2017 General Rate Application

Volume II

July 28, 2017

Revised – September 15, 2017

Revised – October 16, 2017

Revised – October 27, 2017

Revised – November 27, 2017

Revised – July 4, 2018

newfoundland labrador hydro

Table of Contents

VOLUME I — Application and Company Evidence

Application

Company Evidence

	Chapter 1 Corporate Overview	**Page**
1.1	Introduction	1.1
1.2	Managing Customer Electricity Rates in Transition to Interconnection with the North American Grid	1.8
1.3	Corporate Organization	1.12
1.4	Customer Service and Satisfaction	1.14
1.5	Safe and Reliable Operations	1.16
1.6	Financial Performance	1.20
1.7	Conclusion	1.21
	Chapter 2 Customers	
2.1	Overview	2.1
2.2	Serving Customers	2.3
2.3	Measuring Customer Satisfaction	2.8
2.4	Balancing Customer Service and Costs	2.11
2.5	Conservation and Demand Management	2.13
2.6	Net Metering	2.16
2.7	Identification of the Rural Subsidy on Customer Bills	2.17
2.8	Conclusion	2.17
	Chapter 3 Operations	
3.1	Overview	3.1
3.2	Hydro's Organizational Structure	3.2
3.3	Reliability and Customer Focus	3.4
3.4	Reliable Operations – System Performance	3.8
3.5	System Planning and Meeting Customer Load Requirements	3.14
3.6	Rural Deficit	3.31
3.7	2018 and 2019 Operating and Capital Costs	3.33
3.8	Island Interconnection with the North American Grid	3.43
3.9	Conclusion	3.46

newfoundland labrador hydro
a nalcor energy company

Table of Contents

(cont'd)

Chapter 4 Finance		Page
4.1	Overview	4.1
4.2	2018 Test Year and 2019 Test Year Revenue Requirement	4.3
4.3	Average Rate Base	4.8
4.4	Return and Capital Structure	4.12
4.5	Return on Rate Base	4.14
4.6	Other Matters	4.15
4.7	Hydro's Proposals	4.17

Chapter 5 Rates and Regulations

5.1	Overview	5.1
5.2	Cost of Service Methodology Review	5.2
5.3	2017 GRA Cost of Service Methodology Proposals	5.6
5.4	Recovery of Revenue Requirement	5.13
5.5	Supply Cost Deferral Accounts	5.16
5.6	Rate Design for Newfoundland Power	5.17
5.7	Rate for Island Industrial Customers	5.24
5.8	Rates for Rural Customers	5.30
5.9	Labrador Industrial Rates	5.34
5.10	Summary	5.38

Chapter 6 – Supplemental Evidence

6.1	Background	6.1
6.2	Accounting Treatment of Muskrat Falls Project Costs	6.2
6.3	Off-Island Purchases Deferral Account	6.3
6.4	Summary	6.8

List of Abbreviations

VOLUME II – Exhibits

Exhibit 1	Provincial Electrical System
Exhibit 2	Organizational Responsibility
Exhibit 3	Customer Service Roadmap Update
Exhibit 4	Report on Rural Subsidy Communication to Customers
Exhibit 5	Intercompany Transactions Costing Guidelines
Exhibit 6	Capital Expenditures and Carryover Reports, 2015, and 2016
Exhibit 7	Annual Reports on Key Performance Indicators, 2014, 2015, and 2016
Exhibit 8	Holyrood Decommissioning Study
Exhibit 9	Working Capital Methodology
Exhibit 10	Average Rate Base Methodology
Exhibit 11	2016 Depreciation Study
Exhibit 12	Automatic Return on Equity Adjustment Report
Exhibit 13	Cost of Service Expert Evidence

VOLUME III – Exhibits

Exhibit 14	2018 Test Year Cost of Service Study
Exhibit 15	2019 Test Year Cost of Service Study
Exhibit 16	Interim Rates, Rules and Regulations
Exhibit 17	Final Rates, Rules and Regulations

Exhibit 1 – Provincial Electrical System

Provincial Electrical System

July 2017

Table of Contents

1.0 Overview 1
1.1 Island Interconnected 1
1.2 Labrador Interconnected 5
1.3 Rural Interconnected Distribution 7
1.4 Hydro – Rural Isolated 7

List of Schedules

Schedule I – Provincial Generation and Transmission Grid
Schedule II – Island Interconnected System 2018/2019 Plant Assignment
Schedule III – Generating Capacity 2015
Schedule IV – Labrador Interconnected System 2019 Plant Assignment
Schedule V – TRO Communities Served by Interconnected Systems & Diesel Systems - Island
Schedule VI – TRO Communities Served by Interconnected Systems & Diesel Systems - Labrador
Schedule VII – Isolated Rural Systems Installed Generating Capacity

1.0 Overview

Newfoundland and Labrador Hydro (Hydro) owns and operates two interconnected power systems, one on the Island and the other in Labrador. As well, Hydro owns and operates 21 isolated generation and distribution systems located around coastal Newfoundland and Labrador,[1] and numerous distribution systems on the Island Interconnected System, primarily on the Great Northern Peninsula, the South Coast and the White Bay-Baie Verte area, as well as the Labrador Interconnected System. The below information is consistent with the proposed arrangement of the electrical system to the end of 2019.

1.1 Island Interconnected

On the Island Interconnected System, capacity and energy are provided by Hydro through a mix of hydroelectric and fossil-fired generation, as well as power purchases. This generation, along with the transmission system, is operated by Hydro's Energy Control Centre (ECC) to ensure the economic and reliable dispatch of available resources.

On the Island Interconnected System, Hydro owns and maintains approximately 3,500 km of high voltage lines, and more than 50 high voltage terminal stations operating at 230, 138 and 69/66 kV which connect to the generation and the delivery points for Newfoundland Power Inc., the Island Industrial Customers, and Hydro's rural distribution systems.

The general location of Hydro's Island facilities are indicated in Schedule I. A single line diagram of the Island Interconnected System 2018/2019 Plant Assignments is provided in Schedule II.

Since Hydro's last general rate application, the following additions and removals have been made to or are planned for the Island Interconnected System. These will be assigned to the Cost of Service areas consistent with Board of Commissioners of Public Utilities (the Board) approved

[1] Hydro also operates the Natuashish generation and distribution system on behalf of the Mushuau Innu First Nation.

methodology as follows:

- Addition of six mobile diesel units (total capacity of 10 MW) at Holyrood Terminal Station – assigned as common;
- Oxen Pond transformer T3, rated for 75/100/125 MVA, was relocated to Hardwoods Terminal Station and went in service as Hardwoods T1 in 2015 – assigned as common;
- Oxen Pond transformer T1, rated for 40/53.3/ 66.6 MVA, was relocated to Hardwoods as Hardwoods Spare T7S in 2014 – assigned as common;
- Hardwoods transformer T1, rated for 40/53.3/ 66.6 MVA, was removed from service in 2015 and became Hardwoods Spare T6S – assigned as common;
- Holyrood transformer T8, rated for 75/100/125 MVA, was relocated to Sunnyside to replace transformer T1 in 2014 – assigned as common. A new transformer, rated for 75/100/125 MVA, was installed for Holyrood T8 in 2014 – assigned as common;
- Replacement of 230/13.8 kV transformer T7 at Bay d'Espoir in 2016 with 129/172 MVA unit – assigned as common;
- Replacement of 230/13.8 kV transformer T1 at Cat Arm in 2016 with 60/80 MVA unit – assigned as common;
- Addition of a third 230 kV transmission line between Bay d'Espoir Terminal Station and Western Avalon Terminal Station, TL267, and associated terminal station reconfigurations are due to be complete in 2017 – assigned as common;
- Addition of a 230 kV Terminal Station at Soldiers Pond, as well as a 230 kVac – 350 kVdc Converter Station for the Labrador Island Link, three 175 MVAR Synchronous Condensers, and six 75 MVAR filters – assigned as owned by others;[2]
- Reconfiguration of the 230 kV transmission lines on the Avalon Peninsula due to interconnection at Soldiers Pond Terminal Station – all transmission lines assigned as common, including;
    - TL201 – Western Avalon to Soldiers Pond,
    - TL217 – Western Avalon to Soldiers Pond,

[2] These assets are not yet in-service. Hydro is not seeking cost recovery in this General Rate Application.

- TL242 – Soldiers Pond to Hardwoods,
- TL265 – Soldiers Pond to Holyrood (eastern portion of old TL217),
- TL266 – Soldiers Pond to Hardwoods (eastern portion of old TL201),[3] and
- TL268 – Soldiers Pond to Holyrood (western portion of old TL242);

- Rebuild of 230 kV transmission line TL266 between Soldiers Pond Terminal Station and Hardwoods Terminal Station to be completed in 2017 – assigned as common;
- Addition of 230 kV Granite Canal Tap Terminal Station, as well as a 15 MVAR reactor – assigned as owned by others;[4]
- Reconfiguration of 230 kV transmission line TL263 such that it ties in to Granite Canal Tap Terminal Station, with the remaining portion of the line renamed as TL270 to connect Granite Canal Tap Terminal Station to Granite Canal Generating Station – assigned as common;[5]
- Addition of a second 230 kV Terminal Station at Bottom Brook, as well as a 230 kVac – 200 kVdc Converter Station for the Maritime Link, and one 60 MVAR filter – assigned as owned by others;[6]
- Reconfiguration of 230 kV transmission lines TL211, TL233 and TL209 such that they tie in to Bottom Brook Terminal Station 2 instead of the original Bottom Brook Terminal Station– assigned as common;[7]
- Addition of 230 kV transmission line TL269, connecting Bottom Brook Terminal Station 2 and Granite Canal Tap Terminal Station – assigned as owned by others;[8]
- Addition of the 500 MW, 200 kVdc Maritime Island Link – assigned as owned by others;[9]
- Addition of 230 kV ring bus at Western Avalon Terminal Station – assigned as common;

[3] This work was new construction to replace a section of TL201 from Soldiers Pond to Hardwoods
[4] These assets are not yet in-service. Hydro is not seeking cost recovery in this General Rate Application.
[5] ibid.
[6] ibid.
[7] ibid.
[8] ibid.
[9] ibid.

- Western Avalon 230 kV buses B1 and B3, and circuit breaker B1B3 assignments changed from owned by Newfoundland Power to common due to the interconnection of the 230 kV ring bus;
- Stephenville circuit breakers B2L405 and L405T4, and Sunnyside circuit breaker B3L19 assignments changed from owned by Newfoundland Power to common; [10]
- Holyrood circuit breaker B4B15 assignment changed from owned by Newfoundland Power to common; and[11]
- Deer Lake circuit breaker B1L39 assignment changed from owned by Hydro Rural to common.[12]

Hydro's Island Interconnected System production facilities consist of hydroelectric, thermal, and standby generating facilities that vary in size from less than 1 MW to 613 MW. Hydro's Island Interconnected System installed capacity totals 1699 MW. Hydro also has a number of power purchase agreements with Non-Utility Generators to provide additional power to the system. Including these contracts, the total installed capacity for the Island Interconnected System is 2132 MW. For 2017 through to the 2018 and 2019 Test Years, the total from all power purchases is forecast to provide approximately 14% annually of Hydro's Island Interconnected total net energy supply. Schedule III provides the provincial interconnected generation capability.

[10] Assigned to common due to being part of ring bus configuration.
[11] Assigned to common due to being part of breaker and a half configuration.
[12] Assigned to common due to being part of ring bus configuration.

1.2 Labrador Interconnected

The majority of power and energy for the Labrador Interconnected System is purchased from Churchill Falls (Labrador) Corporation Ltd. Hydro has a total of 300 MW and 2,362 GWh available annually through Recapture Energy, and 225 MW and 1,971 GWh per year through the TwinCo Block.[13] Hydro also maintains gas turbine and diesel assets in the Labrador Interconnected System with a combined capacity of 30 MW.[14]

Hydro owns and maintains 269 km of 3-phase 138 kV transmission line and the associated terminal stations in Labrador, interconnecting Happy Valley/Goose Bay to Churchill Falls, two parallel 3-phase 230 kV transmission lines (each line having a length of approximately 216 km) and the associated terminal stations interconnecting Labrador West to Churchill Falls and over 44 km of 46 kV sub-transmission lines in Labrador West.

The general location of Hydro's facilities in Labrador are indicated in Schedule I. A single line diagram of the Labrador Interconnected System 2019 Plant Assignments is provided in Schedule IV. Since Hydro's last general rate application the following additions were made or are planned to be made to the Labrador Interconnected System.

- Addition of 138/25 kV transformer T4, rated for 15/20/28 MVA, in Happy Valley Terminal Station in 2016 – assigned to common;
- Addition of 735/315 kV Churchill Falls Terminal Station 2 – assigned as owned by others;
- Addition of 315/138/25 kV Muskrat Falls Terminal Station 2, as well as a 315 kVac – 350 kVdc Converter Station for the Labrador Island Link, the 824 MW Muskrat Falls Generating Station (under construction), and five 72 MVAR filters – assigned as owned by others;

[13] On May 12, 1969, Hydro-Quebec (HQ) and the Churchill Falls (Labrador) Corporation (CF(L)Co) entered into a power contract for the purchase of power from the CF(L)Co plant by HQ (the 1969 Power Contract). Pursuant to section 6.6 of the 1969 Power Contract, CF(L)Co has exercised its right to recapture 300 MW of power (Recapture Energy) generated at the CF power plant. Under the terms of a PPA between Hydro and CF(L)Co (the NLH-CF(L)Co PPA) dated March 9, 1998, and amended on April 1, 1999, Hydro is able to, and does, purchase up to 300 MW of Recapture Energy from CF(L)Co for use outside of the Province of Quebec. Under the terms of the HQ-Hydro Shareholders Agreement governing the operation of the Churchill Falls plant, CF(L)Co must make a firm 225 MW block of power and energy available to Hydro for distribution and use in Labrador West.

[14] The Happy Valley North Plant has been de-rated to 5 MW due to a fire in January 2012.

- Addition of two 315 kV transmission lines L3101 and L3102, connecting Churchill Falls Terminal Station 2 and Muskrat Falls Terminal Station 2 – assigned as owned by others;[15]
- Addition of 138 kV transmission line L1302 extension, connecting Churchill Falls to Muskrat Falls Terminal Station 2 – assigned to common;
- Addition of the 830 MW, 350 kVdc Labrador Island Link – assigned as owned by others;[16]
- 230/46 kV Wabush Terminal Station (with the exception of Synchronous Condenser 3 and transformer T6) and 230 kV transmission line L2304 and L2303 assignments changed from owned by others to common;
- Addition of load from Great North Data on Wabush Terminal Station feeder L32 – assigned as Hydro Rural; and
- Addition of 46/12.5 kV transformer T6, rated for 10/13.33/16.67 MVA, in Wabush Substation in 2014. Load was transferred from feeder L12 to L3 to off-load transformer T3 and add more load to the larger transformer T6 – assigned as Hydro Rural.

1.3 Rural Interconnected Distribution

On the Island Interconnected System, Hydro owns and maintains approximately 2,260 km of low voltage (up to 25 kV) distribution lines and 45 low voltage substations, which serve approximately 22,900 Rural Customers.[17] These Rural Customers are served from distribution systems located in approximately 180 communities on the South Coast, Northeast Coast, and along the Great Northern Peninsula.

On the Labrador Interconnected System, Hydro owns and maintains approximately 350 km of low voltage distribution lines and seven substations, serving six communities with approximately 11,200 Rural Customers.

[15] These assets are not yet in-service. Hydro is not seeking cost recovery in this General Rate Application.
[16] ibid
[17] Rural customer counts do not include street and area lighting customers.

The general location of these service areas, as well as the isolated service areas are provided in Schedules V and VI.

1.4 Hydro – Rural Isolated

Hydro owns and operates 21 isolated diesel generating and distribution systems serving approximately 4,500 customers[18] in over 40 communities throughout coastal Newfoundland and Labrador.[19] Fifteen of these systems are located in Labrador and six are on the island of Newfoundland.

Schedules V and VI show the location of these isolated diesel generating plants and Schedule VII provides a breakdown of their proposed installed capacity as of December 31, 2019. The total installed capacity of Hydro's 21 isolated diesel plants is approximately 37.0 MW.

[18] ibid.
[19] ibid., page 1

Exhibit 1 – Schedule I

Provincial Generation and Transmission Grid

Revision 3 - October 27, 2017
Exhibit 1 - Schedule I
Page 1 of 1

Provincial Generation and Transmission Grid

LEGEND

- 735 kV
- 315 kV
- 230 kV
- 138 kV
- 69 kV
- LOW VOLTAGE
- 138kV CUSTOMER OWNED
- 69kV CUSTOMER OWNED
- HYDRO PLANT
- THERMAL PLANT
- TERMINAL STATION
- TERMINAL STATION & CONVERTER STATION
- FREQ. CONVERTOR
- NF. POWER
- CORNER BROOK PULP AND PAPER
- ALGONQUIN POWER
- MUSHUAU 1st NATION
- WIND GENERATION
- OPERATED BY NALCOR
- GAS TURBINE
- DIESEL PLANT

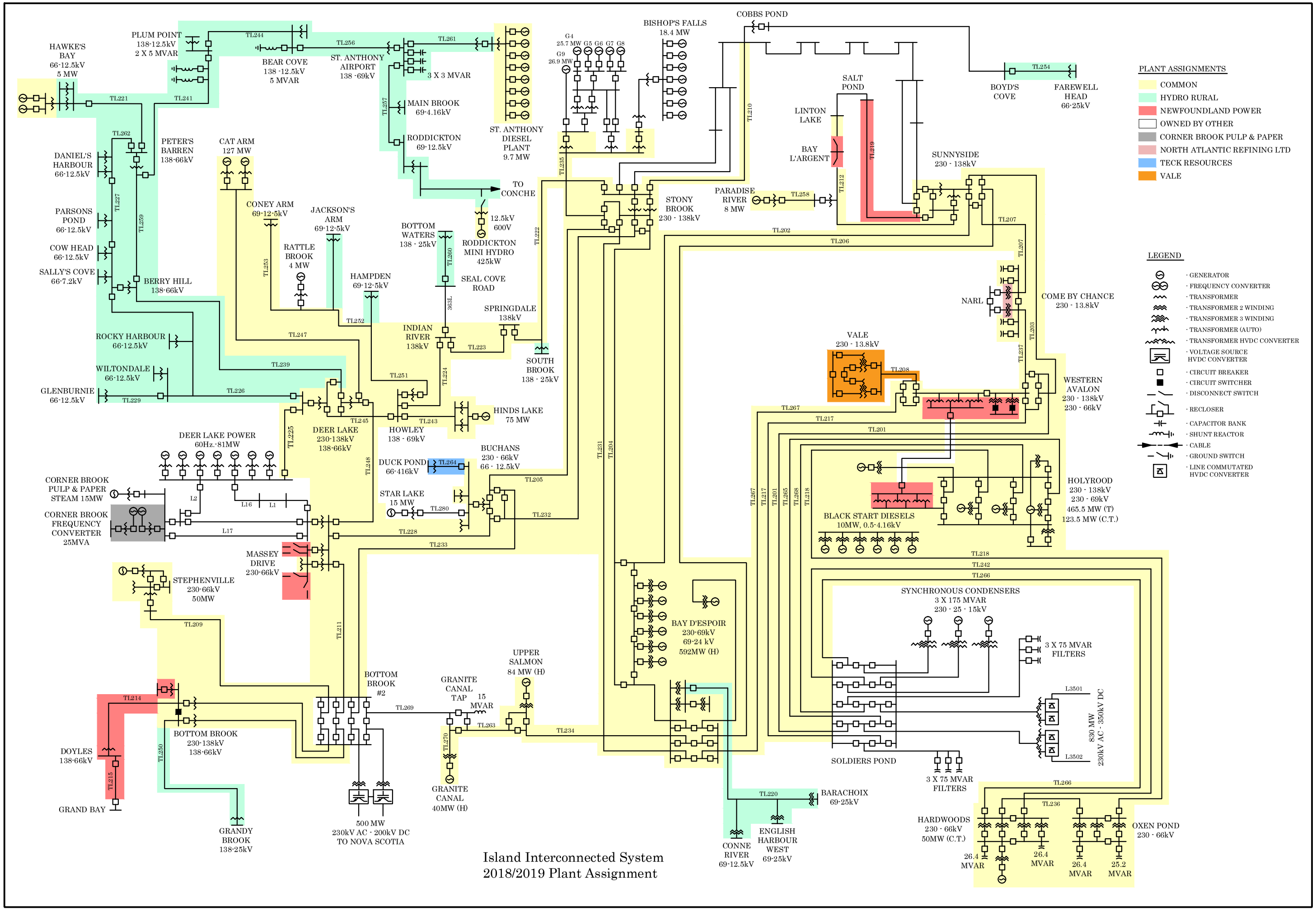
DC LEGEND

- ± 350 /± 200kV HVdc
- SUBMARINE CABLE
- ELECTRODE LINE
- ELECTRODE STATION

Revised: September 29, 2017

Exhibit 1 – Schedule II

Island Interconnected System 2018/2019 Plant Assignment



Revision 4 - November 27, 2017
Exhibit 1 - Schedule II
Page 1 of 1

Exhibit 1 – Schedule III

Generating Capacity 2018

Newfoundland and Labrador Hydro
Generating Capacity

Plant	Net Installed Capacity (MW)	Gross Continuous Unit Rating (MW)	Average Annual Energy (GWh)	Firm Annual Energy (GWh)
		Island Interconnected System		
Hydroelectric[2]	959	954	4,600	3,961
Thermal	490	490	2,895	2,895
Standby	250	248	-	-
Non-Utility Generation	196	97	1,026	866
Total Capability	**1,895**	**1,789**	**8,521**	**7,722**
Customer Generation[3]	237	217	1,310	1,117
Total Island Interconnected System Capability	**2,132**	**2,006**	**9,831**	**8,839**
Interruptible Contracts		113		
Total Gross Continuous Unit Rating including Interruptible Contracts		**2,119**		
		Labrador Interconnected System		
Happy Valley Gas Turbine	27	27	-	-
Goose Bay North Plant, Mud Lake	5	5	-	-
CF(L)Co. Supply[4]	532	532	4,387	4,387
Total Labrador Interconnected System Capability	**564**	**564**		

Note:

1. All values rounded to nearest MW or GWh.
2. Forecast assumes average inflows
3. Customer Generation average annual energy and firm annual energy reflect both 50 and 60 Hz energy for CBPP.
4. CF(L)Co. Supply includes both recapture and Twin Co. supply at CF Plant.

Exhibit 1 – Schedule IV

Labrador Interconnected System []2019 Plant Assignment

CHURCHILL FALLS
15-230kV
5428MW

L1301/TL240

230-138kV

MFATS1
PUMPING
STATION

MFATS3
TAP
STATION

L2304

L2303

230-735kV

T76 T75 T74 T73 T72 T71

SC 1 & SC 2
-45/+60 MVAR

SC 3
-20/+60 MVAR

27.55 MVAR

WABUSH
230-46kV

T1 T2 T3 T4 T5 T6 T7 T8

L7053 165 MVAR

L7052 165 MVAR

L7051 165 MVAR

735kV

315kV

LABRADOR
QUEBEC
BORDER

CHURCHILL FALLS
TERMINAL STATION 2
735-315kV

L1302

L3101

L3102

IOC 1
IOC 2
IOC 3
SS1
IOC 4
25.2 MVAR
IOC 5A
SS2
IOC 5B
IOC 6
IOC 7
WABUSH MINES 1
WABUSH MINES 2
25.2 MVAR

3 X 72 MVAR FILTERS

TO SOLDIERS POND
900MW
+/- 350kV
TO SOLDIERS POND

2 X 72 MVAR FILTERS

315kV

MUSKRAT FALLS TERMINAL STATION 2
315-138-25kV

MUSKRAT FALLS
GENERATING STATION
15-315kV
(UNDER CONSTRUCTION)
824MW

HAPPY VALLEY
GOOSE BAY
138-25kV
25 MW

11.4 MVAR

T1 T2 T4 T3

L16 L17

L1 L7 L8 L10 L15

25-4.16kV

25-4.16kV

L11

NORTH SIDE
DIESEL PLANT
5.0 MW

L32 L33 L36 L36

L40 L40

WABUSH TOWN
46-12.5kV

QUARTZITE
46-25kV

COOPER
HILL
46-4.16kV

GREAT
NORTH
DATA

TO
FERMONT

WALSH
RIVER
46-14.4kV

LANDFILL
46-14.4kV

VANIER
46-25kV

LABRADOR
CITY

PLANT ASSIGNMENTS

- COMMON
- HYDRO RURAL
- IOC
- OWNED BY OTHER

LEGEND

- GENERATOR
- TRANSFORMER
- TRANSFORMER 2 WINDING
- TRANSFORMER 3 WINDING
- TRANSFORMER (AUTO)
- TRANSFORMER HVDC CONVERTER
- CIRCUIT BREAKER
- DISCONNECT SWITCH
- RECLOSER
- CAPACITOR BANK
- SHUNT REACTOR
- CABLE
- GROUND SWITCH
- LINE COMMUTATED HVDC CONVERTER

Labrador Interconnected System
2019 Plant Assignment

Revision 3 - October 27, 2017
Exhibit 1 - Schedule IV
Page 1 of 1

Exhibit 1 – Schedule V

TRO Communities Served by Interconnected System & Diesel Systems - Island



NOTE:

Name in capital letters (RED) denotes interconnection point with the bulk power system

Name in capital letters (GREEN) denotes location of the diesel generating plant.

Communities Served by Interconnected Systems & Diesel Systems

Exhibit 1 – Schedule VI

TRO Communities Served by Interconnected System & Diesel Systems - Labrador



Communities Served by Interconnected Systems & Diesel Systems

Exhibit 1 – Schedule VII

Isolated Rural Systems Installed Generating Capacity

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED RURAL SYSTEMS
PROPOSED INSTALLED GENERATING CAPACITY - END OF 2019 – kW

Plant Location	Individual Unit Sizes						Firm Capacity	Installed Capacity
Labrador								
Black Tickle	300	455	250				550	1,005
Cartwright	450	720	450	600			1,500	2,220
Charlottetown	300	725	725	500	910		2,075	3,160
Hopedale	545	569	475	925			1,589	2,514
L'Anse Au Loup[1]	1,500[2]	1,825	800	1,100	1,000	1,825	6,950	8,050
Makkovik	565[2]	565	635				1,130	1,765
Mary's Harbour	545	545	820	725			1,815	2,635
Nain	865	865	1,275	750			2,480	3,755
Norman Bay	40	50	70				90	160
Paradise River	50	48	50				98	148
Port Hope Simpson	455	750[2]	455	600			1,365	1,965
Postville	252	365	275				527	892
Rigolet	320	455	545				775	1,320
St. Lewis	365	455	200				565	1,020
Williams Harbour	210	80	90				170	380
SUBTOTAL							**21,679**	**30,989**
Island								
Francois	275	150	210				360	635
Grey River	136	136	250				272	522
Little Bay Islands	450	275	205				480	930
McCallum	136	210	100				236	446
Ramea[3]	925	925	925				1,850	2,775
St. Brendan's	277	210	225				435	712
SUBTOTAL							**3,633**	**6,020**
TOTAL INSTALLED CAPACITY								**37,009**

[1] Excludes Hydro Quebec interconnected capacity at 4,000 kW.
[2] Includes proposed capacity increases to December 31, 2019
[3] Excludes power purchase capacity of 390 kW from Frontier Power and Nalcor Wind Hydrogen capacity.

Exhibit 2 - Organizational Responsibility

Organizational Responsibility

July 2017

Table of Contents

1.0 Overview 1
2.0 Executive Leadership 1
3.0 Production 2
3.1 Thermal Generation 2
3.2 Hydraulic Generation 2
3.3 Resource and Production Planning 2
4.0 Transmission and Distribution and NLSO 2
4.1 Transmission and Rural Operations 3
4.2 Rural Planning 3
4.3 Newfoundland and Labrador System Operator 3
5.0 Engineering Services 5
5.1 Engineering 5
5.2 Information and Operations Technology 5
5.3 Asset Management and Reliability 5
6.0 Corporate Services and Regulatory Affairs 6
6.1 Regulatory Affairs 6
6.2 Customer Service 6
6.3 Energy Efficiency 6
6.4 Safety and Health 6
6.5 Environment 6
6.6 Human Resources and Labour Relations 7
6.7 Communications 7
7.0 Corporate Secretary and General Counsel 7
8.0 Financial Services 7
8.1 Finance 7
8.2 Supply Chain Management and Administration 8
8.3 Internal Audit 8

List of Schedules

Schedule I – Organizational Charts

1.0 Overview

Newfoundland and Labrador Hydro is a Crown corporation continued and existing under the *Hydro Corporation Act, 2007.*[1] Hydro's mandate is to provide safe, reliable, and least cost electricity to customers in Newfoundland and Labrador. This report is intended to provide an overview of Hydro's operations and organizational structure.

Hydro's organizational structure was updated in 2016. There are seven divisions within Hydro: Executive Leadership, Production, Transmission and Distribution and NLSO, Engineering Services, Financial Services, Corporate Services and Regulatory Affairs, and Corporate Secretary and General Counsel.

Schedule I to this exhibit provides the organizational structure of Hydro.

2.0 Executive Leadership

Hydro's Executive Leadership division consists of the Senior Leadership team as depicted in Schedule I, page 1 of 33. The Executive team are accountable for leading and managing all functions associated with delivering utility service to fulfill Hydro's core mandate to provide safe, reliable, and least cost electricity to customers in the Province. Each of the Vice-Presidents lead their respective divisions.

Hydro has also created a new temporary position, Manager, Interconnection & Integration, reporting directly to the President to manage Hydro's activities associated with the interconnection to the North American grid. This position is responsible for evaluating opportunities and risks associated with interconnection, and managing Hydro's key activities for effective integration.

[1] *Hydro Corporation Act, 2007*, SNL 2007, c. H-17, copy available at http://www.assembly.nl.ca/legislation/sr/statutes/h17.htm
Although Hydro has its own enabling legislation, it is also a subsidiary of the Crown corporation Nalcor Energy (Nalcor)which was created in 2007 to manage the province's energy resources by the *Energy Corporation Act*, SNL 2007, c. E-11.01, copy available at http://www.assembly.nl.ca/Legislation/sr/statutes/e11-01.htm.

3.0 Production

The Production division, as depicted in Schedule I, pages 2 through 8 of 33, is responsible for all aspects of power generation and supply. Hydro's various sources of thermal and hydro generation collectively represent a total installed generation capacity of 1763 MW and are geographically dispersed across the island and in Labrador. There are three departments within Production.

3.1 Thermal Generation

The Thermal Generation department is responsible for the operation and maintenance of the Holyrood Thermal Generating Station and Hydro's Gas Turbines, as well the long term planning for Hydro's remote diesels and related facilities.

3.2 Hydraulic Generation

The Hydraulic Generation department is responsible for the operation and maintenance of Hydro's nine hydroelectric generating stations and related facilities.[2]

3.3 Resource and Production Planning

The Resource and Production Planning department is responsible for generation planning and water management.

4.0 Transmission and Distribution and NLSO

This division includes transmission, distribution, and the Newfoundland and Labrador System Operator (NLSO) as depicted in Schedule I, pages 9 through 18 of 33. This division is responsible for: operating and maintaining Hydro's transmission and terminal station infrastructure for the interconnected system; operating and maintaining the distribution and isolated diesel systems;

[2] Hydraulic Generation is also responsible for the operation of the Exploits assets owned by the Government of Newfoundland and Labrador. Costs associated with the operations are recovered from the asset owner and do not impact Hydro customers.

rural planning; operating the electrical power system, including generation dispatch; and directing the operations of the transmission facilities to meet anticipated load.

There are three departments within Transmission and Distribution and NLSO.

4.1 Transmission and Rural Operations

Transmission and Rural Operations (TRO) is responsible for the maintenance of Hydro's transmission systems and the operation and maintenance of the rural distribution and isolated diesel assets. TRO has two sections: 1) Northern and Labrador to focus on the assets and requirements in Northern part of the Island and in Labrador; and 2) Western and Eastern to focus on assets in Western, Central, and Eastern Newfoundland, including the Avalon Peninsula.

4.2 Rural Planning

Rural Planning is responsible for planning the distribution and rural generation facilities located on the Labrador Interconnected System, the Isolated Rural systems, and Island Interconnected System. This includes recommending system modifications or expansion, completing system studies, and preparing operational and long-term planning load forecasts for the various rural power systems, as well as load forecasts for the Labrador Interconnected and Island Interconnected Systems. These are then used to assess and ensure facilities are available to serve customer requirements.

4.3 Newfoundland and Labrador System Operator

The creation of the Newfoundland and Labrador System Operator (NLSO) is an important step in the integration of the Muskrat Falls assets into the provincial electrical system and the Island's interconnection with the North American electricity grid. Industry recognized standards, such as those developed by the Federal Energy Regulatory Commission

(FERC),[3] recommend that functional separation exist between power production and the NLSO. FERC imposes additional requirements in its Standards of Conduct regulations that govern that employees of the NLSO function independently from Nalcor Energy Marketing employees.[4]

The NLSO will reside in Hydro but will be functionally separate and will act as the independent system operator for the transmission system in the Province. It will operate the facilities owned by Hydro and Nalcor along with interconnections to Emera's Maritime Link assets on the island.

Hydro has structured the NLSO into three main areas: Transmission Planning, System Operations, and Reliability and Commercial Management:

- Transmission Planning – The transmission planning group is responsible for the safe, efficient, reliable, and environmentally responsible planning of the provincial interconnected transmission system.
- System Operations – The System Operations group manages the Newfoundland and Labrador power system and coordinates the supply of and demand for electricity in accordance with reliability standards in effect in the province.
- Reliability and Commercial Management – The NLSO is responsible for establishing the reliability framework for operating the bulk electrical system.[5] The NLSO is also responsible for offering open and non-discriminatory access to the Newfoundland and Labrador interconnected transmission system to all transmission customers, including Nalcor affiliates and non-affiliated third parties.

[3] The Federal Energy Regulatory Commission (FERC) is an independent agency, based in Washington, D.C., which regulates the inter-state transmission of electricity, natural gas, and oil. In the United States, and in neighboring Canadian jurisdictions, wholesale sales of electricity are typically governed by FERC's Open Access Transmission Tariff, which sets out standards and other requirements governing market access and system reciprocity.

[4] The purpose of this requirement is to ensure that there is no collaboration or exchange of non-public transmission information between affiliated business units which could impair non-discriminatory, open system access within the wider electricity market.

[5] The bulk electrical system is an interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and point for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

5.0 Engineering Services

Engineering Services, as depicted in Schedule I, pages 19 through 27 of 33, is responsible for Hydro's engineering activities, project execution, and asset oversight. There are three main areas in Engineering Services: Engineering; Asset Management and Reliability; and Information and Operations Technology.

5.1 Engineering

The Engineering department includes the following functions: Project Execution; Asset Management and Reliability; Civil, Transmission, and Distribution Engineering; Electrical Engineering; Mechanical Engineering; Protection, Controls, and Communication Engineering; and Engineering Support Services. Some of the functions of engineering include:

- Managing capital and operating projects;
- Managing engineering design standards;
- Providing engineering support services including legal surveys, property acquisitions, drafting services; and
- Providing engineering expertise and project management services.

5.2 Information and Operations Technology

The Information and Operations Technology Department provides information and operating technology solutions related to the Energy Management System (EMS) and Network Services. It also manages the delivery of Information Systems services from Nalcor to Hydro.

5.3 Asset Management and Reliability

The Asset Management and Reliability Department is responsible for establishing and maintaining asset management framework and procedures and coordinating corporate capital budget development.

6.0 Corporate Services and Regulatory Affairs

This division consists of the following seven departments: Regulatory Affairs; Customer Service; Energy Efficiency; Safety and Health; Environment; Human Resources and Labour Relations; and Communications. Please refer to Schedule I, pages 28 through 31 of 33.

6.1 Regulatory Affairs

Regulatory Affairs is responsible for all aspects of utility regulation, rate design, and policy. Regulatory Affairs is also responsible for monitoring and managing the Company's relationship with the Board of Commissioners of Public Utilities and ensuring appropriate processes and interfaces between regulatory, operations, and other support teams within Hydro.

6.2 Customer Service

The Customer Service department is Hydro's primary interface with customers. This department is responsible for communicating with customers regarding account enquiries, service requests, outage reporting, and other matters.

6.3 Energy Efficiency

This department is responsible for the delivery of Hydro's energy efficiency and conservation programs.

6.4 Safety and Health

Safety and Health provides functional services and support, as well as strategic and policy leadership, to all areas of Hydro on matters related to safety and health. It also manages the delivery of safety and health services from Nalcor.

6.5 Environment

The Environment department provides environmental services and support to all areas of Hydro, as well as general strategic and policy leadership in relation to environmental stewardship. It also manages the delivery of environment services from Nalcor.

6.6 Human Resources and Labour Relations

The Human Resources and Labour Relations department provides strategic leadership to Hydro in the areas of human resources management. This department administers and negotiates the Hydro's collective bargaining agreement and also manages the delivery of human resources services from Nalcor.

6.7 Communications

Hydro's Communications department is responsible for corporate communications, media relations, employee communications, community investment and community relations, and stakeholder engagement and consultation.

7.0 Corporate Secretary and General Counsel

Hydro's Corporate Secretary and General Counsel department provides core legal oversight to Hydro as well as Board Secretarial functions.

8.0 Financial Services

The Financial Services division, as depicted in Schedule I, pages 32 and 33 of 33, consists of three departments: Finance; Supply Chain Management and Administration; and Internal Audit.

8.1 Finance

The Finance department provides the following functions:

- Controller functions including financial reporting, regulatory finance, budgeting and forecasting, and general corporate accounting functions, including accounts payable;
- Treasury services of cash and debt management and tax services;
- Corporate planning to coordinate the corporate strategic planning and associated performance measurements and reporting;
- Enterprise risk management and control framework management; and
- Commercial services that manage the development of key commercial arrangements.

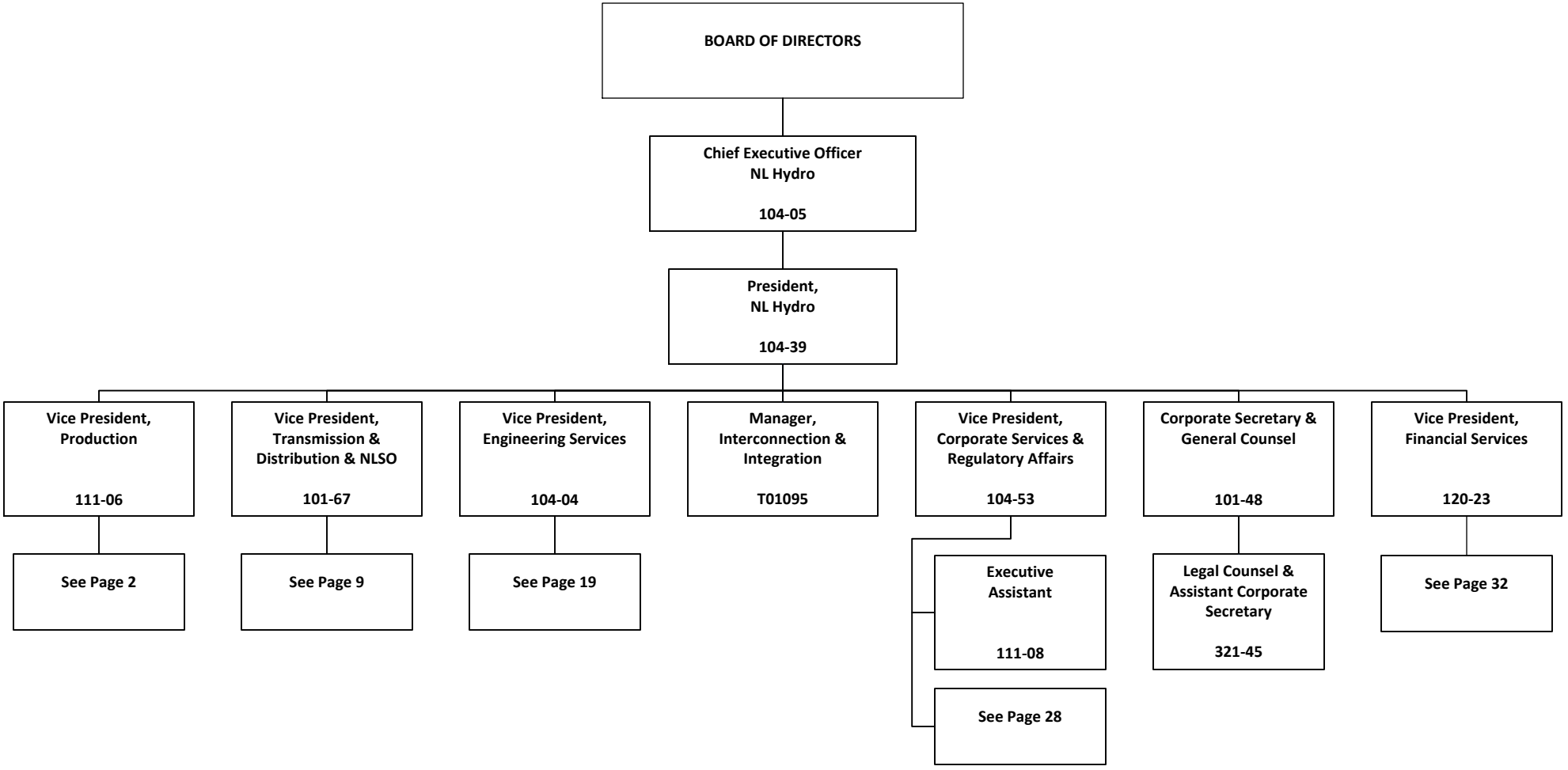
8.2 Supply Chain Management and Administration

The Supply Chain Management and Administration department manages procurement and contract management, materials management, and the management of Hydro Place.

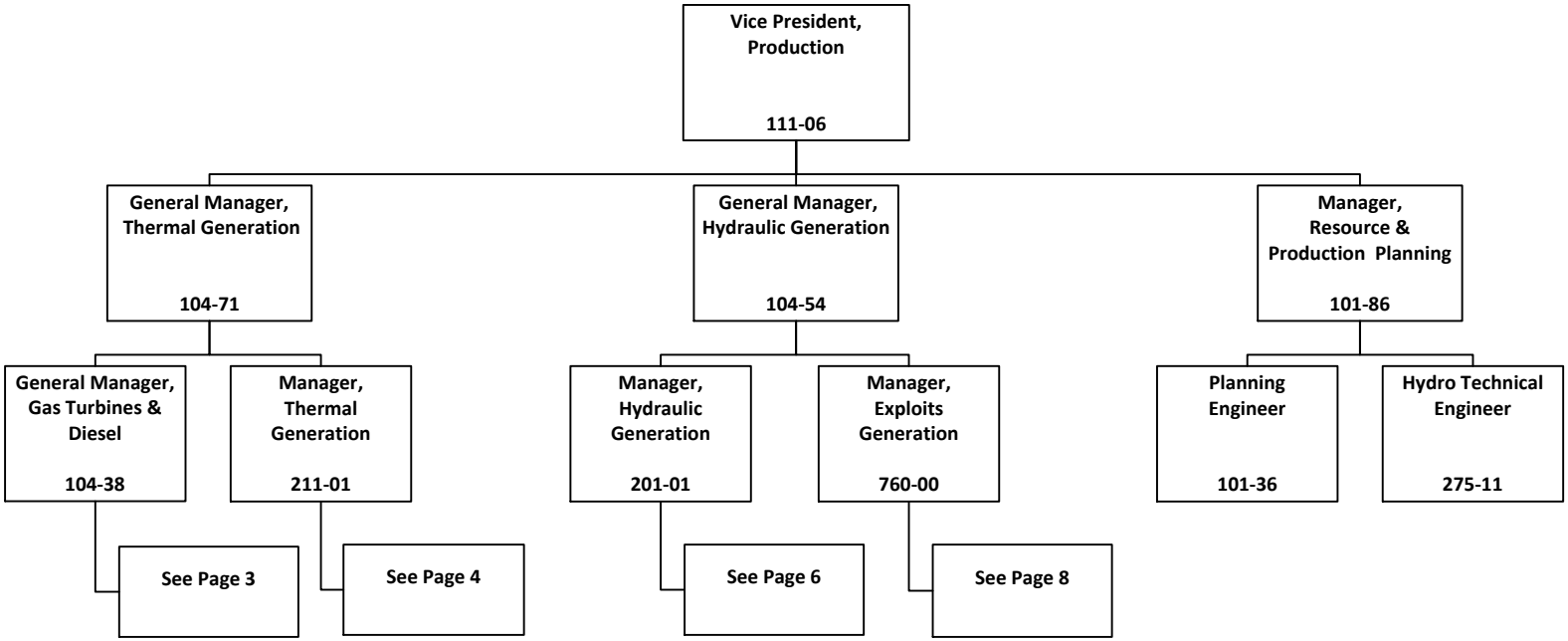
8.3 Internal Audit

The Internal Audit department conducts the internal audit function for Hydro. The Internal Audit department is accountable directly to the Hydro Board of Directors but reports administratively through the Finance division.

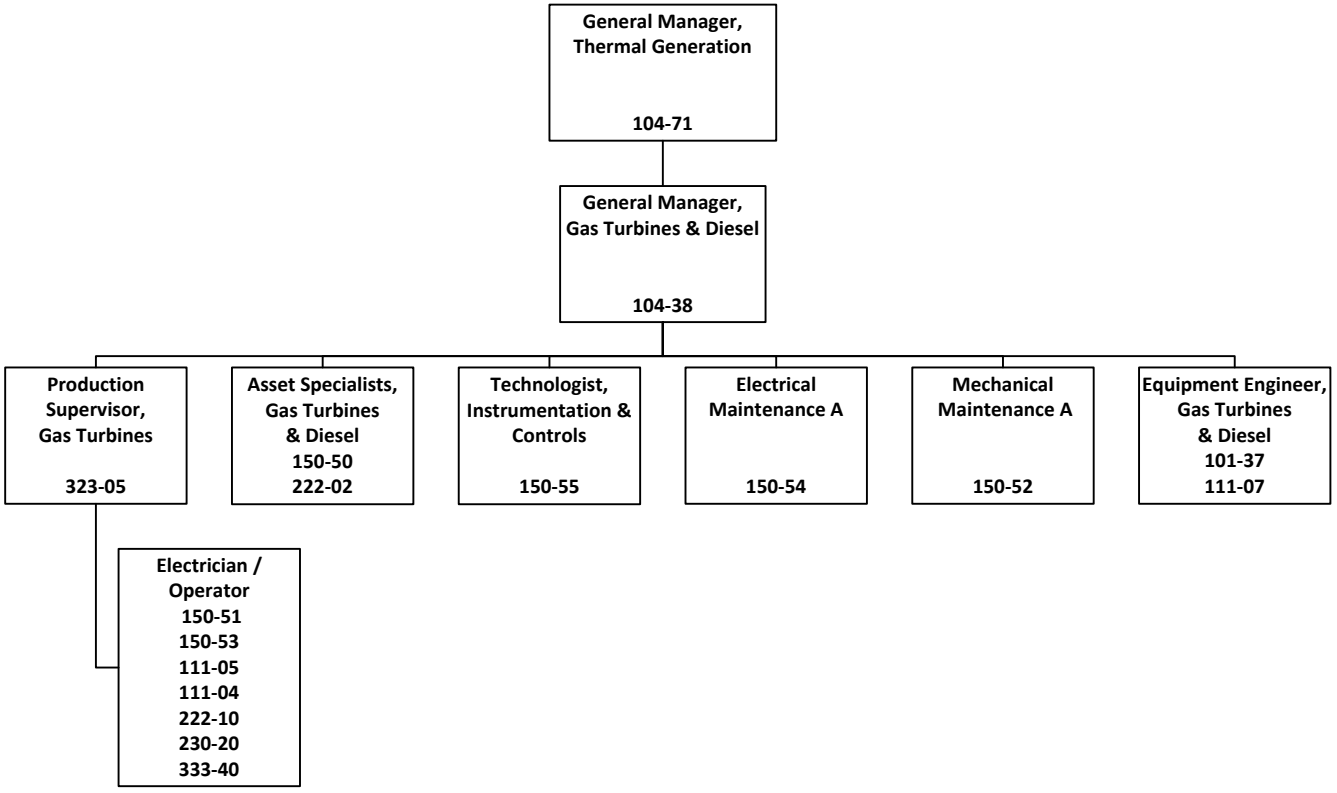
Executive Leadership



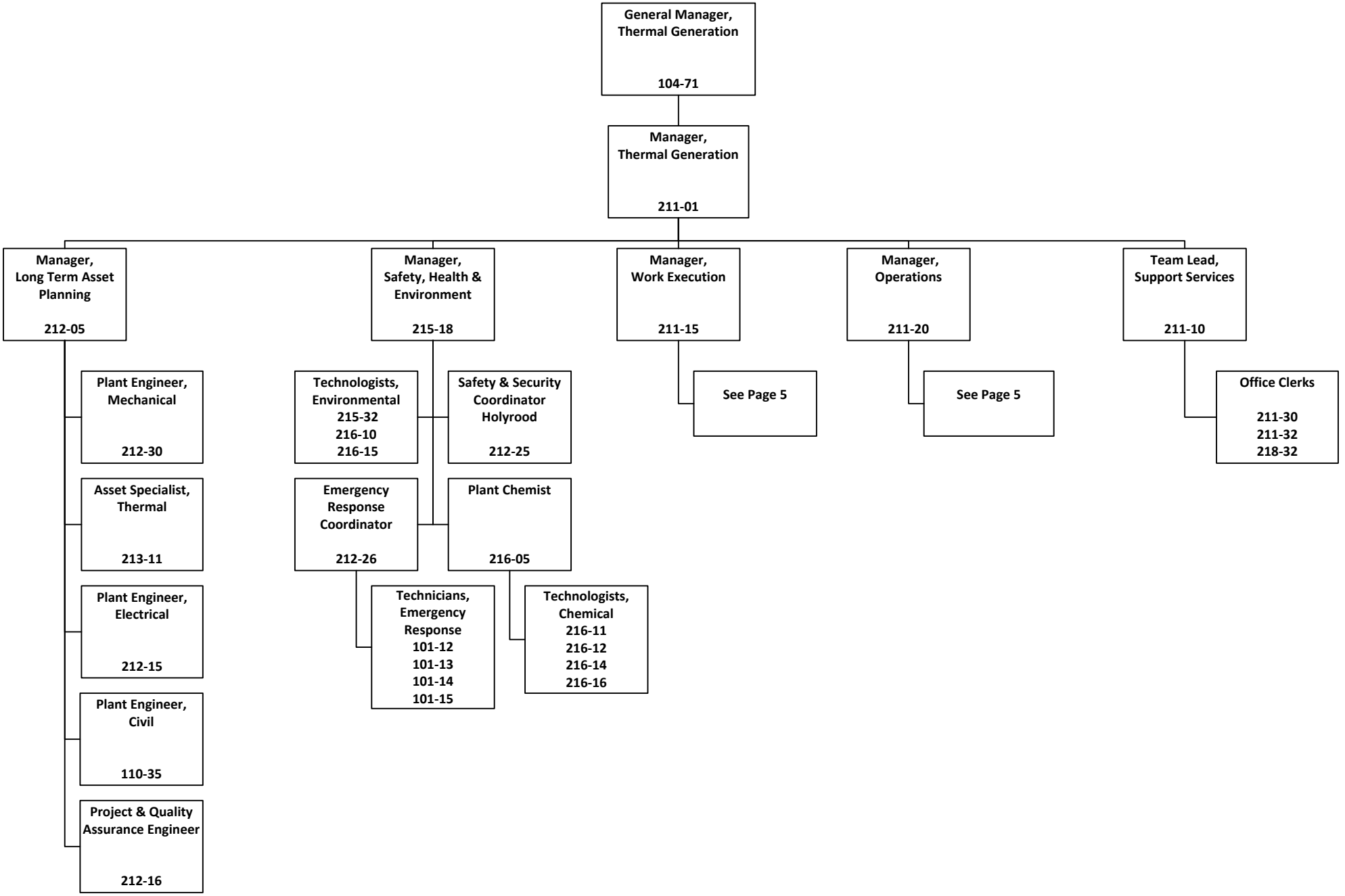
Production


Vice President, Production
111-06
General Manager, Thermal Generation
104-71
General Manager, Hydraulic Generation
104-54
Manager, Resource & Production Planning
101-86
General Manager, Gas Turbines & Diesel
104-38
Manager, Thermal Generation
211-01
Manager, Hydraulic Generation
201-01
Manager, Exploits Generation
760-00
Planning Engineer
101-36
Hydro Technical Engineer
275-11
See Page 3
See Page 4
See Page 6
See Page 8

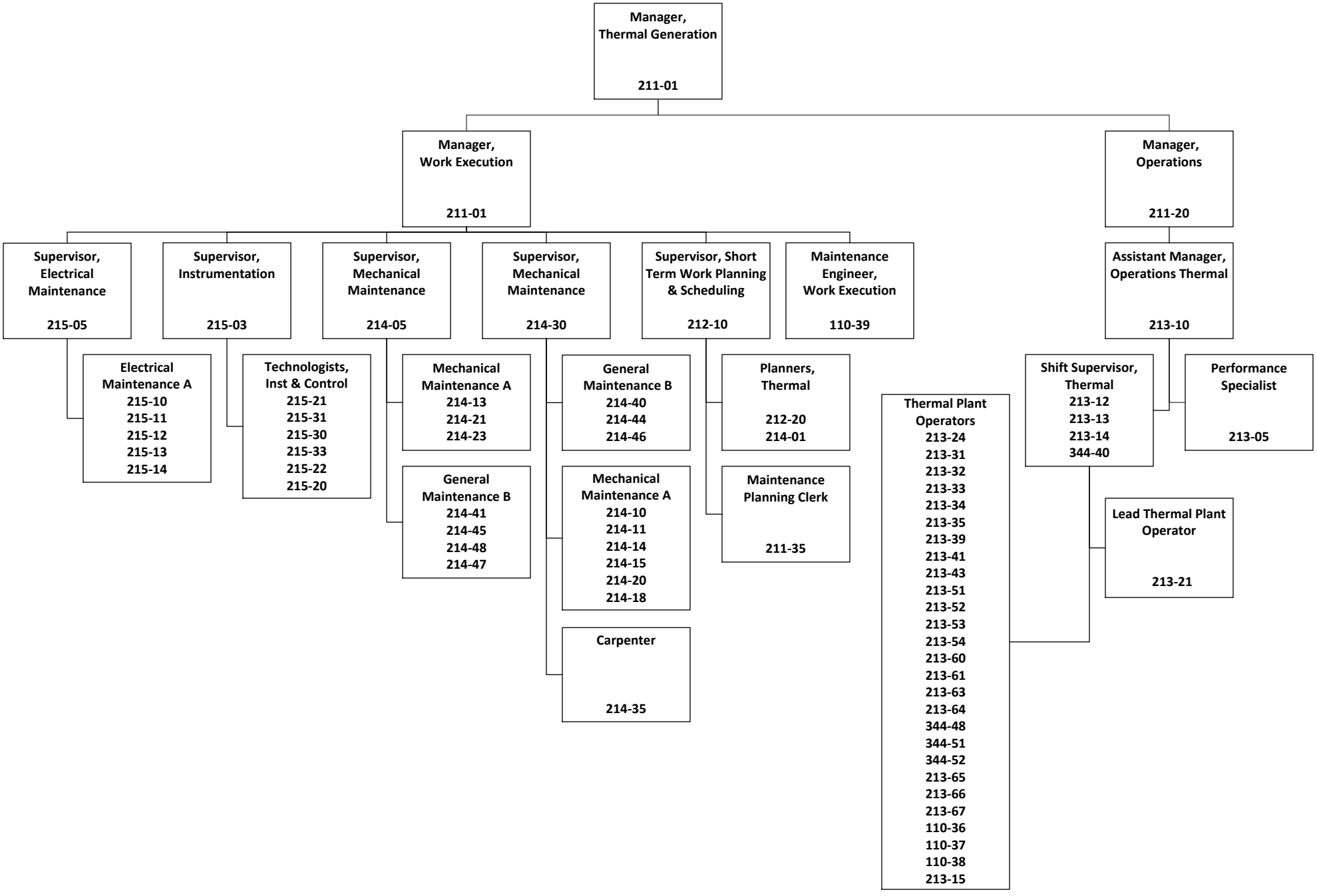
Production
Gas Turbines & Diesel



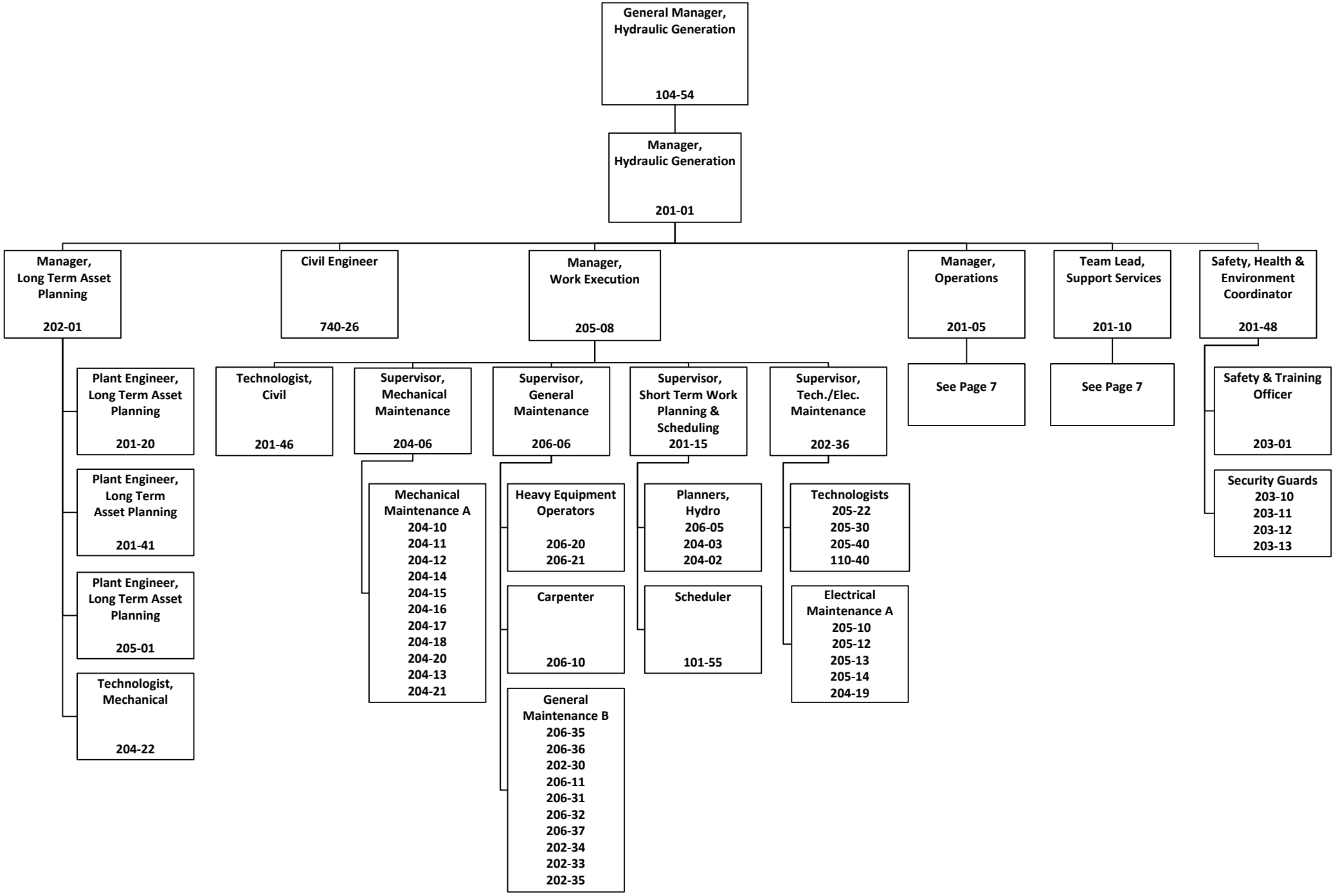
Production
Thermal Generation



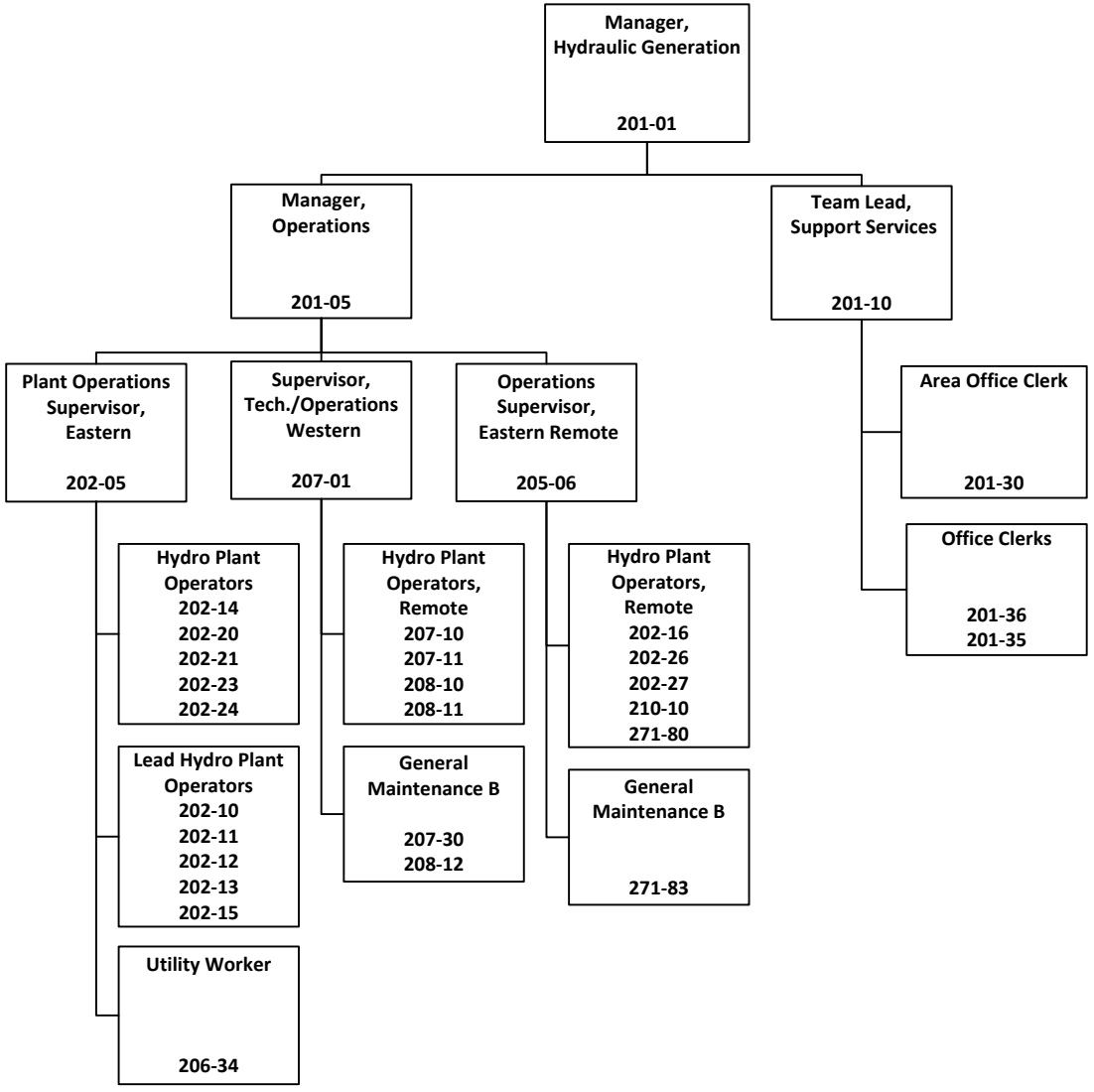
Production
Thermal Generation, Work Execution & Operations



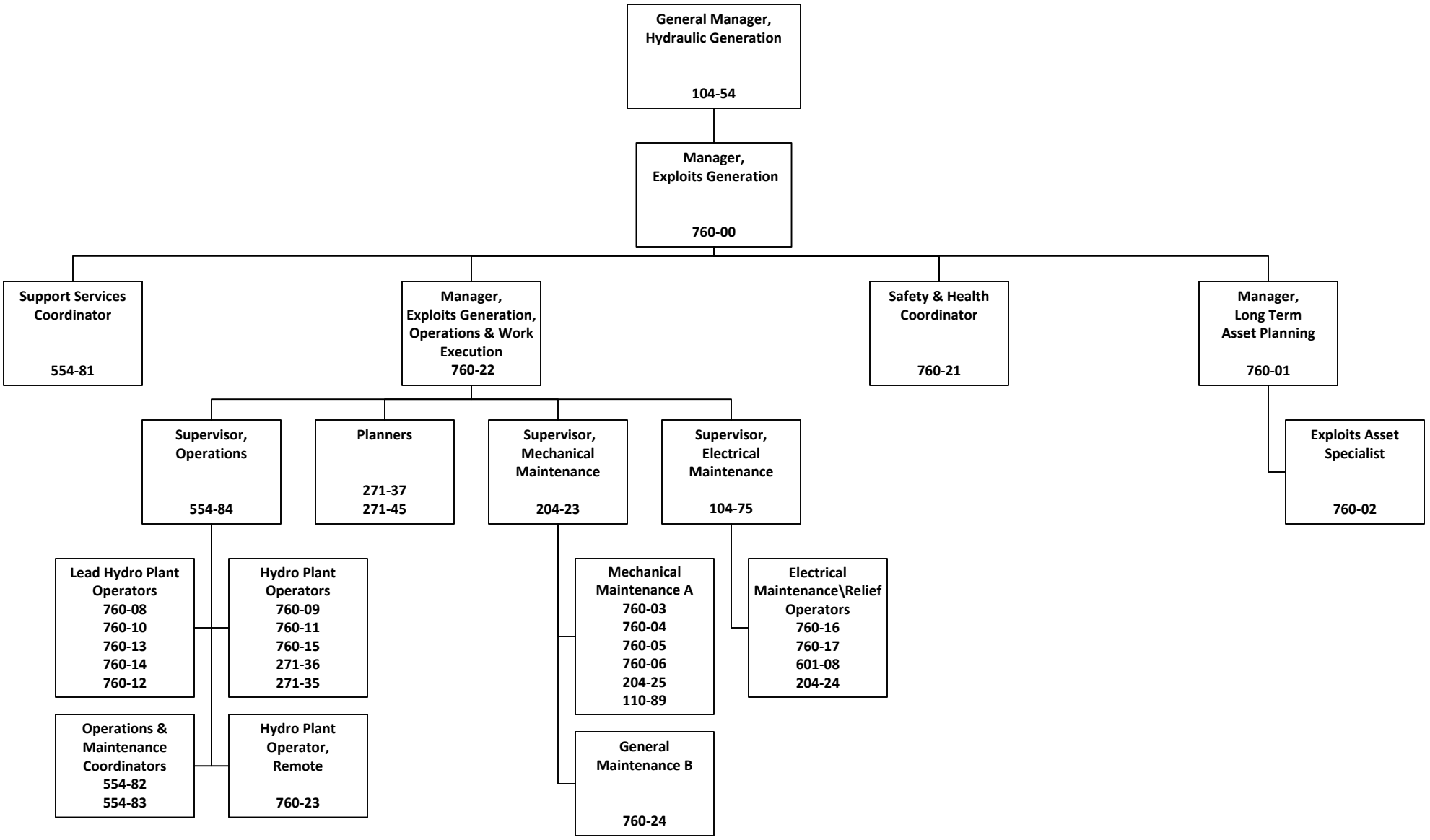
Production
Hydraulic Generation



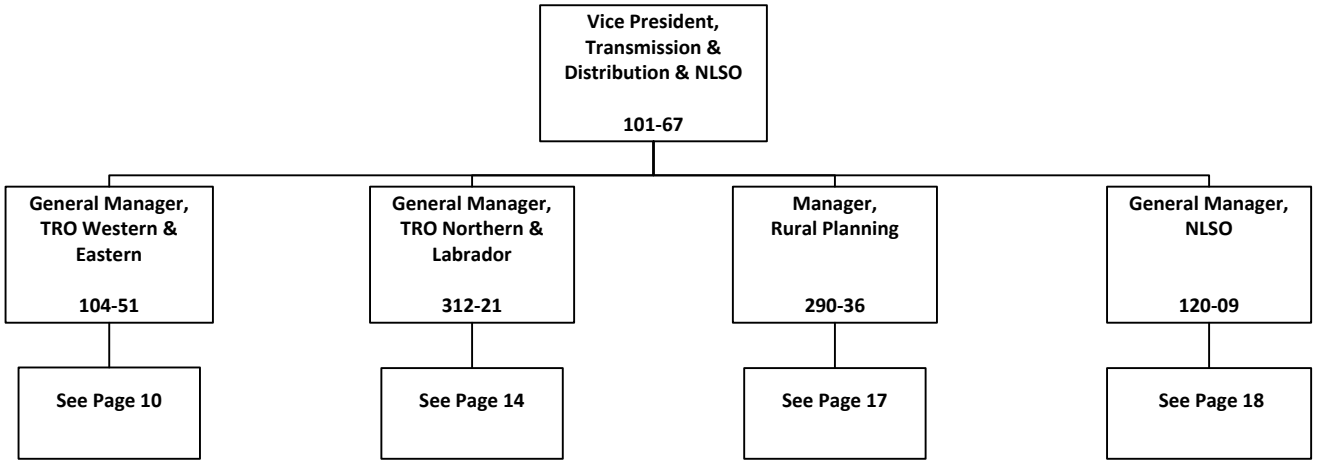
Production
Hydraulic Generation, Operations and Support Services



