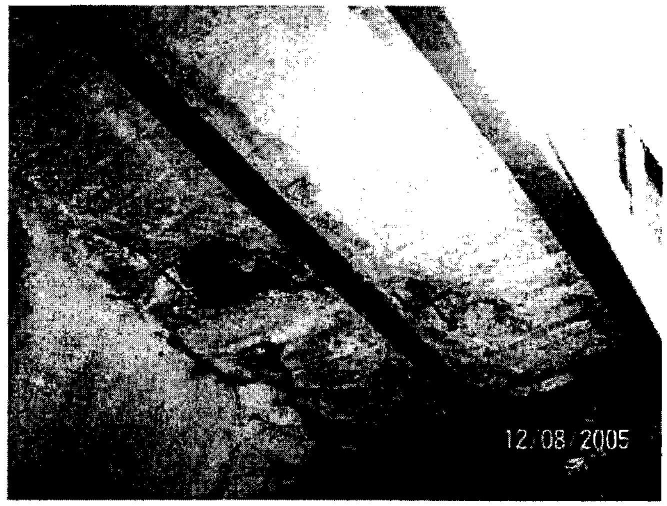


South Wall

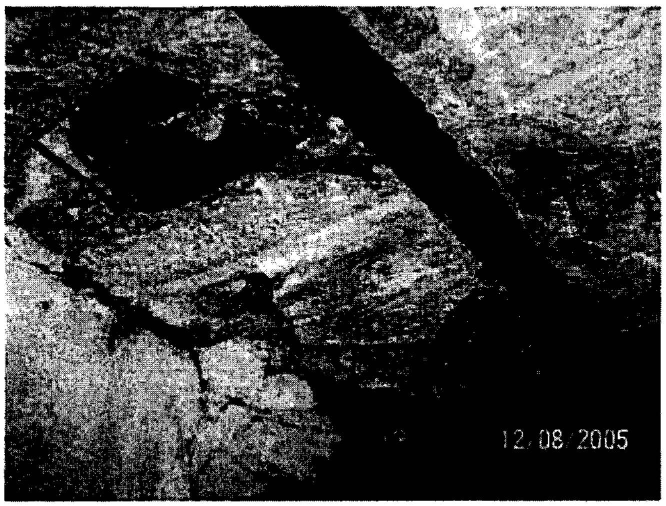
Manhole No. 3



Roof



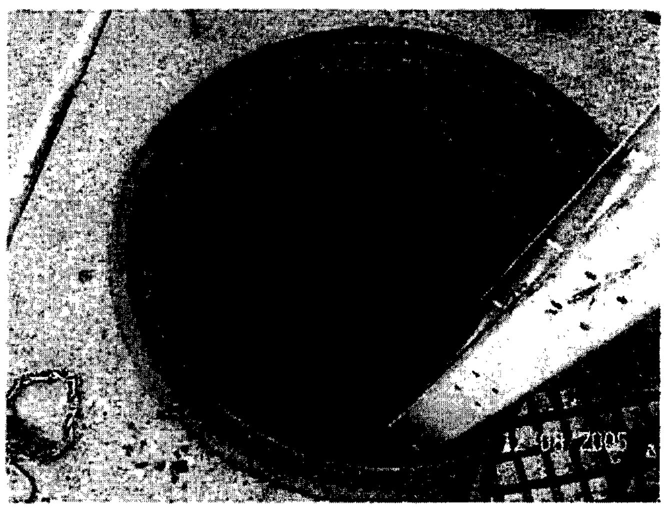
Roof



Roof

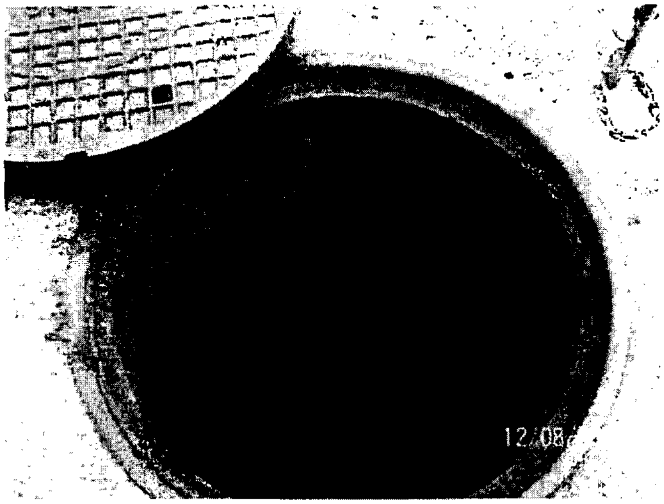
Roof

Floor

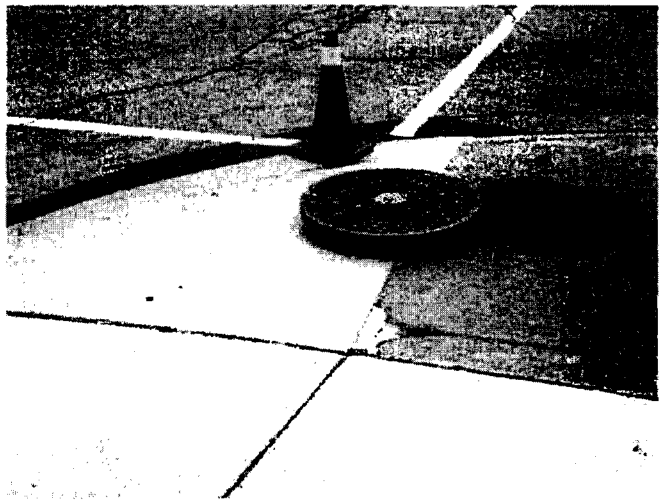


Chimney

Manhole No. 3



Chimney

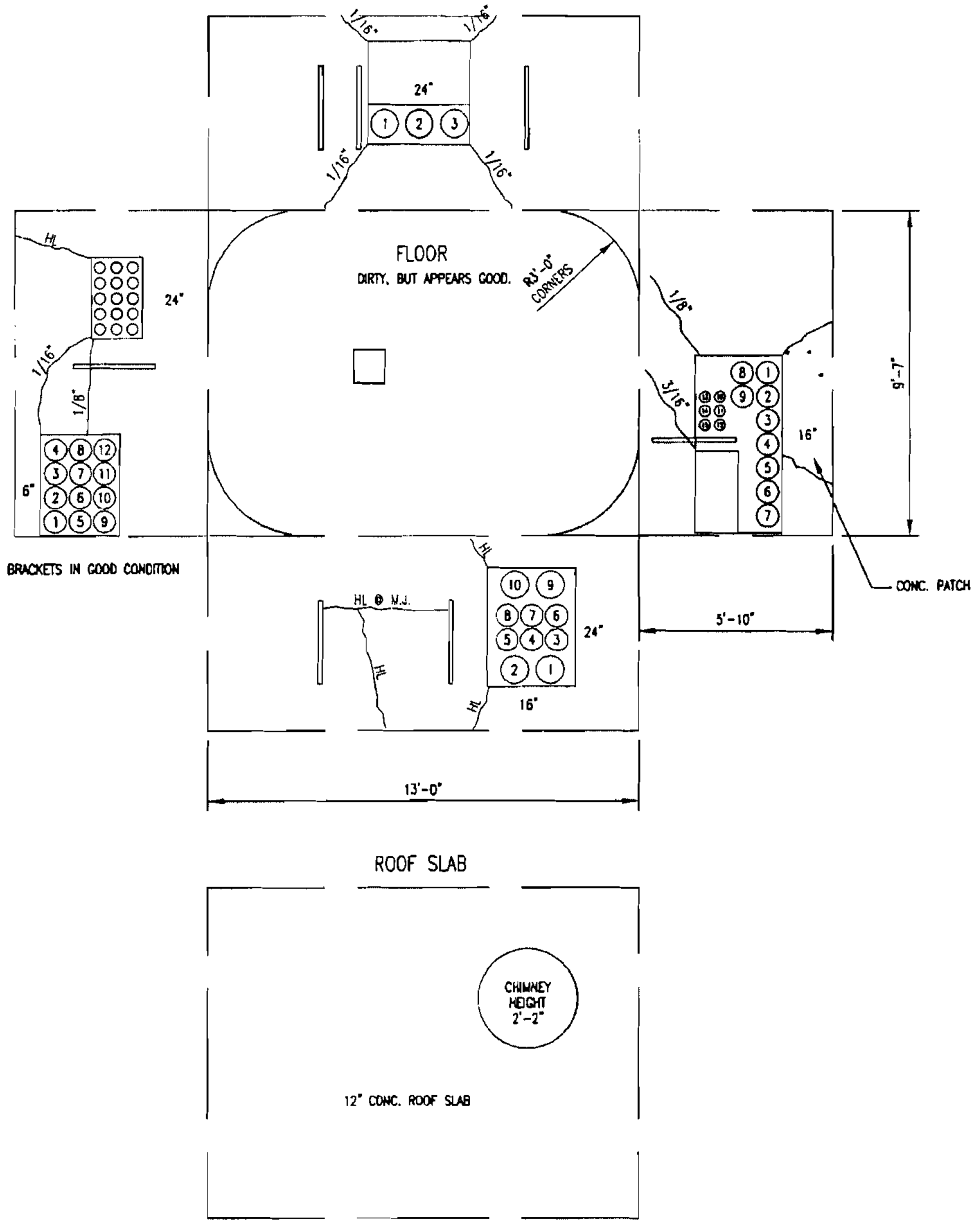


Sidewalk Adjacent to Chimney

MANHOLE No. : 9

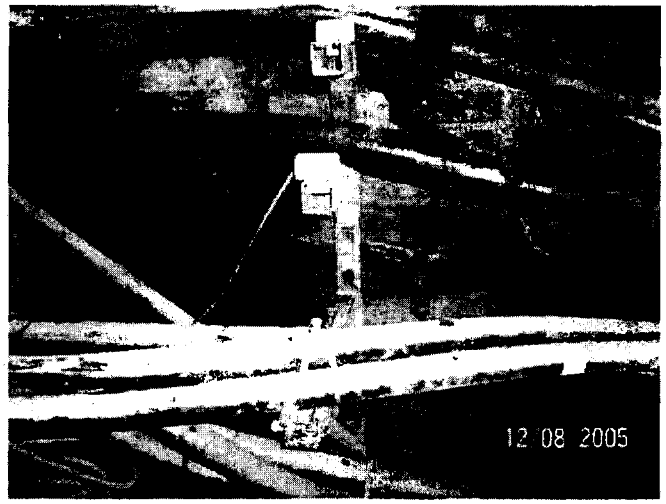
LOCATION: NORTHEAST CORNER OF MERCER & ERIE
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS BRICK WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.

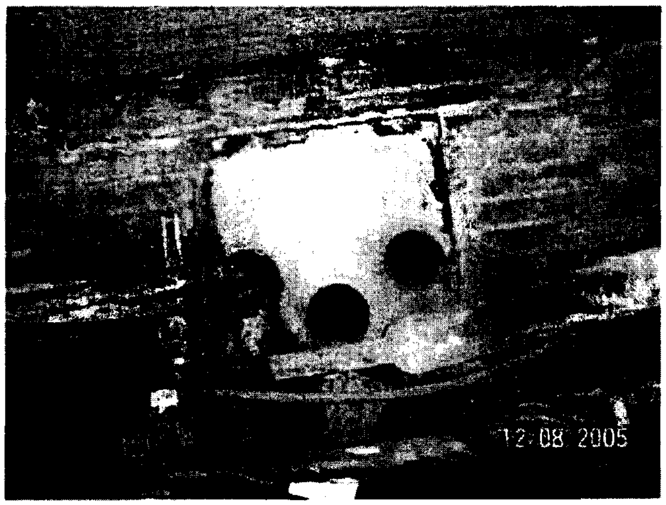


Manhole No. 9

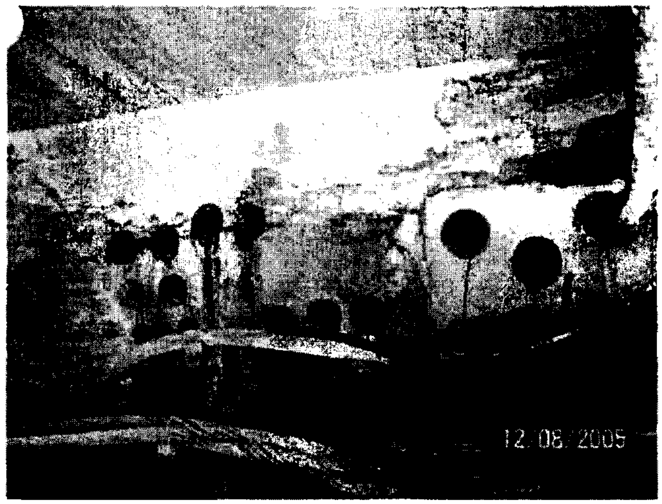
West Wall



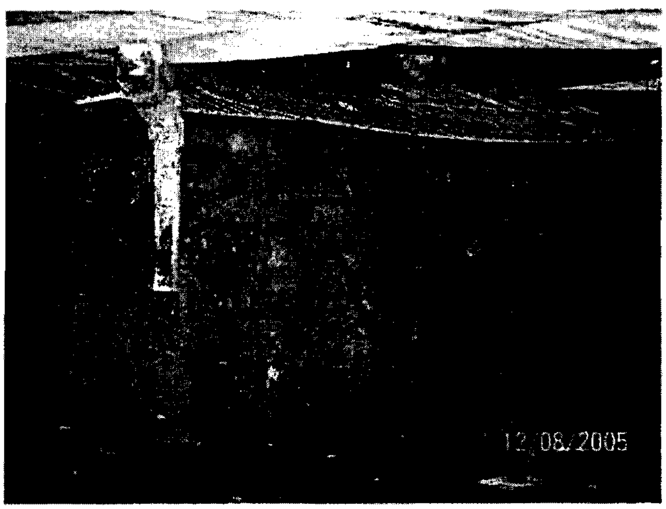
Northwest Corner



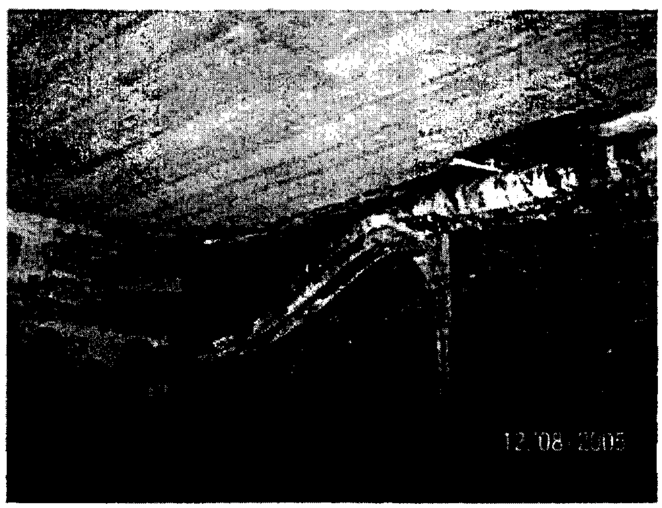
North Wall



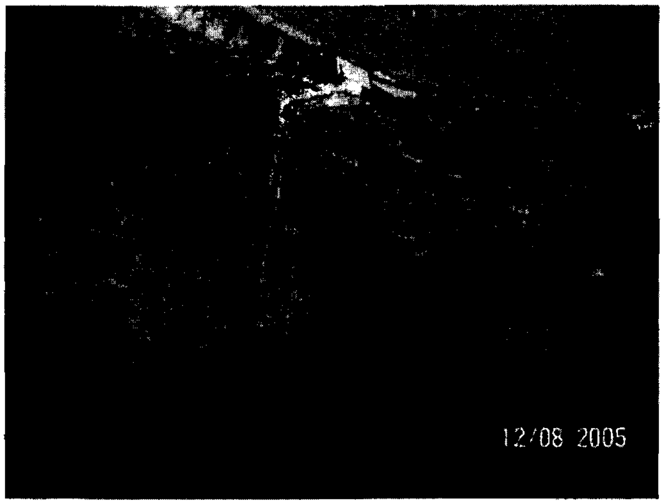
East Wall (Top)



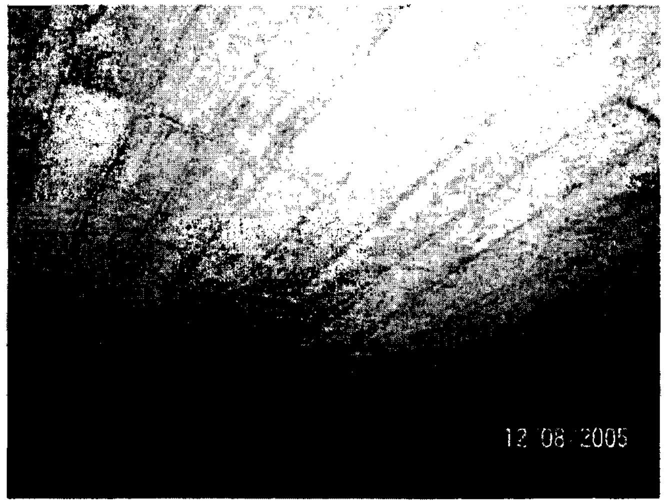
East Wall


Southeast Corner

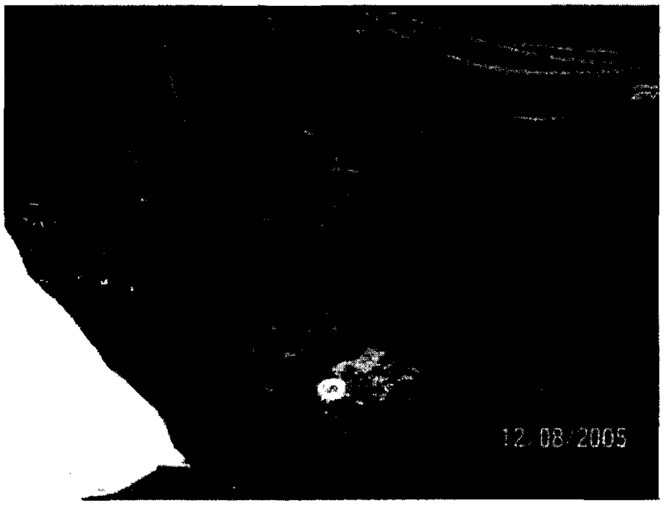
Manhole No. 9



Southwest Corner



Roof (West)



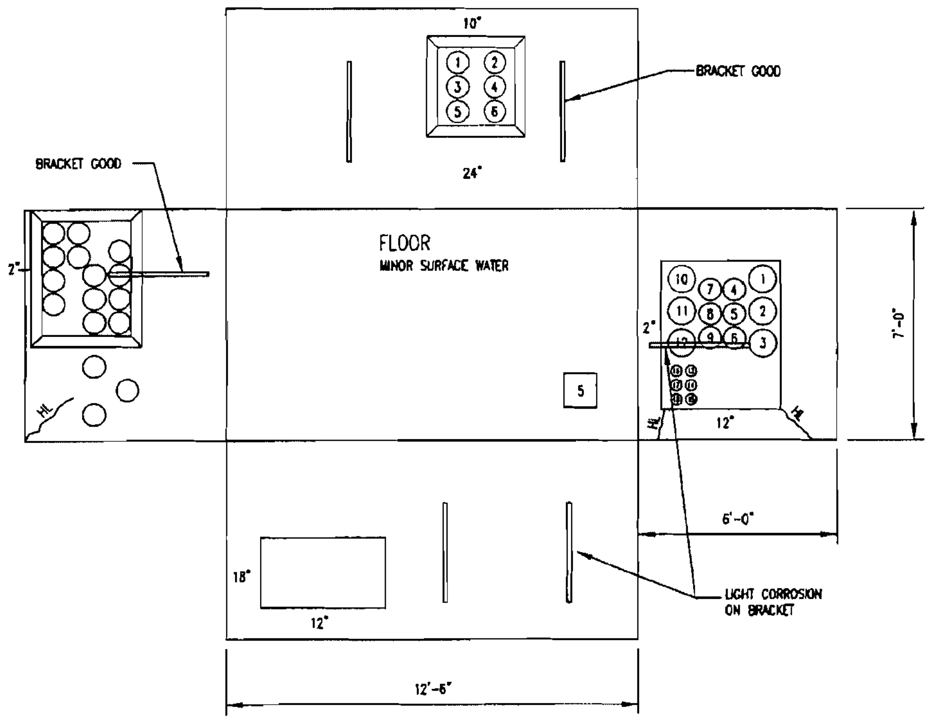
Floor (West)

Chimney

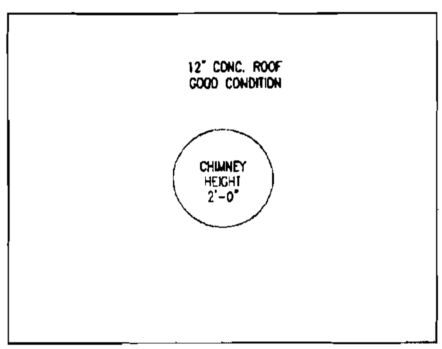
MANHOLE No.: 10

NORTH SIDE OF ERIE. ALLEY EAST OF MERCER.
OVERALL CONDITION: GOOD.

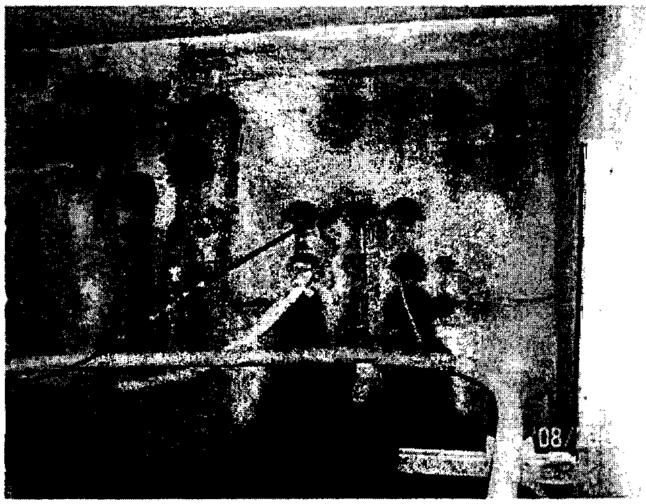
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



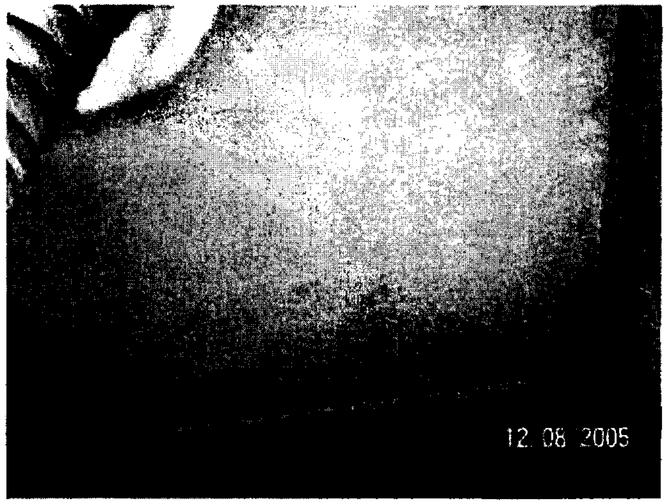
ROOF SLAB



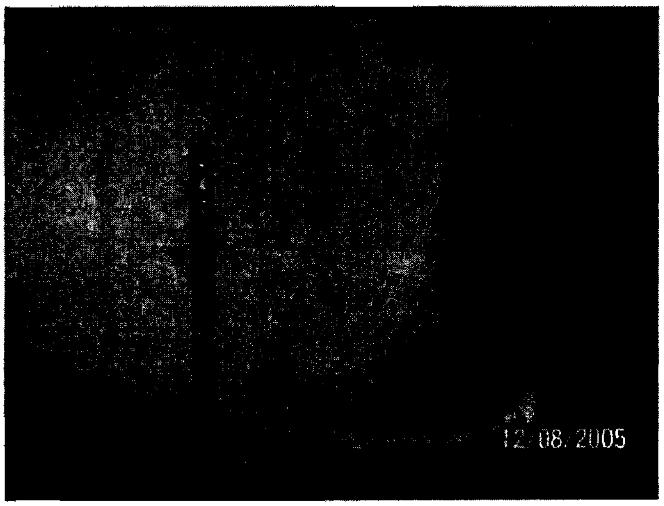
Manhole No. 10



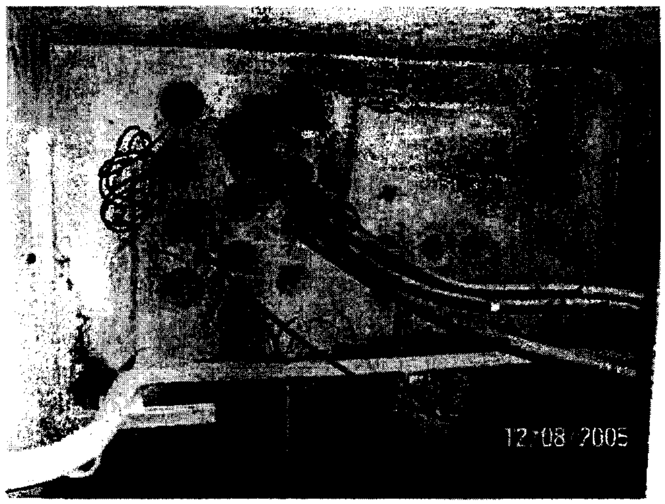
West Wall



Roof (West)



North Wall

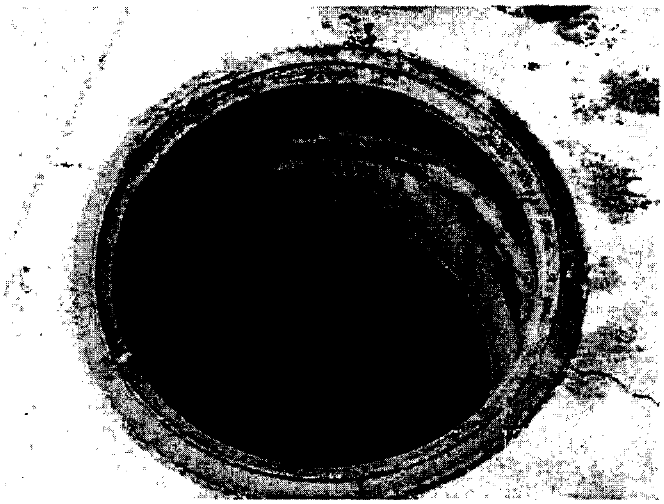


East Wall

South Wall

Floor (West)

Manhole No. 10

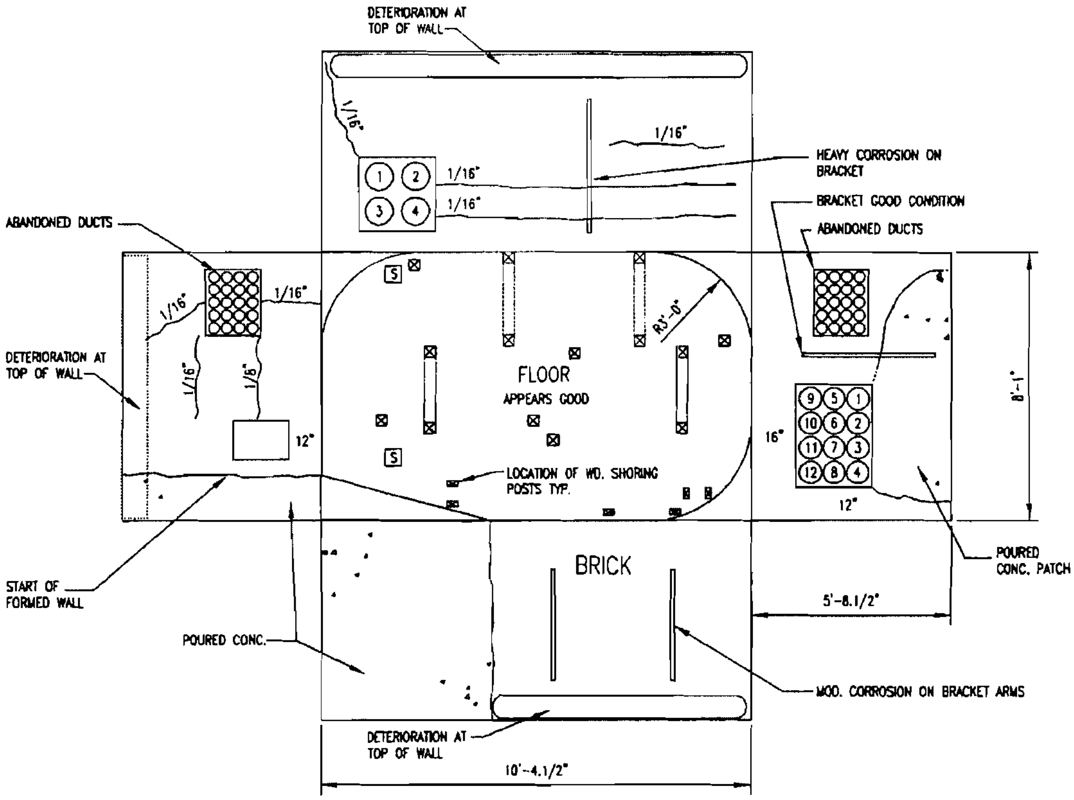


Chimney

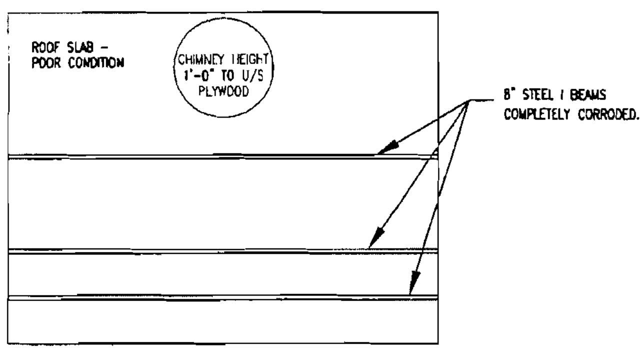
MANHOLE No. : 12

LOCATION: NORTH SIDE OF ERIE, ALLEY WEST OF GOYEAU.
OVERALL CONDITION: WALLS–FAIR, ROOF–POOR.
REMARKS: BRICK WALLS DRY DURING INSPECTION.

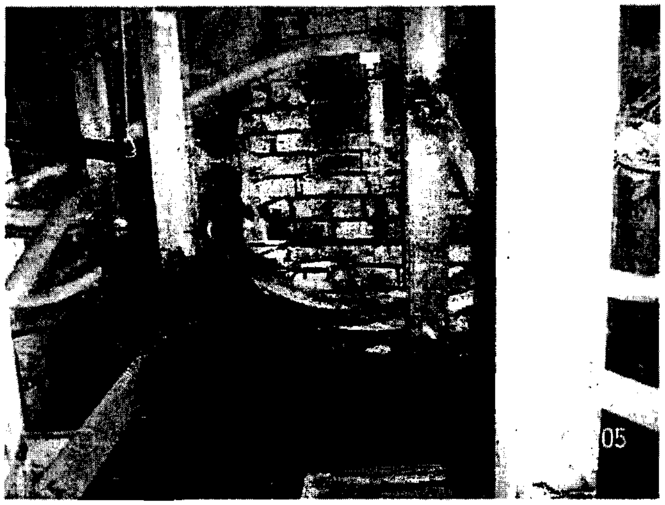
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



ROOF SLAB

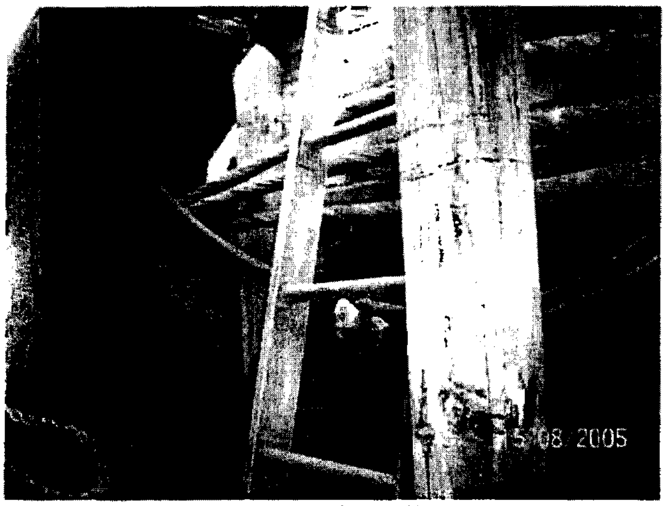


Manhole No. 12

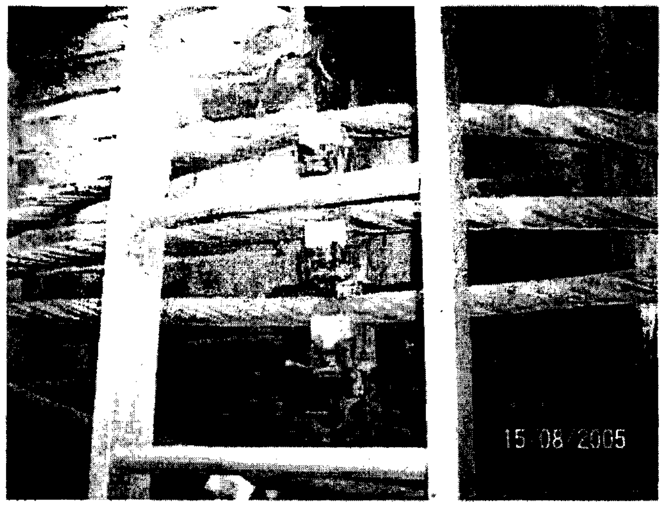


West Wall

West Wall



North Wall



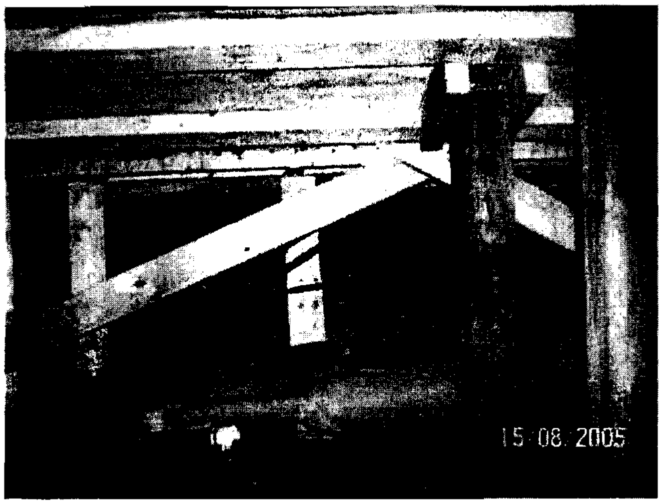
North Wall

Floor (East)

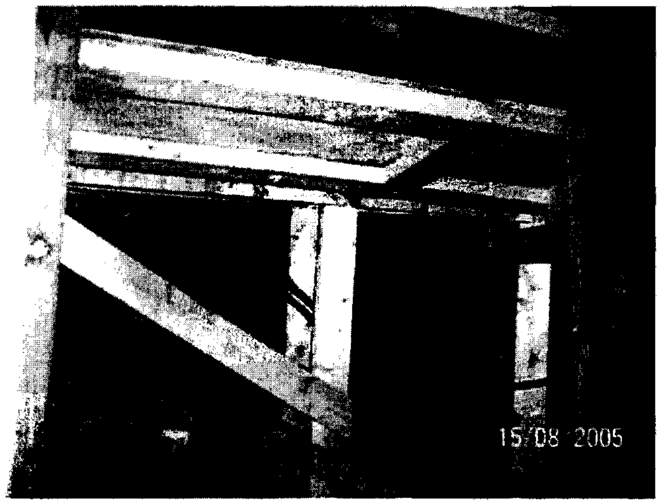
East Wall

[redacted]