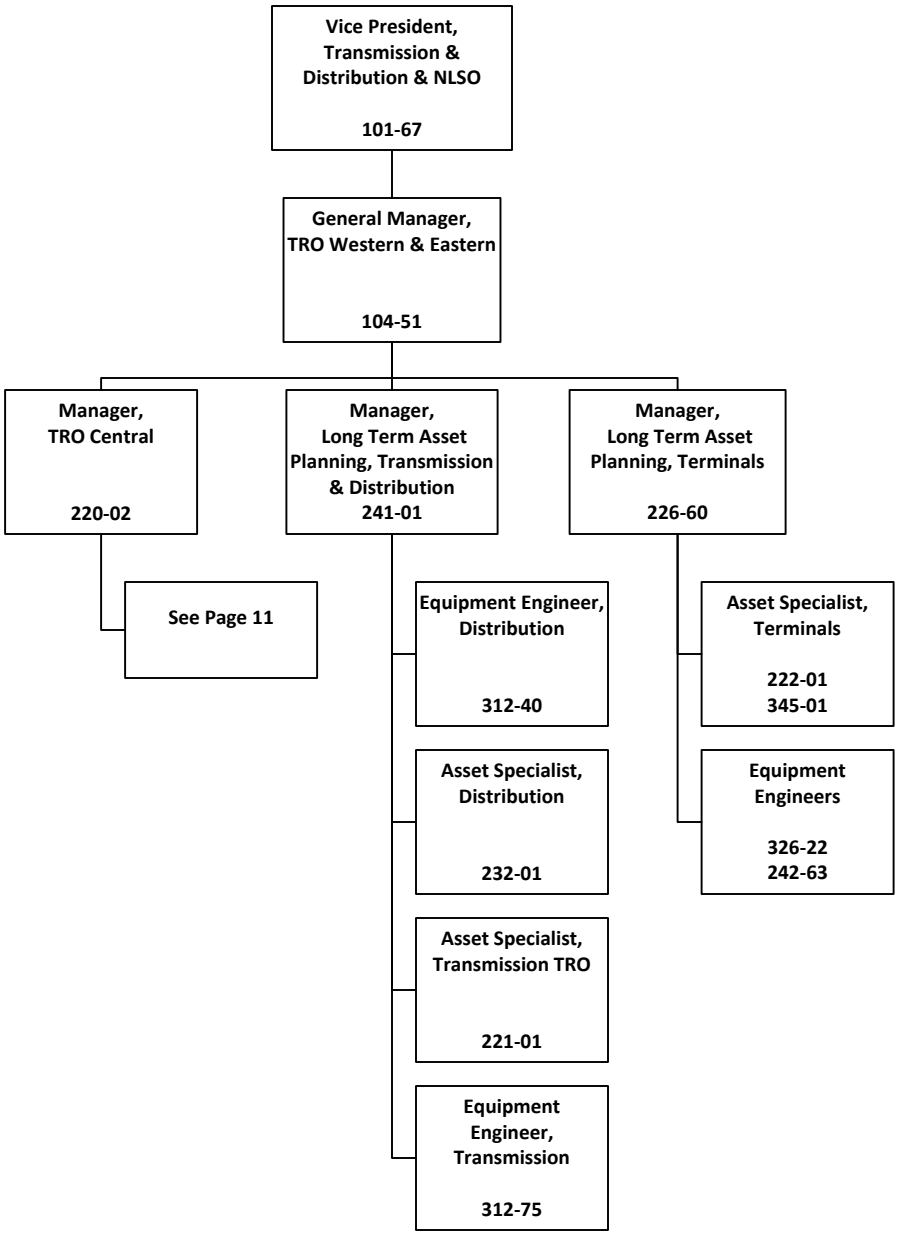
Production
Exploits Generation



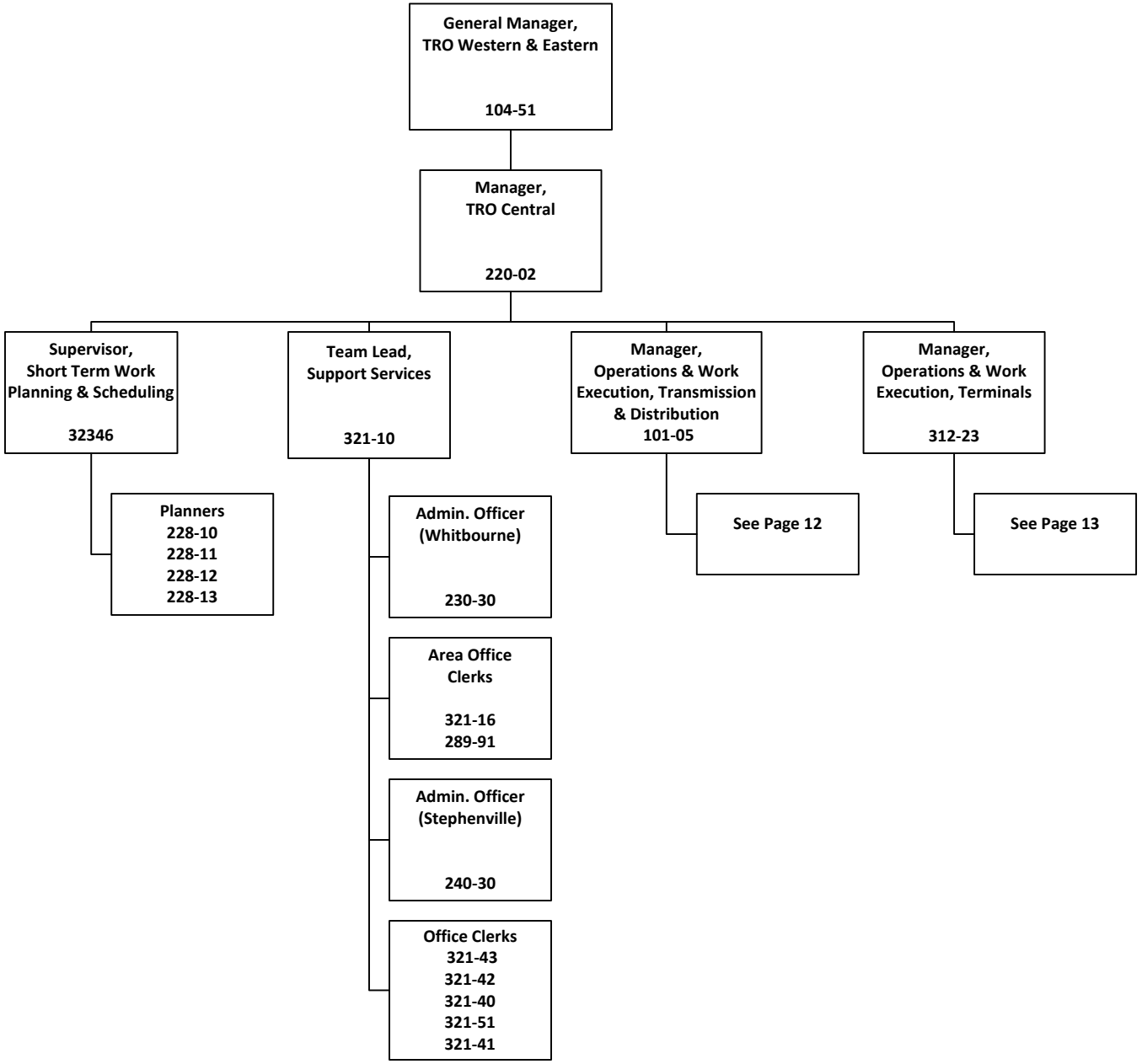
Transmission & Distribution & NLSO



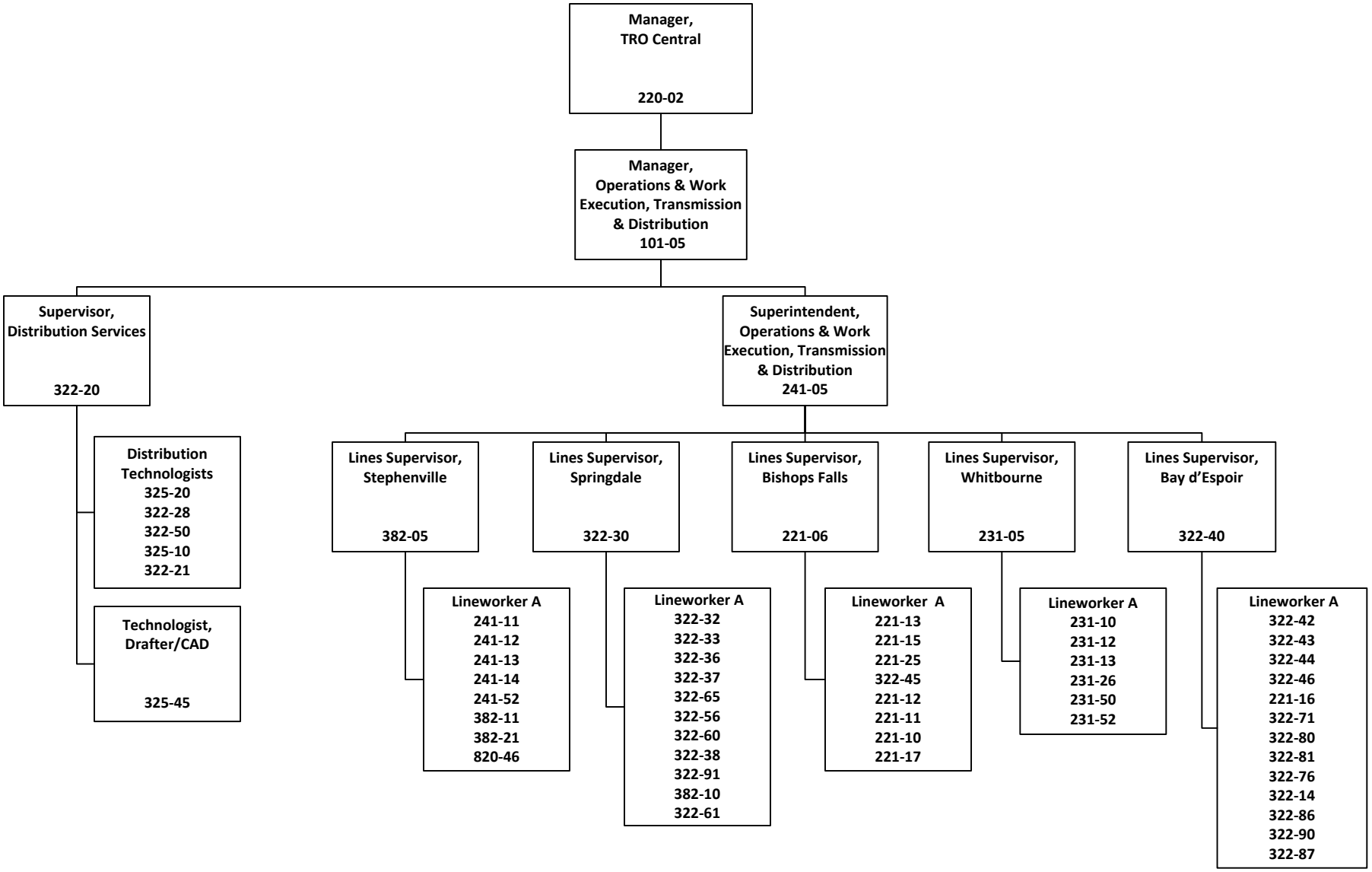
Transmission & Distribution & NLSO
TRO Western & Eastern



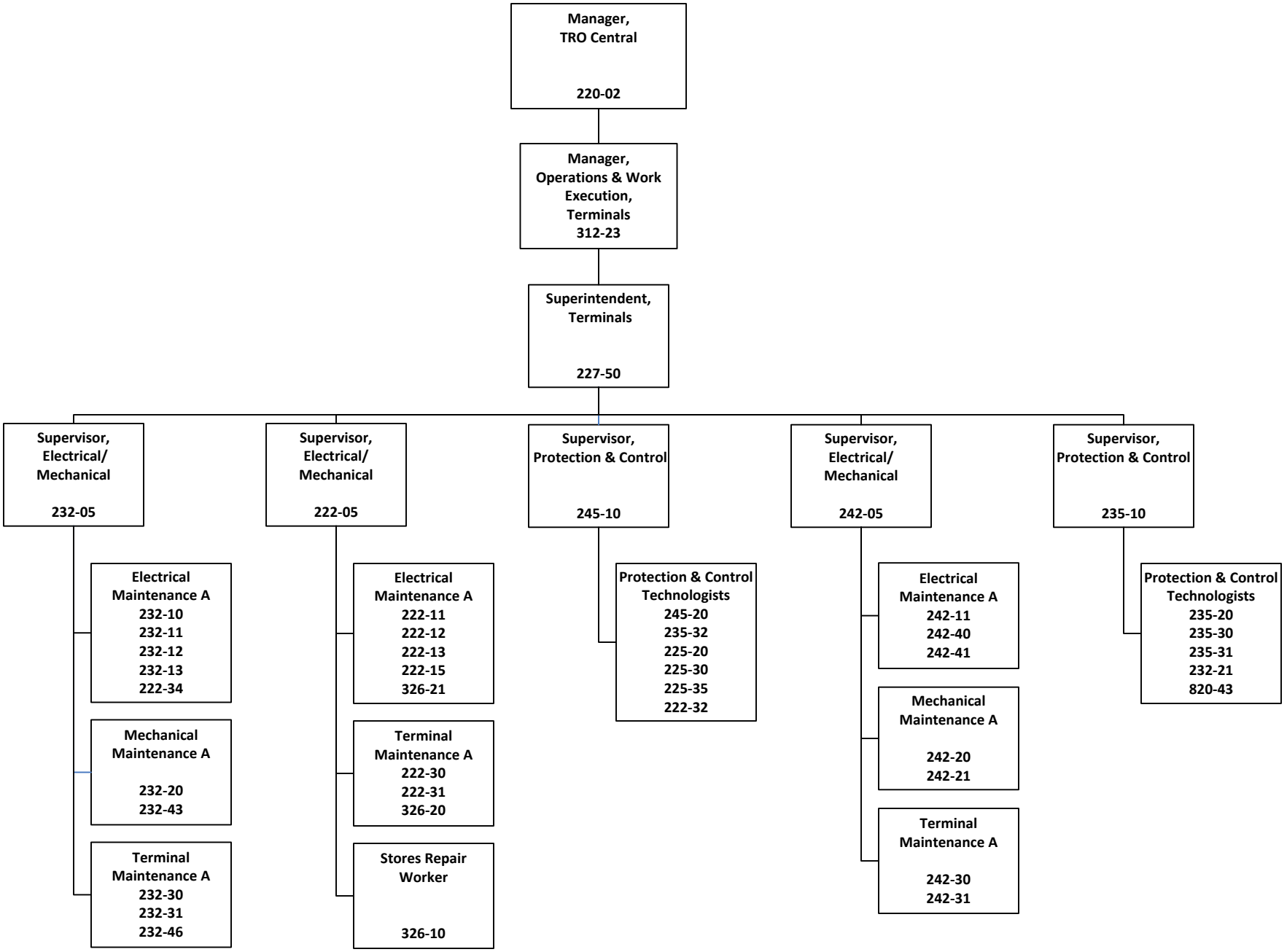
Transmission & Distribution & NLSO
TRO Western & Eastern



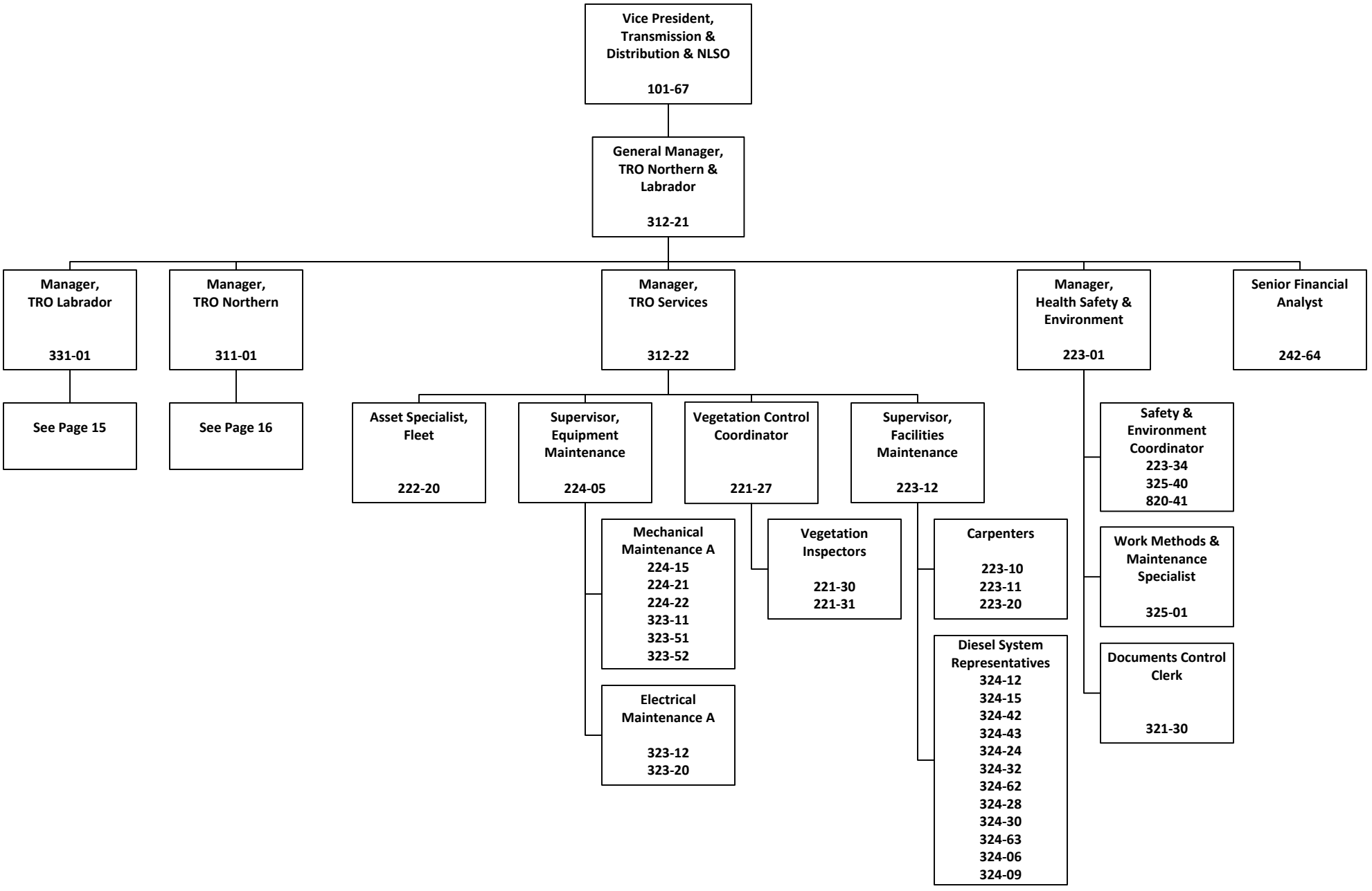
Transmission & Distribution & NLSO
TRO Western & Eastern
Operations & Work Execution, Transmission & Distribution



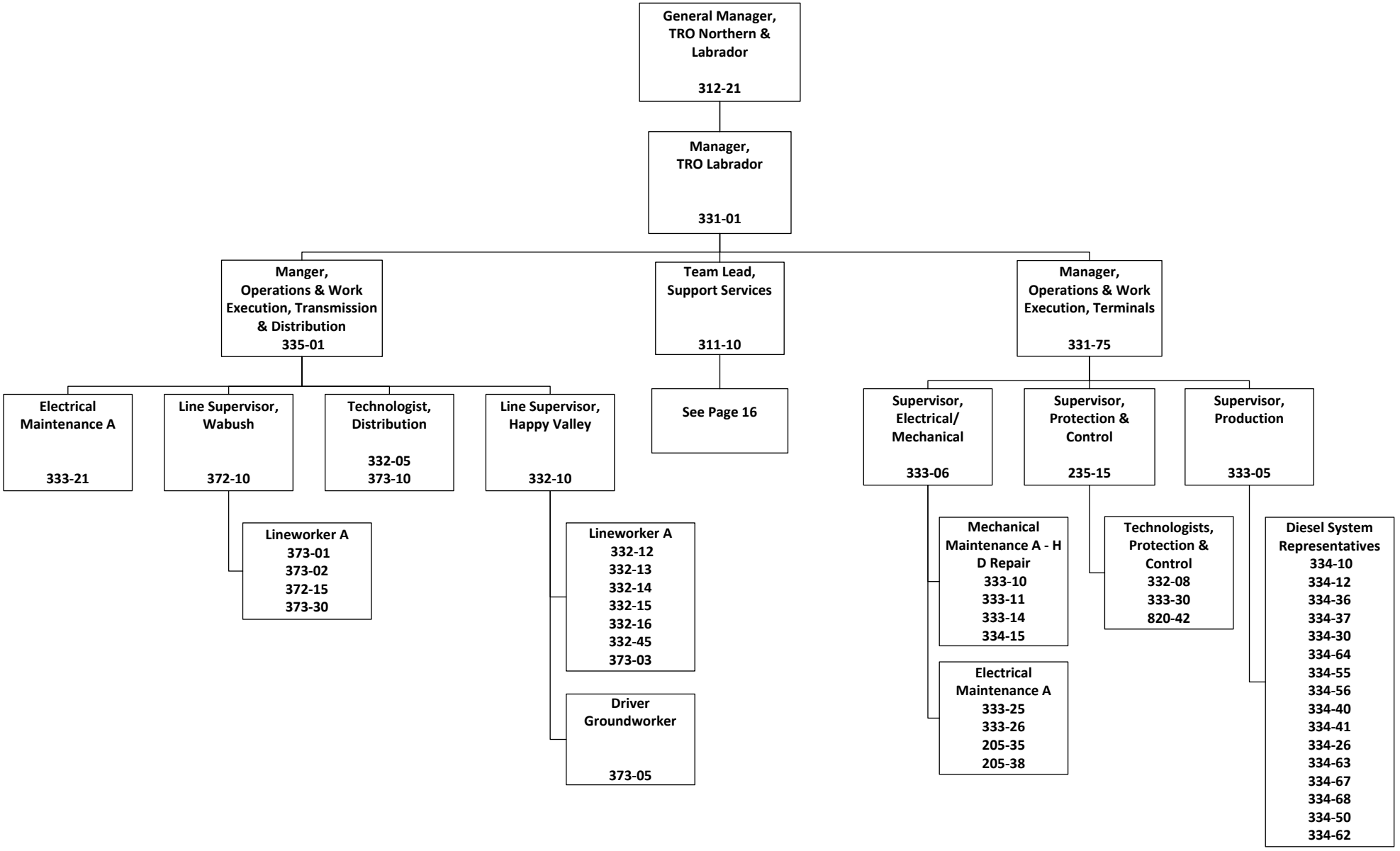
Transmission & Distribution & NLSO
TRO Western & Eastern
Work Execution, Terminals



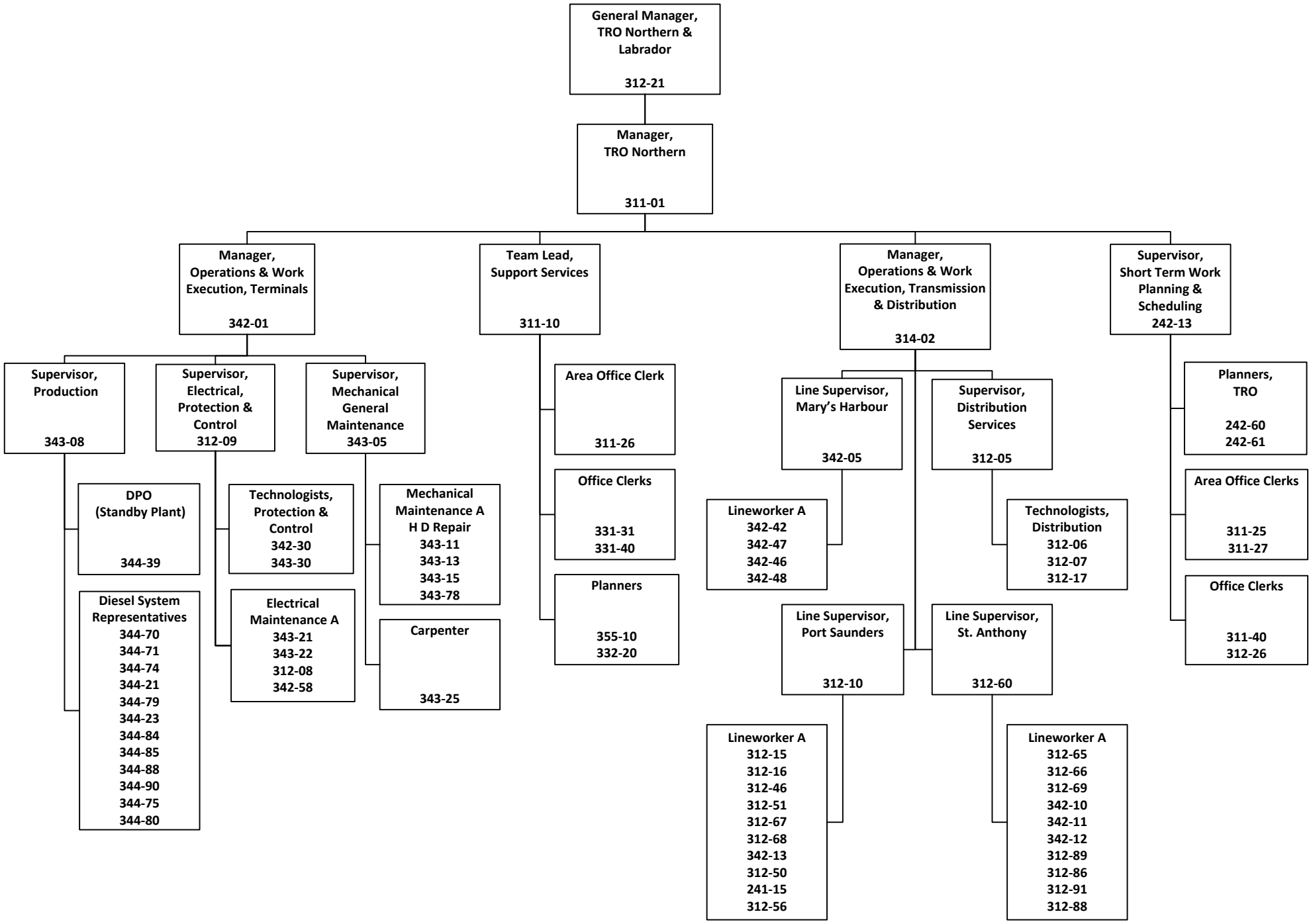
Transmission & Distribution & NLSO
TRO Northern & Labrador



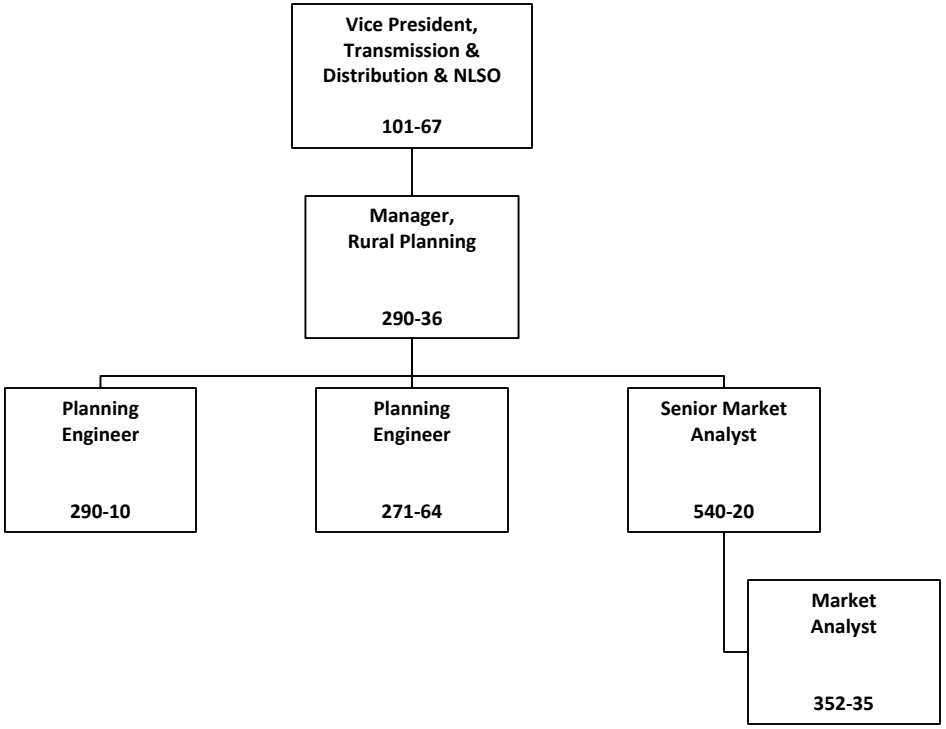
Transmission & Distribution & NLSO
TRO Northern & Labrador



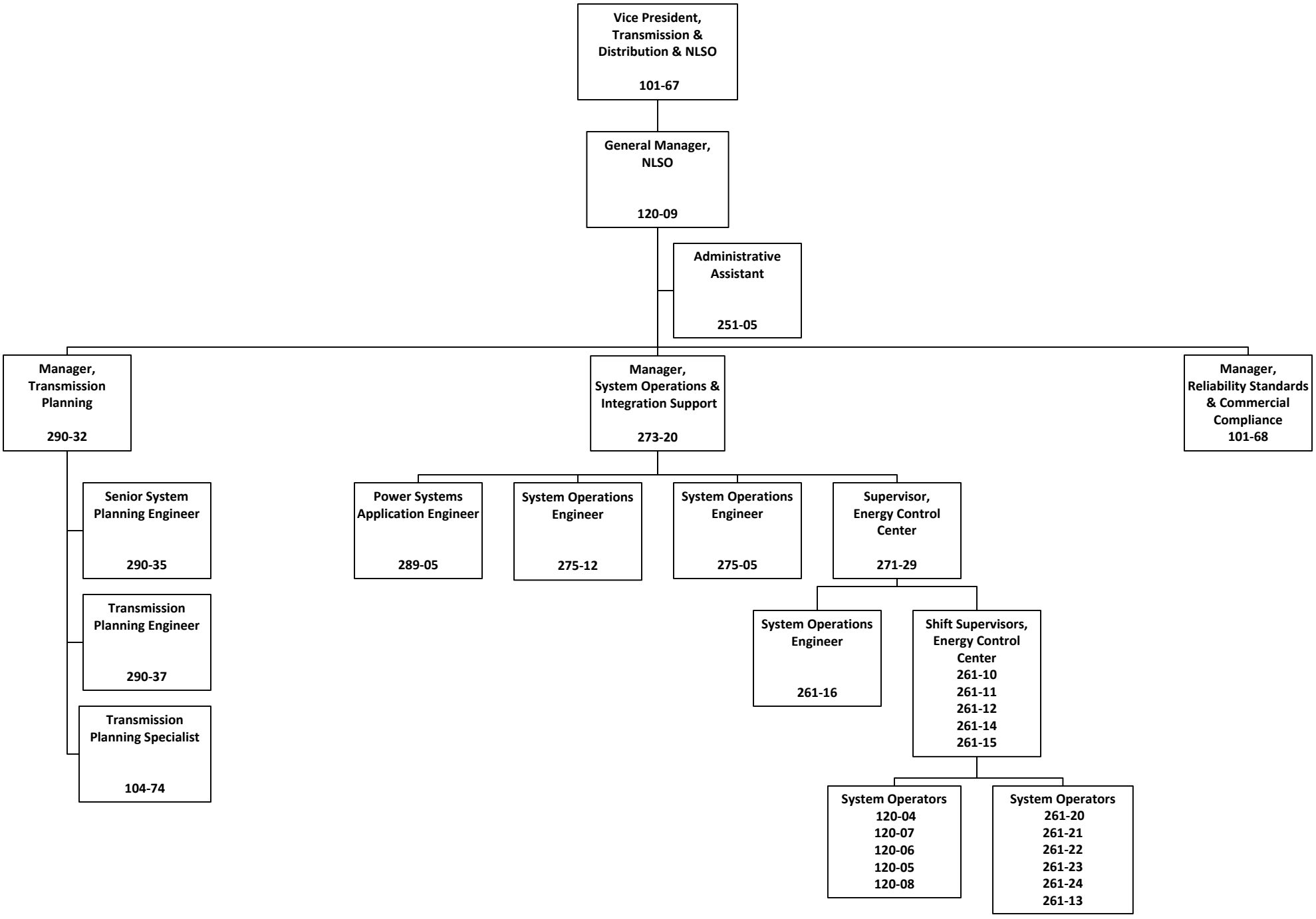
Transmission & Distribution & NLSO
TRO Northern & Labrador



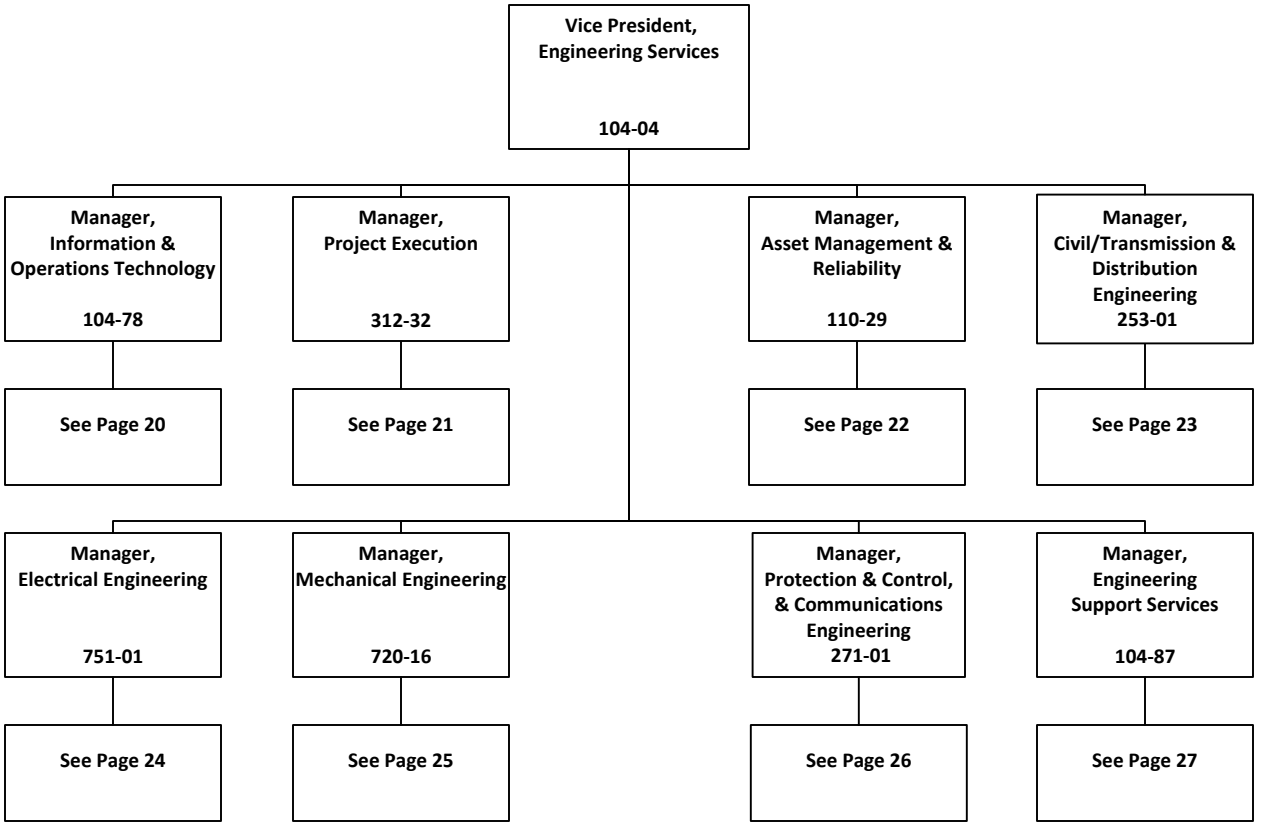
Transmission & Distribution & NLSO
Rural Planning



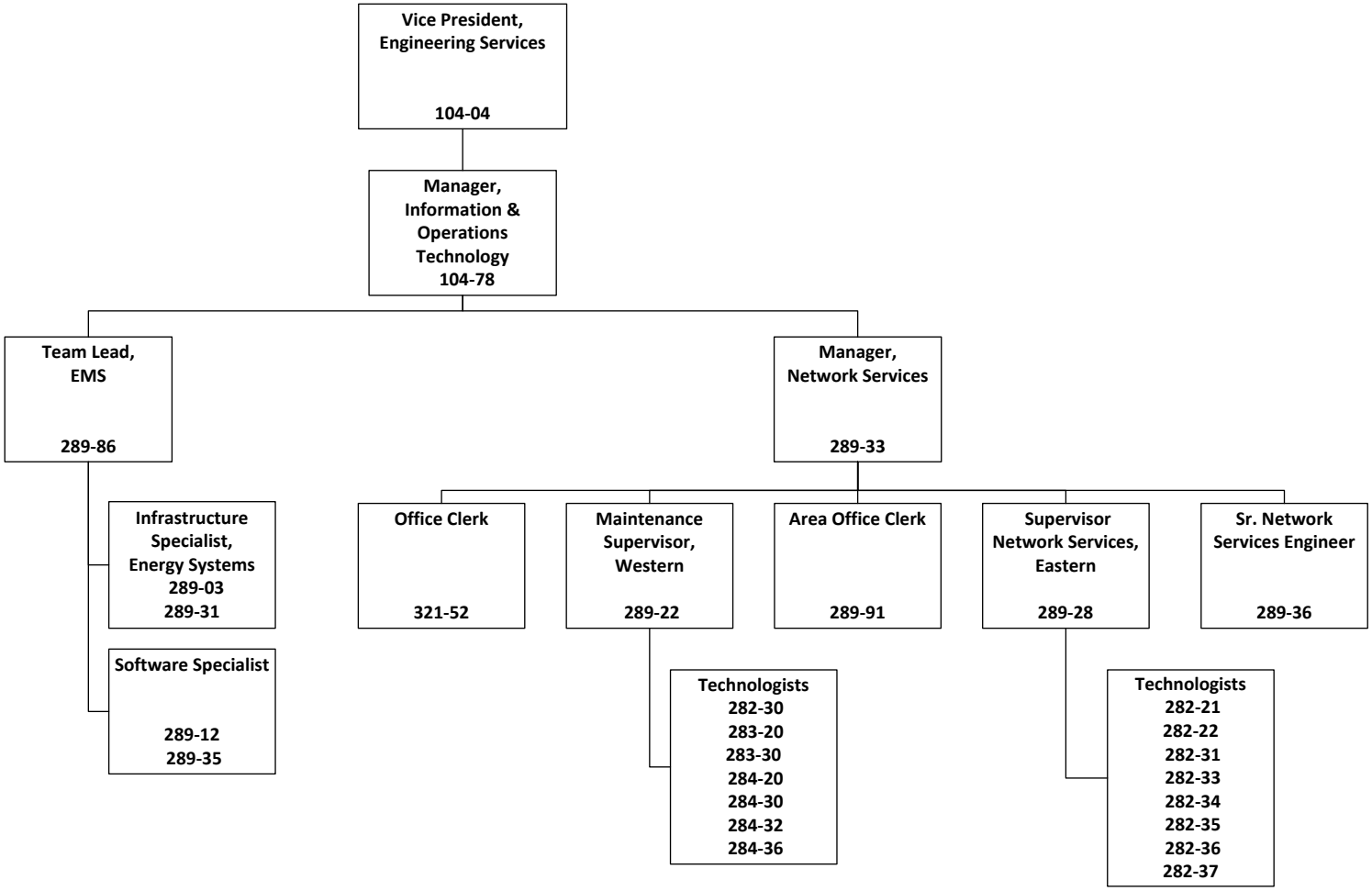
Transmission & Distribution & NLSO
Newfoundland & Labrador System Operator



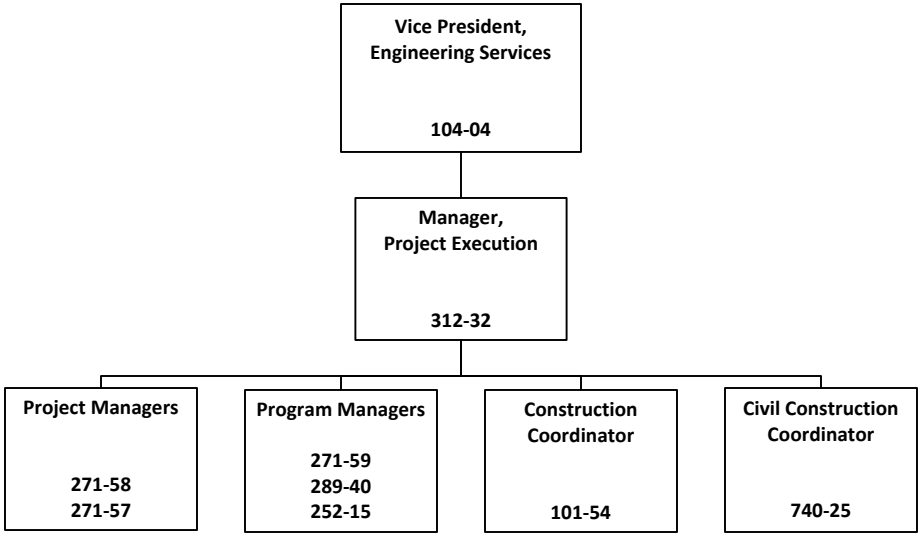
Engineering Services



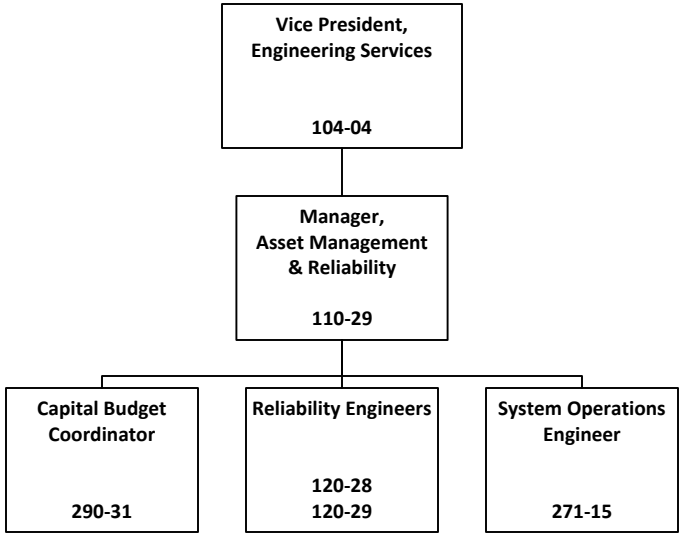
Engineering Services
Information & Operations Technology



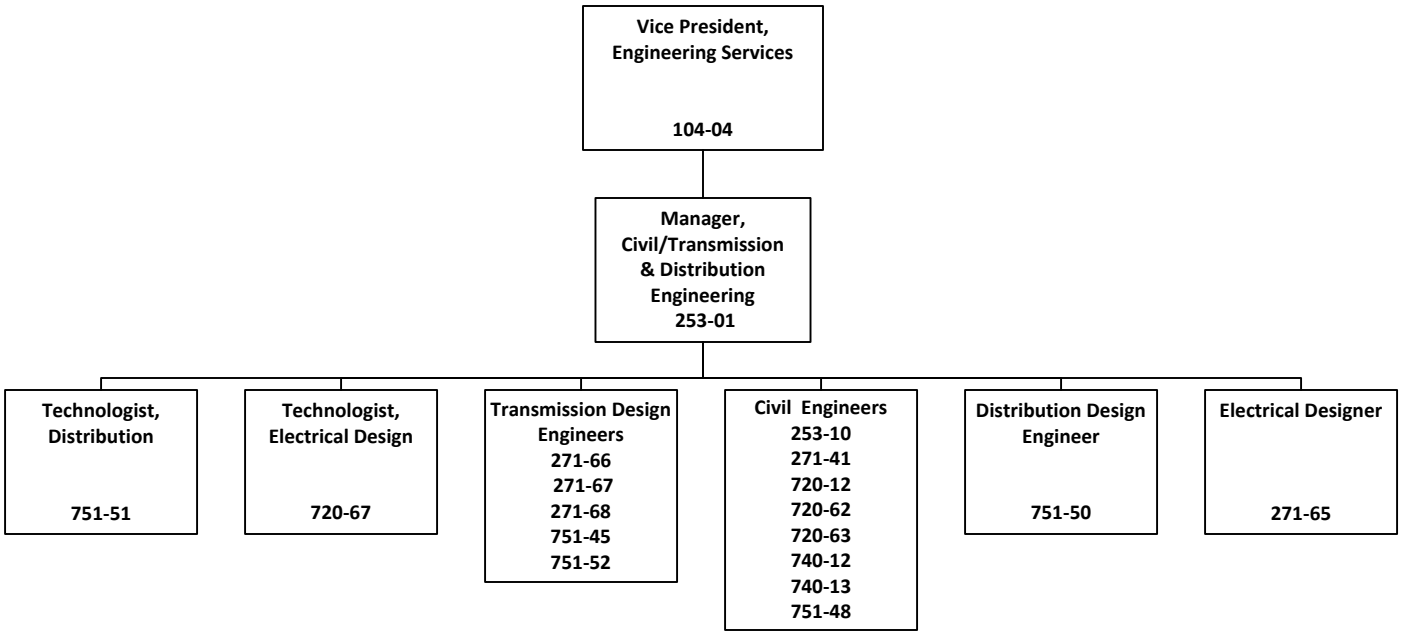
Engineering Services
Project Execution



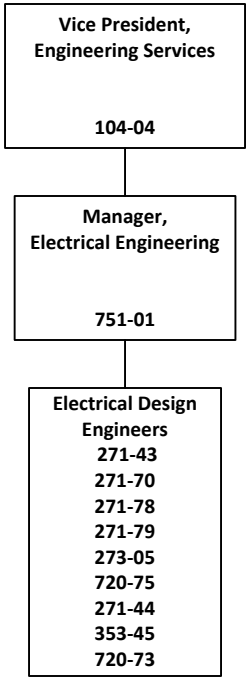
Engineering Services
Asset Management & Reliability



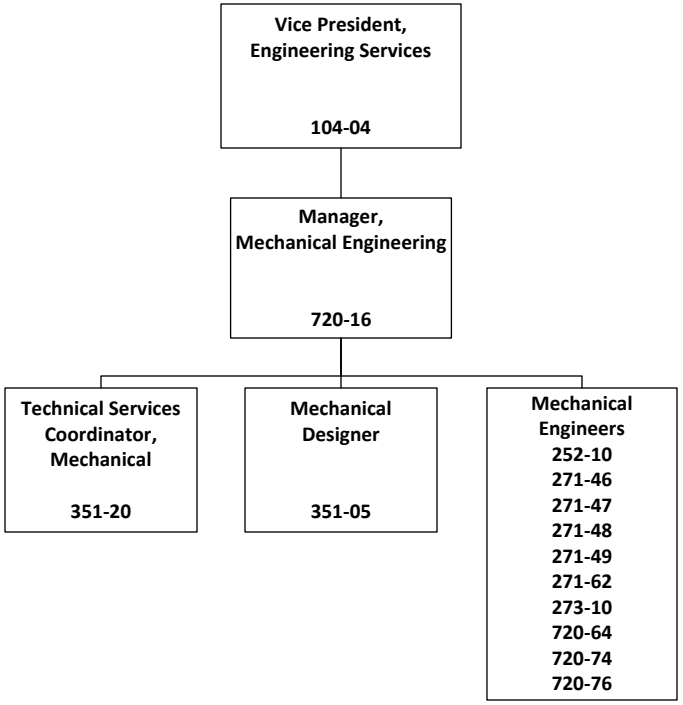
Engineering Services
Civil/Transmission & Distribution Engineering



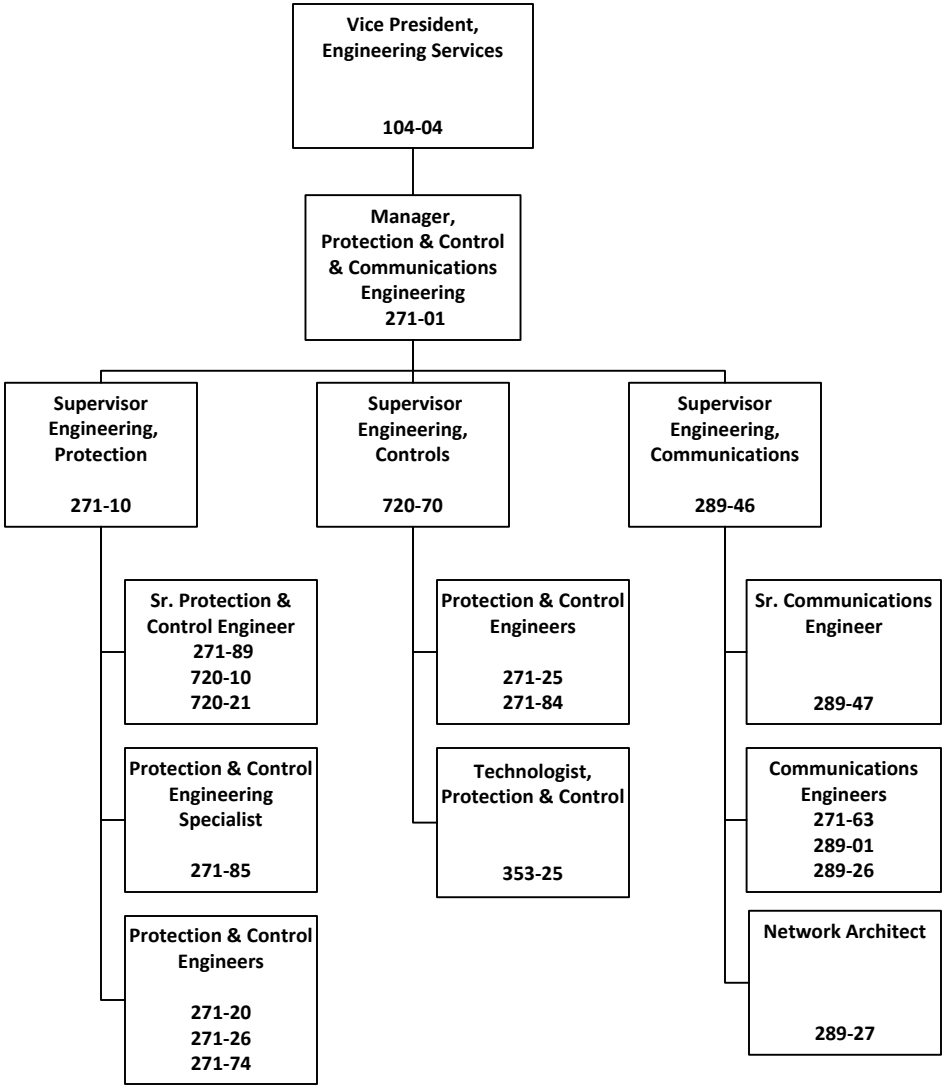
Engineering Services
Electrical Engineering



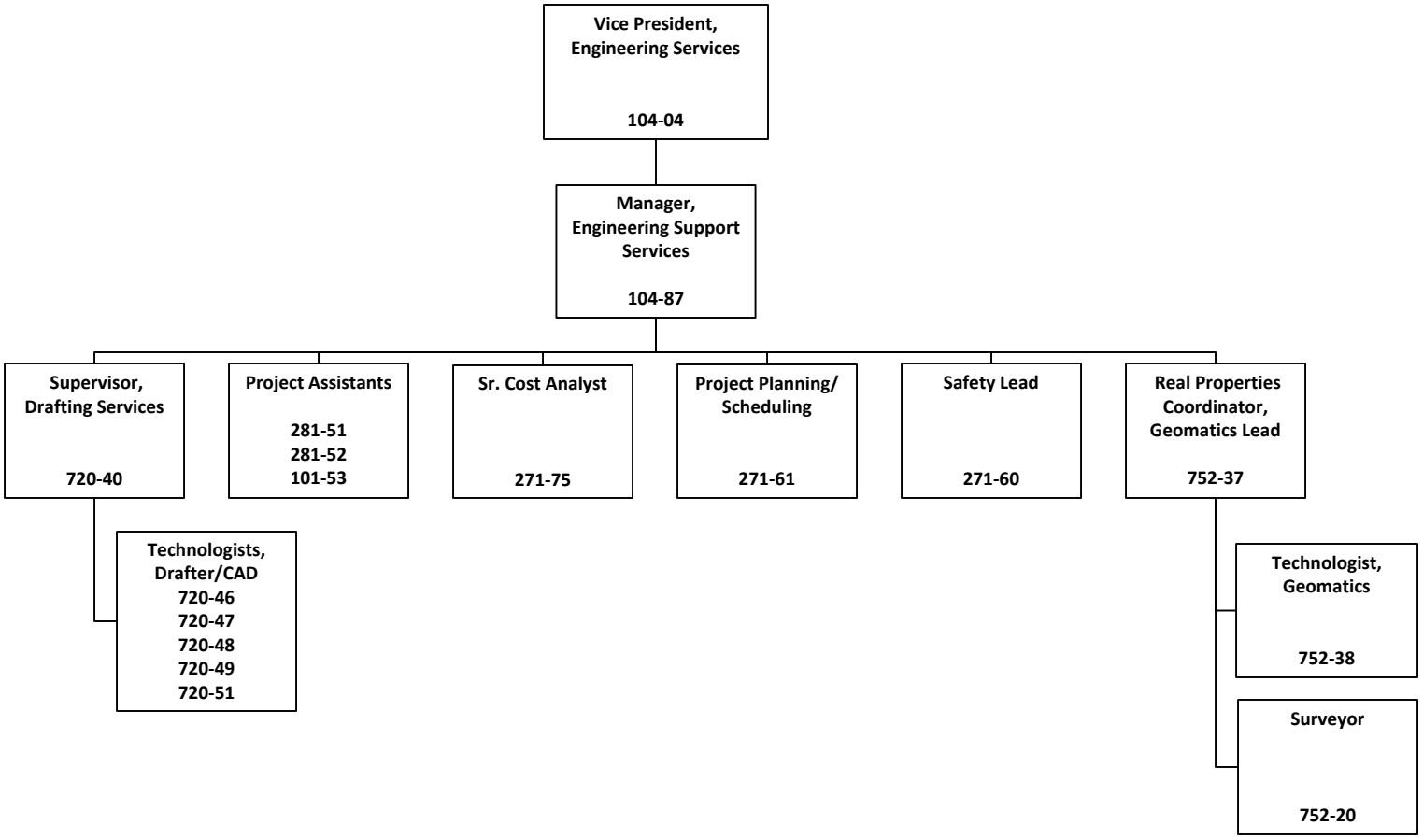
Engineering Services
Mechanical Engineering



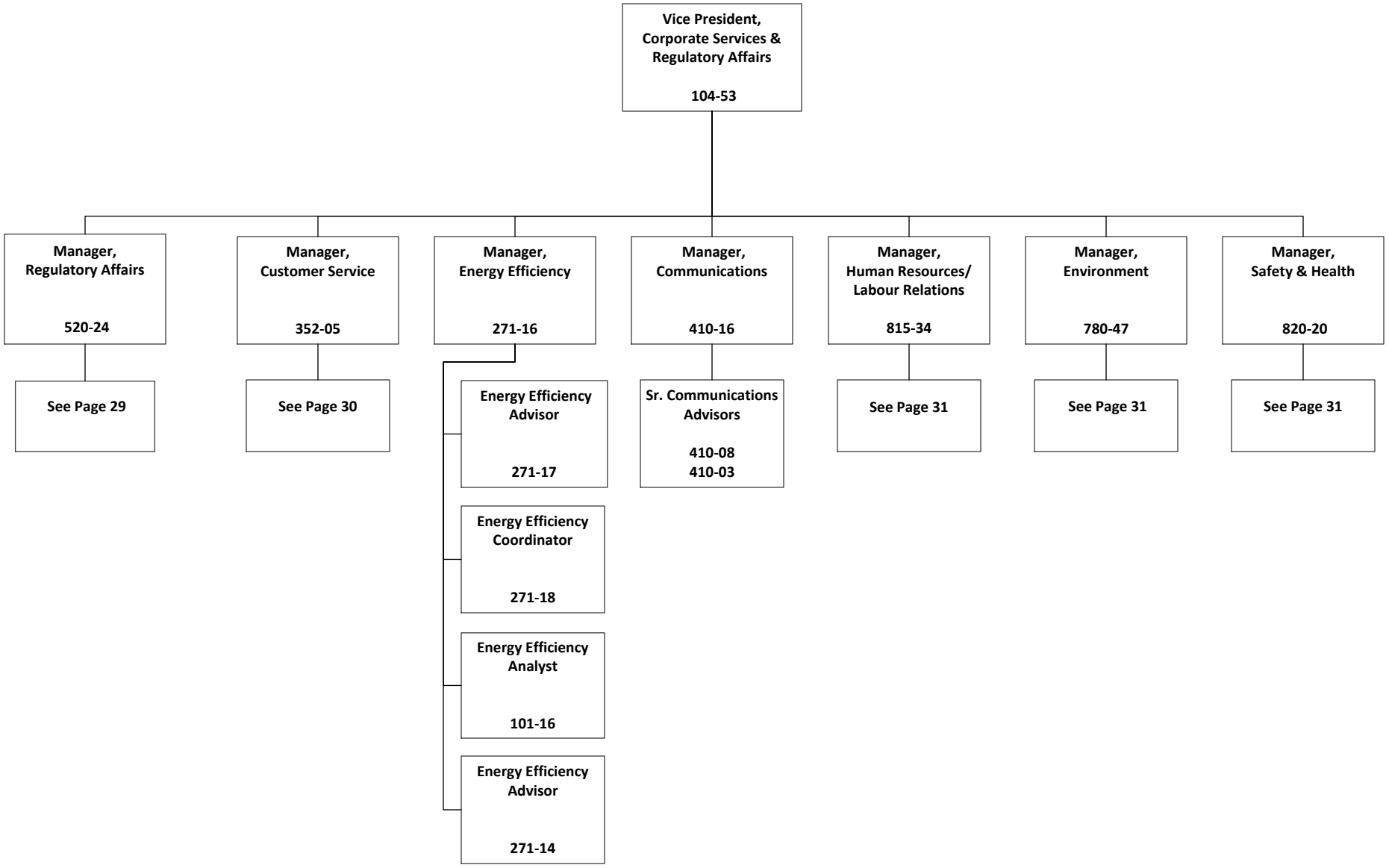
Engineering Services
Protection & Control & Communications Engineering



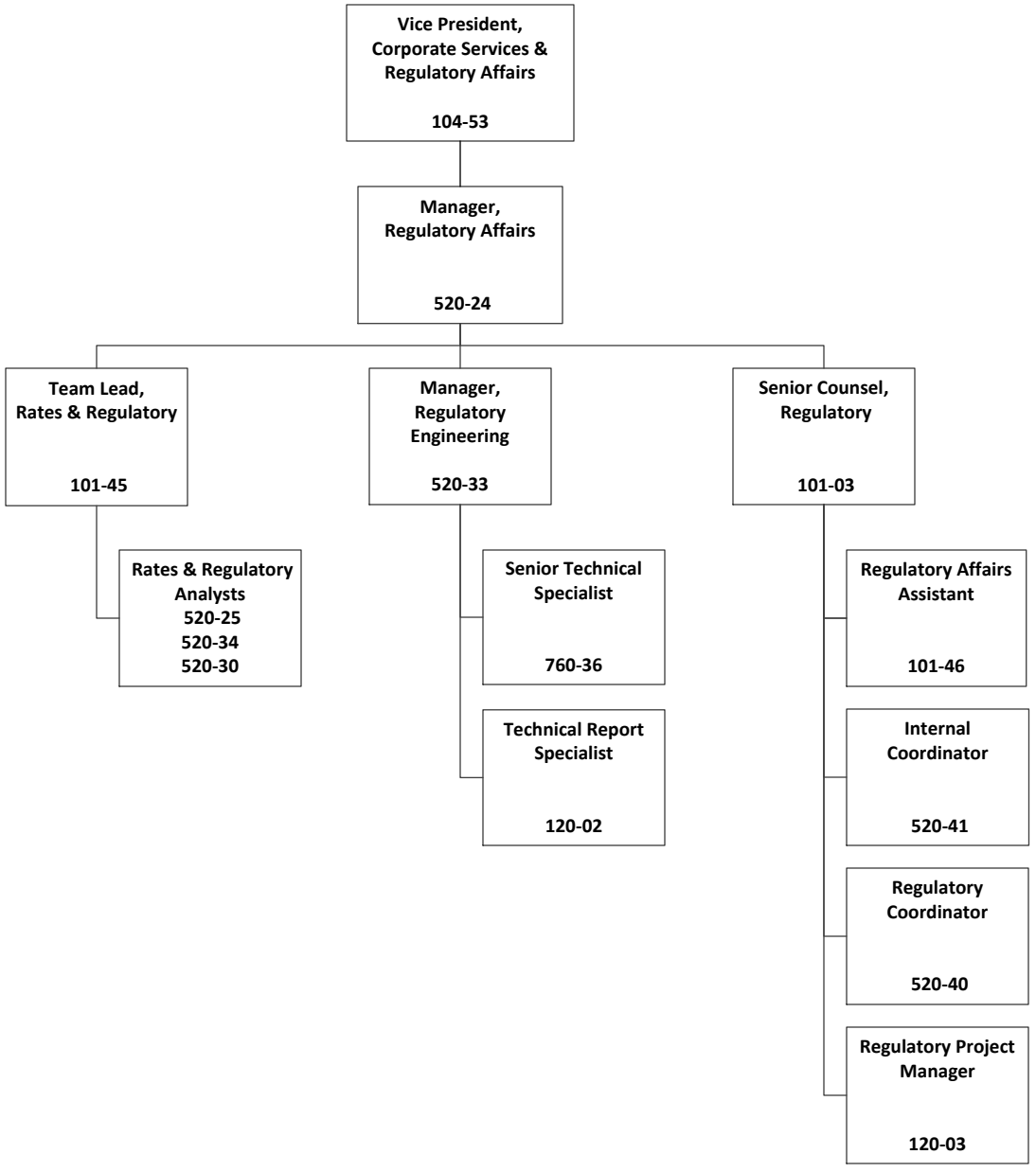
Engineering Services
Engineering Support Services



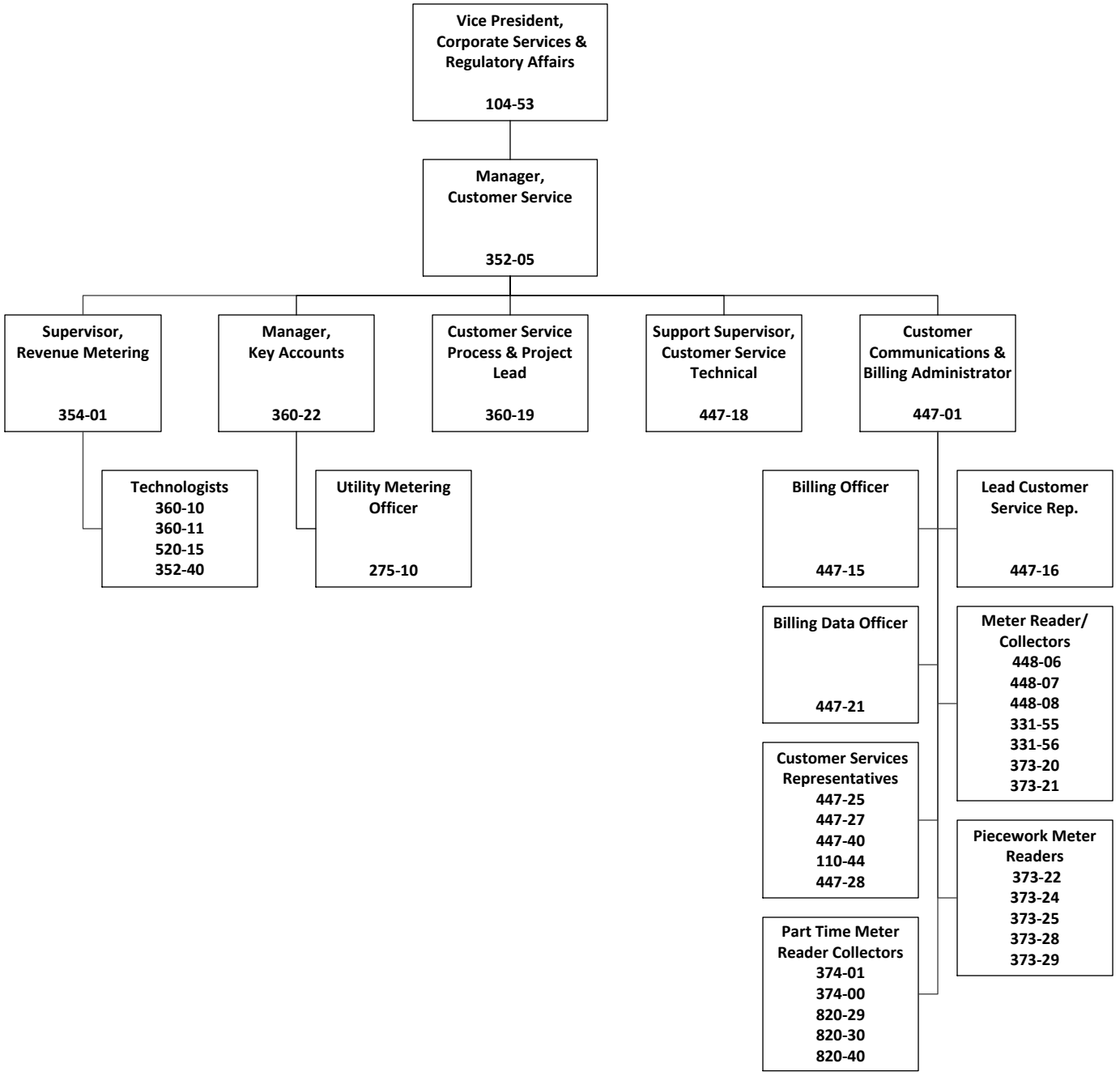
Corporate Services & Regulatory Affairs



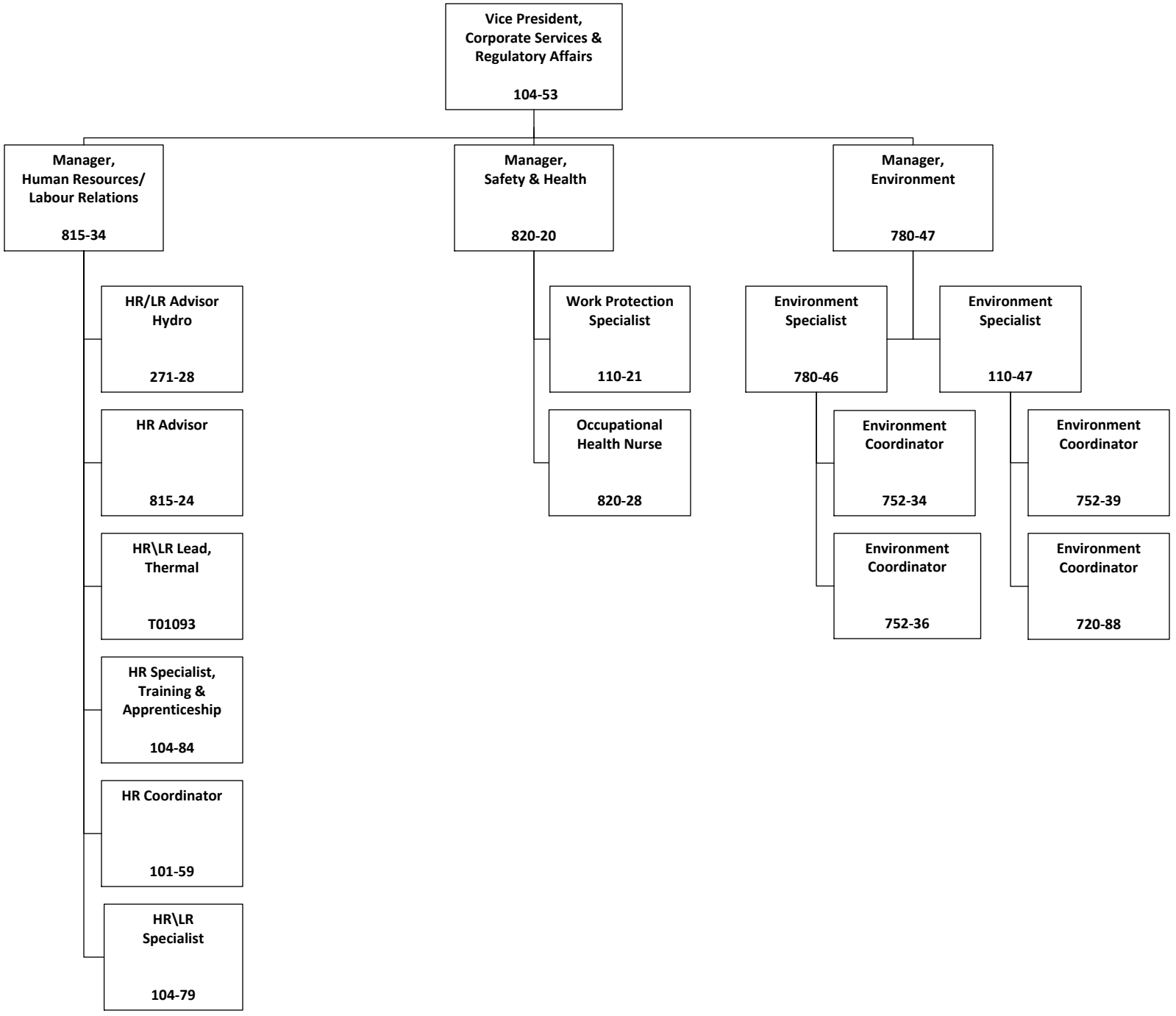
Corporate Services & Regulatory Affairs
Regulatory Affairs



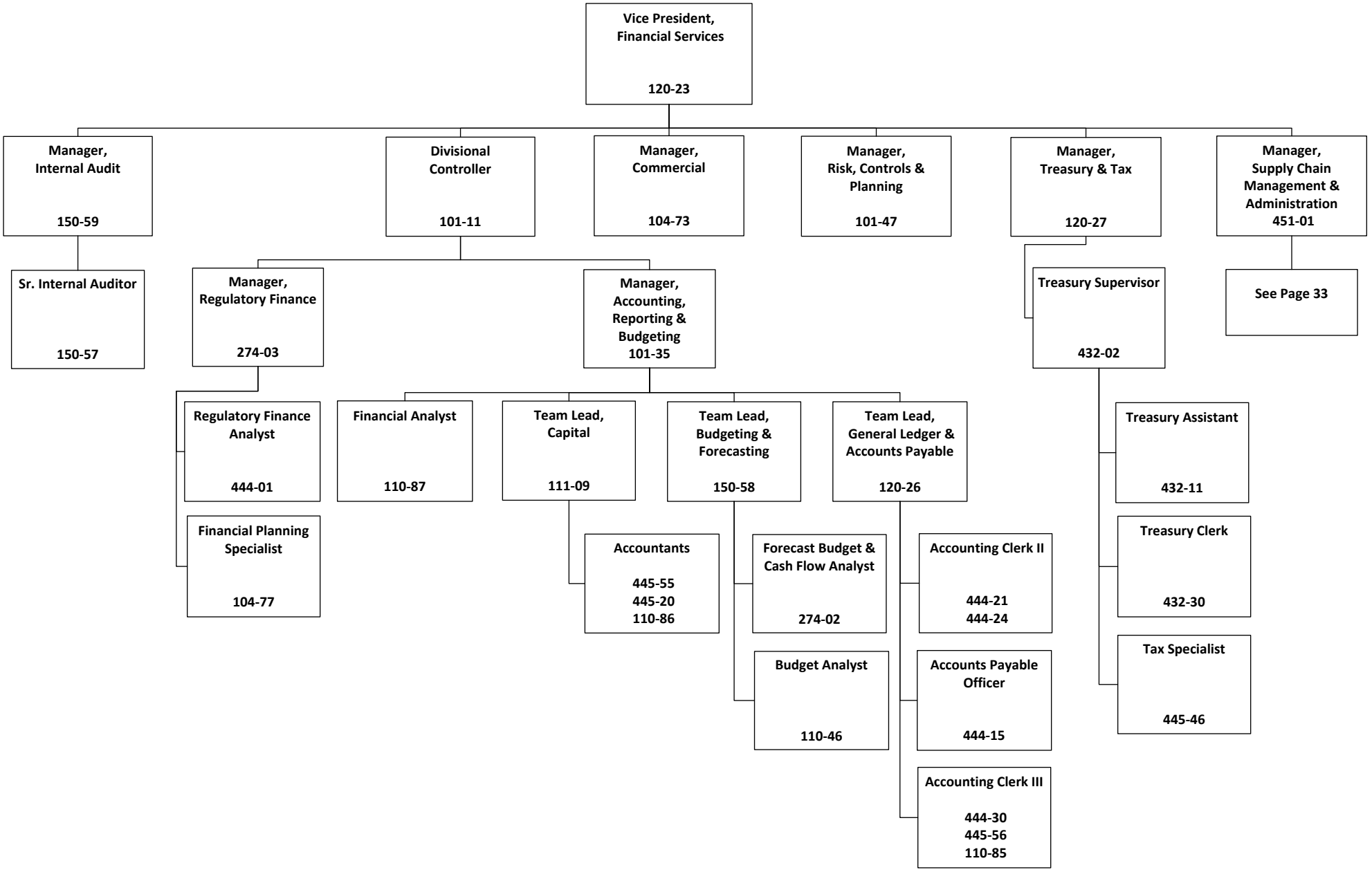
Corporate Services & Regulatory Affairs
Customer Service



Corporate Services & Regulatory Affairs
Human Resources, Labour Relations, Safety, Health & Environment



Financial Services



Financial Services
Supply Chain Management & Administration

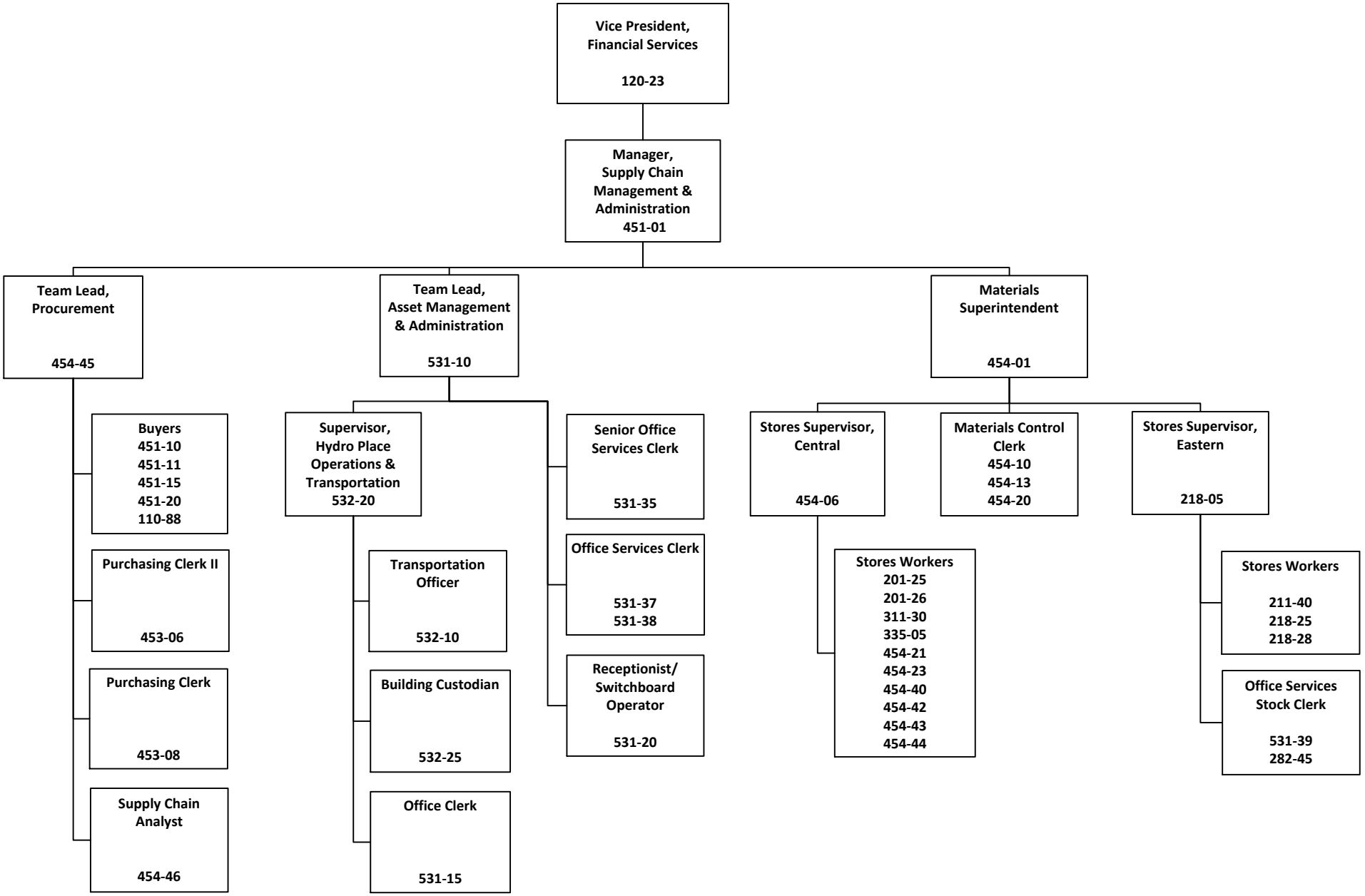


Exhibit 3 - Customer Service Roadmap Update

Customer Service Roadmap Update

July 2017

Table of Contents

1.0 Introduction 1
1.1 Customer Service Assessment Using External Vendor to Validate Customer Service Strategy 1
2.0 Goals and Key Performance Indicators 2
3.0 Goals and Objectives 2
3.1 Update on 2014-2016 2
3.1.1 Development of Account Management Framework 2
3.1.2 Implement New Customer Focused Website 3
3.1.3 Develop a Five-Year Plan for eBilling Penetration 3
3.1.4 Implement Transactional Customer Surveys 3
3.1.5 Complete Process Review of Hydro's Industrial Billing Process 4
3.1.6 Implement Complex Billing Software for Key Accounts 4
3.1.7 Implement Application to Capture Customer Interactions 5
3.1.8 Complete Customer Satisfaction Surveys 5
3.1.9 Investigate and Develop a Solution for a New IVR Phone System 5
3.1.10 Formalize After-Hours Support 6
3.1.11 Implement New Billing & Customer Information System (Utiligy-360) 6
3.2 2017 Planned Objectives 6
3.3 2018 and Beyond 7
4.0 Conclusion 8

List of Schedules

Schedule I - Customer Service Monthly KPI Dashboard

Schedule II - 2014-2017 Customer Service Strategic Roadmap Initiatives

1.0 Introduction

In 2014, Newfoundland and Labrador Hydro (Hydro) developed a customer service strategy for the period 2015 to 2017 (the Customer Service Strategy) to provide a strategic roadmap for delivering improved customer service at Hydro.[1] This report is in response to Order No. P.U. 49(2016), wherein the Board of Commissioners of Public Utilities (the Board) directed Hydro to file a report with its next general rate application setting out its status in meeting the goals and objectives in the Customer Service Strategic Roadmap for the period 2015 to 2017. This report also identifies appropriate Key Performance Indicators (KPIs) and benchmarks against which customer service is measured and reported.

1.1 Customer Service Assessment Using External Vendor to Validate Customer Service Strategy

Ernst & Young (EY) was engaged to perform a target operating model rapid assessment for the following areas to validate Hydro's internal findings:

- Contact Centre Strategy;
- Training;
- Quality Assurance;
- Knowledge Management;
- KPI Reporting;
- Customer Experience Insight;
- Payment Processing (Billing);
- Field Operations;
- IVR/Telephony;
- Mobile App & SMS;
- Outage Management; and
- Web Self Service.

[1] A report entitled *Customer Service Strategic Roadmap 2015 - 2017* was filed with the Board on September 30, 2014, and describes a vision for improving service to Hydro's industrial, utility, and retail customers. The report also identified the supporting strategies and guiding principles to meet Hydro's business needs and support long-term customer service strategies.

The results of the assessment identified and prioritized improvement opportunities and initiatives to help Hydro's Customer Service department reach its desired future state. The following sections outline the actions Hydro has taken as it progresses through its Customer Service Strategy.

2.0 Goals and Key Performance Indicators

To measure Hydro's progress against its strategy for better serving its customers, four goals were established: employee; customers; process; and financial performance. KPIs were then developed for each goal. The goals and KPIs are reported as a dashboard and results are shared with customer service staff, and Hydro's Leadership Team, on a monthly basis. Hydro's *Customer Service Monthly KPI Dashboard – December 2016*, is provided in Schedule I.

3.0 Goals and Objectives

3.1 Update on 2014-2016

Since filing the Customer Service Strategy in September 2014, Hydro has accomplished a number of noteworthy achievements. Below are some of the significant activities completed that have enhanced the customer service experience for Hydro's customers. For a detailed list of initiatives and current status refer to Schedule II.

3.1.1 Development of Account Management Framework

An essential requirement identified in Hydro's Account Management Framework was the creation of a dedicated account manager within Hydro's Customer Service department to support Hydro's industrial and identified commercial customers as well as its utility customer, and partner for the deliver of power to island customers, Newfoundland Power.

Acting as a single point of contact between the customer and Hydro, the key account function allows all interactions to be handled via a single channel and be efficiently managed within

Hydro. Once a customer request is received by the Manager, Key Accounts it is their responsibility to advocate on behalf of the customer within Hydro and pursue a resolution.[2]

3.1.2 Implement New Customer Focused Website

Hydro launched a new customer focused mobile and web portal platform called *myNLhydro* in April of 2016. *myNLhydro* provides customers with unlimited access to their account anytime, anywhere, and on any device. Users can easily and conveniently:

- View account balance, payment history, and set up payment options online;
- Subscribe to text and email notifications for planned and unplanned power outages;
- View and report power outages online;
- Subscribe to payment reminders via text and email notifications;
- Sign up for paperless eBilling and equal payment plan;
- Track and manage electricity usage in easy-to-read charts, set budget goals, compare power usage year over year, and against the average usage of residents in their neighborhood; and
- Submit service requests.

3.1.3 Develop a Five-Year Plan for eBilling Penetration

Hydro developed a five-year plan to increase electronic billing (eBilling) subscriptions to support cost management within Customer Service and meet customer expectations. In 2014 there were 3,522, or approximately 9% of, customers subscribing to eBilling. Hydro's target by 2019 is to increase the subscriptions to approximately 10,000, or 25%, of its customers. The target is tracking according to plan with 7,917, or 20%, of Hydro's customers currently subscribing to the eBilling service.

3.1.4 Implement Transactional Customer Surveys

To ensure timely feedback on services provided to customers by Hydro's call centre, Hydro implemented a transactional survey process. Bi-weekly transactional surveys are conducted

[2] Please refer to Hydro's *Key Account Management Report*, filed with the Board on January 13, 2017.

through an automated outbound call service where customers are asked four questions about their most recent experience with Hydro staff. The survey focuses on the quality of service received, staff knowledge of issue, and overall first contact satisfaction. These survey results are reviewed with customer service staff to ensure activities are effective, or to determine if any changes are needed. Transactional survey results for the period of January to March 2017 show that 88% of Hydro's customers are satisfied with the service they received.

3.1.5 Complete Process Review of Hydro's Industrial Billing Process

Hydro's objectives for the industrial billing process review were to:

- Document and validate the industrial billing workflow process;
- Identify opportunities to improve the workflow process;
- Identify considerations for implementation of the improvements; and
- Engage stakeholders to aid in their understanding of the industrial billing process, their role in the process, and how their role/activities/outputs affect the process.

This review produced the following outcomes:

- Industrial billing workflow process chart;
- Industrial billing workflow process policy;
- Process review recommendations; and
- Completed RACI (Responsible, Accountable, Consulted, Informed) chart.

The output of this review was then used as part of an initiative to implement complex billing software for Hydro's industrial and wholesale customers, and is discussed in section 3.1.6.

3.1.6 Implement Complex Billing Software for Key Accounts

In 2016, Hydro started a project to implement the Itron MV-PBS software application to support industrial and wholesale billing for identified key account customers. The new application, for complex billing, will be more effective, remove manual processes, and minimize potential for input errors, while at the same time improving billing to its largest customers. MV-

PBS will also integrate with the existing industrial meter data collection application, automate calculations, decrease meter-to-bill time, and provide reporting and audit tracking capabilities.

3.1.7 Implement Application to Capture Customer Interactions

Hydro implemented a Customer Assistance Database to record all customer interactions digitally. This new system provides a shared database of all customer communications for all Customer Service Representatives (CSRs). The database provides a historical and holistic view of each customer for each time they call that allows the CSRs to reference and improve the customer experience. It also provides reporting and analytics, and provides the customer service team a view of the most frequent call types, facilitating further discussion on broader customer concerns and potential resolutions.

3.1.8 Complete Customer Satisfaction Surveys

Since the filing of the Customer Service Strategy the following surveys have been completed:

- Residential Customer Survey;
- In-depth research with Hydro's Key Customers (Industrial and select Commercial);
- Survey conducted with senior staff from Newfoundland Power; and
- Transactional bi-weekly surveys.

Hydro's residential customer satisfaction ratings have remained strong in comparison to the Canadian Electricity Association (CEA) averages, and have shown an upward trend over the past two survey periods, indicating 84% and 90%, in 2014 and 2016, respectively.[3]

3.1.9 Investigate and Develop a Solution for a New IVR Phone System

Hydro installed a new Interactive Voice Response (IVR) telephone system to better support its customers. Hydro's enhanced IVR system replaces an older, unsupported system and provides improved functionality such as more specific outage information and links to Hydro's online

[3] CEA averages for the 2014 and 2016 period were 55% and 56% respectively.

customer outage notification application in *myNLhydro* so customers receive up to date information.

3.1.10 Formalize After-Hours Support

Hydro established a formal after-hours support arrangement with a third party vendor for handling power outage and emergency calls. *TeleLink* has been trained in and provided with Hydro's process for dealing with power outage and emergency calls. It now provides Hydro with call handling and reporting service for after-business hours customer calls of this nature. *TeleLink* engages on-call staff when required to follow-up with Hydro customers to resolve individual and widespread unplanned outages.

Hydro's customers, as well as Hydro's Energy Control Centre (ECC), have experienced the benefit of this new process as it removes responsibility from ECC operators to manage outage related calls which allows them to focus on supporting the electricity system operation and restoration while customers are served more efficiently and effectively.

3.1.11 Implement New Billing & Customer Information System (Utiligy-360)

As part of the Corporate Business Systems Transformation program, Hydro's Customer Service Department will receive a new billing and customer information system. The new system, Utiligy-360, will include improvements to service provided to Hydro's customers and support Hydro's three-year strategic plan. The Utiligy-360 module includes submodules such as account management, billing management and meter management. Through the Business Systems Transformation program, there will be a focus on automating existing manual processes and providing enhanced functionality.

3.2 2017 Planned Objectives

Hydro's areas of focus for 2017 are service, communications, billing and payments, collections, key account management, performance measurement, and knowledge management. Hydro's initiatives include i) online, mobile and self-service options; ii) continuation of improvements to

billing and payment options; iii) enhanced outage communications; iv) enhancements to collection processes; v) development of key account management processes and performance indicators; vi) continued target setting for customer interactions; and vii) developing a customer service knowledge database that will be available to all employees who interact with and provide customer service. Schedule II provides a complete list of initiatives and status as of the end of March 2017.

3.3 2018 and Beyond

Hydro's Customer Service Team is presently looking beyond its current strategy and will be updating plans to commence initiatives into 2020. The strategy will continue to focus on enhancing the customer experience through continuous improvement of existing processes and procedures, and the implementation of new technology to support process where needed.

The future focus areas for Hydro are:

- Update current Customer Service Strategic Roadmap to 2020;
- Develop a revenue protection strategy;
- Implement a pilot using tablet technology to automate customer information updates during automated meter reading (AMR) projects;
- Further cost reduction initiatives such as increased subscribers to eBilling and redefined collections process;
- Develop Key Account Plans and establish KPIs;
- Develop a five-year plan for Revenue Metering with aim to improve equipment and resource planning;
- Complete customer satisfaction surveys for Key Accounts, and Commercial and Residential customers;
- Closer integration of energy efficiency and customer service teams focused on improved delivery of programs and education to customers;
- Implement new billing and customer information system; and

- Design a new, easier to understand customer bill, with more information, such as consumption trending.

4.0 Conclusion

There has been a stronger organizational focus placed on customer service throughout the Company. Hydro continues the execution of its Customer Service Strategy and has seen a number of investments and improvements to software applications, hardware, processes and procedures, training, and the addition of new roles such as the Manager, Key Accounts and Customer Service Process and Project Lead without adding additional full time equivalent positions. The development of a customer service strategy and clear accountability and performance indicators has broadened the corporate focus on customer service.

The strategic plan is being reviewed and refreshed in 2017 to take Hydro into 2020, as it continues to enhance the customer experience for all customers in the province, including those not directly served by Hydro. Based on survey feedback from its customers, Hydro believes its investments and renewed focus are benefiting its customers, and will continue to improve the service it provides.

Exhibit 3 - Schedule I

Customer Service Monthly KPI Dashboard

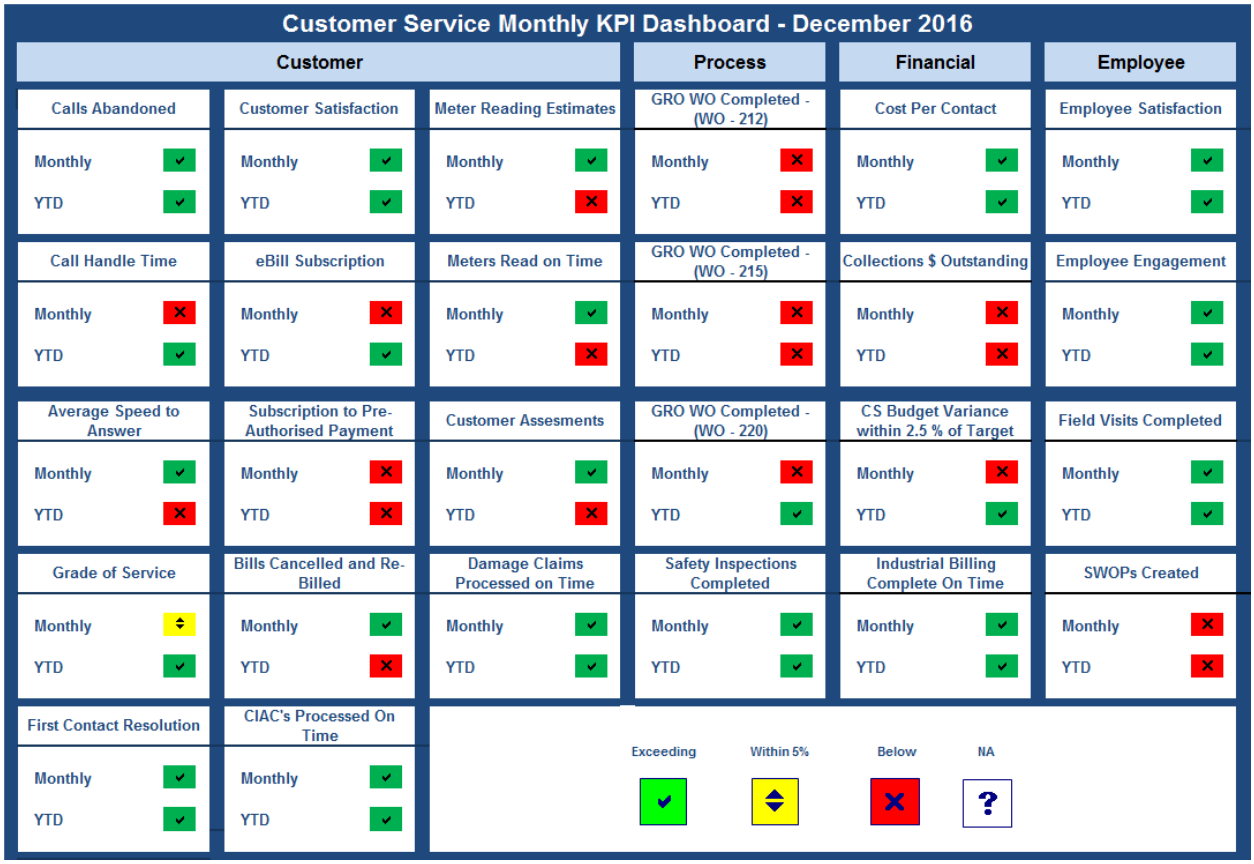

Customer Service Monthly KPI Dashboard - December 2016
Customer
Process
Financial
Employee
Calls Abandoned
Monthly
YTD
Customer Satisfaction
Monthly
YTD
Meter Reading Estimates
Monthly
YTD
GRO WO Completed - (WO - 212)
Monthly
YTD
Cost Per Contact
Monthly
YTD
Employee Satisfaction
Monthly
YTD
Call Handle Time
Monthly
YTD
eBill Subscription
Monthly
YTD
Meters Read on Time
Monthly
YTD
GRO WO Completed - (WO - 215)
Monthly
YTD
Collections $ Outstanding
Monthly
YTD
Employee Engagement
Monthly
YTD
Average Speed to Answer
Monthly
YTD
Subscription to Pre-Authorised Payment
Monthly
YTD
Customer Assesments
Monthly
YTD
GRO WO Completed - (WO - 220)
Monthly
YTD
CS Budget Variance within 2.5 % of Target
Monthly
YTD
Field Visits Completed
Monthly
YTD
Grade of Service
Monthly
YTD
Bills Cancelled and Re-Billed
Monthly
YTD
Damage Claims Processed on Time
Monthly
YTD
Safety Inspections Completed
Monthly
YTD
Industrial Billing Complete On Time
Monthly
YTD
SWOPs Created
Monthly
YTD
First Contact Resolution
Monthly
YTD
CIAC's Processed On Time
Monthly
YTD
Exceeding
Within 5%
Below
NA

Exhibit 3 -Schedule II

2014-2017 Customer Service Strategic Roadmap Initiatives

Initiative - 2014	Status
Complete current state assessment of customer service process and technology	Completed
Develop Customer Service roadmap, excellence framework & vision and plans	Completed
Develop resourcing and budget for the outlined strategy	Continual
Develop base training & orientation program in Customer Service skills for Customer Service Representatives and technologists	Complete
Review and revise outage protocols and processes	Completed
Develop long term business case for complete AMR	Completed
Define and evaluate current service offerings	Completed
Enable online documentation	Completed
Formalize after hours support	Completed
Complete a review of current billing cycles	Completed
Develop a plan with targets for increasing eBilling with customers	Completed
Complete requirements of Hydro's QMS program	Completed
Develop three year meter replacement plan	Completed
Complete 2014 customer satisfaction survey	Completed
Work with Newfoundland Power to develop synergies for shared technologies	Completed
Create a Customer Service improvement committee	Completed
Develop a Customer Service continuous improvement plan	Completed
Complete outstanding items related to the Liberty audit	Completed

Initiative - 2015	Status
Promote eBilling with customers	Completed
Identify Customer Service Project Team	Completed
Structure cross functional customer steering committee leading and advising on long term customer service strategy are focused on "making it right“	Completed
Complete resource assessment for Customer Service Strategy execution	Completed
Scope and secure external resource support	Completed
Develop communication strategy for social media integration	Continual
Develop strategy for tighter cross functional integration with takeCharge team to maximize customer value	Completed
Conduct internal focus groups and research for input on strategy	Completed
Develop training program for all customer touchpoints/contacts on broader strategy, standards, processes, etc.	Completed
Framework developed for integrated account management for commercial and key customers	Completed as part of the Account Management Framework – Section 3.1.1
Implement new customer focused web site with mobile capabilities	Completed as part of *myNLhydro* implementation – Section 3.1
Implement process and software to track customer interactions	Completed as part of the Customer Assistance Database implementation – Section 3.1.7
Implement process to establish transactional surveys as part of broader research and insights plan	Completed as per the customer transactional surveys process – Section 3.1.8
Enhance Customer Service account information online web portal	Completed as part of *myNLhydro* implementation – Section 3.1
Review AMR business case being developed by engineering	Completed
Create an action plan from the customer satisfaction survey	Completed
Broaden company strategy to enhance industrial and Newfoundland Power customer experience	Completed as part of the Account Management Framework – Section 3.1.1
Secure Hydro Leadership Team alignment	Completed
Establish regular reporting and updates to Hydro Leadership Team	Completed

Initiative - 2016	Status
Develop service standards, establish KPIs for services	Completed
Investigate new metering/billing/customer interface systems and make recommendations for 2016 implementation	Completed as part of *myNLhydro* , IVR, and Utiligy implementations – Sections 3.1.2, 3.1.9, and 3.1.11
Enhance customer communications through an upgraded IVR phone system	Completed as part of IVR implementation – Section 3.1.9
Begin assessment of automated billing tools	Completed
Complete an assessment of key Customer Service processes and procedures and map corporately	Completed
Complete a Customer Service maturity assessment	Planned for 2017
Develop a Customer Service complaint process	Planned for 2017
Customer Service Training plan for Energy Efficiency	Completed
Define new online service offerings determined for customers integrated with billing application	Completed as part of *myNLhydro* implementation – Section 3.1.2
Upgrade MV-PBS application to improve billing process	Planned for 2017
Develop a research strategy and conduct deep research to understand Hydro customers and their expectations	Completed
Map all key customers processes & associated work flow	Continual

Initiative - 2017	Status
Launch online service offerings	Completed as part of myNLhydro implementation – Section 3.1.2
Complete mobile and self-service options	Completed as part of myNLhydro implementation – Section 3.1.2
Continue to improve billing and payment options	Completed as part of myNLhydro implementation – Section 3.1.2
Investigate an outage system – online & IVR system and implement enhancements	Completed as part of *myNLhydro* , and IVR, implementation – Sections 3.1.2 and 3.1.9
Clear targets for customer interactions such as eBilling, autopay, account alerts	Completed as part of eBilling implementation – Section 3.1.3
Create a Customer Service knowledge base that can be shared across the organization	Ongoing
Implement enhancements to the collection process such as automated outbound calling, effective and efficient processes	Ongoing
Complete a Customer Service maturity assessment and revise strategy as required	Ongoing
Develop performance indicators for key account management around planned and unplanned outages, service reliability, and requests and response time	New
Develop a specific account plan for each key account that includes strategies, objectives, initiatives, and measurement of plan performance	New
Complete the interconnection process document for industrial customer requests	Completed
Complete the interconnection process document for large general service customer requests	New

Exhibit 4 - Report on Rural Subsidy Communication to Customers

Identification of the Rural Subsidy on Customer Bills Report

July 2017

Table of Contents

1.0 Introduction 2
2.0 Hydro Activities 4
2.1 Research on Jurisdictional Practices 4
2.2 Consumer Survey 7
2.3 Options to Address Transparency 8
3.0 Other Concerns and Potential Issues 9
4.0 Conclusion 10

List of Schedules

Schedule I – Subsidized Rate Study Report

1.0 Introduction

Hydro owns and operates 21 isolated diesel generating plants serving approximately 4,500 customers throughout Newfoundland and Labrador. Hydro also serves rural customers on the Island Interconnected System and has approximately 23,000 customers in 182 communities on the south coast, northeast coast, and along the Great Northern Peninsula. The cost of providing service to these approximately 27,500 rural customers exceeds the revenues collected from rates, resulting in a deficit which is commonly referred to as the Rural Deficit. Until 1989, the Rural Deficit was funded by Government; however, as a result of a change in policy by Government in 1989, the Rural Deficit is currently funded by means of a cross-subsidy from other ratepayers.

The rural deficit adds to the cost of electricity for Newfoundland Power and for Labrador Interconnected customers. Industrial Customers have not contributed to the Rural Deficit since 1999. Hydro's rates designs for its Hydro Rural customers reflect Government direction.[1] The Hydro Rural customers on the Island and in the Labrador Straits area pay the same rates as those charged by Newfoundland Power to its customers. These rates automatically change as Newfoundland Power alters its rates. In the case of isolated systems' customers, the rates charged by Newfoundland Power apply to the lifeline block; however, rates beyond this level of consumption are higher.[2]

The forecast Rural Deficit for the 2018 Test Year and 2019 Test Year is approximately $67 million and $72 million, respectively. The Rural Deficit increases rates for customers of Newfoundland Power by approximately 10%[3] and 15% for retail customers on the Labrador Interconnected System.[4]

[1] Order in Council 2003-347 provides government direction on Hydro Rural rate designs.
[2] The purpose of the lifeline block is to provide domestic households located on diesel systems with access to electricity at an affordable price for essential, non-substitutable end-use requirements. The size of the lifeline block ranges from 700 kWh per month in non-winter months to 1,000 kWh per month in the winter months.
[3] The Newfoundland Power wholesale rate is 15% higher as a result of the requirement to pay the Rural Deficit. However, because Hydro's cost to serve Newfoundland Power represents approximately 67.5% of the cost to serve the customers of Newfoundland Power, the Rural Deficit impacts retail customer bills by approximately 10%.
[4] The Labrador industrial customers are not required to pay the Rural Deficit.

In Hydro's 2013 Amended General Rate Application (GRA) proceeding, the Consumer Advocate supported a recommendation made by Dr. James Feehan to include rural subsidy information on customer bills.[5] Currently, customer bills do not include information specifically related to the rural subsidy. Hydro identified concerns with that proposal and submitted that further information was required.[6]

In Order No. P.U. 49(2016), the Board of Commissioners of Public Utilities (the Board) determined that the implications of including rural subsidy information on customer bills should be carefully considered before a decision on the proposal is made. The Board also acknowledged there may be other options available to provide rural subsidy information to customers.[7] The Board directed Hydro to provide a report with its next GRA identifying:[8]

- practices in other jurisdictions;
- other options to address transparency concerns;
- what, if any, information customers would like to have on their bills in this circumstance; and
- any other concerns or potential issues and options to address these concerns.

[5] Dr. Feehan's recommendation was made in his Report on the Allocation of the Rural Deficit, dated April 20, 2014. The Consumer Advocate supported this recommendation on page 55 of his final written submission to the 2013 Amended GRA proceeding, dated December 23, 2015.
[6] Hydro's Final Written Submission to the 2013 Amended GRA, Revision 1, dated January 22, 2016, page 95.
[7] Order No. P.U. 49(2016), page 91.
[8] Ibid.

2.0 Hydro Activities

Hydro has completed the following activities to inform a plan on this matter.

2.1 Research on Jurisdictional Practices

Hydro conducted a jurisdictional scan of the practices of other utilities to determine what information, if any, is communicated to their customers regarding rate subsidization, and how this is done.[9] The results suggest that in jurisdictions utilizing some form of subsidization between high-cost, rural/isolated customers and lower cost urban/interconnected customers, communication of subsidy amounts on customer bills is common when the subsidization is provided by Government. When the subsidization is provided by utilities' customers, Ontario was the only province in which information was provided on customer bills concerning subsidization. Below is a brief summary of the findings per province and territory.

Newfoundland and Labrador

Hydro identifies on its Labrador Isolated residential customer bills the Northern Strategic Plan (NSP) rebate funded by the Provincial Government. The customer bill impact of the NSP rebate effectively results in customers on the Labrador Isolated Systems paying the same electricity rate as the customers on the Labrador Interconnected system for their monthly customer charge and the lifeline block.

Neither Hydro nor Newfoundland Power provide information on customer bills concerning the Rural Deficit subsidization reflected in customer rates.

Ontario

Hydro One Remote Communities Inc. generates and distributes electricity to 21 communities in the most northern part of the province. Ontario has a Rural or Remote Rate Protection Program (RRRP), which is designed to reduce costs for eligible customers located in rural or remote

[9] Hydro conducted a survey of the following utilities: BC Hydro, NB Power, Manitoba Hydro, Hydro Quebec, Northwest Territories Power Corporation, Yukon Energy, Nova Scotia Power, and Hydro One. Information included in this report is based on responses provided and publically available information.

areas, where the cost of distributing electricity to these customers is higher than distributing to customers in more urban areas. The RRRP cost is recovered from all electricity customers in the province through a charge that is reviewed annually and approved by the Ontario Energy Board (OEB).[10]

The RRRP appears on the tariffs of rates and charges of all licensed Ontario electricity distributors and is included as one of several components of the Regulatory Charges line item located on customers' bills. The RRRP is credited monthly to eligible customers at a flat dollar amount. Customers who receive the RRRP credit have a line item on their bill which indicates how much RRRP they receive.

Customers in Ontario can learn more about the contents of their electricity bills by accessing the Understanding your Electricity Bill page on the OEB's website. The website explains the contents of the Regulatory Charges line item on customer bills.[11]

On June 1, 2017, the *Ontario Fair Hydro Act* came into effect, which removed some of the cost of the RRRP from electricity bills, and instead funds the majority of the RRRP program through taxes. As such, effective July 1, 2017, approximately 80% of the RRRP charge is paid by taxpayers. The remaining amount continues to be paid by ratepayers.[12]

Manitoba

Manitoba Hydro serves 4 communities on 4 isolated systems with 767 customers. Their Domestic customers pay the same rates as grid customers. There is an inclining block rate for General Service customers. Manitoba Hydro does not track details on the amount of rural subsidization.

[10] Approval for 2017 was made in Order No. EB-206-0362, dated December 15, 2016.
[11] https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017
[12] https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017 and http://www.ieso.ca/sector-participants/ieso-news/2017/02/rural-and-remote-electricity-rate-protection-charge-increase-for-2017

Manitoba Hydro's rural subsidization is recovered in several ways: through a rate surcharge applicable to government customers served by diesel generation; through government capital contributions; and through reductions to the utility's net income. There is no presentation of rural subsidization on customer bills.

British Columbia

BC Hydro has 24 communities served on 13 isolated systems serving 6,400 customers. There are inclining block rates for Domestic and General Service customers. BC Hydro does not track details on the amount of rural subsidization.

BC Hydro recovers the rural subsidization provided to customers on isolated systems from customers on the integrated system. BC Hydro also receives federal funding for First Nations communities where BC Hydro has, in recent years, taken over the provision of electricity service from the Federal Government. There is no presentation of information on rural subsidization on customer bills.

Northwest Territories

Northwest Territories Power Corporation (NTPC) has 22 communities served on 22 isolated systems serving approximately 6,300 customers. The subsidization of customer rates based on the Yellowknife rate is provided by Government.

The amount of the subsidy provided to customers is identified on the monthly bills of the customers that are subsidized. [13]

Yukon

Based on a review of the Yukon Electrical website, Hydro determined that the Yukon Government program provides a rebate to reduce the bill for the first 1,000 kWh of usage on residential accounts. This rebate is identified on customer bills.

[13] https://www.ntpc.com/customer-service/territorial-power-support-program---tpsp

Nunavut

The Government of Nunavut provides the Nunavut Electricity Subsidy Program (NESP) in support of the development of northern businesses and the encouragement of private home ownership. The cost differential between Iqaluit rates and those of other Nunavut communities is provided by the NESP up to specified consumption levels.[14]

For residential customers, the subsidization is identified as the NESP and is automatically deducted from their power bills. Commercial customers must apply for the available rebate.

2.2 Consumer Survey

Hydro engaged Corporate Research Associates (CRA) to conduct quantitative research to assess Newfoundland and Labrador residents' perceptions of rural subsidization of electricity rates in the Province. The research was completed by a random telephone survey of 600 participants who pay a utility bill. Of the respondents, 400 contribute to subsidized rates and 200 receive the subsidy. Overall findings provided results accurate to within +/- 4.0%. Key findings from the research are:

- There is limited awareness about rate subsidization in the Province, but residents are keen to know more, regardless of whether they contribute to or receive subsidization.
- Across the Province, customers expressed a desire to learn more about the different costs included in their power bills and how rates are determined.
- Customers would like more information about subsidization of rates, including what they are paying or receiving in terms of a subsidy. Over 90 percent of customers agreed that this information should be identified on their bill, regardless of whether they contribute to or receive subsidization.

[14] Source:http://gov.nu.ca/sites/default/files/files/NU%20Electricity%20Subsidy%20Program%20Contribution%20Policy.pdf.

- When asked what would be the best way for an electricity provider to inform customers on the topic of electricity costs and the rural rate subsidy, a variety of mediums were mentioned.[15]
- Results show that power bills are considered a key method of communication, either through information included directly on the power bill or provided as a bill insert. However, younger residents (aged 18-34) are more likely to prefer to receive information by email, website or online.
- Across the Province, most electricity customers recognize that identifying a subsidy on the power bill may create a negative perception of higher cost communities, or rural Newfoundland and Labrador; however, that does not impede the clear preference for information on subsidization.

A copy of the Subsidized Rate Study report prepared by CRA is provided as Schedule I.

Any decision relating to the identification of the rural subsidy on customer bills will impact Newfoundland Power as it is their customers that pay a significant share of the rural subsidy and the billings to those customers would also have to be changed. Hydro is consulting with Newfoundland Power regarding how best to communicate information on the Rural Deficit to customers.

2.3 Options to Address Transparency

The rural subsidy is presently embedded within the electricity rates of Hydro and Newfoundland Power, which may present transparency concerns. However, the provision of a high-level rural subsidy overview on a web page and an annual bill insert with a similar level of explanation may be a reasonable option to communicate details of the Rural Deficit to customers.[16] The presentation of information with respect to the Rural Deficit on customer bills

[15] The most common mediums mentioned include: on power bills; direct mail out to customers; email; and as bill inserts.
[16] In Ontario, the subsidy details are provided on the utility and regulatory websites.

is also an option. However, this approach requires a more detailed review of potential issues that may arise.

3.0 Other Concerns and Potential Issues

Depending on the level of detail provided and the method in which it is provided, identifying the rural subsidy on customer bills may present various issues and concerns for Hydro. Potential concerns include, but are not limited to the following:

- Should the rural subsidy be shown separately on the bills of individual customers who pay it?
- Should the rural subsidy be shown separately on the bills of customers who receive it?
- Should the rural subsidy be shown on a per kWh basis, or flat charge or credit, as applicable?
- Will presentation of the rural deficit on the bill as a charge or savings (i.e., for those receiving the subsidy) cause confusion for customers?
- Some customers have accounts located in areas that both pay the rural subsidy and receive subsidization. A bill from Newfoundland Power showing a Rural Deficit costs and a bill from Hydro showing a Rural Deficit savings may cause confusion and dissatisfaction.
- Can the existing utility billing system deal with either a new cost item or credit item?
- What costs are associated with modifying the billing systems? How much cost should be incurred to permit the identification of the Rural Deficit on customer bills and any continued adjustments over time?
- Will the addition of the cost or savings item resulting from rural subsidization create increased call volumes to the call centres and increased operating costs to customers?
- Will credit concerns arise from some customers refusing to pay the portion of their bill related to the Rural Deficit?

4.0 Conclusion

Subsidization is inherent in all electricity rates because it is not practical to attempt to isolate the precise costs of serving each individual customer. Based on a review of utilities' practices in Canada, it is not common for utilities to identify on customer bills the subsidization required to provide affordable electricity to high cost rural systems.

In the Province of Newfoundland and Labrador, the degree of rural subsidization reflected in customer billing is materially higher than in other jurisdictions. The results of Hydro's customer research indicate that customers want more information on the degree of rural subsidization.

Hydro acknowledges that consumers have a particular interest in the formulation of electricity rates and billing; however, there are methods by which Hydro can provide customers with adequate information regarding the composition of their bills without explicitly providing the rural subsidy as a line item on bills, which, based upon a preliminary review, is complex. This includes posting information on its website and including a bill insert with an explanation of the rural subsidy.

Hydro will work with Newfoundland Power to develop a communications plan for providing more transparency to customers on the Rural Deficit to ensure alignment and consistency for the provincial customer base. When the communication plan has been developed, Hydro will provide the plan to the Board.

Exhibit 4 – Schedule I

Subsidized Rates Study

Report

Subsidized Rate Study



Prepared for Newfoundland Labrador Hydro

May 2017

newfoundland labrador hydro
a nalcor energy company

CRA
CORPORATE RESEARCH ASSOCIATES

Accredited Gold Seal Corporate Member

NL Hydro will be making a recommendation to the Public Utilities Board regarding how the issue of 'rural subsidy' should be handled with its customer base. To direct its recommendation, NL Hydro was interested in conducting quantitative research to assess Newfoundland & Labrador residents' perceptions on the topic. Primary research objectives included:

- Assess the current level of awareness of power rate subsidization in the Province;
- Determine how Newfoundlanders and Labradorians feel about the issue of subsidization;
- Identify consumers' interest in learning more on this topic (e.g. is there a desire for additional information and what specific type of information would consumers be interested in); and
- Identify consumers preferred method of communication on this topic.

To meet research objectives, NL Hydro and its agency of record (National PR) commissioned Corporate Research Associates to undertake the ***Subsidized Rate Study*** within Newfoundland and Labrador. Given that the results of this study would inform policy decisions, a random telephone methodology using a probability sample was employed. More specifically, a total of 600 random telephone surveys were conducted, with adults 18 years of age and older, who pay a utility bill. Overall findings provide results accurate to within +/- 4.0%. Of note, 400 surveys were completed with those who are subsidizing power rates, while 200 were completed with those who are subsidized. Further, cell sample was included to provide access to the younger demographic.

To ensure representation of the population, region, gender and age quotas were established and overall results were weighted to ensure accurate representation of the population's true distribution.

The following summary report presents an overview of the ***2017 Subsidized Rate Study*** and includes study highlights and an analysis of survey findings. Appended to this report is a copy of the questionnaire (Appendix A).



Executive Summary & Direction

The results of the ***2017 Subsidized Rate Study*** confirm that while there is limited awareness of a rate subsidization in Newfoundland and Labrador, residents are keen to learn more about the subsidization, regardless of whether they are being subsidized or are subsidizing. Highlights of the survey findings are as follows:

- ***The vast majority of NL residents are aware that NL Hydro both generates power and delivers power directly to customers***. NL Hydro customers are more likely than Newfoundland Power customers to express awareness.
- ***There is limited awareness of a rate subsidization in NL***. Perceptions are generally consistent across the population, with no marked difference by utility or by region.
- Across the Province, ***electricity customers express a strong desire for more information*** about the different costs included in their electricity bill and how power rates are determined. Results are consistent across the population.
- The vast majority of electricity customers (across regions and utilities) ***regularly review their power bill***, and the likelihood of reviewing a bill increases with age.
- Electricity customers ***clearly want more information about the subsidization of rat***es, including what they are paying or receiving in terms of a subsidy. ***There is an expectation that such information would be provided on their power bill***.
- Across the Province, most electricity customers recognize that ***identifying a subsidy on a power bill may create a negative perception*** of higher cost communities or rural Newfoundland and Labrador. This recognition, however, does not impede the clear preference for information on subsidization.
- Although the ***power bill will play a key role*** in communicating to customers on electricity rates and rural rate subsidies, findings suggest a ***multi-mode communications strategy is warranted***.
- ***There is significant opportunity to expand customers' participation in both an equal payment plan and an automatic payment plan***. Only a minority of electricity customers are enrolled in an equal payment plan, although incidence is higher among Newfoundland Power customers. Few customers are signed up for an automatic payment plan.



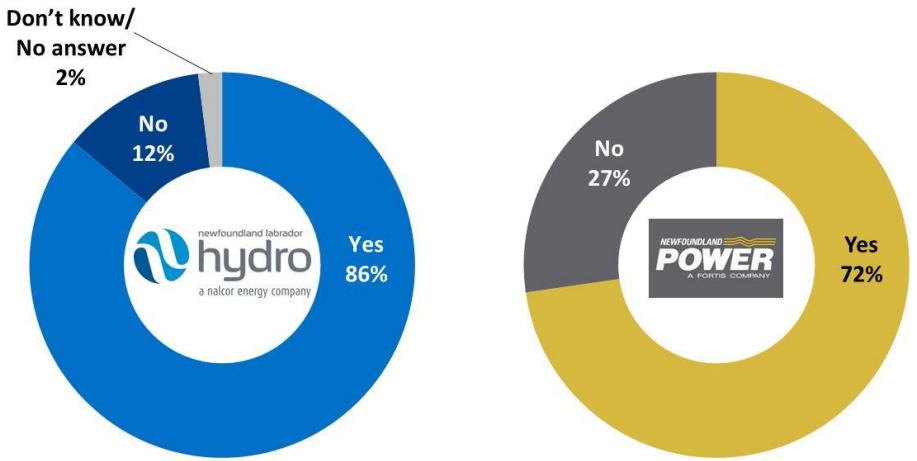
Detailed Results

The vast majority of NL residents are aware that NL Hydro both generates power and delivers power directly to customers.

Survey respondents were told that in Newfoundland and Labrador (NL), there are two electricity utilities. In particular, they were told that NL Hydro is a crown corporation, owned by the Government of Newfoundland and Labrador and is the primary generator of electricity in the Province. Newfoundland Power, an investor-owned utility company, is the primary distributor (or service provider) on the island, delivering electricity directly to homes and businesses.

- The vast majority of NL residents (76%) are aware that NL Hydro not only generates power but also delivers power directly to customers throughout Labrador and to rural and coastal communities across the Province. Although findings are generally consistent across the Province, NL Hydro customers are more likely than Newfoundland Power customers to express awareness. Similarly, residents over the age of 55 are most likely to have such knowledge.

Aware That NL Hydro Generates and Directly Delivers Power to Customers Throughout NL

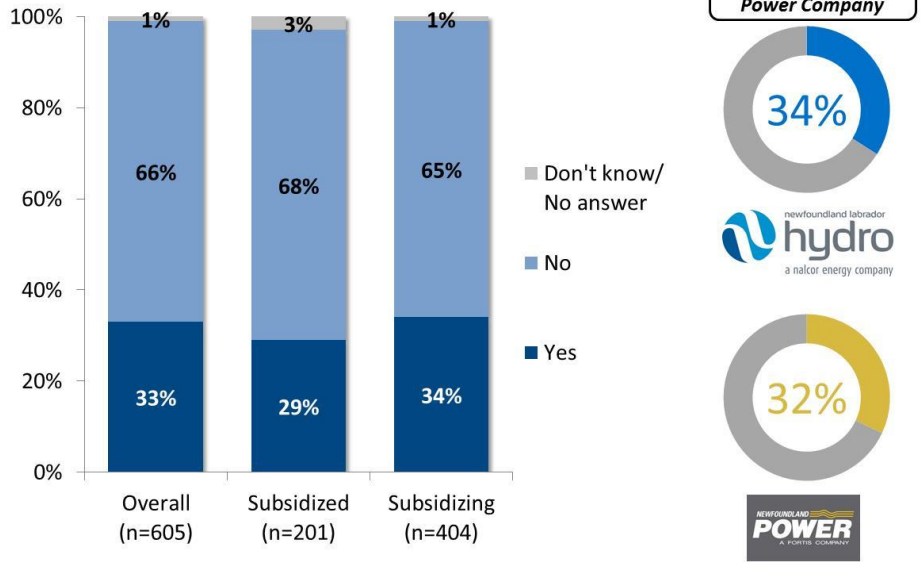


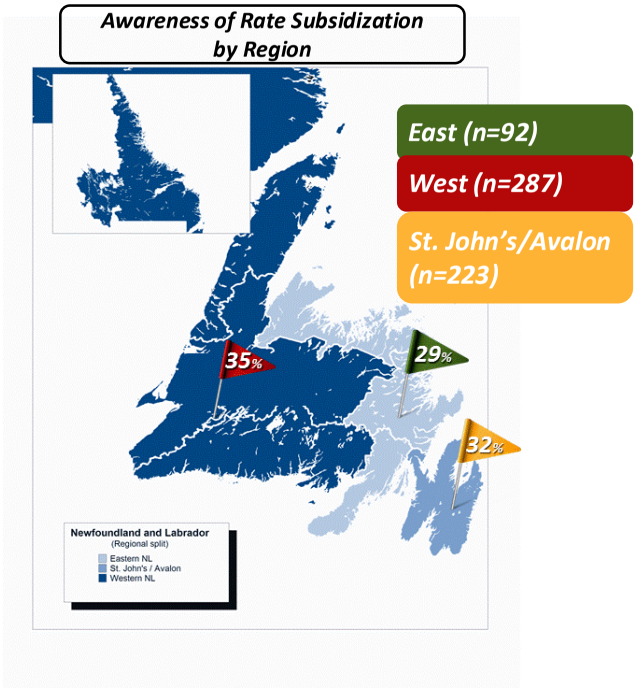
Q.6: (following description) Are you aware that NL Hydro, not only generates power but also directly delivers power directly to customers throughout Labrador and over 200 rural and coastal communities across the province? (NL Hydro n=250, Newfoundland Power n=338)

There is limited awareness of a rate subsidization in NL, regardless of location.

- Residents are generally unaware that most customers outside certain rural areas pay between 10 and 15 percent more on their monthly power bill to help make power more affordable for customers in those rural and remote communities. In fact, only three in ten residents were generally aware of such subsidization.
- Perceptions are generally consistent across the population, with no marked difference by utility or by region. The exception to this is across gender and age, with males being almost twice as likely as females to be aware (42% vs 23%), and older residents being more than twice as likely as those aged 18-34 (41% vs 16%) to be aware of subsidization.

Awareness of Rate Subsidization



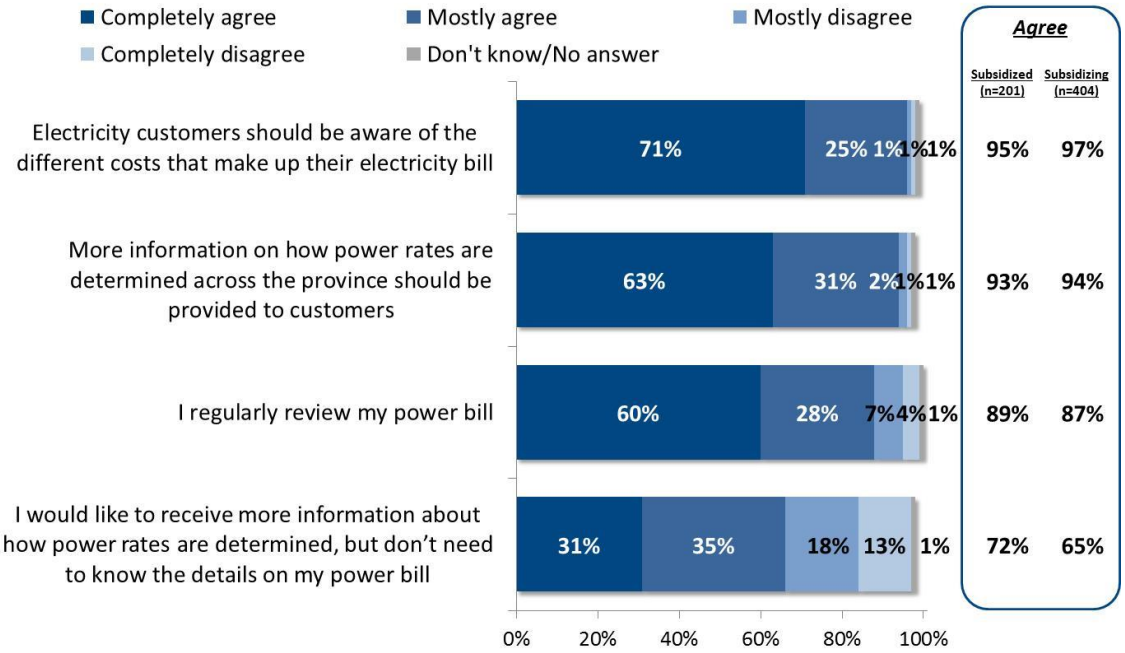


Q.7: (following description) Were you aware that most customers outside of those rural areas pay between 10 and 15 percent more on their monthly power bill to help make power more affordable for customers in those rural and remote communities?
(NL Hydro n=250, Newfoundland Power n=338)

Across the Province, electricity customers express a strong desire for more information about the different costs included in their electricity bill and how power rates are determined. Results are consistent across the population.

- Electricity customers clearly believe they ***should be aware of the different costs that make up their electricity bill***, regardless of whether or not they are subsidized or subsidizing. Results are consistent across regions and all demographics.
- Similarly, customers strongly agree that ***more information should be provided to customers on how power rates are determined*** across the Province.
- The vast majority of electricity customers (across regions and utilities) reportedly ***regularly review their power bill***, and likelihood of reviewing their bill increases with age.
- While the need for information about how power rates are determined is pronounced, customers do not believe details need to be provided on their power bill. While opinions are generally consistent, subsidized customers are ***less likely*** to feel this way, as are older customers.

Opinion of Statements About Power Rates and Bills

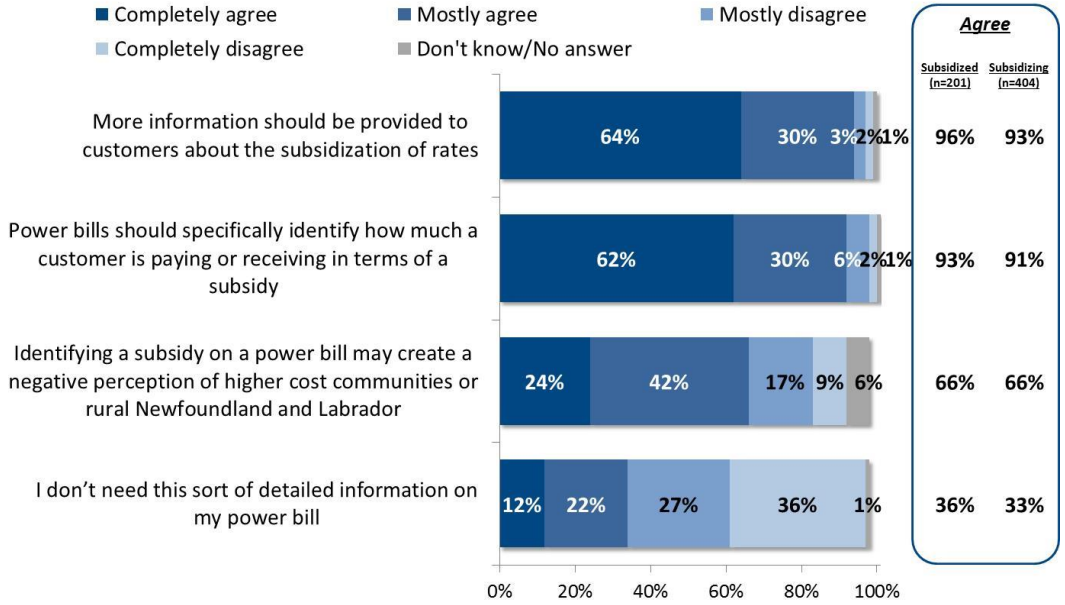


Q.8a, e, g-h: Please indicate whether you completely agree, mostly agree, mostly disagree, or completely disagree with each of the following statements? (n=605)

Electricity customers clearly want more information about the subsidization of rates, including what they are paying or receiving in terms of a subsidy. There is an expectation that such information would be provided on their power bill.

- Regardless of whether or not a customer is paying or receiving a subsidy, customers concur that more information should be provided about the subsidization of rates. Further, almost all customers believe that how much a customer is paying or receiving in terms of a subsidy should be identified on a power bill and most customers would like to see detailed information regarding subsidization on their power bill.
- Results are consistent across the population, although older customers are more likely than their younger counterparts to believe that they don't need such detailed information on their power bill.
- Across the Province, most electricity customers recognize that identifying a subsidy on a power bill may create a negative perception of higher cost communities or rural Newfoundland and Labrador. This recognition, however, does not impede the clear preference for information on subsidization.

Opinion of Statements About Power Rates and Bills



Q.8b-d, f: Please indicate whether you completely agree, mostly agree, mostly disagree, or completely disagree with each of the following statements? (n=605)

Multiple communications mediums are suggested to best communicate to customers on electricity rates and rural rate subsidies.

When asked what would be the ***best*** way for an electricity provider to inform customers on the topic of electricity costs and rural rate subsidies, a variety of mediums were mentioned, suggesting that no one communication source should be used in isolation.

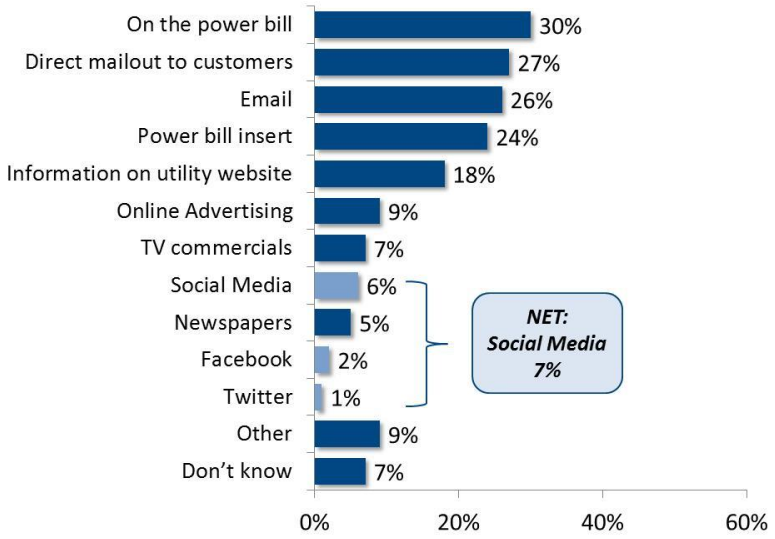
- Results show that ***power bills*** are considered a key method of communications, whether it be information on the power bill or provided as a bill insert. Indeed, more than half of residents considered the power bill (through either mode) to be the best communication method. Combined, those mentions are most prevalent among Newfoundland Power customers (59%), those with higher household incomes (63%) and among residents 55 years or older (58%).

- By contrast, a ***direct mailout*** to customers is the preferred method among NL Hydro customers (33%), females (31%) and those in lower income households (32%).

- Not surprisingly, communications preferences vary notably by age with younger residents having greater reliance on ***electronic communications***. Indeed, those aged 18-34 years are more likely than others to prefer receiving information by ***email*** (46%), via a ***utility's website*** (22%) or through ***online advertising*** (14%).

Best Communication Mediums on Electricity Costs and Rural Rate Subsidies

Total Unaided Mentions

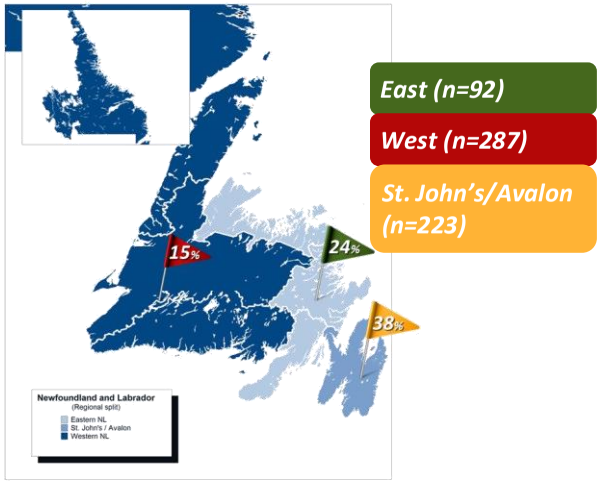


Q.9: What would be the best way for your electricity provider to provide information to customers on the topic of electricity costs and rural rate subsidies? Probe: Any other way? (n=605)

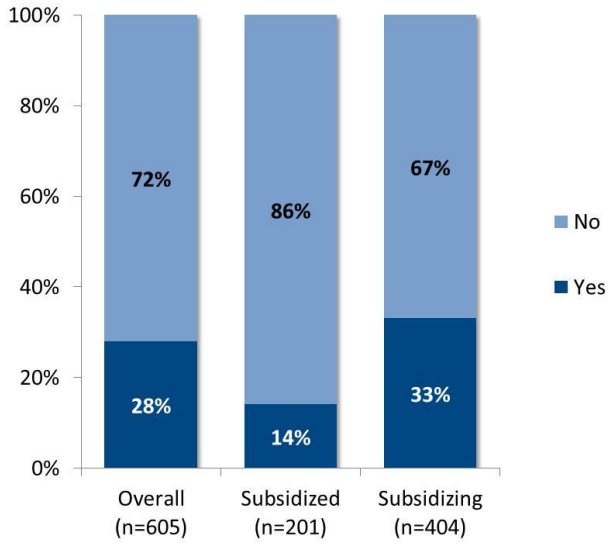
Only a minority of electricity customers are enrolled in an equal payment plan, although incidence is higher among Newfoundland Power customers.

- The vast majority of electricity customers in the Province are not currently on a equal payment plan. In fact, only a small minority choose to pay the same amount each month for their energy bill.
- Enrollment on a equal payment plan varies across utilities, and correspondingly, by subsidization. Newfoundland Power customers are more than twice as likely as NL Hydro customers to currently be on an equal payment plan. Accordingly, subsidizing customers are more than twice as likely as subsidized customers. Further, likelihood of being on an equal payment plan is most prevalent in the St. John's / Avalon region.

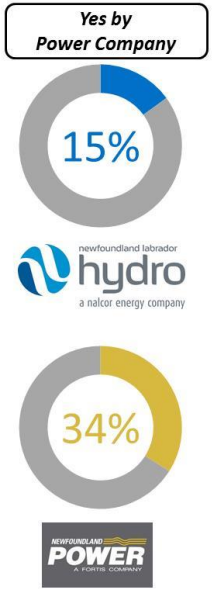
Equal Payment Plan Incidence (by region)



Currently on an Equal Payment Plan



Yes by Power Company

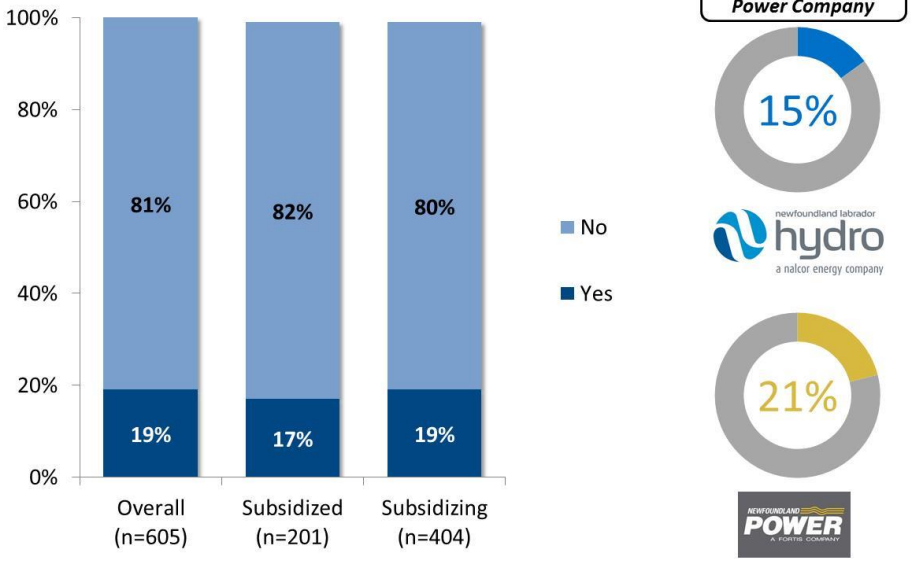


Q.10: Are you currently on an equal payment plan, where you pay the same amount each month for your energy bill?
(NL Hydro n=250, Newfoundland Power n=338)

Few customers are signed up for an automatic payment plan.

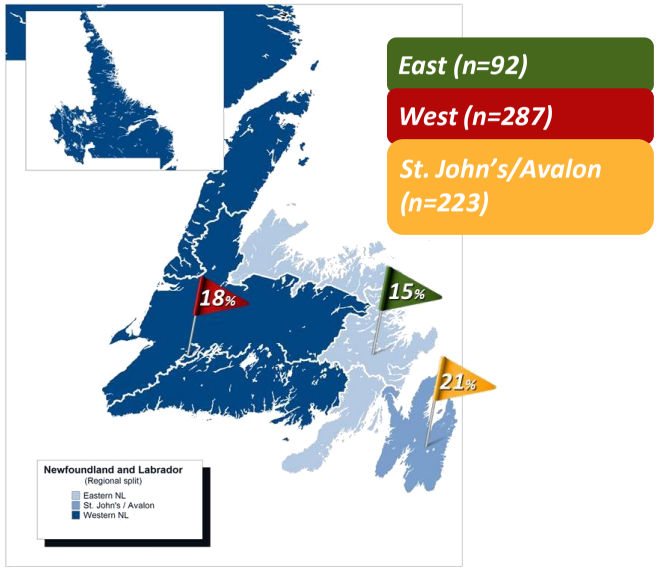
- The vast majority of electricity customers are <u>not</u> currently signed up for an automatic payment plan. In fact, only two in ten have chosen to do so. Incidence is general consistent across the Province, although customers in the St. John's / Avalon region are slightly more likely to have signed up for an automatic payment plan.
- Across utilities, Newfoundland Power customers are only slightly more likely than NL Hydro customers to have signed up for an automatic payment plan and the likelihood of having done so increases with age.