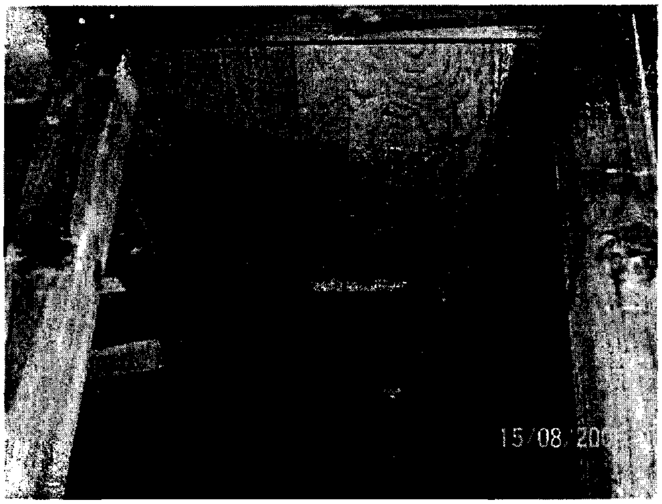
Manhole No. 12

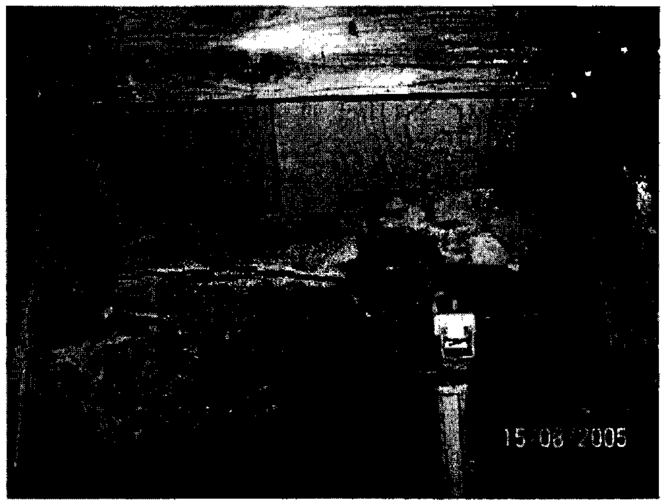


South Wall

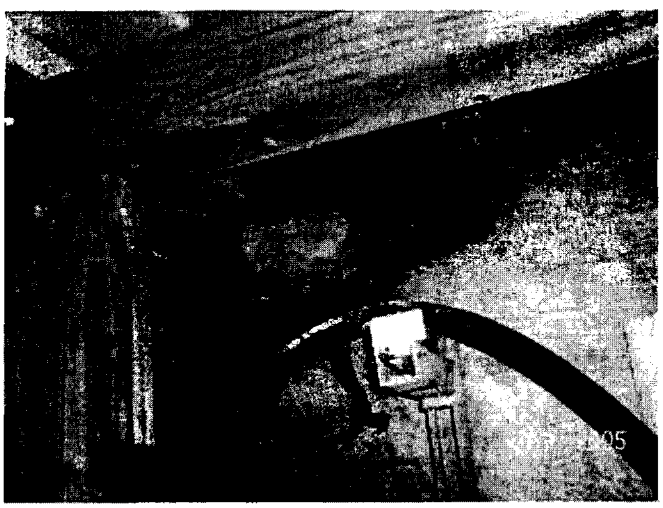


South West Corner


Roof (West)

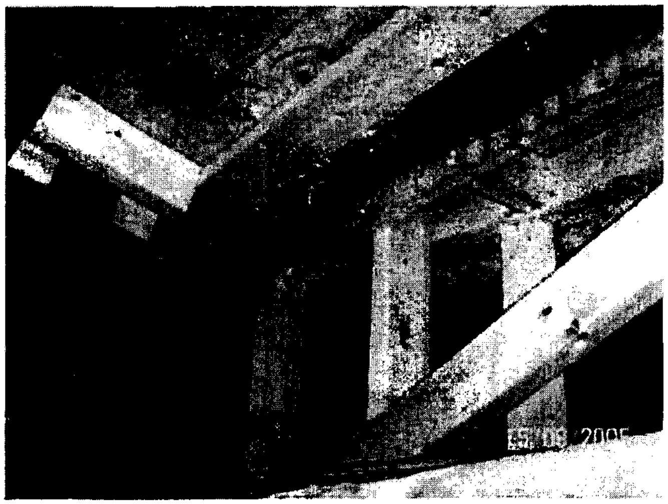


Roof (East)

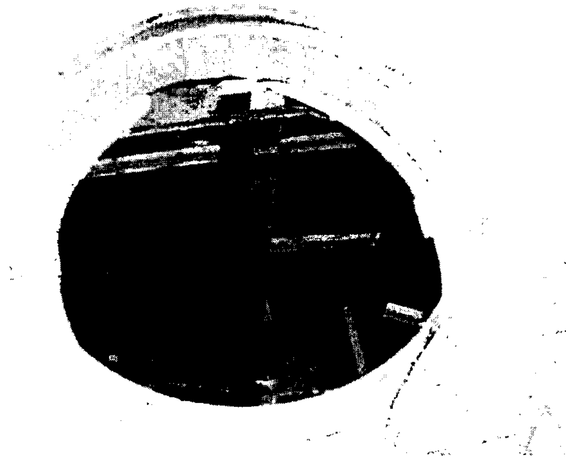

Roof (East)

Roof (East)

Manhole No. 12



Roof (South East)

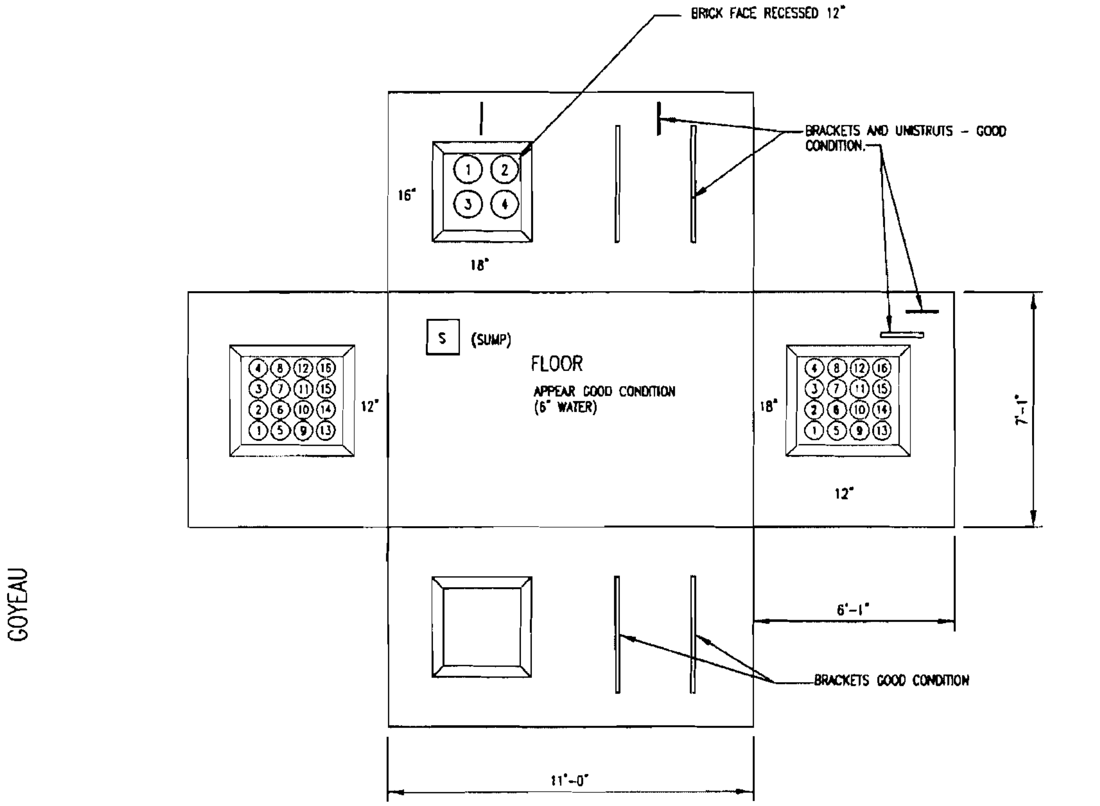


Chimney

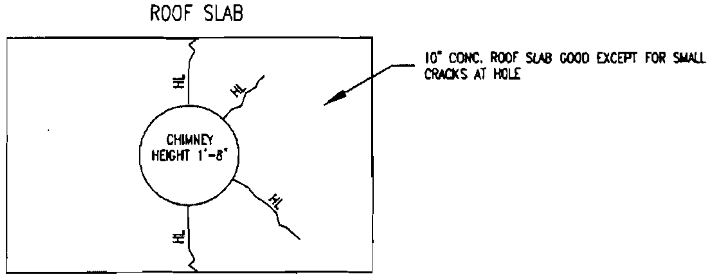
MANHOLE No. : 13

LOCATION: ERIE BETWEEN GOYEAU & WINDSOR
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.

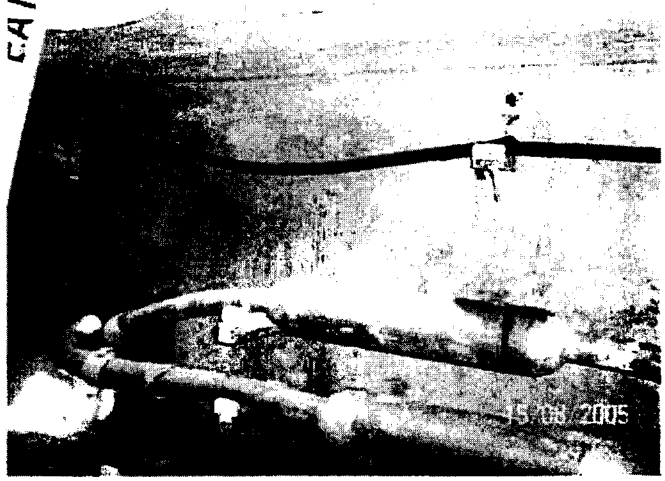


ROOF SLAB

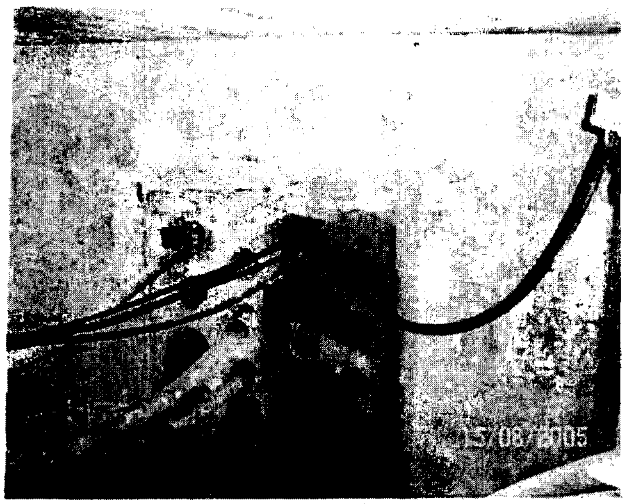


Manhole No. 13

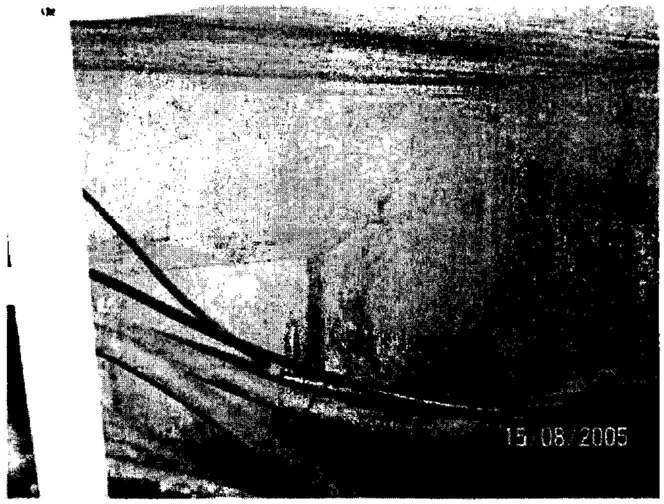
East Wall



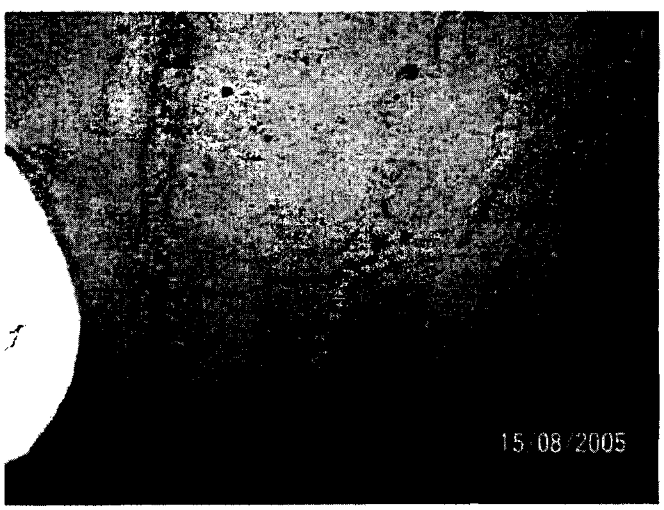
North Wall



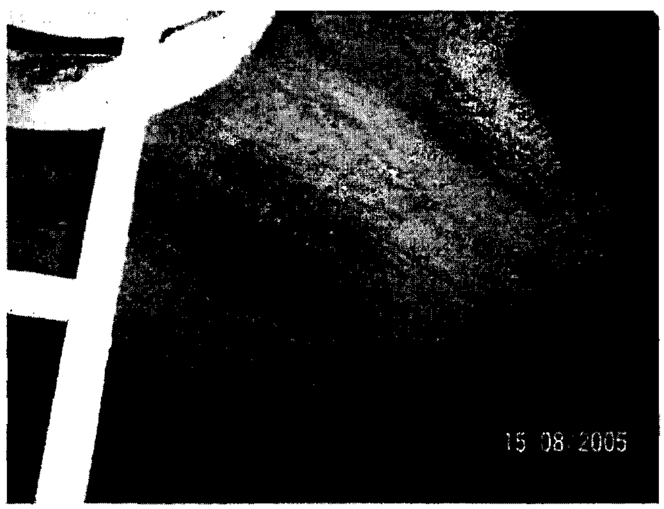
West Wall



South Wall (West)

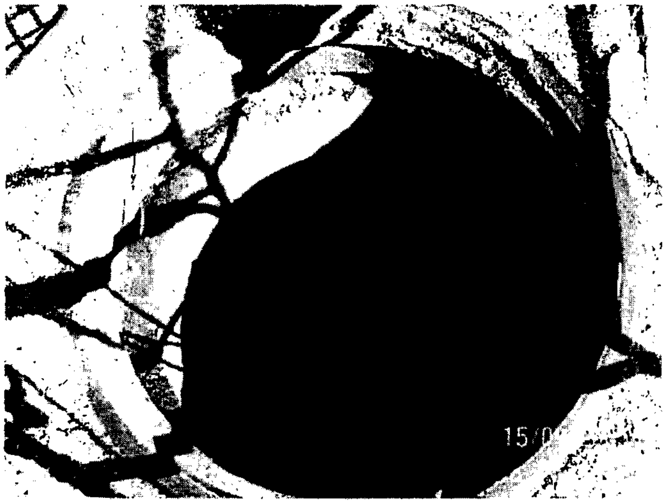


Roof (Crack on North Side)



Roof (West)

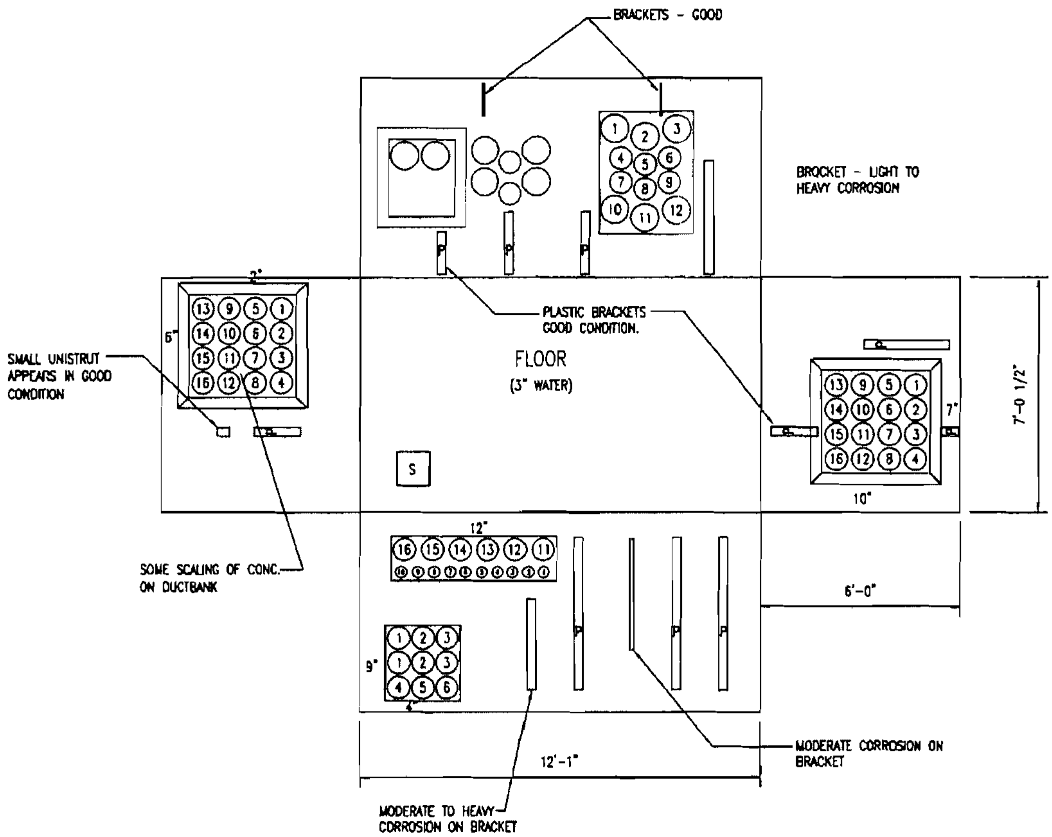
Manhole No. 13


Chimney

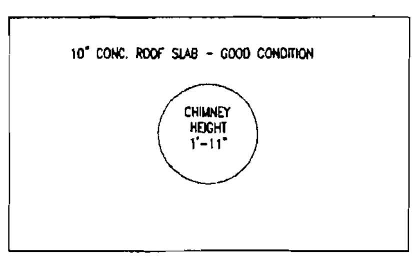
MANHOLE No. : 14

LOCATION: NORTH SIDE OF ERIE AT DUFFERIN.
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

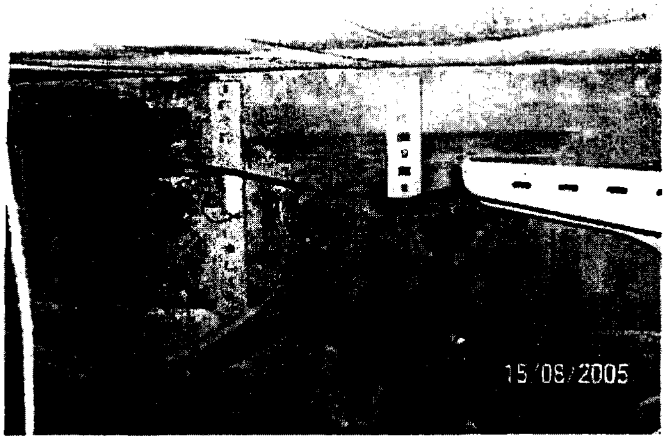
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



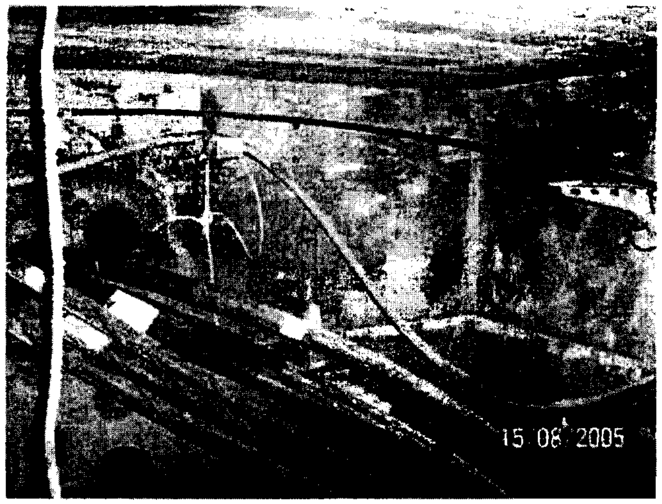
ROOF SLAB



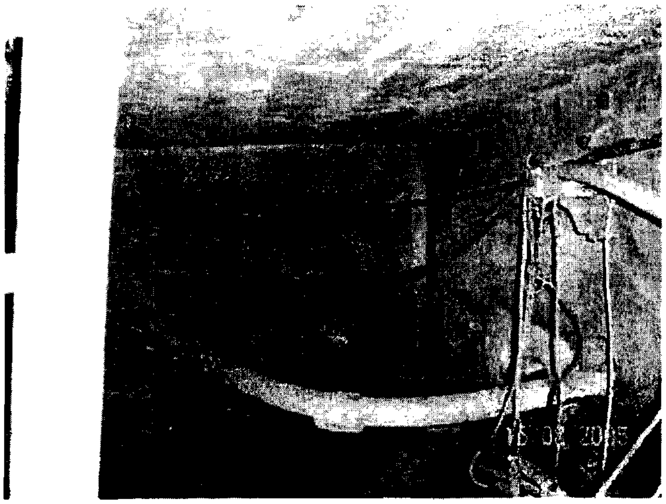
Manhole No. 14

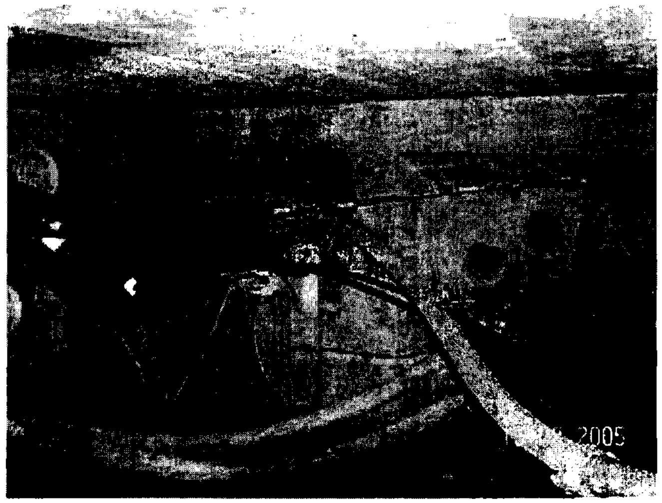


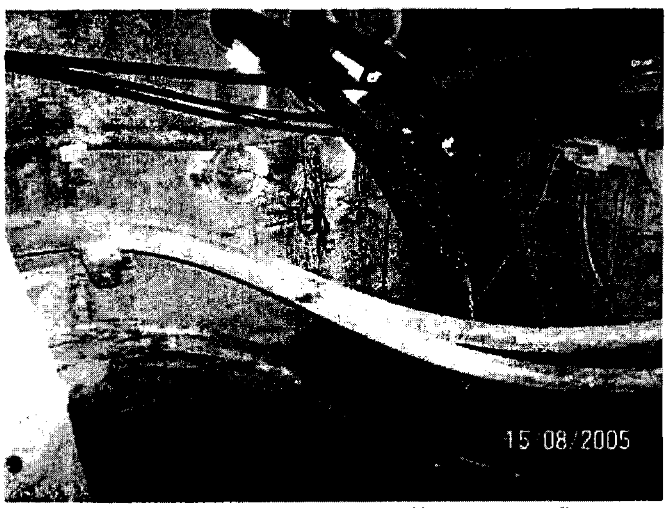
East Wall



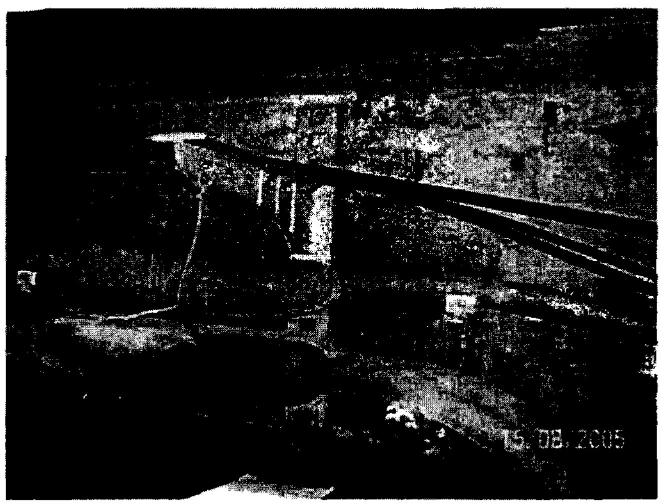
Northeast Corner


Northwest Corner

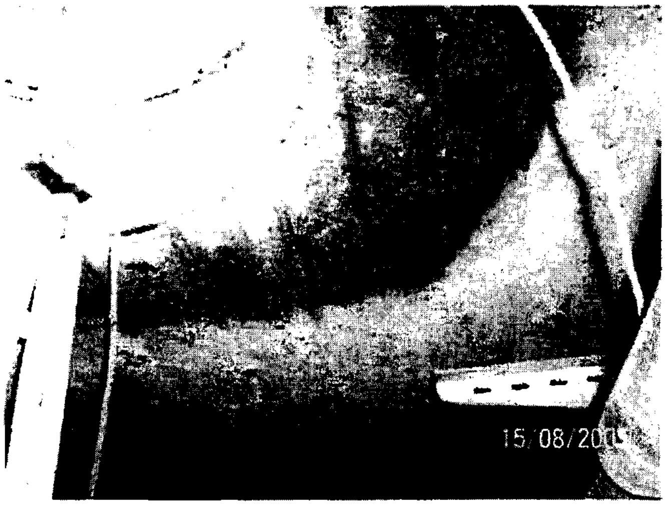

West Wall



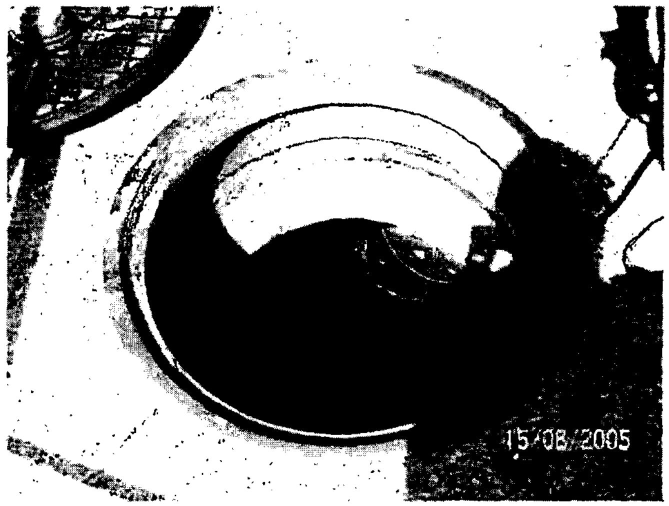
South Wall (West End)


South Wall

Manhole No. 14



Roof (West)

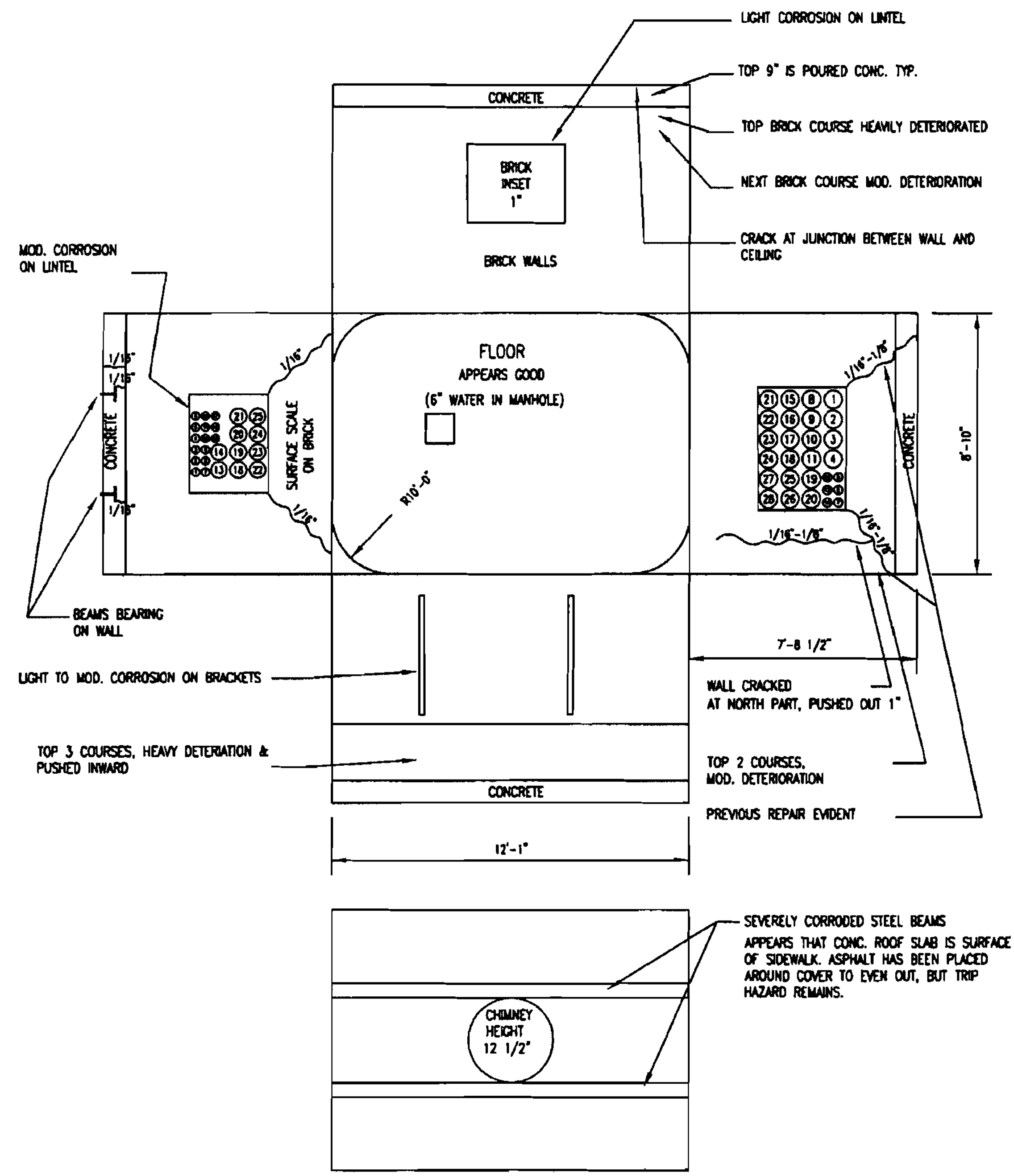


Chimney

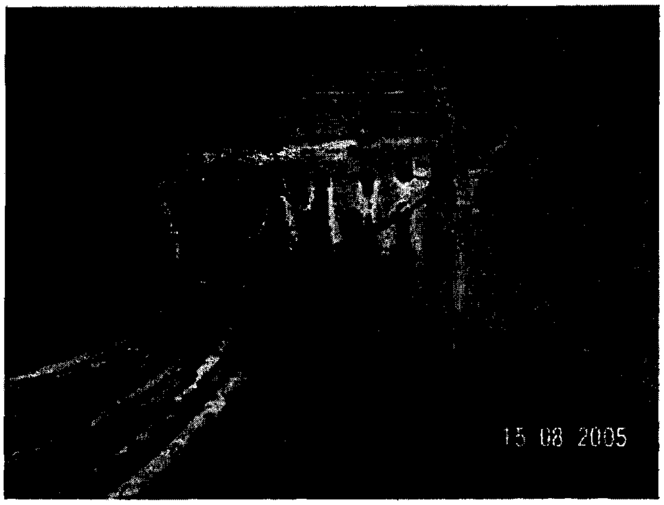
MANHOLE No. : 15

LOCATION: NORTHWEST CORNER OF ERIE & OUELLETTE
OVERALL CONDITION: WALLS – FAIR, ROOF – POOR
REMARKS: MANHOLE HAS BRICK WALLS

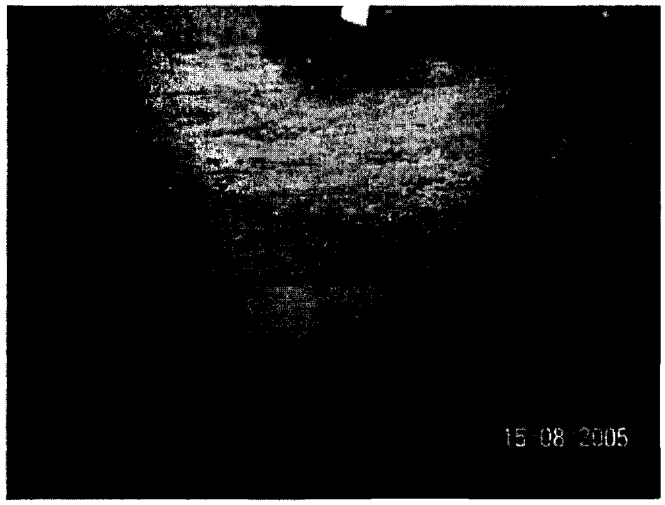
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 15, 2005.