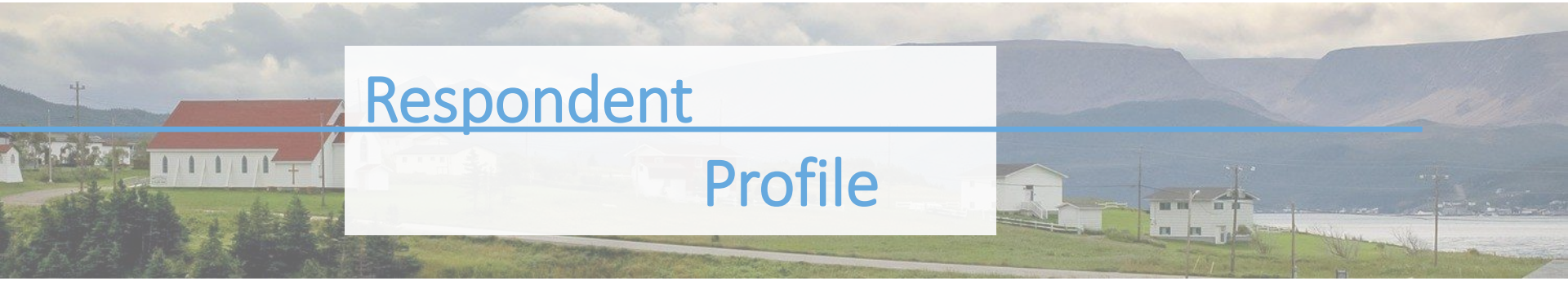
Currently Signed Up for the Automatic Payment Plan



Q.11: Are you currently signed up for the automatic payment plan where your electricity bill is automatically deducted from your bank account each month? (NL Hydro n=250, Newfoundland Power n=338)

Automatic Payment Plan Incidence (by region)





Respondent Profile

- The following visually depicts the profile of survey respondents, including gender, age, household income, education, and utility.

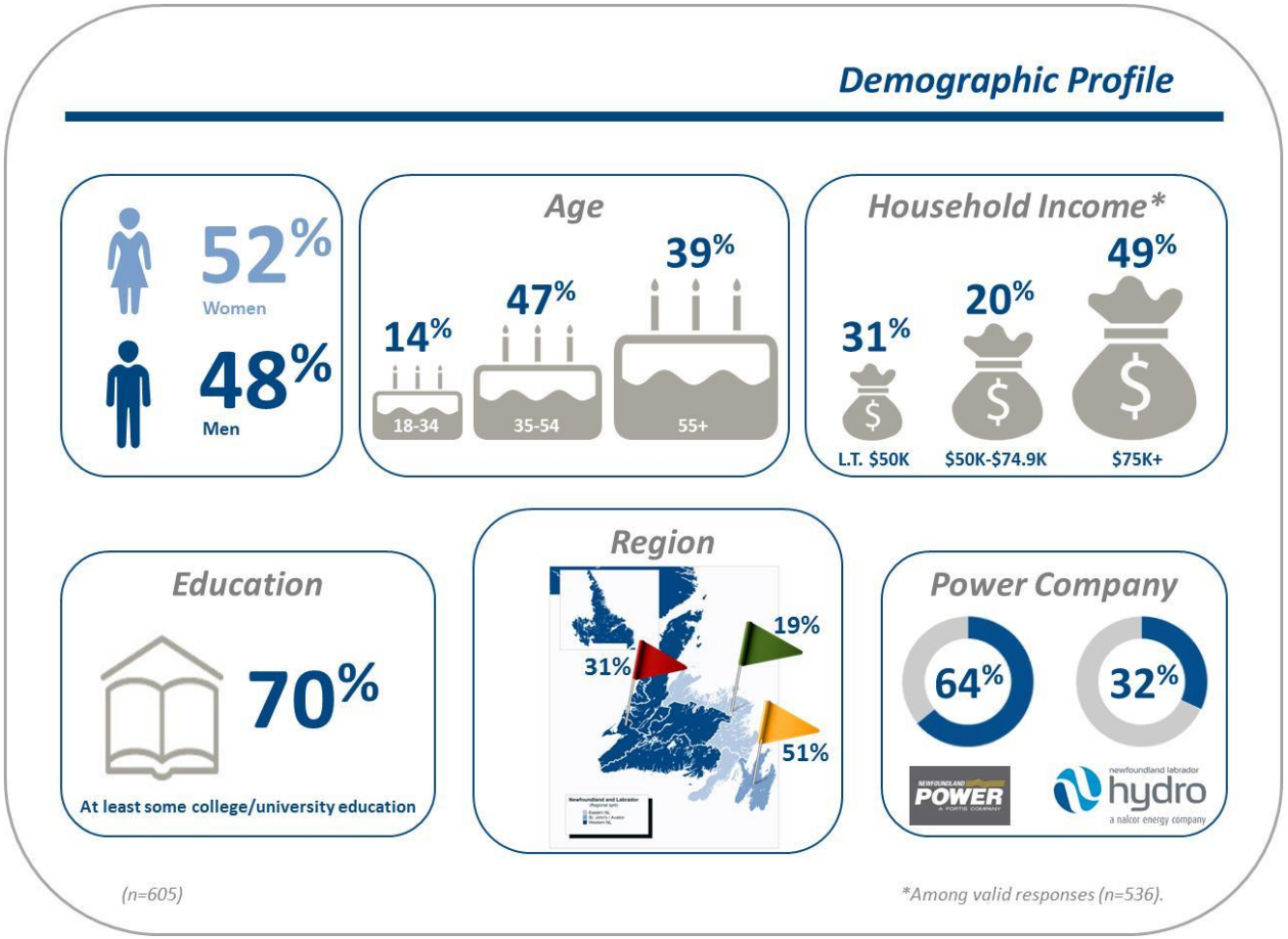


Exhibit 5 - Intercompany Transactions Costing Guidelines

Intercompany Transactions Costing Guidelines

July 2017

Table of Contents

1.0 Purpose 1
2.0 Introduction 1
3.0 Costing Methods 2
3.1 Type 1 – Common Service Costs 2
3.1.1 Human Resources 3
3.1.2 Safety and Health 3
3.1.3 Environmental Services 4
3.1.4 Information Systems 4
3.1.5 Office Space 4
3.1.6 Telephone Infrastructure (PBX) Costs 4
3.2 Type 2 – Corporate Costs 5
3.2.1 Employee Labour Costs 5
3.2.2 Overtime 5
3.2.3 Time Sheets 6
3.2.4 Corporate Services 6
3.2.5 Fixed Charge 7
3.2.6 Materials Costs 8
3.2.7 Vehicle and Other Equipment Costs 8
3.2.8 Computers 8
3.3 Type 3 – Cost Recovery Business Units 8
4.0 Billing and Collection 8

List of Tables

Table 1 – Common Services 3

List of Schedules

Schedule I - Operating Bill Rate Components

1.0 Purpose

This document is intended to outline the guidelines for charging costs across the lines of business within Nalcor Energy (Nalcor or the Company).

2.0 Introduction

Nalcor is a Crown corporation that was established in 2007 as part of one of the key initiatives of Newfoundland and Labrador's Energy Plan. The Company, which is wholly owned by the Government of Newfoundland and Labrador, was established to take a lead role in the development of the province's energy resources. The Nalcor legal entity structure is outlined in Figure 1.

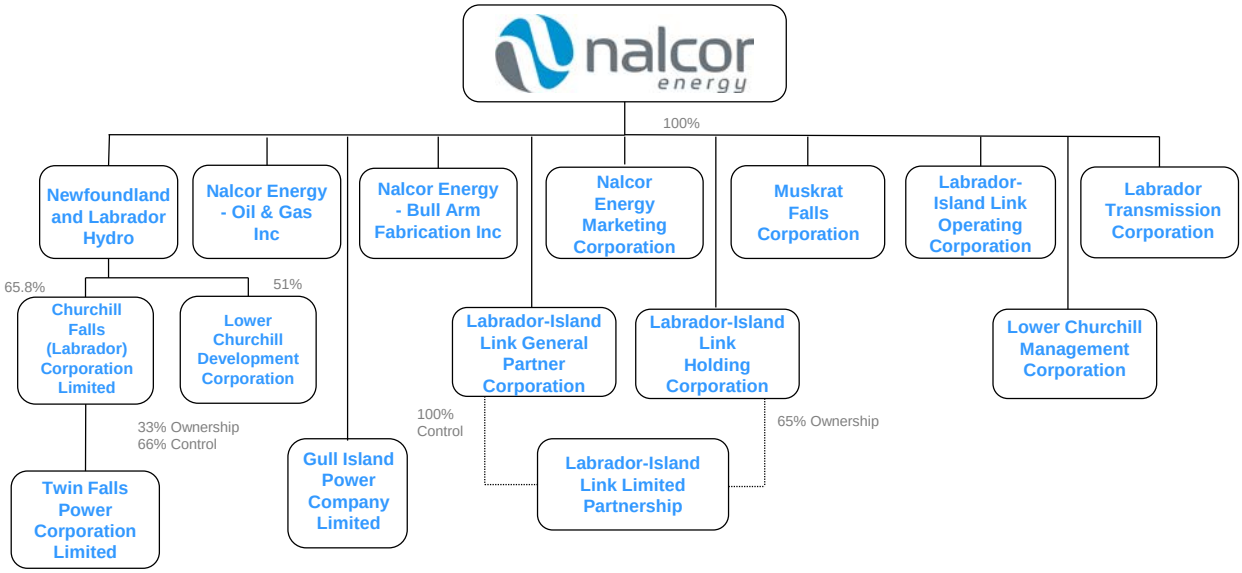


Figure 1 – Nalcor Energy Legal Entity Structure

Nalcor's business includes the development, generation, transmission and distribution of electricity; the exploration, development, production and sale of oil and gas; industrial fabrication and energy marketing. These intercompany transaction costing guidelines apply to both intra-company and intercompany transactions.

The guidelines are based on the principle of cost based recovery. There is no profit component and employees track time worked for other lines of business using a weekly time sheet. This results in a labour recharge which is also used in the calculation of net full time equivalents (FTEs). Costs associated with the operations of certain departments that provide common services available to all lines of business are allocated through an Administration Fee as outlined in this document. Common service business units are based in both Nalcor and Hydro.

3.0 Costing Methods

The costing framework used includes three primary means of charging costs among lines of business at Nalcor.

Type 1 - Common Service Costs (via Administration Fee);

Type 2 - Costs related to the provision of Corporate Services; and

Type 3 – Cost Recovery business units.

3.1 Type 1 – Common Service Costs

Certain functions provide common services to various lines of business. Costs are recovered through an Administration fee as described below. FTEs in common service business units are counted in the entity in which they are based, however their costs are allocated through an Administration Fee.

Table 1 – Common Services

Common Service Departments	Allocation Basis	Entity
Human Resources	FTE	Nalcor
Safety and Health	FTE	Nalcor
Environment	FTE	Nalcor
Information Systems (IS)	Average Users[1]	Nalcor
Hydro Place office space and related costs	Square footage	Hydro
Telephone and Local Area Network (LAN) costs	Users	Hydro

3.1.1 Human Resources

Human Resources provides service to all lines of business in the areas of:

- Payroll;
- Human Resources Systems;
- Pension administration;
- Employee recognition programs;
- Administration of the performance management system;
- Maintenance of the human resources database.

Operating costs incurred in providing Human Resources services in the common service business unit are allocated to the lines of business on a FTE basis.

3.1.2 Safety and Health

The Safety and Health department provides Occupational Health services including coordinating corporate efforts with regard to employee safety and wellness. Operating costs incurred in providing safety and health services are allocated to the lines of business on a FTE basis.

[1] Average users is the average of the number of FTEs and contractors, Lotus Notes mail boxes, number of computers and JDE Users.

3.1.3 Environmental Services

The Environment department coordinates corporate efforts with regard to environmental stewardship. Operating costs incurred in providing environmental oversight services are allocated to the lines of business on a FTE basis.

3.1.4 Information Systems

Information Systems (IS) provides assistance and support in the areas of software applications, planning and integration and business solutions. This department is also responsible for the maintenance and administration of the company-wide computer infrastructure and provides technical support. Operating costs incurred in providing IS services are allocated to the lines of business on an average user basis. Depreciation expenses and a return on rate base at the weighted average cost of capital (WACC) for costs capitalized such as servers and software are allocated to each line of business on an average user basis. Costs that are incurred solely for a particular line of business, rather than shared among the lines of business are charged to that line of business and are excluded from the determination of shared costs.

3.1.5 Office Space

Each line of business occupying floor space at Hydro Place is charged a rental charge for floor space. The square footage rental rate reflects the average annual capital and operating cost for Hydro Place as determined by the following formula:

$$\frac{\text{Hydro Place operating costs + return on rate base + annual depreciation}}{\text{Hydro Place total square footage}}$$

3.1.6 Telephone Infrastructure (PBX) Costs

All lines of business are charged their share of Telephone Infrastructure (PBX) costs including long distance charges. The Local Area Network (LAN) costs provided by Network Services are divided by the total number of LAN ports to derive a cost per user. The telephone costs

provided by Network Services are divided by the number of telephone, fax, and modem lines to derive a cost per telephone.

3.2 Type 2 – Corporate Costs

Certain departments provide corporate services (or shared services) to other lines of business within Nalcor. These services include management, general accounting, treasury, purchasing, legal, human resources, safety and health, engineering services and administration. Transactions associated with these services are governed by these guidelines. Intercompany transactions operate on the premise that all transactions are billed at cost. Corporate costs incurred within various lines of business are charged to the appropriate line of business as described below.

3.2.1 Employee Labour Costs

All employees of Nalcor are required to charge time by completing time sheets which allocate labour to work orders based on activity. The guiding principle is that where an employee spends time on specific tasks and work activities for another entity or line of business, time is to be charged at cost. Cost, or the bill rate, is defined as labour costs, fringe benefits (including time off) and other direct costs. See Schedule I for a detailed listing of the components of the bill rate. The operating bill rates are reviewed annually and updated as required. Labour hours that are recharged through this process are used in the calculation of net FTEs.

3.2.2 Overtime

Overtime will be charged as incurred in accordance with the overtime policy and no additional mark-up or fixed charge is applied.

3.2.3 Time Sheets

All employees are required to complete weekly time sheets. All work hours must be coded to work orders in order to adequately track hours to the appropriate business unit. Time is coded in 30 minute increments.

3.2.4 Corporate Services

The functions and departments that may share services across entities include:

a) Leadership Team[2]

Executive management provides strategic oversight and general management.

b) Legal

General Counsel's responsibilities include the provision of legal and corporate secretary services.

c) Internal Audit

The Internal Audit department provides auditing services as determined in an annual audit plan as part of the annual update of the Five-Year Internal Audit Plan.

d) Engineering Services

This division provides services in all engineering disciplines and covers such items as:

a) Design, construction and project management;

b) Engineering studies, technical specifications and construction coordination;

c) Tender preparation and analysis including interaction with consultants; and

d) Review and resolution of maintenance problems.

e) Environmental Services

The Environmental Services department's activities include auditing for compliance with government regulations and corporate policy, obtaining permits and approvals for proposed programs and advising on environmental matters.

[2] Excludes Hydro as Hydro has a separate Leadership team that supports Hydro only.

f) Financial Planning

The Investment Evaluation department provides services to facilitate the production, review and distribution of annual long-term financial plans. As well, they provide financial planning and analyses for various activities and scenarios.

h) Risk and Insurance

The Risk and Insurance department provides services related to the placement, policy and claims administration, risk control and risk financing of the corporate insurance program.

i) Finance

The Finance department provides accounting and treasury services.

j) Supply Chain Management

The Supply Chain Management department coordinates all efforts related to procurement process activities including tendering, purchasing and contract administration.

3.2.5 Fixed Charge

In addition to labour costs, a fixed rate will be applied to each hour of regular labour charged to lines of business. The fixed charge accounts for the additional cost, beyond basic salary and benefit costs, of having an employee available to provide service. The fixed charge recovers costs originally charged in the Administration Fee as well as other employee related costs, including:

- Telephone and fax;
- Books and subscriptions;
- Membership fees and dues;
- Conferences;
- Training; and
- Employee expenses (e.g. overtime meal allowance).

While most employees who provide intercompany services are located in Hydro Place, this rate will also be used as a proxy for employees working from other locations.

The fixed charge rate is reviewed annually and updated accordingly.

3.2.6 Materials Costs

Materials issued from inventory will be charged at cost to the applicable line of business.

3.2.7 Vehicle and Other Equipment Costs

Vehicles utilized across lines of business will be charged a rental rate which is based upon the type of vehicle utilized. The rental charge is calculated by multiplying the usage time by the daily or hourly rental rate for the applicable vehicle. The rental rates are updated annually.

3.2.8 Computers

Computer purchases are charged directly to the applicable line of business.

3.3 Type 3 – Cost Recovery Business Units

Certain functions incur costs on a cost recovery basis. In these cases, all costs associated with the activity are charged in accordance with the applicable cost recovery arrangements.

4.0 Billing and Collection

Invoices for the recovery of intercompany transactions are to be issued on a monthly basis. Billings to and from related entities shall be undertaken within 30 days of the end of the month in which the service, resource or asset is provided. Receivables between related companies are paid upon invoice receipt from a related entity. If the invoice is not paid in full within 30 days from the date of invoice, Finance will calculate an intercompany interest charge. The amount of the charge will be such that there is no net financing impact on the Company to which the balance is owed. Finance charges are calculated by applying a rate to the intercompany balance(s) that is equal to the cost of short-term financing for the Company to which the balance is owed. If the Company to which the balance is owed is Hydro, then the rate applied to such balances is the last approved WACC, which is currently 6.61% (2013 Amended GRA).

Exhibit 5 - Schedule I

Operating Bill Rate Components

Operating Bill Rate Components

Components of the operating bill rate are as follows:

- Salary Cost Components:
  - Salaries & Temporary Salaries including the payroll code for Easeback/Return to Work
  - Other Salary Costs - Retroactive Pay

- Mark Up Components:
  - Fringe Benefit Costs
    - Canada Pension Plan
    - Employment Insurance
    - Public Service Pension Plan
    - Group Money Purchase Plan
    - Prior Service Matched PSPP
    - Workplace Health Safety and Compensation Premiums
  - Insurances:
    - Life Insurances
    - A D&D Insurance
    - Medical Insurance
    - Dental Insurance
  - Company Costs:
    - Employee Future Benefits expense
    - Payroll Taxes
    - Other Salary Costs - Bonus, Performance Contracts & Signing Bonus
  - Leave:
    - All paid leave types.

Exhibit 6 – Capital Expenditures and Carryover Reports

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

CAPITAL EXPENDITURES AND CARRYOVER REPORT

For Year Ending December 31, 2015

March 2016

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO
CAPITAL EXPENDITURES AND CARRYOVER REPORT
For Year Ending December 31, 2015

TABLE OF CONTENTS

CAPITAL BUDGET OVERVIEW 1

CAPITAL EXPENDITURES BY YEAR 2

CAPITAL EXPENDITURES BY CATEGORY 3

VARIANCE EXPLANATIONS (GREATER THAN $100,000 and 10% Variance from Budget): 17

CAPITAL BUDGET VERSUS ACTUAL EXPENDITURES 2006 - 2015 32

CARRYOVER REPORT 33

REMOVE SAFETY HAZARDS 35

Total Capital Project Variance
2015 Overview
($000)

Asset Type	Board Approved Budget	Total Project Expenditures and Forecast	Variance
HYDRAULIC	14,243.1	13,558.6	(684.5)
THERMAL	9,953.5	10,740.1	786.6
GAS TURBINES	6,855.0	6,905.9	50.9
TERMINAL STATIONS	42,910.1	43,223.2	313.1
TRANSMISSION	5,010.5	5,238.4	227.9
DISTRIBUTION	31,384.6	29,862.3	(1,522.3)
RURAL GENERATION	25,574.3	23,121.4	(2,452.9)
PROPERTIES	3,312.8	3,230.4	(82.4)
METERING	2,054.0	2,010.4	(43.6)
RURAL SYSTEMS TOOLS AND EQUIPMENT	2,069.3	1,871.5	(197.8)
INFORMATION SYSTEMS	3,391.6	3,519.0	127.4
TELECONTROL	1,794.2	1,813.1	18.9
TRANSPORTATION	5,502.5	5,419.0	(83.5)
ADMINISTRATIVE	1,549.6	1,372.7	(176.9)
ALLOWANCE FOR UNFORESEEN	1,250.0	945.1	(304.9)
SUPPLEMENTAL PROJECTS	773,585.1	462,469.7	(311,115.4)
PROJECTS APPROVED FOR LESS THAN $50,000	554.5	493.2	(61.3)
TOTAL CAPITAL BUDGET	**930,994.7**	**615,794.0**	**(315,200.7)**

2015 Capital Expenditures By Year ($000)

Summary	Capital Budget[1]										Actual Expenditure and Forecast											
	A					B	C	D (B+C)	E	F (A+C+E)	G					H	I	J	K (G+H+I+J)	K-F	H-D
	2010	2011	2012	2013	2014	Carryover 2015	Original 2015[3]	Revised 2015[3]	2016 and Beyond	Total	2010	2011	2012	2013	2014[2]	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance
2015 Projects							65,471.2	65,471.2	29,309.7	94,780.9						55,850.2	29,269.4	4,792.1	89,911.7	(4,869.2)	(9,621.0)
2014 Projects					173,298.2	25,576.1	207,102.1	232,678.2	399,524.0	779,924.3					119,176.6	55,028.4	289,475.7	3,324.3	467,005.0	(312,919.3)	(177,649.8)
2013 Projects				8,851.1	29,588.6	10,030.9	836.1	10,867.0	1,983.5	41,259.3			76.6	2,505.4	26,816.5	12,157.1	1,983.5	183.1	43,722.2	2,462.9	1,290.1
2012 Projects			110.4	-	-	-	-	-	-	110.4			43.6	69.2	-	-	-	-	112.8	2.4	-
2011 Projects		750.7	704.3	720.0	738.9	798.1	758.5	1,556.6	-	3,672.4		391.1	332.4	657.0	735.3	1,228.8	-	-	3,344.6	(327.8)	(327.8)
2010 Projects	1,088.9	3,501.2	3,840.7	969.5	608.9	(634.5)	1,238.2	603.7	-	11,247.4	1,524.6	2,825.0	4,120.6	1,129.8	1,243.4	854.3	-	-	11,697.7	450.3	250.6
Grand Total	1,088.9	4,251.9	4,655.4	10,540.6	204,234.6	35,770.6	275,406.1	311,176.7	430,817.2	930,994.7	1,524.6	3,216.1	4,573.2	4,361.4	147,971.8	125,118.8	320,728.6	8,299.5	615,794.0	(315,200.7)	(186,057.9)

2015 Capital Budget Approved by Board Order No. P.U. 50(2014)	76,832.9
New Project Approved by Board Order No. 16(2014)	9,248.8
New Project Approved by Board Order No. 29(2014)	1,226.4
New Project Approved by Board Order No. 34(2014)	360.0
New Project Approved by Board Order No. 38(2014)	61.1
New Project Approved by Board Order No. 45(2014)[3]	1,238.2
New Project Approved by Board Order No. 53(2014)	18,964.7
New Project Approved by (O.C. 2014-033)[4]	163,145.3
New Project Approved by Board Order No. 24(2015)	1,536.3
New Project Approved by Board Order No. 27(2015)	327.9
New Project Approved by Board Order No. 29(2015)	1,249.3
New Project Approved by Board Order No. 31(2015)	500.1
New Project Approved by Board Order No. 34(2015)	250.0
2015 New Projects under $50,000 Approved by Hydro	465.1
Total Approved Capital Budget Before Carryovers	275,406.1
Carryovers from 2014 to 2015	35,770.6
TOTAL APPROVED CAPITAL BUDGET	311,176.7

[1] Annual budgets previous to 2015 pertain to projects that have expenditures in 2015.

[2] Includes Insurance Proceeds relating to Sunnyside - Transformer T1 Replacement ($1.8M).

[3] As per Board Order No. P.U. 45(2014) the Board did not approve the $0.2M Voltage Conversion - Labrador City actual costs over budget from 2010 to 2013. Hydro has excluded the $0.2M from average rate base.

[4] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014 of which $163.1M was included in the 2015 Capital Budget. The capital expenditures associated with this project are $11.6M as at December 31, 2015 and are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board of Commissioners of Public Utilities.

2015 Capital Expenditures By Category ($000)

Hydraulic Generation Projects	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	H-D	
	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2012	2013	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																		
Refurbish Unit Relay Protection - Paradise River	-	-	-	-	8.7	8.7	79.7	88.4	-	-	-	9.0	79.7	(0.3)	88.4	-	0.3	
Refurbish Generation Unit - Snook's Arm	-	-	-	-	352.9	352.9	-	352.9	-	-	-	315.0	-	-	315.0	(37.9)	(37.9)	
Replace Station Service Breakers - Cat Arm	-	-	-	-	644.9	644.9	363.4	1,008.3	-	-	-	646.1	363.4	(1.2)	1,008.3	-	1.2	
Refurbish Access Road - Cat Arm	-	-	-	-	990.0	990.0	-	990.0	-	-	-	939.8	-	-	939.8	(50.2)	(50.2)	
Replace ABB Exciter Unit 2 - Cat Arm	-	-	-	-	845.9	845.9	-	845.9	-	-	-	680.8	-	-	680.8	(165.1)	(165.1)	1
Replace Interior Coating on Surge Tank 3 - Bay d'Espoir	-	-	-	-	1,629.3	1,629.3	-	1,629.3	-	-	-	1,262.7	-	-	1,262.7	(366.6)	(366.6)	2
Rehabilitate Salmon River Spillway - Bay d'Espoir	-	-	-	-	745.6	745.6	556.8	1,302.4	-	-	-	522.9	556.8	222.7	1,302.4	-	(222.7)	3
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	-	-	-	-	14.7	14.7	633.3	648.0	-	-	-	8.1	633.3	6.6	648.0	-	(6.6)	
Automate Generator Deluge Systems - Bay d'Espoir	-	-	-	-	645.2	645.2	-	645.2	-	-	-	567.9	-	-	567.9	(77.3)	(77.3)	
Replace Pump House and Associated Equipment - Bay d'Espoir	-	-	-	-	22.7	22.7	522.5	545.2	-	-	-	137.0	522.5	(114.3)	545.2	-	114.3	4
Upgrade Public Safety Around Dams and Waterways - Various Sites	-	-	-	-	483.9	483.9	-	483.9	-	-	-	468.7	-	-	468.7	(15.2)	(15.2)	
Install Hydrometeorological Stations - Various Sites	-	-	-	-	377.9	377.9	-	377.9	-	-	-	372.2	-	-	372.2	(5.7)	(5.7)	
Upgrade Equipment Doors - Various Sites	-	-	-	-	348.5	348.5	-	348.5	-	-	-	285.4	-	63.1	348.5	-	(63.1)	
Refurbish Intakes - Bay d'Espoir	-	-	-	-	72.6	72.6	262.3	334.9	-	-	-	26.4	262.3	46.2	334.9	-	(46.2)	
Replace Automatic Greasing Systems Units 2 and 4 - Bay d'Espoir	-	-	-	-	254.4	254.4	-	254.4	-	-	-	231.5	-	-	231.5	(22.9)	(22.9)	
Install Infrared View Ports - Various Sites	-	-	-	-	83.7	83.7	113.1	196.8	-	-	-	54.7	113.1	29.0	196.8	-	(29.0)	
Replace Generator Bearing Coolers - Bay d'Espoir	-	-	-	-	153.8	153.8	-	153.8	-	-	-	132.2	-	-	132.2	(21.6)	(21.6)	
Overhaul Turbine/Generator Units - Bay d'Espoir and Paradise River	-	-	-	-	304.4	304.4	-	304.4	-	-	-	325.8	-	-	325.8	21.4	21.4	
Purchase Tools and Equipment Less than $50,000	-	-	-	-	108.6	108.6	-	108.6	-	-	-	75.2	-	-	75.2	(33.4)	(33.4)	
2014 Projects																		
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	-	110.2	(15.9)	1,201.9	1,186.0	-	1,312.1	-	-	126.1	640.2	-	545.8	1,312.1	-	(545.8)	5
Upgrade Victoria Control Structure - Bay d'Espoir	-	-	495.1	415.5	-	415.5	-	495.1	-	-	79.6	235.0	-	180.5	495.1	-	(180.5)	6
Upgrade Generator Bearings Unit 2 - Bay d'Espoir	-	-	18.9	9.5	396.0	405.5	-	414.9	-	-	9.4	252.8	-	-	262.2	(152.7)	(152.7)	7
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir	-	-	57.5	44.7	96.3	141.0	-	153.8	-	-	12.8	169.5	-	53.5	235.8	82.0	28.5	
Install Handheld Pendant to Overhead Crane - Bay d'Espoir	-	-	49.9	4.9	170.8	175.7	-	220.7	-	-	45.0	19.3	-	156.4	220.7	-	(156.4)	8
2013 Projects																		
Upgrade Units 1 to 6 By-Pass Valves - Bay d'Espoir	-	141.9	-	(43.1)	-	(43.1)	-	141.9	3.0	9.5	172.5	35.5	-	-	220.5	78.6	78.6	
Upgrade Burnt Dam Spillway - Bay d'Espoir	-	885.8	-	12.3	-	12.3	-	885.8	15.0	223.1	635.4	94.4	-	-	967.9	82.1	82.1	
Total Hydraulic Generation Projects	-	1,027.7	731.6	427.9	9,952.7	10,380.6	2,531.1	14,243.1	18.0	232.6	1,080.8	8,508.1	2,531.1	1,188.0	13,558.6	(684.5)	(1,872.5)	

2015 Capital Expenditures By Category ($000)

Thermal Generation Projects	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	H-D	
	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2012	2013	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																		
Overhaul Turbine Valves Unit 1 - Holyrood	-	-	-	-	1,577.5	1,577.5	-	1,577.5	-	-	-	1,707.6	-	-	1,707.6	130.1	130.1	
Overhaul Boiler Feed Pump East Unit 1 - Holyrood	-	-	-	-	196.3	196.3	-	196.3	-	-	-	215.2	-	-	215.2	18.9	18.9	
Replace DC Distribution Panels and Breakers - Holyrood	-	-	-	-	127.9	127.9	-	127.9	-	-	-	131.5	-	-	131.5	3.6	3.6	
Upgrade Powerhouse Roofing - Holyrood	-	-	-	-	1,047.8	1,047.8	-	1,047.8	-	-	-	802.9	-	244.9	1,047.8	-	(244.9)	9
Upgrade Quarry Brook Dam Equipment - Holyrood	-	-	-	-	498.7	498.7	-	498.7	-	-	-	490.9	-	-	490.9	(7.8)	(7.8)	
Upgrade Fire Protection (Main Warehouse) - Holyrood	-	-	-	-	46.2	46.2	197.6	243.8	-	-	-	76.4	197.6	(30.2)	243.8	-	30.2	
Overhaul Extraction Pumps - Holyrood	-	-	-	-	189.6	189.6	-	189.6	-	-	-	192.5	-	-	192.5	2.9	2.9	
Purchase Tools and Equipment Less than $50,000	-	-	-	-	15.7	15.7	-	15.7	-	-	-	15.5	-	-	15.5	(0.2)	(0.2)	
2014 Projects																		
Replace Economizer Inlet Valves - Holyrood	-	-	192.0	58.4	329.1	387.5	-	521.1	-	-	133.6	409.1	-	-	542.7	21.6	21.6	
Install Cold-Reheat Condensate Drains and High Pressure Heater Trip Level Unit 3 - Holyrood	-	-	49.8	(51.5)	467.4	415.9	-	517.2	-	-	101.3	453.9	-	-	555.2	38.0	38.0	
Upgrade Plant Elevators - Holyrood	-	-	533.2	(46.7)	-	(46.7)	-	533.2	-	-	579.9	309.3	-	-	889.2	356.0	356.0	10
Upgrade Vibration Monitoring System - Holyrood	-	-	524.9	48.1	-	48.1	-	524.9	-	-	476.8	31.7	-	-	508.5	(16.4)	(16.4)	
Install Fire Protection Upgrades - Holyrood	-	-	56.6	(255.4)	312.5	57.1	-	369.1	-	-	312.0	20.6	-	-	332.6	(36.5)	(36.5)	
Replace DC Distribution Panels and Breakers - Holyrood	-	-	174.2	148.6	-	148.6	-	174.2	-	-	25.6	159.7	-	-	185.3	11.1	11.1	
Purchase Tools and Equipment Less than $50,000	-	-	59.2	15.1	-	15.1	-	59.2	-	-	37.7	11.8	-	-	49.5	(9.7)	(3.3)	
2013 Projects																		
Install Variable Frequency Drives on Forced Draft Fans - Holyrood	-	697.6	2,659.7	390.7	-	390.7	-	3,357.3	13.8	206.0	2,746.8	665.7	-	-	3,632.3	275.0	275.0	11
Total Thermal Generation Projects	-	697.6	4,249.6	307.3	4,808.7	5,116.0	197.6	9,953.5	13.8	206.0	4,413.7	5,694.3	197.6	214.7	10,740.1	786.6	578.3	

2015 Capital Expenditures By Category ($000)

Gas Turbine Generation Projects	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	G			H	I	J	K (G+H+I+J)	K-F	H-D	
	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2012	2013	2014	2015	2016 and Beyond	Carryover to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																		
Upgrade Gas Turbine Plant Life Extension - Stephenville	-	-	-	-	2,655.2	2,655.2	2,525.4	5,180.6	-	-	-	2,613.6	2,525.4	41.6	5,180.6	-	(41.6)	
Replace Alternator Shaft - Happy Valley	-	-	-	-	484.4	484.4	-	484.4	-	-	-	131.1	-	320.0	451.1	(33.3)	(353.3)	12
2013 Projects																		
Upgrade Gas Turbine PLC - Happy Valley	-	61.4	1,128.6	734.2	-	734.2	-	1,190.0	2.3	22.6	430.9	818.4	-	-	1,274.2	84.2	84.2	
Total Gas Turbine Generation Projects	-	61.4	1,128.6	734.2	3,139.6	3,873.8	2,525.4	6,855.0	2.3	22.6	430.9	3,563.1	2,525.4	361.6	6,905.9	50.9	(310.7)	

2015 Capital Expenditures By Category ($000)

Terminal Stations Projects	Capital Budget									Actual Expenditure and Forecast										
	A				B	C	D (B+C)	E	F (A+C+E)	G				H	I	J	K (G+H+I+J)	K-F	H-D	
	2011	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2011	2012	2013	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																				
Upgrade Circuit Breakers - Various Sites (2015-2016)	-	-	-	-	-	6,189.1	6,189.1	6,873.8	13,062.9	-	-	-	-	7,570.4	6,873.8	(1,381.3)	13,062.9	-	1,381.3	13
Replace Surge Arrestors - Various Sites	-	-	-	-	-	198.1	198.1	-	198.1	-	-	-	-	172.2	-	-	172.2	(25.9)	(25.9)	
Install Transformer On line Gas Monitoring - Various Sites	-	-	-	-	-	700.5	700.5	975.7	1,676.2	-	-	-	-	786.5	975.7	(86.0)	1,676.2	-	86.0	
Upgrade Power Transformers - Various Sites	-	-	-	-	-	4,440.4	4,440.4	7,002.3	11,442.7	-	-	-	-	2,357.3	7,002.3	2,083.1	11,442.7	-	(2,083.1)	14
Replace Disconnect Switches - Various Sites (2015-2016)	-	-	-	-	-	963.7	963.7	642.9	1,606.6	-	-	-	-	563.1	642.9	400.6	1,606.6	-	(400.6)	15
Design and Install Fire Protection in 230 kV Station - Various Sites	-	-	-	-	-	67.6	67.6	424.3	491.9	-	-	-	-	74.9	424.3	(7.3)	491.9	-	7.3	
Perform Site Work for Mobile Substation - Barachoix	-	-	-	-	-	489.3	489.3	-	489.3	-	-	-	-	516.5	-	-	516.5	27.2	27.2	
Upgrade Terminal Station Protection and Control - Various Sites	-	-	-	-	-	172.7	172.7	307.2	479.9	-	-	-	-	162.5	307.2	10.2	479.9	-	(10.2)	
Upgrade Terminal Station Foundations - Various Sites	-	-	-	-	-	302.3	302.3	-	302.3	-	-	-	-	313.1	-	-	313.1	10.8	10.8	
Upgrade Control Wiring Phase 1 to Terminal Station 1 - Bay d'Espoir	-	-	-	-	-	301.0	301.0	-	301.0	-	-	-	-	336.3	-	-	336.3	35.3	35.3	
Install Support Structures C2 Capacitor Bank - Hardwoods	-	-	-	-	-	199.3	199.3	-	199.3	-	-	-	-	58.0	-	26.4	84.4	(114.9)	(141.3)	16
Replace Station Lighting - Bay d'Espoir	-	-	-	-	-	16.7	16.7	160.3	177.0	-	-	-	-	20.0	160.3	(3.3)	177.0	-	3.3	
Upgrade Transformer Differential Protection - Grandy Brook	-	-	-	-	-	154.0	154.0	-	154.0	-	-	-	-	75.0	-	-	75.0	(79.0)	(79.0)	
2014 Projects																				
Upgrade Circuit Breakers - Various Sites	-	-	-	3,695.4	2,123.7	1,642.5	3,766.2	-	5,337.9	-	-	-	1,571.7	4,167.5	-	-	5,739.2	401.3	401.3	17
Replace Disconnect Switches - Various Sites	-	-	-	815.9	667.5	189.5	857.0	-	1,005.4	-	-	-	148.4	939.7	-	-	1,088.1	82.7	82.7	
Replace Optimho Relays on TL203 - Western Avalon to Sunnyside	-	-	-	89.1	70.9	96.9	167.8	-	186.0	-	-	-	18.2	200.7	-	-	218.9	32.9	32.9	
2013 Projects																				
Replace Instrument Transformers - Various Sites	-	-	593.2	552.8	206.7	538.4	745.1	1,983.5	3,667.9	-	9.6	230.7	699.0	755.5	1,983.5	(10.4)	3,667.9	-	10.4	
Replace Insulators - Various Sites	-	-	187.1	287.9	41.6	-	41.6	-	475.0	-	5.1	67.0	361.3	68.0	-	-	501.4	26.4	26.4	
2011 Projects																				
Perform Grounding Upgrades - Various Sites	321.2	324.0	329.0	337.1	51.8	345.4	397.2	-	1,656.7	287.6	240.7	507.2	224.0	313.5	-	-	1,573.0	(83.7)	(83.7)	
Total Terminal Stations Projects	321.2	324.0	1,109.3	5,778.2	3,162.2	17,007.4	20,169.6	18,370.0	42,910.1	287.6	255.4	804.9	3,022.6	19,450.7	18,370.0	1,032.0	43,223.2	313.1	(718.9)	

2015 Capital Expenditures by Category ($000)

Transmission Projects	Capital Budget						Actual Expenditure and Forecast								
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	Original 2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects														
Perform Wood Pole Line Management Program - Various Sites	-	-	2,830.6	2,830.6	-	2,830.6	-	3,058.5	-	-	3,058.5	227.9	227.9	
2014 Projects														
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	1,191.7	980.2	988.2	1,968.4	-	2,179.9	211.5	28.2	1,940.0	0.2	2,179.9	-	(1,940.2)	18
Total Transmission Projects	1,191.7	980.2	3,818.8	4,799.0	-	5,010.5	211.5	3,086.7	1,940.0	0.2	5,238.4	227.9	(1,712.3)	

2015 Capital Expenditures By Category ($000)

Distribution Projects	Capital Budget										Actual Expenditure and Forecast												
	A					B	C	D (B+C)	E	F (A+C+E)	G					H	I	J	K (G+H+IJ)	K-F	H-D		
	2010	2011	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2010	2011	2012	2013	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes	
2015 Projects																							
Construct Second Distribution Feeder - Nain	-	-	-	-	-	-	1,050.3	1,050.3	-	1,050.3	-	-	-	-	-	1,139.4	-	-	1,139.4	89.1	89.1		
Relocate Voltage Regulator - Hawkes Bay	-	-	-	-	-	-	166.4	166.4	-	166.4	-	-	-	-	-	116.6	-	-	116.6	(49.8)	(49.8)		
Provide Service Extensions - All Service Areas	-	-	-	-	-	-	6,328.0	6,328.0	-	6,328.0	-	-	-	-	-	4,797.0	-	-	4,797.0	(1,531.0)	(1,531.0)	19	
Provide Service Extensions - All Service Areas - CIAC	-	-	-	-	-	-	(248.0)	(248.0)	-	(248.0)	-	-	-	-	-	(214.7)	-	-	(214.7)	33.3	33.3		
Upgrade Distribution Systems - All Service Areas	-	-	-	-	-	-	3,402.0	3,402.0	-	3,402.0	-	-	-	-	-	2,985.7	-	-	2,985.7	(416.3)	(416.3)	20	
Upgrade Distribution Systems - All Service Areas - CIAC	-	-	-	-	-	-	(62.0)	(62.0)	-	(62.0)	-	-	-	-	-	0.8	-	-	0.8	62.8	62.8		
Upgrade Distribution Systems - Various Sites (2015/2016)	-	-	-	-	-	-	1,136.1	1,136.1	818.8	1,954.9	-	-	-	-	-	1,379.1	818.8	(243.0)	1,954.9	-	243.0	21	
2014 Projects																							
Replace Recloser Control Panels - Various Sites	-	-	-	-	111.3	26.3	84.4	110.7	-	195.7	-	-	-	-	85.0	147.7	-	-	232.7	37.0	37.0		
Upgrade Distribution Systems - Various Sites (2014/2015)	-	-	-	-	2,499.8	177.1	4,850.1	5,027.2	-	7,349.9	-	-	-	-	2,142.5	5,009.7	-	-	7,152.2	(197.7)	(17.5)		
2010 Projects																							
Voltage Conversion - Labrador City[5]	1,088.9	3,501.2	3,840.7	969.5	608.9	-634.5	1238.2	603.7	-	11,247.4	1,524.6	2,825.0	4,120.6	1,129.8	1,243.4	854.3	-	-	11,697.7	450.3	250.6	22	
Total Distribution Projects	1,088.9	3,501.2	3,840.7	969.5	3,220.0	(431.1)	17,945.5	17,514.4	818.8	31,384.6	1,524.6	2,825.0	4,120.6	1,129.8	3,470.9	16,215.6	818.8	(243.0)	29,862.3	(1,522.3)	(1,298.8)		

[3] As per Board Order No. P.U. 45(2014) the Board did not approve the $0.2M Voltage Conversion - Labrador City actual costs over budget from 2010 to 2013. Hydro has excluded the $0.2M from average rate base.

2015 Capital Expenditures By Category ($000)

Rural Generation Projects	Capital Budget									Actual Expenditure and Forecast										
	A				B	C	D (B+C)	E	F (A+C+E)	G				H	I	J	K (G+H+I+J)	K-F	H-D	
	2011	2012	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2011	2012	2013	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																				
Overhaul Diesel Units - Various Sites	-	-	-	-	-	1,199.2	1,199.2	-	1,199.2	-	-	-	-	958.4	-	240.8	1,199.2	-	(240.8)	23
Install Disconnect Switches for Mobile Generators - Various Sites	-	-	-	-	-	10.0	10.0	189.3	199.3	-	-	-	-	7.8	189.3	2.2	199.3	-	(2.2)	
Inspect Fuel Storage Tanks - Various Sites	-	-	-	-	-	1,761.1	1,761.1	-	1,761.1	-	-	-	-	769.3	-	-	769.3	(991.8)	(991.8)	24
Increase Fuel Storage - Rigolet	-	-	-	-	-	1,666.8	1,666.8	-	1,666.8	-	-	-	-	837.1	-	-	837.1	(829.7)	(829.7)	25
Upgrade Ventilation Systems - Various Sites	-	-	-	-	-	175.9	175.9	317.3	493.2	-	-	-	-	245.6	317.3	(69.7)	493.2	-	69.7	
Upgrade Building Exterior - Makkovik	-	-	-	-	-	309.5	309.5	-	309.5	-	-	-	-	229.8	-	-	229.8	(79.7)	(79.7)	
Increase Generation Capacity - Makkovik	-	-	-	-	-	272.6	272.6	-	272.6	-	-	-	-	221.3	-	-	221.3	(51.3)	(51.3)	
Replace Unit 2038 - Mary's Harbour	-	-	-	-	-	103.5	103.5	1,241.5	1,345.0	-	-	-	-	101.7	1,241.5	1.8	1,345.0	-	(1.8)	
Replace Unit 254 - Paradise River	-	-	-	-	-	66.8	66.8	429.3	496.1	-	-	-	-	80.5	429.3	(13.7)	496.1	-	13.7	
Replace Programmable Logic Controllers - Various Sites	-	-	-	-	-	366.9	366.9	591.1	958.0	-	-	-	-	397.2	591.1	(30.3)	958.0	-	30.3	
Install Fire Protection - L'Anse au Loup	-	-	-	-	-	220.6	220.6	1,126.2	1,346.8	-	-	-	-	96.4	1,126.2	124.2	1,346.8	-	(124.2)	26
2014 Projects																				
Install Fire Protection System - Nain	-	-	-	107.1	66.4	892.2	958.6	-	999.3	-	-	-	40.7	33.1	-	-	73.8	(925.5)	(925.5)	27
Construct Storage Facility - Postville	-	-	-	183.8	177.8	-	177.8	-	183.8	-	-	-	66.7	164.2	-	-	230.9	47.1	(13.6)	
Upgrade Diesel Plant Production Data Collection Equipment - Various Sites	-	-	-	268.9	161.1	269.8	430.9	280.7	819.4	-	-	-	107.8	57.8	280.7	3.1	449.4	(370.0)	(373.1)	28
2013 Projects																				
Additions for Load Isolator Generation Stations - Various Sites	-	-	2,040.2	9,357.9	4,310.1	-	4,310.1	-	11,398.1	-	27.8	1196.4	6,853.5	3,916.4	-	393.7	12,387.8	989.7	(393.7)	
2012 Projects																				
Perform FEED for Diesel Plant Remediation - Various Sites	-	110.4	-	-	-	-	-	-	110.4	-	43.6	69.2	-	-	-	-	112.8	2.4	-	
2011 Projects																				
Perform Arc Flash Remediation - Various Sites	429.5	380.3	391.0	401.8	746.3	413.1	1,159.4	-	2,015.7	103.5	91.7	149.8	511.3	915.3	-	-	1,771.6	(244.1)	(244.1)	29
Total Rural Generation Projects	429.5	490.7	2,431.2	10,319.5	5,461.7	7,728.0	13,189.7	4,175.4	25,574.3	103.5	163.1	1,415.4	7,580.0	9,031.9	4,175.4	652.1	23,121.4	(2,452.9)	(4,157.8)	

2015 Capital Expenditures By Category ($000)

Properties Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects														
Replace Accommodations and Septic System - Ebbegunbaeg	-	-	489.4	489.4	1,061.4	1,550.8	-	94.2	1,061.4	395.2	1,550.8	-	(395.2)	30
Upgrade Line Depots - Various Sites	-	-	953.3	953.3	-	953.3	-	877.0	-	-	877.0	(76.3)	(76.3)	
Reshingle Roof - Stephenville	-	-	76.8	76.8	-	76.8	-	74.9	-	-	74.9	(1.9)	(1.9)	
Install Fall Protection Equipment - Various Sites	-	-	198.9	198.9	-	198.9	-	180.7	-	-	180.7	(18.2)	(18.2)	
Upgrade HVAC System - Port Saunders	-	-	137.0	137.0	-	137.0	-	150.2	-	-	150.2	13.2	13.2	
Legal Survey of Primary Distribution Line Right of Ways - Various Sites 2015	-	-	158.6	158.6	40.3	198.9	-	200.0	-	-	200.0	1.1	41.4	
2014 Projects														
Legal Survey of Primary Distribution Line Right of Ways - Various Sites 2014	156.8	(90.6)	40.3	(50.3)	-	197.1	247.3	(50.5)	-	-	196.8	(0.3)	(0.2)	
Total Properties Projects	156.8	(90.6)	2,054.3	1,963.7	1,101.7	3,312.8	247.3	1,526.5	1,061.4	395.2	3,230.4	(82.4)	(437.2)	

2015 Capital Expenditures By Category ($000)

Metering Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects														
Purchase Meters, Equipment and Metering Tanks - Various Sites	-	-	196.2	196.2	-	196.2	-	235.0	-	-	235.0	38.8	38.8	
Install Automatic Meter Reading - Various Sites (2015-2016)	-	-	559.9	559.9	401.8	961.7	-	90.6	401.8	469.3	961.7	-	(469.3)	31
2014 Projects														
Purchase Meters, Equipment and Metering Tanks - Various Sites	199.0	61.4	-	61.4	-	199.0	137.6	12.3	-	-	149.9	(49.1)	(49.1)	
Install Automatic Meter Reading - Various Sites (2014-2015)	356.9	23.7	340.2	363.9	-	697.1	333.2	330.6	-	-	663.8	(33.3)	(33.3)	
Total Metering Projects	555.9	85.1	1,096.3	1,181.4	401.8	2,054.0	470.8	668.5	401.8	469.3	2,010.4	(43.6)	(512.9)	

2015 Capital Expenditures By Category ($000)

Tools and Equipment	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects														
Replace Light Duty Mobile Equipment - Various Sites	-	-	494.4	494.4	-	494.4	-	423.1	-	-	423.1	(71.3)	(71.3)	
Replace Off Road Track Vehicles - Unit 7861, Stephenville (2015-2016)	-	-	1.1	1.1	397.8	398.9	-	176.8	397.8	(175.7)	398.9	-	175.7	32
Tools and Equipment Less than $50,000	-	-	622.7	622.7	-	622.7	-	563.1	-	35.8	598.9	(23.8)	(59.6)	
2014 Projects														
Tools and Equipment Less than $50,000	553.3	31.3	-	31.3	-	553.3	416.7	33.9	-	-	450.6	(102.7)	2.6	33
Total Tools and Equipment	553.3	31.3	1,118.2	1,149.5	397.8	2,069.3	416.7	1,196.9	397.8	(139.9)	1,871.5	(197.8)	47.4	

2015 Capital Expenditures By Category ($000)

Information Systems Projects	Capital Budget							Actual Expenditure and Forecast						K-F	H-D	
	A		B	C	D (B+C)	E	F (A+C+E)	G		H	I	J	K (G+H+I+J)			
	2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2013	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																
Perform Minor Application Enhancements - Hydro Place	-	-	-	329.5	329.5	-	329.5	-	-	482.1	-	-	482.1	152.6	152.6	34
Cost Recoveries	-	-	-	(141.6)	(141.6)	-	(141.6)	-	-	(205.9)	-	-	(205.9)	(64.3)	(64.3)	
Upgrade Energy Management System - Hydro Place	-	-	-	194.9	194.9	-	194.9	-	-	185.1	-	-	185.1	(9.8)	(9.8)	
Upgrade Lotus Notes - Hydro Place	-	-	-	635.4	635.4	-	635.4	-	-	559.2	-	-	559.2	(76.2)	(76.2)	
Cost Recoveries	-	-	-	(273.1)	(273.1)	-	(273.1)	-	-	(240.4)	-	-	(240.4)	32.7	32.7	
Replace Customer Care System - Hydro Place	-	-	-	134.9	134.9	-	134.9	-	-	141.0	-	-	141.0	6.1	6.1	
Replace Peripheral Infrastructure - Various Sites	-	-	-	200.5	200.5	-	200.5	-	-	201.7	-	-	201.7	1.2	1.2	
Upgrade Enterprise Storage Capacity - Hydro Place	-	-	-	621.3	621.3	-	621.3	-	-	627.7	-	-	627.7	6.4	6.4	
Cost Recoveries	-	-	-	(267.0)	(267.0)	-	(267.0)	-	-	(269.9)	-	-	(269.9)	(2.9)	(2.9)	
Replace Personal Computers - Various Sites	-	-	-	573.3	573.3	-	573.3	-	-	570.5	-	-	570.5	(2.8)	(2.8)	
Upgrade Server Technology Program - Hydro Place	-	-	-	601.3	601.3	-	601.3	-	-	639.8	-	-	639.8	38.5	38.5	
Cost Recoveries	-	-	-	(227.1)	(227.1)	-	(227.1)	-	-	(234.1)	-	-	(234.1)	(7.0)	(7.0)	
2013 Projects																
Upgrade Microsoft Project - Hydro Place	656.7	455.1	14.4	465.2	479.6	-	1,577.0	619.6	477.8	562.3	-	-	1,659.7	82.7	82.7	
Cost Recoveries	(236.4)	(163.8)	(5.1)	(167.5)	(172.6)	-	(567.7)	(223.1)	(172.0)	(202.4)	-	-	(597.5)	(29.8)	(29.8)	
Total Information Systems Projects	420.3	291.3	9.3	2,680.0	2,689.3	-	3,391.6	396.5	305.8	2,816.7	-	-	3,519.0	127.4	127.4	

2015 Capital Expenditures By Category ($000)

Telecontrol Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects														
Purchase Tools and Equipment less than $50,000	-	-	45.6	45.6	-	45.6	-	49.6	-	-	49.6	4.0	4.0	
Replace Network Communications Equipment - Various Sites	-	-	169.5	169.5	-	169.5	-	170.2	-	-	170.2	0.7	0.7	
Upgrade Site Facilities - Various Sites	-	-	48.3	48.3	-	48.3	-	51.7	-	-	51.7	3.4	3.4	
Replace Telephone Systems - Various Sites	-	-	132.7	132.7	-	132.7	-	145.5	-	-	145.5	12.8	12.8	
Replace WIFI Access Points - Various Sites	-	-	126.3	126.3	-	126.3	-	137.8	-	-	137.8	11.5	11.5	
Replace GDC Metroplex - Various Sites	-	-	69.2	69.2	-	69.2	-	38.7	-	30.5	69.2	-	(30.5)	
Replace DTI Phone Turrets Energy Control Center - Hydro Place	-	-	44.7	44.7	-	44.7	-	29.8	-	-	29.8	(14.9)	(14.9)	
2014 Projects														
Replace Battery Banks and Chargers - Various Sites	267.0	(26.5)	398.0	371.5	-	665.0	293.5	275.4	-	-	568.9	(96.1)	(96.1)	
Upgrade IP SCADA Network - Various Sites	254.2	109.4	238.7	348.1	-	492.9	144.8	445.6	-	-	590.4	97.5	97.5	
Total Telecontrol Projects	521.2	82.9	1,273.0	1,355.9	-	1,794.2	438.3	1,344.3	-	30.5	1,813.1	18.9	(11.6)	

2015 Capital Expenditures By Category ($000)

Transportation	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects														
Replace Vehicles and Aerial Devices - Hydro System (2015-2016)	-	-	2377.1	2,377.1	225.3	2,602.4	-	1,734.9	225.3	642.2	2,602.4	-	(642.2)	35
2014 Projects														
Replace Vehicles and Aerial Devices - Various Sites (2014-2015)	1809.1	908.6	1,091.0	1,999.6	-	2,900.1	900.5	1,916.1	-	-	2,816.6	(83.5)	(83.5)	
Total Transportation	1,809.1	908.6	3,468.1	4,376.7	225.3	5,502.5	900.5	3,651.0	225.3	642.2	5,419.0	(83.5)	(725.7)	

Administrative	Capital Budget						Actual Expenditure and Forecast							
	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	2014	2015	2016 and Beyond	Carryovers to 2016	Total	Variance	Annual Variance	Notes
2015 Projects														
Remove Safety Hazards - Various Sites - 2015	-	-	194.9	194.9	-	194.9	-	176.9	-	-	176.9	(18.0)	(18.0)	
Replace Roof - Hydro Place	-	-	671.9	671.9	-	671.9	-	623.2	-	-	623.2	(48.7)	(48.7)	
Replace Cooling Tower and Auxiliaries - Hydro Place	-	-	45.7	45.7	311.3	357.0	-	52.5	311.3	(6.8)	357.0	-	6.8	
Purchase Tools and Equipment less than $50,000	-	-	68.0	68.0	-	68.0	-	18.6	-	-	18.6	(49.4)	(49.4)	
2014 Projects														
Remove Safety Hazards - Various Sites - 2014	257.8	50.2	-	50.2	-	257.8	207.6	(10.6)	-	-	197.0	(60.8)	(60.8)	
Total Administrative	257.8	50.2	980.5	1,030.7	311.3	1,549.6	207.6	860.6	311.3	(6.8)	1,372.7	(176.9)	(170.1)	

2015 Capital Expenditures By Category ($000)

Allowance For Unforeseen

	Capital Budget A 2013	A 2014	B Carryover 2014	C Original 2015	D (B+C) Revised 2015	E 2016 and Beyond	F (A+C+E) Total	Actual Expenditure and Forecast G 2013	G 2014	H 2015	I 2016 and Beyond	J Carryover to 2016	K (G+H+I+J) Total	K-F Project Variance	H-D Annual Variance	Notes
2015 Projects																
Contingency Fund	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	-	-	(1,000.0)	(1,000.0)	
Additional Allowance for Unforeseen - Board Order No. P.U. 34(2015)	-	-	-	250.0	250.0	-	250.0	-	-	-	-	-	-	(250.0)	(250.0)	
Unit Service Transformer for Unit 3 - Holyrood Thermal Generating Station								-	-	75.8	-	-	75.8	75.8	75.8	
Perform Upgrades - Western Avalon Transformer T5 Tap Changer								-	-	869.3	-	-	869.3	869.3	869.3	
Total Allowance For Unforeseen	-	-	-	1,250.0	1,250.0	-	1,250.0	-	-	945.1	-	-	945.1	(304.9)	(304.9)	36

Supplemental Projects

	Capital Budget 2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	Actual Expenditure and Forecast 2013	2014	2015	2016 and Beyond	Carryover to 2016	Total	Project Variance	Annual Variance	Notes
2015 Projects																
Purchase Critical Spares Generation Stations	-	-	-	1,536.3	1,536.3	-	1,536.3	-	-	495.2	-	1,041.1	1,536.3	-	(1,041.1)	37
Replace Rectifier Transformers - Holyrood Units 1 and 2	-	-	-	327.9	327.9	428.3	756.2	-	-	32.0	428.3	295.9	756.2	-	(295.9)	38
Hardwoods Gas Turbine Engine Refurbishment	-	-	-	1,249.3	1,249.3	-	1,249.3	-	-	1,252.1	-	-	1,252.1	2.8	2.8	
Internal Assessment and Repair of Transformer VBN T1	-	-	-	500.1	500.1	-	500.1	-	-	321.7	-	178.4	500.1	-	(178.4)	39
2014 Projects																
100 MW (Nominal) Combustion Turbine Addition - Holyrood	-	109,677.0	14,241.5	9,248.8	23,490.3	-	118,925.8	-	95,435.5	33,061.3	-	-	128,496.8	9,571.0	9,571.0	40
Labrador West Transmission Project - Construction Phase[6]	-	37,484.2	-	163,145.3	163,145.3	128,962.6	329,592.1	-	10,996.0	628.0	-	-	11,624.0	(317,968.1)	(162,517.3)	41
Transformer T1 Replacement - Sunnyside[7]	-	7,197.8	2,135.1	1,226.4	3,361.5	-	8,424.2	-	3,236.7	1,549.7	-	-	4,786.4	(3,637.8)	(1,811.8)	42
Excitation Transformers Replacement - Bay d'Espoir	-	636.7	255.7	360.0	615.7	-	996.7	-	381.0	659.6	-	-	1,040.6	43.9	43.9	
Replace Unit #1 Air Compressor - Holyrood	-	259.5	145.6	61.1	206.7	-	320.6	-	113.9	205.5	-	-	319.4	(1.2)	(1.2)	
Purchase of Critical Spares	-	491.8	491.8	-	491.8	-	491.8	-	-	491.8	-	-	491.8	-	-	
230 kV Transmission Line - Bay d'Espoir to Western Avalon	-	2,412.6	2,412.6	18,964.7	21,377.3	270,280.7	291,658.0	-	-	2,018.2	287,255.0	2,384.8	291,658.0	-	(19,359.1)	43
2013 Projects																
Increase 230 kV Transformer Capacity - Oxen Pond	3,823.6	15,310.4	4,369.1	-	4,369.1	-	19,134.0	153.6	14,611.3	5,443.3	-	(200.2)	20,008.0	874.0	1,074.2	44
Total Supplemental Projects Approved by PUB	3,823.6	173,470.0	24,051.4	196,619.9	220,671.3	399,671.6	773,585.1	153.6	124,774.4	46,158.4	287,683.3	3,700.0	462,469.7	(311,115.4)	(174,512.9)	

Projects Less than $50,000

	Capital Budget 2013	2014	Carryover 2014	Original 2015	Revised 2015	2016 and Beyond	Total	Actual Expenditure and Forecast 2013	2014	2015	2016 and Beyond	Carryover to 2016	Total	Variance	Annual Variance	Notes
2015 Projects																
Replace Pumps on Mobile Transformer P235 - Bishop's Falls	-	-	-	30.4	30.4	-	30.4	-	-	30.2	-	-	30.2	(0.2)	(0.2)	
Replace Generator Unit # 580 - William's Harbour	-	-	-	9.8	9.8	-	9.8	-	-	10.0	-	-	10.0	0.2	0.2	
Purchase Pick-Up - Holyrood Gas Turbine	-	-	-	36.7	36.7	-	36.7	-	-	27.2	-	-	27.2	(9.5)	(9.5)	
Replace 125VDC Battery Bank - Paradise River Hydro Plant	-	-	-	45.9	45.9	-	45.9	-	-	29.1	-	-	29.1	(16.8)	(16.8)	
Elevator Fire Alarm Tie-in - Holyrood	-	-	-	41.7	41.7	-	41.7	-	-	46.0	-	-	46.0	4.3	4.3	
Replace Unit 7 Carbon Seal - Bay d'Espoir	-	-	-	49.2	49.2	-	49.2	-	-	46.6	-	-	46.6	(2.6)	(2.6)	
Replace Unit 7 Turbine Base Plate - Bay d'Espoir	-	-	-	49.4	49.4	-	49.4	-	-	46.4	-	-	46.4	(3.0)	(3.0)	
Spare Turbine Bearing Refurbishment Unit 1-6 - Bay d'Espoir	-	-	-	47.4	47.4	-	47.4	-	-	37.2	-	-	37.2	(10.2)	(10.2)	
Replace Unit 1 Turbine Guide Gearing - Bay d'Espoir	-	-	-	40.3	40.3	-	40.3	-	-	49.5	-	-	49.5	9.2	9.2	
Replace Valve Breaker B12L42 - Holyrood TS	-	-	-	34.0	34.0	-	34.0	-	-	-	-	-	-	(34.0)	(34.0)	
Purchase Portable Generating Unit - Oxen Pond TS	-	-	-	28.0	28.0	-	28.0	-	-	28.0	-	-	28.0	-	-	
Replace Horizontal Fuel Tanks - St. Anthony Diesel Plant	-	-	-	48.8	48.8	-	48.8	-	-	50.1	-	-	50.1	1.3	1.3	
Thrust Bearing Refurbishment Units 1 - 6, Bay d'Espoir	-	-	-	2.5	2.5	41.2	43.7	-	-	0.1	41.2	2.4	43.7	-	(2.4)	
Replace Interupter Bottom Brook Breaker B3L50	-	-	-	1.0	1.0	48.2	49.2	-	-	-	48.2	1.0	49.2	-	(1.0)	
Total Projects Less than $50,000	-	-	-	465.1	465.1	89.4	554.5	-	-	400.4	89.4	3.4	493.2	(61.3)	(64.7)	

[6] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014. The capital expenditures associated with this project are $11.6M as at December 31, 2015 and are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board of Commissioners of Public Utilities.

[7] Includes Insurance Proceeds relating to Sunnyside - Transformer T1 Replacement ($1.8M).

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

The projects discussed in the following section have variances of more than 10% and $100,000 when comparing budget to the 2015 expenditure, whether it is a single year project or a multiyear project. Also discussed are projects where there is a total project variance that is greater than 10% and $100,000. The projects are ordered and numbered for explanation below based on the order and number they appear in the preceding set of tables.

The majority of projects noted were executed against a Class 3 estimate that was completed for the Capital Budget Application. A Class 3 estimate is considered to have an accuracy range of -20% to +30% based on the total project budget. There is also generally a 20% contingency applied to the projects.

Hydraulic Generation Projects

1. Replace ABB Exciter Unit 2 - Cat Arm (2015)

Budget: $845.9 **Total: $680.8** **Variance: ($165.1)**

This project is complete. The project costs for exciter manufacturing were lower than estimated. The variance is also attributable to contingency funds not being required.

2. Replace Interior Coating on Surge Tank 3 - Bay d'Espoir (2015)

Budget: $1,629.3 **Total: $1,262.7** **Variance: ($366.6)**

This project is complete. The approved budget included a structural inspection as well as anticipated repairs resulting from the findings of the inspection report. The inspection report determined that structural repairs and associated costs were not required. The variance is also attributable to the contingency funds not being required.

3. Rehabilitate Salmon River Spillway - Bay d'Espoir (2015-2016)

Budget: $745.6 **Total: $522.9** **Variance: ($222.7)**

This is a two-year project that commenced in 2015. A portion of the scope has been rescheduled from 2015 to 2016. There is no change to the total project budget, scope or completion date. The installation of the gate drive brakes was rescheduled from 2015 to 2016 due to a vendor supply issue. The gate

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

heater replacement was rescheduled from 2015 to 2016 to allow for re-planning of the work to lower the safety risk during construction.

4. Replace Pump House and Associated Equipment - Bay d'Espoir (2015-2016)

Budget: $22.7 Total: $137.0 Variance: $114.3

This is a two-year project that commenced in 2015. The original project schedule included engineering design from November 2015 to February 2016. The annual variance is due to the fact that engineering work was advanced and largely completed in 2015. There is no change to the overall project scope, budget or completion date.

5. Upgrade Burnt Dam Spillway - Bay d'Espoir (2014-2015)

Budget: $1,186.0 Total: $640.2 Variance: ($545.8)

This project is partially complete with the remaining scope carried into for 2016. The engineering and procurement of the diesel generator units took longer than estimated in order to ensure best available control technology in compliance with Air Pollution Control Regulations. Electrical upgrades to the Burnt Dam structure and replacement of the stop-log seals were completed later in 2015 than originally scheduled. In order to avoid congestion at site and ensure safe execution of the remaining work, the upgrades to the emergency backup hydraulic system and the mechanical gate inspection were rescheduled for 2016. The total project budget is presently being re-forecasted, and any resultant material change will be discussed with the Board.

6. Upgrade Victoria Control Structure - Bay d'Espoir (2014-2015)

Budget: $415.5 Total: $235.0 Variance: ($180.5)

This is a two-year project that commenced in 2014. The project is partially complete with the remaining scope carried into for 2016. Electrical scope and civil assessment portions of this project were completed in 2015. Due to ongoing work at Burnt Dam in 2015, the start of work at Victoria Control Structure was delayed, so as not to have both Burnt Dam and Victoria systems out of service concurrently. The late

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

start resulted in the mechanical scope being rescheduled to 2016. The total project budget is presently being re-forecasted, and any resultant material change will be discussed with the Board.

7. Upgrade Generator Bearings Unit 2 - Bay d'Espoir (2014)

Budget: $414.9 Total: $262.2 Variance: ($152.7)

This project is complete. The original project scope included modification of the guide bearing segments and modifications to the bearing oil pot covers in order to reduce generator bearing oil leakage. Upon reviewing the impacts of the modification to the bearing guide, as completed on Unit 2 in 2014 (a separate project), it was decided to only replace bearing oil pot covers and not modify the generator guide bearing segments for remaining generating units, as this achieved the desired project intent. The variance is also attributable to the contingency funds not being required.

8. Install Handheld Pendant to Overhead Crane - Bay d'Espoir (2014-2015)

Budget: $175.7 Total: $19.3 Variance: ($156.4)

This is a two-year project that commenced in 2014. The engineering and procurement for this project are complete and construction is rescheduled for 2016. This is a carryover but not a change to the total project budget or scope. During acceptance testing of the replacement parts, it was determined that additional parts were required which were not available until late December 2015. The cost of the additional parts was the responsibility of the vendor and thus did not impact the project cost.

Thermal Generation Projects

9. Upgrade Powerhouse Roofing - Holyrood (2015)

Budget: $1,047.8 Total: $802.9 Variance: ($244.9)

This was a single year project scheduled for completion in 2015. This project is partially complete with the remaining scope rescheduled for 2016. There is no change to the total project budget or scope. Due to weather delays that exceeded the estimated weather allowance originally included in the project plan, a portion of the roofing work was rescheduled to 2016.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

10. Upgrade Plant Elevators - Holyrood (2014)

Budget: $533.2 Total: $889.2 Variance: $356.0

This project is complete. The overall project costs included labour associated with working in a confined space. This cost was not included in the original estimate as it was not identified as a confined space. Additionally, prior to a return of service, a provincial inspector required additional upgrades that were not included in the original budget.

11. Install Variable Frequency Drives on Forced Draft Fans - Holyrood

Budget: $390.7 Total: $665.7 Variance: $275.0

This project is complete. This was a two year project that was originally planned to be completed in 2014 but was carried over into 2015. The project was completed within 10% of the total approved budget. The annual variance is attributable to engineering rework required to address issues identified during commissioning.

Gas Turbine Generation Projects

12. Replace Alternator Shaft - Happy Valley (2015)

Budget: $484.4 Total: $131.1 Variance: ($353.3)

This was a single year project scheduled for completion in 2015. The project engineering and procurement are complete and construction has been rescheduled for 2016. There is no change to the project total budget or scope. Upon delivery of the long lead equipment in the fall of 2015 it was decided, from a winter readiness perspective, that it would be more prudent to complete this work in the spring of 2016. The unit's availability through the winter was not impacted by this carry over.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

Terminal Stations Projects

13. Upgrade Circuit Breakers - Various Sites (2015-2016)

Budget: $6,189.1 Total: $7,570.4 Variance: $1,381.3

This is a two year project that commenced in 2015 and is a portion of an ongoing program to replace circuit breakers. Some breaker procurement was advanced from 2016 to 2015 to allow implementation flexibility and to enhance early 2016 work implementation to meet winter readiness timelines. The project is expected to be completed on budget.

14. Upgrade Power Transformers - Various Sites (2015-2016)

Budget: $4,440.4 Total: $2,357.3 Variance: ($2,083.1)

This is a two year project that commenced in 2015. The variance from the planned 2015 expenditures is primarily attributable to Cat Arm and Bay d'Espoir Generating Stations transformer orders being placed later than planned.

15. Replace Disconnect Switches - Various Sites (2015-2016)

Budget: $963.7 Total: $563.1 Variance: ($400.6)

This is a two year project that commenced in 2015. There is no change to the overall project scope, budget, or completion date. The detailed project planning completed in early 2015 resulted in more of the procurement being scheduled in 2015 and a greater portion of the construction scheduled for 2016. This resulted in a net negative variance in 2015 actual expenditure against the original planned expenditure, but no impact on overall project budget.

16. Install Support Structures C2 Capacitor Bank - Hardwoods (2015)

Budget: $199.3 Total: $58.0 Variance: ($141.3)

This was a single year project scheduled for completion in 2015. The project engineering and procurement are complete and construction has been rescheduled for 2016. A less costly design to address the original issue is anticipated to result in an overall budget reduction. The deferral of the

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

construction work to 2016 was based on winter readiness planning and a review of impacts on system capacity and reliability; the work was rescheduled to coordinate with the replacement of a disconnect switch (another project), thereby further reducing costs.

17. Upgrade Circuit Breakers - Various Sites (2014-2015)

Budget: $3,766.2 Total: $4,167.5 Variance: $401.3

This project is complete and the overall project variance was within 10% of approved budget. The variance from the annual planned 2015 expenditure is attributable to increased engineering and field work associated with breaker controls.

Transmission Projects

18. Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside (2014)

Budget: $1,968.4 Total: $28.2 Variance: ($1,940.2)

This project commenced in 2014. The engineering is complete and during project planning, it was decided to align construction with execution of the new transmission line between Bay d'Espoir and Western Avalon Terminal Stations, which is along the same corridor. The new line was approved by the Board under Order No. P. U. 53(2014) on December 12, 2014. The alignment of this project with the construction of the transmission line will result in overall cost savings to the project as well as a reduced environmental impact.

Distribution Projects

19. Provide Service Extensions - All Service Areas (2015)

Budget: $6,328.0 Total: $4,797.0 Variance: ($1,531.0)

This is a one year project with budget based on previous years expenditures to provide service extensions to customers. The budget and actual expenditures in 2015 are shown by area in table below. The annual variance is primarily due to less than expected service extensions in Labrador than in

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

previous years due to the economic climate in Labrador, resulting in fewer customer requests requiring extensions. The service extension numbers in Labrador are customer driven.

	Budget ($000)	Actual ($000)	Variance ($000)
Central	1,710.0	1,869.7	159.7
Northern	1,570.0	1,661.5	91.5
Labrador	3,048.0	1,265.8	(1,782.2)
Total	6,328.0	4,797.0	(1,531.0)

20. Upgrade Distribution Systems - All Service Areas (2015)

Budget: $3,402.0 Total: $2,985.7 Variance: ($416.3)

This is a one year project with budget based on previous years expenditures to provide distribution upgrades to customers. The budget and actual expenditures in 2015 are shown by area in table below. The variance is primarily due to less than expected distribution upgrades in Northern than in the previous years.

	Budget ($000)	Actual ($000)	Variance ($000)
Central	1,735.0	1,900.0	165.0
Northern	1,217.0	735.7	(481.3)
Labrador	450.0	350.0	(100.0)
Total	3,402.0	2,985.7	(416.3)

21. Upgrade Distribution Systems - Various Sites (2015-2016)

Budget: $1,136.1 Total: $1,379.1 Variance: $243.0

This is a multiyear project that began in 2015. There is no overall change to the project budget or completion date. The annual variance is attributable to work on the Farewell Head distribution system which included the replacement of additional cross arms and hardware to facilitate insulator replacement on Fogo Island. The cost of the additional cross arms was absorbed through the project contingency. As well, for the Bottom Waters system upgrade, a portion of the engineering design was advanced from 2016 to 2015.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

22. Voltage Conversion - Labrador City (2010)

Budget: $603.7 Total: $854.3 Variance: $250.6

This multi-year project is complete and the overall project variance was within 10% of approved budget. Annual variance is due to higher than planned execution costs.

Rural Generation Projects

23. Overhaul Diesel Units - Various Sites (2015)

Budget: $1,199.2 Total: $958.4 Variance: ($240.8)

This is a one year project to overhaul diesel units that are being carried over into 2016. The variance in project cost is mostly due to the late delivery of material.

24. Inspect Fuel Storage Tanks - Various Sites (2015)

Budget: $1,761.1 Total: $769.3 Variance: ($991.8)

This one-year project is complete. Resultant work from inspections was less than expected at Hardwoods Gas Turbine, McCallum and Port Hope Simpson Diesel Plants. In addition, the project contract prices were lower than estimated. One tank in L'Anse au Loup was inspected and condemned by the inspector. Following consultation with the Board, it was agreed to replace the tank under this project using available budget as any attempt to repair the tank would have exceeded the cost to replace.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

25. Increase Fuel Storage - Rigolet (2015)

Budget: $1,666.8 Total: $837.1 Variance: ($829.7)

This one-year project is complete. The contract and corresponding on-site supervision costs were significantly lower than estimated. The variance is also attributable to the contingency funds not being required.

26. Install Fire Protection - L'Anse au Loup (2015-2016)

Budget: $220.6 Total: $96.4 Variance: ($124.2)

This is a two year project that commenced in 2015. The annual variance is attributed to rescheduling a portion of the engineering design and procurement activity into 2016 Q1.

27. Install Fire Protection System - Nain (2014)

Budget: $999.3 Total: $73.8 Variance: ($925.5)

This is a multi-year project that commenced in 2014. Early in 2015, project spending was suspended when it was determined that the approved budget was inadequate to complete the planned scope of work. A revised project proposal was submitted as part of the 2016 Capital Budget Application and subsequently approved. This project will now be executed as part of the 2016 budget.

28. Upgrade Diesel Plant Production Data Collection Equipment - Various Sites (2014-2016)

Budget: $430.9 Total: $57.8 Variance: ($373.1)

This is a three-year project that commenced in 2014. There is no change to the overall scope or completion date. The variance from the planned 2015 expenditure is primarily related to an overestimation of engineering and construction costs. It is anticipated that the project will be completed in 2016 under budget.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

29. Perform Arc Flash Remediation - Various Sites (2011-2015)

Budget: $2,015.7 Total: $1,771.6 Variance: ($244.1)

This was a five year project initiated in 2011 to perform arc flash hazard remediation. The planned work is complete and the project is closed. The variance is primarily attributable to the contingency funds not being required.

Properties Projects

30. Replace Accommodations and Septic System - Ebbegunbaeg (2015-2016)

Budget: $489.4 Total: $94.2 Variance: ($395.2)

This is a two year project that commenced in 2015. There is no change to the total project budget, scope or completion date. Due to the requirement for an environmental assessment and flood study, the bridge installation and road upgrades planned for 2015 were rescheduled to 2016.

Metering Projects

31. Install Automatic Meter Reading - Various Sites (2015-2016)

Budget: $559.9 Total: $90.6 Variance: ($469.3)

This is a two year project that commenced in 2015. There is no change to the total project budget, scope or completion date. The procurement of the new meters was originally planned to be received in December 2015. Delivery is now expected in 2016 Q1 with no risk to overall project completion.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

Tools and Equipment Projects

32. Replace Off Road Track Vehicles - Unit 7861 - Stephenville (2015-2016)

Budget:	$1.1	Total:	$176.8	Variance:	$175.7

This is a two-year project, with two years required due to the timing of delivery post ordering. The variance in the 2015 planned expenditure is primarily due to early arrival of the equipment.

33. Tools and Equipment Less than $50,000 (2014)

Budget:	$555.3	Total:	$450.6	Variance:	($102.7)

The overall project variance is primarily due to the cancellation of the replacement of a material ramp until the completion of a condition assessment.

Information Systems Projects

34. Perform Minor Application Enhancements - Hydro Place (2015)

Budget:	$329.5	Total:	$482.1	Variance:	$152.6

This is a one-year project that was completed in 2015. The variance was primarily for additional minor enhancements that were not anticipated.

Transportation Projects

35. Replace Vehicles and Aerial Devices - Hydro System (2015-2016)

Budget:	$2,377.1	Total:	$1,734.9	Variance:	($642.2)

This is a two-year project initiated in 2015. The variance from 2015 planned expenditure is related to timing of material delivery. Various chassis manufacturers were delayed in supplying chassis to the up fitters, including five chassis and six van conversions.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

36. Allowance For Unforeseen

Budget: $1,250.0 Total: $945.1 Variance: ($304.9)

The Allowance for Unforeseen is an annual allotment that permits Hydro to act expeditiously to deal with events affecting the electrical system which cannot wait for specific approval of the Board. Unforeseen expenditures for 2015 under this account include costs associated with the Inspection and Repair of Unit Service Transformer (UST-3) for Unit 3 at Holyrood Thermal Generating Station and Performing Upgrades to the Western Avalon Terminal Station Transformer T5 Tap Changer. Reports on these items have been filed with the Board of Commissioners of Public Utilities (the Board).

The annual budget for Allowance for Unforeseen is $1,000,000. Hydro applied for and the Board approved a supplementary amount of $250,000 to be added to the balance in the Allowance for Unforeseen (P.U. 34(2015)).

Supplemental Projects

37. Purchase Critical Spares - Generation Stations (2015)

Budget: $1,563.3 Total: $495.2 Variance: ($1,041.1)

A number of the critical spares included in this project have lead times in excess of nine months. Orders for materials were placed upon Board approval, and therefore, materials will be received in 2016. While no additional funding is required to complete the project, the project will not be completed until 2016.

38. Replace Excitation Transformers - Holyrood Units 1 and 2 (2015)

Budget: $327.9 Total: $32.0 Variance: ($295.9)

This is a supplemental project approved by the Board in 2015 Q4. There is no overall change to the total project budget, scope or completion date. The transformers were originally planned to be received in 2015 Q4 but were actually received in 2016 Q1.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

39. Internal Assessment and Repair of Transformer VBN T1 (2015)

Budget: $500.1 Total: $321.7 Variance: ($178.4)

This is a supplemental project approved by the Board in 2015 Q4. This project was initiated and substantially completed in 2015. The scope included a major internal inspection and an allowance for repairs; however substantial repairs were not required. The project carried into 2016 for final testing and project completion. It is anticipated that the project will close under budget.

40. 100 MW (Nominal) Combustion Turbine Addition - Holyrood (2014)

Budget: $23,490.3 Total: $33,061.3 Variance: $9,571.0

This was a two year project initiated in 2014 and is now complete. The overall project variance was within 10% of approved budget. The variance from the planned 2015 expenditure was mainly attributed to the higher than budgeted cost for the building. The main contributors to the higher than budgeted cost for the building were generally as follows:

1. Building construction progress was impacted for safety considerations associated with constructing the building in parallel with and around other work fronts. Also, there were many interruptions of heavy lifts and other aerial work due to high winds and inclement weather.

2. As the priority was to get the CT into operation, a phased approach to building construction was implemented to accommodate priority work fronts. This significantly extended the construction phase of the building.

3. Increased building complexity due to interface with the turbine generator. In particular, the Heating Ventilation Air Conditioning (HVAC) system is complex due to the nature of the equipment that is being housed in the building. Also, the fire protection system is complex due to the nature of the equipment that is being protected and integrated with the HVAC system. Fire protection system design is in full compliance with FM Global standards.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

41. Labrador West Transmission Project - Construction Phase (2014)

Budget: $163,145.3 Total: $628.0 Variance: ($162,517.3)

In 2014, the Provincial Government approved the construction of the third transmission line in Labrador to help supply power for planned new developments in Labrador West, such as the Kami Iron Ore Project, and improve reliability for all customers in the region. In September 2014, work on the line was temporarily suspended until completion of Alderon's financing plan which resulted in 2015 expenditures being lower than budgeted. All project costs incurred to date, including the 2015 Interest During Constriction costs, are covered by the security Alderon has already provided. Construction will proceed should additional funding be secured.

42. Transformer T1 Replacement - Sunnyside (2014-2015)

Budget: $8,424.2 Total: $4,786.4 Variance: ($3,637.8)

This project is complete. The variance from 2015 planned expenditure is attributed to a cost recovery from insurance proceeds and lower than estimated materials and installation costs. The variance is also attributable to the contingency funds not being required.

43. 230 kV Transmission Line - Bay d'Espoir to Western Avalon (2014-2018)

Budget: $21,377.3 Total: $2,018.2 Variance: ($19,359.1)

The original budget for 2015 was $21.4M. The revised 2015 expenditure for TL267 as submitted to the Board in the 2016 Capital Budget Application on August 1 was $4.4M. As of the end of 2015, the actual expenditure was $2.018M. The noted differences were in the areas of Project Management and Engineering, where efficiencies have been realized by expanding upon the work already completed for similar designs. The work plan to this point is on schedule, with only engineering possible at this time given that the project has not been released from Environmental Assessment. The unused funds will be carried over to 2016 for the continuation and completion of engineering and the start of construction, given the relatively early stage of the project.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

44. Increase 230 kV Transformer Capacity - Oxen Pond (2013-2014)

Budget: $4,369.1 **Total: $5,443.3** **Variance: $1,074.2**

This is a multiyear project that commenced in 2013, was substantially completed in 2014 and 2015, and has been carried into 2016 to complete project deficiencies. The approved project scope included work at both Oxen Pond and Hardwoods Terminal Stations. The overall project variance at completion will be within 10% of approved budget. The annual variance from the 2015 planned expenditures is attributed to higher than anticipated contract costs associated with additional purchase and processing of transformer oil to achieve required quality, and overall higher contract pricing.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 VARIANCE EXPLANATIONS
FOR THE YEAR ENDING DECEMBER 31, 2015
(Greater than $100,000 and 10% Variance from Budget)
($000)

Captial Budgets/Expenditures 2006-2015

Year	Budget	Actual Expenditures	Variance	Percentage Variance
2006	49,024	41,217	7,807	15.9%
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%
2009	61,544	54,152	7,392	12.0%
2010	63,297	55,553	7,744	12.2%
2011	67,454	63,116	4,338	6.4%
2012	93,840	77,252	16,588	17.7%
2013	116,373	84,755	31,618	27.2%
2014	280,601	204,728	75,873	27.0%
2015	311,177	125,119	186,058	59.8%

The 2015 variance in actual expenditures compared to budget is primarily attributable to:

- $163.0M associated with work that was planned to be completed in 2015 on the Labrador West Transmission Line[1] however was not completed due to a temporary suspension of the work in September 2014. Work is suspended until completion of Alderon's financing plan for the Kami mine.
- $19.4M variance is related to the original 2015 budget for 230 kV Transmission Line - Bay d'Espoir to Western Avalon (TL267) project. This budget was revised in early 2015 to $4.4M, and the actual expenditure in 2015 was $2.0M.

[1] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014. The capital expenditures associated with this project are $11,624,000 as at December 31, 2015 and are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board.

2015 Carryover Report
For the Year Ending December 31, 2015
($000)

Project Name	PUB Approved Budget 2015	Revised Budget 2015	Total Actual Expenditures 2015	Carryover Amount	Original Completion Year
Replace GDC Metroplex - Various Sites	69.2	69.2	38.7	30.5	2015
Upgrade Burnt Dam Spillway - Bay d'Espoir	1,186.0	1,186.0	640.2	545.8	2015
Upgrade Victoria Control Structure - Bay d'Espoir	415.5	415.5	235.0	180.5	2015
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir	141.0	223.0	169.5	53.5	2015
Install Handheld Pendant to Overhead Crane - Bay d'Espoir	175.7	175.7	19.3	156.4	2015
Upgrade Equipment Doors - Various Sites	348.5	348.5	285.4	63.1	2015
Purchase of Critical Spares - Generation Stations	1,536.3	1,536.3	495.2	1,041.1	2015
Upgrade Powerhouse Roofing - Holyrood	1,047.8	1,047.8	802.9	244.9	2015
Increase 230kV Transformer Capacity - Oxen Pond	4,369.1	5,243.1	5,443.3	(200.2)	2015
Install Support Structures C2 Capacitor Bank - Hardwoods	199.3	84.4	58.0	26.4	2015
Internal Assessment and Repair of Transformer VBN T1	500.1	500.1	321.7	178.4	2015
Overhaul Diesel Units - Various Sites	1,199.2	1,199.2	958.4	240.8	2015
Additions for Load Isolator Generation Stations - Various Sites	4,310.1	4,310.1	3,916.4	393.7	2014
Tools and Equipment Less than $50,000	622.7	622.7	0.0	35.8	2015
Replace Alternator Shaft - Happy Valley	484.4	451.1	131.1	320.0	2015
Install Automatic Meter Reading - Various Sites (2015-2016)	559.9	559.9	90.6	469.3	2016
Refurbish Unit Relay Protection - Paradise River	8.7	8.7	9.0	(0.3)	2016
Replace Station Service Breakers - Cat Arm	644.9	644.9	646.1	(1.2)	2016
Rehabilitate Salmon River Spillway - Bay d'Espoir	745.6	745.6	522.9	222.7	2016
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	14.7	14.7	8.1	6.6	2016
Replace Pump House and Associated Equipment - Bay d'Espoir	22.7	22.7	137.0	(114.3)	2016
Refurbish Intakes - Bay d'Espoir	72.6	72.6	26.4	46.2	2016
Install Infrared View Ports - Various Sites	83.7	83.7	54.7	29.0	2016
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	489.4	94.2	395.2	2016

2015 Carryover Report
For the Year Ending December 31, 2015
($000)

Project Name	PUB Approved Budget 2015	Revised Budget 2015	Total Actual Expenditures 2015	Carryover Amount	Original Completion Year
Thrust Bearing Refurbishment Units 1 - 6, Bay d'Espoir	2.5	2.5	0.1	2.4	2016
Replace Rectifier Transformers - Holyrood Units 1 and 2	327.9	327.9	32.0	295.9	2016
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	46.2	76.4	(30.2)	2016
Replace Instrument Transformers - Various Sites	745.1	745.1	755.5	(10.4)	2017
Upgrade Circuit Breakers - Various Sites (2015-2016)	6,189.1	6,189.1	7,570.4	(1,381.3)	2016
Install Transformer On line Gas Monitoring - Various Sites	700.5	700.5	786.5	(86.0)	2016
Upgrade Power Transformers - Various Sites	4,440.4	4,440.4	2,357.3	2,083.1	2016
Replace Disconnect Switches - Various Sites (2015-2016)	963.7	963.7	563.1	400.6	2016
Design and Install Fire Protection in 230 kV Station - Various Sites	67.6	67.6	74.9	(7.3)	2016
Upgrade Terminal Station Protection and Control - Various Sites	172.7	172.7	162.5	10.2	2016
Replace Station Lighting - Bay d'Espoir	16.7	16.7	20.0	(3.3)	2016
Replace Interupter Bottom Brook Breaker B3L50	1.0	1.0	0.0	1.0	2016
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	2,655.2	2,613.6	41.6	2016
Upgrade Diesel Plant Production Data Collection Equipment-Various	430.9	60.9	57.8	3.1	2016
Install Disconnect Switches for Mobile Generators - Various Sites	10.0	10.0	7.8	2.2	2016
Replace Vehicles and Aerial Devices Hydro System (2015-2016)	2,377.1	2,377.1	1,734.9	642.2	2016
Replace Off Road Track Vehicles - Unit 7861, Stephenville (2015-2016)	1.1	1.1	176.8	(175.7)	2016
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	1,968.4	28.4	28.2	0.2	2017
Construct 230kV Transmission Line - Bay d'Espoir to Western Avalon	21,377.3	4,403.0	2,018.2	2,384.8	2018
Upgrade Distribution Systems - Various Sites (2015/2016)	1,136.1	1,136.1	1,379.1	(243.0)	2016
Upgrade Ventilation Systems - Various Sites	175.9	175.9	245.6	(69.7)	2016
Replace Unit 2038 - Mary's Harbour	103.5	103.5	101.7	1.8	2016
Replace Unit 254 - Paradise River	66.8	66.8	80.5	(13.7)	2016
Replace Programmable Logic Controllers - Various Sites	366.9	366.9	397.2	(30.3)	2017
Install Fire Protection - L'Anse au Loup	220.6	220.6	96.4	124.2	2016
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	45.7	52.5	(6.8)	2016
Total Carryover Amount				8,299.5	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 REMOVE SAFETY HAZARDS
FOR THE YEAR ENDING DECEMBER 31, 2015
($000)

Total Approved Budget: **$194,900**
Total Expenditure: **$176,891**

Board Order P.U. 38(2010)

As part of Board Order No. P.U. 38(2010) 2011 Capital Budget, the following was included: "Because of the nature of this project the Board would expect to see an explanation in Hydro's annual report on capital expenditures as to each project that was undertaken, setting out the safety hazard that was identified, the location, the steps taken to address the issue and the amount of the expenditure." Please see the following table for projects undertaken in 2014:

Safety Hazards

Project Title/Location	Expenditure	Safety Hazard Identified	Project Scope
Resurface deteriorated concrete floor to remove safety hazards	$34.9	The concrete floor of the Wastewater Treatment Plant (WWTP) dyke is in rough shape with the majority of the concrete surface eroded. This poses a safety issue. When a chemical spill occurs it is difficult to do a proper clean up. The chemical residue will become lodged in the cracked and peeling concrete surface leaving behind hazardous waste in the dyke. The deteriorating surface no longer has any chemical resistant coating remaining, therefore the problem will continue to progress. This has also created a tripping hazard when working in the WWTP dyke. The concrete floor in the Chemical Storage Building poses similar safety risks. The rough uneven surface interferes with the proper clean-up of a spill due to hazardous chemicals becoming lodge in the cracked concrete. If spills cannot be cleaned up properly, hazardous waste is left behind posing a safety risk to those entering the storage facility. The concrete sealer is deteriorating and sections are pealing from the floor creating a slipping and tripping hazard from the dislodged sections.	Resurfacing of the concrete floors in the WWTP dyke and the chemical storage building.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 REMOVE SAFETY HAZARDS
FOR THE YEAR ENDING DECEMBER 31, 2015
($000)

Safety Hazards

Project Title/Location	Expenditure	Safety Hazard Identified	Project Scope
Install safe walkway on Oil Tank #1 roof	$142.0	Testing concluded that the roof plate for Tank #1 was under the minimal required thickness. An evaluation of the fuel oil storage tanks, associated pipelines and dyked drainage system was carried out at Holyrood by SGE Acres Limited. The study concluded that large areas of the Tank #1 roof plate were below the minimum required thickness of 0.09 inches; based on samples that were taken for testing. There is a risk of a worker falling through the roof plate into a large batch of bunker C oil which can result in death.	Construction of a walkway on the heavy fuel oil Tank #1 roof to allow safe access for operation of the east and west fuel oil suction heater valves.

Capital Expenditures and Carryover Report
For the Year Ended December 31, 2016

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1.0 Capital Budget Overview 1
2.0 Capital Expenditures by Year 2
3.0 Capital Expenditures by Category 4
4.0 Variance Explanations (Greater than $100,000 and 10% Variance from Budget) 19
5.0 Capital Budget Verses Actual Expenditures 2007 – 2016 40
6.0 Carryover Report 41
7.0 Safety Hazards 44

1.0 Capital Budget Overview

During 2016, Hydro invested $205 million to execute capital projects to contribute to the provision of safe, reliable and least-cost electricity to the people of the province. This included $59 million expended for the construction of a new transmission line between Bay d'Espoir and Western Avalon Terminal Stations. This project was released from environmental assessment in June of 2016. Significant engineering, procurement and construction activities were completed in 2016 and will continue in 2017. A significant portion of the overall capital investment included sustaining capital to replace boiler tubes for Units 1 and 2 and to overhaul the turbine and generator for Unit 3 at Holyrood Thermal Generating Station. There were also significant investments in power transformers and circuit breakers.

Table 1

Total Capital Project Variance
2016 Overview
($000)

Asset Type	Board Approved Budget	Total Project Expenditures and Forecast	Variance
HYDRAULIC	28,981	28,312	(669)
THERMAL	17,094	19,500	2,406
GAS TURBINES	6,125	6,656	531
TERMINAL STATIONS	122,691	125,064	2,373
TRANSMISSION	326,871	327,155	284
DISTRIBUTION	19,464	19,210	(255)
RURAL GENERATION	34,197	34,589	392
PROPERTIES	4,553	4,193	(360)
METERING	2,119	2,588	468
RURAL SYSTEMS TOOLS AND EQUIPMENT	2,159	1,762	(396)
INFORMATION SYSTEMS	4,433	4,363	(69)
TELECONTROL	5,583	5,683	100
TRANSPORTATION	5,135	5,069	(66)
ADMINISTRATIVE	1,633	1,382	(251)
ALLOWANCE FOR UNFORESEEN	3,000	13,667	10,667
SUPPLEMENTAL PROJECTS	361,387	42,500	(318,888)
PROJECTS APPROVED FOR LESS THAN $50,000	362	333	(29)
TOTAL CAPITAL BUDGET	**945,787**	**642,024**	**(303,764)**

2.0 Capital Expenditures by Year

The following tables provide a summary of Hydro's Capital Expenditures by Year for the period 2012-2017.

[rest of page intentionally left blank]

Table 2

2016 Capital Expenditures By Year
($000)

Summary	Capital Budget[1]								Actual Expenditure and Forecast									
	A				B	C	D (B+C)	E	F (A+C+E)	G				H	I	J	K (G+H+I+J)	K-F	H-D
	2012	2013	2014	2015	Carryover 2016	Original 2016	Revised 2016	2017 and Beyond	Total	2012	2013	2014	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance
2016 Projects						106,199.7	106,199.7	120,950.2	227,149.9					105,800.6	120,950.2	9,556.0	236,306.8	9,156.9	(399.1)
2015 Projects				28,736.9	4,792.1	29,024.3	33,816.4	245.1	58,006.3				23,772.8	34,334.5	245.1	1,118.2	59,470.6	1,464.3	518.1
2014 Projects			38,677.3	169,315.5	3,324.3	205,566.0	208,890.3	212,872.3	626,431.1			11,578.8	3,796.2	62,032.2	205,115.0	27,270.5	309,792.7	(316,638.4)	(146,858.1)
2013 Projects		6,457.0	25,221.1	538.4	183.1	1,511.7	1,694.8	471.9	34,200.1	37.4	1,580.7	22,163.8	10,115.2	1,773.7	471.9	311.0	36,453.7	2,253.6	78.9
Grand Total	-	6,457.0	63,898.4	198,590.8	8,299.5	342,301.7	350,601.2	334,539.5	945,787.4	37.4	1,580.7	33,742.6	37,684.2	203,941.0	326,782.2	38,255.7	642,023.8	(303,763.6)	(146,660.2)

2016 Capital Budget Approved by Board Order No. P.U. 33(2015)	183,082.8
New Project Approved by (O.C. 2014-033)[2]	128,962.6
New Project Approved by Board Order No. P.U. 27(2015)	428.3
New Project Approved by Board Order No. P.U. 8(2016)	1,000.0
New Project Approved by Board Order No. P.U. 17 & P.U. 23 (2016)	4,700.0
New Project Approved by Board Order No. 19 (2016)	11,800.0
New Project Approved by Board Order No. 20 (2016)	717.0
New Project Approved by Board Order No. 22 (2016)	3,047.1
New Project Approved by Board Order No. 28 (2016)	1,977.3
New Project Approved by Board Order No. 37 (2016)	490.0
New Project Approved by Board Order No. 40 (2016)	4,738.3
New Project Approved by Board Order No. 48 (2016)	1,000.0
2016 New Projects under $50,000 Approved by Hydro	358.3
Total Approved Capital Budget Before Carryovers	342,301.7
Carryovers from 2015 to 2016	8,299.5
TOTAL APPROVED CAPITAL BUDGET	350,601.2

[1] Annual budgets previous to 2016 pertain to projects that have expenditures in 2016.

[2] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014. The capital expenditures associated with this project are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board of Commissioners of Public Utilities.

3.0 Capital Expenditures by Category

The following tables provide Hydro's Capital Expenditures by category including: Hydraulic Generation, Thermal Generation, Gas Turbine Generation, Terminal Stations, Transmission, Distribution, Rural Generation, Properties, Metering, Tools and Equipment, Information Systems, and Telecontrol Projects.

[rest of page intentionally left blank]

Table 3

2016 Capital Expenditures By Category ($000)

Hydraulic Generation Projects	Capital Budget							Actual Expenditure and Forecast								
	A		B	C	D (B+C)	E	F (A+C+E)	G		H	I	J	K (G+H+I+J)	K-F	H-D	
	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2014	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects																
Install Hydrometeorological Equipment - Various Sites	-	-	-	314.1	314.1	-	314.1	-	-	4.3	-	309.8	314.1	-	(309.8)	1
Perform Condition Assessment of Control Structures - Hinds Lake	-	-	-	323.4	323.4	-	323.4	-	-	351.1	-	-	351.1	27.7	27.7	
Replace Generator Cooling Water Piping - Hinds Lake	-	-	-	181.7	181.7	-	181.7	-	-	278.4	-	-	278.4	96.7	96.7	
Replace Control Room/Communications Room Air Conditioning - Hinds Lake	-	-	-	41.3	41.3	53.0	94.3	-	-	31.0	53.0	10.3	94.3	-	(10.3)	
Refurbish Station Water System - Upper Salmon	-	-	-	96.6	96.6	197.6	294.2	-	-	38.3	197.6	58.3	294.2	-	(58.3)	
Upgrade Work - Cat Arm	-	-	-	558.3	558.3	1,353.0	1,911.3	-	-	240.4	1,353.0	317.9	1,911.3	-	(317.9)	2
Rehabilitate Shoreline Protection - Cat Arm	-	-	-	112.2	112.2	1,030.7	1,142.9	-	-	104.7	1,030.7	7.5	1,142.9	-	(7.5)	
Replace Site Facilities - Bay d'Espoir	-	-	-	928.3	928.3	11,053.0	11,981.3	-	-	270.4	11,053.0	657.9	11,981.3	-	(657.9)	3
Replace Interior and Exterior Protective Coating on Surge Tank 2 - Bay d'Espoir	-	-	-	2,959.6	2,959.6	-	2,959.6	-	-	2,735.7	-	-	2,735.7	(223.9)	(223.9)	
Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir	-	-	-	477.6	477.6	-	477.6	-	-	334.7	-	-	334.7	(142.9)	(142.9)	4
Replace PH1 Station Service Transformer - Bay d'Espoir	-	-	-	46.7	46.7	354.5	401.2	-	-	45.0	354.5	1.7	401.2	-	(1.7)	
Replace Monitoring Vibration System Unit 7 - Bay d'Espoir	-	-	-	366.0	366.0	-	366.0	-	-	272.1	-	-	272.1	(93.9)	(93.9)	
Replace Spherical By-Pass Valves Units 1 and 2 - Bay d'Espoir	-	-	-	183.6	183.6	167.9	351.5	-	-	154.8	167.9	28.8	351.5	-	(28.8)	
Assess Vent Chambers Units 1 to 6 - Bay d'Espoir	-	-	-	85.7	85.7	-	85.7	-	-	85.7	-	-	85.7	-	-	
Overhaul Turbine/Generator Units #6 and #7 - Bay d'Espoir	-	-	-	1,345.6	1,345.6	-	1,345.6	-	-	544.5	-	56.2	600.7	(744.9)	(801.1)	5
Purchase Tools and Equipment Less than $ 50,000	-	-	-	96.1	96.1	-	96.1	-	-	90.8	-	-	90.8	(5.3)	(5.3)	
2015 Projects																
Refurbish Unit Relay Protection - Paradise River	-	8.7	(0.3)	79.7	79.4	-	88.4	-	9.0	129.1	-	-	138.1	49.7	49.7	
Replace Station Service Breakers - Cat Arm	-	644.9	(1.2)	363.4	362.2	-	1,008.3	-	646.1	185.9	-	176.3	1,008.3	-	(176.3)	6
Rehabilitate Salmon River Spillway - Bay d'Espoir	-	745.6	222.7	556.8	779.5	-	1,302.4	-	522.9	871.1	-	-	1,394.0	91.6	91.6	
Upgrade Generator Bearings Units 1 and 3 - Bay d'Espoir	-	14.7	6.6	633.3	639.9	-	648.0	-	8.1	277.1	-	-	285.2	(362.8)	(362.8)	7
Replace Pump House and Associated Equipment - Bay d'Espoir	-	22.7	(114.3)	522.5	408.2	-	545.2	-	137.0	128.6	-	279.6	545.2	-	(279.6)	8
Upgrade Equipment Doors - Various Sites	-	348.5	63.1	0.0	63.1	-	348.5	-	285.4	115.4	-	46.7	447.5	99.0	52.3	
Refurbish Intakes - Bay d'Espoir	-	72.6	46.2	262.3	308.5	-	334.9	-	26.4	262.2	-	-	288.6	(46.3)	(46.3)	
Install Infrared View Ports - Various Sites	-	83.7	29.0	113.1	142.1	-	196.8	-	54.7	151.3	-	-	206.0	9.2	9.2	
2014 Projects																
Upgrade Burnt Dam Spillway - Bay d'Espoir	110.2	1,201.9	545.8	-	545.8	-	1,312.1	126.1	640.2	740.2	-	-	1,506.5	194.4	194.4	9
Upgrade Victoria Control Structure - Bay d'Espoir	495.1	-	180.5	-	180.5	-	495.1	79.6	235.0	446.9	-	-	761.5	266.4	266.4	10
Replace Spherical By Pass Valve Assemblies Units 1 and 2 - Bay d'Espoir	57.5	96.3	53.5	-	53.5	-	153.8	12.8	169.5	77.2	-	-	259.5	105.7	23.7	11
Install Handheld Pendant to Overhead Crane - Bay d'Espoir	49.9	170.8	156.4	-	156.4	-	220.7	45.0	19.3	166.8	-	-	231.1	10.4	10.4	
Total Hydraulic Generation Projects	712.7	3,410.4	1,188.0	10,647.9	11,835.9	14,209.7	28,980.7	263.5	2,753.6	9,133.7	14,209.7	1,951.0	28,311.5	(669.2)	(2,702.2)	

Table 4

2016 Capital Expenditures By Category
($000)

Thermal Generation Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Upgrade Powerhouse Building Envelope - Holyrood	-	-	2,723.8	2,723.8	3,754.0	6,477.8	-	2,239.9	3,754.0	483.9	6,477.8	-	(483.9)	12
Overhaul Steam Turbine Generator Unit 3 - Holyrood	-	-	5,868.6	5,868.6	-	5,868.6	-	8,147.9	-	-	8,147.9	2,279.3	2,279.3	13
Rewind Rotor and Install Flux Probe Unit 3 - Holyrood	-	-	2,755.5	2,755.5	-	2,755.5	-	2,879.8	-	-	2,879.8	124.3	124.3	
Study of Space Heating and Boiler Startup Assistance - Holyrood	-	-	148.7	148.7	-	148.7	-	154.0	-	-	154.0	5.3	5.3	
Overhaul Pumps - Holyrood	-	-	536.2	536.2	-	536.2	-	532.4	-	-	532.4	(3.8)	(3.8)	
Purchase Tools and Equipment Less than $ 50,000	-	-	15.8	15.8	-	15.8	-	13.7	-	-	13.7	(2.1)	(2.1)	
2015 Projects														
Upgrade Powerhouse Roofing - Holyrood	1,047.8	244.9	-	244.9	-	1,047.8	802.9	218.8	-	-	1,021.7	(26.1)	(26.1)	
Upgrade Fire Protection (Main Warehouse) - Holyrood	46.2	(30.2)	197.6	167.4	-	243.8	76.4	196.1	-	-	272.5	28.7	28.7	
Total Thermal Generation Projects	1,094.0	214.7	12,246.2	12,460.9	3,754.0	17,094.2	879.3	14,382.6	3,754.0	483.9	19,499.8	2,405.6	1,921.7	

Table 5

2016 Capital Expenditures By Category
($000)

Gas Turbine Generation Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryover to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Replace Fuel Piping - Hardwoods and Stephenville	-	-	44.8	44.8	267.0	311.8	-	11.6	267.0	33.2	311.8	-	(33.2)	
Install Transfer Switches for Diesel Automation - Happy Valley	-	-	148.4	148.4	-	148.4	-	147.7	-	-	147.7	(0.7)	(0.7)	
2015 Projects														
Upgrade Gas Turbine Plant Life Extension - Stephenville	2,655.2	41.6	2,525.4	2,567.0	-	5,180.6	2,613.6	3,107.4	-	-	5,721.0	540.4	540.4	14
Replace Alternator Shaft - Happy Valley	484.4	320.0	-	320.0	-	484.4	131.1	344.1	-	-	475.2	(9.2)	24.1	
Total Gas Turbine Generation Projects	3,139.6	361.6	2,718.6	3,080.2	267.0	6,125.2	2,744.7	3,610.8	267.0	33.2	6,655.7	530.5	530.6	

Table 6

2016 Capital Expenditures By Category
($000)

Terminal Stations Projects	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D (B+C)	E	F (A+C+E)	G				H	I	J	K (G+H+I+J)	K-F	H-D	
	2013	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2012	2013	2014	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects																			
Upgrade Circuit Breakers - Various Sites (2016-2020)	-	-	-	-	6,969.1	6,969.1	54,491.3	61,460.4	-	-	-	-	5,599.5	54,491.3	1,369.6	61,460.4	-	(1,369.6)	15
Replace Surge Arrestors - Various Sites	-	-	-	-	144.4	144.4	53.0	197.4	-	-	-	-	175.1	53.0	(30.7)	197.4	-	30.7	
Replace Protective Relays - Various Sites	-	-	-	-	700.6	700.6	1,156.4	1,857.0	-	-	-	-	1,425.8	1,156.4	(725.2)	1,857.0	-	725.2	16
Replace Disconnect Switches - Various Sites (2016-2017)	-	-	-	-	646.9	646.9	1,320.9	1,967.8	-	-	-	-	131.7	1,320.9	515.2	1,967.8	-	(515.2)	17
Upgrade Digital Fault Recorders - Various Sites	-	-	-	-	197.9	197.9	304.6	502.5	-	-	-	-	221.2	304.6	(23.3)	502.5	-	23.3	
Upgrade Roof - Indian River	-	-	-	-	48.3	48.3	-	48.3	-	-	-	-	46.0	-	-	46.0	(2.3)	(2.3)	
Upgrade Aluminum Support Structure - Holyrood	-	-	-	-	401.1	401.1	-	401.1	-	-	-	-	186.1	-	-	186.1	(215.0)	(215.0)	18
Upgrade Terminal Station Equipment Foundations - Various Sites	-	-	-	-	319.9	319.9	-	319.9	-	-	-	-	300.2	-	-	300.2	(19.7)	(19.7)	
Upgrade Data Alarm Systems - Various Sites	-	-	-	-	74.4	74.4	234.1	308.5	-	-	-	-	49.7	234.1	24.7	308.5	-	(24.7)	
Install Breaker Failure Protection - Various Sites	-	-	-	-	65.7	65.7	211.3	277.0	-	-	-	-	81.8	211.3	(16.1)	277.0	-	16.1	
Install Fire Protection in 230 kV Stations - Bay d'Espoir	-	-	-	-	200.0	200.0	566.0	766.0	-	-	-	-	91.4	566.0	108.6	766.0	-	(108.6)	19
Install Spare Transformer - Happy Valley	-	-	-	-	2,040.9	2,040.9	-	2,040.9	-	-	-	-	2,026.8	-	-	2,026.8	(14.1)	(14.1)	
Upgrade Terminal Station for Mobile Substation - Cow Head	-	-	-	-	40.0	40.0	444.7	484.7	-	-	-	-	27.5	444.7	12.5	484.7	-	(12.5)	
Replace Air Receivers and Compressors - St. Anthony	-	-	-	-	120.7	120.7	-	120.7	-	-	-	-	215.4	-	-	215.4	94.7	94.7	
2015 Projects																			
Upgrade Circuit Breakers - Various Sites (2015-2016)	-	-	6,189.1	(1,381.3)	6,873.8	5,492.5	-	13,062.9	-	-	-	7,570.4	6,022.4	-	-	13,592.8	529.9	529.9	
Install Transformer On line Gas Monitoring - Various Sites	-	-	700.5	(86.0)	975.7	889.7	-	1,676.2	-	-	-	786.5	1,065.6	-	-	1,852.1	175.9	175.9	20
Upgrade Power Transformers - Various Sites	-	-	4,440.4	2,083.1	7,002.3	9,085.4	-	11,442.7	-	-	-	2,357.3	9,472.8	-	-	11,830.1	387.4	387.4	
Replace Disconnect Switches - Various Sites (2015-2016)	-	-	963.7	400.6	642.9	1,043.5	-	1,606.6	-	-	-	563.1	946.3	-	-	1,509.4	(97.2)	(97.2)	
Design and Install Fire Protection in 230 kV Station - Various Sites	-	-	67.6	(7.3)	424.3	417.0	-	491.9	-	-	-	74.9	458.7	-	-	533.6	41.7	41.7	
Upgrade Terminal Station Protection and Control - Various Sites	-	-	172.7	10.2	307.2	317.4	-	479.9	-	-	-	162.5	734.9	-	-	897.4	417.5	417.5	21
Install Support Structures C2 Capacitor Bank - Hardwoods	-	-	199.3	26.4	-	26.4	-	199.3	-	-	-	58.0	21.7	-	-	79.7	(119.6)	(4.7)	22
Replace Station Lighting - Bay d'Espoir	-	-	16.7	(3.3)	160.3	157.0	-	177.0	-	-	-	20.0	178.4	-	-	198.4	21.4	21.4	
2013 Projects																			
Replace Instrument Transformers - Various Sites	593.2	552.8	538.4	(10.4)	1,511.7	1,501.3	471.9	3,668.0	9.6	230.7	699.0	755.5	1,190.3	471.9	311.0	3,668.0	-	(311.0)	23
Increase 230 kV Transformer Capacity - Oxen Pond	3,823.6	15,310.4	-	(200.2)	-	(200.2)	-	19,134.0	-	153.6	14,611.3	5,443.3	98.3	-	-	20,306.5	1,172.5	298.5	24
Total Terminal Stations Projects	4,416.8	15,863.2	13,288.4	831.8	29,868.1	30,699.9	59,254.2	122,690.7	9.6	384.3	15,310.3	17,791.5	30,767.6	59,254.2	1,546.3	125,063.8	2,373.1	67.7	

Table 7

2016 Capital Expenditures by Category
($000)

Transmission Projects	Capital Budget							Actual Expenditure and Forecast								
	A		B	C	D	E	F (A+C+E)	G		H	I	J	K(G+H+I+J)	K-F	H-D	
	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2014	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects																
Construct 230 kV Transmission Line - Soldiers Pond to Hardwoods	-	-	-	3,699.0	3,699.0	22,861.9	26,560.9	-	-	3,501.6	22,861.9	197.4	26,560.9	-	(197.4)	
Replace Insulators - TL203	-	-	-	1,985.6	1,985.6	-	1,985.6	-	-	2,008.2	-	-	2,008.2	22.6	22.6	
Replace Aircraft Markers at Grand Lake Crossing - TL228	-	-	-	589.6	589.6	978.3	1,567.9	-	-	61.8	978.3	527.8	1,567.9	-	(527.8)	25
Perform Wood Pole Line Management Program - Various Sites	-	-	-	2,919.0	2,919.0	-	2,919.0	-	-	3,180.1	-	-	3,180.1	261.1	261.1	
2014 Projects																
Refurbish Anchors and Footings TL202 and TL206 - Bay d'Espoir to Sunnyside	211.5	28.4	0.2	1,038.4	1,038.6	901.6	2,179.9	211.5	28.2	19.9	901.6	1,018.7	2,179.9	-	(1,018.7)	26
230 kV Transmission Line - Bay d'Espoir to Western Avalon	-	4,403.0	2,384.8	75,284.3	77,669.1	211,970.7	291,658.0	-	2,018.2	59,317.8	204,213.4	26,108.6	291,658.0	-	(18,351.3)	27
Total Transmission Projects	211.5	4,431.4	2,385.0	85,515.9	87,900.9	236,712.5	326,871.3	211.5	2,046.4	68,089.4	228,955.2	27,852.5	327,155.0	283.7	(19,811.5)	

Table 8

2016 Capital Expenditures By Category
($000)

Distribution Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D (B+C)		F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Provide Service Extensions - All Service Areas	-	-	5,350.0	5,350.0	-	5,350.0	-	6,021.5	-	-	6,021.5	671.5	671.5	28
Provide Service Extensions - All Service Areas - CIAC	-	-	(200.0)	(200.0)	-	(200.0)	-	(833.1)	-	-	(833.1)	(633.1)	(633.1)	29
Upgrade Distribution Systems - All Service Areas	-	-	3,990.0	3,990.0	-	3,990.0	-	3,357.4	-	-	3,357.4	(632.6)	(632.6)	30
Upgrade Distribution Systems - All Service Areas - CIAC	-	-	(100.0)	(100.0)	-	(100.0)	-	(153.7)	-	-	(153.7)	(53.7)	(53.7)	
Upgrade Distribution Systems - Various Sites (2016/2017)	-	-	285.6	285.6	6,350.3	6,635.9	-	361.8	6,350.3	(76.2)	6,635.9	-	76.2	
Construct Overhead Distribution Line - Pilley's Island to Long Island	-	-	1,239.9	1,239.9	-	1,239.9	-	1,509.0	-	-	1,509.0	269.1	269.1	31
Additions for Load Growth - Happy Valley	-	-	593.7	593.7	-	593.7	-	582.6	-	-	582.6	(11.1)	(11.1)	
2015 Projects														
Upgrade Distribution Systems - Various Sites (2015-2016)	1,136.1	(243.0)	818.8	575.8	-	1,954.9	1,379.1	710.8	-	-	2,089.9	135.0	135.0	32
Total Distribution Projects	1,136.1	(243.0)	11,978.0	11,735.0	6,350.3	19,464.4	1,379.1	11,556.3	6,350.3	(76.2)	19,209.5	(254.9)	(178.7)	

Table 9

2016 Capital Expenditures By Category
($000)

Rural Generation Projects	Capital Budget								Actual Expenditure and Forecast										
	A			B	C	D	E	(A+C+E)	G				H	I	J	(G+H+I+J)	K-F	H-D	
	2013	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2012	2013	2014	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects																			
Overhaul Diesel Units - Various Sites	-	-	-	-	2,078.4	2,078.4	-	2,078.4	-	-	-	-	2,526.4	-	-	2,526.4	448.0	448.0	33
Upgrade Human Machine Interface - Various Sites	-	-	-	-	114.0	114.0	320.0	434.0	-	-	-	-	125.3	320.0	(11.3)	434.0	-	11.3	
Install Variable Frequency Drives - Grey River	-	-	-	-	46.9	46.9	123.0	169.9	-	-	-	-	49.7	123.0	(2.8)	169.9	-	2.8	
Inspect Fuel Storage Tanks - Various Sites	-	-	-	-	1,326.9	1,326.9	-	1,326.9	-	-	-	-	1,024.5	-	-	1,024.5	(302.4)	(302.4)	34
Replace Diesel Unit - Charlottetown	-	-	-	-	1,384.9	1,384.9	46.1	1,431.0	-	-	-	-	1,442.2	46.1	-	1,488.3	57.3	57.3	
Install Fire Protection Systems - Cartwright and Nain	-	-	-	-	3,030.7	3,030.7	1,376.4	4,407.1	-	-	-	-	782.8	1,376.4	1,557.1	3,716.3	(690.8)	(2,247.9)	35
Upgrade Transformer Systems - Postville and Cartwright	-	-	-	-	465.2	465.2	-	465.2	-	-	-	-	296.0	-	169.2	465.2	-	(169.2)	36
Additions for Load Growth - Various Sites	-	-	-	-	883.4	883.4	4,746.0	5,629.4	-	-	-	-	190.4	4,746.0	693.0	5,629.4	-	(693.0)	37
2015 Projects																			
Overhaul Diesel Units - Various Sites	-	-	1,199.2	240.8	-	240.8	-	1,199.2	-	-	-	958.4	249.6	-	-	1,208.0	8.8	8.8	
Install Disconnect Switches for Mobile Generators - Various Sites	-	-	10.0	2.2	189.3	191.5	-	199.3	-	-	-	7.8	287.5	-	-	295.3	96.0	96.0	
Upgrade Ventilation Systems - Various Sites	-	-	175.9	(69.7)	317.3	247.6	-	493.2	-	-	-	245.6	290.3	-	-	535.9	42.7	42.7	
Replace Unit 2038 - Mary's Harbour	-	-	103.5	1.8	1,241.5	1,243.3	-	1,345.0	-	-	-	101.7	1,059.3	-	-	1,161.0	(184.0)	(184.0)	38
Replace Unit 254 - Paradise River	-	-	66.8	(13.7)	429.3	415.6	-	496.1	-	-	-	80.5	434.0	-	-	514.5	18.4	18.4	
Replace Programmable Logic Controllers - Various Sites	-	-	366.9	(30.3)	346.0	315.7	245.1	958.0	-	-	-	397.2	345.5	245.1	(29.8)	958.0	-	29.8	
Install Fire Protection - L'Anse au Loup	-	-	220.6	124.2	1,126.2	1,250.4	-	1,346.8	-	-	-	96.4	1,067.3	-	-	1,163.7	(183.1)	(183.1)	39
2014 Projects																			
Upgrade Diesel Plant Production Data Collection Equipment-Various	-	268.9	269.8	3.1	280.7	283.8	-	819.4	-	-	107.8	57.8	510.6	-	143.2	819.4	-	226.8	40
2013 Projects																			
Additions for Load Isolator Generation Stations - Various Sites	2,040.2	9,357.9	-	393.7	-	393.7	-	11,398.1	27.8	1,196.4	6,853.5	3,916.4	485.1	-	-	12,479.2	1,081.1	91.4	
Total Rural Generation Projects	2,040.2	9,626.8	2,412.7	652.1	13,260.7	13,912.8	6,856.6	34,197.0	27.8	1,196.4	6,961.3	5,861.8	11,166.5	6,856.6	2,518.6	34,589.0	392.0	(2,746.3)	

Table 10

2016 Capital Expenditures By Category
($000)

Properties Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Upgrade Warehouse Lighting - Bishop's Falls	-	-	15.2	15.2	180.4	195.6	-	28.1	180.4	(12.9)	195.6	-	12.9	
Upgrade Line Depots - Various Sites	-	-	861.4	861.4	-	861.4	-	955.5	-	-	955.5	94.1	94.1	
Upgrade Office Facilities and Control Buildings - Various Sites	-	-	1,134.0	1,134.0	-	1,134.0	-	675.0	-	-	675.0	(459.0)	(459.0)	41
Replace Roof on Service Building - Bishop's Falls	-	-	612.8	612.8	-	612.8	-	327.8	-	285.0	612.8	-	(285.0)	42
Install Fall Protection Equipment - Various Sites	-	-	198.8	198.8	-	198.8	-	203.6	-	-	203.6	4.8	4.8	
2015 Projects														
Replace Accommodations and Septic System - Ebbegunbaeg	489.4	395.2	1,061.4	1,456.6	-	1,550.8	94.2	811.2	-	645.4	1,550.8	-	(645.4)	43
Total Properties Projects	489.4	395.2	3,883.6	4,278.8	180.4	4,553.4	94.2	3,001.2	180.4	917.5	4,193.3	(360.1)	(1,277.6)	

Table 11

2016 Capital Expenditures By Category
($000)

Metering Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Install Automated Meter Reading - Labrador West	-	-	433.8	433.8	533.4	967.2	-	130.4	533.4	303.4	967.2	-	(303.4)	44
Purchase Meters, Equipment and Metering Tanks - Various Sites	-	-	190.4	190.4	-	190.4	-	155.6	-	-	155.6	(34.8)	(34.8)	
2015 Projects														
Install Automatic Meter Reading - Various Sites (2015-2016)	559.9	469.3	401.8	871.1	-	961.7	90.6	1,374.1	-	-	1,464.7	503.0	503.0	45
Total Metering Projects	559.9	469.3	1,026.0	1,495.3	533.4	2,119.3	90.6	1,660.1	533.4	303.4	2,587.5	468.2	164.8	

Table 12

2016 Capital Expenditures By Category
($000)

Tools and Equipment	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Replace Light Duty Mobile Equipment - Various Sites	-	-	348.0	348.0	-	348.0	-	351.4	-	-	351.4	3.4	3.4	
Purchase Excavator - Bay d'Espoir	-	-	312.0	312.0	-	312.0	-	187.0	-	35.0	222.0	(90.0)	(125.0)	46
Tools and Equipment Less than $ 50,000	-	-	477.0	477.0	-	477.0	-	418.5	-	-	418.5	(58.5)	(58.5)	
2015 Projects														
Replace Off Road Track Vehicles - Unit 7861, Stephenville (2015 - 2016)	1.1	(175.7)	397.8	222.1	-	398.9	176.8	-	-	-	176.8	(222.1)	(222.1)	47
Tools and Equipment Less than $ 50,000	622.7	35.8	-	35.8	-	622.7	563.1	30.4	-	-	593.5	(29.2)	(5.4)	
Total Tools and Equipment	623.8	(139.9)	1,534.8	1,394.9	-	2,158.6	739.9	987.3	-	35.0	1,762.2	(396.4)	(407.6)	

Table 13

2016 Capital Expenditures By Category
($000)

Information Systems Projects	Capital Budget						Actual Expenditure and Forecast								
	A	B	C	D	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Perform Minor Application Enhancements - Hydro Place	-	-	346.7	346.7	-	346.7	-	360.5	-	-	360.5	13.8	13.8	
Cost Recoveries	-	-	(148.8)	(148.8)	-	(148.8)	-	(154.6)	-	-	(154.6)	(5.8)	(5.8)	
Implement Industrial Billing Software - Hydro Place	-	-	443.1	443.1	-	443.1	-	169.5	-	273.6	443.1	-	(273.6)	48
Upgrade Microsoft Project - Hydro Place	-	-	683.7	683.7	1,910.7	2,594.4	-	656.9	1,910.7	26.8	2,594.4	-	(26.8)	
Cost Recoveries	-	-	(317.1)	(317.1)	(886.2)	(1,203.3)	-	(304.8)	(886.2)	(12.3)	(1,203.3)	-	12.3	
Upgrade Sharepoint/Document Repository - Hydro Place	-	-	267.6	267.6	-	267.6	-	260.3	-	-	260.3	(7.3)	(7.3)	
Cost Recoveries	-	-	(124.1)	(124.1)	-	(124.1)	-	(120.8)	-	-	(120.8)	3.3	3.3	
Upgrade Energy Management System - Hydro Place	-	-	246.2	246.2	-	246.2	-	256.5	-	-	256.5	10.3	10.3	
Refresh Security Software - Hydro Place	-	-	230.4	230.4	-	230.4	-	230.5	-	-	230.5	0.1	0.1	
Cost Recoveries	-	-	(106.9)	(106.9)	-	(106.9)	-	(107.0)	-	-	(107.0)	(0.1)	(0.1)	
Replace Peripheral Infrastructure - Various Sites	-	-	611.3	611.3	-	611.3	-	507.3	-	-	507.3	(104.0)	(104.0)	49
Cost Recoveries	-	-	(186.8)	(186.8)	-	(186.8)	-	(154.7)	-	-	(154.7)	32.1	32.1	
Upgrade Enterprise Storage Capacity - Hydro Place	-	-	628.8	628.8	-	628.8	-	464.5	-	164.3	628.8	-	(164.3)	50
Cost Recoveries	-	-	(291.6)	(291.6)	-	(291.6)	-	(215.5)	-	(76.1)	(291.6)	-	76.1	
Replace Personal Computers - Various Sites	-	-	861.7	861.7	-	861.7	-	850.0	-	-	850.0	(11.7)	(11.7)	
Upgrade Server Technology Program - Hydro Place	-	-	492.5	492.5	-	492.5	-	451.1	-	41.4	492.5	-	(41.4)	
Cost Recoveries	-	-	(228.5)	(228.5)	-	(228.5)	-	(209.3)	-	(19.2)	(228.5)	-	19.2	
Total Information Systems Projects	-	-	3,408.2	3,408.2	1,024.5	4,432.7	-	2,940.4	1,024.5	398.5	4,363.4	(69.3)	(467.8)	

Table 14

2016 Capital Expenditures By Category
($000)

Telecontrol Projects	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Purchase Tools and Equipment less than $50,000	-	-	45.6	45.6	-	45.6	-	51.9	-	-	51.9	6.3	6.3	
Replace Battery Banks and Chargers - Various Sites	-	-	425.0	425.0	456.6	881.6	-	365.7	456.6	59.3	881.6	-	(59.3)	
Replace MDR 4000 Microwave Radio East - Various Sites	-	-	77.4	77.4	1,093.1	1,170.5	-	113.4	1,093.1	(36.0)	1,170.5	-	36.0	
Replace UPS Systems - Hydro Place	-	-	889.8	889.8	-	889.8	-	928.6	-	(38.8)	889.8	-	38.8	
Replace Network Communication Equipment - Various Sites	-	-	186.4	186.4	-	186.4	-	183.0	-	-	183.0	(3.4)	(3.4)	
Upgrade Site Facilities - Various Sites	-	-	49.5	49.5	-	49.5	-	56.1	-	-	56.1	6.6	6.6	
Replace Radomes - Various Sites	-	-	235.2	235.2	-	235.2	-	230.1	-	-	230.1	(5.1)	(5.1)	
Replace Air Conditioners - Various Sites	-	-	39.9	39.9	152.0	191.9	-	51.2	152.0	(11.3)	191.9	-	11.3	
Replace Video Conferencing Bridge - Hydro Place	-	-	182.6	182.6	-	182.6	-	213.8	-	-	213.8	31.2	31.2	
Upgrade Access Roads to Microwave Sites - Various Sites	-	-	141.1	141.1	-	141.1	-	161.3	-	-	161.3	20.2	20.2	
Upgrade Remote Terminal Units - Various Sites	-	-	89.6	89.6	-	89.6	-	106.2	-	-	106.2	16.6	16.6	
Replace Wescom Transceivers - Various Sites	-	-	49.3	49.3	-	49.3	-	55.2	-	-	55.2	5.9	5.9	
Replace Powerline Carrier - Various Sites	-	-	73.4	73.4	763.4	836.8	-	77.4	763.4	(4.0)	836.8	-	4.0	
Upgrade Telecontrol Facilities - Sandy Brook Hill	-	-	101.6	101.6	462.4	564.0	-	81.7	462.4	19.9	564.0	-	(19.9)	
2015 Projects														
Replace GDC Metroplex - Various Sites	69.2	30.5	-	30.5	-	69.2	38.7	51.7	-	-	90.4	21.2	21.2	
Total Telecontrol Projects	69.2	30.5	2,586.4	2,616.9	2,927.5	5,583.1	38.7	2,727.3	2,927.5	(10.9)	5,682.6	99.5	110.4	

Table 15

2016 Capital Expenditures By Category
($000)

Transportation	Capital Budget						Actual Expenditure and Forecast							
	A	B	C	D	E	F (A+C+E)	G	H	I	J	K (G+H+I+J)	K-F	H-D	
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Project Variance	Annual Variance	Notes
2016 Projects														
Replace Vehicles and Aerial Devices - Various Sites (2016-2017)	-	-	1,443.3	1,443.3	534.2	1,977.5	-	1,032.7	534.2	410.6	1,977.5	-	(410.6)	51
Purchase Vehicles and Aerial Devices - Various Sites	-	-	382.5	382.5	172.7	555.2	-	470.4	172.7	(87.9)	555.2	-	87.9	
2015 Projects														
Replace Vehicles and Aerial Devices Hydro System (2015-2016)	2,377.1	642.2	225.3	867.5	-	2,602.4	1,734.9	801.8	-	-	2,536.7	(65.7)	(65.7)	
Total Transportation	2,377.1	642.2	2,051.1	2,693.3	706.9	5,135.1	1,734.9	2,304.9	706.9	322.7	5,069.4	(65.7)	(388.4)	

Administrative	Capital Budget						Actual Expenditure and Forecast							
	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2015	2016	2017 and Beyond	Carryovers to 2017	Total	Variance	Annual Variance	Notes
2016 Projects														
Remove Safety Hazards - Various Sites - 2015	-	-	199.3	199.3	-	199.3	-	175.4	-	-	175.4	(23.9)	(23.9)	
Replace Roof - Hydro Place	-	-	639.5	639.5	-	639.5	-	576.2	-	-	576.2	(63.3)	(63.3)	
Replace Air Conditioning Units 8 and 14 - Hydro Place	-	-	34.6	34.6	229.5	264.1	-	31.0	229.5	3.6	264.1	-	(3.6)	
Purchase Tools and Equipment less than $50,000	-	-	172.6	172.6	-	172.6	-	55.1	-	-	55.1	(117.5)	(117.5)	52
2015 Projects														
Replace Cooling Tower and Auxiliaries - Hydro Place	45.7	(6.8)	311.3	304.5	-	357.0	52.5	258.5	-	-	311.0	(46.0)	(46.0)	
Total Administrative	45.7	(6.8)	1,357.3	1,350.5	229.5	1,632.5	52.5	1,096.2	229.5	3.6	1,381.8	(250.7)	(254.3)	

Table 16

2016 Capital Expenditures By Category
($000)

Allowance For Unforeseen	Capital Budget							Actual Expenditure and Forecast									
	A		B	C	D	E	F (A+C+E)	G		H	I	J	K (G+H+I+J)	K-F	H-D		
	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2014	2015	2016	2017 and Beyond	Carryover to 2017	Total	Project Variance	Annual Variance	Notes	
2016 Projects																	
Contingency Fund	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	-	0.0	(1,000.0)	(1,000.0)		
Perform Upgrades - Western Avalon Transformer T5 Tap Changer	-	-	-	-	-	-	-	-	-	474.0	-	-	474.0	474.0	474.0		
Boiler Tube Replacement - Holyrood Generating Station Unit 2	-	-	-	-	-	-	-	-	-	1,565.6	-	-	1,565.6	1,565.6	1,565.6		
Boiler Tube Replacement - Holyrood Generating Station Unit 1	-	-	-	-	-	-	-	-	-	928.3	-	-	928.3	928.3	928.3		
Transmission Line TL 259 Rerouting - Sally's Cove	-	-	-	-	-	-	-	-	-	1,387.2	-	-	1,387.2	1,387.2	1,387.2		
Penstock #1 Weld Refurbishment - Bay d'Espoir				-	-	-	-	-	-	6,589.2	-	-	6,589.2	6,589.2	6,589.2		
Access Road Rehabilitations - Bay d'Espoir				-	-	-	-	-	-	2,722.6	-	-	2,722.6	2,722.6	2,722.6		
Contingency Top Up - P.U.8 (2016)	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	-	-	(1,000.0)	(1,000.0)		
Contingency Top Up -P.U.48 (2016)	-	-	-	1,000.0	1,000.0	-	1,000.0	-	-	-	-	-	-	(1,000.0)	(1,000.0)		
Total Allowance For Unforeseen	-	-	-	3,000.0	3,000.0	-	3,000.0	-	-	13,666.9	-	-	13,666.9	10,666.9	10,666.9	53	

Supplemental Projects	Capital Budget							Actual Expenditure and Forecast									
	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2014	2015	2016	2017 and Beyond	Carryover to 2017	Total	Project Variance	Annual Variance	Notes	
2016 Projects																	
Upgrade Units 1 and 2 Lower Reheaters	-	-	-	11,800.0	11,800.0	-	11,800.0	-	-	11,734.4	-	-	11,734.4	(65.6)	(65.6)		
Purchase of 12 MW Diesel Generation - Holyrood	-	-	-	4,700.0	4,700.0	[. . .]	4,700.0	-	-	3,784.0	[. . .]	916.0	4,700.0	-	(916.0)	62	
TL 227 Distribution Line Sally's Cove L1	-	-	-	717.0	717.0	1,533.0	2,250.0	-	-	186.3	1,533.0	530.7	2,250.0	-	(530.7)	54	
Refurbish Gas Generator Engines - Hardwoods and Stephenville	-	-	-	3,047.1	3,047.1	-	3,047.1	-	-	2,538.7	-	508.4	3,047.1	-	(508.4)	55	
Unit 4 Turbine Primary Seal Clearance - Bay d'Espoir	-	-	-	1,977.3	1,977.3	-	1,977.3	-	-	1,517.9	-	-	1,517.9	(459.4)	(459.4)	56	
CT - Combustion Inspection and Overhaul - Holyrood	-	-	-	4,738.3	4,738.3	-	4,738.3	-	-	3,967.2	-	-	3,967.2	(771.1)	(771.1)	57	
Purchase Wabush Terminal Station	-	-	-	490.0	490.0	-	490.0	-	-	464.1	-	-	464.1	(25.9)	(25.9)		
2015 Projects																	
Purchase Critical Spares Generation Stations	-	1,536.3	1,041.1	-	1,041.1	-	1,536.3	-	495.2	731.2	-	-	1,226.4	(309.9)	(309.9)	58	
Replace Rectifier Transformers - Holyrood Units 1 and 2	-	327.9	295.9	428.3	724.2	-	756.2	-	32.0	838.4	-	-	870.4	114.2	114.2	59	
Transformer VBN T1 Major Internal Assessment	-	500.1	178.4	-	178.4	-	500.1	-	321.7	23.8	-	-	345.5	(154.6)	(154.6)	60	
2014 Projects																	
Labrador West Transmission Project - Construction Phase[1]	37,484.2	163,145.3	-	128,962.6	128,962.6	-	329,592.1	10,996.0	628.0	752.8	-	-	12,376.8	(317,215.3)	(128,209.8)	61	
Total Supplemental Projects Approved by PUB	37,484.2	165,509.6	1,515.4	156,860.6	158,376.0	1,533.0	361,387.4	10,996.0	1,476.9	26,538.8	1,533.0	1,955.1	42,499.8	(318,887.6)	(131,837.2)		

Projects Less than $50,000	Capital Budget							Actual Expenditure and Forecast									
	2014	2015	Carryover 2015	Original 2016	Revised 2016	2017 and Beyond	Total	2014	2015	2016	2017 and Beyond	Carryover to 2017	Total	Project Variance	Annual Variance	Notes	
2016 Projects																	
Hardwoods Station Service Artificial Neutral	-	-	-	42.1	42.1	-	42.1	-	-	42.2	-	-	42.2	0.1	0.1		
Tank 1 External Inspection and Condition Assessment - Holyrood	-	-	-	39.8	39.8	-	39.8	-	-	24.4	-	-	24.4	(15.4)	(15.4)		
Exciter Refurbishment - Corner Brook Frequency Converter (CBFC)	-	-	-	49.0	49.0	-	49.0	-	-	46.9	-	-	46.9	(2.1)	(2.1)		
HWD Snow Door Overhaul	-	-	-	46.7	46.7	-	46.7	-	-	48.4	-	-	48.4	1.7	1.7		
Replace Radiator Unit 2029 Makkovik	-	-	-	49.0	49.0	-	49.0	-	-	27.5	-	21.5	49.0	-	(21.5)		
St. Anthony, Mary's Harbour, Port Hope Simpson - Lighting Replacement	-	-	-	42.3	42.3	-	42.3	-	-	40.4	-	-	40.4	(1.9)	(1.9)		
2015 Projects																	
Thrust Bearing Refurbishment Units 1 - 6, Bay d'Espoir	-	2.5	2.4	41.2	43.6	-	43.7	-	0.1	32.7	-	-	32.8	(10.9)	(10.9)		
Replace Interrupter Bottom Brook Breaker B3L50	-	1.0	1.0	48.2	49.2	-	49.2	-	-	48.5	-	-	48.5	(0.7)	(0.7)		
Total Projects Less than $50,000	-	3.5	3.4	358.3	361.7	-	361.8	-	0.1	311.0	-	21.5	332.6	(29.2)	(50.7)		

[1] The construction of the Labrador West Transmission was approved by OC2014-033, February 2, 2014. The capital expenditures associated with this project are included in Work In Progress and as a result are currently excluded from average rate base. The costs to be included in rate base will be subject to review by the Board of Commissioners of Public Utilities.