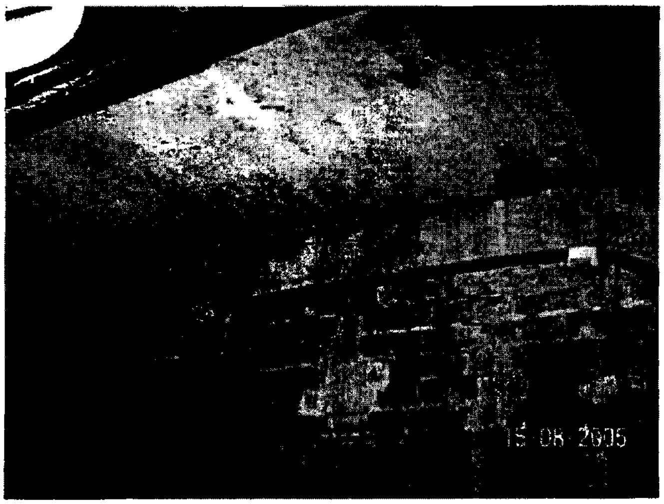
Manhole No. 15



West Wall

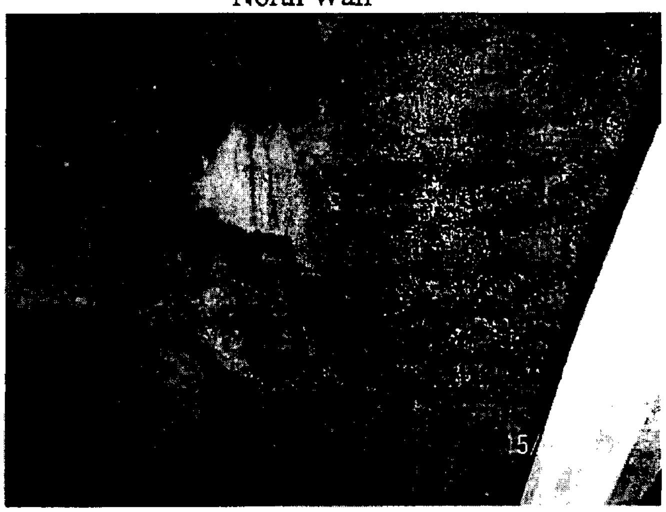


Roof - West

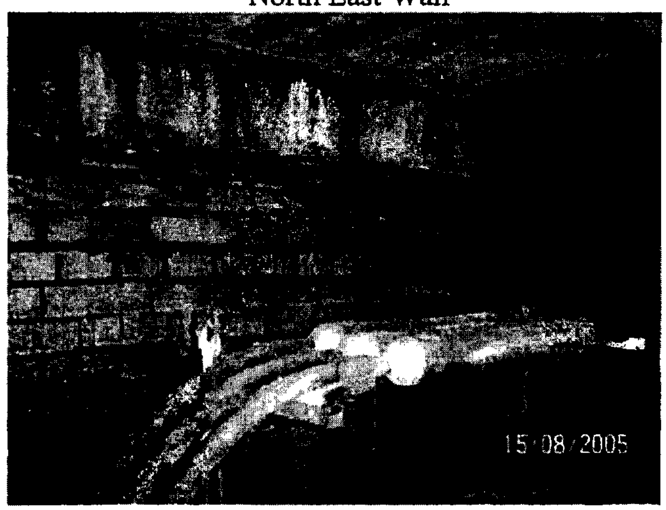


North Wall

North East Wall



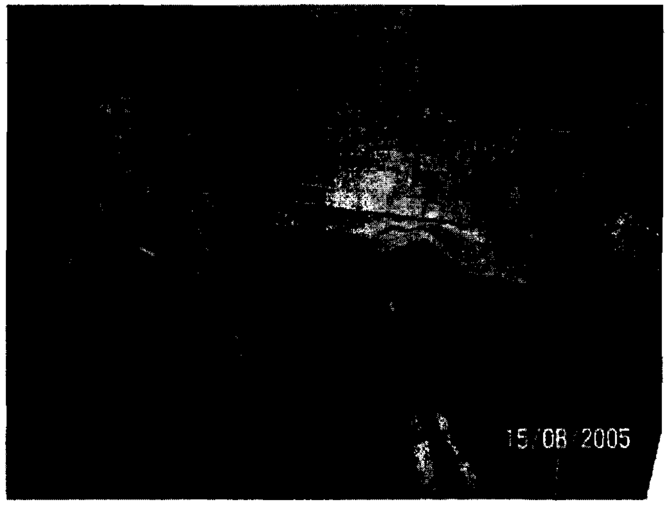
South Wall



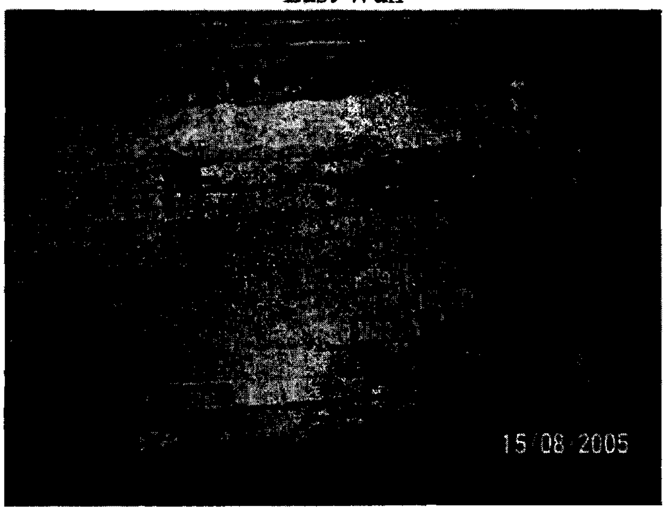
South Wall

Manhole No. 15

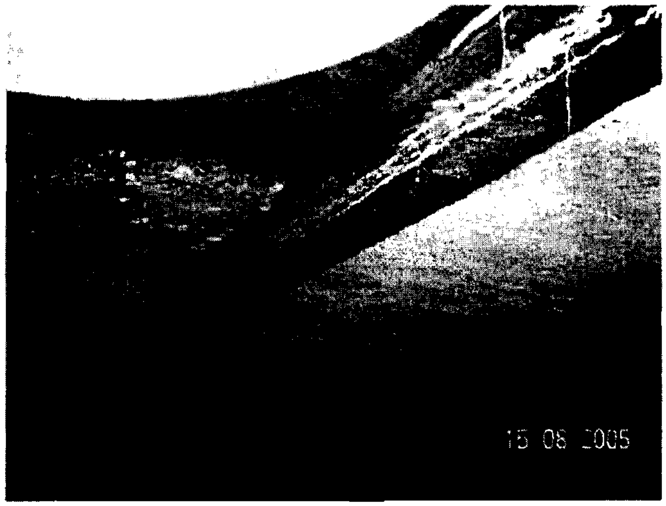
East Wall



East Wall

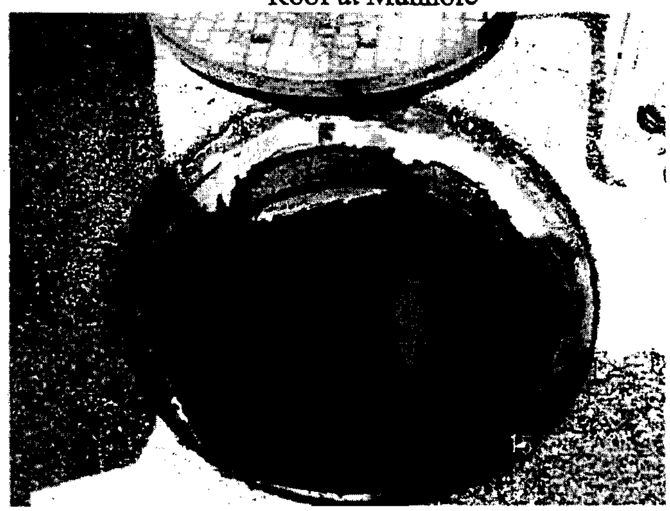


East Wall



Roof at Manhole

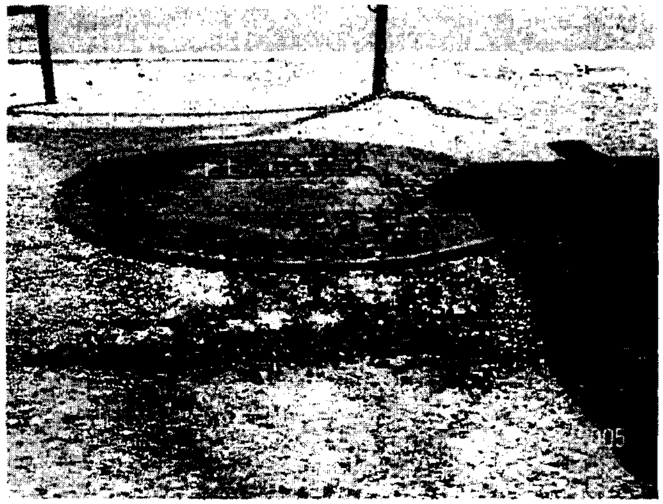
Roof to North Wall



Chimney

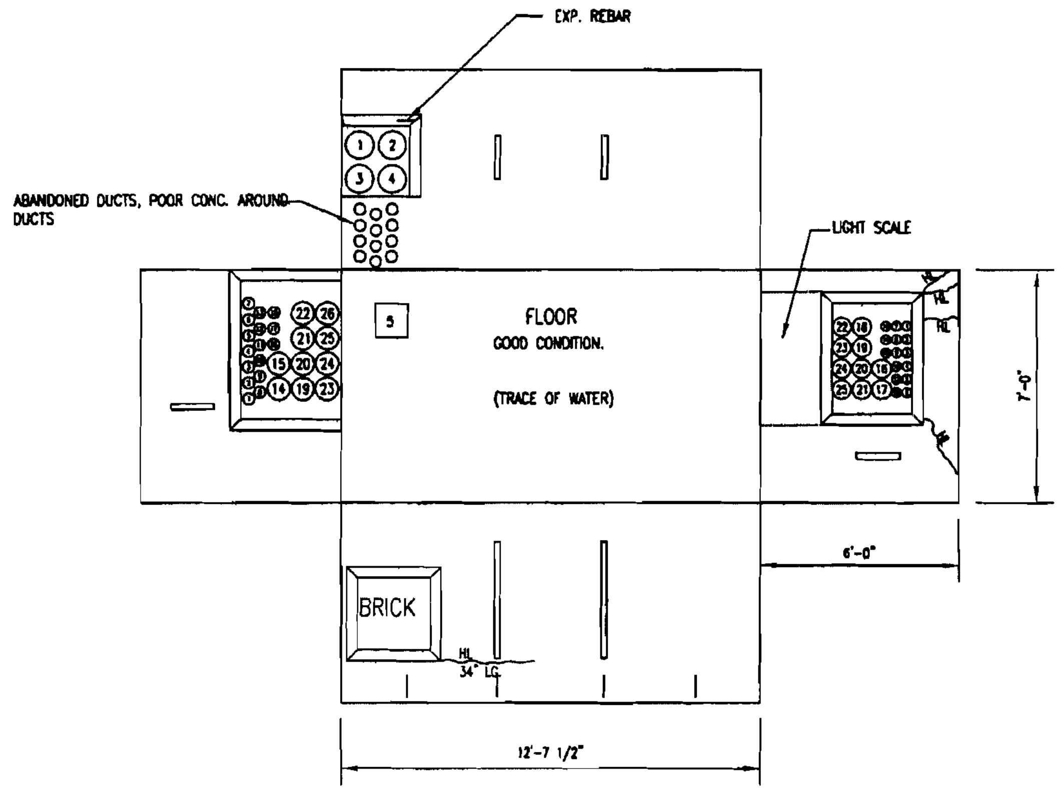
Manhole No. 15

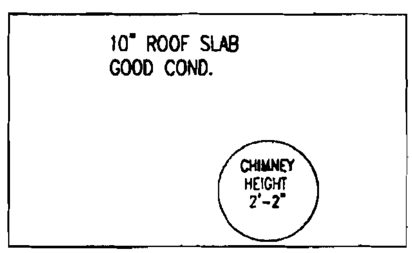
Ground around Chimney


Cover

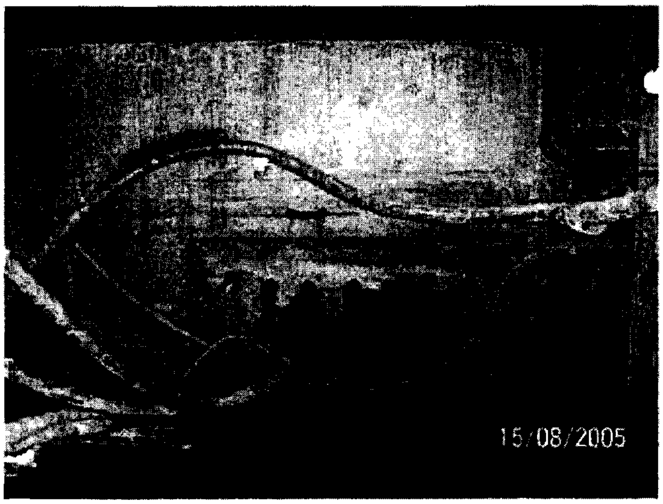
MANHOLE No. : 16

LOCATION: NORTHEAST CORNER OF ERIE & PELISSIER
OVERALL CONDITION: GOOD TRACE OF WATER (APPEARS TO BE NEWER CONC. VAULT. EVIDENCE OF BRICK AT DUCTBANKS)
REMARKS: BRACKETS IN GOOD CONDITION
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 15, 2005.

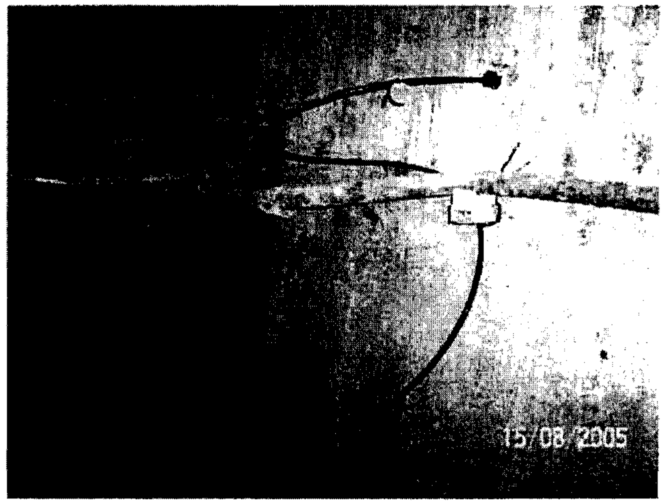




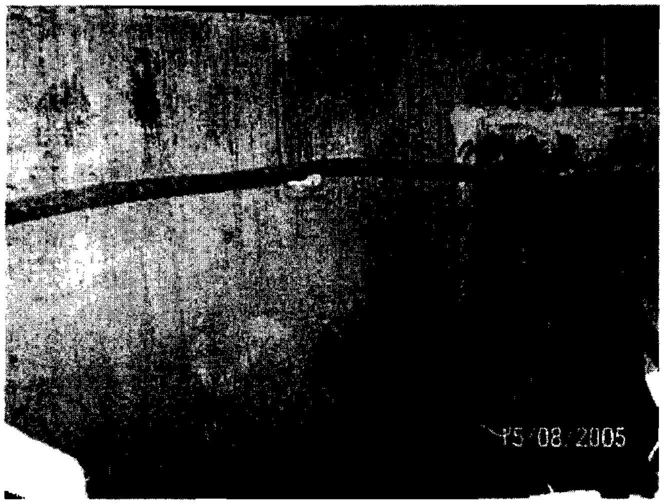
Manhole No. 16



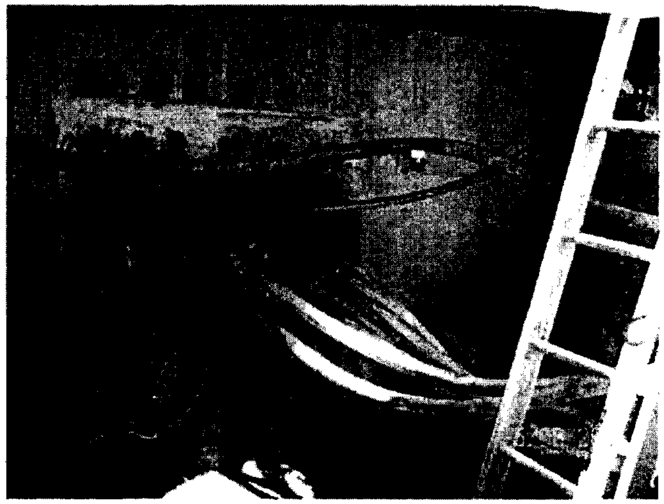
West Wall



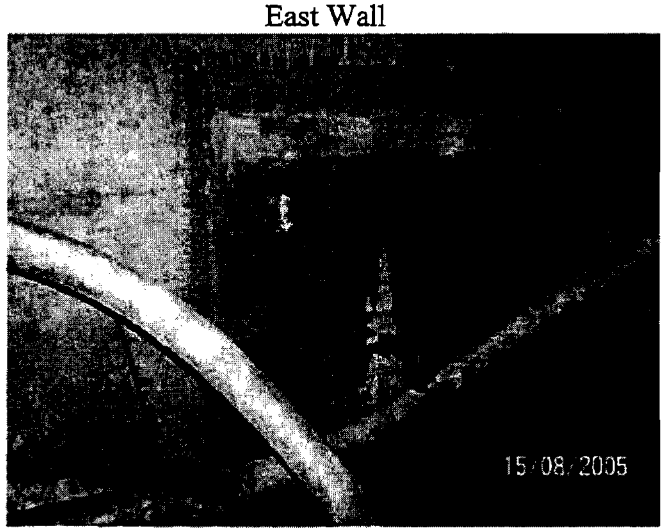
North West Wall



North Wall


East Wall

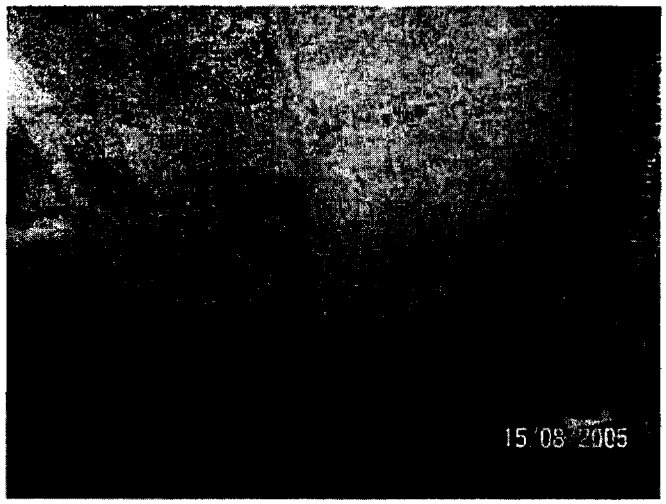
South Wall

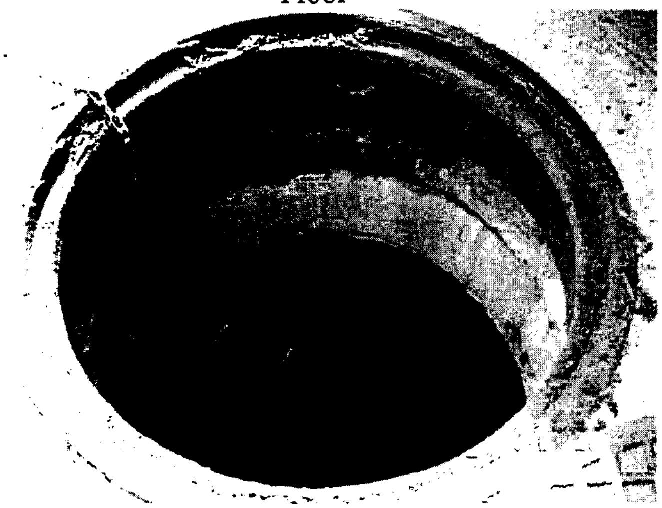


South West Wall

Manhole No. 16


Floor

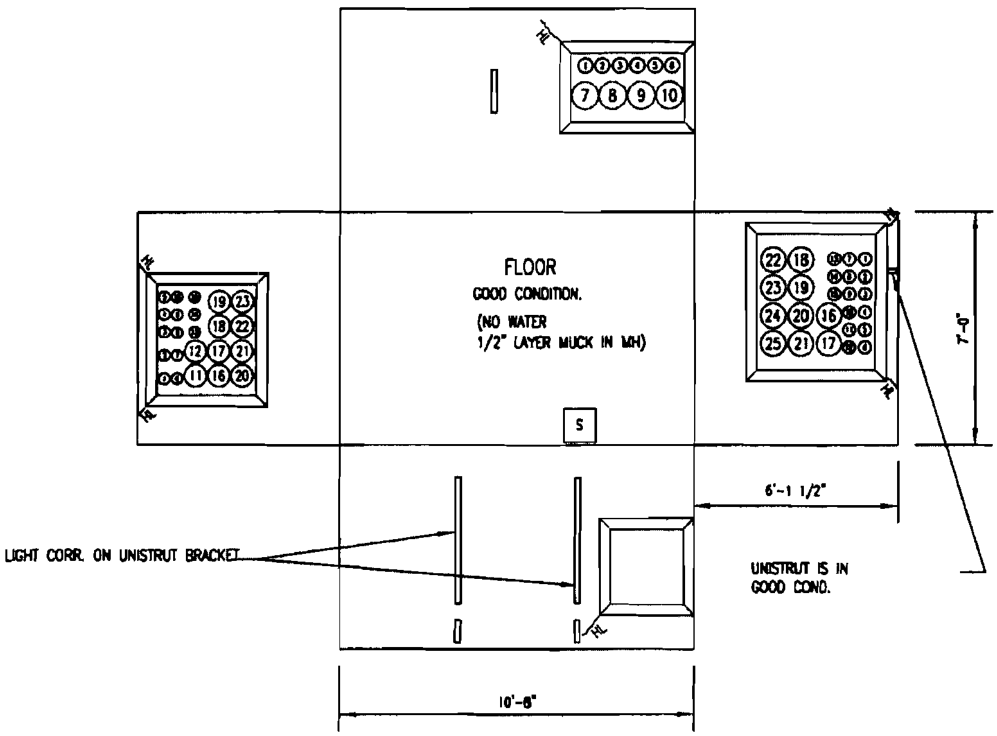

West Roof

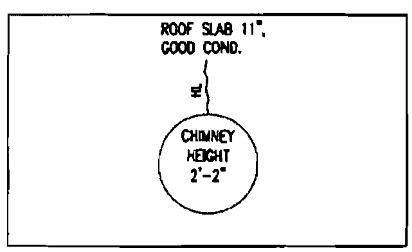

Chimney

MANHOLE No. : 17

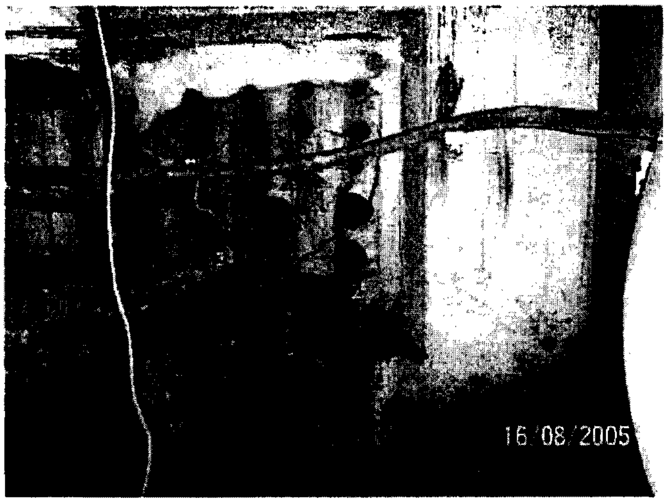
LOCATION: NORTH SIDE OF ERIE, ALLEY WEST OF PELISSIER
OVERALL CONDITION: GOOD, APPEARS TO HAVE BEEN RECETNLY CONSTRUCTED
REMARKS: MANHOLE HAS CONCRETE WALLS, BRACKETS IN GOOD CONDITION

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 16 2005.

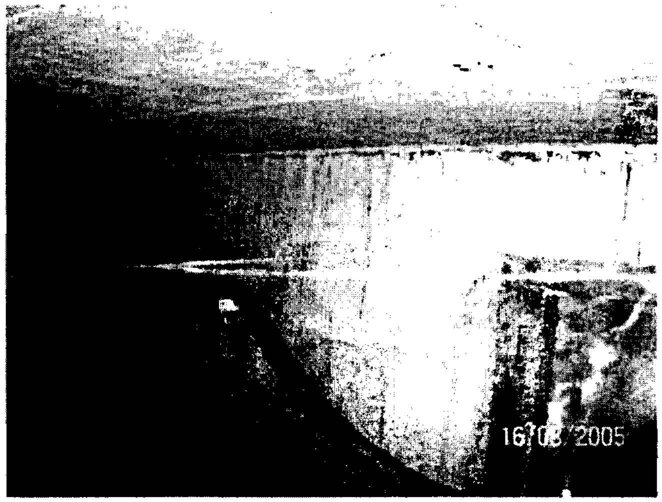


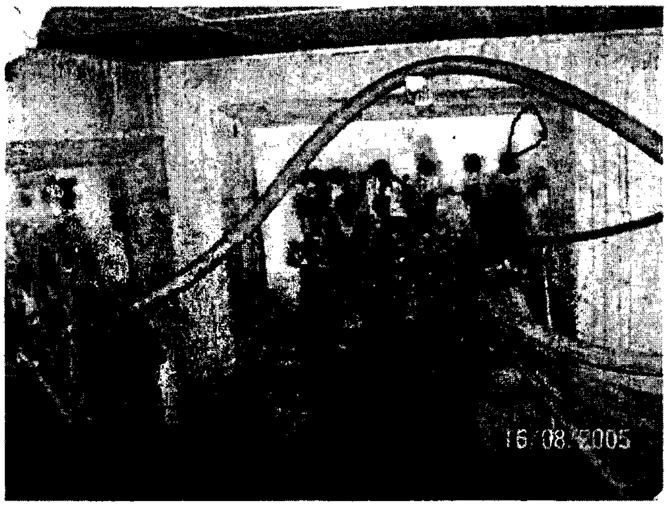


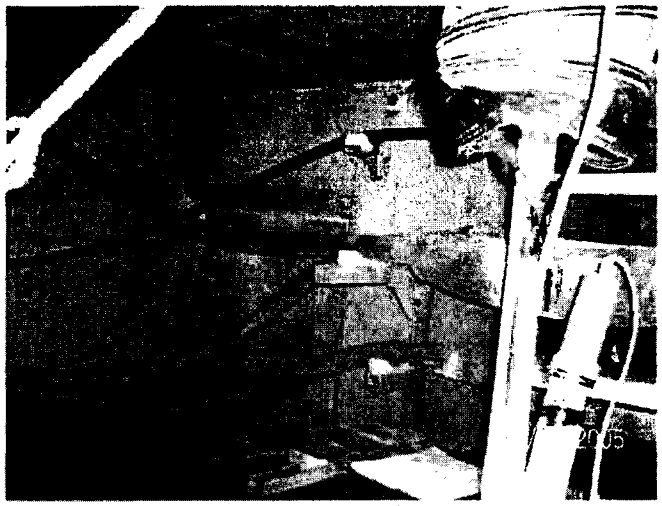
Manhole No. 17

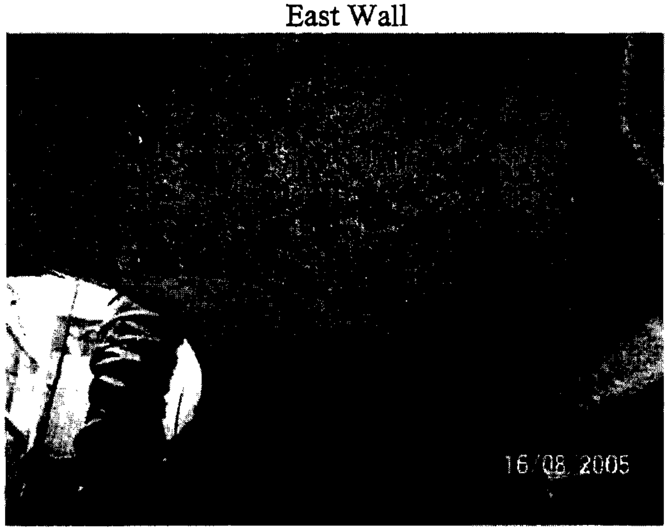


West Wall


North Wall


East Wall

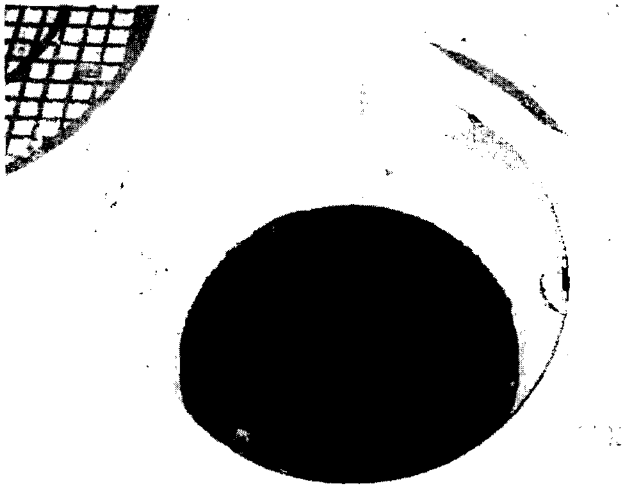

South Wall



Ceiling (West)


Floor

Manhole No. 17

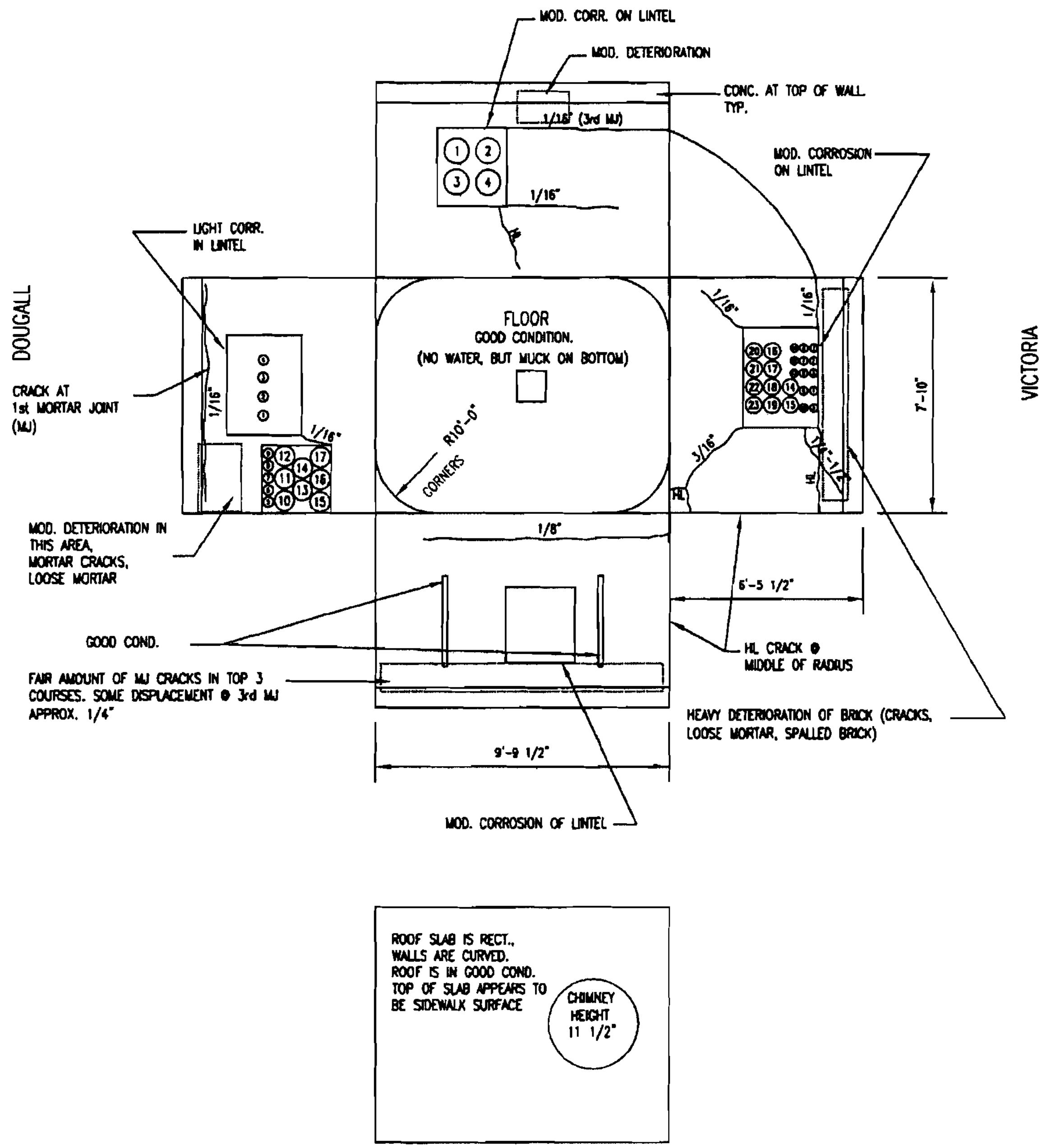


Chimney

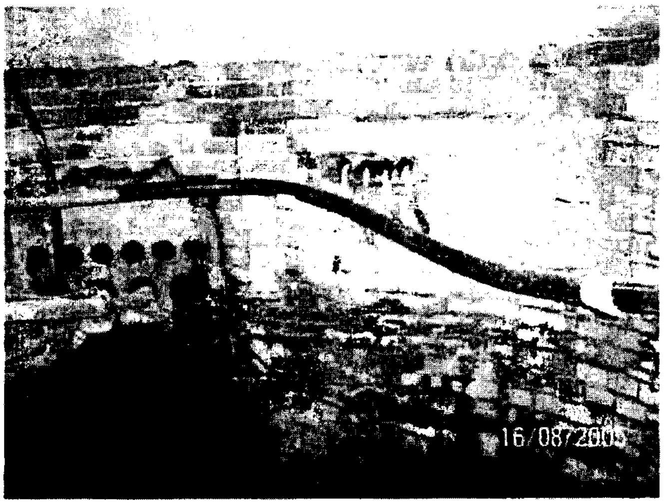
MANHOLE No. : 18

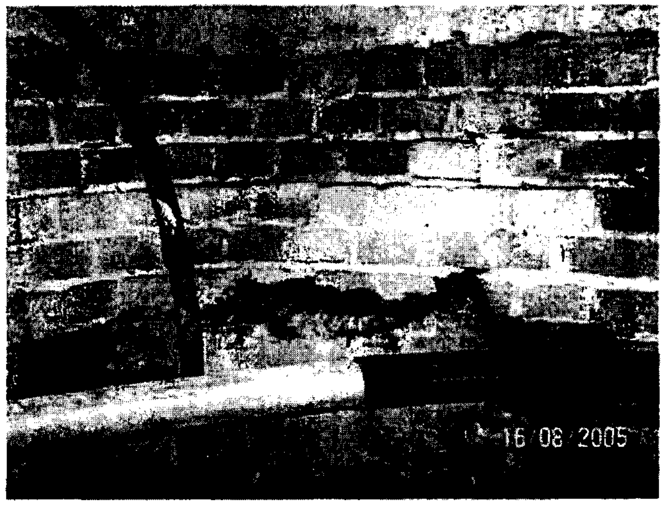
LOCATION: NORTH SIDE OF ERIE, ALLEY WEST OF VICTORIA
OVERALL CONDITION: ROOF – GOOD, WALLS – FAIR TO POOR
REMARKS: MANHOLE HAS BRICK WALLS.

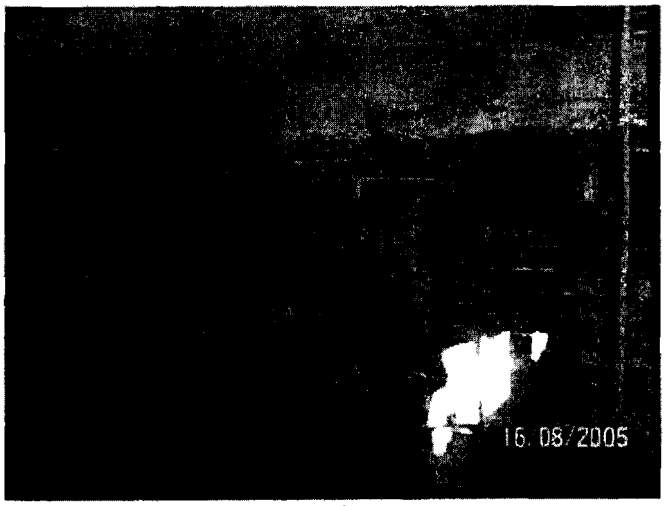
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 16, 2005.

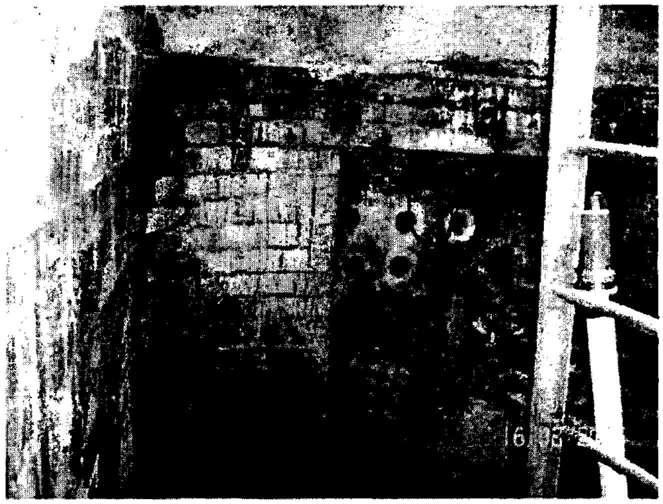


Manhole No. 18


East Wall


Southwest Corner Top


North


East

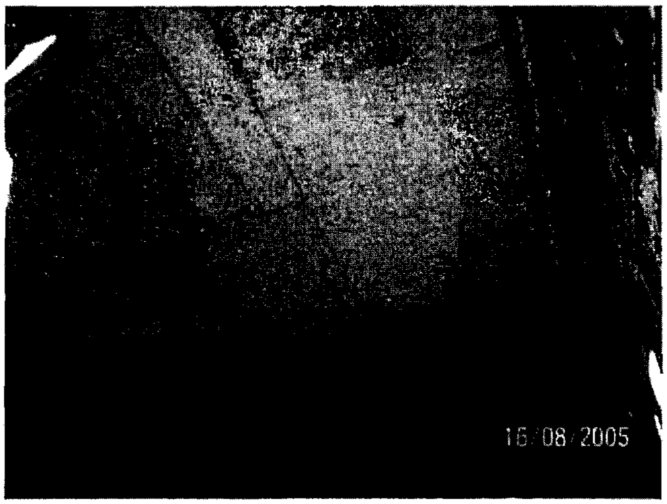

East Top


Southeast Corner Top

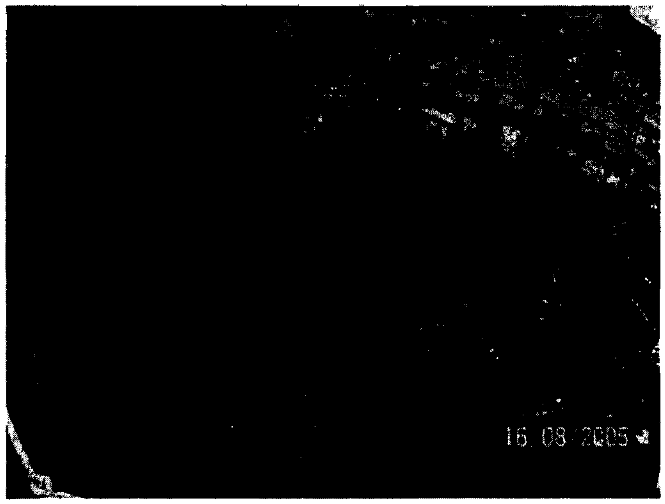
Manhole No. 18

South Wall

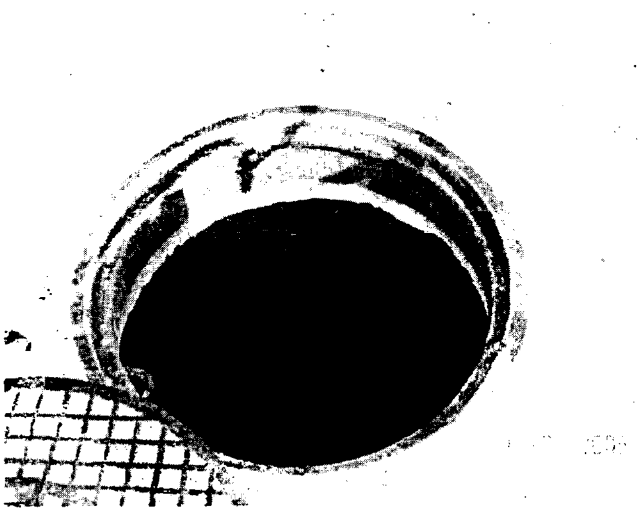
South Wall (Bottom)



Roof West



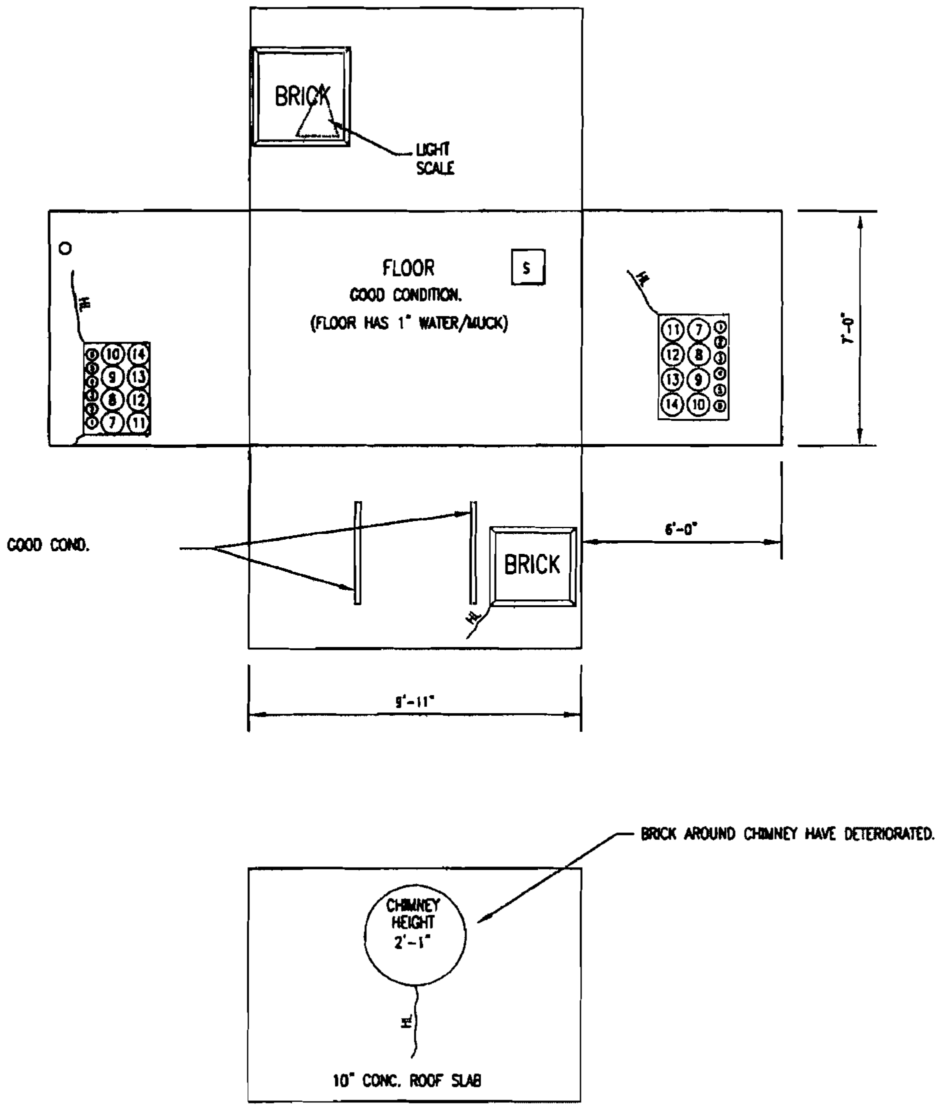
Floor West


Chimney

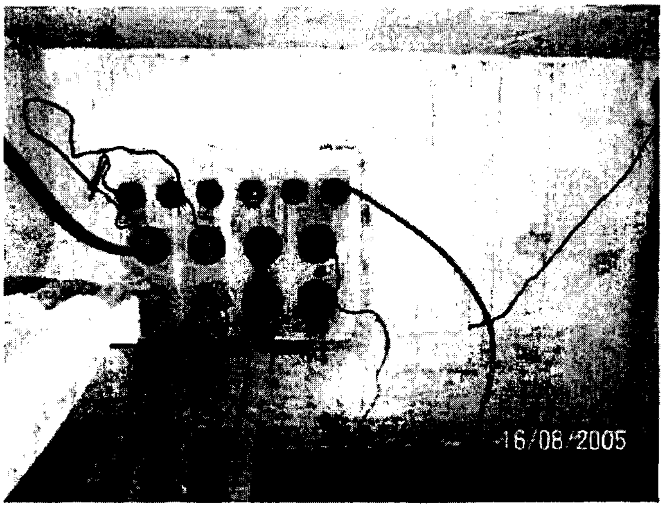
MANHOLE No. : 32

LOCATION: NORTH SIDE OF ERIE, ALLEY WEST OF DOUGALL
OVERALL CONDITION: GOOD RECENTLY RECONSTRUCTED
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 16, 2005.