4.0 Variance Explanations (Greater than $100,000 and 10% Variance from Budget)

The projects discussed in the following section have 2016 variances of more than 10% and $100,000 when comparing the approved budget to the 2016 expenditures, whether it is a single year project or a multiyear project. Also discussed are projects where there is a total project variance greater than 10% and $100,000. The projects are ordered and numbered based upon the order and number they appear in the preceding set of tables.

4.1 Hydraulic Generation Projects

1. Install Hydrometeorological Equipment - Various Sites (2016)

Budget: $314.1 Total: $4.3 Variance: ($309.8)

This is a one year project that has been carried over into 2017 for further evaluation of the technology prior to construction. In 2015, prior to this project, a snow water equivalent sensor was loaned to Hydro and installed at Victoria Hydrometeorological Station. The 2016 project was to purchase the loaner and an additional three snow water equivalent sensors for other sites. The data collected from the loaner sensor in the spring of 2016 was not accurate, so the project was put on hold. The sensor supplier believes the problem to be a calibration error. Hydro has requested to keep the loaner for an additional year with recalibration. If the recalibration gives acceptable results in spring of 2017, then the project will proceed.

2. Upgrade Work – Cat Arm (2016)

Budget: $558.3 Total: $240.4 Variance: ($317.9)

This is a two year project that commenced in 2016. Procurement of the deflector servo motor was originally scheduled for late 2016 and will now be procured in early 2017 with no effect on the overall execution schedule. The budget, scope and schedule remain unchanged.

3. Replace Site Facilities – Bay d'Espoir (2016)

Budget: $928.3 Total: $270.4 Variance: ($657.9)

This is a three year project that commenced in 2016. The less than forecasted spend in the first year was due to lower than expected design consultant cost. The project remains on schedule with no change to the overall budget, scope or completion date.

4. Upgrade Public Safety Around Dams and Waterways - Bay d'Espoir (2016)

Budget: $477.6 Total: $334.7 Variance: ($142.9)

This was a one year project that is part of an ongoing program to upgrade public safety around dams and waterways. The 2016 work was cut short due to Hurricane Matthew's impact on crew availability, and therefore the project was closed in 2016. Remaining scope will be completed in 2017 as part of the next Public Safety Around Dams Project. The scope of work that has been moved into 2017 is within the contingency for the 2017 project. The variance is also attributable to the 2016 contingency funds not being required.

5. Overhaul Turbine/Generator Units #6 and #7 – Bay d'Espoir (2016)

Budget: $1,345.6 Total: $544.5 Variance: ($801.1)

This was a one year project and due to unresolved contract terms with the original equipment manufacturer, and schedule conflicts with other on-going work, it was decided to limit part of the rotor scope that was included in the whole project. The rotor scope was to address unacceptable vibration levels and was limited to design only, with construction deferred until 2017. The generator bearing was replaced during the outage and resulted in a significant improvement to the operating vibration levels. Based on this improved performance, it was decided to cancel the remaining rotor scope instead of deferring it to 2017 in order to provide a timeframe to assess the long term performance of the generator with the new bearing. Approximately $60,000 of the project funds was carried into 2017 to allow time for the old generator bearing to be refurbished and returned as a capital critical spare.

6. Replace Station Service Breakers – Cat Arm (2015)

Budget: $362.2 Total: $185.9 Variance: ($176.3)

This is a two year project that commenced in 2015 and was carried over to 2017. The primary scope of this project, accounting for approximately 65% of the project budget, was the replacement of the breakers, which was completed in 2015. The programmable logic controller upgrade was scheduled for 2016 during the planned outage to Cat Arm Units 1 and 2. That planned outage was compressed as a result of the need for emergency refurbishment of Penstock 1 in Bay d'Espoir. The risk of completing this project in a compressed 2016 outage was weighed against the risk of carrying the project over to 2017 and it was determined that moving the project to 2017 would be the least risk option.

7. Upgrade Generator Bearings Units 1 and 3 – Bay d'Espoir (2015)

Budget: $648.0 Total: $285.2 Variance: ($362.8)

This is a two year project that commenced in 2015 and is now complete. The original project scope included bearing modifications to reduce generator bearing oil leakage. Upon reviewing the impacts of bearing modifications that were completed on Unit 2 in 2014 (a separate project), it was decided to reduce the scope to only what was necessary and the desired project intent was still achieved.

8. Replace Pump House and Associated Equipment – Bay d'Espoir (2015)

Budget: $408.2 Total: $128.6 Variance: ($279.6)

This is a two year project that commenced in 2015 and is being carried over into 2017/2018. Engineering work commenced, and the construction was tendered but not awarded in early 2016, since tendered prices were significantly higher than the budget. The project was carried over to realign on scope and determine if any savings could be realized in pairing this project with the construction of the Replace Site Facilities Project in Bay d'Espoir. The site facilities construction project is planned to commence in 2017 with completion in fall of 2018. The schedule for the Replace Pump House and Associated Equipment project has been modified to align with the construction schedule for the Replace Site Facilities Project.

9. Upgrade Burnt Dam Spillway – Bay d'Espoir (2014)

Budget: $1,312.1 Total: $1,506.5 Variance: $194.4

This project is complete. This was a two year project that commenced in 2014 with partial scope carried over to 2016. Additional funds were required to complete 2016 construction due to higher than expected engineering and operations support costs. The higher costs were attributed to the lack of suitable accommodations close to site resulting in longer travel time, extended construction schedules, and additional vehicle and helicopter cost. The material supply cost for the new diesel generator sets was also higher than the original estimate.

10. Upgrade Victoria Control Structure - Bay d'Espoir (2014)

Budget: $495.1 Total: $761.5 Variance: $266.4

This project is complete. This was a two year project that commenced in 2014 with partial scope carried over to 2016. Additional funds were required to complete 2016 construction due to higher than expected contractor and operations support costs. The higher costs were attributed to the lack of suitable accommodation close to site resulting in longer travel time, extended construction schedules, and additional vehicle and helicopter cost.

11. Replace Spherical By Pass Valve Assemblies Units 1 and 2 – Bay d'Espoir (2014)

Budget: $153.8 Total: $259.5 Variance: $105.7

This project is complete. The cost of the replacement by-pass valves and actuator, and the amount of construction labour required, was higher than originally budgeted.

4.2 Thermal Generation Projects

12. Upgrade Powerhouse Building Envelope - Holyrood (2016)

Budget: $2,723.8 Total: $2,239.9 Variance: ($483.9)

This is a three year project that commenced in 2016. A portion of the planned construction in 2016 has been deferred to 2017. The delay was a result of the need to tender the construction work a second time (after the first tender call was unsuccessful due to bidders

not meeting the safety requirements), as well as greater than expected weather delays. There is no change to the overall budget, scope or completion date for this project.

13. Overhaul Steam Turbine Generator Unit 3 - Holyrood (2016)

Budget: $5,868.6 Total: $8,147.9 Variance: $2,279.3

This is a one year project. The variance is due to several factors. Internal labor costs were higher than estimated due to the removal and reinstallation of the synchronous condenser skid. The contractor experienced difficulty in dismantling the unit due to the fact that the last major overhaul was 9 years ago, resulting in additional labour hours and broken parts. Finally, findings during the inspection and discovery phase of the overhaul resulted in more repairs and parts replaced than estimated.

4.3 Gas Turbine Generation Projects

14. Upgrade Gas Turbine Plant Life Extension - Stephenville (2015)

Budget: $5,180.6 Total: $5,721.0 Variance: $540.4

This is a two year project that commenced in 2015 and is complete. The total project variance is attributed to higher than expected publicly tendered prices for the fire protection upgrades, and the requirement of more extensive refurbishment of the exhaust stacks than expected. The extent of the stack refurbishment could only be accurately determined once the unit was disassembled for the work.

4.4 Terminal Stations Projects

15. Upgrade Circuit Breakers - Various Sites (2016-2020)

Budget: $6,969.1 Total: $5,599.5 Variance: ($1,369.6)

This is a five year project that commenced in 2016 and is a part of an ongoing program to replace circuit breakers in terminal stations. Some breaker procurement and engineering work was advanced from 2016 to 2015 (against the Upgrade Circuit Breakers - Various Sites (2015-2016) Project) to allow implementation flexibility in 2016 and to ensure successful completion of breaker installations for winter readiness timelines. The overall project is

currently expected to be completed on budget. An overall reforecast of the project will be undertaken at the end of 2017

16. Replace Protective Relays – Various Sites (2016)

Budget: $700.6 Total: $1,425.8 Variance: $725.2

This is a two year project that commenced in 2016. During the design phase of the project, Hydro's design standard for protection relays was revised to address lessons learned from system events experienced since 2014. The updated standard significantly impacted the overall design for all protection relays. This increased the engineering design effort on the project and resulted in increased procurement and construction costs due to the requirement for additional components to adhere to the new standard.

17. Replace Disconnect Switches - Various Sites (2016-2017)

Budget: $646.9 Total: $131.7 Variance: ($515.2)

This is a two-year project that commenced in 2016. The variance in the first year expenditure is attributable to a delay in receipt of materials. The new disconnect switches were originally expected to be delivered in Q4 of 2016, but are delayed until Q1 of 2017. This delay in materials delivery does not impact the construction schedule. The original budget included an allowance in 2016 for any unforeseen construction for early failures, but this was not required. There is no change to the overall project scope, budget or completion date.

18. Upgrade Aluminum Support Structure – Holyrood (2016)

Budget: $401.1 Total: $186.1 Variance: ($215.0)

This was a single year project completed in 2016. This project was executed in parallel with a separate project to Upgrade Terminal Station Equipment Foundations. This allowed Hydro to realize efficiencies and cost savings for engineering, procurement and construction.

19. Install Fire Protection in 230 kV Stations – Bay d'Espoir (2016)

Budget: $200.0 Total: $91.4 Variance: ($108.6)

This is a two year project that commenced in 2016. During detailed project planning, it was determined that the procurement of materials could wait until 2017 without impacting the construction schedule. There is no change to the overall project scope, budget or schedule.

20. Install Transformer On line Gas Monitoring – Various Sites (2015)

Budget: $1,676.2 Total: $1,852.1 Variance: $175.9

This was a two-year project that commenced in 2015 and was completed in 2016. The overall project variance was within 10.5% of approved budget. The variance is attributed to higher than anticipated engineering efforts to integrate the new technology to existing transformers, as well as telecommunications upgrades to support the new equipment.

21. Upgrade Terminal Station Protection and Control – Various Sites (2015)

Budget: $479.9 Total: $897.4 Variance: $417.5

This is a two year project that commenced in 2015 and was completed in 2016. During the design phase of the project, Hydro's design standard for breaker failure protection was revised. The changes to the standard were made to address lessons learned from system events experienced since 2014. The updated standard significantly impacted the overall design for breaker failure protection. This increased the engineering design effort on this project and resulted in increased procurement and construction costs due to the requirement for additional components to adhere to the new standard.

22. Install Support Structures C2 Capacitor Bank - Hardwoods (2015)

Budget: $199.3 Total: $79.7 Variance: ($119.6)

This was a one year project that commenced in 2015 and was carried over and completed in 2016. During detailed engineering, a less expensive design was identified, resulting in savings for materials and construction.

23. Replace Instrument Transformers – Various Sites (2013)

Budget: $1,501.3 Total: $1,190.3 Variance: ($311.0)

This is a five-year project that commenced in 2013. The variance in 2016 expenditure is attributed to a small portion of the 2016 scope being rescheduled for 2017, due to the inability to secure the necessary equipment outages to perform the work. The remaining work on the project is expected to be completed in 2017 with no change to the overall project scope, budget or schedule.

24. Increase 230 kV Transformer Capacity – Oxen Pond (2013)

Budget: ($200.2) Total: $98.3 Variance: $298.5

This was a two year project that commenced in 2013 and was substantially completed through 2014 and 2015. It was carried over into 2016 for completion of project. The identified items were completed at a cost of $98.3k and the project was completed at an overall cost of 6.1% over the approved budget.

4.5 Transmission Projects

25. Replace Aircraft Markers at Grand Lake Crossing – TL228 (2016)

Budget: $589.6 Total: $61.8 Variance: ($527.8)

This is a two-year project that commenced in 2016 to replace four aircraft marker systems that are located on four 230 kV transmission crossing tower structures that span over a section of Grand Lake at Glover's Island. The variance in the first year expenditure is attributed to the materials procurement being deferred to Q1 of 2017. There is no change to the overall project scope, budget and completion date.

26. Refurbish Anchors and Footings TL202 and TL206 – Bay d'Espoir to Sunnyside (2014)

Budget: $1,038.6 Total: $19.9 Variance: ($1,018.7)

This project commenced in 2014. During project planning, it was decided to align construction with execution of the new transmission line between Bay d'Espoir and Western Avalon Terminal Stations, which is along the same corridor. The new line was approved by the Board under Order No. P. U. 53(2014) on December 12, 2014. The alignment of this

project with the construction of the new transmission line will result in overall cost savings to the project as well as a reduced environmental impact. Access roads for the new transmission line were originally anticipated to be completed in the fall of 2016; however, they will not be ready until 2017. For this reason, all construction work for this project will take place in 2017 instead of being spread across 2016 and 2017 as previously planned.

27. 230 kV Transmission Line – Bay d'Espoir to Western Avalon (2015)

Budget: $77,669.1 Total: $59,317.8 Variance: ($18,351.3)

The approved capital budget for 2016 (including 2015 carryover) was $77.7M. As of the end of 2016, the actual expenditure was $59.3M. As per the TL267 Monthly Status Update Report submitted to the PUB this project has undergone schedule and cash flow changes. The anticipated in service date has been accelerated from May 2018 to October 2017 with no change to the overall project budget.

4.6 Distribution Projects

28. Provide Service Extensions - All Service Areas (2016)

Budget: $5,350.0 Total: $6,021.5 Variance: $671.5

This is an annual budget that is based on data from past experience to provide service extensions to customers. The variance is primarily due to the Duley Lake Cottage Development, which had 26 customers request connections in 2016, at a cost of approximately $750k.

29. Provide Service Extensions - All Service Areas - CIAC (2016)

Budget: ($200.0) Total: ($833.1) Variance: ($633.1)

This is an annual budget that is based on past Contributions in Aid of Construction (CIAC) to provide service extensions to customers. The variance is primarily due to the Duley Lake Cottage area line extension and Hampden Tap – LCP Repeater site. As per Board Order P.U.16(2016), the Board approved $13,900 per customer for Duley Lake, and as of December 31, 2016, 26 customers have requested connections and provided their funding, resulting in contributions of approximately $350k. The installation of the Hampden Tap – LCP Repeater

site, executed by Hydro, carried a CIAC from the Muskrat Falls project of approximately $350k.

30. Upgrade Distribution Systems - All Service Areas (2016)

Budget: $3,990.0 Total: $3,357.4 Variance: ($632.6)

This is a one year project to provide distribution upgrades to customers, with a budget based on 2015 expenditures. The budget and actual expenditures in 2016 are shown by area in the table below. The variance is primarily due to less than expected distribution upgrade requests across all areas.

Table 17

	Budget ($000)	Actual ($000)	Variance ($000)
Central	1,910.0	1,702.3	(207.7)
Northern	1,150.0	937.1	(212.9)
Labrador	930.0	718.0	(212.0)
Total	3,990.0	3,357.4	(632.6)

31. Construct Overhead Distribution Line – Pilley's Island to Long Island (2016)

Budget: $1,239.9 Total: $1,509.0 Variance: $269.1

This was a one year project completed in 2016. During the budget stage, Hydro determined the least cost alternative to provide reliable power to Long Island was construction of an overhead distribution line. This was based on standard requirements for navigable waters, including a 24 m wire clearance over the water. After this project had been submitted for approval in the 2016 Capital Budget Application, the Canadian Coast Guard increased their wire clearance requirement to a minimum of 40 m to allow for their largest ice breaking vessel to safely pass underneath. This extra 16 m of clearance resulted in a change in the overhead design, and the project estimate increased to approximately $3.6 M dollars. The evaluation of project alternatives was revisited and an updated cost benefit analysis concluded that the least cost option was to replace the original submarine cables with new cables. The supply and installation of two submarine cables was completed.

32. Upgrade Distribution Systems – Various Sites (2015-2016)

Budget: $575.8 Total: $710.8 Variance: $135.0

This was a two year project that commenced in 2015 and is complete. The variance in the annual expenditure is attributable to work on the Bottom Waters distribution system that was planned to be performed under de-energized conditions but was carried out under energized conditions, to manage customer impact. This resulted in higher construction costs. The total project expenditure was within 7% of the approved budget.

4.7 Rural Generation Projects

33. Overhaul Diesel Units - Various Sites (2016)

Budget: $2,078.4 Total: $2,526.4 Variance: $448.0

This was a one year project completed in 2016. The project is part of an ongoing program to overhaul diesel engines at diesel generating plants to sustain reliability of the generating equipment. Project estimates are based on the projected number of engines that will reach the criteria for overhaul (20,000 hours of operation), and typical extent of refurbishment. The project variance is attributable to more extensive refurbishment than typically required for some of the engines, which was unknown until the engines were disassembled for the overhauls. Additionally, the higher United States dollar exchange rate resulted in an increase in material costs.

34. Inspect Fuel Storage Tanks - Various Sites (2016)

Budget: $1,326.9 Total: $1,024.5 Variance: ($302.4)

This was a one year project completed in 2016. The project is part of an ongoing program to inspect fuel storage tanks for diesel plants. After a detailed review and prioritization of the sites to be inspected in 2016, an update was made to the schedule as provided for in the Capital Budget Application for this project. Nain tank inspections were deferred to 2018, and Rigolet tank inspections were advanced to 2016. This change resulted in significant savings for contracted work in 2016. Additionally, after an external inspection, tanks in St. Brendan's were discovered to be leaking. As detailed in the 2016 Capital Budget Application, "Hydro

may inspect a higher priority tank should conditions change and defer a lower priority tank." The St. Brendan's tank, having failed, was replaced as it became a higher priority, given that fuel leakage was occurring. Other tanks inspected in 2016 did not require significant refurbishment, contributing to the project underspend.

35. Install Fire Protection Systems – Cartwright and Nain (2016)

Budget: $3,030.7 Total: $782.8 Variance: ($2,247.9)

This is a two year project that commenced in 2016. Design is complete and procurement is in progress. Most of the procurement and construction activity planned to be completed in late 2016 will now be completed in the first quarter of 2017. This schedule change was made to balance the overall capital work plan and to reduce the project schedule and delivery risks. There is no change to the overall project scope, budget or completion date.

36. Upgrade Transformer Systems – Postville and Cartwright (2016)

Budget: $465.2 Total: $296.0 Variance: ($169.2)

This was a one year project that has been carried over into 2017. The project is to replace transformers at Postville and Cartwright. The work at Postville was completed in 2016. The transformers purchased for Cartwright were determined to have incorrect secondary voltages and have been returned to the manufacturer for rewind. Construction is rescheduled for early 2017, ahead of the anticipated load growth (i.e. the transformers will be installed prior to start-up of the fish plant). There is no change to the overall project scope or budget.

37. Additions For Load Growth – Various Sites (2016)

Budget: $883.4 Total: $190.4 Variance: ($693.0)

This is a multi-year project that commenced in 2016. The annual variance in 2016 expenditure is attributable to delay in material purchases from Q4 2016 to Q1 2017. There is no change to the overall project scope, budget or completion date.

38. Replace Unit 2038 – Mary's Harbour (2015)

Budget: $1,345.0 Total: $1,161.0 Variance: ($184.0)

This was a two year project that commenced in 2015 and was completed as planned. A portion of the project contingency was not required.

39. Install Fire Protection – L'anse Au Loup (2015)

Budget: $1,346.8 Total: $1,163.7 Variance: ($183.1)

This was a two-year project that commenced in 2015 and was completed as planned. A portion of the project contingency was not required.

40. Upgrade Diesel Plant Production Data Collection Equipment - Various (2014)

Budget: $283.8 Total: $510.6 Variance: $226.8

This is a three year project that commenced in 2014. At commencement of the detailed engineering in year three for the sites that are included in year three of the project, it was determined that the design and construction would be more complex than the sites completed in the first two years of the project, which attributes to additional cost of the project for additional engineering, construction labour and materials. This prompted a review of the overall project scope and justification. From this review, it was determined that the diesel plant production data is not critical for three of the diesel plants that are connected to the Island Interconnected System (St. Anthony, Hawkes Bay, and Little Bay Islands), since these plants are not prime power. The diesel plant production data collection equipment work for these plants was subsequently removed from the project scope, mitigating the impact of cost overrun. The work is complete for all isolated diesel plants, with the exception of the construction for L'Anse au Loup, which has been carried into 2017. The project is expected to be completed in 2017 within 10% of the total project budget.

4.8 Properties Projects

41. Upgrade Office Facilities and Control Buildings – Various Sites (2016)

Budget: $1,134.0 Total: $675.0 Variance: ($459.0)

This was a one year project completed as planned in 2016. Publicly tendered prices for the construction at all three sites were lower than estimated.

42. Replace Roof on Service Building – Bishop's Falls (2016)

Budget: $612.8 Total: $327.8 Variance: ($285.0)

This was a one year project scheduled for completion in 2016, and carried over into 2017. Engineering and procurement are complete with construction partially completed in 2016. Due to factors including contractor resource issues, unforeseen design issues, and frequent inclement weather, the full roof replacement could not be completed before winter conditions set in. The building is weather tight and remaining roof work will be completed in the spring of 2017, when conditions allow. There is no change to the overall project scope or budget.

43. Replace Accommodations and Septic System - Ebbegunbaeg (2015)

Budget: $1,456.6 Total: $811.2 Variance: ($645.4)

This is a two year project that commenced in 2015 and is being carried over to 2017. The project scope includes installation of new accommodations and septic system, installation of a bridge at Noel Paul Brook, and access road upgrades. The bridge and road upgrades were completed as planned. The manufacturer was unable to deliver the new accommodations in accordance with the planned schedule. Delivery has been deferred to the spring of 2017 and construction will be completed in the summer of 2017. There is no change to the overall project scope or budget.

4.9 Metering Projects

44. Install Automatic Meter Reading – Labrador West (2016)

Budget: $433.8 Total: $130.4 Variance: ($303.4)

This is a two-year project that commenced in 2016. Engineering is complete and materials with long lead times have been ordered. The original budget estimate included receipt of materials in Q4 2016, but materials will be received in Q1 2017. There is no change to the overall project budget or completion date.

45. Install Automatic Meter Reading – Various Sites (2015-2016)

Budget: $961.7 Total: $1,464.7 Variance: $503.0

This is a two year project completed in 2016. The two primary drivers of the cost variance were higher than estimated equipment costs and higher than expected meter installation costs. Equipment costs were higher than budgeted due to a higher cost of the United States Dollar exchange rate, and estimates that were based on equipment costs of an earlier, less sophisticated generation of the equipment. Higher installation costs were incurred due to: greater than anticipated number of failed meter bases related to corrosive (salty) environmental conditions; low residential densities; long distances between communities; and the requirement for a dedicated line crew to ensure prompt restoration of service. An updated project cost estimate and updated assumptions for project benefits were used to re-evaluate the project. The updated cost-benefit analysis confirmed that the project remains the least cost alternative versus the status quo.

4.10 Tools and Equipment Projects

46. Purchase Excavator – Bay d'Espoir (2016)

Budget: $312.0 Total: $187.0 Variance: ($125.0)

The cost of the excavator was less than the original budget as it was a new product line for the supplier and a lower cost than historical similar purchases. The mulcher head attachment procurement was delayed to ensure the compatibility with the unit. The project will be completed by March 2017.

47. Replace Off Road Track Vehicles – Unit 7861, Stephenville (2015-2016)

Budget: $398.9 Total: $176.8 Variance: ($222.1)

This was budgeted as a two year project with the actual purchase completed in 2015 due to early availability and at a reduced cost.

4.11 Information Systems Projects

48. Implement Industrial Billing Software - Hydro Place (2016)

Budget: $443.1 Total: $169.5 Variance: ($273.6)

Vendor resources, when required, were unavailable resulting in a delay in commencement of the project and a carryover to 2017.

49. Replace Peripheral Infrastructure - Various Sites (2016)

Budget: $611.3 Total: $507.3 Variance: ($104.0)

An evaluation of the number of required printers indicated that some that were removed from service did not require replacement, thereby reducing the number of printers acquired.

50. Upgrade Enterprise Storage Capacity – Hydro Place (2016)

Budget: $628.8 Total: $464.5 Variance: ($164.3)

Resources were not available to work on the upgrade due to demands of other projects, causing a delay in execution; however, the Project is scheduled for completion in Q1 2017.

4.12 Transportation Projects

51. Replace Vehicles and Aerial Devices - Various Sites (2016-2017)

Budget: $1,443.3 Total: $1,032.7 Variance: ($410.6)

This is a two year project. There was a limitation on vehicle availability; however, the vehicles will be delivered in 2017.

4.13 Administrative

52. Purchase Tools and Equipment less than $50,000 (2016)

Budget: $172.6 Total: $55.1 Variance: ($117.5)

The overall project variance is primarily due to overall cost savings to the project due to items such as reduction in the estimated requirements for office equipment, and lower than estimated costs for some equipment.

4.14 Allowance for Unforeseen Items

53. Allowance for Unforeseen Items

Budget: $3,000.0 Total: $13,666.9 Variance: $10,666.9

The Allowance for Unforeseen is an annual allotment that permits Hydro to act expeditiously to deal with events affecting the electrical system which cannot wait for specific approval of the Board. Unforeseen expenditures for 2016 under this account include costs associated with Performing Upgrades to the Western Avalon Terminal Station Transformer T5 Tap Changer, Holyrood Units 1 and 2 – Boiler Re-Heat Tubes, Sally's Cove Transmission Line Reroutes, Bay d'Espoir-Penstock 1 and Access Roads Refurbishments. Reports on these items have been filed with the Board of Commissioners of Public Utilities.

4.15 Supplemental Projects

54. TL 227 Distribution Line Sally's Cove L1 (2016)

Budget: $717.0 Total: $186.3 Variance: ($530.7)

This is a two year supplemental project that commenced in 2016. In early 2016, a coastal landslide occurred south of Sally's Cove on the Northern Peninsula. This project is required to re-route a section of transmission line TL227 and distribution line L1 away from the high-risk zone surrounding the landslide. The variance in the first year expenditure is attributed to a delay in material delivery that was scheduled for November 2016, but was not received until early 2017. This late delivery of materials does not impact the construction schedule. There is no change to the overall project scope, budget or completion date.

55. Refurbish Gas Generator Engines – Hardwoods and Stephenville (2016)

Budget: $3,047.1 Total: $2,538.7 Variance: ($508.4)

This is a supplemental project approved in 2016 and carried into 2017. The engine for Hardwoods Gas Turbine was refurbished and successfully returned to service. The engine for the Stephenville Gas Turbine was refurbished and reinstalled, but experienced vibration issues during commissioning. The project is carried over into 2017 to assess and resolve the vibration issues.

56. Unit 4 Turbine Primary Seal Clearance – Bay d'Espoir (2016)

Budget: $1,977.3 Total: $1,517.9 Variance: ($459.4)

This project is complete. This was a supplementary project approved and executed in 2016. The contract cost to complete the refurbishment of the turbine seal (concrete grouting and seal machining) of the turbine was less than original estimate. The variance is also attributed to the contingency funds not being required.

57. CT – Combustion Inspection and Overhaul - Holyrood (2016)

Budget: $4,738.3 Total: $3,967.2 Variance: ($771.1)

This is a supplemental project approved and completed in 2016. The variance from the planned expenditure is primarily attributed to the fact that the contingency was not required.

58. Purchase Critical Spares Generation Stations (2015)

Budget: $1,536.3 Total: $1,226.4 Variance: ($309.9)

This is a supplemental project approved in 2015 for procurement in 2016. The variance was due to material costs being lower than budgeted and the contingency not being required.

59. Replace Rectifier Transformers – Holyrood Units 1 and 2 (2015)

Budget: $756.2 Total: $870.4 Variance: $114.2

This is a two-year project that commenced in 2015 and is complete. The project variance is due to higher than anticipated remediation costs required for the proper disposal of the removed rectifying transformers for Units 1 and 2.

60. Transformer VBN T1 Major Internal Assessment (2015)

Budget: $500.1 Total: $345.5 Variance: ($154.6)

This is a supplemental project that was substantially completed in 2015, with final testing in 2016. The project is now complete. The scope included a major internal assessment of a transformer. The budget included an allowance for refurbishment, but the level of refurbishment estimated was not required.

61. Labrador West Transmission Project – Construction Phase (2014)

Budget: $329,592.1 Total: $12,376.8 Variance: ($317,215.3)

In 2014, the provincial Government approved the construction of the third transmission line in Labrador to help supply power for planned new development in Labrador West, such as the Kami Iron Ore Project, and improved reliability for all customers in the region. In September 2014, work on the line was temporarily suspended until completion of Alderson's financing plan which resulted in overall expenditures being lover than budgeted. All project costs to date, including the 2016 Interest During Construction costs, are covered by the security Alderon has already provided. Construction will proceed should additional funding be secured.

62. Purchase of 12 MW Diesel Generation - Holyrood

Budget: $4,700.0 Total: $3,784.0 Variance: ($916.0)

This supplemental capital project was initially envisioned as a one year project. Once approved, the purchase of the 6 diesel engines was completed in 2016. The remaining scope to make the new infrastructure permanent, including the environmental modeling and

changes to the exhaust stacks, could not be completed in the available time frame and was carried over to 2017. There is no change to the original budget.

4.16 Units 1 and 2 Boilers Lower Re-heater Boiler Tube Replacement and Reliability Improvements, Holyrood Thermal Generating Station

This supplemental project was approved and completed in 2016, with the actual expenditure within 1% of the approved project budget. The project scope included replacement of boiler lower re-heater tubes and a number of other reliability improvements. Item 10 of the reliability improvements (Section 3.3.2. of the supplementary application) was stated as:

> "While Hydro has not currently identified additional equipment for immediate replacement, it is possible an additional component may require replacement during the annual outages. Hydro proposes that any item, material in dollar value, that meets capitalization criteria, is required to be replaced to mitigate an unplanned outage in the coming winter season, and that can be replaced within this project's contingency, would be replaced and communicated to the Board via the year end Capital Expenditures Variance report."

The Board of Commissioners of Public Utilities approved this project with Board Order No. P.U. 19(2016) and ordered that: "Hydro shall report on the contingency expenditures associated with additional component replacements arising from this project, setting out in detail the work which was done, the associated costs and the justification, as a part of its year-end capital expenditures variance report."

Hydro identified and completed four items under these criteria, as summarized in Table 18.

Table 18

Item	Description	Cost ($,000)	Scope of Work and Justification
1	Boiler Floor Tube Refurbishment Unit 3	47.3	This work was based on an ultrasonic thickness inspection that was carried out that found pitting in the tubing, and tubing approaching minimum wall thickness. Welding refurbishment was completed to bring these tubes to an acceptable level.
2	Thermal Performance Study on Unit 3	210.9	This work included a review of Holyrood de-rate assessment analysis to identify any derating that should be applied to the power boilers, after the 2016 annual outages and the planned tube replacements were made. Tube samples were taken and specialized non-destructive examination were completed to confirm or deny the theoretical analysis, which induced the de-rate on Unit 3. The results of this work ensured that the de-rate of Unit 3 could be lifted. This would allow Hydro to operate reliably as planned to the end of service in 2021.
3	Steam Coil Air Heaters (SCAH) (Units 1 & 2)	124.4	This work was based on a condition identified during the unit outages. The SCAH were replaced because they were determined to be fouled and damaged beyond repair. Replacement was necessary prior to unit start-up.
4	Corrosion Mapping for 9 Air Receivers	73.0	During replacement of the #2 air compressor (an approved reliability scope item for this project), it was determined that a level 2 condition assessment of the nine associated air receivers (storage tanks) was required. This assessment was completed to ensure the long term reliability of the compressed air system.
TOTAL		455.6	

5.0 Capital Budget Verses Actual Expenditures 2007 – 2016

Table 19 provides a summary of Hydro's Capital Budget Variances for the years 2007-2016.

Table 19

Capital Budgets/Expenditures 2007-2016

Year	Budget	Actual Expenditures	Variance	Percentage Variance
2007	43,304	35,669	7,635	17.6%
2008	53,579	46,246	7,333	13.7%
2009	61,544	54,152	7,392	12.0%
2010	63,297	55,553	7,744	12.2%
2011	67,454	63,116	4,338	6.4%
2012	93,840	77,252	16,588	17.7%
2013	116,373	84,755	31,618	27.2%
2014	280,601	204,728	75,873	27.0%
2015	311,177	125,119	186,058	59.8%
2016	350,601	203,941	146,660	41.8%

The 2016 variance in actual expenditures compared to budget, an underspend of $145.9M, is attributable to two major projects, the 230 kV transmission line from Bay d'Espoir to Western Avalon (TL 267 – Variance #27), and the 230 kV line from Churchill Falls to Wabush (Labrador West Transmission Line – Variance #61). TL 267 includes a project underspend of $18.4M in relation to the original 2016 budget. The Labrador West Transmission Line work is suspended until completion of Alderson's financing plan for the Kami mine. Therefore, $129.0M associated with work that was planned to be completed in 2016 on the Labrador West Transmission Line was not completed due to a temporary suspension of the work in September 2014. These two projects account for approximately $147M.

6.0 Carryover Report

Table 20 provides a summary listing of the carryovers from 2010-2017.

[rest of page intentionally left blank]

Table 20

2016 Carryover Report
For the Year Ending December 31, 2016
($000)

Project Name	PUB Approved Budget 2016	Revised Budget 2016	Total Actual Expenditures 2016	Carryover Amount	Original Completion Year
Replace Pump House and Associated Equipment - Bay d'Espoir	522.5	408.2	128.6	279.6	2016
Upgrade Equipment Doors - Various Sites	0.0	162.1	115.4	46.7	2015
Replace UPS Systems - Hydro Place	889.8	889.8	928.6	(38.8)	2016
Install Hydrometeorological Equipment - Various Sites	314.1	314.1	4.3	309.8	2016
Overhaul Turbine/Generator Units #6 and #7 - Bay d'Espoir	1,213.5	466.4	410.2	56.2	2016
Refurbish Gas Generator Engines - Hardwoods and Stephenville	0.0	3,047.1	2,538.7	508.4	2016
Purchase Excavator - Bay d'Espoir	312.0	222.0	187.0	35.0	2016
Replace Roof on Service Building – Bishop's Falls	612.8	612.8	327.8	285.0	2016
Replace Radiator Unit 2029 Makkovik	0.0	49.0	27.5	21.5	2016
Upgrade Transformer Systems - Postville and Cartwright	465.2	465.2	296.0	169.2	2016
Implement Industrial Billing Software - Hydro Place	443.1	443.1	169.5	273.6	2016
Upgrade Enterprise Storage Capacity - Hydro Place	628.8	628.8	464.5	164.3	2016
Cost Recoveries	(291.6)	(291.6)	(215.5)	(76.1)	2016
Upgrade Server Technology Program - Hydro Place	492.5	492.5	451.1	41.4	2016
Cost Recoveries	(228.5)	(228.5)	(209.3)	(19.2)	2016
Replace Station Service Breakers - Cat Arm	363.4	362.2	185.9	176.3	2016
Replace Accommodations and Septic System - Ebbegunbaeg	1,061.4	1,456.6	811.2	645.4	2016
Upgrade Diesel Plant Production Data Collection Equipment-Various	280.7	653.8	510.6	143.2	2016
Purchase of 12 MW Diesel Generation - Holyrood	0.0	4,700.0	3,784.0	916.0	2016
Install Automated Meter Reading - Labrador West	433.8	433.8	130.4	303.4	2017
Replace Battery Banks and Chargers - Various Sites	425.0	425.0	365.7	59.3	2017
Replace MDR 4000 Microwave Radio East - Various Sites	77.4	77.4	113.4	(36.0)	2017
Replace Air Conditioners - Various Sites	39.9	39.9	51.2	(11.3)	2017
Replace Powerline Carrier - Various Sites	73.4	73.4	77.4	(4.0)	2017
Upgrade Telecontrol Facilities - Sandy Brook Hill	101.6	101.6	81.7	19.9	2017
Replace Control Room/Communications Room Air Conditioning – Hinds Lake	41.3	41.3	31.0	10.3	2017
Refurbish Station Water System – Upper Salmon	96.6	96.6	38.3	58.3	2017
Upgrade Work – Cat Arm	558.3	558.3	240.4	317.9	2017
Rehabilitate Shoreline Protection – Cat Arm	112.2	112.2	104.7	7.5	2017
Replace PH1 Station Service Transformer – Bay d'Espoir	46.7	46.7	45.0	1.7	2017
Replace Spherical By-Pass Valves Units 1 and 2 – Bay d'Espoir	183.6	183.6	154.8	28.8	2017
[					}
Replace Instrument Transformers – Various Sites	1,511.7	1,501.3	1,190.3	311.0	2017
Replace Surge Arrestors – Various Sites	144.4	144.4	175.1	(30.7)	2017

Replace Protective Relays – Various Sites	700.6	700.6	1,425.8	(725.2)	2017
Replace Disconnect Switches – Various Sites (2016-2017)	646.9	646.9	131.7	515.2	2017
Upgrade Digital Fault Recorders – Various Sites	197.9	197.9	221.2	(23.3)	2017
Upgrade Data Alarm Systems – Various Sites	74.4	74.4	49.7	24.7	2017
Install Breaker Failure Protection – Various Sites	65.7	65.7	81.8	(16.1)	2017
Install Fire Protection in 230 kV Stations – Bay d'Espoir	200.0	200.0	91.4	108.6	2017
Upgrade Warehouse Lighting – Bishop's Falls	15.2	15.2	28.1	(12.9)	2017
Replace Fuel Piping – Hardwoods and Stephenville	44.8	44.8	11.6	33.2	2017
Upgrade Human Machine Interface – Various Sites	114.0	114.0	125.3	(11.3)	2017
Install Variable Frequency Drives – Grey River	46.9	46.9	49.7	(2.8)	2017
Replace Vehicles and Aerial Devices – Hydro System (2016-2017)	1,443.3	1,443.3	1,032.7	410.6	2017
Purchase Vehicles and Aerial Devices – Various Sites	382.5	382.5	470.4	(87.9)	2017
Refurbish Anchors and Footings TL202 and TL206 – Bay d'Espoir to Sunnyside	1,038.4	1,038.6	19.9	1,018.7	2017
Replace Aircraft Markers at Grand Lake Crossing – TL228	589.6	589.6	61.8	527.8	2017
Upgrade Distribution Systems – Various Sites (2016-2017)	285.6	285.6	361.8	(76.2)	2017
Additions for Load Growth – Various Sites	883.4	883.4	190.4	693.0	2017
Install Fire Protection Systems – Cartwright and Nain	3,030.7	2,339.9	782.8	1,557.1	2017
Replace Programmable Logic Controllers – Various Sites	346.0	315.7	345.5	(29.8)	2017
TL 227 Distribution Line Sally's Cove L1	0.0	717.0	186.3	530.7	2017
Upgrade Terminal Station for Mobile Substation – Cow Head	40.0	40.0	27.5	12.5	2017
Replace Air Conditioning Units 8 and 14 – Hydro Place	34.6	34.6	31.0	3.6	2017
Replace Site Facilities – Bay d'Espoir	928.3	928.3	270.4	657.9	2018
Upgrade Powerhouse Building Envelope – Holyrood	2,723.8	2,723.8	2,239.9	483.9	2018
230 kV Transmission Line – Bay d'Espoir to Western Avalon	75,284.3	85,426.4	59,317.8	26,108.6	2018
Construct 230 kV Transmission Line – Soldiers Pond to Hardwoods	3,699.0	3,699.0	3,501.6	197.4	2018
Upgrade Microsoft Project – Hydro Place	366.6	366.6	352.1	14.5	2018
Upgrade Circuit Breakers – Various Sites (2016-2020)	6,969.1	6,969.1	5,599.5	1,369.6	2020
				38,255.7	

7.0 Safety Hazards

In Board Order No. P.U. 38(2010) 2011 Capital Budget, the Board directed Hydro to include an explanation in Hydro's annual. Please see the following Table 21 for projects undertaken in 2016.

Total Approved Budget: **$199,300**
Total Expenditure: **$175,378**

[rest of page intentionally left blank]

Table 21

Safety Hazards			
Project Title/Location	**Expenditure**	**Safety Hazard Identified**	**Project Scope**
Holyrood Unit 3 – Upgrade Continuous Blowdown Throttling Valve	$57.1	Prior to this improvement, the piping and manual throttling valve configuration for the boiler blowdown tank for Holyrood Unit 3 did not allow quick egress in the event that a failure occurred, resulting in emitted steam. If a release occurred, steam would have quickly filled the area, creating a visibility hazard and making egress more difficult. In addition to this concern, the valve location required an operator to extend beyond the range of safe ergonomics to operate the valve. As this throttling valve is required to be continuously adjusted while the boiler is online, the ability to operate the valve in a safe location, using proper ergonomics is required.	To address the hazard, an upgrade to the Unit 3 continuous blowdown tank throttling valve was completed. The manually operated valve was upgraded to an actuated throttling valve, which allows the operator to adjust it while outside the valve location. This removes the plant operator from any potential safety or ergonomic hazards, eliminating the need for a plant operator to enter an unsafe location while the boiler is online. The valve was equipped with a digital controller that adjusts the position of the throttling valve; this allows the operator to verify the valve is operating correctly.

Safety Hazards			
Project Title/Location	**Expenditure**	**Safety Hazard Identified**	**Project Scope**
Holyrood Unit 3 – Upgrade Main Steam Seat Drain Valves	$25.3	Prior to this improvement, a plant operator had to descend a ladder to operate a main steam valve which is located above the seat drain valves. The existing piping and valve configuration did not allow quick egress in the event that a failure occurred, resulting in emitted steam. If a release occurred, steam would quickly fill the area, creating a visibility hazard and making egress more difficult.	To address this hazard, an upgrade to the two Unit 3 main steam stop valves was completed. The existing y-pattern main steam valves were replaced with t-pattern valves complete with handle extensions. This allows operation from the plant floor

			level and eliminates the need for a plant operator to enter a hazardous location.
Holyrood – Install Chemical Shower & Eye Wash Station Water Heaters	$93.0	Prior to this improvement, equipment did not include any form of heating for the domestic water used by the critical emergency showers and eye wash stations at the Holyrood Thermal Generating Station. Emergency showers and eye wash stations are required safety equipment and have a defined required performance, as outlined in ANSI Z358.1-2014. Emergency showers must provide tepid water, between 16°C and 38°C, with a minimum flow of 20 gallons per minute for the required decontamination time. The chemical showers currently meet flow requirements but provided water at 4°C to 12°C, depending on the seasonal temperature of Quarry Brook, the water source. Based on the treatment requirements of the chemical exposures, the minimum required shower time is 20 minutes creating a safety hazard due to the exposure time at potentially cold temperatures.	To address this hazard, water heaters and automatic mixing valves were installed for critical emergency showers and eye wash stations at the Holyrood Thermal Generating Station.

Exhibit 7 - Annual Reports on Key Performance Indicators

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2014 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14(2004)

NEWFOUNDLAND AND LABRADOR HYDRO

TABLE OF CONTENTS

1 Introduction 3
2 Overview of Key Performance Indicator Results 4
2.1 Overview 4
2.2 Performance in 2014 versus 2014 Target 5
3 Performance Indices 6
3.1 Reliability Performance Indicators 6
3.1.1 Reliability KPI: Generation 6
3.1.2 Reliability KPI: Transmission 10
3.1.3 Reliability KPI: Distribution 17
3.1.4 Reliability KPI: Other 23
3.2 Operating Performance Indicators 26
3.2.1 Operating KPI: Generation 26
3.3 Financial Performance Indicators 29
3.4 Customer-Related Performance Indicators 34

Appendix A: Rationale for Hydro's 2014 KPI Targets
Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance
Appendix C1: Significant Transmission Events – 2014
Appendix C2: Significant Distribution Events – 2014 (Excluding Fourth Quarter)
Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)
Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

1 Introduction

In Order No. P.U. 14(2004), the Board required Newfoundland and Labrador Hydro (Hydro) to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 16 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. At the time of this report, CEA data has been published only to 2013. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2014 compared with the prior year as well as a comparison of actual KPI results compared with targets.

Section 3 of this report provides a detailed analysis of each individual KPI within the four categories named above in Section 3. In addition, it provides fourth quarter data for transmission and distribution reliability which is routinely included in Hydro's quarterly regulatory reports.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available. In addition, it provides fourth quarter data for transmission and distribution reliability which is routinely reported in quarterly regulatory reports.

The 2014 financial data and 2015 targets in Section 4 Data Table of Key Performance Indicators are not available at this time. This section will be re-filed after the financial data is available and the 2015 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Overview

A number of key indices measured by Hydro showed improvement when compared to 2013 or the targets for 2014. All indices are discussed in the following sections of this Appendix. Some highlights are below.

- Residential Customer Satisfaction was 84% in 2014 compared to a target of 80%.

- There was an improvement in generation availability in 2014 when compared to 2013. Hydro's Weighted Capability factor, which measures generating unit availability, was 79.7% in 2014 compared to 75.5% in 2.13. The availability of the Holyrood thermal plant improved to 63% in 2014, compared to 46% in 2013. The availability of gas turbines improved to 80%, compared to 62% in 2013. The availability of Hydro's hydraulic plants was 88% in 2014, compared to 92% in 2013. With the exception of Unit 6 at the Bay d'Espoir generating station, Hydro's hydraulic units' availability was consistent with historic performance. Impacting on the overall hydraulic unit availability was a failure of a rectifying transformer Unit 6 and the subsequent failure of the spare during the winter months. These transformer issues resulted in an extended outage to Unit 6 that impacted hydraulic availability.

- Derating-Adjusted Forced Outage Rate (*DAFOR - measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages*)
- Hydro's DAFOR performance was 8.2% in 2014, compared to 13.7% in 2013.
- The frequency of transmission delivery point outages improved in 2014, compared to 2013. The forced outage component of transmission delivery point outages also improved in 2014, compared to 2013.
- The hydraulic conversion factor at Bay d'Espoir improved in 2014 from 2013. In 2014, the water levels experienced in the reservoirs were generally lower. This allowed greater output flexibility resulting in improved water utilization at the Bay d'Espoir plant. The target was met in 2014 for this measure.

Other indices did not exhibit the same improvement in comparison to the 2013 performance or target.

- There were 14 underfrequency load shedding events in 2014. This is compared to a 2014 target of six events and a 2013 performance of seven events.
- Transmission and Distribution reliability were impacted by the significant disturbances on January 4 and 5 which were precipitated by a transformer failure at Sunnyside Terminal Station and subsequent breaker failures. Additionally, there were a number of severe weather related outages, primarily occurring in the Central region in February and April.

The 2014 operating KPI for energy conversion at Holyrood was primarily impacted by the low heating content in the fuel consumed at the plant, in addition to a lower average unit loading.

A review of all indices are contained in the following sections.

2.2 Performance in 2014 versus 2014 Target

The table below summarizes Hydro's KPI performance in 2014. The rationale for the 2014 targets was summarized in the February 2014 report to the Board entitled *2013 Annual Report on Key Performance Indicators*. The 2014 rationale is included in this report as Appendix A.

Category	KPI	Units	2014 Target	2014 Results
Reliability	Weighted Capability Factor (WCF)	%	84.0[1]	79.7
	DAFOR	%	2.7	8.2
	T-SAIDI	Minutes/Point	180[2]	458
	T-SAIFI	Number/Point	1.6	3.8
	T-SARI	Minutes/Outage	114	121
	SAIDI	Hours/Customer	5.9	19.56
	SAIFI	Number/Customer	3.6	6.77
	Underfrequency Load Shedding	# of events	6	14
Operating	Hydraulic CF	GWh/MCM	0.433	0.433
	Thermal CF	kWh/BBL	615	584
Financial	Controllable Unit Cost	$/MWh	Not Applicable	18.09
Other	Customer Satisfaction (Residential)	Max=100%	80%	84%

[1] The Weighted Capability Factor target is based on planned annual maintenance outages, an allowance for other short duration maintenance outages and targeted forced outage durations.
[2] Transmission and distribution reliability targets were set on combined planned and unplanned outages.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator data within four general categories: Reliability, Operating, Financial, and Customer-Related.

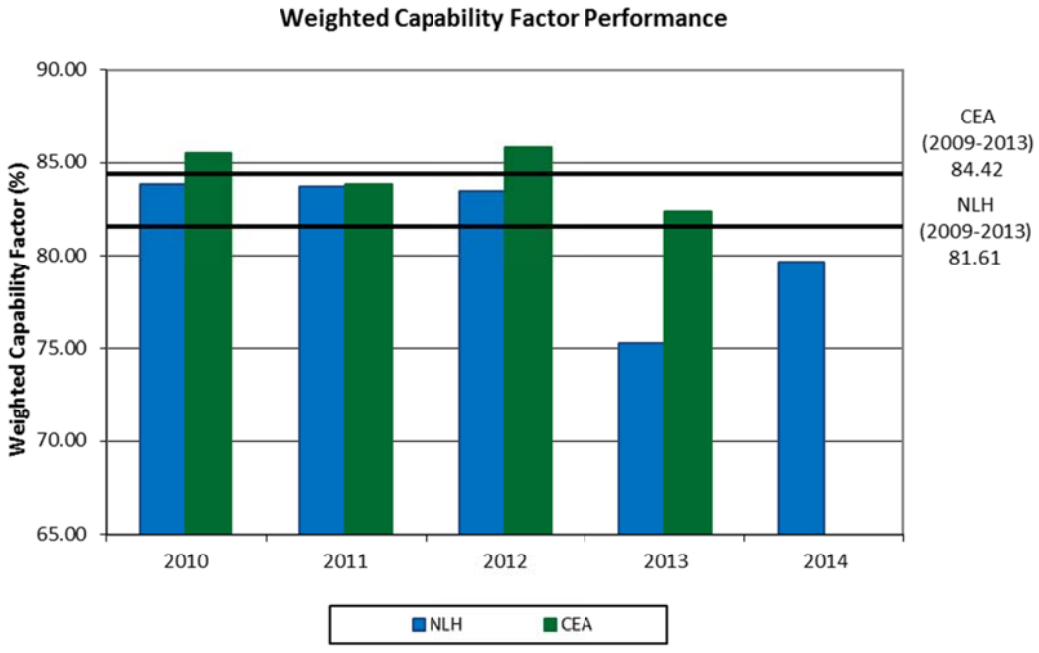
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2014, Hydro's WCF was 79.7%, compared to 75.5% in 2013 and a target of 84%. The 2009 to 2013 Hydro five-year average is 81.6%. The annual target for availability includes the time that units are out for maintenance. Therefore, the capability in any year is affected by the maintenance and capital work planned for that year.



Thermal unit WCF was 63% in 2014 compared to 46% in 2013. The overall 2014 Thermal WCF target was 67%. Holyrood Unit 3 had a capability factor of 69%, Unit 2 had a capability factor of 61%, and Unit 1 had a capability factor of 60%. Holyrood unit maintenance and planned outages were completed within the intended timeframes. A Holyrood unit was operated throughout the summer months in 2014 in order to support the transmission into the Avalon Peninsula.

Overall, the hydraulic unit WCF performance was 88%, compared to 92% in 2013 and a target of 92%. The primary driver for the 88% WCF is the failure of two rectifying transformers on Bay d'Espoir Unit 6. The in-service rectifying transformer failed on January 30 and the unit was returned to service on February 1, using the spare transformer. This spare transformer failed on February 17 and, with no other spares available, a new transformer was required to be built. The unit was returned to service on August 5 with a new rectifying transformer. Removing the impact of the rectifying transformer failure from the hydraulic WCF, results in an annual hydraulic WCF outcome which is approximately equal to the target of 92%.

Gas turbine availability improved to 80% in 2014 from 62% in 2013. The 2014 gas turbine WCF target was 86%.

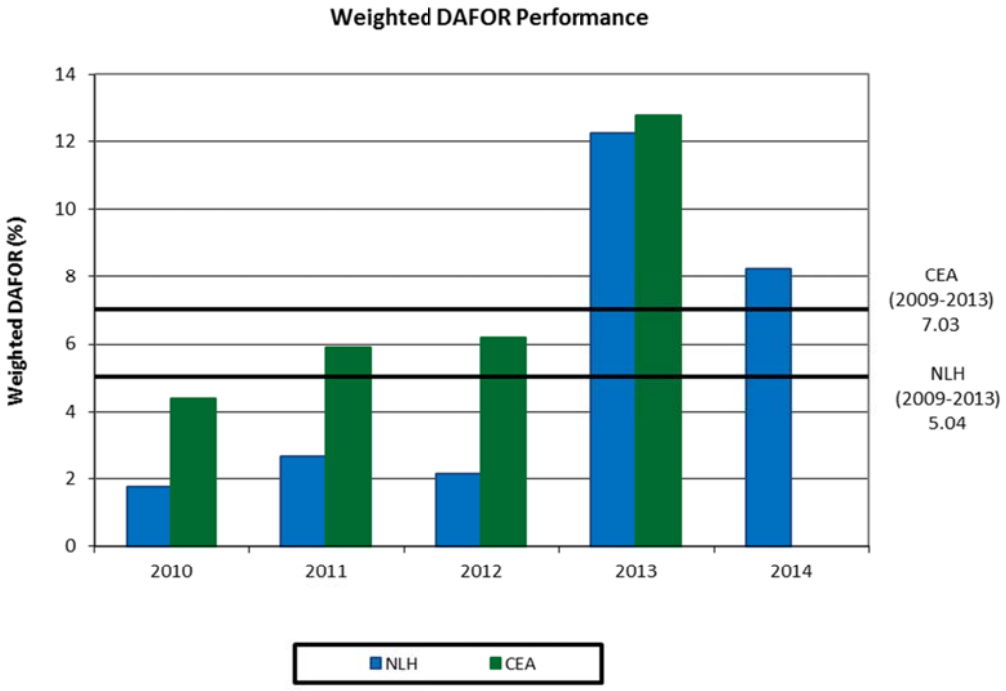
Calculation details for weighted capability as well as a list of factors that can impact KPI performance are included in Appendix B of this report.

3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[3]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2014, Hydro's weighted DAFOR was 8.2%, compared to 12.2% in 2013 and a target of 2.7%. The thermal DAFOR for 2014 was 13.7%, compared to 36.6% in 2013 and a target of 8.0%. The variance from target for the thermal units was not attributed to any major failures on any one unit, but rather a series of minor failures of one to three days in duration. The hydraulic DAFOR was 5.9% compared to 0.55% in 2013 and a target of 0.6%. The hydraulic DAFOR was impacted by the failures of the rectifying transformers on Bay d'Espoir Unit 6, as described in the previous section. These failures contributed approximately 83% of the overall 2014 hydraulic DAFOR.

Hydro's overall weighted DAFOR for the period 2009 to 2013 is 5.0%, 2.0% better than the equivalently weighted national average of 7.0% for the same period.

[3] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.



3.1.1 c) Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2013 and for the latest CEA national average for the period 2009-2013 are included for comparison.

Generation Performance Indices

Index		Hydro	Thermal	Gas Turbine
Failure Rate	NLH 2014	2.67	11.72	160.36
(Forced Outages per 8,760	NLH 2013	1.42	8.84	144.46
operating hours)	CEA '09-'13	2.01	7.12	22.39
Incapability	NLH 2014	11.30	36.41	17.36
Factor	NLH 2013	7.97	53.96	35.64
(Percent of Time)	CEA '09-'13	10.27	26.76	13.33
Derating Adjusted Forced	NLH 2014	5.87	13.74	
Outage Rate	NLH 2013	0.55	36.58	
(Percent of Time)	CEA '09-'13	4.17	12.69	
Utilization	NLH 2014			14.34
Forced Outage	NLH 2013			28.07
Probability (Percent of Time)	CEA '09-'13			13.07

Hydraulic Unit Performance

The extended forced outage to Unit 6 at Bay d'Espoir resulting from the rectifying transformer failures impacted all hydraulic unit measures in 2014, when compared to 2013 and to the national five year averages. In excluding these transformer failures, the performance of the remaining hydraulic units was consistent with past performance.

Thermal Unit Performance

Thermal unit performance improved in 2014 in the areas of Incapability Factor and DAFOR, when compared to 2013. Failure rate performance in 2014, when compared to 2013, was impacted by a series of minor vibration issues at Unit 2 which occurred during startup of the unit following its annual maintenance. These vibration issues were addressed in the fourth quarter of 2014.

Gas Turbine Unit Performance

The Incapability Factor and Utilization Forced Outage Probability (UFOP) performance of Hydro's gas turbines improved in 2014 when compared to 2013. In comparison to the national average, the Failure Rate is high due to the normally low operating hour requirements of Hydro's gas turbines. Units across the country are often used on a more frequent basis and therefore their failure rate percentage is lower than those of a standby unit. Of particular importance to Hydro's gas turbines fleet is the UFOP which measure the degree to which a standby unit can be called upon to supply load when requested. The UFOP in 2014 was 14.3%, compared to 28.1% in 2013 and the CEA five year average of 13.1%.

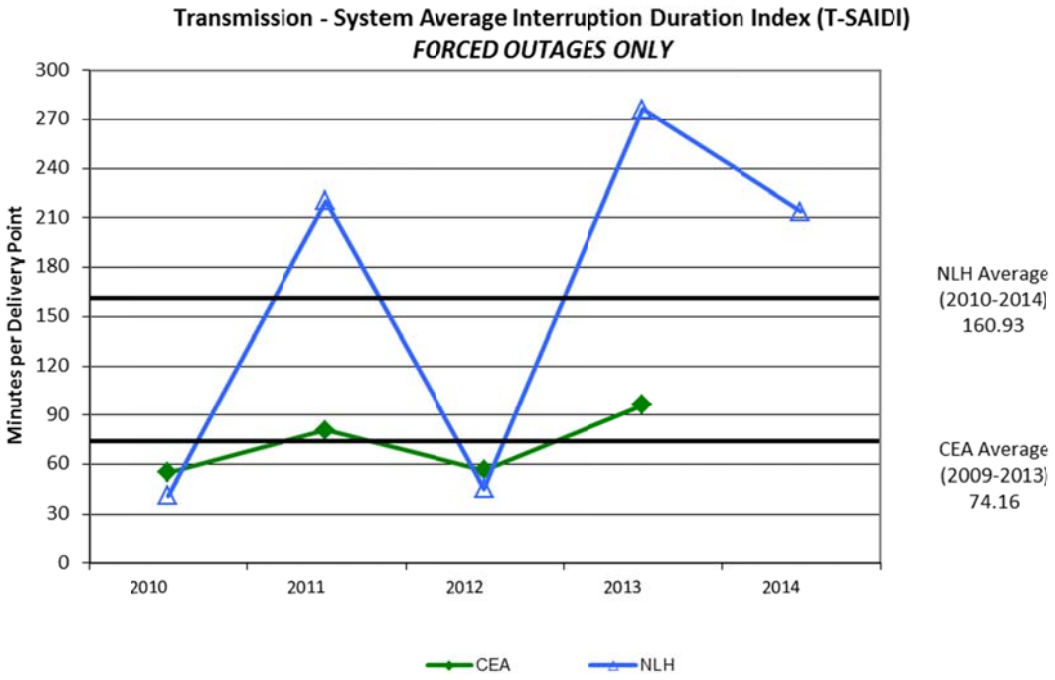
3.1.2 Reliability KPI: Transmission

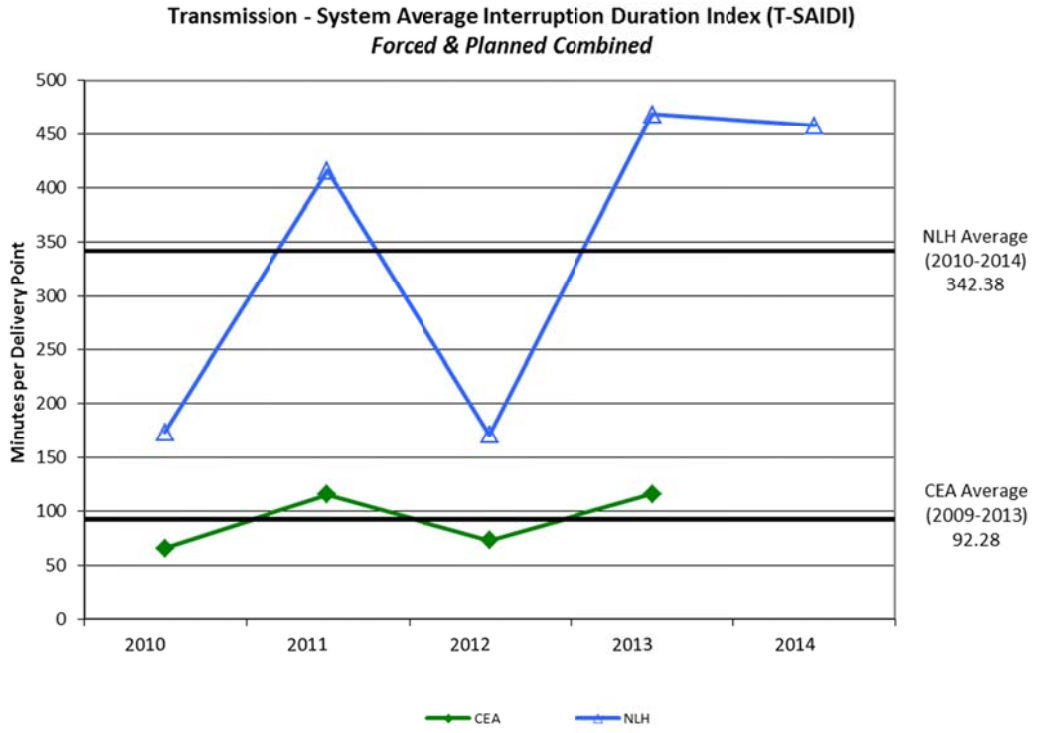
3.1.2 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 96 minutes per delivery point (forced and planned combined) compared to 120 minutes in 2013.

The total 2014 T-SAIDI was 458 minutes per delivery point compared to a 2013 total of 469 minutes per delivery point and a target of 180 minutes per delivery point. The forced outage duration in 2014 was 214 minutes, compared to 277 minutes in 2013 and a 2014 target of 53 minutes per delivery point. The planned outage duration was 244 minutes, compared to 192 minutes in 2013 and a target of 128 minutes per delivery point.

The significant outages which occurred on January 4 and 5, originating on the Avalon Peninsula, contributed 120 minutes per delivery point to the forced outage T-SAIDI for 2014 (approximately 56% of the total forced T-SAIDI). The increase in the T-SAIDI for planned outages was the result of increased maintenance on terminal station equipment.



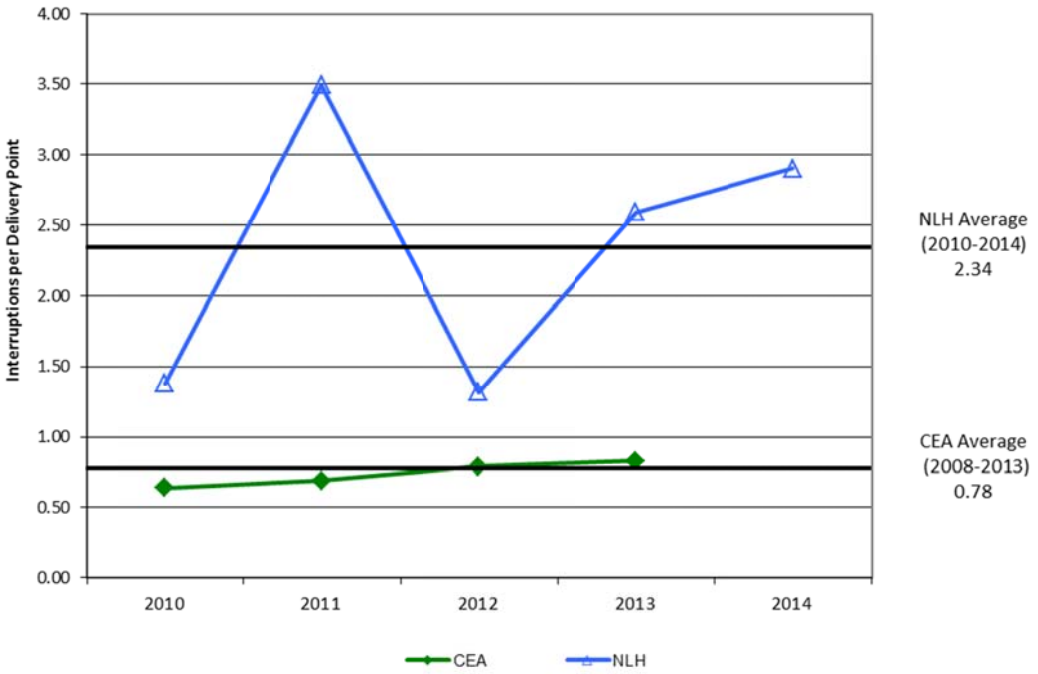


3.1.2 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

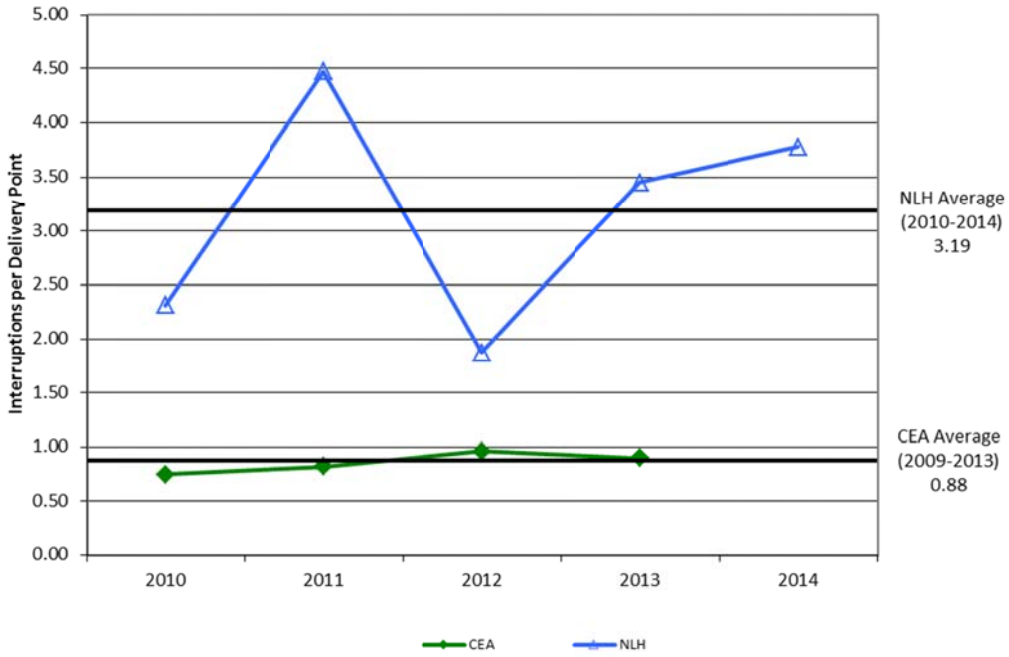
The fourth quarter T-SAIFI was 0.48 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.17 and 0.31, respectively. The 2013 fourth quarter T-SAIFI was 0.91 outages per bulk delivery point.

The 2014 T-SAIFI was 3.78 outages per bulk delivery point, compared to 2013 T-SAIFI of 3.45 outages per delivery point and the 2014 target of 1.58. The number of forced outages per delivery point in 2014 was 2.90 compared to 2.59 in 2013. The number of planned outages per delivery point in 2014 was 0.88 compared to 0.86 in 2013.