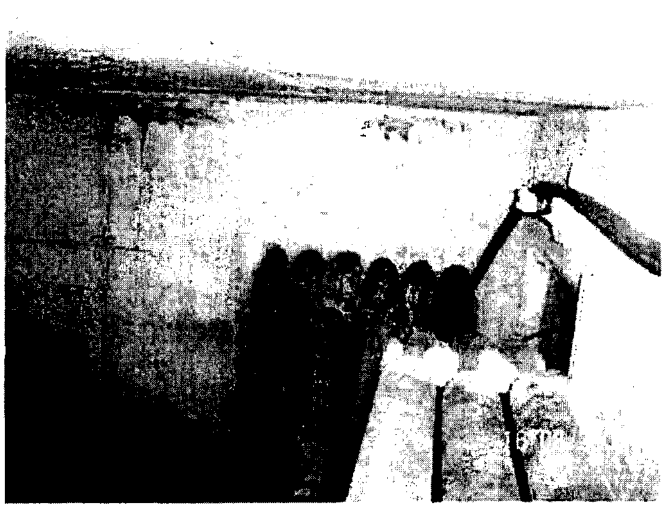


Manhole No. 32

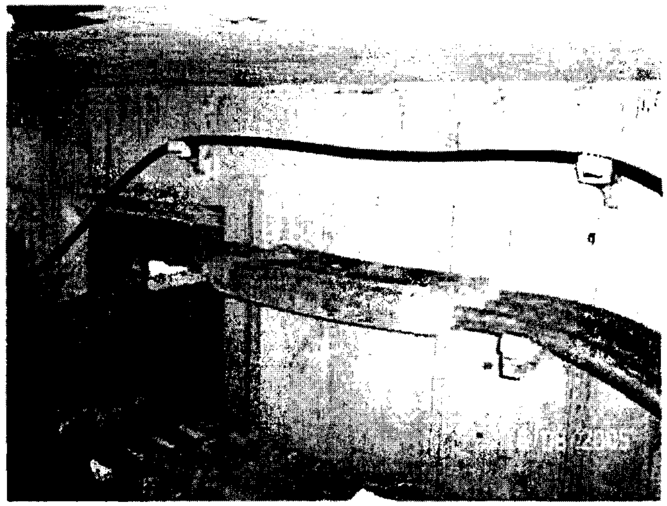


West

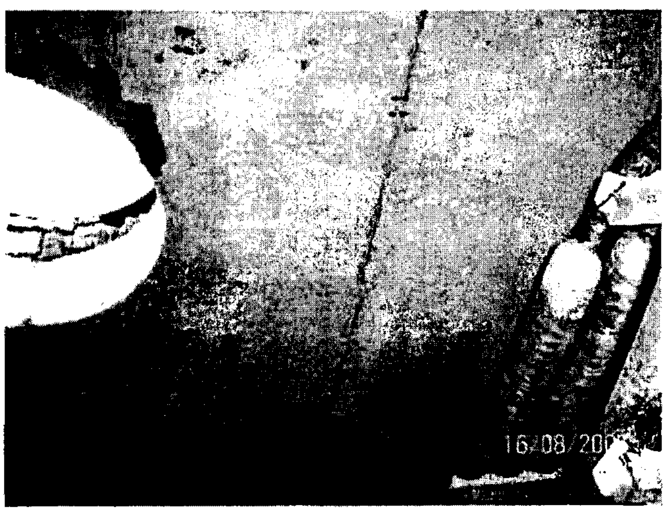
North



East



South



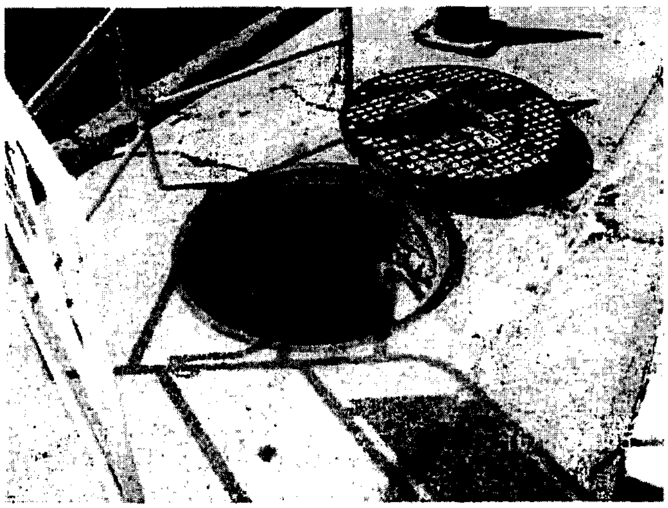
Ceiling

Floor

Manhole No. 32

Chimney

Chimney

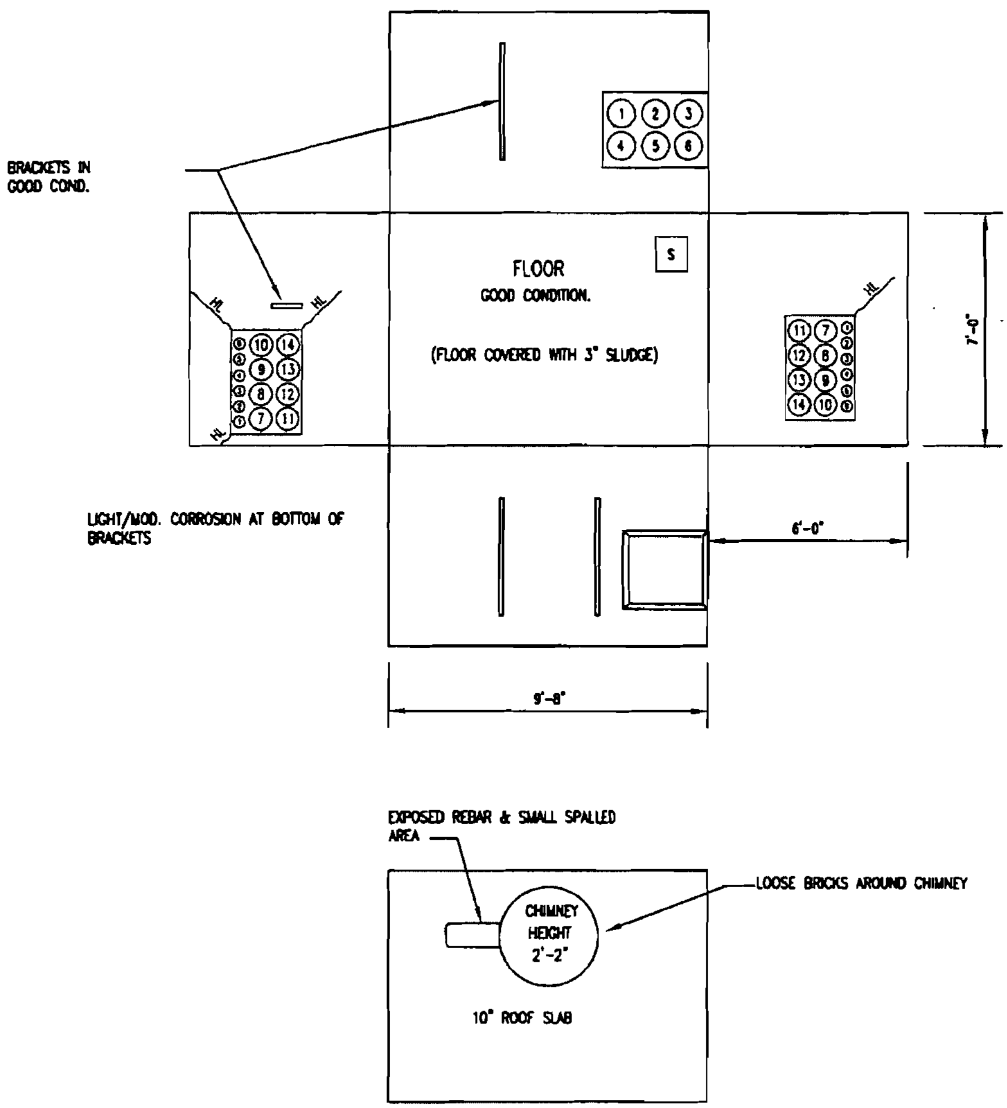


Surface

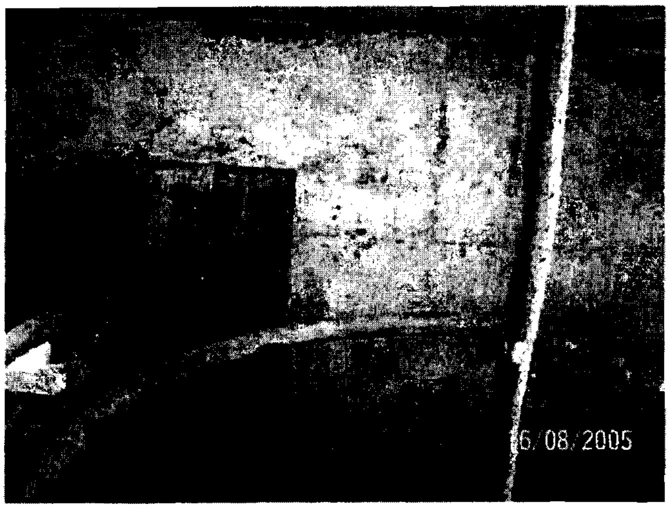
MANHOLE No. : 33

LOCATION: NORTH SIDE OF ERIE, ALLEY WEST OF CHURCH
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

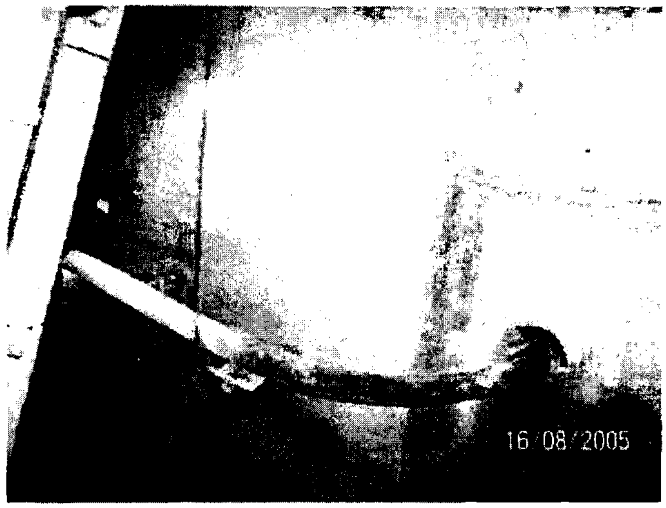
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 16, 2005.



Manhole No. 33

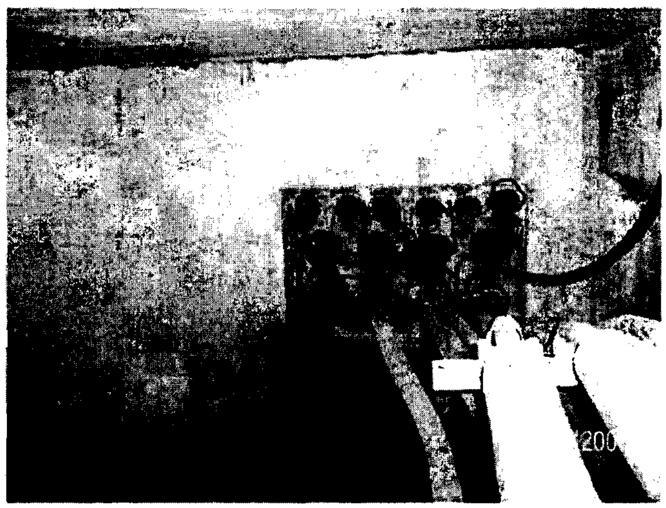


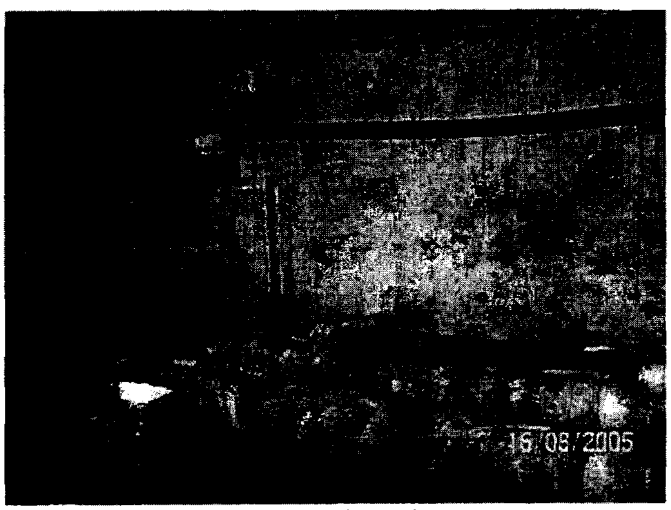
West Wall



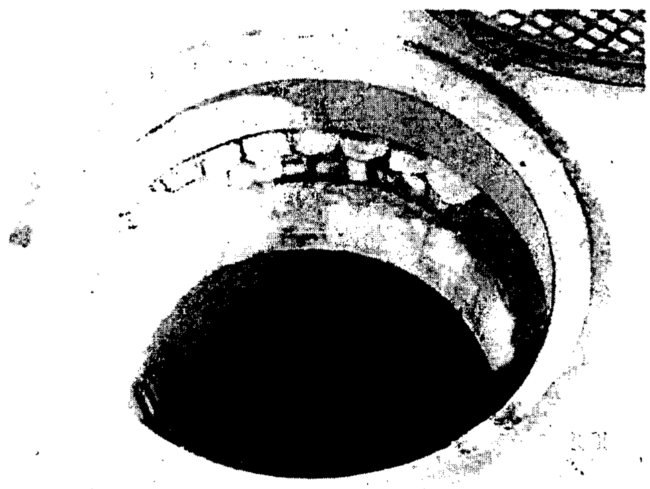
North Wall

Roof West


East Wall



South Wall


Chimney

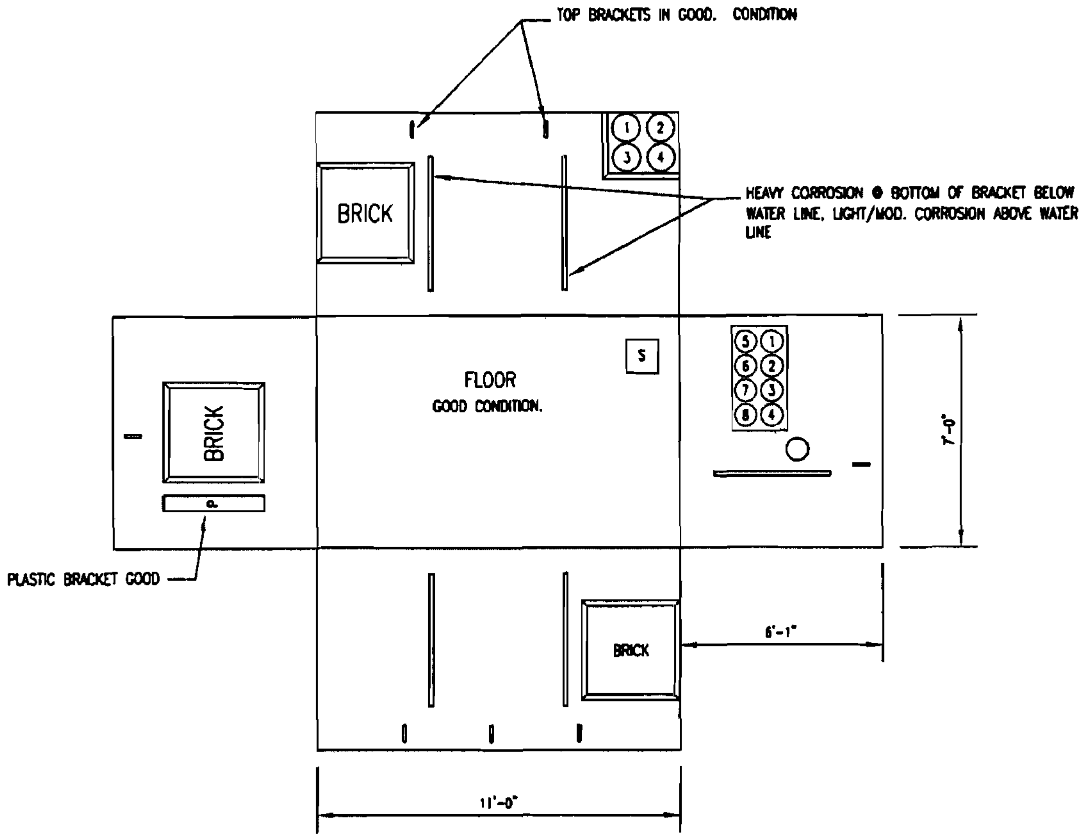
Manhole No. 33

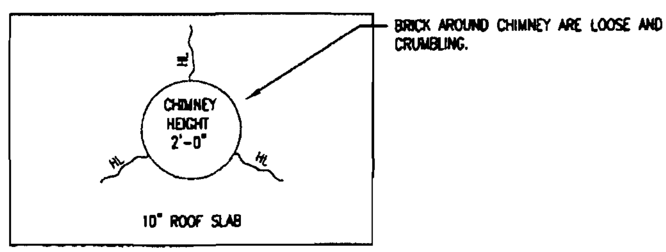
Chimney

MANHOLE No. : 34

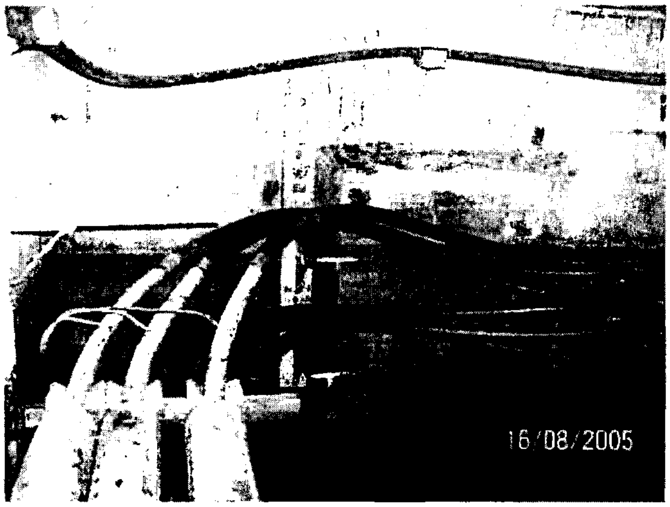
LOCATION: NORTH SIDE OF ERIE, ALLEY WEST OF BRUCE
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 16, 2005.

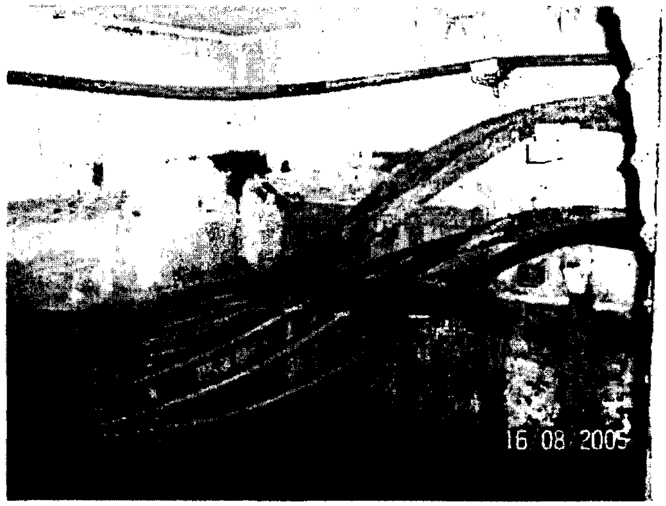




Manhole No. 34

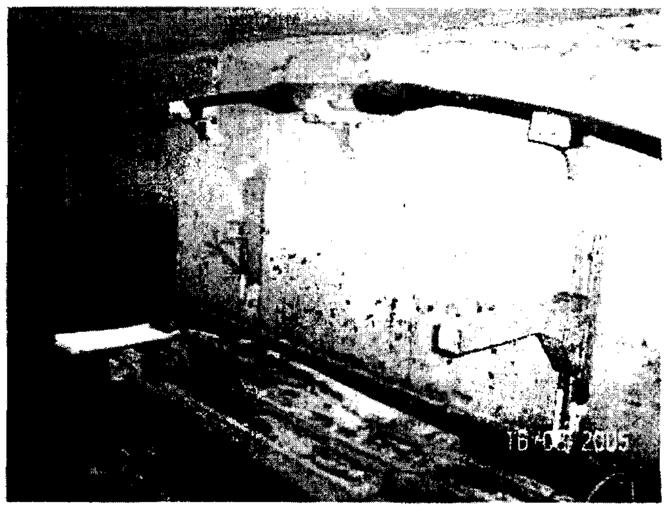


West Wall

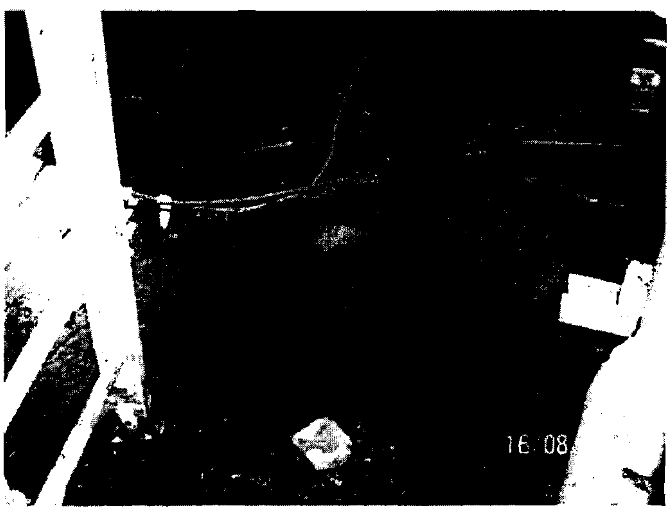


North Wall

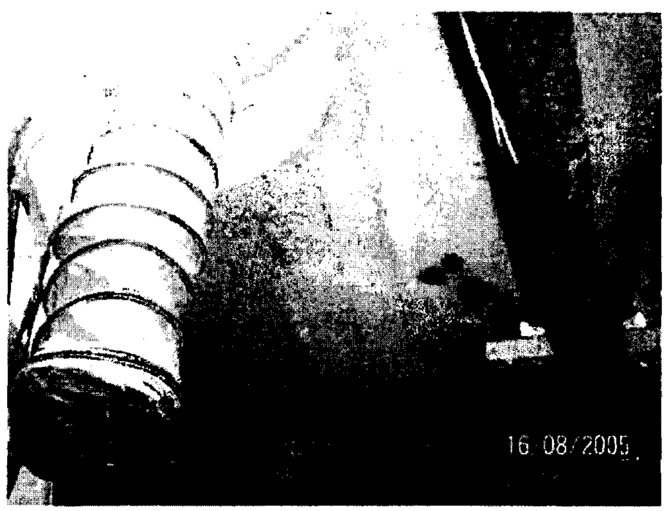
East Wall



South Wall

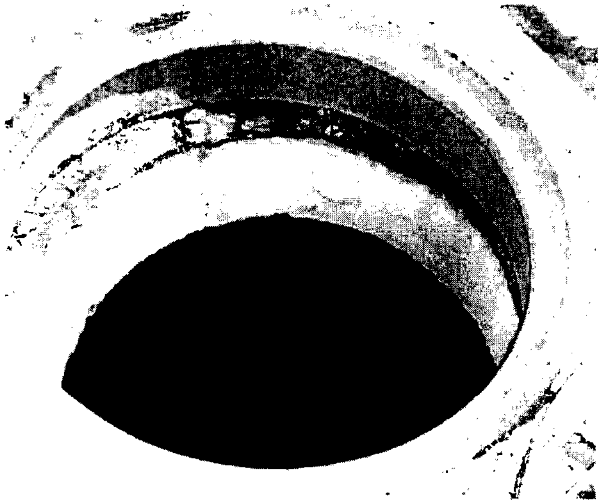


Floor



Roof

Manhole No. 34

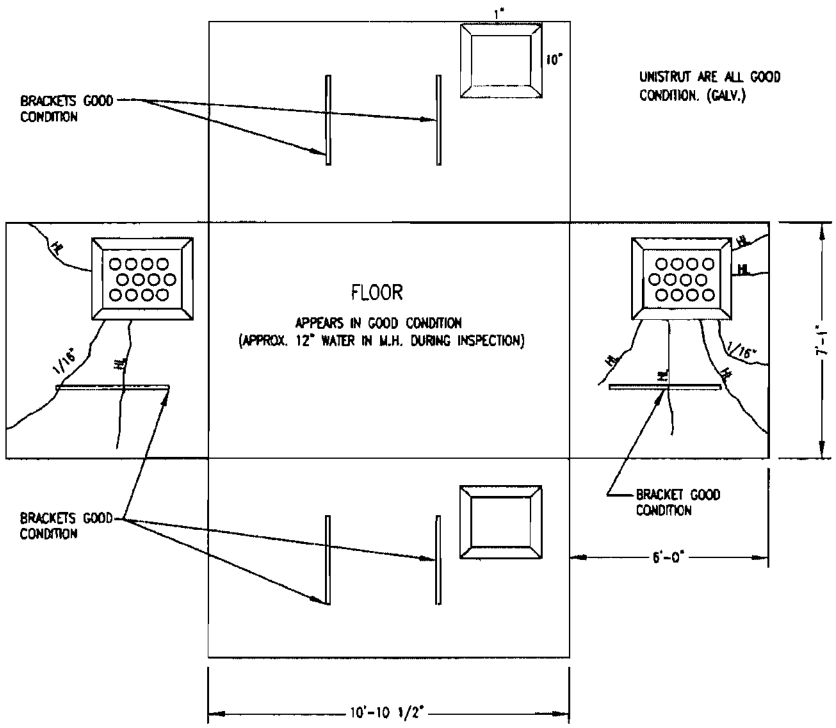


Chimney

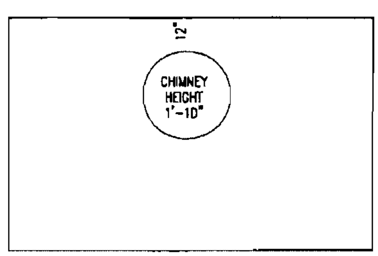
MANHOLE No. : 225

LOCATION: ERIE BETWEEN HOWARD & HIGHLAND.
OVERALL CONDITION: GOOD TO FAIR.
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



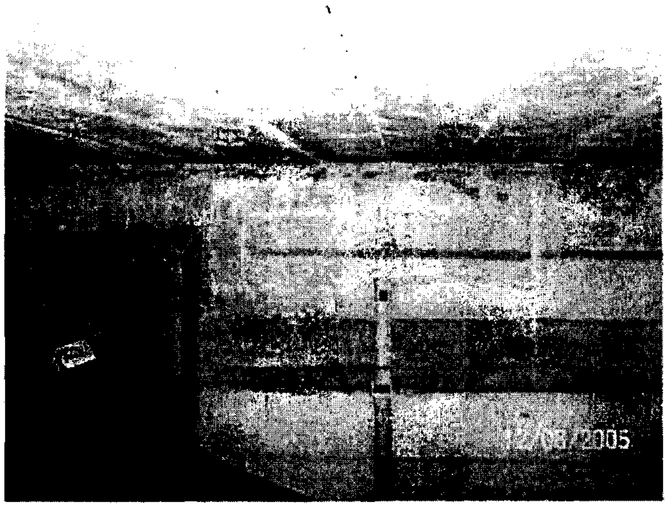
ROOF SLAB



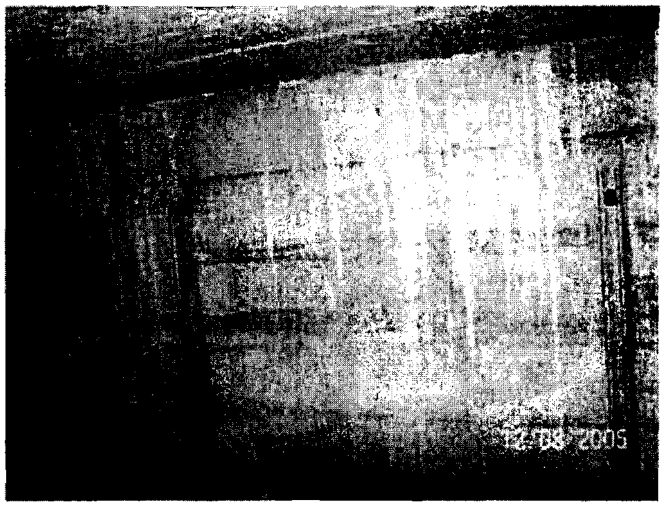
Manhole No. 225

West Wall

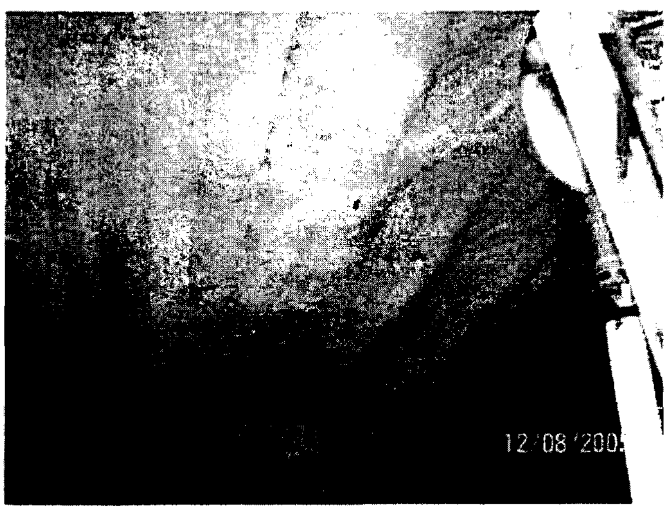
North Wall



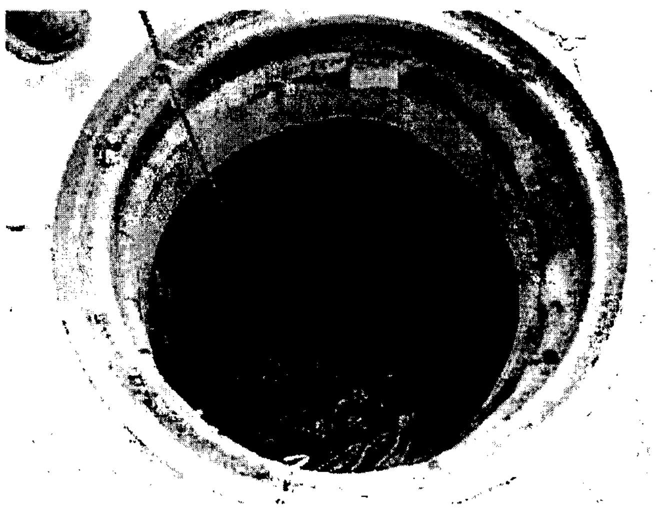
East Wall



South Wall



Roof (West)

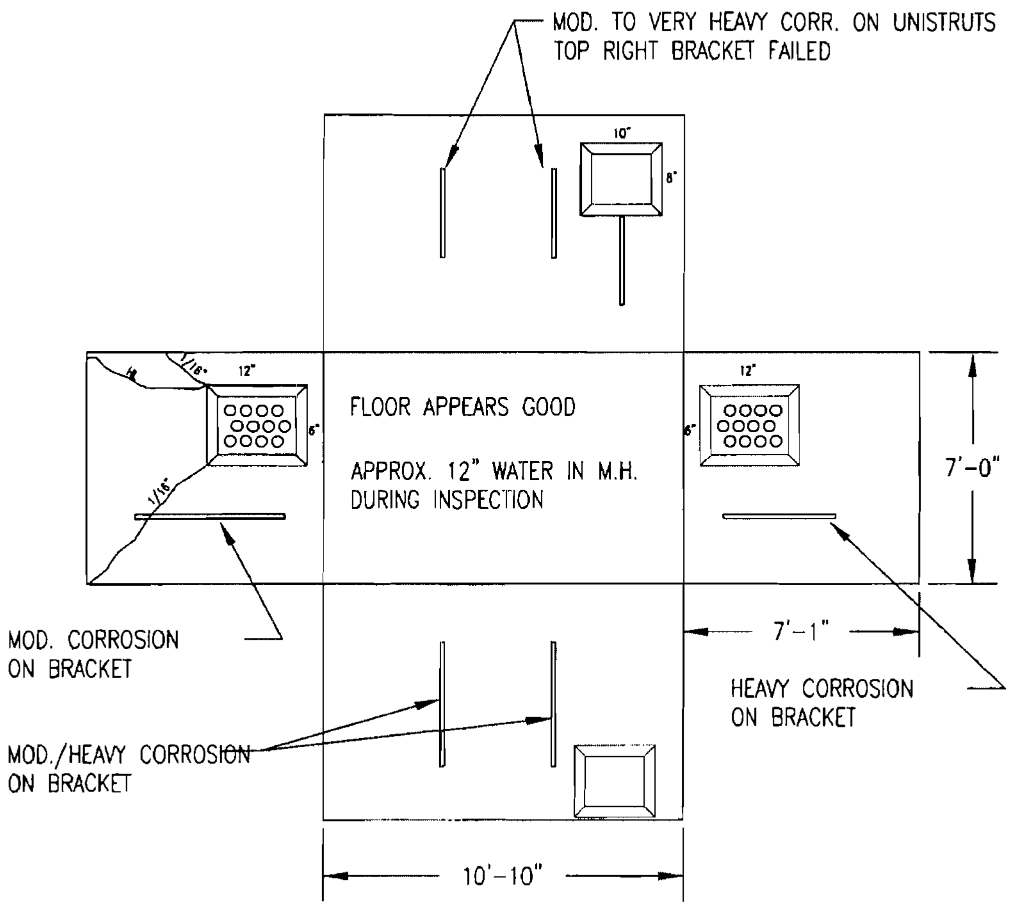


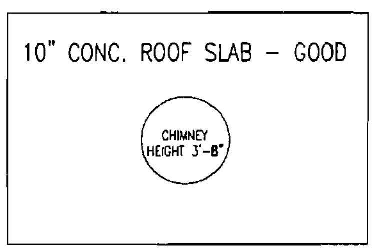
Chimney

MANHOLE No. : 226

LOCATION: ERIE BETWEEN LILLIAN & HOWARD.
OVERALL CONDITION: GOOD TO FAIR.
REMARKS: MANHOLE HAS CONCRETE WALLS.

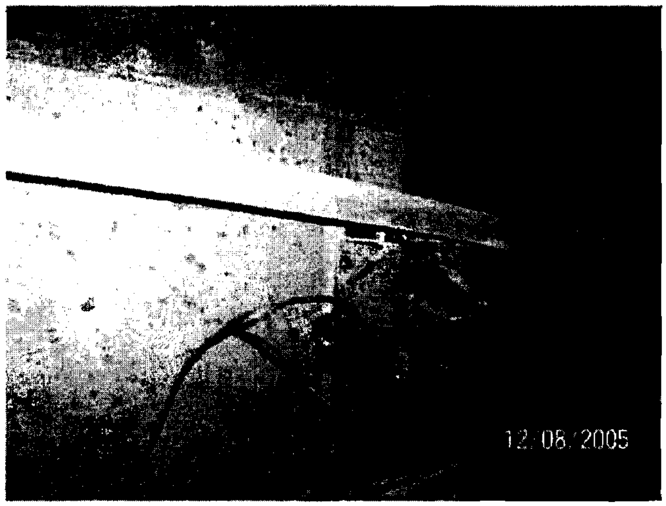
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 12, 2005.



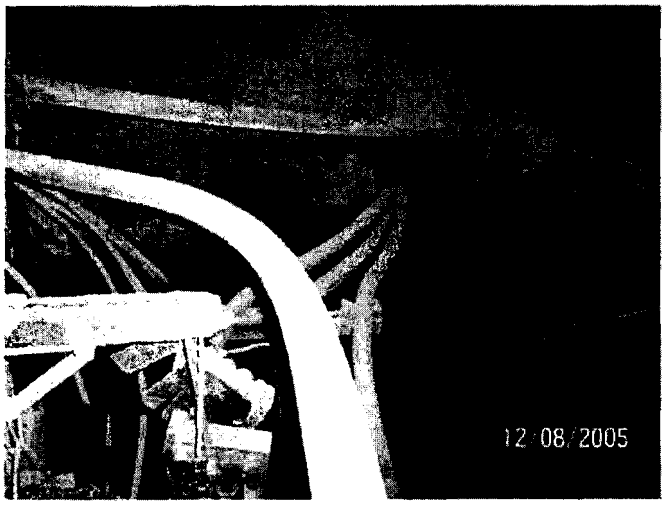


Manhole No. 226

West Wall



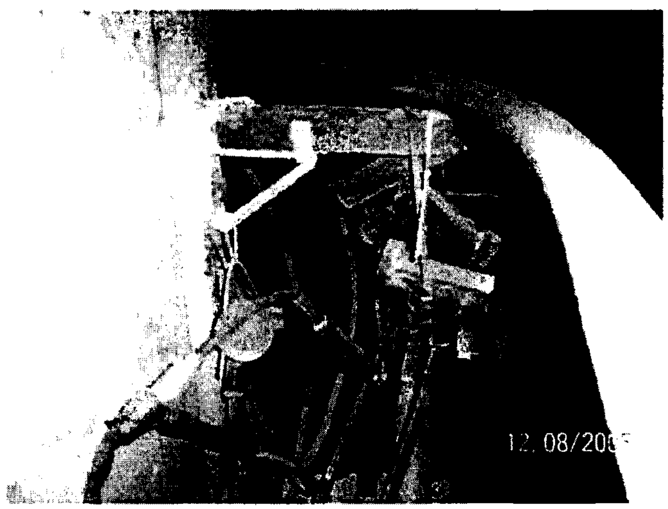
North Wall



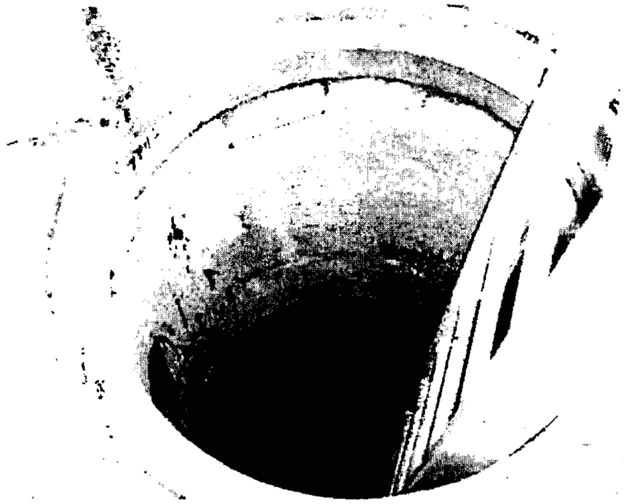
East Wall

Roof (West)


South Wall


North Wall Bracket

Manhole No. 226

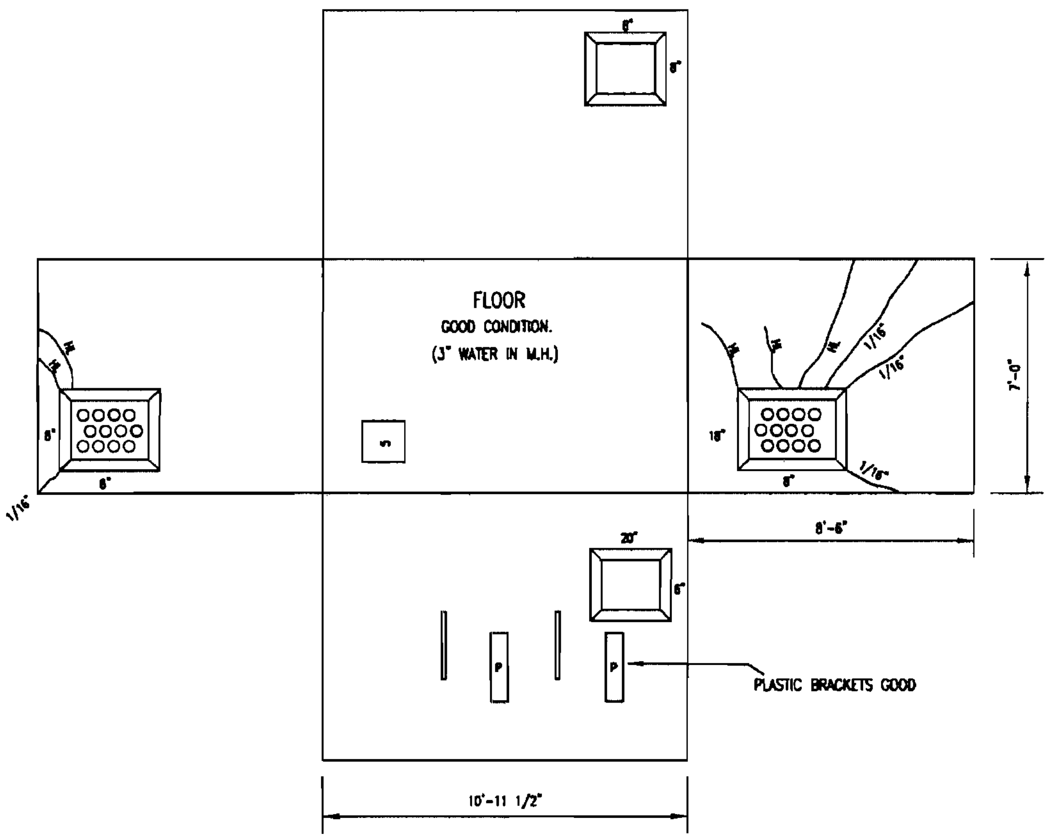


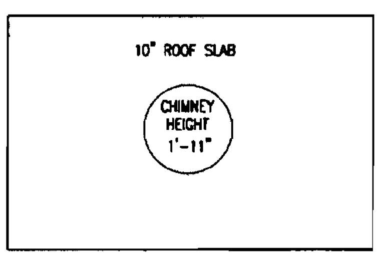
Chimney

MANHOLE No. : 227

LOCATION: ERIE AT LOUIS
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

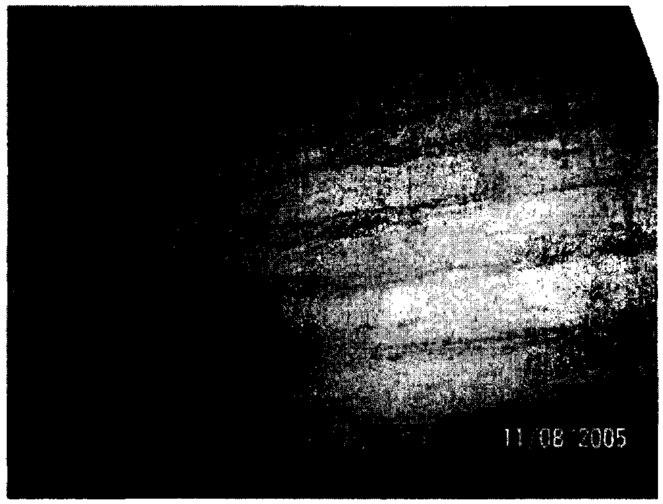
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



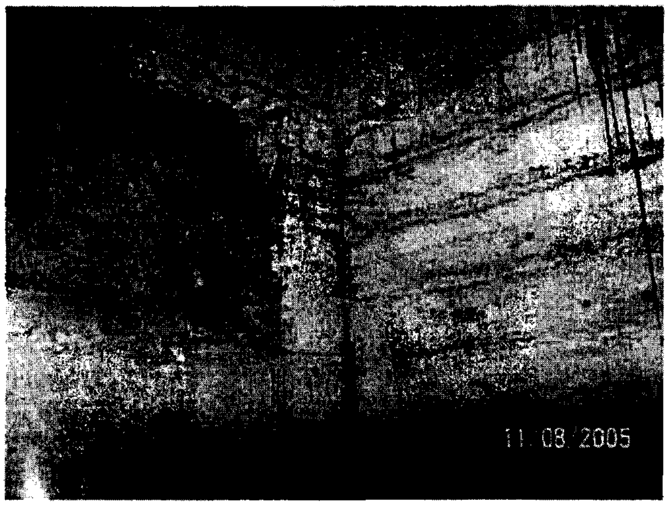


Manhole No. 227

West Wall

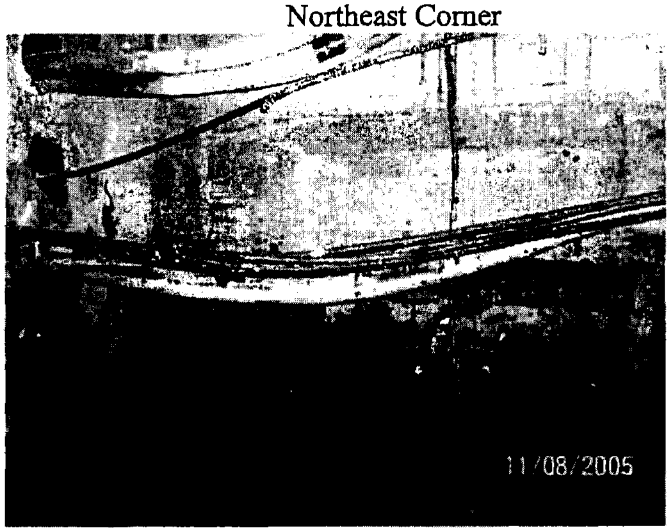


North Wall



Northeast Corner

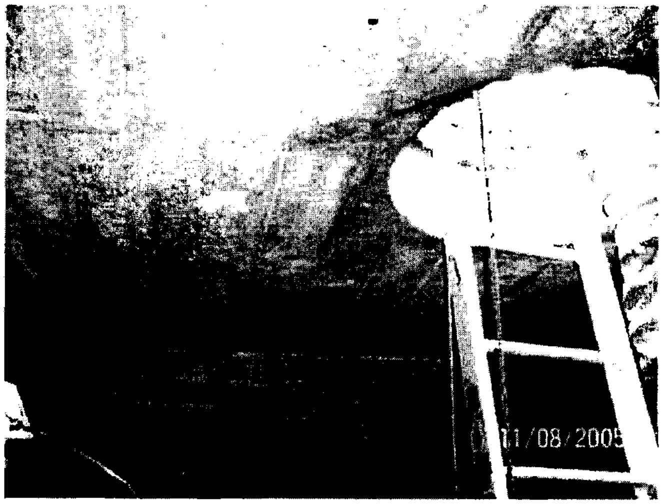
East Wall



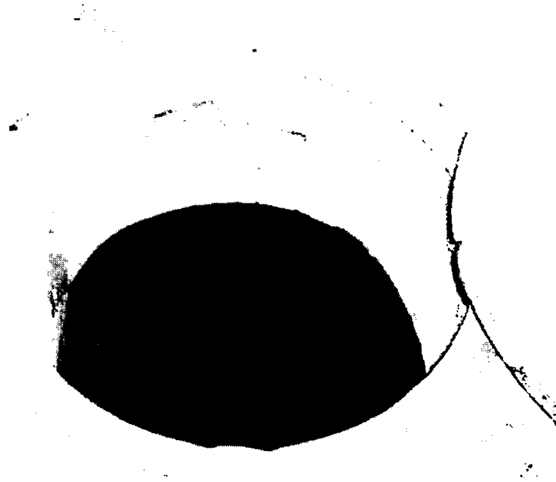
East Wall

South Wall

Manhole No. 227



West Roof

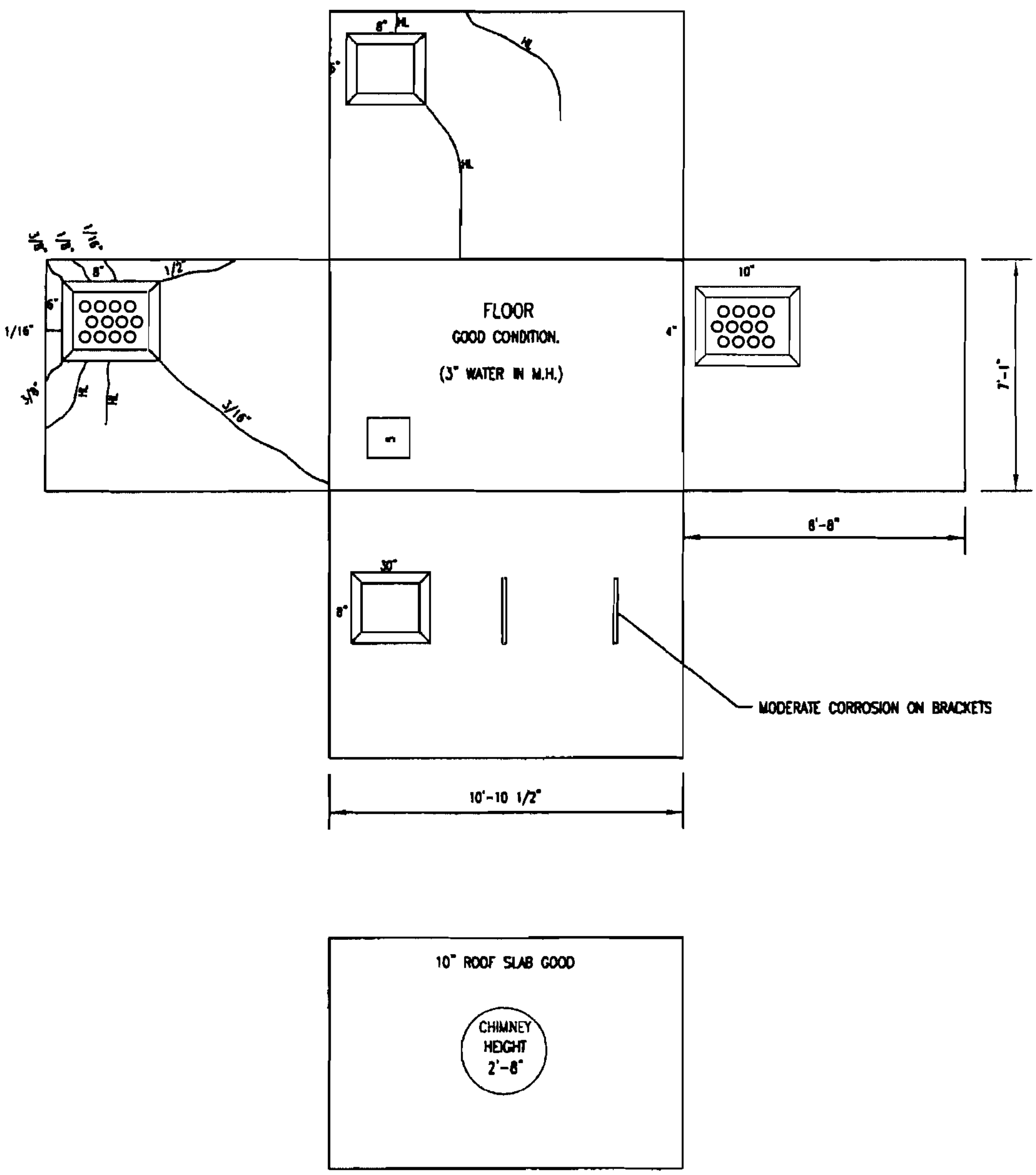


Chimney

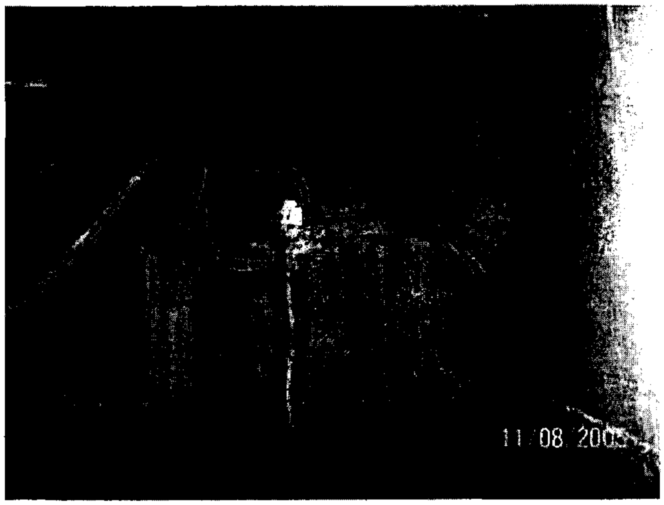
MANHOLE No. : 228

LOCATION: ERIE AT MARANETTE: (NW)
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

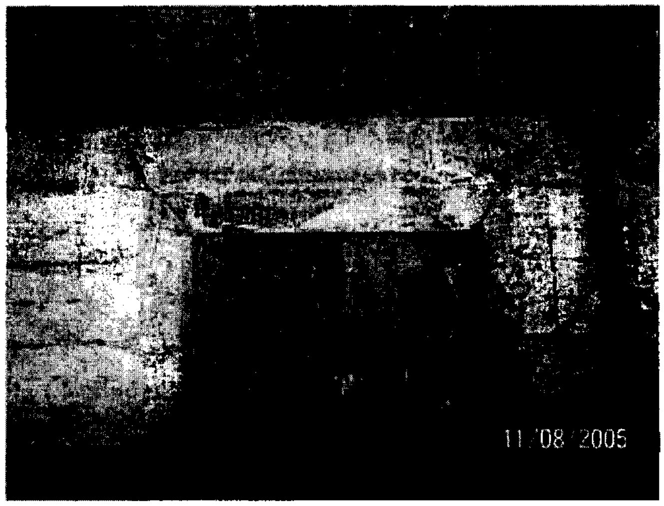
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



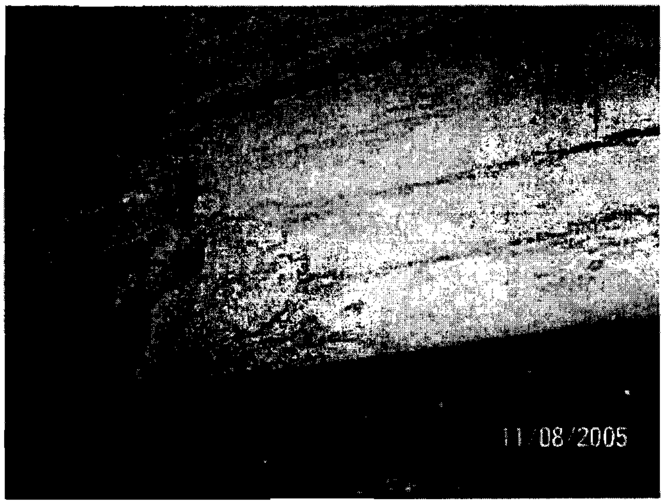
Manhole No. 228



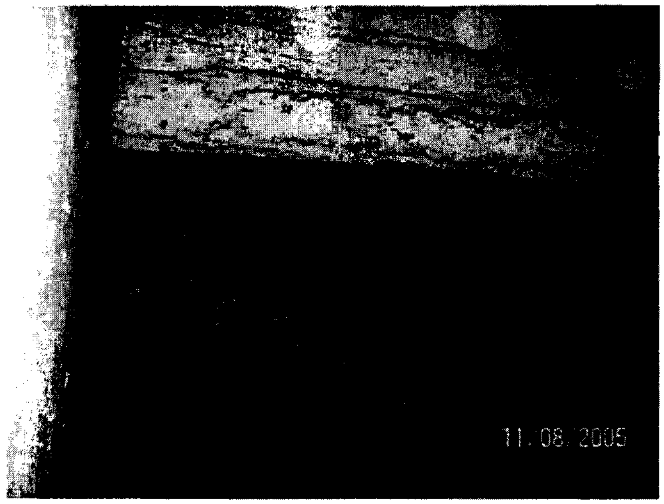
West Wall



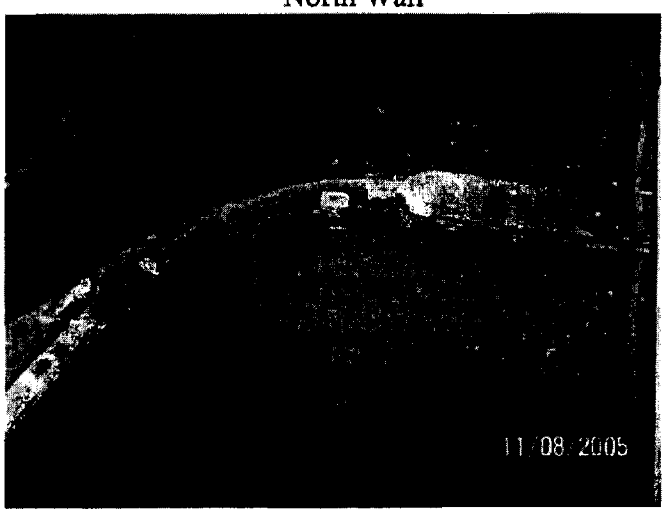
West Wall



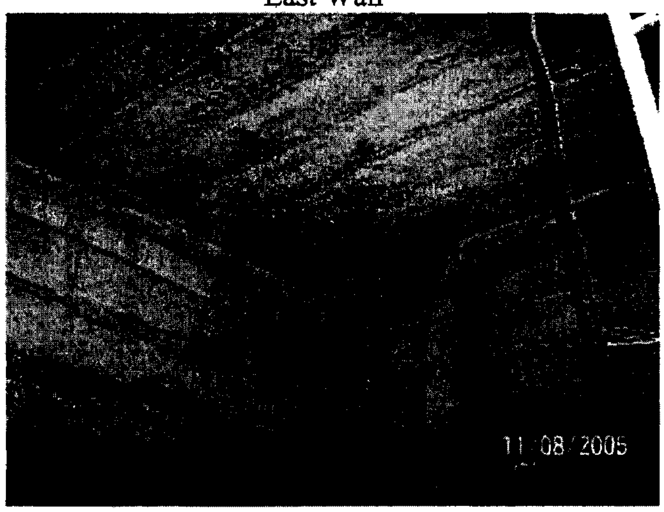
North Wall



East Wall



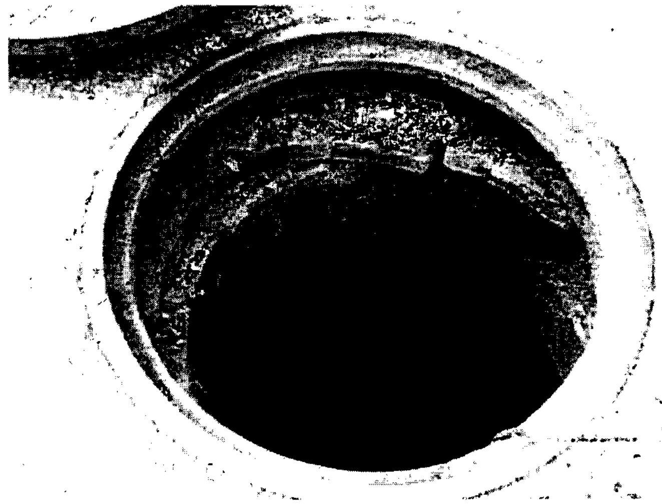
South Bracket



Southeast Roof

Manhole No. 228

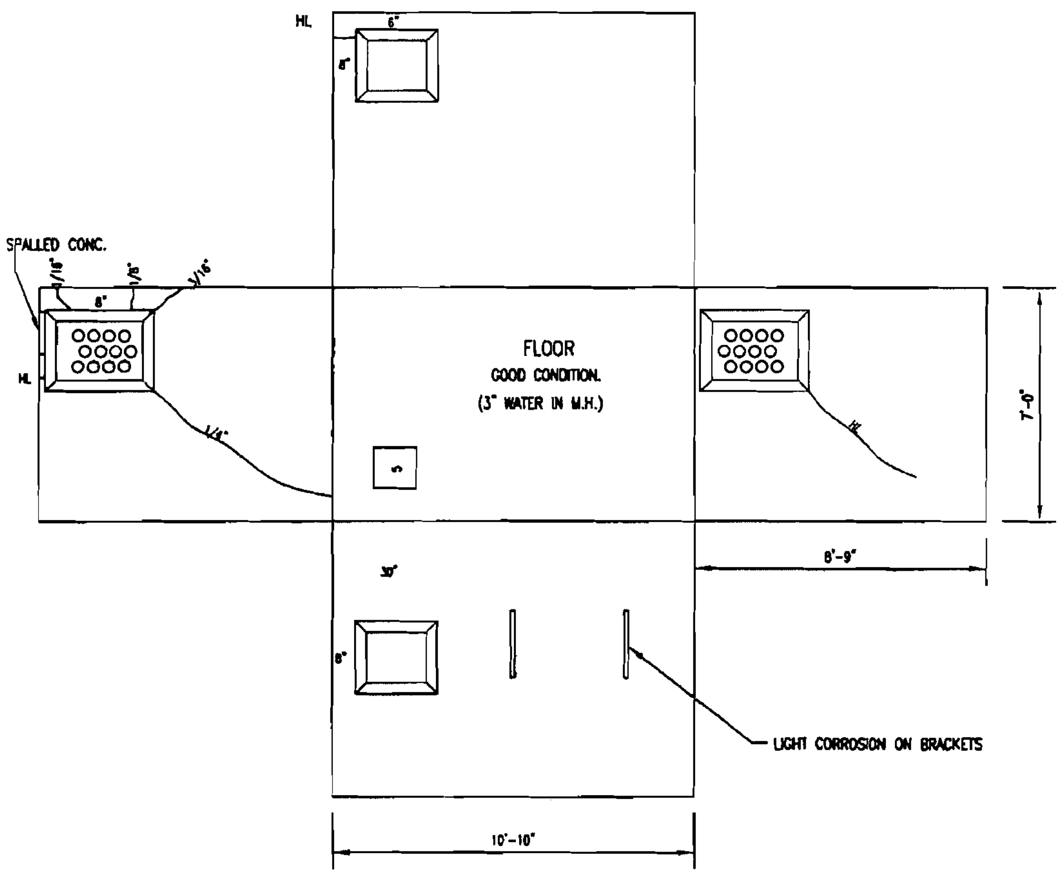
South west Wall

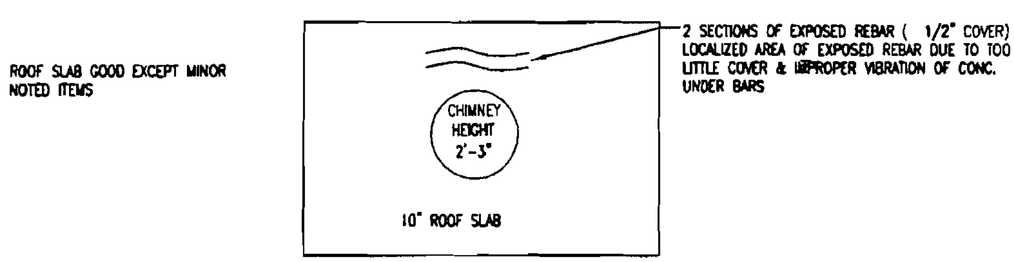

Chimney

MANHOLE No. : 229

LOCATION: ERIE & ELSMERE
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.

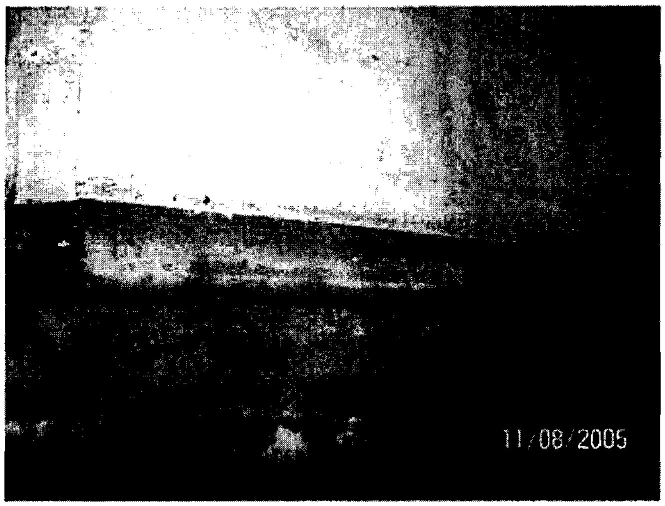




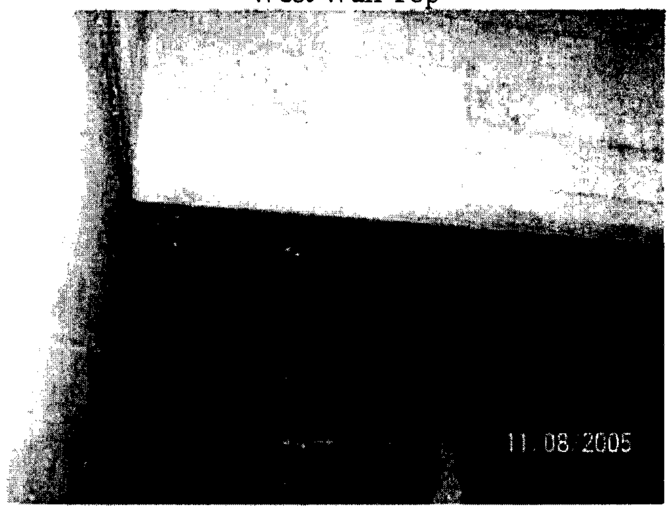
Manhole No. 229

West Wall Bottom

West Wall Top



North Wall

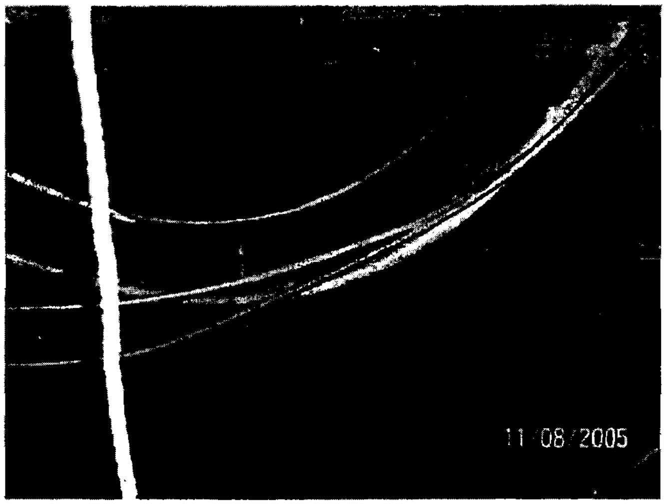


East Wall

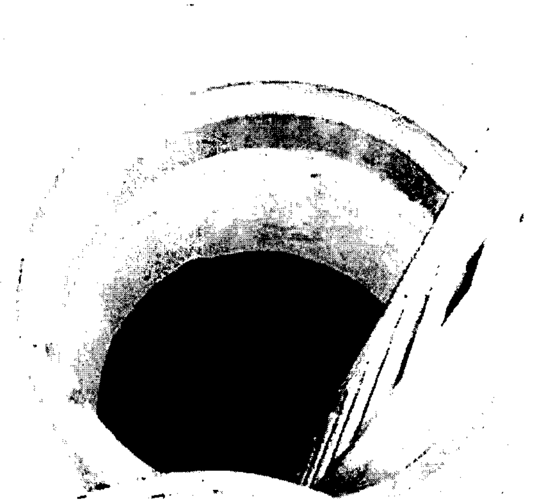
South Wall

East Roof

Manhole No. 229



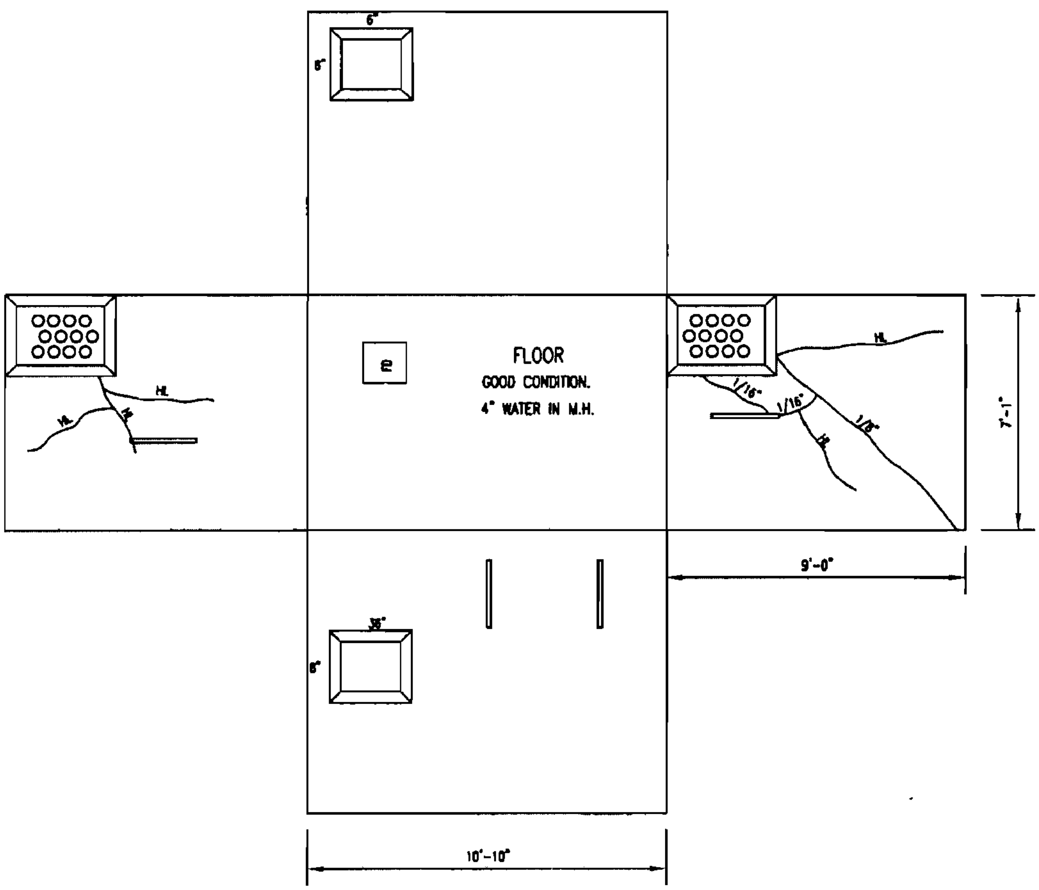
Southwest Corner


Chimney

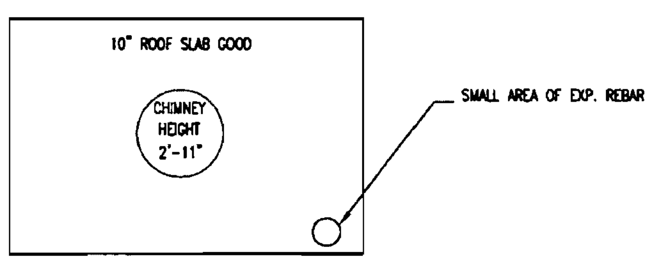
MANHOLE No. : 230

LOCATION: ERIE @ PARENT (NW CORNER)
OVERALL CONDITION: GOOD, ALL BRACKETS GOOD (LIGHT CORROSION)
REMARKS: MANHOLE HAS CONCRETE WALLS.