Transmission - System Average Interruption Frequency Index (T-SAIFI)
FORCED OUTAGES ONLY



Transmission - System Average Interruption Frequency Index (T-SAIFI)
Forced & Planned Combined

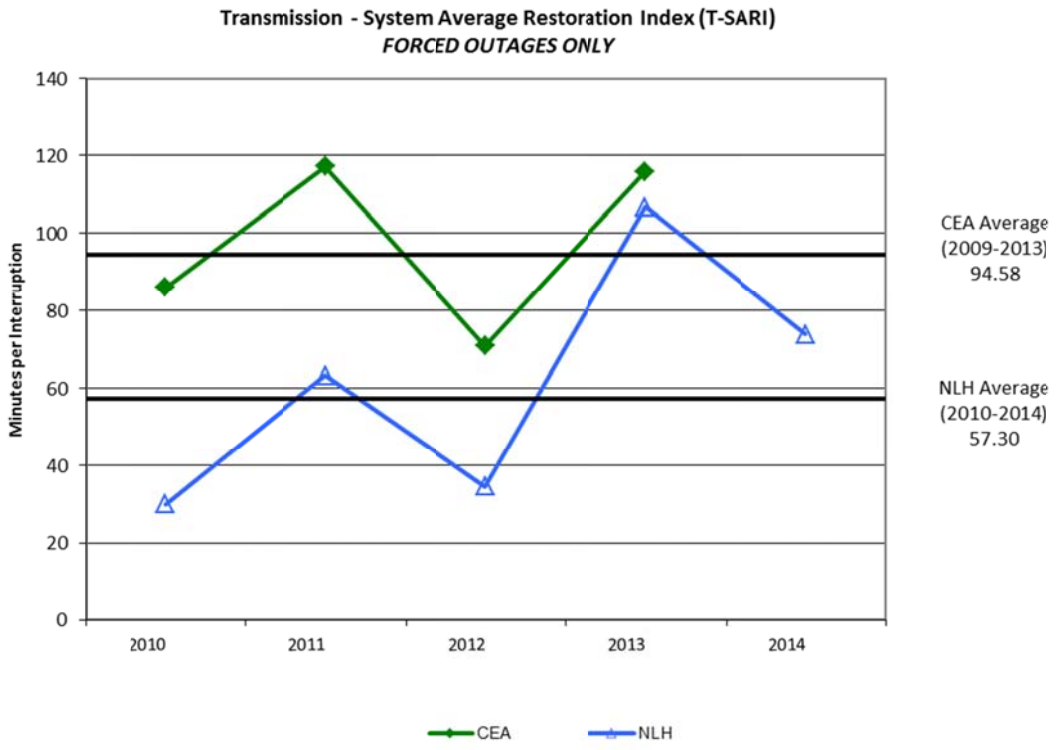


3.1.2 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

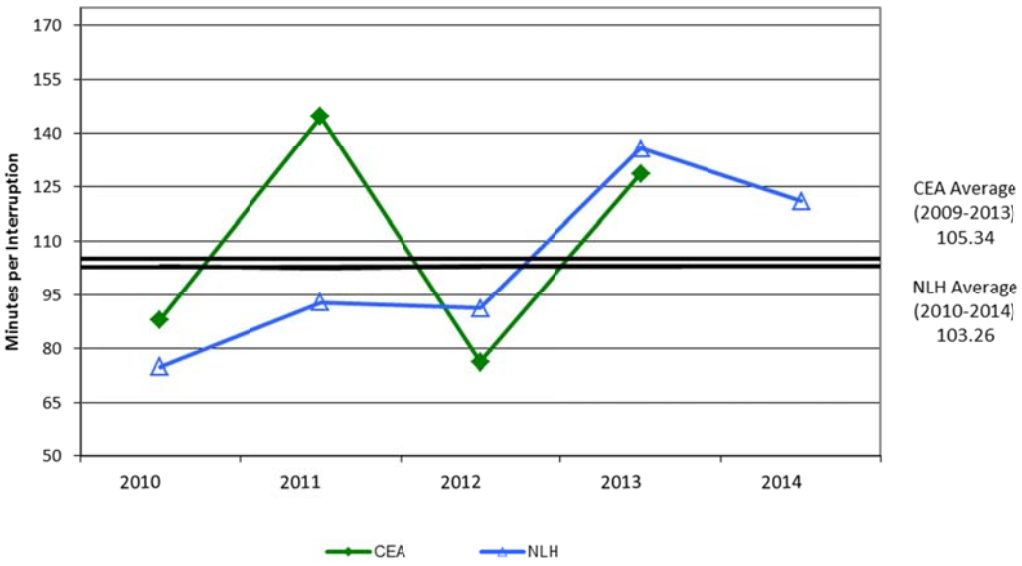
Hydro's total transmission T-SARI was 199 minutes per interruption for the fourth quarter of 2014, compared to 131 minutes per interruption during the same quarter in 2013. The forced outage component of T-SARI was 42 minutes per interruption, compared to 91 minutes per interruption in 2013. The planned outage component of T-SARI was 286 minutes per interruption compared to 192 minutes in 2013.

Hydro's 2014 total transmission T-SARI on an annual basis was 121 minutes per interruption, compared to 136 minutes in 2013 and a 2014 target of 114 minutes. The forced outage component of T-SARI was 74 minutes per interruption, compared to 107 minutes in 2013. The planned outage component of T-SARI was 277 minutes per interruption, compared to 223 minutes in 2013. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase results from the increase in T-SAIDI relative to T-SAIFI.

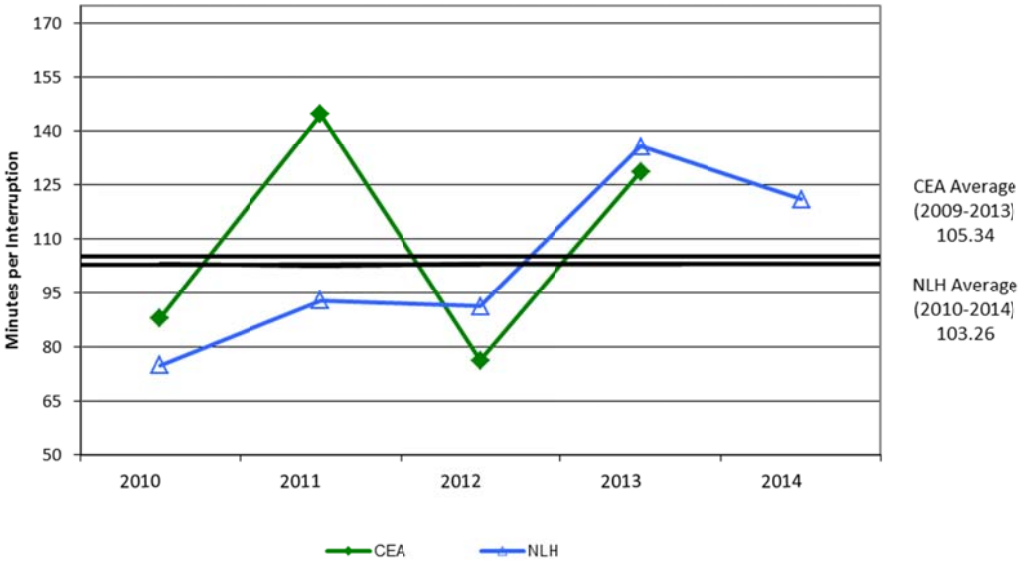
Hydro's total T-SARI performance improved in 2014 compared to 2013 and is better than the latest CEA five year average.



Transmission - System Average Restoration Index (T-SARI)
Forced & Planned Combined



Transmission - System Average Restoration Index (T-SARI)
Forced & Planned Combined



There were four forced transmission outages and 11 planned transmission outages in the fourth quarter. A summary of these outages follows:

Forced

On October 4, customers supplied by the Main Brook and Roddickton Terminal Stations experienced an unplanned power outage of ten minutes. The outage occurred at the commencement of a planned outage to perform preventative maintenance on breakers at the St. Anthony Airport Terminal Station. During the switching to prepare for the planned outage, there was a protection trip of TL261 on opening L56T1. Customers in St. Anthony continued to be supplied via the St. Anthony Diesel Plant.

On October 29, all customers on the Great Northern Peninsula, north of and including Plum Point, experienced an unplanned power outage of up to one hour and 32 minutes. The outages were caused by the misoperation of the neutral overcurrent protection on Plum Point transformer T1 resulting in a transformer lockout which tripped transmission Lines TL241 and TL244. The protection was activated by issues on feeder L2 in the Plum Point distribution area. Customers north of Plum Point were subjected to an extended outage due to the failure of a micro switch on the high side disconnect switch B1T1 on T1 at Plum Point. The failure of this micro switch required that personnel travel to Plum Point to reset the transformer lockout before TL241 and TL244 could be restored. The St. Anthony Diesel Plant was started to restore St. Anthony customers.

On November 9, customers supplied by the Main Brook and Roddickton Terminal Stations experienced an unplanned power outage of 25 minutes. The outage occurred during switching for a planned outage at the St. Anthony Airport Terminal Station. The customers in Main Brook, Roddickton and St. Anthony distribution systems were planned to be supplied by the St. Anthony diesel plant. The outage occurred when TL261 tripped when disconnect switch L56T1 was opened. The trip is related to an issue with the line distance protection on TL261 operating when the St. Anthony Airport Terminal Station is disconnected from the grid, while the St. Anthony Diesel Plant is on-line supplying customers in the St Anthony, Roddickton and Main Brook areas. A similar trip occurred on October 4. The problem with the line protection has been addressed to prevent further misoperations.

On December 17, customers supplied by the Hawke's Bay Terminal Station experienced an unplanned power outage of 16 minutes. The outage occurred after a fault occurred during the energization of the Mobile Substation P235 at Hawke's Bay during planned work. A set of temporary transportation grounds were not removed from P235 prior to its energization.

Planned

On October 4, customers supplied by the Bear Cove Terminal Station experienced a planned power outage of 13 minutes. The outage was required to isolate transmission line TL244 to perform preventative maintenance on breaker B1L44 at Plum Point Terminal Station.

On October 7, customers supplied by the Parson's Pond Terminal Station experienced a planned power outage of five hours and 16 minutes. The outage was required to perform preventative maintenance on equipment in the terminal station.

On October 18, customers supplied by the Wiltondale and Glenburnie Terminal Stations experienced a planned power outage of five hours. The outage was required to connect mobile substation P235 in Wiltondale in order to perform terminal station improvements.

On November 1, customers supplied by the Jackson's Arm and Hampden Terminal Stations experienced a planned power outage of six hours and 17 minutes. The outage was required to perform preventive maintenance on equipment in the terminal stations.

On November 2, customers supplied by the Jackson's Arm and Hampden Terminal Stations experienced a planned power outage of five hours and 36 minutes. The outage was required to complete preventive maintenance on equipment in the terminal stations.

On November 3, customers supplied by the Cow Head Terminal Station experienced a planned power outage of five hours and 36 minutes. The outage was required to remove the high voltage leads on circuit breaker B1L27 in the terminal station. Working is continuing to replace this breaker.

On November 5, customers supplied by the Rocky Harbour Terminal Station experienced a planned power outage of one hour and 11 minutes (71 minutes). The outage was required to obtain a dissolved gas analysis sample from transformer T1 in the station, in addition to the installation of a new pole on feeder L1 in the Rocky Harbour distribution system.

On November 13, customers supplied by the Cow Head and Parson's Pond Terminal Stations experienced a planned power outage of five minutes. The outage was required to safely close bypass switch B1L27-BP at Cow Head Terminal Station.

On November 16, all customers supplied by the Plum Point and Bear Cove Terminal Stations and customers supplied by feeder L2 in St. Anthony experienced a planned power outage of up to seven hours and 44 minutes. Customers in Main Brook, Roddickton, and St. Anthony feeders L1 and L3 were supplied via the St. Anthony Diesel Plant. The outages were required to perform preventative/corrective maintenance on circuit breaker B1L56, disconnect switch B1L44 and the BC6-R1 recloser structure at the Bear Cove station; and to perform preventative/corrective maintenance on circuit breaker B1L41, bypass switch B1L41-BP and disconnect switch B1T1 at the Plum Point station. In addition, the outage facilitated replacement of a pole on structure 405 on transmission line TL241.

On November 22, NP customers supplied by the Sunnyside Terminal Station experienced a planned power outage of five hours and 45 minutes. The outage was required to complete corrective and preventive maintenance on disconnect switches on bus B3 at the terminal station.

On December 2, customers supplied by the Wiltondale and Glenburnie Terminal Stations experienced a planned power outage of five hours and 51 minutes. The outage was required to disconnect the mobile substation P235 in Wiltondale and to energize the new Wiltondale Terminal Station.

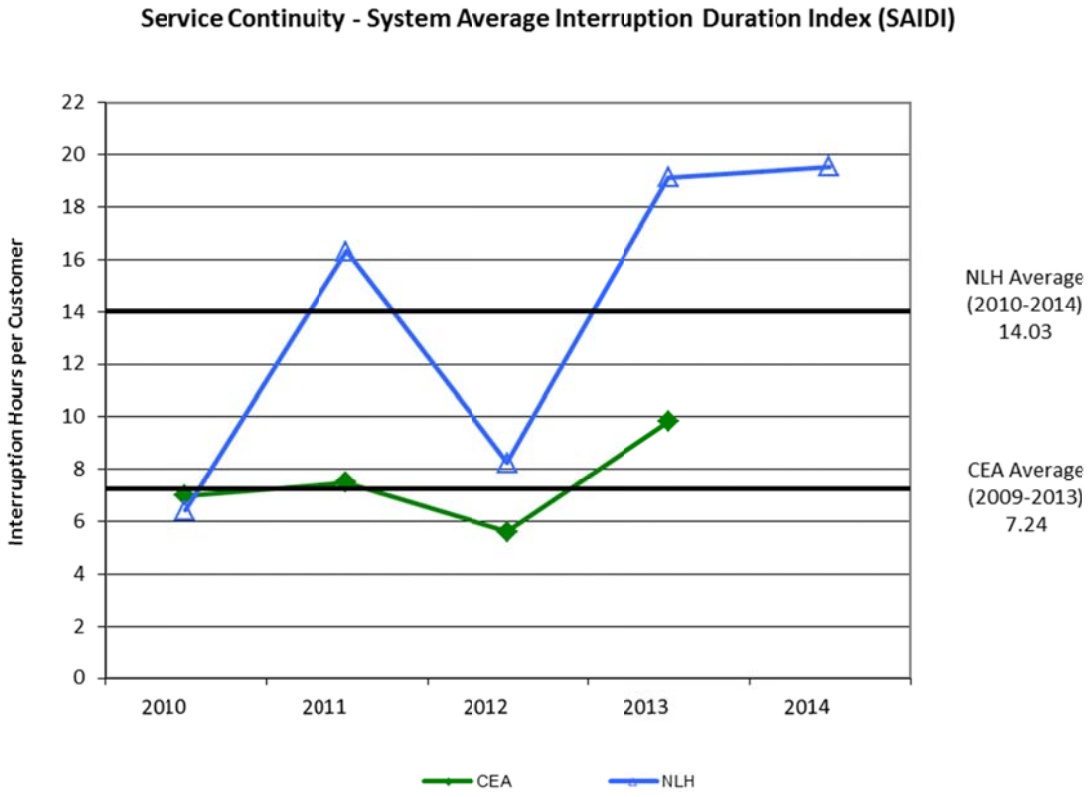
3.1.3 Reliability KPI: Distribution

3.1.3 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2014, SAIDI was 2.56 hours per customer, compared to 5.01 hours per customer during the same quarter of 2013.

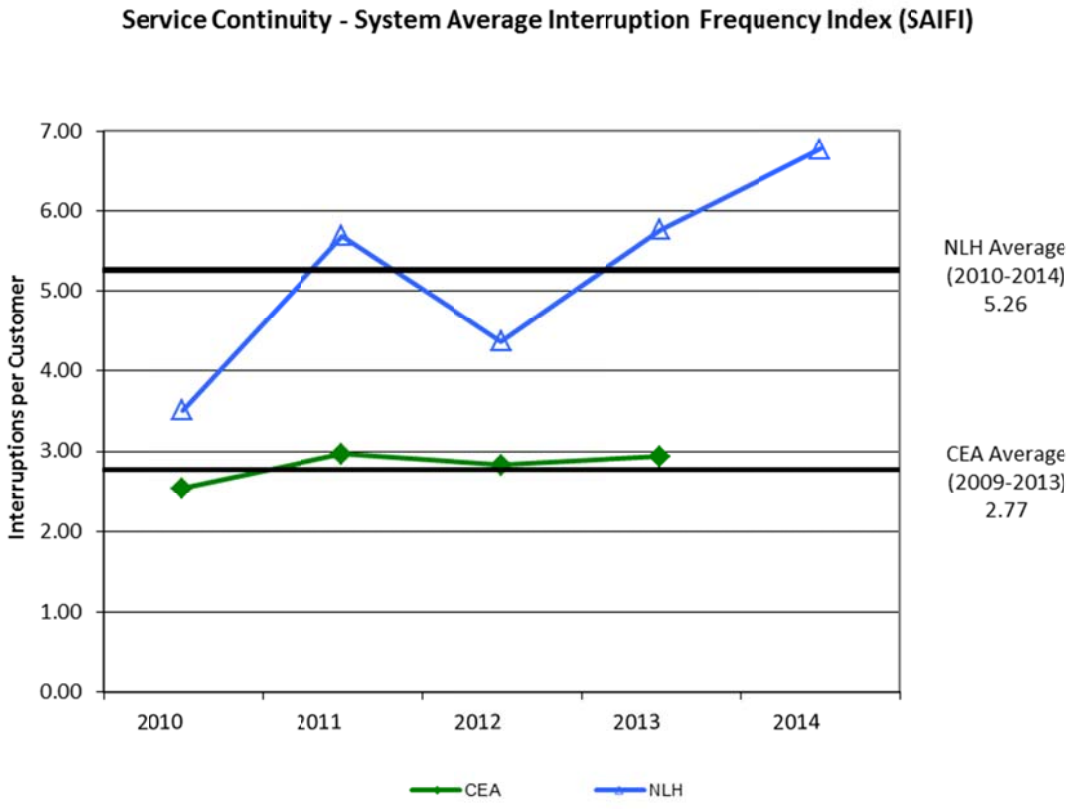
The total 2014 SAIDI was 19.56 hours per customer, compared to 19.22 hours per customer in 2013.

One of the main contributors to SAIDI was a series of planned outages in Labrador City and Wabush in the summer and fall of 2014. The planned outages in Labrador City were required to complete the voltage conversion project, while the Wabush planned outages were to complete upgrades at the Wabush Substation and for various distribution feeders.



3.1.3 b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter of 2014 SAIFI was 1.18, compared to 1.41 during the same quarter of 2013. The total 2014 SAIFI was 6.77, compared to 5.82 in 2013 and a target of 3.65 in 2014.



The outages during the fourth quarter resulted from a variety of causes. The following table presents a summary of the major interruptions.

Distribution System	Outage Date	Outage Cause	Customers Affected	Outage Duration (Hours)	Notes
Labrador City	Oct 04, 2014	Sched Outage-Planned	593	4.00	Planned outage to safely perform voltage conversion upgrades
Labrador City	Oct 19, 2014	Sched Outage-Planned	207	4.00	Planned outage to safely perform voltage conversion upgrades
L'Anse-Au-Loup	Oct 25, 2014	Adverse Weather	984	7.47	High Winds/Line damaged and required repairs
Ramea	Oct 31, 2014	Adverse Weather	330	4.77	Phase wired burnt off and had to be re-attached
Rigolet	Nov 08, 2014	Loss of Supply	172	50.00	Problems with diesel generator. Power rotation
Black Tickle	Nov 19, 2014	Defective Equipment	33	22.25	Broken Conductor on feeder. Outage extended to due weather delay in getting extra crews on site.
Black Tickle	Dec 25, 2014	Loss of Supply	102	24.22	Severe icing on feeder caused problems on diesel plant. Outage extended to due weather delays In getting extra crews on site.

A summary of the more significant 2014 interruptions affecting the distribution systems (i.e., outages generally to a complete system with duration of greater than five hours) are contained in Appendix C2.

3.1.3 c) Additional Information

As per Hydro's regular quarterly report, this section provides more detailed information on distribution system interruptions with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2014	**2013**	**2014**	**2013**	**Average**
Central					
Interconnected	0.27	0.71	2.48	4.02	2.78
Isolated	1.04	0.01	3.63	2.85	3.54
Northern					
Interconnected	1.19	1.91	7.26	4.90	5.22
Isolated	3.89	1.45	13.74	4.81	7.97
Labrador					
Interconnected	1.01	1.75	9.76	8.74	7.22
Isolated	6.10	2.24	10.88	9.04	10.02
Total	1.18	1.41	6.77	5.82	5.26

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2014	**2013**	**2014**	**2013**	**Average**
Central					
Interconnected	0.64	7.46	9.18	21.37	11.90
Isolated	1.88	0.05	4.56	2.55	3.30
Northern					
Interconnected	3.03	6.18	22.87	12.13	14.80
Isolated	10.15	0.94	43.60	6.07	13.87
Labrador					
Interconnected	1.72	2.67	26.48	28.56	16.79
Isolated	11.75	1.40	14.70	8.22	13.14
Total	2.56	5.01	19.56	19.22	14.03

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2014	**2013**	**2014**	**2013**	**Average**
Loss of Supply – Transmission	0.01	0.27	2.34	1.32	1.67
Loss of Supply – NF Power	0.00	0.01	0.00	0.01	0.01
Loss of Supply – Isolated	0.19	0.11	0.46	0.48	0.50
Loss of Supply – L'Anse au Loup	0.03	0.00	0.24	0.05	0.09
Distribution	0.96	1.02	3.73	3.95	2.99
Total	1.18	1.41	6.77	5.82	5.26

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2014	**2013**	**2014**	**2013**	**Average**
Loss of Supply – Transmission	0.04	0.56	4.22	4.36	3.51
Loss of Supply – NF Power	0.00	0.04	0.00	0.05	0.14
Loss of Supply – Isolated	0.15	0.04	0.26	0.21	0.23
Loss of Supply – L'Anse au Loup	0.01	0.00	0.20	0.05	0.07
Distribution	2.36	4.37	14.88	14.55	10.02
Total	2.56	5.01	19.56	19.22	14.03

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type – 2014 Fourth Quarter Only

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.00	0.00	0.27	0.64	0.27	0.64
Isolated	0.16	0.04	0.88	1.84	1.04	1.88
Northern						
Interconnected	0.54	1.38	0.65	1.65	1.19	3.03
Isolated	0.89	6.51	3.00	3.64	3.89	10.15
Labrador						
Interconnected	0.61	1.44	0.40	0.29	1.01	1.72
Isolated	2.35	7.10	3.74	4.66	6.10	11.76
Total	0.47	1.41	0.71	1.15	1.18	2.56

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.4 Reliability KPI: Other

3.1.4 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were four underfrequency events during the fourth quarter of 2014, summarized as follows:

- On October 13, Holyrood Unit 2 tripped. Hydro's investigation has concluded that the Holyrood Terminal Station (HRD TS) Unit #2 unit breakers (B2L42 & B2B11) tripped forcing Unit 2 offline. Hydro was conducting commissioning testing on the HRD TS Unit #1 unit breakers (B1L17 & B1B11) when the incident occurred. As part of the commissioning testing, a protection relay trip check was being performed on the Unit 1 unit breakers. The incorrect protection relay, the protection relay associated with Unit 2 unit breakers, was triggered. The incident and commissioning procedures have been reviewed to ensure a repeat of similar incidents is prevented.

  With the removal of generation (approximately 70 MW) the system frequency dropped to 58.66 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 730 MW. All Newfoundland Power customers were reported to be restored within four minutes after the event occurred. Load Shed: Newfoundland Power: 16 MW. (Unsupplied Energy: 65 MW-Mins)

- On November 15, at 1621 hours, Holyrood Unit 2 tripped. Hydro's investigation has determined that part of the commissioning activities ongoing on Holyrood Unit 1 included control valve programming and testing. Completing this work required working on the Mark V Distributed Control System (DCS) which is common to both Units 1 and 2. Comparisons between Unit 1 and Unit 2 control valve programming were being checked when a test was initiated to stroke the valve on Unit 1. This test was accidentally initiated on Unit 2 causing the trip. The Unit 1 and Unit 2 distributed control system programming parameters are not distinguishable from each other at the programming level. The technologists mistakenly thought they were testing the Unit #1 parameters. Both the Hydro and the OEM contractor technologists are very familiar with this control system. Hydro has identified a failure to check/identify the task as the root cause. The outcomes of the investigation were reviewed with employees who may work inside the DCS to highlight the system limitations on naming convention.

  With the removal of generation (approximately 70 MW) the system frequency dropped to 58.68 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 964 MW. All Newfoundland Power customers were reported to be restored within 2 minutes after the event occurred. Newfoundland Power load loss: 15 MW (Unsupplied Energy: 30 MW-Mins)

- On December 19, at 0849 hours, Holyrood Unit 2 tripped. Hydro's investigation determined the trip was the result of loss of power to all eight of the unit's 4160V motors. The motors tripped due to the failure of a motor lug resulting in a fault which was detected by the overcurrent protection. This subsequently tripped the unit.

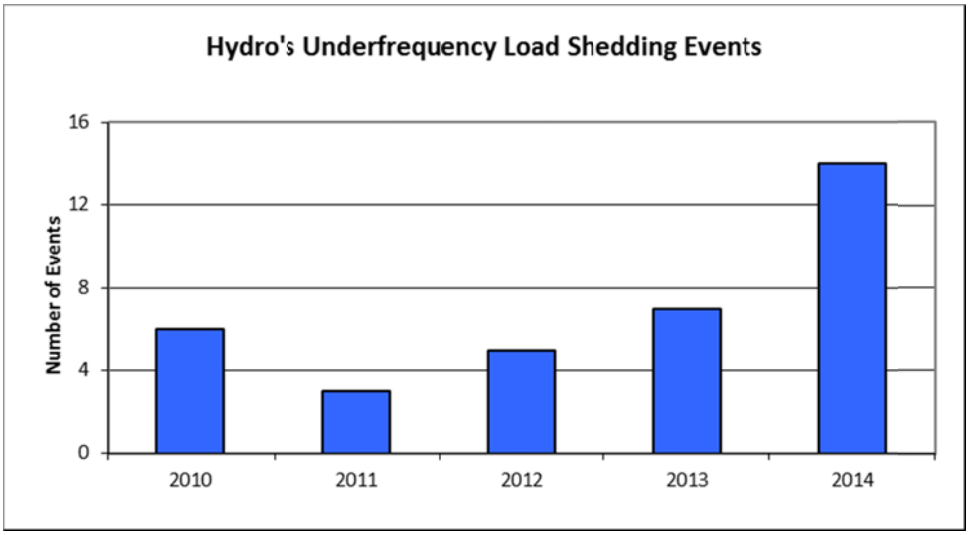
  With the removal of generation (approximately 72 MW) the system frequency dropped to 58.77 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total Island load at the time of the incident was 1125 MW. All Newfoundland Power customers were reported to be restored within 2 minutes after the event occurred. Newfoundland Power load loss: 23 MW (Unsupplied Energy: 46 MW-Mins)

- On December 30, at 2334 hours, Holyrood Unit 3 tripped. Hydro's investigation determined that the unit tripped because of a loss of atomizing steam going to the burner. Operations found two manual valves in the incorrect position (one 90% closed and one 100% closed). The unit controls operated correctly to adjust for a low aux steam pressure but the position of these valves resulted in the cut off of all atomizing steam.

  With the removal of generation (approximately 130 MW) the system frequency dropped to 58.36 Hz resulting in the activation of the under frequency protection at Newfoundland Power, Hydro, and Corner Brook Pulp & Paper Limited. Total Island load at the time of the incident was 1370 MW. Hydro advised Newfoundland Power to begin customer restoration within 4 minutes of the incident. Relative to the time of the incident: all (919) Hydro customers were restored within 4 minutes; Corner Brook Pulp & Paper Limited was restored within 5 minutes; the majority (15,683) of Newfoundland Power customers were reported to be restored within 22 minutes; and the remaining (1299) Newfoundland Power customers were reported to be restored within 69 minutes.

Load Shed:	Newfoundland Power:	95 MW
	Hydro:	3 MW
	Corner Brook Pulp & Paper:	14 MW
	Total Load Shed:	112 MW
	(Unsupplied Energy: 1,664 MW-Mins)	

In total, there were 14 UFLS events in 2014, compared to 7 in 2013 and the five-year average (2009-2013) of 5.6 events. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The following table compares the UFLS events in the fourth quarter of 2014 to the same quarter in 2013 in addition to annual performance.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter		Year to Date		5 Year Average
	2014	2013	2014	2013	(2010–2014)
NF Power	4	1	14	7	7
Industrials	1	0	3	0	1.2
Hydro Rural*	1	1	2	3	1.6
Total Events	4	1	14	7	7

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter		Year to Date		5 Year Average
	2014	2013	2014	2013	(2010–2014)
NF Power	1,722	175	5,798	13,917	4,713
Industrials	70	0	200	0	92
Hydro Rural*	12	0	48	324	96
Total Events	1,804	175	6,046	14,241	4,901

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

The details of the previous 10 UFLS events in 2014 are summarized in Appendix C3.

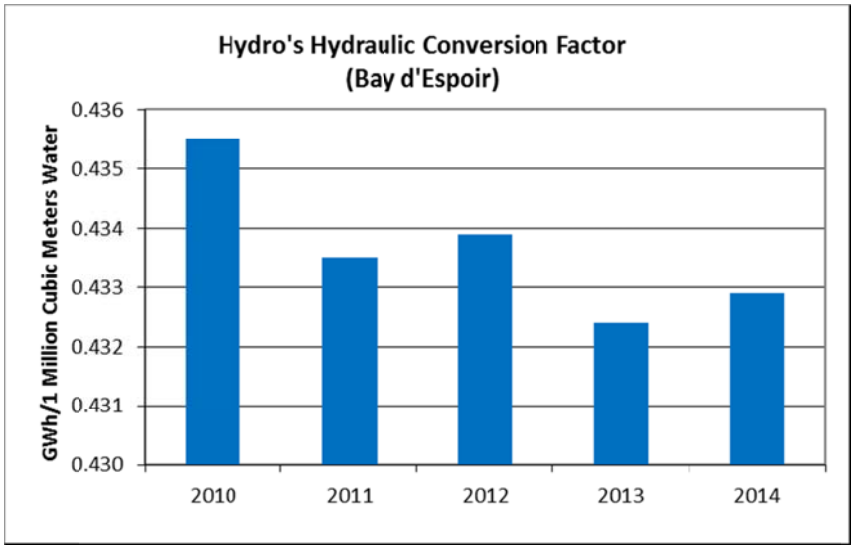
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2014, the hydraulic conversion factor for Bay d'Espoir was 0.4329 GWh/MCM, compared to 0.4324 GWh/MCM compared to a 2014 target of 0.433 GWh/MCM.



In 2014, the water levels were lower in the reservoirs allowing for improved water utilization at the Bay d'Espoir plant, as there were fewer hours where plant production was higher at less efficient output levels.

3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. The output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production on the Island, quantity of power purchases, customer energy requirements and system security requirements. The thermal conversion factor is also impacted by the heating content in the No. 6 fuel consumed at the plant, measured in BTUs/bbl.

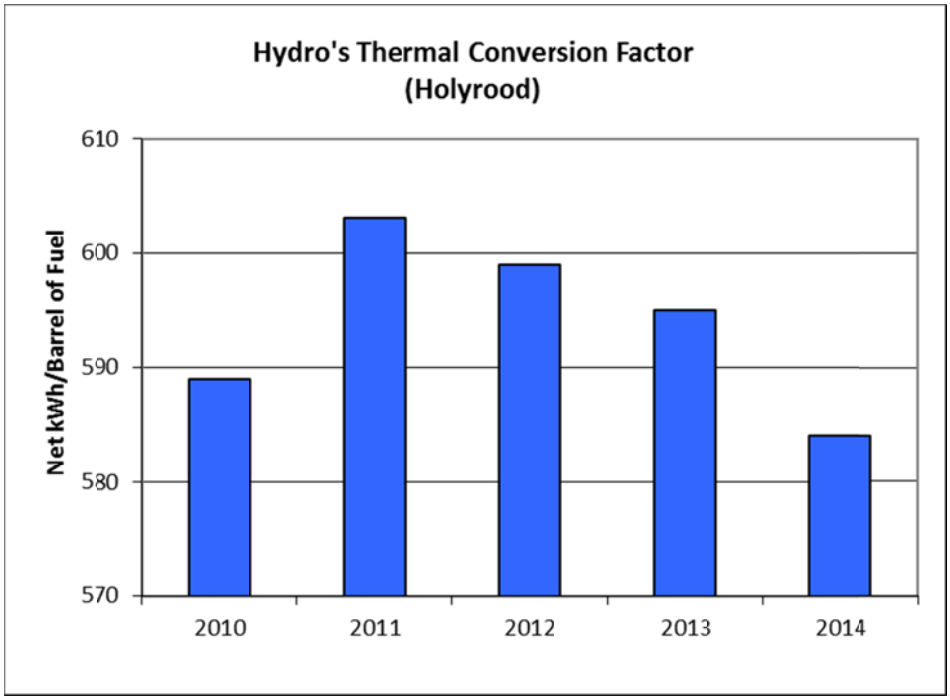
In 2014, Hydro's net thermal conversion factor was 584 kWh per barrel compared to a 2014 target of 615 kWh per barrel. The lower energy conversion rate in 2014, relative to the target, is resulting from two primary factors:

- operating the units at a lower average output level due to the high volume of water resources on the Island and energy receipts relative to the system load requirements; and
- a low heating content in the No. 6 fuel consumed at the Holyrood generating station.

The efficiency at the Holyrood plant has remained relatively consistent with a gross heat rate performance of 10,124 BTU/kWh in 2014 compared to 10,127 BTU/kWh in 2013.

In 2014, the units were dispatched as required for Avalon transmission support and system peak load considerations. The average net unit load while operating was 83.2 MW, down from 87.6 MW in 2013 and a forecast of 92.3 MW for 2014.

Overall, net production from Holyrood for 2014 was 1,315 GWh, a 37% increase from 2013 production levels and a decrease of 8% from the 2014 forecast. The production increase in 2014 relative to 2013 was related to operating one unit throughout the summer months in 2014 in order to support the transmission into the Avalon Peninsula, in addition to higher customer demand requirements during the winter and early spring period.


Hydro's Thermal Conversion Factor
(Holyrood)
Net kWh/Barrel of Fuel
610
600
590
580
570
2010
2011
2012
2013
2014

3.3 Financial Performance Indicators [complete section updated]

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[4]

In Order No. P.U. 8 (2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8 (2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the seventh year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix D. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE) as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[5] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year-over-year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

[4] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.
[5] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

3.3.1 Financial KPI: Corporate

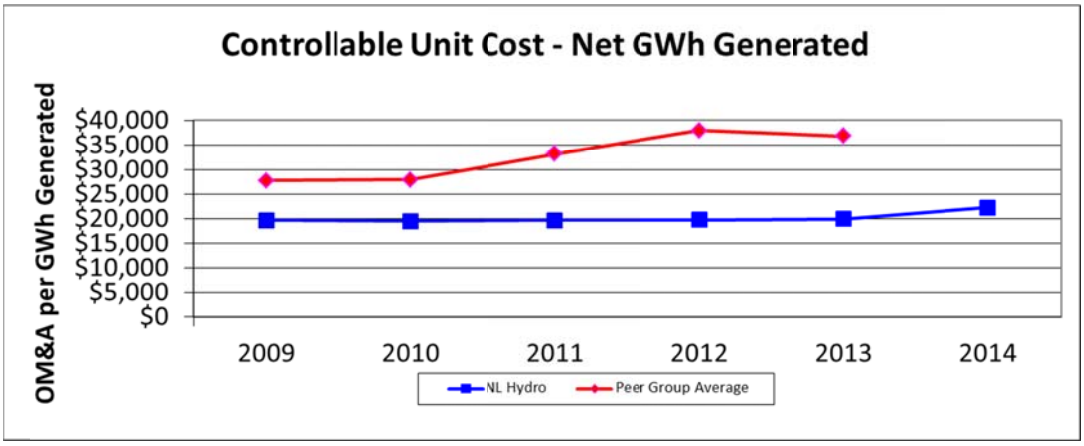
3.3.1 a) Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, and loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs increased from $113.8 million in 2013 to $134.2 million[6] in 2014, resulting in a Controllable Unit Cost of $18.09 per MWh delivered for 2014.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2007-2013 have therefore been herein restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $22.26 per MWh during 2014, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very steady trend as compared to an upward trend from 2009 to 2012 with a slight decline in 2013 for the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.



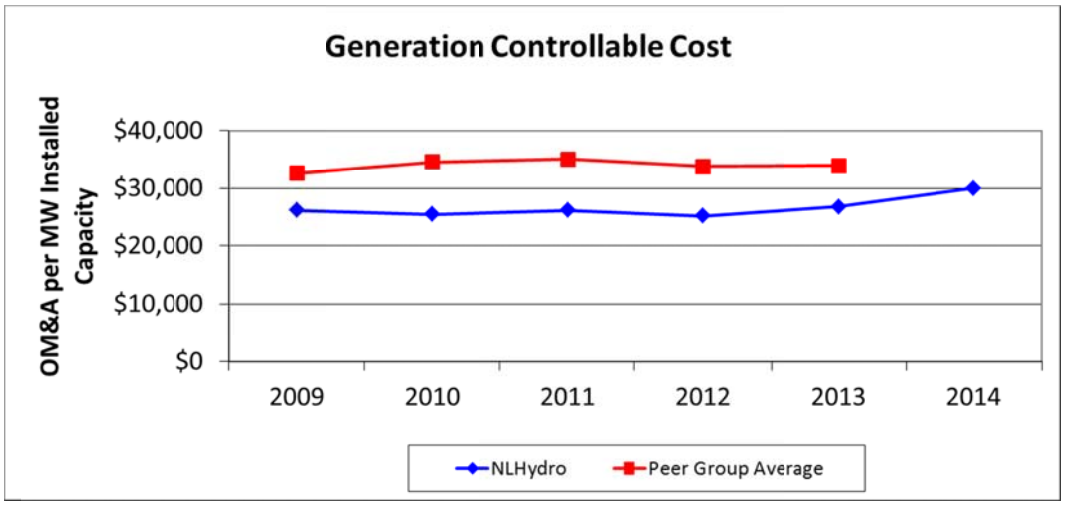
[6] This $ 134.2 million was calculated in the 2014 Cost of Service study and includes a $1.9 million cost to Hydro that was incurred to service an unregulated Industrial Customer. The $1.9 million was excluded when the $132.3 million regulated amount was reported on the Statement of Income – Regulated Operations for 2014, filed as part of the December 31, 2014 Quarterly Regulatory Report.

3.3.2 Financial KPI: Generation

3.3.2 a) Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $30,013 per MW for 2014 compared with $26,774 in 2013 an increase of $3,239 per MW. As mentioned in prior annual KPI reports, an asbestos abatement program was undertaken at Holyrood in 2005 through 2007. Amortization of costs associated with this program concluded during 2012.

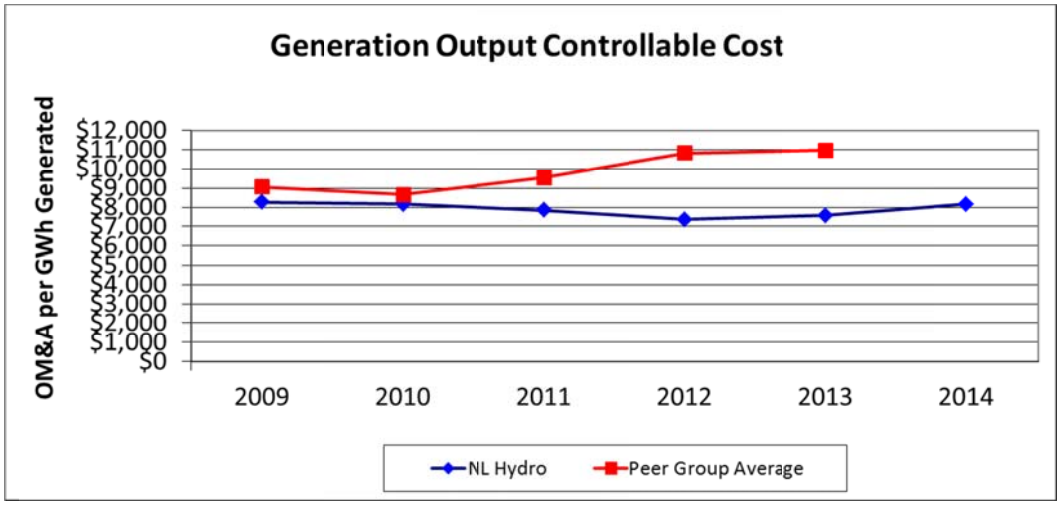
The peer group used to benchmark Generation Controllable Costs appears to be experiencing a steady trend in 2012 and 2013 OM&A per MW installed capacity while Hydro is showing increases in 2013 and 2014.



3.3.2 b) Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2014, Hydro's Generation Output Controllable Cost of $8,150 per GWh, was higher than the $7,568 in 2013. There was an increase in the Generation Costs component of approximately $6.0 million from 2013 to 2014 coupled with an increase of 336 GWh in the Net Energy Generated.

From 2009 through 2010, Hydro's Generation Output Controllable Costs were primarily in line with and trending in a similar direction as those of the peer group with moderate declines for Hydro in 2011 and 2012 and moderate increases recorded in 2013 and 2014.

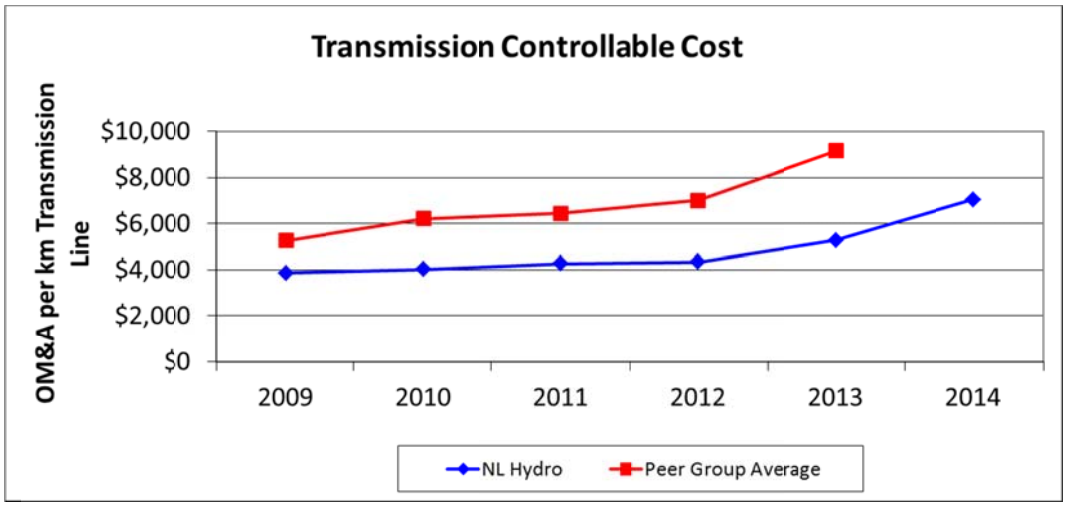


3.3.3 Financial KPI: Transmission

3.3.3 a) Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2014, Hydro's Transmission Controllable Cost was $7,043 per km of transmission, an increase of 33.4% over 2013.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro for the period 2010 to 2013. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



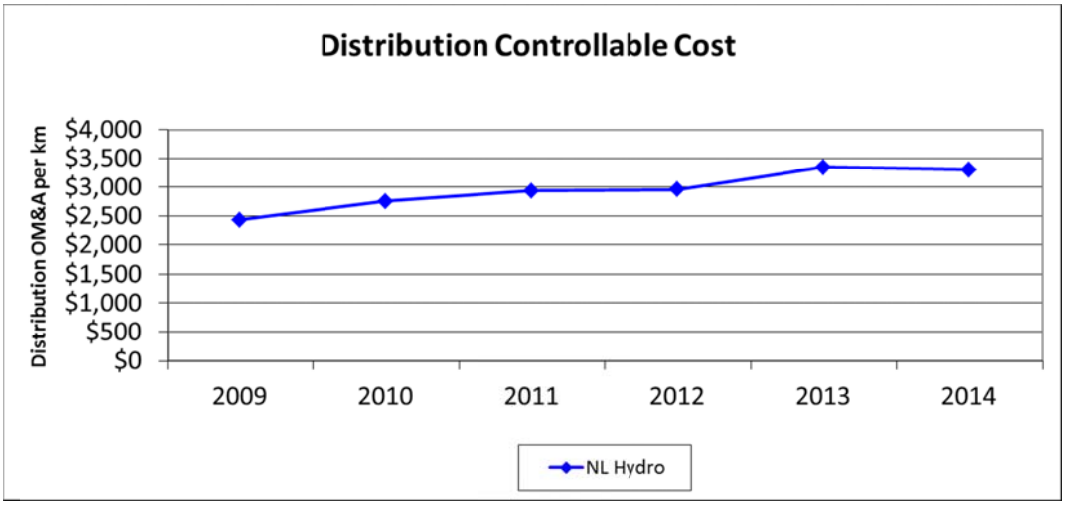
3.3.4 Financial KPI: Distribution

3.3.4 a) Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres*[7].

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

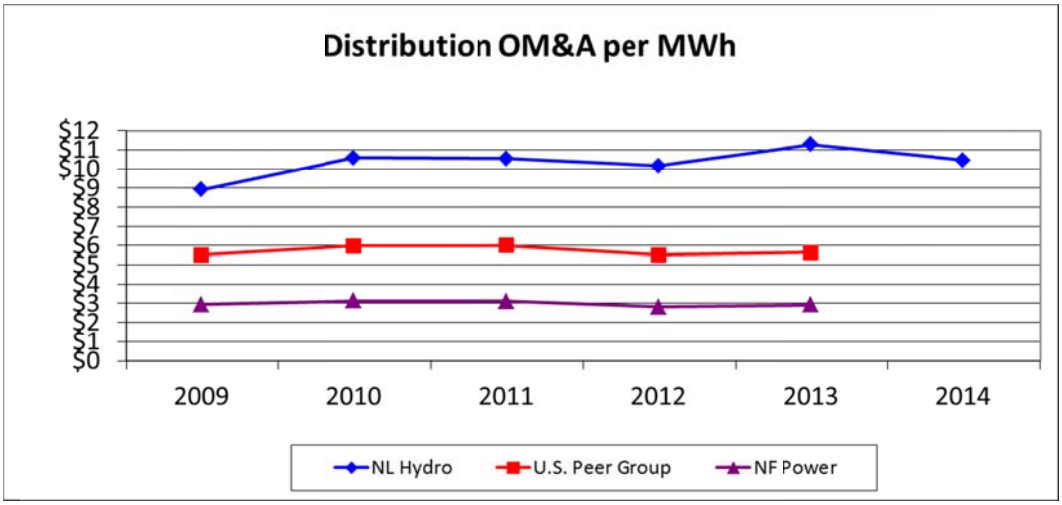
The distribution cost per km of circuit length will continue to be reported for year-over-year trend analysis.

At $3,304 per circuit km Hydro's Distribution Controllable Cost of 2014 decreased from the $3,345 that was recorded in 2013. This is a slight downward trend in this cost in 2014 compared to the increase trend that was seen between 2009 and 2013.



As expected, Hydro's distribution costs of $11.27 in 2013 trend higher than those of its peers in the table below. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs per MWh are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.

[7] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.



3.4 Customer-Related Performance Indicators

3.4.1 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI*[8]*.*

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

The 2014 residential customer satisfaction survey shows that 84% of customers are either very satisfied or somewhat satisfied with Hydro.

[8] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.


Redidential Customer Satisfaction
Overall Customer Satisfaction
94
92
90
88
86
84
82
80
78
76
74
2008
2009
2010
2011
2012
2014

Appendices

Appendix A: Rationale for Hydro's 2014 KPI Targets

KPI	Comment on KPI 2014 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2014 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2014 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2014 targets for forced outage performance are set based upon recent performance improvements. The planned outage contribution to total performance is set using the annual transmission terminals maintenance outage plan.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2014 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	The 2014 target is based on November 2013 budget for 2014 Holyrood plant operation.
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1 - \frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events – 2014

There were 12 significant events in 2014. The details follow:

Event 1

On January 4 at 0905 hours, transformer T1 at the Sunnyside Terminal Station faulted resulting in a fire. Circuit breaker B1L03 failed to isolate T1, and resulted in a trip of transmission lines TL203 and TL237, isolating the Avalon Peninsula from the remainder of the power system. This resulted in the interruption of the following generation: Holyrood Plant, Cat Arm Plant, Hinds Lake Plant, Granite Canal Plant, Upper Salmon Plant, Stephenville Gas Turbine, St. Anthony Diesel Plant, and Hawke's Bay Diesel Plant. **(Unsupplied Energy: 158,954 MW-Mins)**

The following table outlines the delivery point customer interruptions.

Events on January 4, 2014 (09:05 hrs)					
Delivery Point Affected	**Start Time**	**Finish Time**	**Duration of Interruptions (mins)**	**MW Load**	**MW-Mins**
Hardwoods	1/4/2014 9:05	1/4/2014 9:52	47	268	12,596
Oxen Pond	1/4/2014 9:05	1/4/2014 10:43	98	286	28,067
Holyrood - 39L	1/4/2014 9:05	1/4/2014 14:01	296	29	9,320
Holyrood - 38L	1/4/2014 9:05	1/4/2014 14:07	302	46	13,771
Western Avalon - 64L	1/4/2014 9:05	1/4/2014 14:44	339	94	27,735
Western Avalon - Bus B2	1/4/2014 9:05	1/4/2014 14:01	296	46	16,780
Vale (Long Harbour)	1/4/2014 9:05	1/4/2014 12:22	197	6	1,143
Sunnyside - rural (T5)	1/4/2014 9:05	1/4/2014 20:07	662	9	6,091
Sunnyside - TL219	1/4/2014 9:05	1/4/2014 20:07	662	29	20,445
Linton Lake	1/4/2014 9:05	1/4/2014 20:07	662	17	11,985
Bay L'Argent	1/4/2014 9:05	1/4/2014 20:07	662	17	4,653
Monkstown	1/4/2014 9:05	1/4/2014 20:07	662	17	2,397
Duck Pond Mine	1/4/2014 9:05	1/4/2014 12:46	221	9	1,923
Wiltondale	1/4/2014 9:05	1/4/2014 9:33	28	0.1	4
Glenburine	1/4/2014 9:05	1/4/2014 9:33	28	3	78
Rocky Harbour	1/4/2014 9:05	1/4/2014 9:33	28	4	118
Grandy Brook	1/4/2014 9:05	1/4/2014 9:33	28	5	132
St Alban's	1/4/2014 9:05	1/4/2014 10:19	74	5	548
Conne River	1/4/2014 9:05	1/4/2014 10:37	92	2	187
English Harbour West	1/4/2014 9:05	1/4/2014 10:37	92	4	362
Barachoix	1/4/2014 9:05	1/4/2014 10:37	92	7	619
Come By Chance T2	1/4/2014 9:05	1/4/2014 13:18	N/A (BES: 253 mins)	N/A	N/A
		Totals			158,954

Appendix C1: Significant Transmission Events – 2014 (Cont'd)

Event 2

On January 4 at 1533 hours, personnel were in the process of re-energizing SSD T4. The transformer had tripped after transformer T1 locked out earlier in the day. During the re-energization there was a breaker failure protection operation associated with the transformer breaker B3T4. Circuit breaker B1L02 at the Sunnyside Terminal Station failed to open due to the breaker failure protection configuration, and resulted in the trip of transmission line TL206 at the Bay d'Espoir Generating Plant. The distance protection was activated on transmission line TL202 but failed to trip this line at the Bay d'Espoir Generating Plant, resulting in a bus lockout on BDE Bus B3 and the loss of the Bay d'Espoir Units 5 and 6. Circuit breaker B5B6 falsely tripped at Bay d'Espoir resulting in the loss of transmission line TL204. Transmission lines TL202, TL203, TL206 and TL207 tripped at the Sunnyside Terminal Station, resulting in the isolation of the Avalon Peninsula from the remainder of the power system. The Come by Chance Oil Refinery was also interrupted. This disturbance resulted in the interruption of the following generation: Cat Arm Plant, Granite Canal Plant, Stephenville Gas Turbine, and Hawke's Bay Diesel Plant. The Holyrood units had not been restored following the events earlier in the morning.
(**Unsupplied Energy: 13,836 MW-Mins)**

The following table outlines the delivery point customer interruptions.

Events on January 4, 2014 (15:33 hrs)

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Hardwoods	1/4/2014 15:33	1/4/2014 15:55	22	164	3,608
Oxen Pond	1/4/2014 15:33	1/4/2014 16:06	33	166	5,478
Holyrood - 38L	1/4/2014 15:33	1/4/2014 16:10	37	24	870
Western Avalon - 64L	1/4/2014 15:33	1/4/2014 16:18	45	61	2,750
Come By Chance T1	1/4/2014 15:33	1/4/2014 15:39	6	15	91
Duck Pond Mine	1/4/2014 15:33	1/4/2014 17:47	134	5	724
Wiltondale	1/4/2014 15:33	1/4/2014 15:43	10	0.1	1
Glenburine	1/4/2014 15:33	1/4/2014 15:43	10	3	29
Rocky Harbour	1/4/2014 15:33	1/4/2014 15:43	10	4	43
Grandy Brook	1/4/2014 15:33	1/4/2014 15:39	6	5	28
St Alban's (1)	1/4/2014 15:33	1/4/2014 15:43	10	8	75
Conne River	1/4/2014 15:33	1/4/2014 15:43	10	2	22
English Harbour West	1/4/2014 15:33	1/4/2014 15:43	10	4	43
Barachoix	1/4/2014 15:33	1/4/2014 15:43	10	7	74
Come By Chance T2	1/4/2014 15:33	1/4/2014 15:39	N/A (BES: 6 mins)	N/A	N/A
Holyrood - 39L	1/4/2014 15:33	1/4/2014 16:39	N/A (BES: 66 mins)	N/A	N/A
		Totals			13,836

Appendix C1: Significant Transmission Events – 2014 (Cont'd)

Event 3

On January 5 at 2127 hours, the Holyrood generating Unit 1 was being prepared to be placed on line. The unit disconnect switch was closed as the first step in this procedure. After this switch was closed the unit connected to the grid, out of synch, single phase through a closed breaker contact. This resulted in a 230 KV disturbance and the tripping of Holyrood units 2 and 3, the Stephenville Gas Turbine, and the Hawke's Bay Diesel Plant.
(**Unsupplied Energy: 34,030 MW-Mins)**

The following table outlines the delivery point customer interruptions.

Events on January 5, 2014 (21:27 hrs)

Delivery Point Affected	Start Time	Finish Time	Duration of Interruptions (mins)	MW Load	MW-Mins
Holyrood - 38L	1/5/2014 21:27	1/5/2014 21:31	4	37	146
Holyrood - 39L	1/5/2014 21:27	1/6/2014 8:42	675	17	11,610
Western Avalon - 64L	1/5/2014 21:27	1/6/2014 0:22	175	83	14,525
Western Avalon - Bus B2	1/5/2014 21:27	1/6/2014 0:36	189	41	7,749
		Totals			34,030

Event 4

On January 26, customers supplied by the Grandy Brook Terminal Station experienced an unplanned power outage of eight hours and 46 minutes. The outage occurred after a crossarm failed at a structure in transmission line TL250 during an extreme wind storm. There were wind gusts of over 130 km/h recorded on this day. **(Unsupplied Energy: 1,999 MW-Mins)**

Event 5

On January 28, customers supplied by the Monkstown and Bay L'Argent Terminal Stations experienced an unplanned power outage of three hours and 10 minutes. The outage occurred after a crossarm failed at a structure in transmission line TL212 during an extreme wind storm. There were wind gusts of over 120 km/h recorded on this day. (**Unsupplied Energy: 1,121 MW-Mins)**

Appendix C1: Significant Transmission Events – 2014 (Cont'd)

Event 6

On February 19, Vale at Long Harbour experienced an unplanned power outage of two hours and 52 minutes. The outage was caused by transformer T1 tripping due a protection coordination issue with Vale's protection. These protection issues have since been resolved.
(**Unsupplied Energy: 1,032 MW-Mins)**

Event 7/Event 8/Event 9

On February 23, customers supplied by the Bottom Waters Terminal Station experienced three unplanned power outages of 11 hours and 30 minutes in total. The first outage was caused by a bus lockout operation for a trip of transformer T1. The other two outages occurred during the restoration of T1. The transformer trip was caused by a faulty pressure/vacuum switch. The switch required isolation before T1 could be re-energized.
Event 7: (**Unsupplied Energy: 1,230 MW-Mins)**
Event 8: (**Unsupplied Energy: 2,700 MW-Mins)**
Event 9: (**Unsupplied Energy: 1,238 MW-Mins)**

Event 10

On April 14, customers supplied by the Bottom Waters Terminal Station experienced an unplanned power outage of 2 hours and 32 minutes. The outage was caused by a squirrel that came into contact with a lightning arrestor on the low voltage side (25 kV) of transformer T1 resulting in the operation of the bus lockout. This, in turn, tripped circuit switcher L60T1 on the high side of T1 (138 kV).
(**Unsupplied Energy: 1,170 MW-Mins)**

Event 11

On August 5, 7,345 customers on the Great North Peninsula experienced an unplanned power outage. The outage occurred due to a failure of an SF6 Breaker, B1L41 at the Peter's Barren Terminal Station, tripping transmission line TL241 and causing a bus lockout at the terminal station.
(**Unsupplied Energy: 2,530 MW-Mins)**

The following table outlines the delivery point customer interruptions.

Appendix C1: Significant Transmission Events – 2014 (Cont'd)

Event -TL241 Trip/PBN B1 Lockout

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Parson's Pond	15:16	15:28	12	0.31	3.72
Daniel's Harbour	15:16	15:28	12	0.37	4.44
Hawkes's Bay	15:16	15:28	12	3.75	45
Plum Point	15:16	23:26	490	2.1	1029
Bear Cove	15:16	23:26	490	2.54	1244.6
Main Brook	15:16	15:43	27	1.7	45.9
Roddickton	15:16	15:49	33	1.4	46.2
St Anthony	15:16	15:49	33	5.3	111.3

Event 12

On August 10, customers supplied by the Happy Valley and Muskrat Falls Construction Power Terminal Stations experienced an unplanned power outage of two hours and 40 minutes. The outage occurred when a tertiary lead on the 230/138 kV transformer T71 failed at the Churchill Falls Switchyard, resulting in a fault and a trip of the 138 kV transmission line (L1301/L1302) at the Churchill Falls switchyard.

(**Unsupplied Energy: 2,512 MW-Mins)**

Appendix C2: Significant Distribution Events – 2014 (Excluding Fourth Quarter)

- On January 1, customers in Happy Valley - Goose Bay, Labrador serviced by feeder L16 experienced two unplanned and one emergency planned power outage. The outages occurred due to unbalanced loading on the feeder. See the following for outages details:

  Outage 1: 1745-1817 hours (32 minutes) 3,984 customers
  Outage 2: 1757 – 1811 hours (14 minutes) 1,019 customers
  (Emergency planned outage for switching operations)
  Outage 3: 1815 – 2344 hours (five hours 29 minutes) 1,019 customers

- On January 22, at 2000 hours (Labrador time), 391 customers in Labrador City, Labrador supplied by Line 13 experienced an unplanned power outage. The outage occurred when a piece of jumper conductor burned off a pole. All customers were restored at 2200 hours.

- On January 26, at 0955 hours, all customers (1369) serviced by the Barachoix Terminal Station, including the communities of Gaultois, Harbour Breton, Hermitage, and Seal Cove experienced an unplanned power outage. The outage occurred due to line damage caused by extreme weather and high winds. Hydro crews safely made the necessary repairs and all customers were restored by 1855 hours. Delays in restoration were due to distance and travel time in extreme weather, the investigation into the cause of the outage, and the repair time.

- On January 26, at 0848 hours, all customers (921) serviced by the Grandy Brook Terminal Station, including the communities of Burgeo, Grand Bruit, and La Poile, experienced an unplanned power outage. The outage occurred when the 138 kV Transmission Line TL250 tripped out of service due to a failed cross arm. There were extreme high winds at the time. Hydro crews safely made the necessary repairs and all customers were restored by 1735 hours. Delays in restoration were due to distance and travel time in extreme weather, the investigation into the cause of the outage, and the repair time.

- On January 26, at 0933 hours, all customers (813) serviced by the English Harbour West Terminal Station, including the communities of Boxey, Belleoram, Coombs Cove, English Harbour West, Mose Ambrose, Pools Cove, Rencontre East, St. Jacques, and Wreck Cove experienced an unplanned power outage. The exact cause of the outage is unknown, however it was most likely due to the extreme weather and high winds experienced at the time. All customers were restored by 1323 hours.

- On April 10, at 1400 hours (Labrador time), 330 customers in Happy Valley - Goose Bay, Labrador serviced by Line 7 experienced a planned power outage. The outage was required to safely replace a utility pole. All customers were restored at 1650 hours.

- On April 14, at 0825 hours, 1774 customers serviced by the Bottom Waters Terminal Station experienced an unplanned power outage. The outage occurred when the 138 kV circuit breaker L60T1 tripped open. This circuit breaker is located on the high voltage side (138 kV) of the transformer - T1. Hydro investigated and discovered that a squirrel had come in contact with a lightning arrestor on the low voltage side (25 kV) of the transformer and the

protection systems for transformer T1 commanded circuit breaker L60T1 to trip. All customers were restored by 1057 hours.

- On April 16, at 1906 hours, all customers (990) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred due to a loss of supply from Hydro Québec. Communities affected include L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse au Clair, L'Anse au Loup, West St. Modeste, Capstan Island, L'Anse au Diable, Pinware, Red Bay, and Organ's Island.

  The L'Anse au Loup Diesel Plant was used to restore customers.

  Customer Outage details are as follows:

  Outage 1: 1906 – 1927 hours (21 minutes), 467 customers between L'Anse au Loup to Pinware
  Outage 2: 1906 – 1935 hours (29 minutes), 262 customers in L'Anse Amour and Forteau
  Outage 3: 1906 – 1942 hours (36 minutes), 124 customers in L'Anse au Clair
  Outage 4: 1906 – 1950 hours (44 minutes), 137 customers in Red Bay

  Supply was restored from Hydro Québec at 2330 hours, April 17.

- On May 07, at 0130 hours (Labrador time), 140 customers in Cartwright, Labrador experienced an unplanned power outage. The outage occurred when one phase in a distribution line faulted. Hydro investigated and made the necessary repairs to the line. All customers were restored at 0400 hours.

- On May 22, at 1225 hours, all customers (990) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred due to a loss of supply from Hydro Québec. Hydro Québec reported a pole down. Communities affected include L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse au Clair, L'Anse au Loup, West St. Modeste, Capstan Island, L'Anse au Diable, Pinware, Red Bay, and Organ's Island.

  The L'Anse au Loup Diesel Plant was used to restore customers.

  Customer Outage details are as follows:

  Outage 1: 1225 – 1236 hours (11 minutes), 467 customers between L'Anse au Loup to Pinware
  Outage 2: 1225 – 1241 hours (16 minutes), 262 customers in L'Anse Amour and Forteau
  Outage 3: 1225 – 1245 hours (20 minutes), 124 customers in L'Anse au Clair
  Outage 4: 1225 – 1251 hours (26 minutes), 137 customers in Red Bay

  Supply from Hydro Québec was restored at 1312 hours.

- On May 23, at 2344 hours, all customers (990) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred due to a loss of supply from Hydro Québec. Hydro Québec reported a problem at their Blanc-Sablon Station. Communities affected include L'Anse Amour, English Point, Buckle's Point, Forteau, L'Anse

au Clair, L'Anse au Loup, West St. Modeste, Capstan Island, L'Anse au Diable, Pinware, Red Bay, and Organ's Island.

The L'Anse au Loup Diesel Plant was used to restore customers. All customers were restored by 0034 hours May 24.
Supply from Hydro Québec was restored at 1038 hours May 24.

- On June 08, at 0600 hours (Labrador time), all customers (5813), including Industrial Customers IOCC and Wabush Mines, in Labrador City and Wabush experienced a planned power outage. The outage was required so that CF(L)Co could safely perform maintenance on the Wabush Terminal Station.

  See the following for the number of affected customers and restoration times:

  Wabush: 2006 hours (1466 customers – 14 hours six minutes)
  Labrador City: 2020 hours (4347 customers – 14 hour 20 minutes)

- On June 25, at 1025 hours (Labrador time), all customers (226) in Port Hope Simpson, Labrador experienced a planned power outage. The outage was required to safely disconnect Mobile Unit 2044. All customers were restored at 1150 hours.

- On July 01, 175 customers in Labrador City, Labrador serviced by Lines 18 and 21 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was four hours.

- On July 02, at 0645 hours (Labrador time), 5677 customers in Labrador City and Wabush, Labrador experienced an unplanned power outage. The outage occurred when a fault at the IOCC mine site activated relay protection at the Wabush Terminal Station, tripping breakers 46-32 (Labrador City) and 46-36 (Wabush). See the following for customer restoration details:

  Outage 1: 1467 Wabush customers, 35 minutes
  Outage 2: 4210 Labrador City customers, one hour

- On July 05, 400 customers in Sheshatshui, Labrador serviced by Happy Valley Terminal Station Line 7, experienced a planned power outage. The outage was required to install new equipment on the distribution system. Outage duration was three hours and 40 minutes.

- On July 12, 350 customers in Labrador City, Labrador serviced by Lines 6 and 15 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was five hours.

- On July 13, 350 customers in Labrador City, Labrador serviced by Lines 6 and 15 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was five hours.

- On July 16, all customers (170) on Long Island including the communities of Beaumont and Lushes Bight experienced an unplanned power outage of seven hours and 30 minutes. Hydro's preliminary investigation indicated a subsea cable failure was the cause of the outage. Hydro attempted to energize the primary and all backup cables without success. Hydro involved additional technical and support staff to assist with the restoration efforts. Hydro had also begun to mobilizing a portable diesel generator to site. Power was restored to Long Island via one of the submarine cables. Preliminary investigation indicates three of the four cables have been damaged and remain out of service. Hydro is arranging for inspection of the cables to determine the cause of the outage and why the other cables could not be energized. Preparations are being made to execute repairs, pending the findings from the inspection. In the interim, standby backup generation has been installed on Long Island should the existing energized cable fail.

- On August 21, all customers (1,466) in Wabush, Labrador experienced a planned power outage of nearly two and a half hours in duration. The outage was required to tie in transformers T3 and T5 at the Wabush Substation. This work was required to energize T5 for condition assessment and monitoring.

- On August 26, 451 customers serviced by Bottom Waters Terminal Station Line 4 are experienced an unplanned power outage of approximately 19 hours in duration. The communities affected included Burlington, Smith's Harbour, and Middle Arm. The outage was caused by a failure of a step-down transformer located in the Burlington Substation. Hydro expedited a replacement transformer from the Bishop's Falls warehouse. Hydro crews worked late into the evening of August 26 and resumed work during the morning of August 27, during which time the replacement of the transformer was completed and all customers were restored.

- On September 07, 723 customers in Labrador City, Labrador, serviced by Line 8, experienced a planned power outage. The outage was required to connect new feeders into the Quartzite Substation. Outage duration was three hours.

- On September 11, all customers (874) in Little Bay and King's Point, serviced by the Springdale Terminal Station, experienced an unplanned power outage. The outage occurred when Newfoundland Power's mobile substation, located in the Springdale Terminal Station, failed causing Hydro's breakers to trip. Newfoundland Power made the necessary repairs to mobile substation, Hydro then proceeded to restore supply to customers. Outage duration was seven hours and 43 minutes.

- On September 14, all customers (1466) in Wabush, Labrador experienced a planned power outage. The outage was required to make modifications to the steel structure within the Wabush Substation yard in preparation for the connection of an additional power transformer. Outage duration was five hours and 45 minutes.

- On September 21, all customers (1459) in Wabush, Labrador experienced an extended planned power outage. The outage was required for the installation of a new power transformer (T6) at the Wabush Substation. All customers were planned to be restored by 1000 hours, however due to an issue with breaker WA36-CB1 at the Wabush Substation, the outage was extended beyond this time. Hydro crews resolved the issue with the breaker. Outage duration was eight hours and 15 minutes.

- On September 22, 1765 customers serviced by the Bottom Waters Terminal Station Lines 1 and 3 experienced an unplanned power outage. The communities affected include Brent's Cove, Burlington, Harbour Round, La Scie, Middle Arm, Ming's Bight, Nipper's Harbour, Pacquet, Round Harbour, Snook's Arm, Shoe Cove, Smith's Harbour, Tilt Cove and Woodstock. This outage also affected Rambler Mines. The outage was caused by rain and high winds in the area blowing trees into the distribution lines. Hydro crews responded, patrolled the lines, and safely removed any trees prior to restoring customers. Outage duration was five hours and 10 minutes.

- On September 26, 446 customers in Labrador City, Labrador serviced by Quartzite Substation Line 13 and Bartlett Substation Line 4 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was three hours.