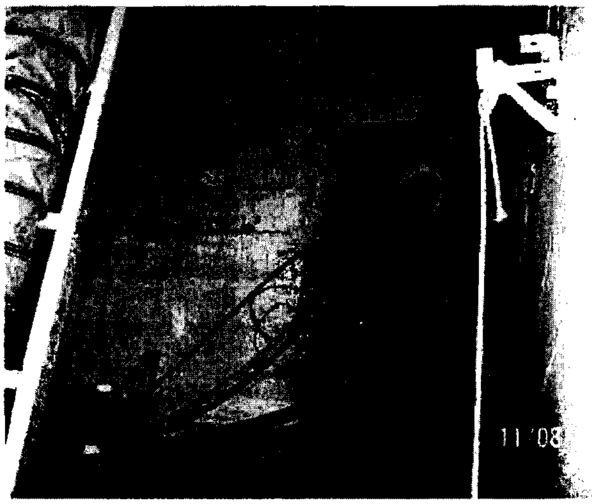
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.

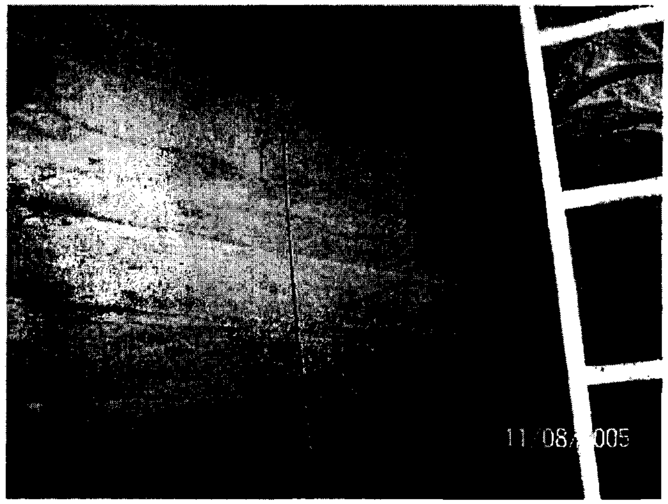


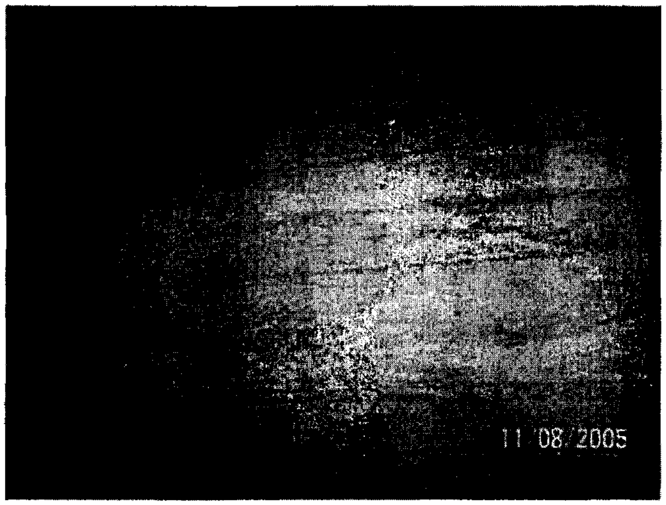
ROOF SLAB OK EXCEPT MINOR NOTED ITEMS



Manhole No. 230

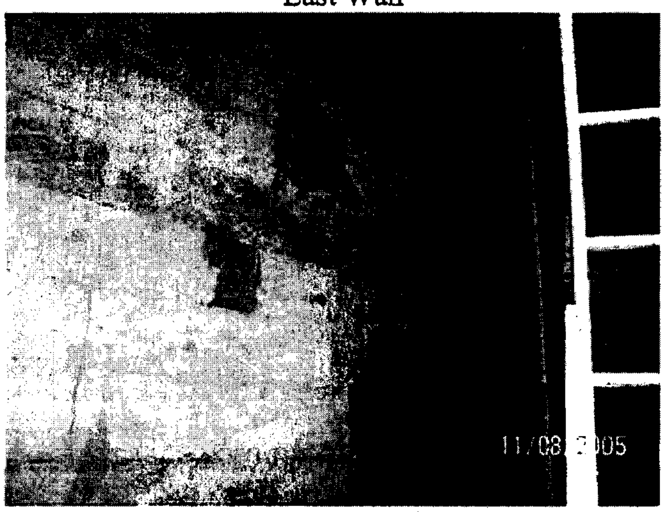

West Wall

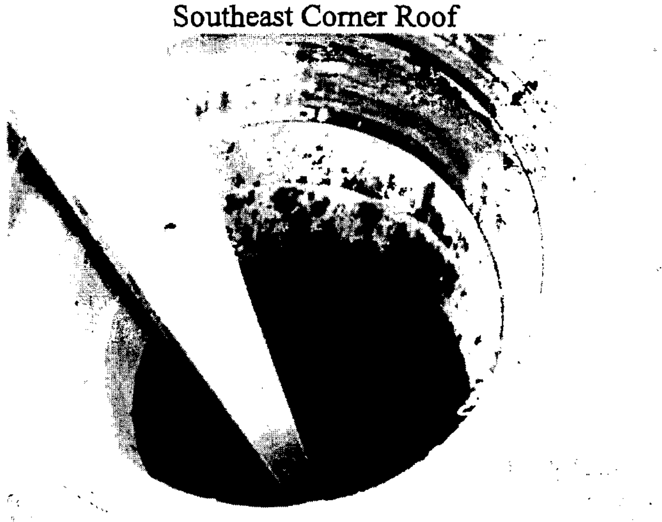

North Wall



East Wall


Southeast Corner Roof

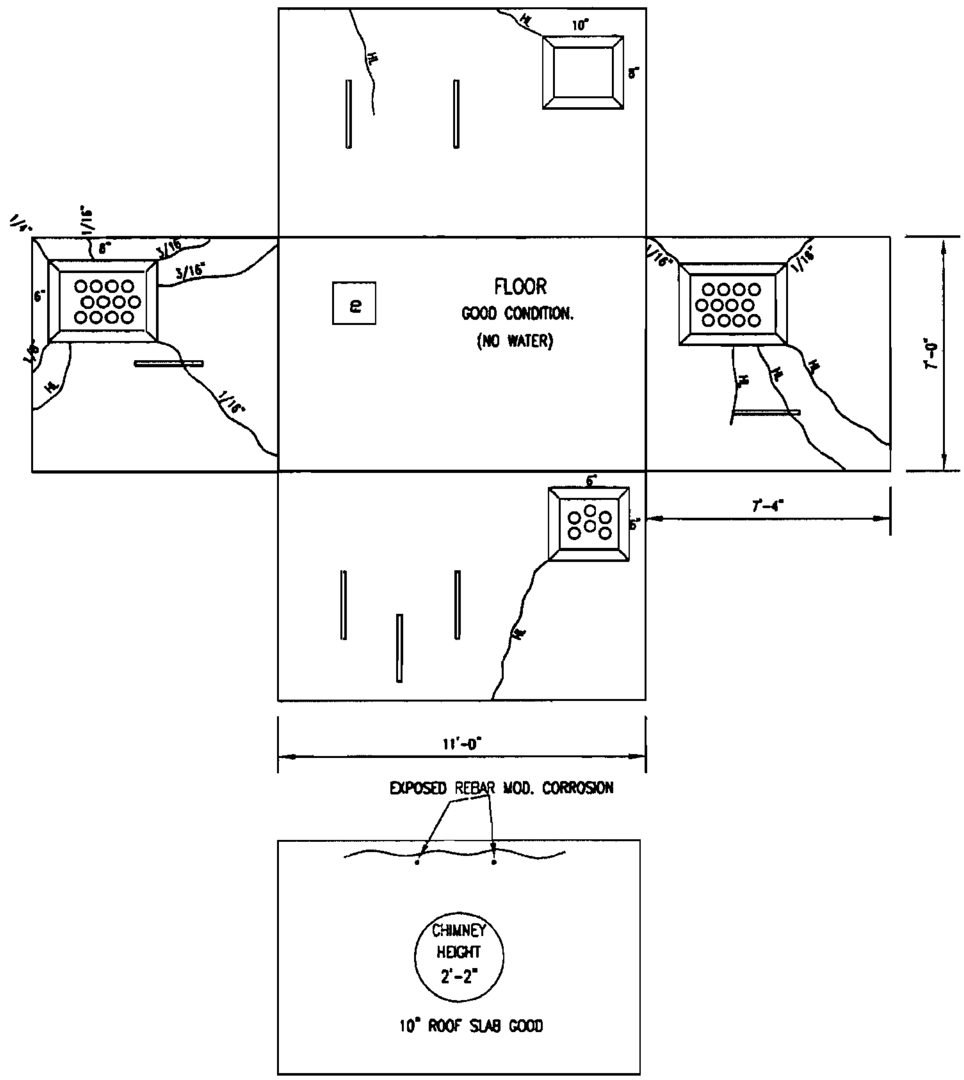

South Wall


Chimney

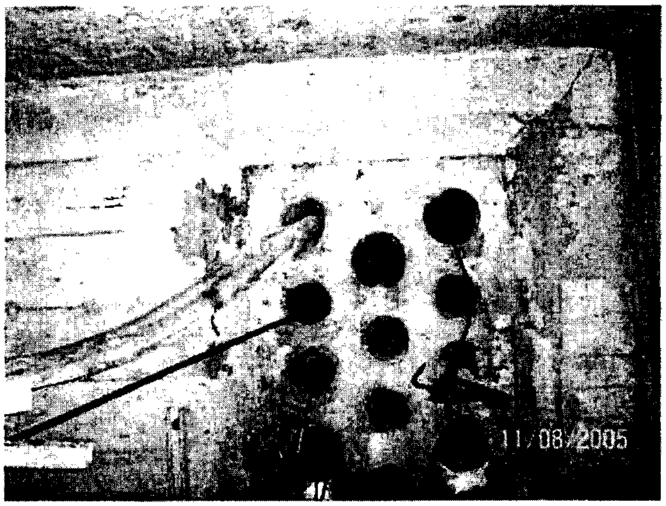
MANHOLE No. : 231

LOCATION: ERIE BETWEEN LANGLOIS & PARENT
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS, ALL BRACKETS GOOD

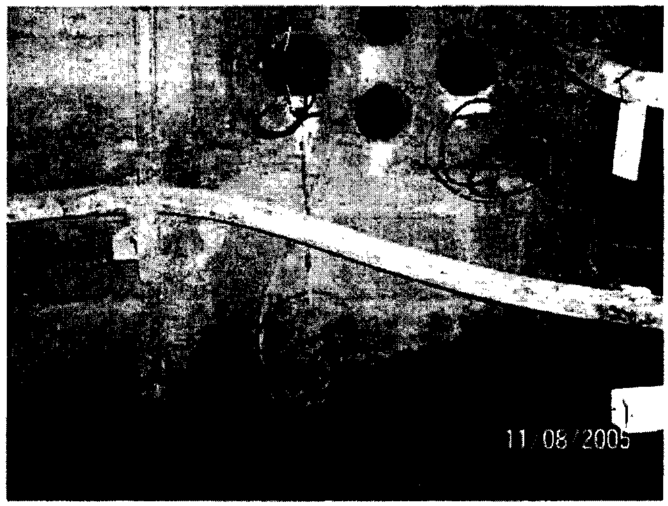
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



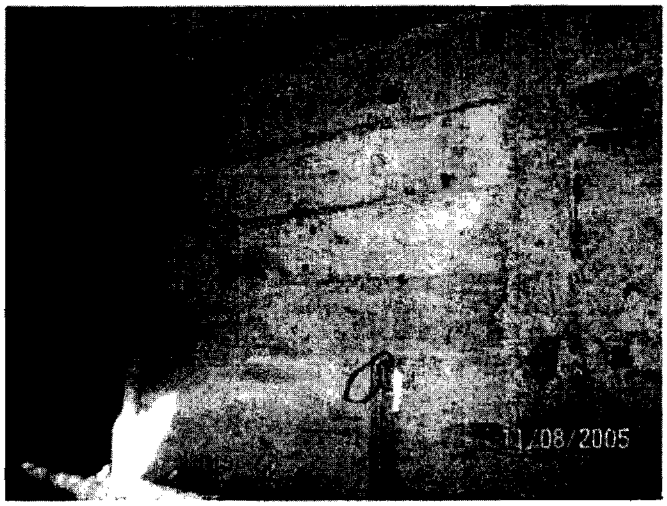
Manhole No. 231



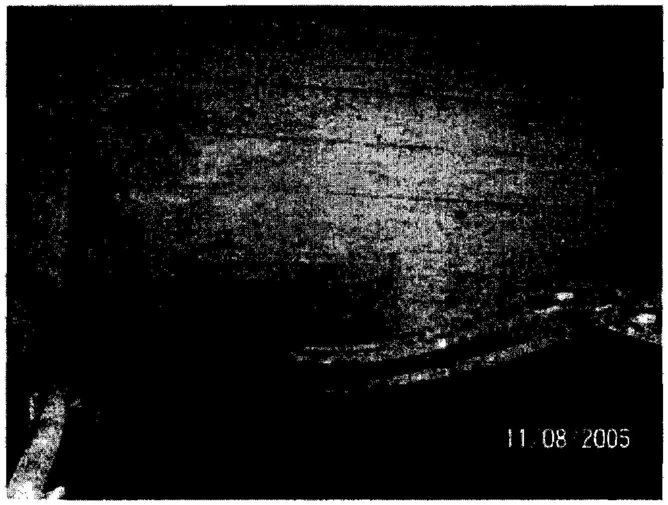
West Wall Top



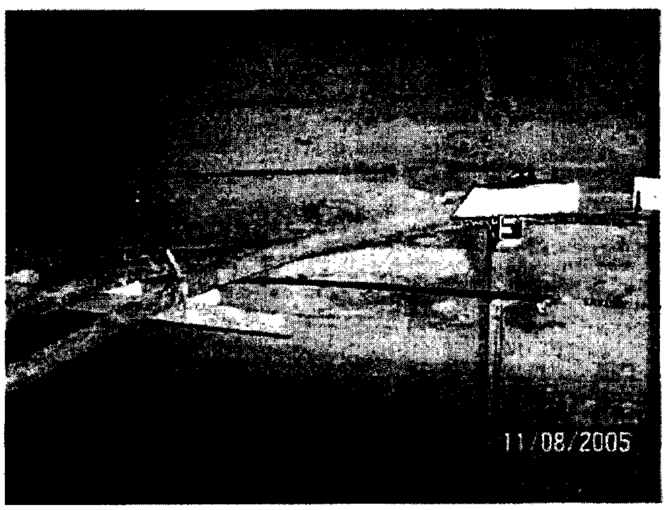
West Wall Bottom



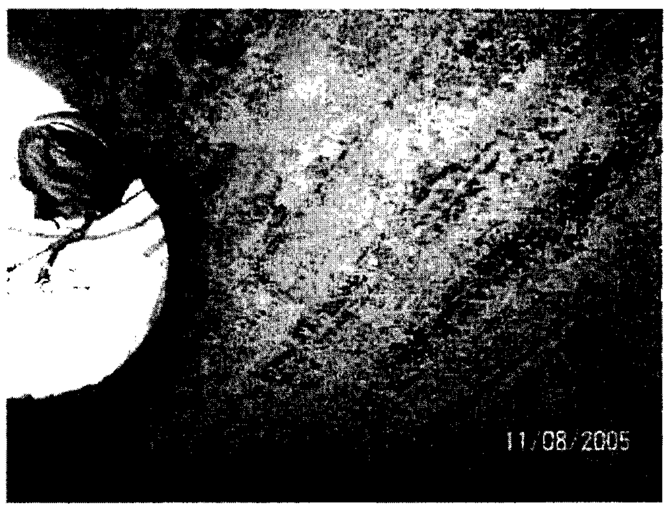
North Wall



East Wall



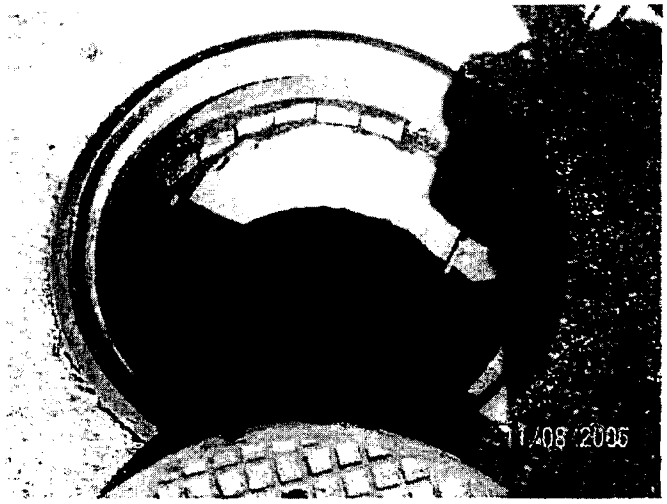
South Wall



Roof

Manhole No. 231

Floor

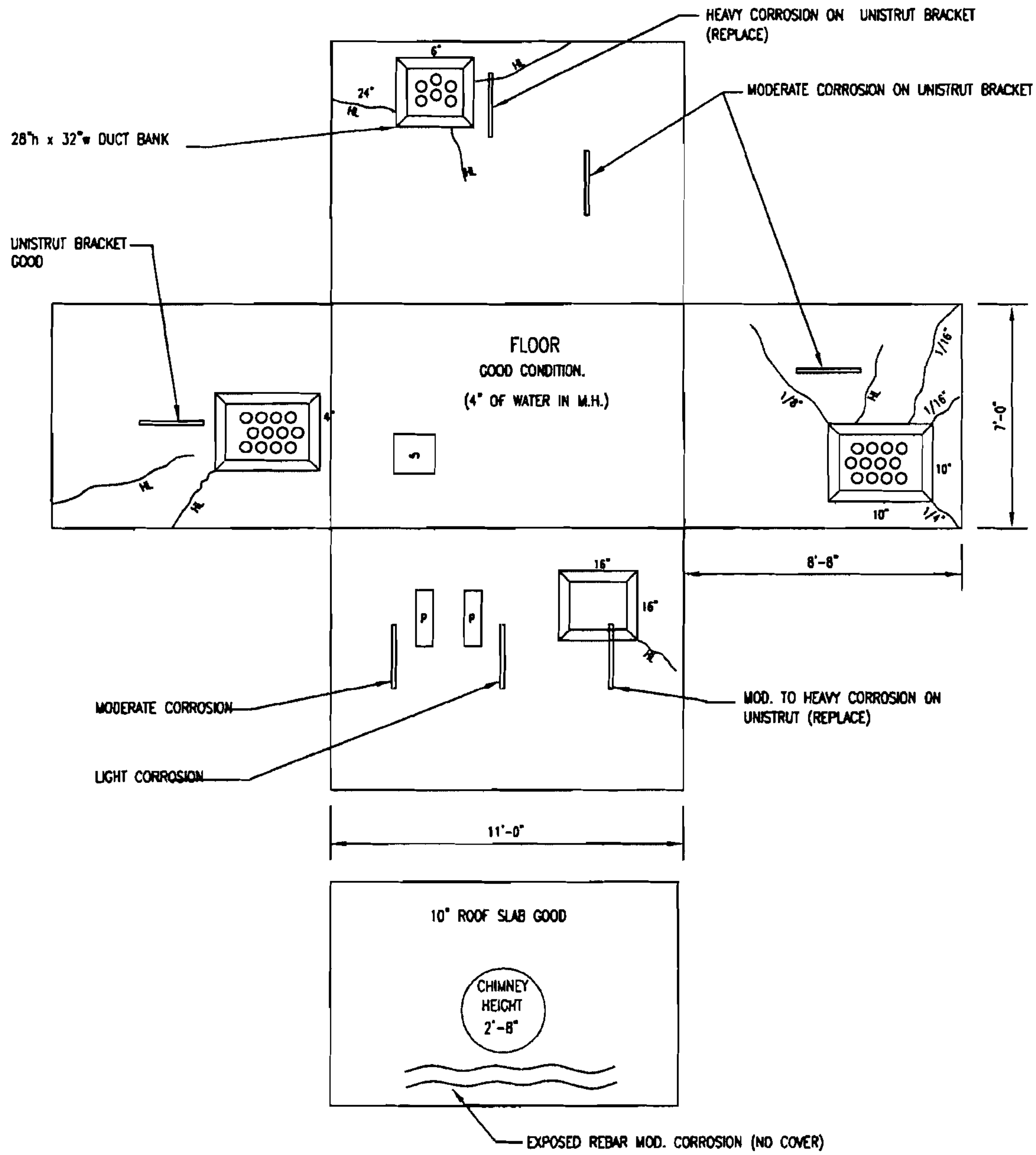


Chimney

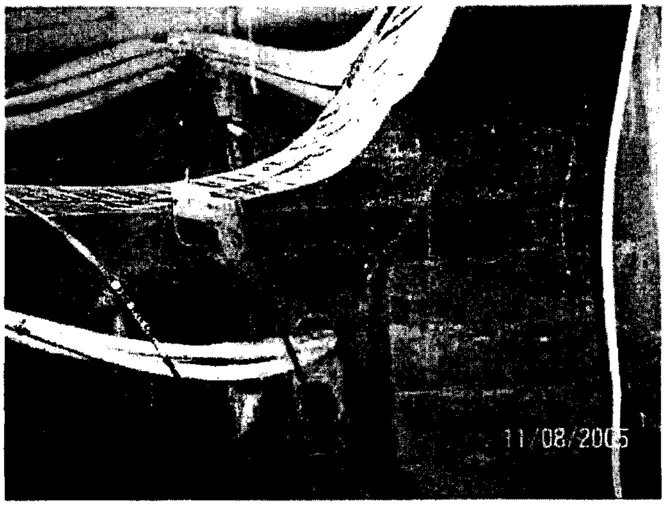
MANHOLE No. : 232

LOCATION: ERIE BETWEEN MARION & LANGLOIS
OVERALL CONDITION: GOOD REPLACE NOTED BRACKTES.
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



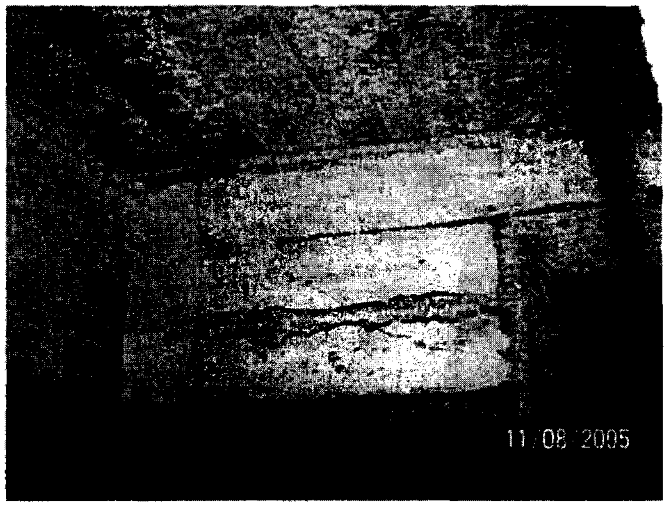
Manhole No. 232



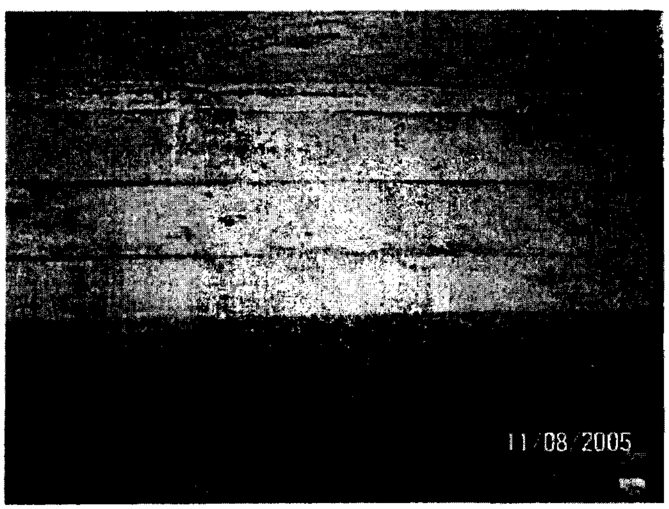
West Wall

North Wall

West Wall



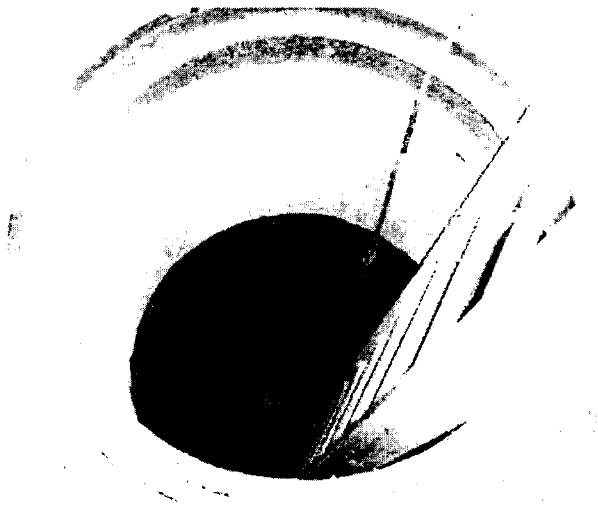
West Wall



South Wall

Roof (South)

Manhole No. 232

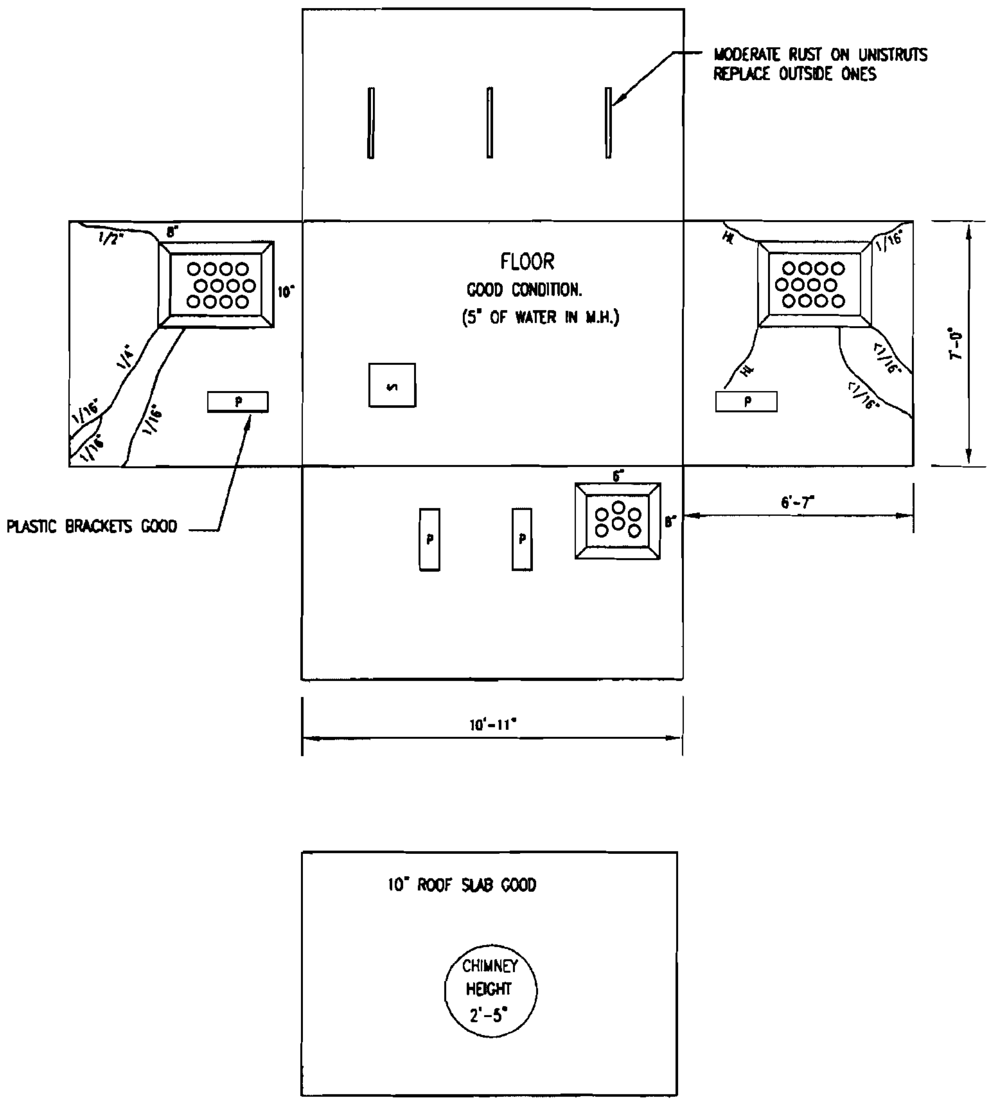


Chimney

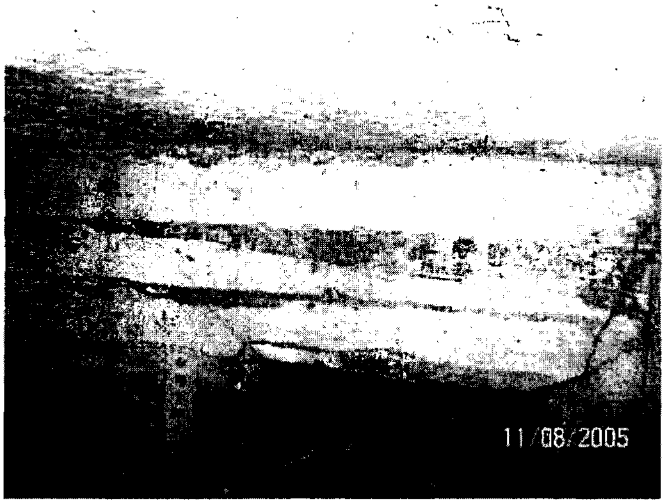
MANHOLE No. : 233

LOCATION: ERIE BETWEEN MARION/PIERRE (IN SIDEWALK)
OVERALL CONDITION: GOOD, REPLACE NOTED BRACKETS
REMARKS: MANHOLE HAS CONCRETE WALLS.

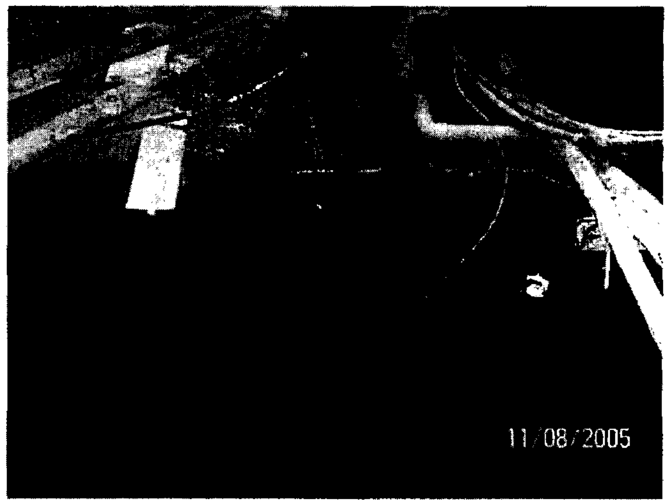
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



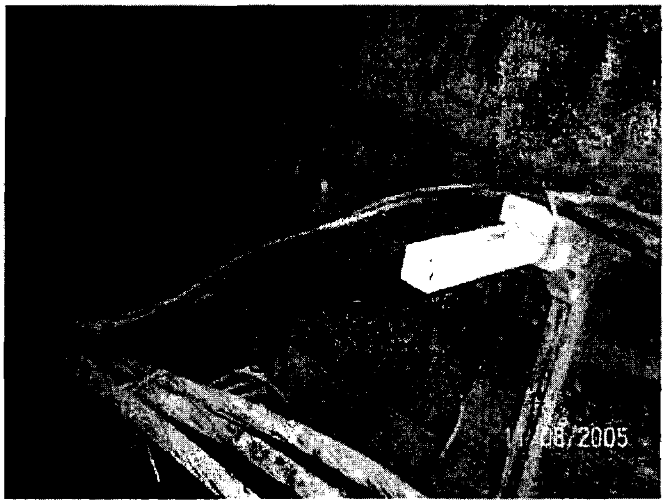
Manhole No. 233



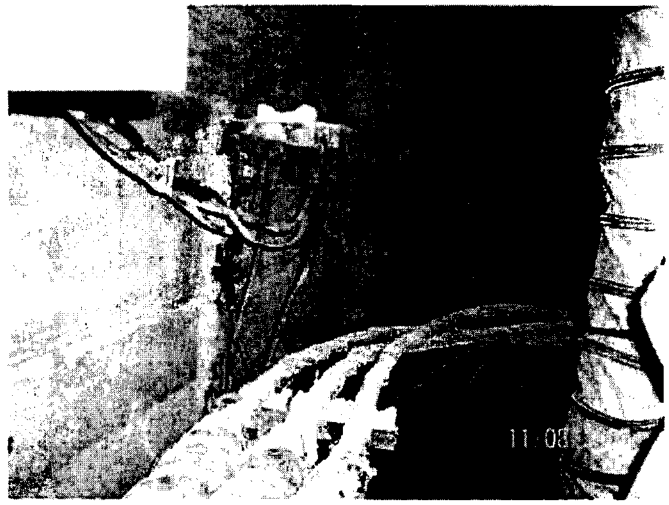
West Wall Top



West Wall Bottom



North Wall (Note Bracket)


East Wall (North Bracket)

East Wall


South Wall

Manhole No. 233

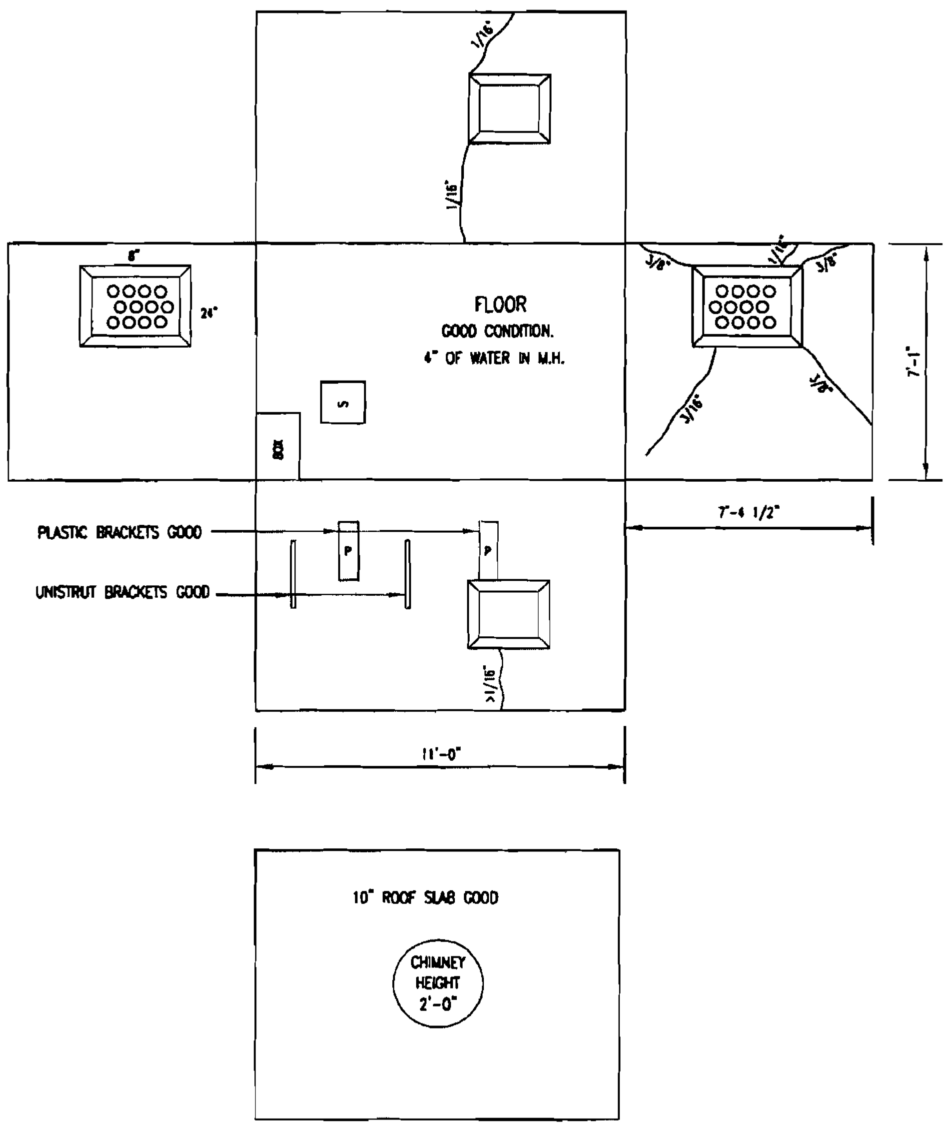
Roof West

Chimney

MANHOLE No. : 234

LOCATION: ERIE @ PIERRE
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

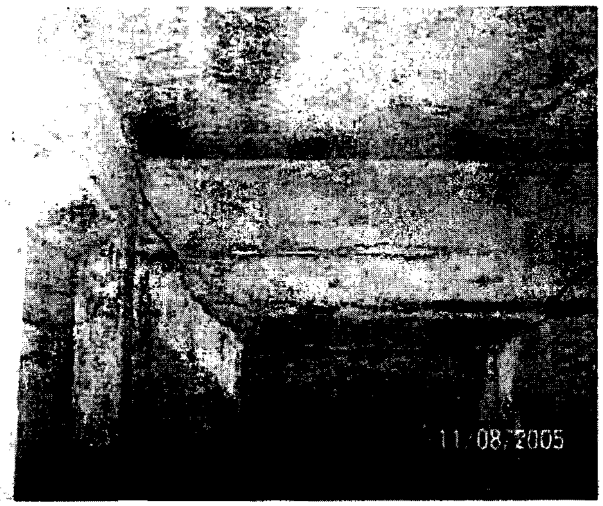
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



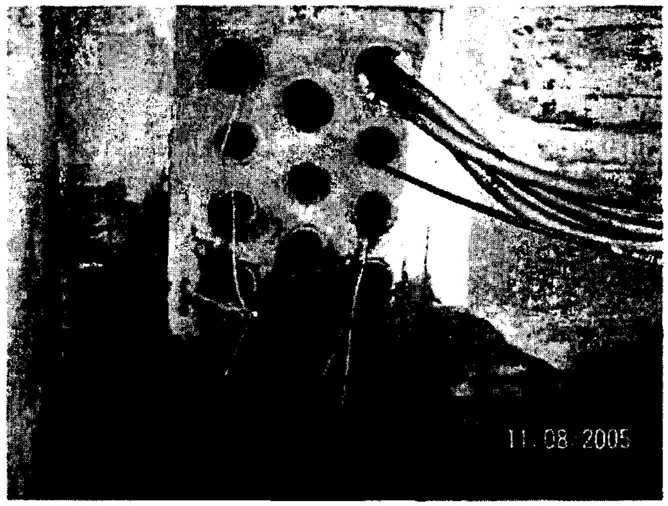
Manhole No. 234

West Wall

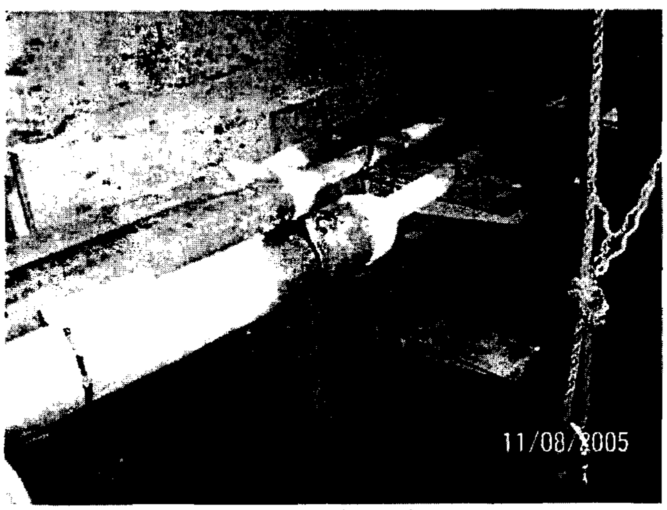
Roof (West)



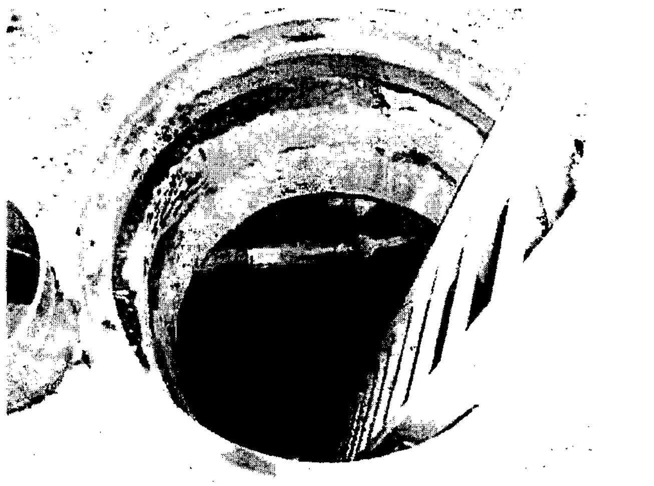
East Wall Top



East Wall Bottom



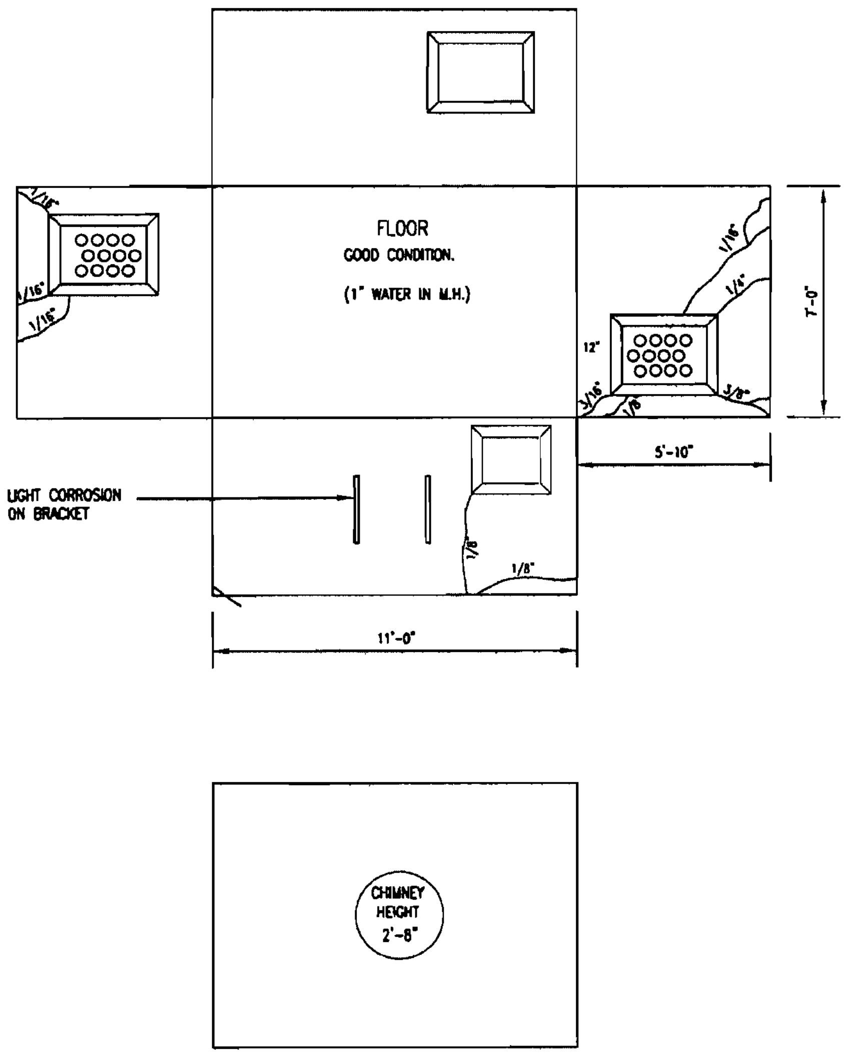
South Wall


Chimney

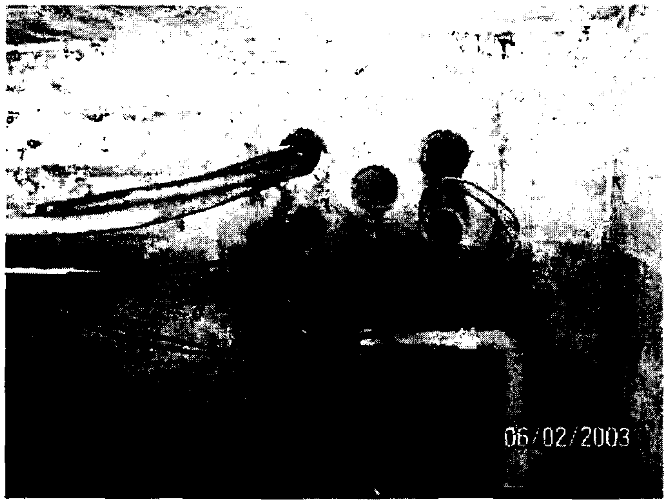
MANHOLE No. : 235

LOCATION: ERIE @ HALL
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

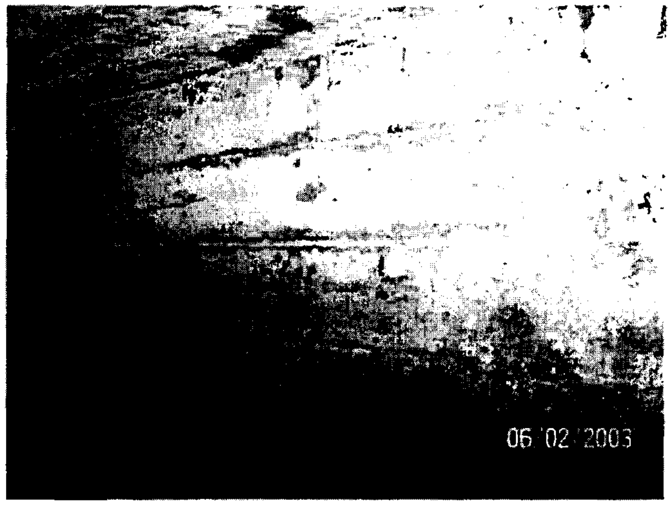
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 11, 2005.



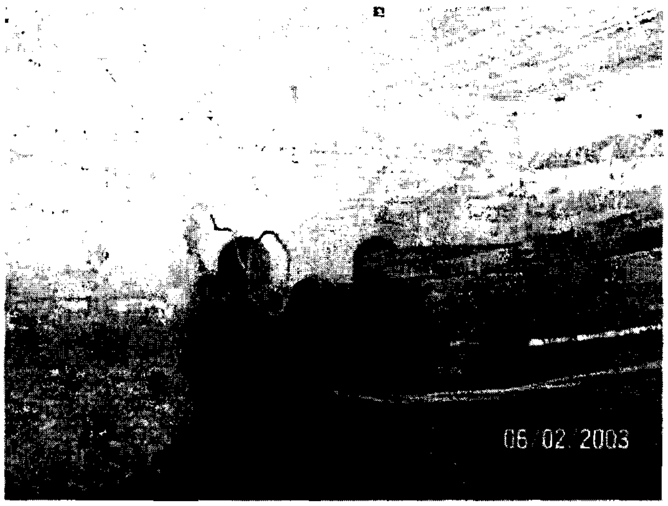
Manhole No. 235



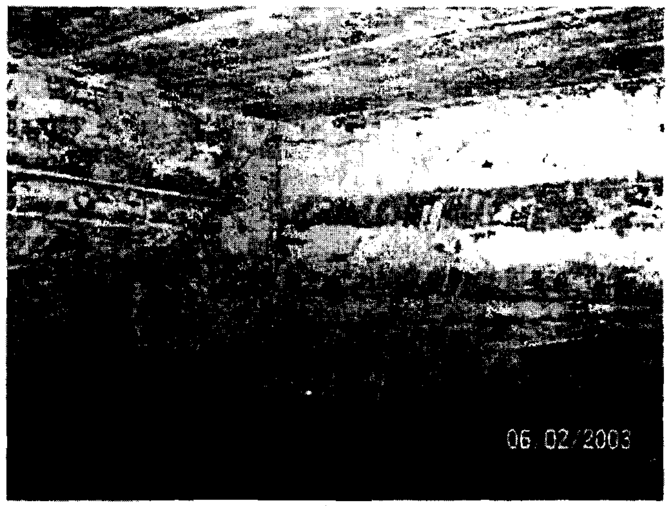
West Wall



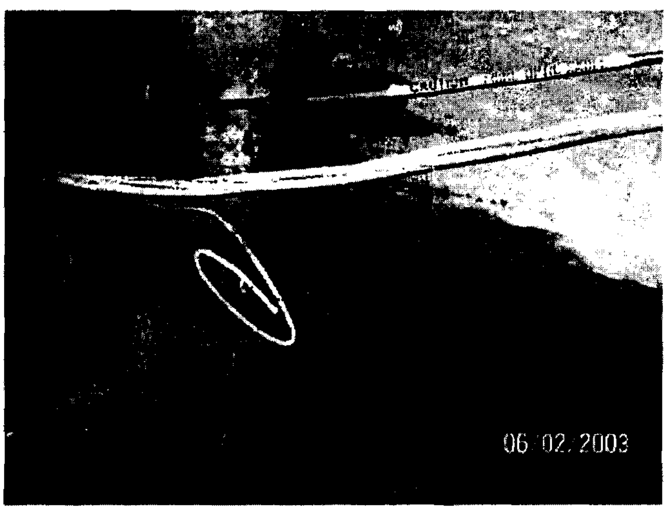
North Wall



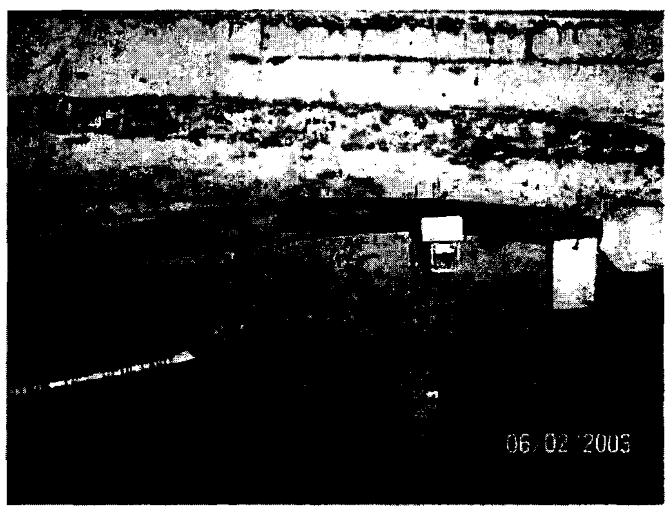
East Wall



Southeast Corner Top

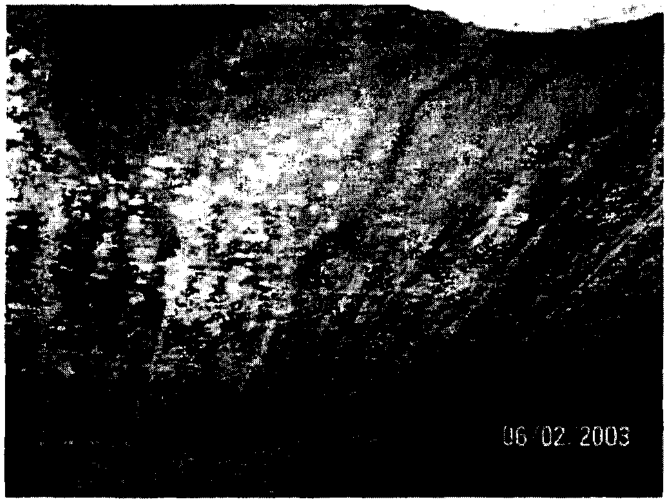


Southeast Corner Bottom



South Wall

Manhole No. 235



Roof East

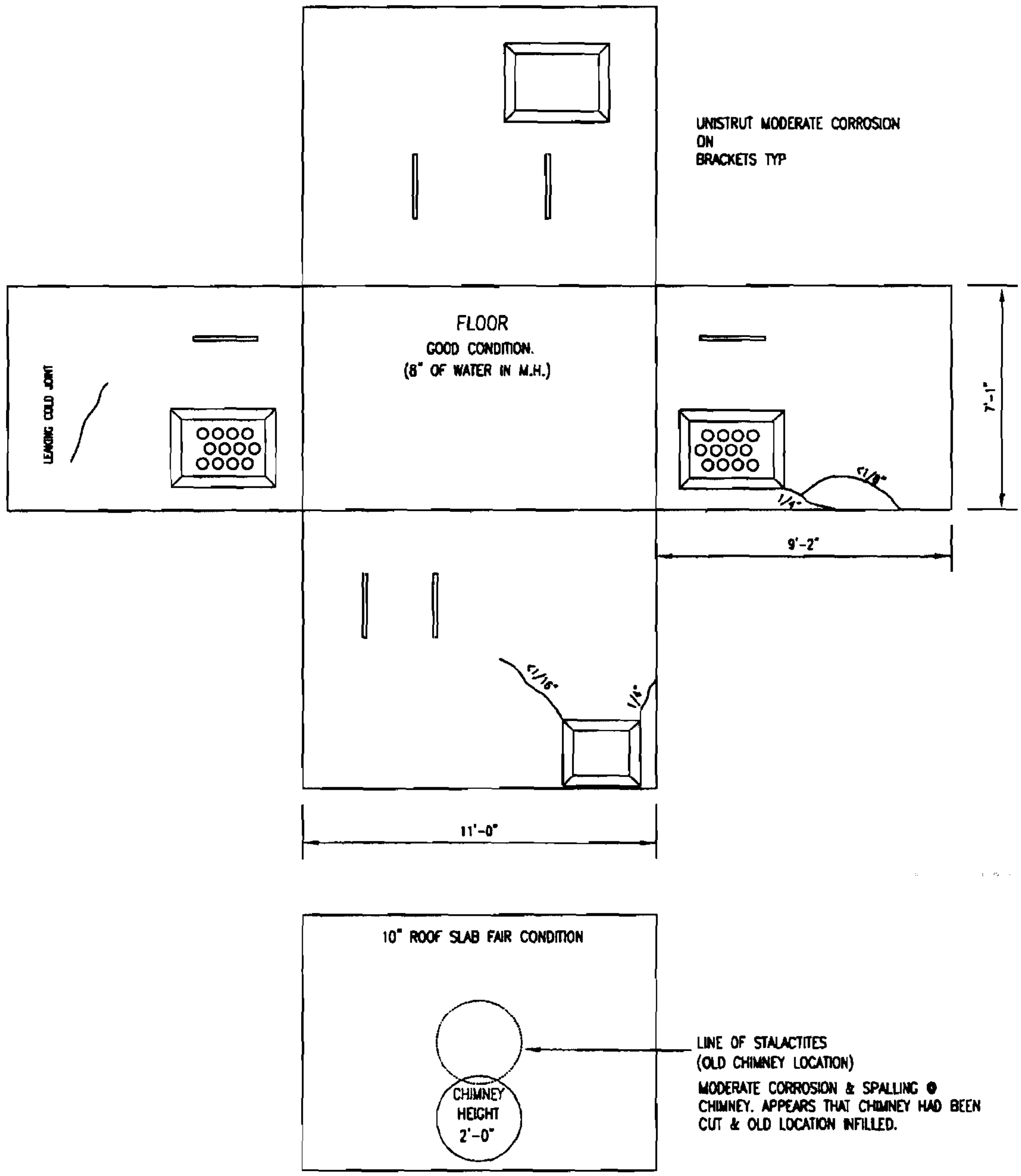
Roof West


Chimney

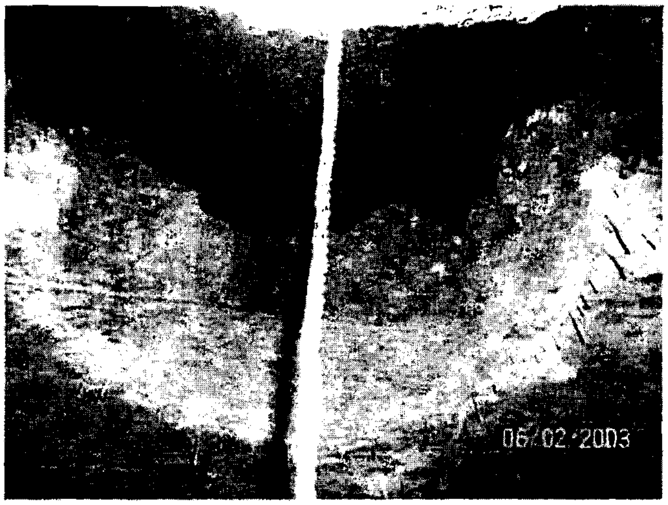
MANHOLE No. : 236

LOCATION: ERIE BETWEEN GLADSTONE & MOY
OVERALL CONDITION: GOOD, ROOF – FAIR
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 10, 2005.

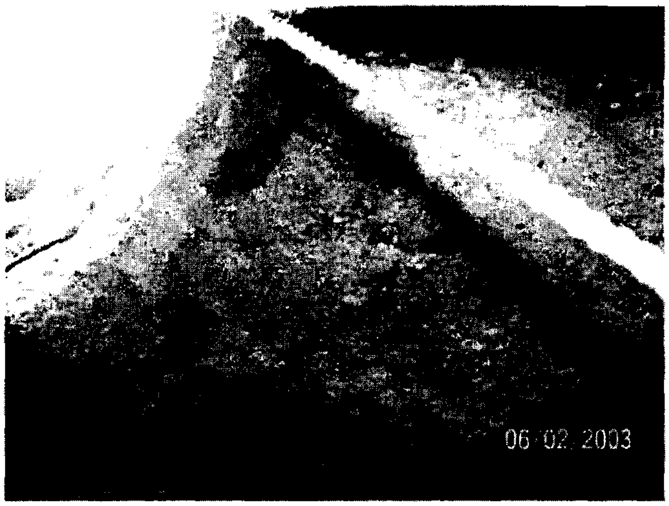


Manhole No. 236

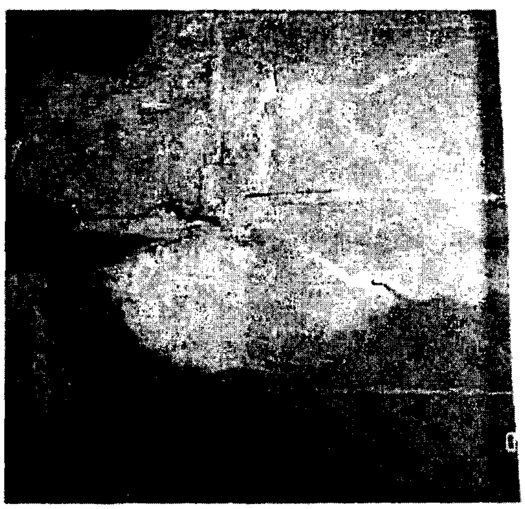


Roof


Roof

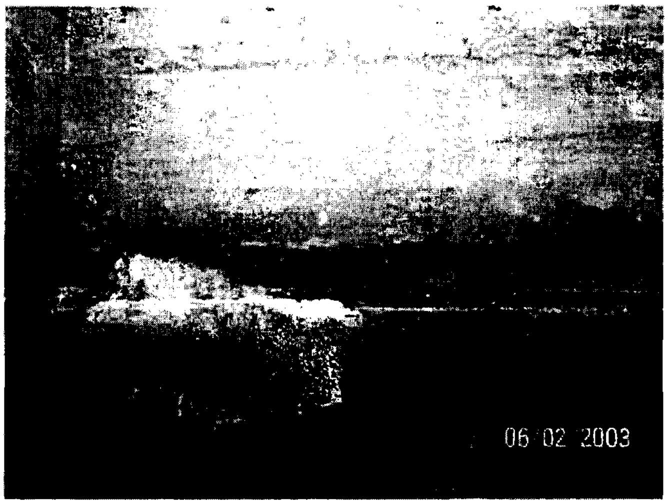


Roof

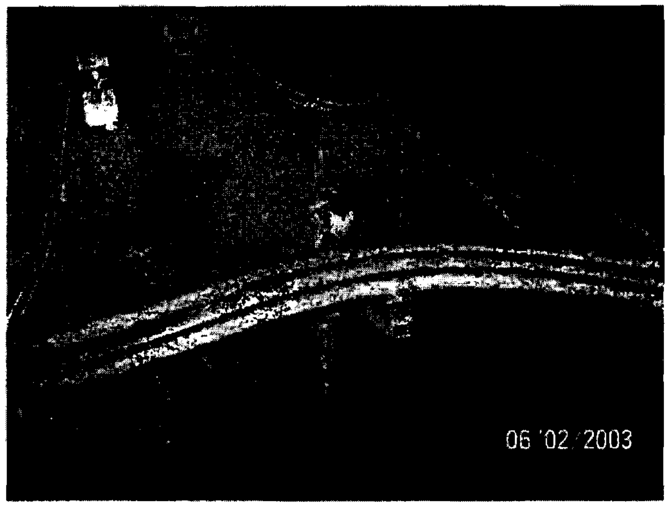

South Wall


Chimney

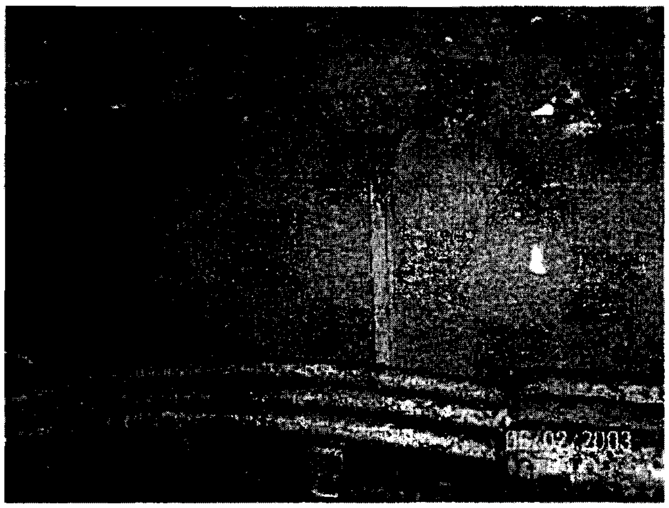
Manhole No. 236



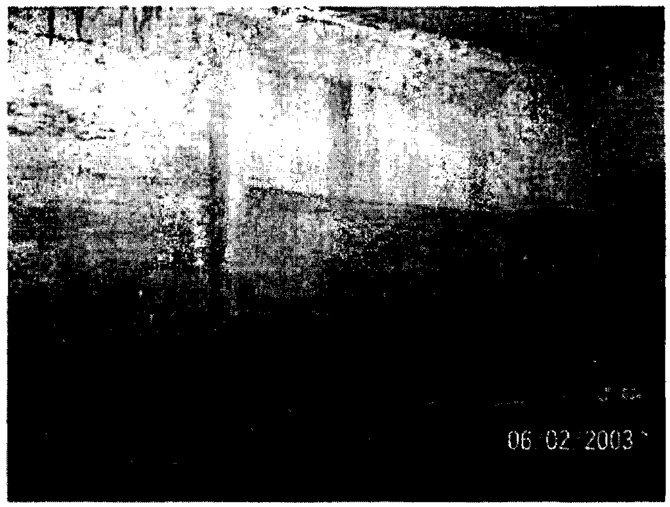
West Wall



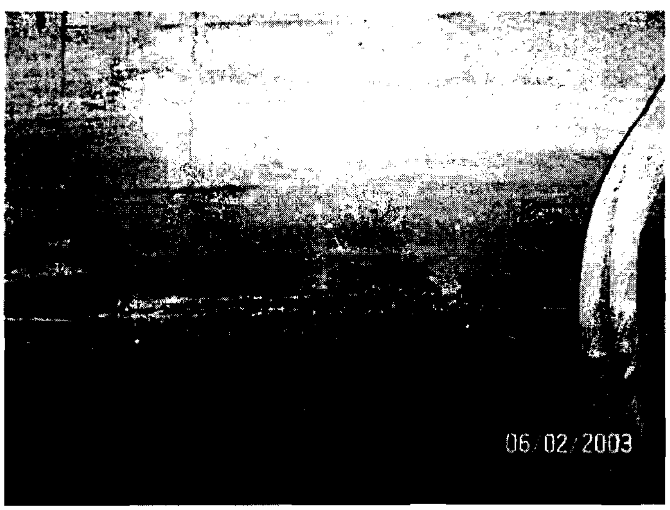
West Wall



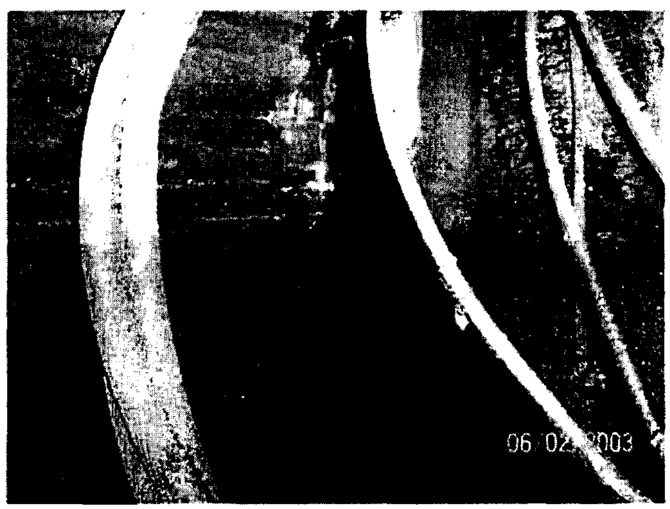
North Wall



North Wall



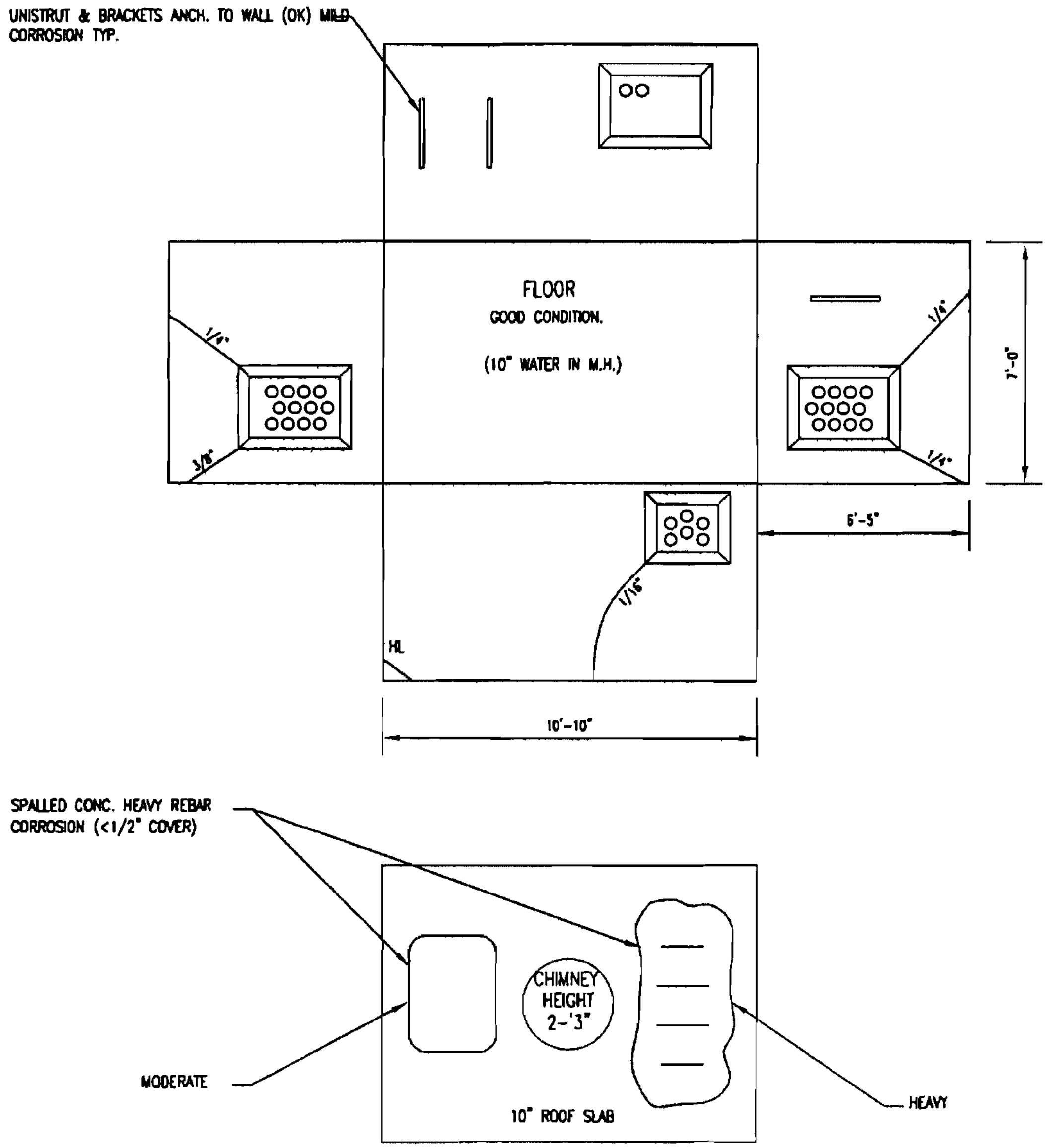
East Wall


East Wall

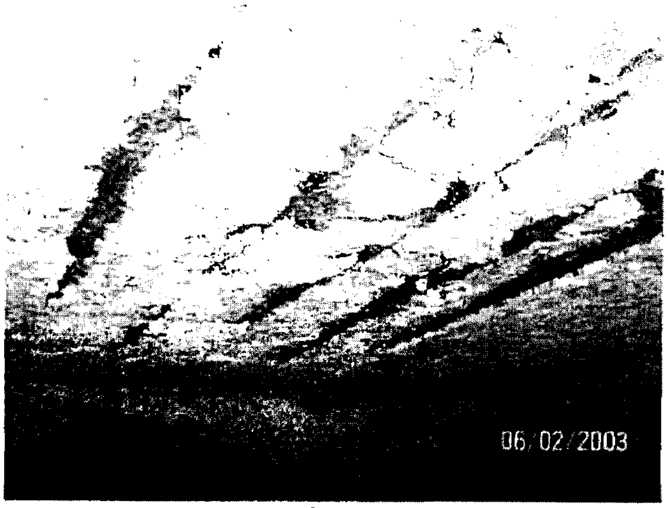
MANHOLE No. : 237

LOCATION: ERIE BETWEEN LINCOLN/GLADSTONE
OVERALL CONDITION: GOOD.
REMARKS: MANHOLE HAS CONCRETE WALLS.

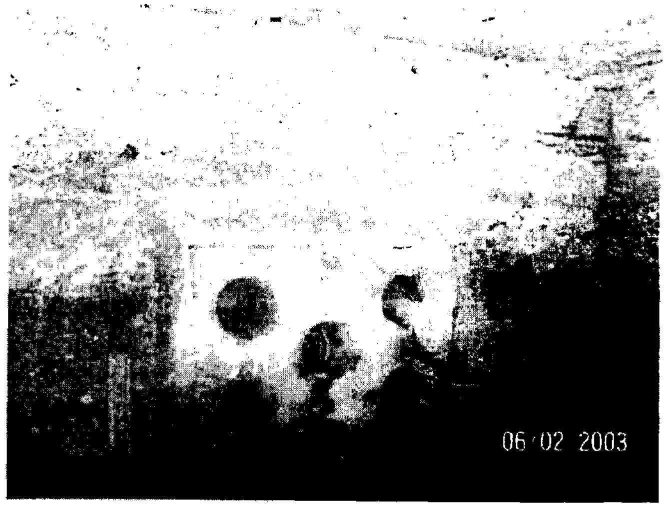
INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 10, 2005.



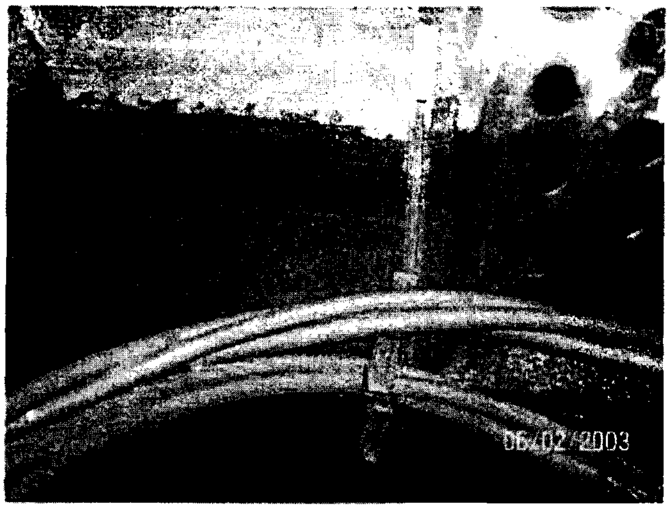
Manhole No. 237



Roof (East)

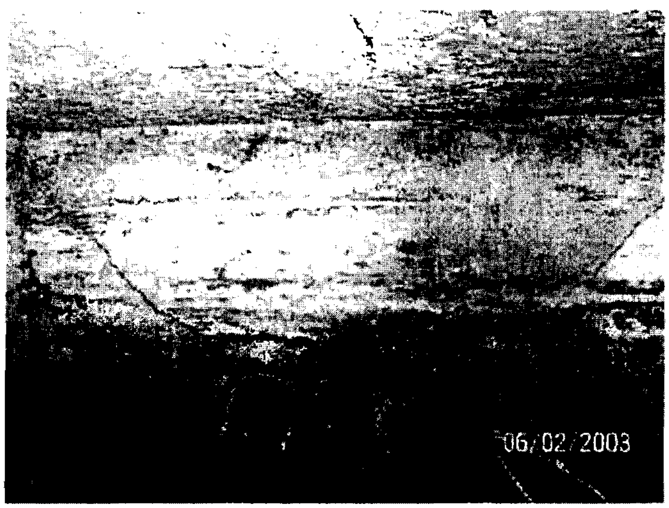


East Wall

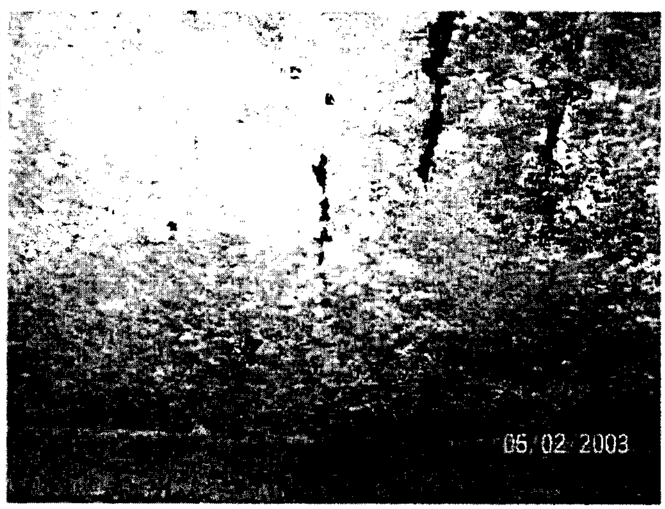


East Wall


South Wall (crack)

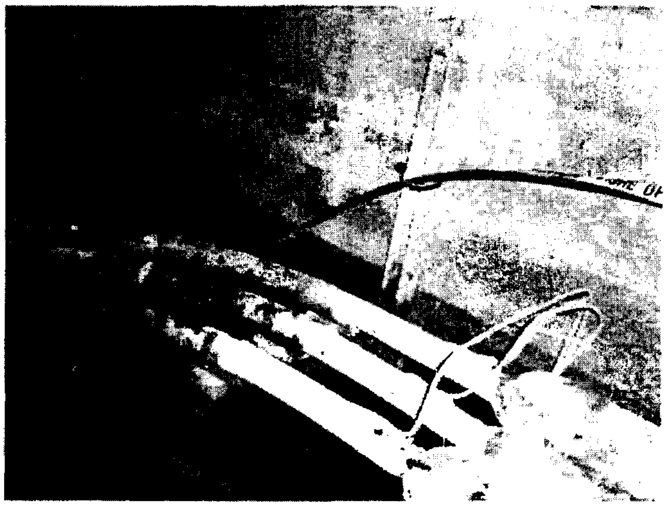


West Wall

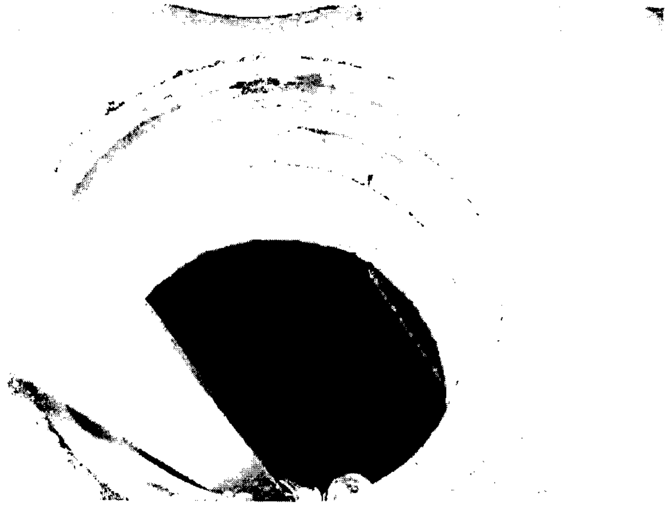


Roof (West)

Manhole No. 237



Bracket North Wall

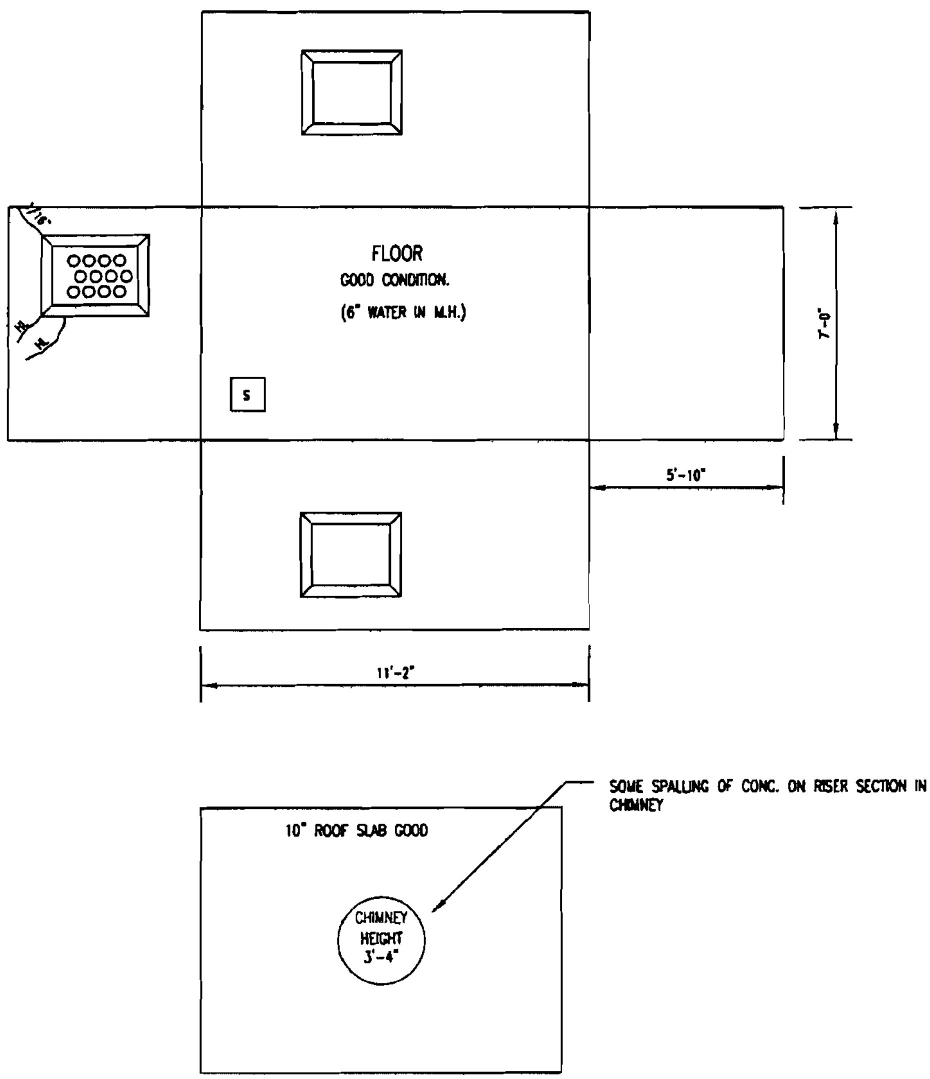


Chimney

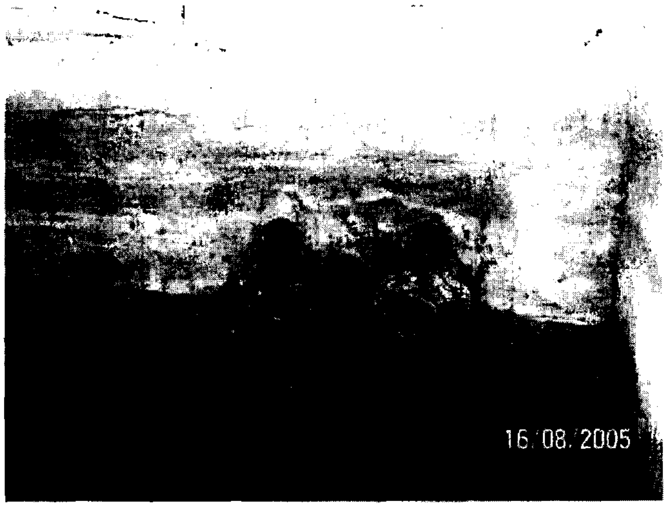
MANHOLE No. : 238

LOCATION: NW CORNER ERIE & LINCOLN
OVERALL CONDITION: GOOD, APPEARS TO BE RECENTLY RECONSTRUCTED
REMARKS: MANHOLE HAS CONCRETE WALLS.

INSPECTED BY: D. McCLOSKEY, P. ENG.
DATE: AUGUST 16, 2005.

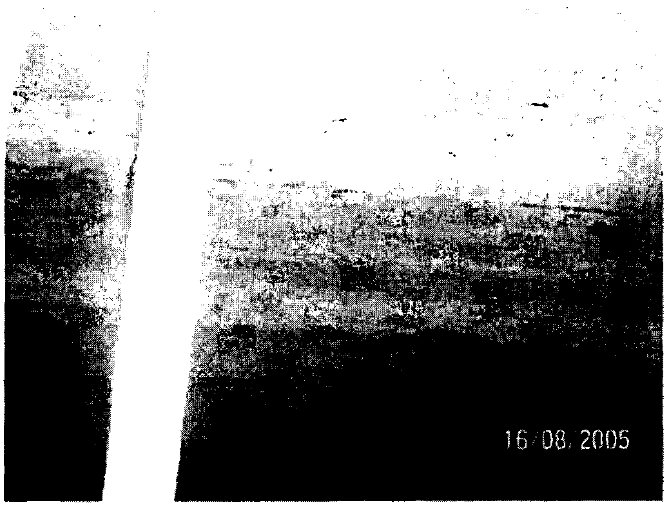


Manhole No. 238



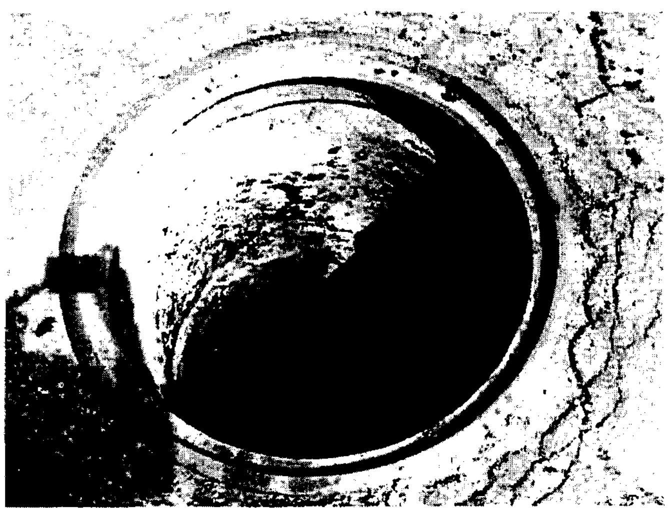
West Wall

South Wall



East Wall


Roof


Chimney

Attachment E

ENWIN UTILITIES LTD.

IT INFRASTRUCTURE UPGRADE REPORT

September 11, 2008

Prepared by: SJH Consulting in conjunction with EnWin Utilities Ltd.

Introduction

This report has been prepared by SJH Consulting in conjunction with EnWin Utilities Ltd. ("EWU") for the purpose of providing the Ontario Energy Board with: (i) an analysis of the limitations of EWU's current IT infrastructure; (ii) a review of alternatives available to EWU to address those limitations; and (iii) a recommendation on the alternative that EWU should adopt to resolve its IT infrastructure limitations.

For purposes of this report IT Infrastructure is defined to mean the system applications, including licensing and implementation, interfaces to legacy applications, data conversions, and hardware for the ERP production environment.

This report is based on a comprehensive internal review with EWU's IT personnel, as well as a series of meetings and interviews between Sarah Horsley of SJH Consulting and a number of EWU personnel in various business units throughout the organization. Specifically, Sarah Horsley met with the following business units: Finance; Regulatory Affairs; Infrastructure; Purchasing; Customer Service; Human Resources; Information Services & Technology; Corporate Communications; Engineering; Fleet & Site Services; and Overhead & Underground. In addition, she reviewed and analyzed company surveys of staff relating to the business processes and the limitations as to functionality and integration of the systems.

The curriculum vitae of Sarah Horsley of SJH Consulting is attached at Appendix "A".

1. Analysis of the Limitations of EWU's Current IT Infrastructure

EWU currently relies on a patchwork of dated software systems to operate its distribution system. Specifically, EWU relies on 7 separate software systems that support all of EWU's major business processes, including:

- customer information & billing;
- meter reading;
- collections management;

- financial accounting (A/P & A/R) & reporting;
- wholesale & retail settlement;
- supply chain/procurement;
- plant maintenance;
- distribution project management;
- asset management;
- work management (field Service); and
- human resources (including payroll & benefits)

A description of each of these major software systems is set out at Appendix “B”.

Over the years, EWU has upgraded these systems with custom developed code, and has attempted to integrate them across the organization by developing custom interfaces. Although this patchwork of systems and custom solutions have historically served their purpose, for the reasons set out below, it is necessary that they be replaced by a comprehensive Enterprise Resource Planning system (“ERP”).

The limitations of EWU’s current IT infrastructure can generally be categorized as follows:

(a) Lack of Vendor Support

Many of EWU’s systems have outlived their shelf-life and are no longer supported by their software vendors. Software vendors who maintained these systems in the past will no longer assist with repairs or modifications, even for a fee because the technology is too old (i.e. many of EWU’s current solutions are at least one or two versions behind the current version of the package application). Being behind on Vendor version support is extremely problematic for EWU for a number of reasons, including:

- EWU’s IT personnel are currently maintaining and managing any maintenance activities for the current IT infrastructure. EWU has some software applications which are more than two versions behind the current version supported by the software vendors. It is common software practice and standard industry practice that vendors release new versions of software on a periodic basis to provide updates, modifications and new functionality to their clients. The practice of keeping current on software releases/version ensures clients are given full software version support in the event the there are software issues or failures. Typically this support is provided for a minimal annual fee to clients. However, EWU was restricted in this practice because of (i) its patchwork of system and (ii) vendor changes. As noted, EWU's system is characterized by a number of custom interfaces between software platforms. Upgrades to individual programs trigger a revision to the custom interface as well as in-depth testing. Upgrades would be needed for each system and also multiple approaches per system. The costs of performing an upgrade are substantial – potentially in the range of $1 million per upgrade. As a result, EWU acted in a cost effective manner to upgrade essential areas only. EWU was also affected by the change of ownership to software providers – PeopleSoft (Finance and HR) and SPL (CIS). EWU deferred upgrades because of uncertainty with respect to the product and an anticipated new comprehensive ERP upgrades by Oracle, the purchaser of PeopleSoft and SPL. To date, this comprehensive ERP has not materialized.

- However, because of the PeopleSoft and SPL versions that EWU has currently implemented, there is a high level of risk for the organization since EWU currently does not have the Vendor support it would require in the event of a major system or toolset failure. In the event of such a failure, there is a high probability that EWU could lose its back-office operations including Finance, HR and Customer Service. In this circumstance, EWU would not have a billing system in order to store Meter reading information, calculate customers' consumption and produce bills to send to customers. EWU would not be able to receive payments on a customer's account, would not be able to respond to a customer's inbound inquires or requests for service (service orders, move-in/out, etc) and EWU would also not be able to pay its employees and other accounts payable, including the IESO. These circumstances could last up to a few weeks.

- Some of EWU's systems have reached their capacity with respect to longevity and the amount of custom development, specifically the CIS system. This system in particular has a large number of customizations (approx. 90) in order to ensure customers are receiving the level of service expected and to keep up with the business and regulatory requirements. Experience has shown that the higher the number of customizations within a standard software application the greater the risk of major failures of the system. EWU would receive no support from the vendor if a system failure occurs. The risk of such an event is increasing as days and months pass due to the age and lack of stability of the system and greater system demands required in the future. Action must be taken by EWU as a means of ensuring they have the software vendor support and system stability for its IT infrastructure.

- Since the different software systems used by EWU require different skill sets, the need to have varying skill sets within an organization the size of EWU results in a minimum amount of IT resources knowledgeable in each of the individual application areas. EWU is at higher risk from having multiple software applications than a Comprehensive ERP or more integrated type solution where

> the required skill set would be the same. The possibility of having the currently skilled resources leave the organization also causes a risk of gaps in the expertise and knowledge of the current applications. This would, therefore, add an additional level of non-support risk of failure.

Because EWU relies on its software systems for almost every aspect of its business, EWU is currently running a very high risk of a major failure due to having old, unsupported versions of their software. It is therefore unadvisable that it continues to rely on software systems that are unsupported by software vendors. For this reason alone, it is recommended EWU should consider software alternatives.

(b) Lack of Integration

The software systems that EWU relies on to operate its business were not designed to communicate with one another, or to store information in a central database that can be accessed by EWU's business units. As mentioned above, over the years EWU has developed custom interfaces to integrate its software functions among business units. However, these custom interfaces do not sufficiently integrate EWU's business units as illustrated by the examples set out below.

A necessary business requirement of the current information age is for accurate and seamless communication between systems and processes. It is a global industry best practice that companies operate using a tightly integrated system. As business and regulatory requirements continue to increase within the utilities industry, it is now an important requirement for employees to have access to real-time information from across business units. There are two aspects in this regard. First, there is a need to establish a real-time end-to-end integrated view of business process allowing those in supervisory roles to see information across a spectrum of areas at a detailed level. Second, information tailored for employees necessary for job specific purposes. This provides for a dynamic and integrated operating format at all levels of the organization. For example, the act of receiving an asset, such as meters, into inventory will allow the procurement department to see that their purchase order request was fulfilled. In the case of the meter shop, the meter shop would see an increase in the number of meters in stock, where they are stored within a warehouse as well as the specific details of the meters (manufacturer, serial number, etc.). Finance would be able to see an account payable entry as there will be an open item to pay the vendor of the meters based on the pricing, amount of good received, payments terms, etc. within a vendor contract or the purchase order. Finance will also see an increase in total asset value within the accounts (General Ledger). A service request would trigger the installation of the meter at a geographic location. Once installed, all business units would have knowledge as to the geographic location. With this information and details of the meter stored on the centralized data base, the meter shop can coordinate preventative maintenance as well as marshal field resources with regard to that maintenance in the most cost effective manner. This integrated sequence is applicable to other distribution equipment.

In all instances, there is no additional effort required within the organization to update a system when an action from another department is taken. Due to the integration of the system this action automatically results in updates to the downstream business areas in real-time. This automated functionality would cause business efficiencies within the organization as accurate, complete, real-time information would be readily available across the entire business. Other than that given through security profiles, there is no restriction to data access within a different business area. The ability to have high level summarized data and drill down to the details required is standard functionality.

The lack of integration of EWU's software systems is problematic for EWU. Practical examples include:

- Fixed asset details and descriptions are maintained in Maximo (work management). However, these assets are capitalized through a manual process within the PeopleSoft financial application. The interface between two applications provides limited information with respect to the asset needed to be inputted within the PeopleSoft financial application at the time of capitalization. This limits the ability of assets to be tracked simultaneously within both systems. Maintenance on capital assets is tracked in a separate module within Maximo that is not linked to the capitalized asset within PeopleSoft. Therefore, costs are reported from Maximo which may not be reflective of costs that have been incurred as per the financial system due to timing differences related to triggers for recording costs. This creates significant work with respect to reconciling the variances between the systems. EWU must rely on queries and manual investigation to obtain the required level of detailed information. The validity of the financial information is not in question. This relates to time and efforts required to reconcile information generated under each application. Currently, there is limited coordination of assets numbers, which makes it difficult to identify the assets within each system as well as manual searches are required to retire/dispose of assets when appropriate.

- Through multiple interfaces, the purchase orders that are created in the PeopleSoft Finance transfer to Maximo and then return to the PeopleSoft Finance for accounts payable processing. Through these interfaces, detailed information is lost. A search of multiple systems and manual investigation is required to isolate errors and identify details. Purchase order receipts (i.e. receipt of goods) are completed in Maximo and then interface to PeopleSoft. The matching of the receipts to the invoices is currently a manual practice, causing administrative burdens.

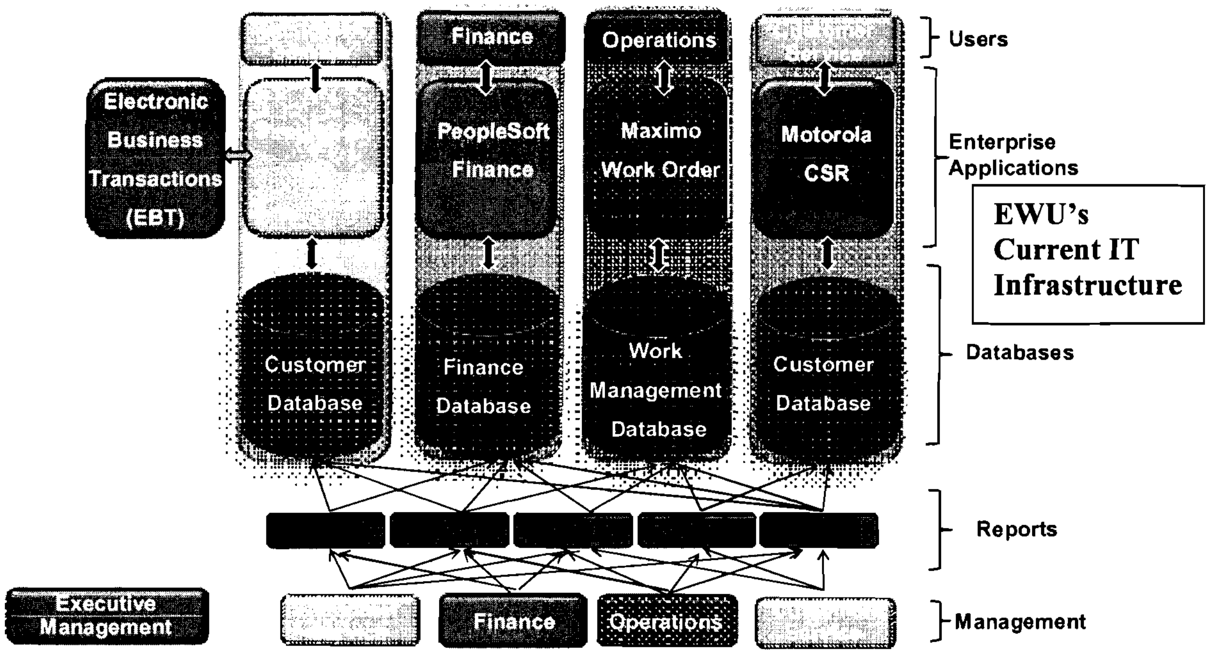
- Manual extractions of data or ad-hoc reports are often run by IT for the business in order to gather detailed information. This information is then required to be entered manually into another source (Excel) to produce management reports. One such report is the operations and maintenance report which takes 5-6 hours to manually extract data and populate the data into an excel spreadsheet in order to prepare the report required. A labour report which shows overtime and regular hours is created manually in a similar manner.

- The custom interfaces developed to integrate systems often provide incomplete information when transferring data from one system to another. For example, there are cases where a data element is not transferred from one system to another correctly due to an inconsistent data character length required for a field within each system (i.e. the field longer in the system of origin than the field within the transferred system, therefore not all of the data is consistent).

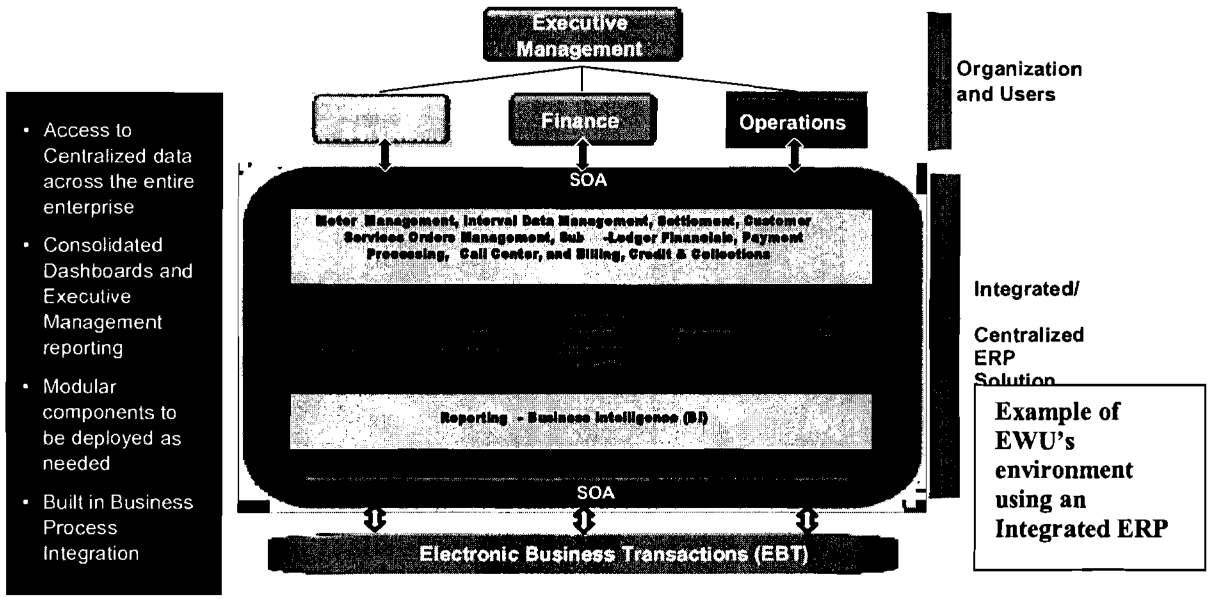
If an integrated IT infrastructure is established, the issues above will be resolved. In addition, there will be efficiencies established. The overall IT efficiencies would be due to the increase in automation. Therefore, less manual work would be required and the ability to use standard functionality instead of customization results in less maintenance and overall long term development effort. The reduced maintenance costs associated with a Comprehensive ERP solution also contribute savings.

An integrated system also allows staff, managers and executives within the organization to run on-line real-time reports with the specific information they receive. This is due to having access to all of the information within one centralized system or database. The ability to provide real-time dashboards and management reporting allows faster, more proactive management of operations. It allows management to make decisions based on real-time data which in turn mitigates any risk of impacts to customers as managers are able to respond to potential issues before becoming a problem.

Below is an illustration providing a high level view of EWU's IT infrastructure environment versus a view of how EWU's environment would appear with an integrated ERP.



EWU's Current IT Infrastructure



Example of EWU's environment using an Integrated ERP

(c) Functionality Limitations

Over the years, EWU has implemented its IT infrastructure based on various business and regulatory requirements. These requirements have subsequently changed. EWU is experiencing difficulty in continuing to adhere to these newer requirements for a number of reasons. The first is the age of EWU's software systems. The software version(s) used by EWU are generally limited in their ability to functionally keep up with EWU's business needs. In other cases, the software version has the functionality required, but was not deployed at the time of implementation. To deploy this functionality at this stage would require an initial upgrade to the most recent software version. This in turn entails installing the new software version, designing new business processes, implementing these business processes (configuration, coding and development of interfaces, reports and forms), testing and deployment. This is a full project that can be at a significant cost. Example of consequences arising from limited functionality is as follows:

- Labour costs are tracked within the PeopleSoft Human Resources system (time and labour) and are allocated to specific work orders. The payroll entries are batch processed through the interface to PeopleSoft financial software and the detailed work orders are lost in the transfer of data. The detailed work orders, including labour charges are provided to Maximo. Because the functionality related to detailed work order is not available in the PeopleSoft Finance, Finance is prevented from obtaining detailed work order information regarding these labour charges.

- Due to the functionality implemented within the Maximo environment it is difficult to undertake planned and preventative maintenance of assets.

- Management reporting is predominantly performed within Excel from exported data from the multiple systems to provide detailed reports. As a result, the preparation of these reports is done manually. For example, most general ledger account reconciliations are performed within Excel with information combined from the various systems (PeopleSoft Finance, Maximo, PeopleSoft HR). All departmental budgets are completed external to the PeopleSoft Financial System. Budgets templates are initiated from Finance and once completed, consolidated manually by Finance in Excel.

- Historically, the existing systems have been generally successful in meeting the threshold reporting requirements of the Ontario Energy Board and other entities. However, these reporting requirements have increased, perhaps in part due to external expectations that contemporary technology should result in readily available reports. Currently, EWU's IT infrastructure is not sufficient to meet the increasing demands to precisely record, monitor and report (particularly on cross-functional operations) such as those set out in the Board's revised service quality requirements.

- International Financial Reporting Standards (IFRS) is a new financial accounting requirement that needs to be in place in Canada for the beginning of the 2011 calendar year. However, in order to meet the requirements for a comparative year, it will need to be in place for the start of 2010. This new standard is not currently developed in the existing EWU financial system (PeopleSoft). Due to the nature of the required changes, to accomplish this result would be a project requiring significant effort in order to ensure compliance. These changes would need to be in place by the end of 2009.

Replacement Options

The following options have been considered to correct the limitations noted above and to achieve EWU's strategic objectives: (i) upgrade current systems; (ii) implementing a Partial ERP solution; or (iii) implementing a Comprehensive ERP solution.

(a) Upgrade Current Systems

Upgrading the existing systems to the latest version does not accomplish EWU's objectives and does not provide a long-term solution. The result would be costly and time-consuming that would not provide long-term solutions or value to the company, its customers, and its regulators. An independent analysis was completed by SJH Consulting to evaluate the requirements and the functionality provided in the latest versions of the current IT infrastructure assuming EWU upgrades its IT infrastructure. This analysis concluded that an upgraded solution of the existing IT infrastructure would still leave gaps in the functionality. These gaps would require custom development in order to provide the functionality required by EWU. As an alternative, EWU may choose not to fill these gaps. However, a manual work around would be required. These gaps included, but are not limited to, lack of real-time asset value within the financial system, inability to track asset location and asset history across the organization, lack of a fleet management system and no integrated document management system. It is estimated only about 65% of the requirements would be met with the Upgrade option. The biggest requirement which would still not be met is the integration between the systems. With the Upgrade option, custom interfaces would still be required. This solution would also not provide for a centralized data repository and as a result, deficiencies related to accessibility of information would persist.

It is expected that such an upgrade of EWU's current IT infrastructure would result in an overall implementation effort (both in time and money) comparable to that of the Comprehensive ERP implementation option. However, the Upgrade option would not address nearly as many deficiencies. Therefore, due to the deficiencies in functionality and integration, and on the basis of cost-benefit comparison, this option is not recommended.

(b) Partial ERP

If EWU were to implement a Partial ERP solution, some of the requirements of EWU may be met. Partial ERP would address the vendor support and functionality deficiencies. However, the integration deficiency would not be addressed. For example, access to centralized information from across the organization would still not be met as data would continue to exist within separate systems. There would also be custom interfaces which would require maintenance and support adding to the total cost of ownership. Experience shows that custom interfaces will require additional on-going support more than that of a Comprehensive ERP where the data is centrally located within one system. The actual number of requirements and the effort associated with such a solution would vary based on which Partial ERP solution was selected. It is assumed for comparison purposes that a Partial ERP solution would replace both of EWU's PeopleSoft (Finance and Human Resource) systems and Maximo. This would leave EWU's CIS (SPL) to be interfaced to the new Partial ERP solution. Given this approach, none of the CIS requirements identified by EWU would be met. There would also be no truly integrated solution with a centralized data repository as the CIS system would still be separate from the new Partial ERP solution.

It is estimated that such a solution would probably be slightly lower in effort than the Comprehensive ERP solution recommended as the effort associated with the implementation of the CIS would not be required. However, this effort can not be completely negated as there will be a major interface required for meter and financial information. Further, effort would be required to conduct integration and regression testing for the business.

(c) Comprehensive ERP Solution

A Comprehensive ERP is a system that integrates all data and processes of an organization into a unified system. A typical ERP system will use multiple components of computer software and hardware to achieve integration. A key ingredient of most ERP systems is the use of a unified database to store data for the various system modules. By simply having a replacement of a single system, for example the CIS system, EWU's requirements would not be met and many cost-effective benefits to the company, its customers, and its regulators would not accrue.

With all system options reviewed by EWU, there will be significant effort and cost required. After performing a review of the requirements and the functionality fit for each option it has been confirmed that a Comprehensive ERP would provide the best fit for the current business and regulatory requirements and provides the lowest total cost of ownership long term (minimal interfaces, customizations, etc).

Comprehensive ERP – Timing and Cost

SJH Consulting recommends EWU implement a Comprehensive ERP system over a period of 2 years (2009-2010). This implementation timeframe would be manageable and mitigate risks associated with prolonged deployment. The initial phase of implementation could include Finance and Human Resources related IT infrastructure. That could be followed by a second phase of the Customer Information System, Procurement, and Work and Asset Management (including Fleet) systems. SJH Consulting has considered a longer period implementation (3 to 4 years). However, based on discussions with other North American utilities and industry experts a lengthier implementation can cause "burn out" and lack of momentum of team members. Given the scope of this initiative, a longer duration would mean unnecessary costs of external resources as the staffing of these resources would be required for a longer duration when the same scope could be implemented in a shorter duration with managed risk.

SJH Consulting has considered a shorter implementation timeline. However, it is SJH Consulting's view that based on a phased approach implemented by other similar North American utilities and based on discussions with industry experts, this is not the most cost effective nor does it do as much to mitigate risk. The shorter timeline would be too aggressive given the scope of work and effort required by external and internal resources. It also would not result in a greater amount of project cost savings as more resources would be required over a shorter duration of time in order to achieve the deadlines required. Given the size of the EWU organization, it is advisable to limit the scope by phase due to the amount and number of internal resources required and available for the project.

EWU is presently in the RFP stage and anticipates selection of a Comprehensive ERP system and System Integrator by the end of 2008 using a standard RFP process. The implementation of the project would start in January 2009 with a total project implementation and support duration of 17 months. That period is short enough to bring the Comprehensive ERP solution selected into full operation in a timely fashion so that the benefits accrue to EWU and its customers in the near term. EWU has assumed this approach for its project cost estimate.

EWU requested that SJH Consulting provide an estimate of project costs for a Comprehensive ERP solution. The following provides a breakdown of the expected project costs:

Cost Element	Total Cost	Total incl. 2009 (Test Year)	Total incl. 2010
Software Licence	$ 1,300,000	$ 1,300,000	$ -
RFP Process	$ 200,000	$ 200,000	$ -
Implementation Costs	$ 13,600,000	$ 5,018,667	$ 8,589,333
Project Management Costs	$ 700,000	$ 500,000	$ 200,000
Hardware Costs	$ 231,778	$ 231,778	
Total	$ 16,031,778	$ 7,250,445	$ 8,789,333

Based on the project phasing described above, it is expected that EWU will spend $7,250,445 on functionality that will "go-live" within the 2009 calendar year. The remaining cost, some of which will actually be spent in 2009, will be in respect of functionality being deployed in 2010, and therefore is not included in the 2009 amount for EWU's rate base.

Summary

Implementing a Comprehensive ERP solution to replace EWU's current patchwork of software systems will not only provide for functionality missing in current systems, but will also improve the processes that are intertwined with data management and that are dependent on the availability of accurate, timely and sophisticated information. Those processes include: customer care, asset management, work order management, fleet management, procurement, finance, human resources, regulatory, settlement, and strategic planning.

Appendix "A"

Curriculum of EnWin Department Meetings with Sarah Horsley

Friday, July 4th

- High Level Discussion of Deliverable
- High Level Review of Current Systems leveraged by each department
- Identify Pain Points by department

Thursday, July 17th

- Review Pain Point Matrix
- Confirm if functionality exists in current solution, just not used or does not exist
- Confirm any additional Pain Points

Appendix "B"

Description of EWU's Current IT Infrastructure

The following is a high level description of EWU's current IT infrastructure.

Systems with Functionalities Requiring Upgrade/Replacement

1. PeopleSoft (PS) Version 7.5.4 (Implemented Yr. 2000)

The following business areas/processes rely on this application:

- Financials: EWU is using the PS application for its financials, including chart of account, general ledger, accounts receivable & payable and expense management
- Procurement – this includes contract management and purchasing
- Asset management – recording of all distribution assets
- Project management – management of construction projects and total project costs

This version is no longer supported by PeopleSoft.

2. PeopleSoft (PS) Version 8.8 (Implemented Yr. 2005)

The following business areas/processes rely on this application:

- Human Resources – workforce administration, employee management, time & labour, payroll & benefits

3. MAXIMO 4.1.1 (implemented Yr. 2003)

The following business areas/processes rely on this application:

- Work Management – work order tracking & costing, maintenance
- Materials Management – inventory management, goods movement
- Procurement – Purchasing, Requisition, receipts
- Asset Management

This version is only supported until September 2008.

4. SPL CIS 8.8 (Implemented Yr. 2004)

The following business areas/processes rely on this application:

- Customer Information
- Meter Management
- Meter Reading Scheduling
- Meter Reading & Validation
- Rate Management
- Billing - bill print & inserts, collections management, sub-ledger accounting
- Electronic Business Transactions (EBT)

5. Motorola CSR (Implemented Yr. 2004)

This application supports some specific customer service field orders types.

6. Lotus Notes

- This application supports the scheduling of appointments for field service orders.

7. Microsoft Excel

The following business areas/processes rely on this application:

- Recruitment
- Departmental/Corporate Budget
- Monthly Management Financial Reporting
- Settlement

Other Systems

There are many more peripheral systems which are stand alone or have "in-house custom interfaces" to the systems identified above.