- On September 27, 311 customers in Labrador City, Labrador serviced by Quartzite Substation Line 13 and Bartlett Substation Line 4 experienced a planned power outage. The outage was required to perform voltage conversion upgrades to the distribution system. Outage duration was two hours and 30 minutes.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

- On January 10, Holyrood Generating Unit No. 2 tripped. The trip of Unit 2 occurred when a compressor failure resulted in an outage to a 600V power center. This power center supplies auxiliary equipment associated with Unit 2 turbine/boiler. Unit 2 was restored to service at 0123 hours January 11. With the removal of generation (approximately 155 MW) the system frequency dropped to 58.25 Hz resulting in the activation of the under frequency protection at Hydro and Newfoundland Power. Total system load at the time of the incident was 1,306 MW. Hydro customers (2,210) were restored within three minutes. Newfoundland Power customers (21,067) were restored in twenty-two load blocks. The first customers were restored in seven minutes and all customers were reported to be restored within 28 minutes after the event occurred. **(Unsupplied Energy: 1,568 MW-Mins)**

- On January 12, Holyrood Generating Unit No. 3 tripped. The under frequency trip occurred when a main feed water isolator did not electrically open. As a result Unit 3 tripped on low drum level. Hydro determined that the problem was with a control power signal from the local control system. Repairs were made and the Unit was restored to service at 1830 hours, January 12. With the removal of generation (approximately 66 MW) the system frequency dropped to 58.78 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,030 MW. All Newfoundland Power customers (5,750) were restored within 10 minutes after the event occurred. **(Unsupplied Energy: 220 MW-Mins)**

- On January 15, transmission line TL-201 (from the Western Avalon to Hardwoods terminal stations) tripped and remained open. The fault created a system disturbance which activated the rate of change (df/dt) underfrequency load shedding protection at Newfoundland Power. The decline in system frequency achieved a maximum value of 0.56 Hz/Sec. All Newfoundland Power customers (3,307) were restored within 1 minute after the event occurred. Total NLH system load at the time of the incident was 998 MW. Upon investigation through line patrol, it was determined that two phases on structure 157 had fallen to the ground after the insulators had separated. The immediate cause is suspected to be a mechanical insulator failure due to high winds and adverse weather. The insulators were replaced and the line was restored to service at 2229 hours on January 15. **(Unsupplied Energy: 15 MW-Mins)**

- On January 27, at 1650 hours, Holyrood Generating Unit No. 1 tripped. Hydro's investigation into the cause of the trip on Unit 1 determined that a circuit breaker supplying the burner management system was inadvertently tripped as corrective maintenance was carried out on another piece of equipment located in the same electrical cabinet. With the removal of generation (approximately 120 MW) the system frequency dropped to 58.56 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,248 MW. All Newfoundland Power customers (11,061) were reported to be restored within 18 minutes after the event occurred. **(Unsupplied Energy: 904 MW-Mins)**

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter) (cont'd)

- On January 30, at 0509 hours, Bay d'Espoir Generating Unit No. 6 tripped. The unit trip was caused by the failure of the rectifying transformer associated with the unit excitation system. The spare transformer was installed. With the removal of generation (approximately 64 MW) the system frequency dropped to 58.71 Hz resulting in the activation of the under frequency protection at Newfoundland Power and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,060 MW. All Newfoundland Power customers (6,087) were reported to be restored within four minutes after the event occurred. **(Unsupplied Energy: 107 MW-Mins)**

- On February 17, at 0422 hours, Bay d'Espoir Generating Unit No. 6 tripped. The unit trip was caused by the failure of the rectifying transformer (this time the spare unit which was installed following the failure on January 30). With the removal of generation (approximately 67 MW) the system frequency dropped to 58.58 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 1,053 MW. 15,108 Newfoundland Power customers were reported to be restored within five minutes after the event occurred. Unit No. 6 remains out of service. **(Unsupplied Energy: 240 MW-Mins)**

- On March 18, at 2203 hours, while taking Bay d'Espoir Unit 4 offline, the unit breaker mis-operated, causing a bus lockout of Bus 2 at Bay d'Espoir, and tripping Unit 3 offline. With the removal of generation (approximately 59 MW) the system frequency dropped to 58.72 Hz resulting in the activation of the under frequency protection at Newfoundland Power and Corner Brook Pulp and Paper. Total system load at the time of the incident was 1,184 MW. There were 7,225 Newfoundland Power customers reported to be restored within five minutes after the event occurred. **(Unsupplied Energy: 190 MW-Mins)**

- On July 14, at 1414 hours, while Holyrood Unit 3 was undergoing a load test, a problem with the forced draft fans caused the unit to trip offline. With the removal of generation (approximately 113 MW) the system frequency dropped to 58.79 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 598 MW. All Newfoundland Power customers were reported to be restored within 16 minutes after the event occurred. Load Shed: Newfoundland Power: 13 MW **(Unsupplied Energy: 208 MW-Mins)**

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter) (cont'd)

- On July 28, at 0728 hours, Holyrood Unit 3 tripped offline. Hydro's investigation into this incident indicated that the root cause stemmed from an issue that occurred during switching, related to an abnormal configuration of the plant's electrical distribution system which was required for planned maintenance at the Holyrood Thermal Generating Station (HTGS). With the removal of generation (approximately 71 MW) the system frequency dropped to 58.41 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 491 MW. All Newfoundland Power customers were reported to be restored within 18 minutes after the event occurred. Load Shed: Newfoundland Power: 19.5 MW **(Unsupplied Energy: 351 MW-Mins)**

- On July 29, at 0943 hours, Holyrood Unit 3 tripped offline. Analysis concluded the root cause of the incident was a lack of clear communication during switching for a planned equipment maintenance outage in the Holyrood Terminal Station (HRD TS). The investigation also found that this specific outage type had not been executed by all control room operators in the past, highlighting the need for a better understanding of this outage type. Hydro has and continues to communicate this incident internally via lessons learned and training programs. With the removal of generation (approximately 70 MW) the system frequency dropped to 58.50 Hz resulting in the activation of the under frequency protection at Newfoundland Power. Total system load at the time of the incident was 588 MW. All Newfoundland Power customers were reported to be restored within 11 minutes after the event occurred. Load Shed: Newfoundland Power: 40 MW **(Unsupplied Energy: 440 MW-Mins)**

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Updated May 2015

Generation and Corporate Peer Group:	**Transmission Peer Group:**
Alcoa Power Generating Inc.	AEP Texas North Company
Allete, Inc.	Allete, Inc.
Aquila, Inc.	Aquila, Inc.
Avista Corporation	Avista Corporation
Buckeye Power, Inc.	Central Illinois Public Service Company
Cleco Power LLC	Delmarva Power & Light Company
Electric Energy, Inc.	Entergy Mississippi, Inc.
Entergy Mississippi, Inc.	Kentucky Utilities Company
Indiana-Kentucky Electric Corporation	MDU Resources Group, Inc.
Kentucky Power Company	Mississippi Power Company
Ohio Valley Electric Corporation	New York State Electric & Gas Corporation
Portland General Electric Company	Northern Indiana Public Service Company
Public Service Company of New Hampshire	Northern States Power Company (Wisconsin)
Puget Sound Energy, Inc.	Oklahoma Gas and Electric Company
Sierra Pacific Power Company	Public Service Company of Colorado
Southern Electric Generating Company	Public Service Company of Oklahoma
Southern Indiana Gas and Electric Company	Sierra Pacific Power Company
The Empire District Electric Company	Southwestern Electric Power Company
	Tucson Electric Power Company
	Westar Energy, Inc.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2015 ANNUAL REPORT
ON
KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

TABLE OF CONTENTS

1 Introduction 3
2 Overview of Key Performance Indicator Results 4
2.1 Overview 4
3 Performance Indices 6
3.1 Reliability Performance Indicators 6
3.1.1 Reliability KPI: Generation 6
3.1.1 c) Generation Equipment Performance 8
3.1.2 Reliability KPI: End User Performance 10
3.1.3 Reliability KPI: Transmission 13
3.1.4 Reliability KPI: Distribution 20
3.1.4 c) Additional Information 22
3.1.5 Reliability KPI: Other 26
3.2 Operating Performance Indicators 29
3.2.1 Operating KPI: Generation 29
3.3 Financial Performance Indicators 31
3.4 Customer-Related Performance Indicators 36

Appendix A: Rationale for Hydro's 2015 KPI Targets
Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance
Appendix C1: Significant Transmission Events – 2015
Appendix C2: Significant Distribution Events – 2015 (Excluding Fourth Quarter)
Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)
Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

1 Introduction

In Order No. P.U. 14(2004), the Board required Newfoundland and Labrador Hydro (Hydro) to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 14 individual KPIs within the following four general categories: Reliability; Operating; Financial; and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. At the time of this report, CEA data has been published only to 2014. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2015 compared with the prior year as well as a comparison of actual KPI results compared with targets.

Section 3 of this report provides a detailed analysis of each individual KPI within the four categories named above in Section 3. In addition, it provides fourth quarter data for transmission and distribution reliability which is routinely included in Hydro's quarterly regulatory reports.

Section 3.3 Financial Performance Indicators are not yet available but will follow after the audited financial statements are available.

The 2015 financial data and 2016 targets in Section 4 Data Table of Key Performance Indicators are not available at this time. This section will be re-filed after the financial data is available and the 2016 target levels have been established.

2 Overview of Key Performance Indicator Results

2.1 Overview

A number of key indices measured by Hydro showed improvement when compared to 2014 or the targets for 2015. All indices are discussed in the following sections of this Appendix.

Generation availability did not change significantly in 2015 when compared to 2014. Hydro's overall Weighted Capability factor, which measures generating unit availability, held at 80% in 2015, the same as for 2014. The availability of the Holyrood thermal plant held at 64% in 2015, the same (63.4%) as for 2014. The availability of gas turbines improved to 80%, the same as for 2014. The availability of Hydro's hydraulic plants held at 88% in 2015, the same as for 2014. With the exception of Unit 1 at the Bay d'Espoir generating station, Hydro's hydraulic units' availability was consistent with historic performance. Impacting on the overall hydraulic unit availability was a vibration and bearing issue on Unit 1.

- The Derating-Adjusted Forced Outage Rate (DAFOR) performance across all generation classes improved considerably to 3.4% in 2015, compared to 8.2% in 2014. The thermal DAFOR improved to 5.0% in 2015 from 13.7% in 2014.
- Both the frequency and duration of transmission delivery point outages improved in 2015, compared to 2014.
- The 2015 hydraulic conversion factor at Bay d'Espoir was affected by lower reservoirs levels then experienced in previous years. The target was met in 2015 for this measure.

Other indices did not exhibit the same improvement in comparison to the 2014 performance or the 2015 target.

- Undefrequency load shedding performance improved to eight events in 2015, compared to 14 events in 2014. The 2015 target of six events was not met.
- Overall Transmission and Distribution reliability were impacted by an increase in planned outages in 2015, offset by a reduction in the number and duration of forced outages as indicated above.

The 2015 operating KPI for energy conversion at Holyrood was primarily impacted by the low heating content in the fuel consumed at the plant in addition to a lower average unit loading.

A review of all indices is contained in the following sections.

2.2 Performance in 2015 versus 2015 Target

The table below summarizes Hydro's KPI performance in 2015. The rationale for the 2015 targets was summarized in the February 2015 report to the Board entitled *2014 Annual Report on Key Performance Indicators*. The 2015 rationale is included in this report as Appendix A.

Category	KPI	Units	2015 Target	2015 Results
Reliability	Weighted Capability Factor (WCF)	%	83.8[1]	79.9
	DAFOR	%	2.7	3.4
	T-SAIDI	Minutes/Point	N/A[2]	476[3]
	T-SAIFI	Number/Point	N/A	3.1
	T-SARI	Minutes/Outage	N/A	154
	SAIDI	Hours/Customer	10.5	17.5
	SAIFI	Number/Customer	4.6	7.0
	End User SAIDI[4]	Hours/Customer	1.9	3.1
	End User SAIFI[4]	Number/Customer	1.1	2.0
	Underfrequency Load Shedding	# of events	6	8
Operating	Hydraulic CF	GWh/MCM	0.433	0.433
	Thermal CF	kWh/BBL	607	602
Financial	Controllable Unit Cost	$/MWh	Not Available	
Other	Customer Satisfaction (Residential)	Max=100%		

[1] The Weighted Capability Factor target is based on planned annual maintenance outages, an allowance for other short duration maintenance outages and targeted forced outage durations.
[2] Transmission targets (T-SAIDI, T-SAIFI, and T-SARI) were not set for 2015.
[3] Transmission and distribution reliability performance is measured on combined planned and unplanned outages.
[4] New measure for 2015, refer to section 3.1.2 for further details.

3 Performance Indices

The following defines and describes detailed Key Performance Indicator data within four general categories: Reliability, Operating, Financial, and Customer-Related.

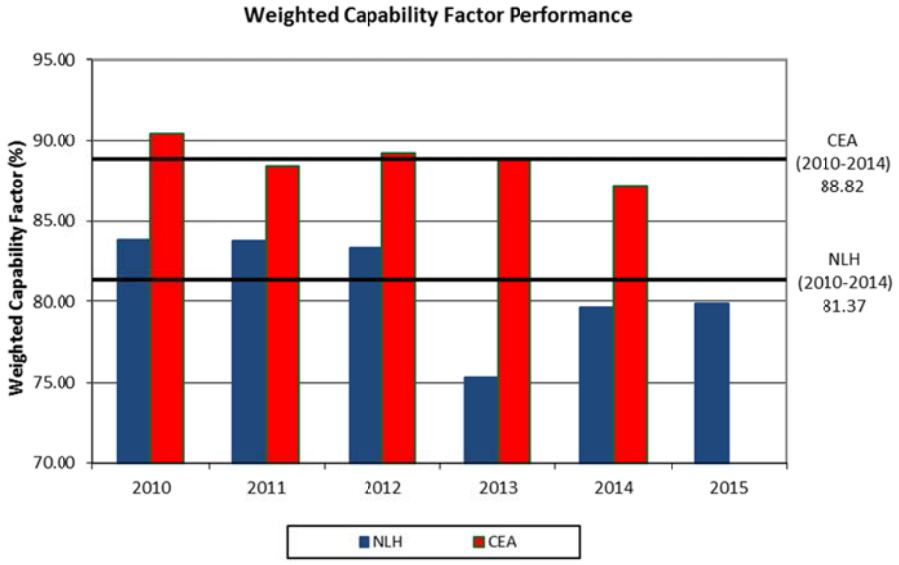
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

3.1.1 a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2015, Hydro's WCF was 79.9%, compared to 79.7% in 2014 and a target of 83.8%. The 2010 to 2014 Hydro five-year average (as last reported to the CEA) is 81.4%. The annual target for availability includes the time that units are out for maintenance. Therefore, the capability in any year is affected by the maintenance and capital work planned for that year.



Thermal unit WCF was 63.6% in 2015 compared to 63.4% in 2014. The 2015 Thermal WCF target was 67.3%. Holyrood Unit 1 had a capability factor of 68.8%, Unit 2 had a capability factor of 65.2%, and Unit 3 had a capability factor of 56.2%. Holyrood unit maintenance and planned outages were completed within the intended timeframes. Unit 3 experienced planned outages of approximately five months in total throughout the year. A Holyrood unit was operated throughout the summer months in 2015 in order to support the transmission into the Avalon Peninsula with the exception of the period of the total plant outage in August.

Overall, the hydraulic unit WCF performance was 88.0%, compared to 87.9% in 2014 and a target of 91.9%. The primary driver for the 88.0% WCF was the forced extension of a planned outage and a derating to Bay d'Espoir Unit 1. The planned annual maintenance was scheduled from April 26 to May 15, and this was extended to July 7. The unit was derated to 45 MW from 77 MW from July 8 to September 30. The problem with the unit involved vibration issues which necessitated the replacement of the thrust bearing. Removing the impact of the issue on Bay d'Espoir Unit 1 from the hydraulic WCF, results in an annual hydraulic WCF outcome of 90.5%.

Gas turbine availability improved to 80.2% in 2015 from 76.9% in 2014. The 2015 gas turbine WCF target was 85.6%.

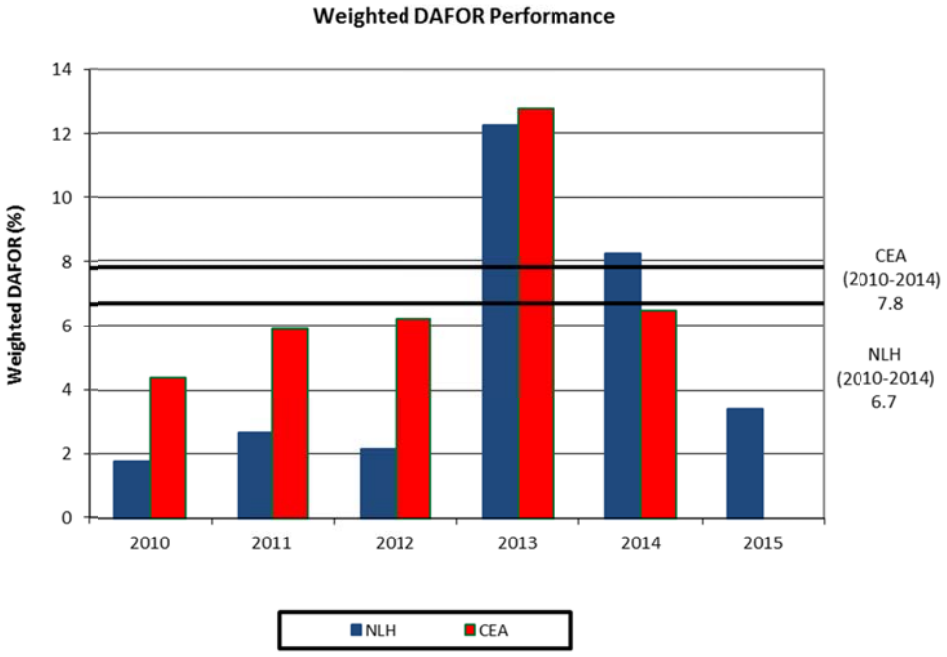
Calculation details for weighted capability as well as a list of factors that can impact KPI performance are included in Appendix B of this report.

3.1.1 b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems[5]. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2015, Hydro's weighted DAFOR improved considerably to 3.4%, compared to 8.3% in 2014. The 2015 target was 2.7%. The thermal DAFOR for 2015 improved to 5.0%, compared to 13.7% in 2014 and a target of 8.0%. The hydraulic DAFOR was 2.7% compared to 5.9% in 2014 and a target of 0.6%. The hydraulic DAFOR was impacted by the Bay d'Espoir Unit 1 vibration and bearing issues, as described in the previous section. These issues contributed approximately 82% to the overall 2015 hydraulic DAFOR.

Hydro's overall weighted DAFOR for the period 2010 to 2014 is 6.7%, 1.1% better than the equivalently weighted national average of 7.8% for the same period.

[5] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.



3.1.1 c) Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2014 and for the latest five year CEA national average (2010-2014) are included for comparison.

Generation Performance Indices

Index		Hydro	Thermal	Gas Turbine
Failure Rate (Forced Outages per 8,760 operating hours)	NLH 2015	1.34	9.07	57.01
	NLH 2014	2.71	11.72	160.36
	CEA '10-'14	2.06	7.79	69.93
Incapability Factor (Percent of Time)	NLH 2015	11.70	36.60	27.21
	NLH 2014	11.30	36.41	23.06
	CEA '10-'14	11.18	26.33	15.84
Derating Adjusted Forced Outage Rate (Percent of Time)	NLH 2015	2.67	5.03	
	NLH 2014	5.97	13.74	
	CEA '10-'14	5.12	13.14	
Utilization Forced Outage Probability (Percent of Time)	NLH 2015			10.55
	NLH 2014			14.34
	CEA '10-'14			19.95

Hydraulic Unit Performance

The forced extension of the annual planned outage and subsequent unit derating on Unit 1 at Bay d'Espoir, resulting from the vibration and bearing issues, impacted the Incapability Factor for hydraulic unit measures in 2015. However, both the Failure Rate and DAFOR performance in 2015 was significantly better than in 2014 and the national five year averages.

Thermal Unit Performance

Thermal unit performance improved considerably in 2015 in the areas of Failure Rate and DAFOR, when compared to 2014. Incapability Factor performance declined slightly in 2015, when compared to 2014, primarily due to an extended planned annual outage on Holyrood Unit 3.

Gas Turbine Unit Performance

The Failure Rate and Utilization Forced Outage Probability (UFOP) performance of Hydro's gas turbines also improved considerably in 2015 when compared to 2014. Of particular importance to Hydro's gas turbines fleet is the UFOP which measure the degree to which a standby unit can be called upon to supply load when requested. The UFOP in 2015 was 10.6%, improving from 14.3% in 2014 and the CEA five year average of 20.0%. Incapability Factor performance declined in 2015, when compared to 2014, primarily due to an extended planned outage at Happy Valley.

3.1.2 Reliability KPI: End User Performance

This performance index was developed to measure the reliability of all end users of electricity in the province supplied by Hydro. The measure is a combination of Hydro's service continuity data and Newfoundland Power (NP) service continuity data for Loss of Supply outages resulting from events on Hydro's transmission system. Therefore, the SAIFI and SAIDI data below is a measure of the duration and frequency of service interruptions experienced as a result of Hydro system events. This does not reflect interruptions to NP customers from issues on NP system.

Targets were developed using the past performance of Hydro and NP service continuity data. The effects of January 11, 2013 and January 2 to 8, 2014 significant interruptions were removed from the data and a modified 2010 to 2014 five year average was created. These events were removed due to the significant effect these events had on the five year data set. This is a normal practice of utilities to remove data associated with major events. This modified average was then compared to the 2013 CEA Region 2 Loss of Supply outcome.

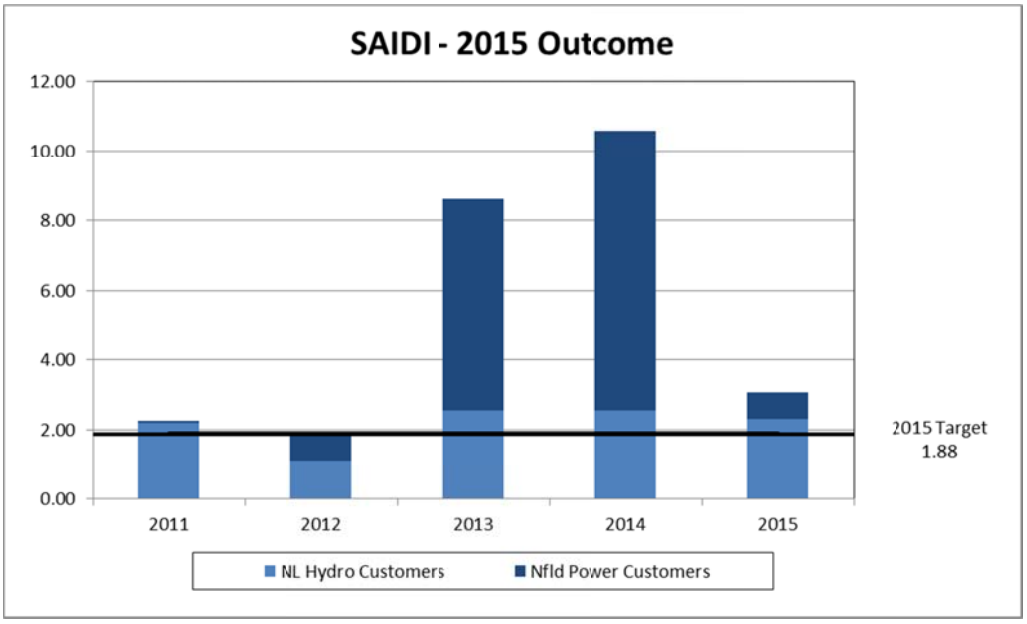
The SAIFI and SAIDI values add cumulatively through the year, with the final target for SAIFI being 1.08 and the final SAIDI being 1.88.

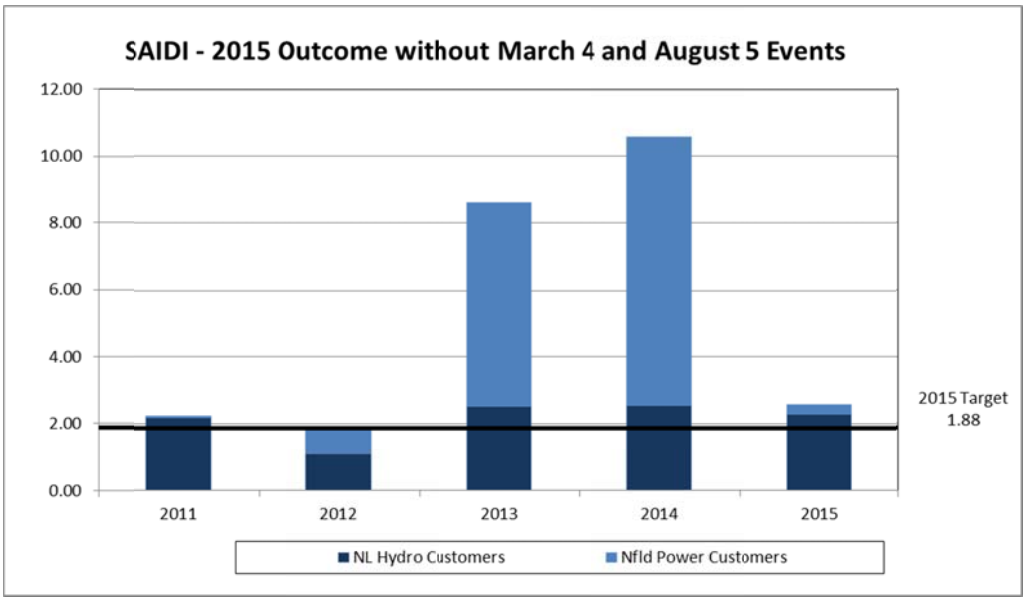
End User Service Continuity Performance

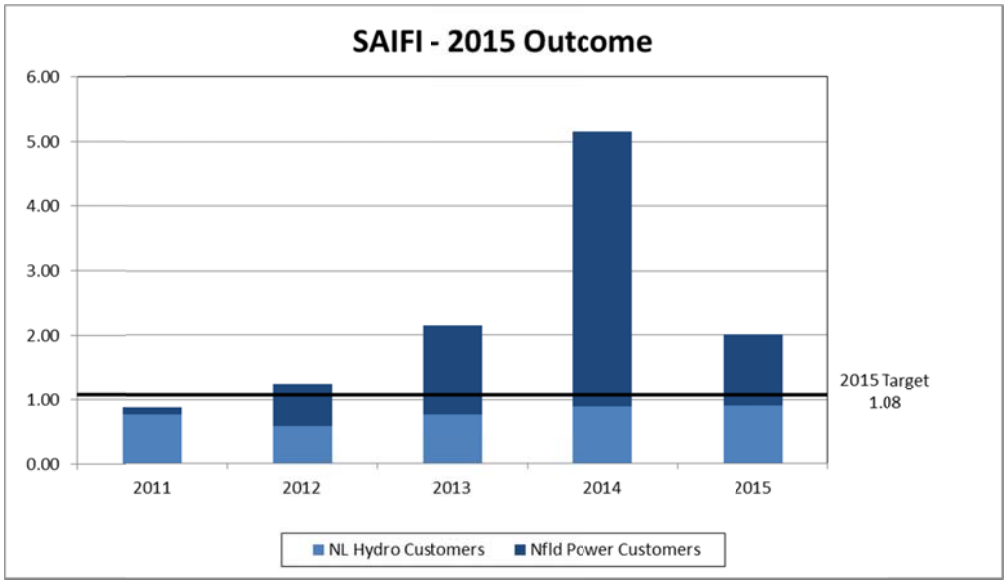
	SAIFI	SAIDI
2015 Q4	0.43	0.66
2015 Outcome	2.00	3.07
Annual Target	1.08	1.88

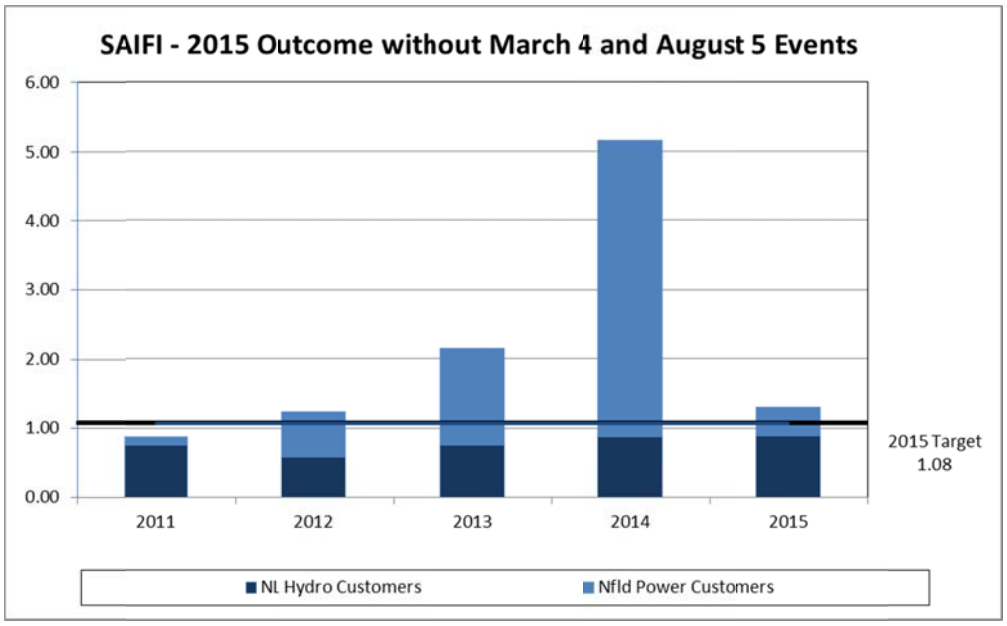
The fourth quarter performance was affected by three underfrequency events. These events are described in a later section. NP customers were also affected by planned transmission outages in the fourth quarter. Hydro's fourth quarter performance was affected by planned outages in Rocky Harbour, Nain, and in Labrador West for the distribution system upgrades.

Overall in 2015, NP customers were affected by two significant events resulting from Hydro system events; the March 4 undervoltage event and the August 5 underfrequency event. These two events contributed approximately 60% of the overall SAIFI and SAIDI for NP customers and without these two events, the 2015 SAIFI would be 1.31 and the SAIDI would be 2.58. These are compared to annual targets of 1.08 for SAIFI and 1.88 for SAIDI.


SAIDI - 2015 Outcome
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2011
2012
2013
2014
2015
2015 Target
1.88
NL Hydro Customers
Nfld Power Customers


SAIDI - 2015 Outcome without March 4 and August 5 Events
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2011
2012
2013
2014
2015
2015 Target
1.88
NL Hydro Customers
Nfld Power Customers


SAIFI - 2015 Outcome
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2011
2012
2013
2014
2015
2015 Target
1.08
NL Hydro Customers
Nfld Power Customers

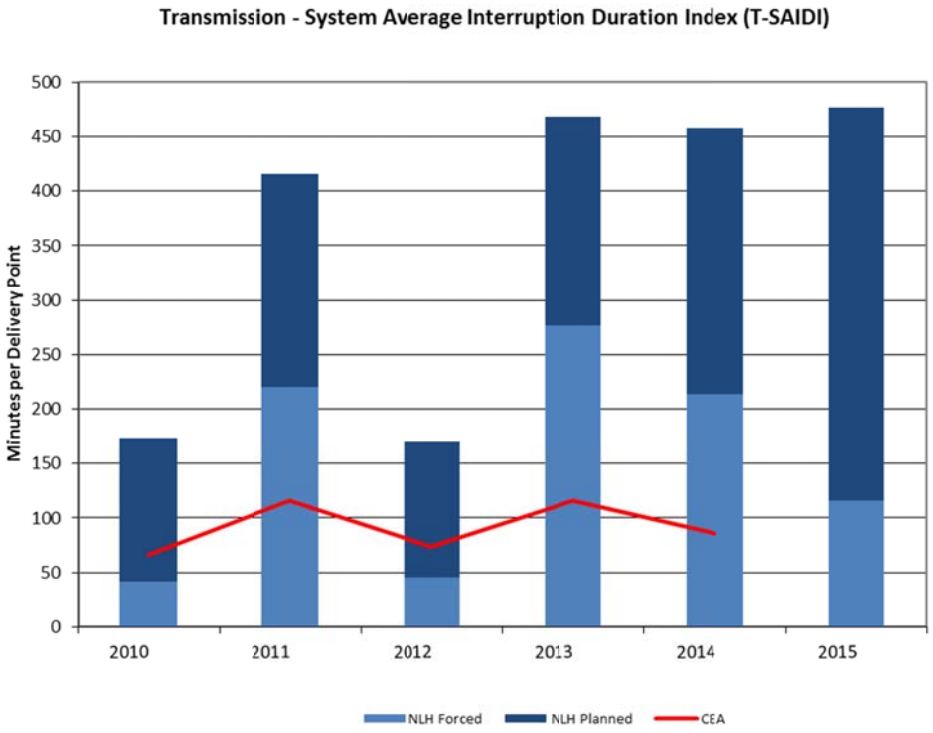

SAIFI - 2015 Outcome without March 4 and August 5 Events
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2011
2012
2013
2014
2015
2015 Target
1.08
NL Hydro Customers
Nfld Power Customers

3.1.3 Reliability KPI: Transmission

3.1.3 a) Transmission System Average Interruption Duration Index (T-SAIDI) - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI was 128 minutes per delivery point (forced and planned combined) compared to 96 minutes in 2014.

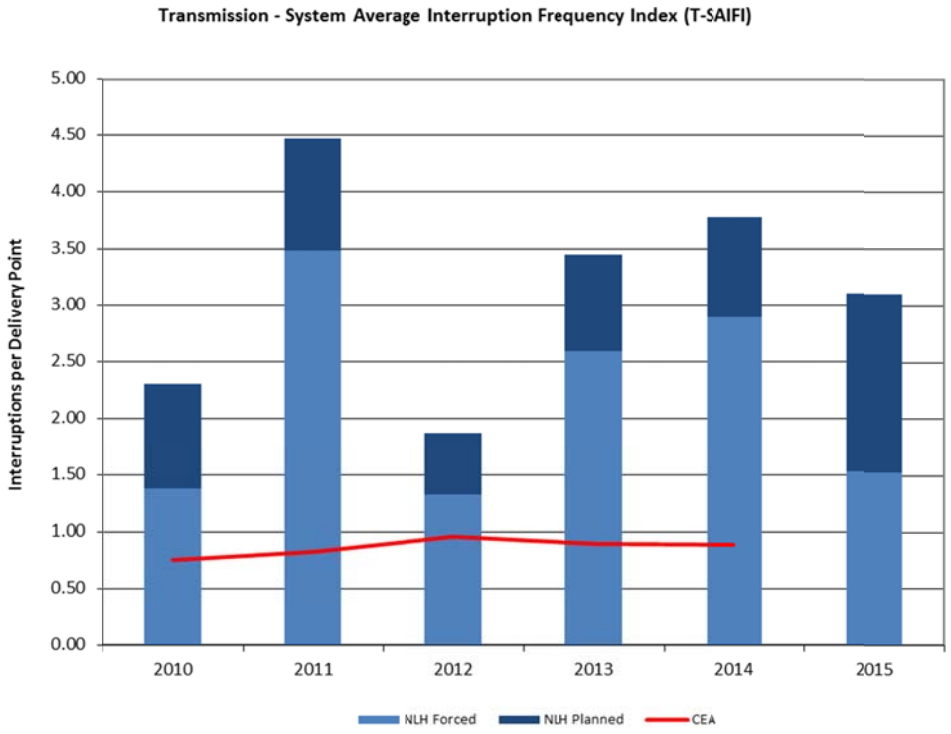
The total 2015 T-SAIDI was 476 minutes per delivery point compared to a 2014 total of 458 minutes per delivery point. There was no target set for 2015. The forced outage duration in 2015 improved considerably to 116 minutes, from 214 minutes in 2014. The planned outage duration was 361 minutes, compared to 244 minutes in 2014. The increase in the T-SAIDI for planned outages was the result of increased maintenance on terminal station equipment.



3.1.3 b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 1.05 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.47 and 0.58, respectively. The 2014 fourth quarter T-SAIFI was 0.48 outages per bulk delivery point.

The 2015 T-SAIFI was 3.10 outages per bulk delivery point, compared to 2014 T-SAIFI of 3.78 outages per delivery point. No target was set for 2015. The number of forced outages per delivery point in 2015 improved considerably to 1.53, compared to 2.90 in 2014. The number of planned outages per delivery point in 2015 was 1.57 compared to 0.88 in 2014. The increase in the T-SAIFI for planned outages was the result of increased maintenance on terminal station equipment.

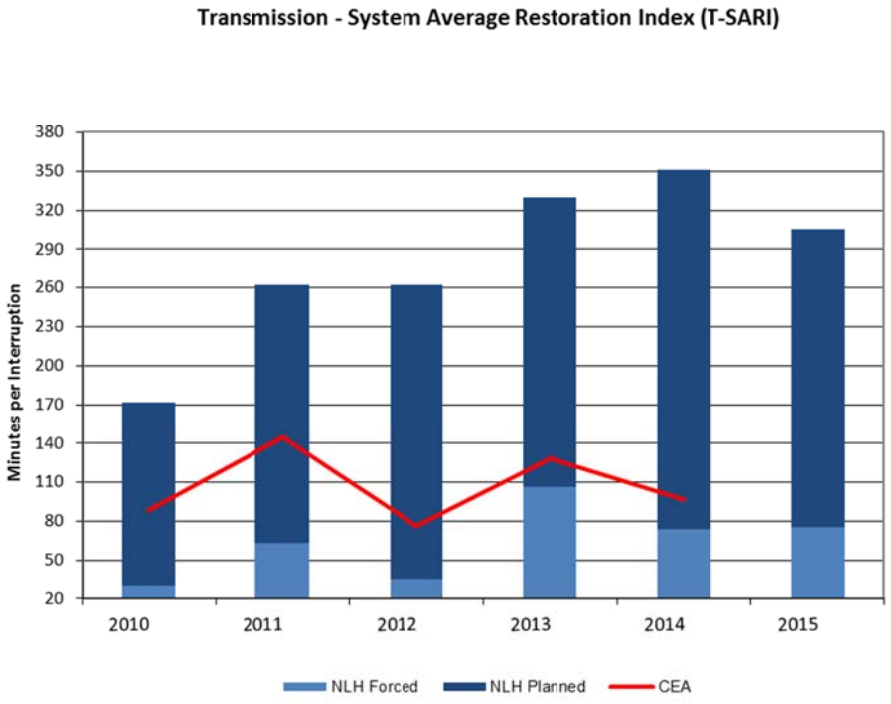


3.1.3 c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's transmission T-SARI was 122 minutes per interruption for the fourth quarter of 2015, compared to 199 minutes per interruption during the same quarter in 2014. The forced outage component of T-SARI was 51 minutes per interruption, compared to 42 minutes per interruption in 2014. The planned outage component of T-SARI was 179 minutes per interruption compared to 286 minutes per interruption in 2014.

Hydro's overall transmission T-SARI for 2015 was 306 minutes per interruption, compared to 351 minutes in 2014. There was no target for 2015. The forced outage component of T-SARI was 76 minutes per interruption, compared to 74 minutes in 2014. The planned outage component of T-SARI was 230 minutes per interruption, compared to 277 minutes in 2014. Since T-SARI is the ratio of T-SAIDI to T-SAIFI, this increase results from the increase in T-SAIDI relative to T-SAIFI.

Hydro's total T-SARI performance improved in 2015 compared to 2014.



There were 13 forced transmission outages and 22 planned transmission outages in the fourth quarter. A summary of these outages follows:

Forced

On October 10, customers served by the Glenburnie, and Wiltondale Terminal Stations experienced an unplanned power outage of three hours and 56 minutes. Customers served by the Rocky Harbour Terminal Station experienced two unplanned power outages of one hour and 27 minutes and nine minutes. These outages were caused by a tree contact on transmission line TL226 during a wind storm.

On October 16, customers served by the Glenburnie, Rocky Harbour, and Wiltondale Terminal Stations experienced an unplanned power outage of 11 minutes. This outage was caused a protection operation during switching to restore TL226 after a planned outage, most likely due to a cold load pickup issue.

On October 23, customers served by the Wabush Terminal Station experienced an unplanned power outage of 49 minutes. The outage was caused by a circuit breaker controls failure during switching at the Churchill Falls Generating Station. This resulted in the tripping of the two transmission lines, L23 and L24, which supply the Wabush station.

On November 2, customers served by the Parson's Pond Terminal Station experienced an unplanned power outage of 13 minutes. This outage resulted from switching operations to close breaker B1L27 at the Cow Head Terminal Station. The bypass was closed on the breaker due to a problem with the synchronizing check relay. An attempt was made to close the breaker after salt contamination on transmission line TL227 (Daniel's Harbour to Parson's Pond) resulted in ten line recloses.

On November 2, customers served by the Cow Head Pond Terminal Station experienced an unplanned power outage of eight minutes. This outage resulted from switching operations to close breaker B1L27 at Cow Head Terminal Station. The bypass was closed on the breaker due to a problem with the synchronizing check relay. An attempt was made to close the breaker after salt contamination on transmission line TL227 (Daniel's Harbour to Parson's Pond) resulted in ten line recloses.

On November 3, customers served by the Happy Valley Terminal Station experienced an unplanned power outage of ten minutes. The outage occurred after maintenance personnel accidentally pulled an incorrect protection relay switch, causing transformers T1 and T2 to trip. Customers served by the Muskrat Falls Construction terminal station experienced an unplanned power outage of 37 minutes due a loss in the communications at site.

On November 21, customers served by the Parson's Pond Terminal Station experienced an unplanned power outage of 25 minutes. This outage resulted from switching operations which were required to safely isolate disconnect switch B1L27-2 at the Daniel's Harbour terminal station for repairs.

On December 4, customers served by the Hawke's Bay Terminal Station experienced an unplanned power outage of 16 minutes. This outage resulted when breaker B1L21 tripped due to cold load pickup during switching operations to restore the distribution system after a planned outage.

On December 10, customers served by the Grandy Brook Terminal Station experienced two unplanned power outages of one hour and 26 minutes and one hour and 30 minutes. These outages occurred after a fault during switching to restore recloser GB5-R1. This action caused the transformer T1 differential protection and T1 lockout to operate which closed the high speed disconnect switch T1AG. The fault was cleared by circuit breaker B2L14 at the Bottom Brook station. The system configuration at Bottom Brook had the circuit switcher L14L50 closed to supply both Doyles and Grandy Brooks stations. Circuit breaker B3L50 was out of service and in the process of being replaced following a failure in August 2015.

On December 10, NP customers in the Port aux Basques and the Codroy Valley areas served by the Doyles Terminal Station experienced two unplanned power outages of five minutes and four minutes. These outages occurred after circuit breaker B2L14 tripped at Bottom Waters Terminal Station. This breaker tripped during a fault that occurred during switching to restore recloser GB5-R1. This action caused the transformer T1 differential protection and T1 lockout to operate which closed the high speed disconnect switch T1AG. The system configuration at Bottom Brook had the circuit switcher L14L50 closed to supply both Doyles and Grandy Brook stations. Circuit breaker B3L50 was out of service and in the process of being replaced following a failure in August 2015.

On December 10, NP customers in the Port aux Basques and the Codroy Valley areas served by the Doyles Terminal Station experienced another unplanned power outage of 16 minutes. This outage occurred after transmission line TL214 tripped due to salt contamination.

On December 25, customers served by the Glenburnie and Wiltondale Terminal Stations experienced an unplanned power outage of two hours and two minutes and customers served by the Rocky Harbour terminal station experienced an unplanned outage of two hours and 28 minutes. These outages occurred after transmission line TL226 tripped due to a tree contact. Personnel responded and isolated the section of TL226 from the Deer Lake to Wiltondale stations. Circuit breaker L26L27 was closed at the Berry Hill station to restore customers.

On December 26, customers served by the Glenburnie, Rocky Harbour and Wiltondale Terminal Stations experienced an emergency unplanned power outage of three minutes. This outage was required to complete switching to restore Rocky Harbour line L1 following a bypass of recloser RHR-R1.

Planned

On October 3, customers served by the Plum Point and Bear Cove Terminal Stations experienced a planned power outage of seven hours and 32 minutes. This outage was required to complete maintenance on transmission line TL241 and transformer T1 at Plum Point station.

On October 5, customers served by the Grandy Brook Terminal Station experienced a planned power outage of three hours and 13 minutes. This outage was required to perform disconnect switch maintenance at the Bottom Brook Terminal Station.

On October 5, NP customers served by the Doyles Terminal Station experienced a planned power outage of one hour and 33 minutes. This outage was required to perform disconnect switch maintenance at the Bottom Brook Terminal Station and to complete planned work on transmission line TL214.

On October 5, customers served by the Glenburnie Terminal Station experienced a planned power outage of four hours and 50 minutes. This outage was required to complete maintenance on transmission line TL229 and transformer T1 at the Glenburnie station.

On October 15, customers served by the Grandy Brook Terminal Station experienced a planned power outage of seven hours. This outage was required to complete disconnect switch maintenance at the Bottom Brook Terminal Station.

On October 15, customers served by the Farewell Head Terminal Station experienced a planned power outage of seven hours and 26 minutes. This outage was required to safely install the mobile substation at the terminal station to facilitate planned maintenance work.

On October 15, NP customers served by the Doyles Terminal Station experienced two planned power outages of 36 minutes and 12 minutes. These outages were required to complete disconnect switch maintenance at the Bottom Brook terminal station and to complete planned work on transmission line TL214.

On October 15, customers served by the Roddickton Terminal Station experienced a planned power outage of six hours and 30 minutes. This outage was required to complete maintenance on transformer T2 at the Roddickton station. Customers served by the Main Brook Terminal Station experienced a planned power outage of four minutes during the restoration of transmission line TL257.

On October 18, customers served by feeder L11 from the Happy Valley Terminal Station experienced a planned power outage of six hours and 22 minutes. The gas turbine supplied the remainder of the town with the 138 kV transmission (L1301/L1302) supply isolated. Customers on feeder L11 experienced an outage to reduce the overall loading on the gas turbine.

On October 20, customers served by the Glenburnie, Rocky Harbour, and Wiltondale Terminal Stations experienced two planned power outages, see below for details. These outages were required for switching to isolate and restore the Rocky Harbour to Wiltondale tap section of transmission line TL226.

- Rocky Harbour Terminal Station: 15 minutes and ten minutes.
- Glenburnie Terminal Station: seven minutes and ten minutes.
- Wiltondale Terminal Station: seven minutes and ten minutes.

On October 20, customers served by the Parson's Pond Terminal Station experienced a planned power outage of 39 minutes. This outage was required to add oil to the conservator tank on transformer T1 at the station.

On October 24, customers served by the Main Brook Terminal Station experienced a planned power outage of four hours and six minutes. This outage was required to complete maintenance on transformer T1 and install AMR equipment at the station.

On October 25, NP customers served by the Western Avalon Terminal Station experienced a planned power outage of three hours and 53 minutes. This outage was required to replace and install three new PTs on the 66 kV bus in the station.

On October 25, customers served by feeder L11 from the Happy Valley Terminal Station experienced a planned power outage of five hours and 38 mins. Customers served by feeder L5 experienced a planned power outage of one hour and 50 minutes. The gas turbine supplied the remainder of the town with the 138 kV transmission (L1301/L1302) supply isolated. Customers on feeder L11 and L5 experienced an outage to reduce the overall loading on the gas turbine during the planned outage.

On November 1, customers served by the Farewell Head Terminal Station experienced a planned power outage of four hours and 56 minutes. This outage was required to safely remove the mobile substation at the terminal station after completion of transmission maintenance work.

On November 4, customers served by the Hampden and Jackson's Arm Terminal Stations experienced a planned power outage of ten minutes. This outage was required to open breaker L51T2 at Howley in order to safely close disconnect switch L53T1 at Coney Arm terminal station following station maintenance

On November 8, NP customers served by the Springdale Terminal Station experienced a planned power outage of five hours and 28 minutes. This outage was required to energize the new B1L23 breaker and to remove the temporary bypass in the terminal station.

On November 17, customers served by the Roddickton and Main Brook Terminal Stations experienced a planned power outage of four hours and ten minutes. The outages were required to perform power factor testing on transformer T1 at St. Anthony Airport terminal station. Customers in St. Anthony were supplied via the St. Anthony Diesel Plant during the transformer testing.

On November 24, Teck Resources, served by the Duck Pond Terminal Station, experienced a planned power outage of seven hours and four minutes. This outage was required to complete maintenance at the Duck Pond terminal station. During this time, Teck Resources used their back generation to supply some of their demand.

On November 25, Teck Resources, served by the Duck Pond Terminal Station, experienced another planned power outage of eight hours and 55 minutes. This outage was also required to complete maintenance at the Duck Pond terminal station. During this time, Teck Resources used their back generation to supply some of their demand.

On November 26, customers served by the Glenburnie and Wiltondale Terminal Stations experienced a planned power outage of 18 minutes. These outages were required for switching to isolate and restore the Rocky Harbour to South East Hill tap section of transmission line TL226.

On December 21, customers served by the Grandy Brook Terminal Station experienced a planned power outage of ten minutes. This outage was required to complete switching to restore circuit breaker B3L50. A new breaker was installed to replace the breaker which had failed in August 2015.

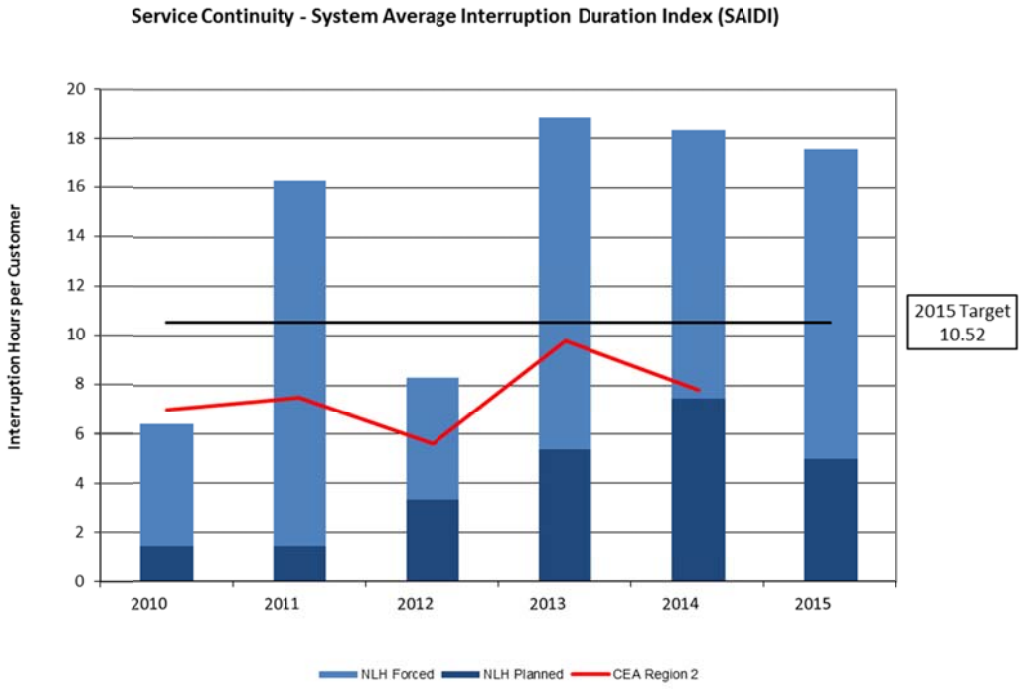
3.1.4 Reliability KPI: Distribution

3.1.4 a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2015, SAIDI was 4.26 hours per Hydro customer, compared to 2.48 hours per customer during the same quarter of 2014.

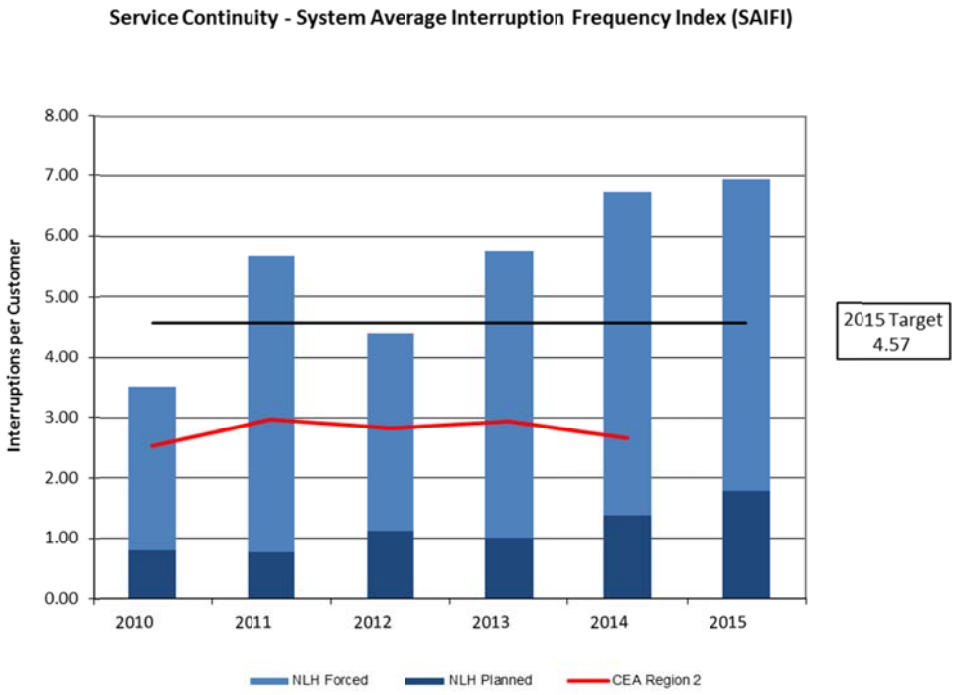
The total 2015 SAIDI was 17.54 hours per Hydro customer, compared to 18.32 hours per customer in 2014 and a target of 10.52 in 2015.

One of the main contributors to SAIDI was a series of planned outages in Labrador City and Wabush in the summer and fall of 2015. The planned outages in Labrador City were required to complete the voltage conversion project, while the Wabush planned outages were to complete upgrades at the Wabush Substation and for various distribution feeders.



3.1.4 b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter of 2015, SAIFI was 1.94, compared to 1.17 during the same quarter of 2014. The total 2015 SAIFI was 6.96, compared to 6.75 in 2014 and a target of 4.57 in 2015.



The outages during the fourth quarter resulted from a variety of causes and occurred mainly in the Labrador Interconnected region.

On October 12, 2015 at 1300 hours (Labrador time), 120 customers in Labrador City, Labrador, serviced by distribution line 3 experienced a planned power outage. The outage was required to safely perform upgrades to the distribution system. All customers were restored at 1715 hours.

On November 1, 2015 at 1530 hours (Labrador time), 729 customers in Wabush, Labrador, serviced by distribution lines 3 and 12 experienced a planned power outage. The outage was required to safely perform maintenance to the distribution system. All customers were restored at 1800 hours.

On November 7, 2015 at 1510 hours, the Muskrat Falls construction site experienced an unplanned power outage when a tree came in contact with the distribution system, causing the recloser to trip. The site was restored at 1734 hours.

On November 7, 2015 at 2330 hours, 860 customers in Happy Valley-Goose Bay, Labrador, supplied by Line 7 experienced an unplanned power outage. The outage occurred due to tree falling on a primary phase of Line 7. All customers were restored at 0220 hours, November 8, 2015.

A summary of the more significant 2015 interruptions affecting the distribution systems (i.e., outages generally to a complete system with duration of greater than five hours) are contained in Appendix C2.

3.1.4 c) Additional Information

As per Hydro's regular quarterly report, this section provides more detailed information on distribution system interruptions with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2015	**2014**	**2015**	**2014**	**Average**
Central					
Interconnected	0.86	0.29	3.98	2.48	3.04
Isolated	0.41	1.04	2.34	3.63	3.58
Northern					
Interconnected	2.72	1.13	6.26	7.20	5.79
Isolated	2.00	3.89	9.05	13.74	8.33
Labrador					
Interconnected	2.32	1.01	10.48	9.76	8.46
Isolated	3.84	6.10	10.83	10.88	9.76
Total	1.94	1.17	6.96	6.75	5.86

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2015	**2014**	**2015**	**2014**	**Average**
Central					
Interconnected	3.12	0.71	12.80	9.21	12.74
Isolated	0.31	1.88	0.60	4.56	3.27
Northern					
Interconnected	5.69	2.64	13.65	22.48	16.51
Isolated	1.45	10.15	6.81	21.15	8.99
Labrador					
Interconnected	4.05	1.72	28.81	26.48	20.87
Isolated	10.92	11.75	23.39	14.70	14.38
Total	4.26	2.48	17.54	18.32	15.67

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)

Area	Fourth Quarter 2015	Fourth Quarter 2014	12 Mths to Date 2015	12 Mths to Date 2014	5 Year Average
Loss of Supply – Transmission	0.72	0.01	2.85	2.34	2.06
Loss of Supply – NF Power	0.00	0.00	0.01	0.00	0.01
Loss of Supply – Isolated	0.08	0.19	0.39	0.46	0.47
Loss of Supply – L'Anse au Loup	0.03	0.03	0.16	0.24	0.11
Distribution	1.11	0.95	3.56	3.72	3.21
Total	1.94	1.17	6.96	6.75	5.86

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)

Area	Fourth Quarter 2015	Fourth Quarter 2014	12 Mths to Date 2015	12 Mths to Date 2014	5 Year Average
Loss of Supply – Transmission	1.93	0.04	9.29	4.21	5.06
Loss of Supply – NF Power	0.00	0.00	0.04	0.00	0.11
Loss of Supply – Isolated	0.03	0.15	0.25	0.26	0.23
Loss of Supply – L'Anse au Loup	0.03	0.01	0.14	0.20	0.09
Distribution	2.27	2.28	7.82	13.64	10.17
Total	4.26	2.48	17.54	18.32	15.67

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type – 2015 Fourth Quarter Only

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.08	0.12	0.78	3.00	0.86	3.12
Isolated	0.00	0.00	0.41	0.31	0.41	0.31
Northern						
Interconnected	0.79	0.93	1.93	4.77	2.72	5.69
Isolated	0.32	0.48	1.68	0.97	2.00	1.45
Labrador						
Interconnected	0.54	1.67	1.78	2.37	2.32	4.05
Isolated	2.51	10.08	1.33	0.84	3.84	10.92
Total	0.52	1.25	1.42	3.02	1.94	4.26

Note:

1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.

2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.5 Reliability KPI: Other

3.1.5 a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were three underfrequency events during the fourth quarter of 2015, summarized as follows:

On October 1, 2015, at 2208 hours, Holyrood Unit #3 tripped. With the removal of generation (approximately 22 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the under frequency protection at NP (4,655 customers) and Corner Brook Pulp and Paper Limited (one Industrial Customer). Total Island load at the time of the incident was 708 MW. Hydro advised NP they could restore load within two minutes after the event occurring (NP reported all customers restored within four minutes). Hydro advised Corner Brook Pulp and Paper they could restore load within four minutes after the event occurred.

Load Shed:	
Newfoundland Power:	7 MW
Corner Brook Pulp and Paper:	15 MW
Total Load Shed:	22 MW

The unit tripped while performing a weekly backwash on the Unit 3 condenser to remove natural biofouling. Both cooling water inlet valves were inadvertently closed at the same time due to an operator procedural error. This interrupted cooling water flow and normal condenser operation. Holyrood control room operations staff recognized the abnormal condenser operation, initiated off-loading and manually tripped the unit as appropriate for the situation. **(Unsupplied Energy: 74 MW-Mins)**

On November 15, 2015, at 0046 hours, Holyrood Unit #1 tripped. With the removal of generation (approximately 60.1 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the under frequency protection at NP (5,437 customers). Total Island load at the time of the incident was 783 MW. NP reported all customers restored within three minutes.

Total Load Shed: 12.4 MW

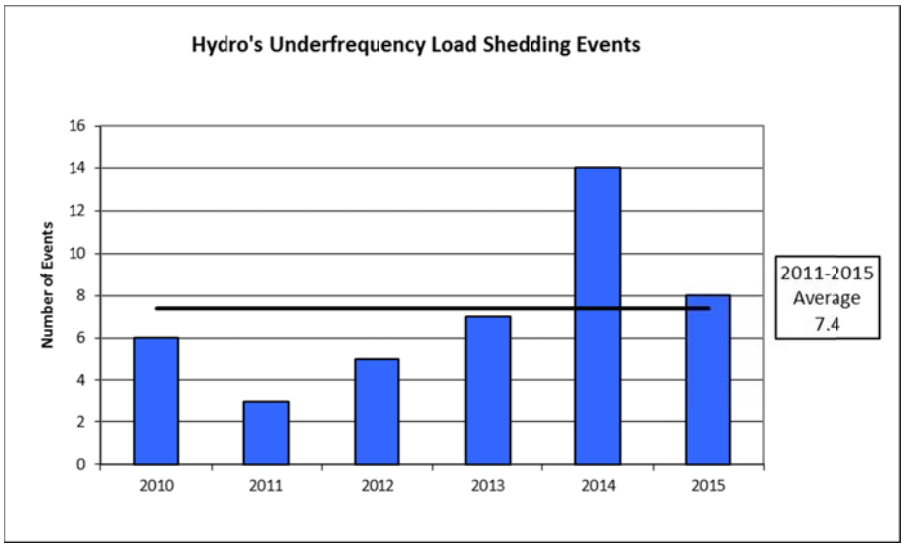
Hydro's investigation has determined that the cause of the trip was an issue with the Mark V governor control system. These issues were repaired after another trip on November 27. **(Unsupplied Energy: 37 MW-Mins)**

On November 27, 2015 at 1033 hours, Holyrood Unit #1 tripped. With the removal of generation (approximately 100 MW) the system frequency dropped to 58.34 Hz resulting in the activation of the under frequency protection at NP (17,582 customers). Total Island load at the time of the incident was 1115 MW. Hydro advised NP they could restore load within seven minutes after the event occurring, NP reported most customers (all but one feeder) were restored within ten minutes and all customers restored within 14 minutes. The delay in restoring the final feeder was due to hold offs on that line. Hydro advised Corner Brook Pulp and Paper they could restore its load within 15 minutes after the event occurred. Hydro customers were restored within ten minutes.

Load Shed:	
Newfoundland Power:	78 MW
NLH:	3 MW
Corner Brook Pulp and Paper:	15 MW
Total Load Shed:	96 MW

Hydro's investigation determined that the cause of the trip was an issue with the Mark V governor control system. Hydro has worked with the OEM and replaced hardware which was suspected to be the cause of the issue. **(Unsupplied Energy: 1,035 MW-Mins)**

In total, there were eight UFLS events in 2015, compared to 14 in 2014 and the five-year average (2011-2015) of 7.4 events. Refer to the graph below which compares the UFLS events over the past five years to this year's performance.



The following table compares the UFLS events in the fourth quarter of 2015 to the same quarter in 2014 in addition to the annual performance.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter		Year to Date		5 Year Average
	2015	2014	2015	2014	(2011–2015)
NF Power	3	4	8	14	7.4
Industrials	2	1	6	3	2.0
Hydro Rural*	1	1	2	2	2.0
Total Events	3	4	8	14	7.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter		Year to Date		5 Year Average
	2015	2014	2015	2014	(2011–2015)
NF Power	831	1,722	2,245	5,798	5,096
Industrials	285	70	660	200	200
Hydro Rural*	30	12	72	48	110
Total Events	1,146	1,804	2,977	6,046	5,406

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

The details of the previous five UFLS events in 2015 are summarized in Appendix C3. Refer to Appendix C4 for Other Significant Transmission System Disturbances.

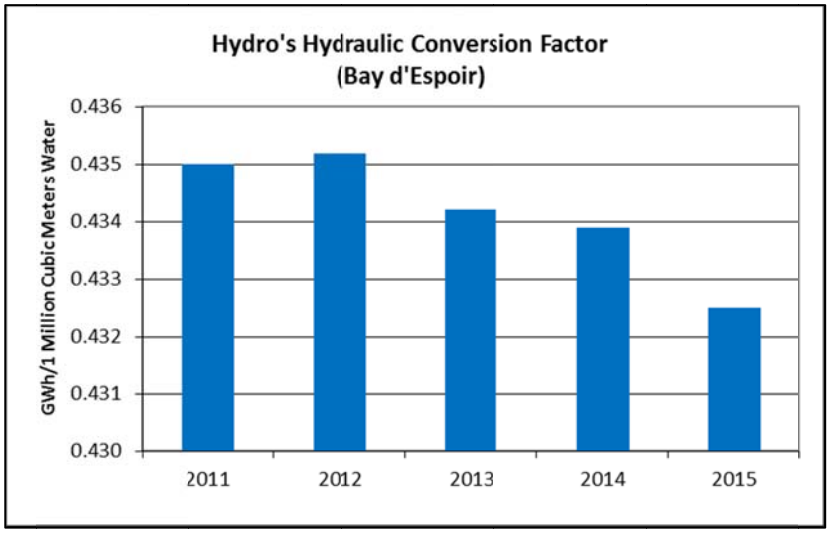
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating KPI: Generation

3.2.1 a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2015, the hydraulic conversion factor for Bay d'Espoir was 0.4325 GWh/MCM, compared to a 2015 target of 0.433 GWh/MCM.



In 2015, the water levels were lower in the reservoirs allowing for improved water utilization at the Bay d'Espoir plant. This resulted in a lower conversion factor than previous years.

3.2.1 b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

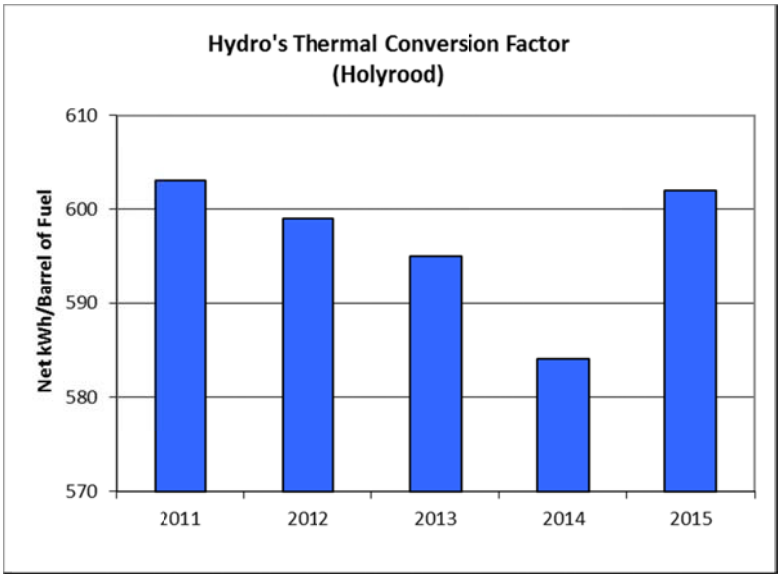
The thermal conversion factor for Holyrood is proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. The output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production on the Island, quantity of power purchases, customer energy requirements and system security requirements. The thermal conversion factor is also impacted by the heating content in the No. 6 fuel consumed at the plant, measured in BTUs/bbl.

In 2015, Hydro's net thermal conversion factor was 602 kWh per barrel compared to 584 kWh per barrel in 2014 and the 2015 target of 607 kWh per barrel. The lower energy conversion rate in 2015, relative to the target, results from a lower average unit loading and a lower heating content in the No. 6 fuel consumed at the Holyrood generating station.

The efficiency at the Holyrood plant has remained relatively consistent with a net heat rate performance of 10,468 BTU/kWh in 2015 compared to 10,779 BTU/kWh in 2014.

In 2015, the units were dispatched as required for Avalon transmission support and system peak load considerations. The average net unit load, while operating, was 88.9 MW, up from 83.2 MW in 2014, but lower than the budget of 109.6 MW for 2015.

Overall, net production from Holyrood for 2015 was 1,458 GWh, an 11% increase from 2014 production levels. The production increase in 2015 relative to 2014 was primarily due to increased Avalon transmission support requirements through the winter and early spring period and overall higher customer demand requirements on the system.



3.3 Financial Performance Indicators

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[6]

In Order No. P.U. 8(2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared. In compliance with Board Order No. P.U. 8(2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the eighth year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix D. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the U.S.-based peer group is in $US and all financial data for Hydro is in $Cdn.

With respect to the Corporate and Distribution KPIs (items 1 and 5 above), in its 2007 Annual Report on KPIs Hydro had incorporated peer benchmarking data from the Canadian Electricity Association's (CEA) Committee on Performance Excellence (COPE), as published in the "Peer Group Performance Measures for Newfoundland Power" report. However, the CEA has informed Newfoundland Power that the composite information for these measures is no longer available, nor are any other cost-related CEA composite indicators available for benchmarking purposes.[7] As a result, Newfoundland Power is now using a peer group of U.S. companies. This group of US companies is not an appropriate group for Hydro due to Hydro's relatively small distribution component. In order to maintain consistency for year-over-year comparisons, Hydro is using the same peer group of U.S. companies for the Corporate Controllable Unit Cost KPI that Hydro uses for its generation financial benchmarking.

[6] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.

[7] "Peer Group Performance Measures for Newfoundland Power", December 23, 2008, p.2.

3.3.1 Financial KPI: Corporate Operating, Maintenance and Administrative Expense (OM&A) per MWh delivered

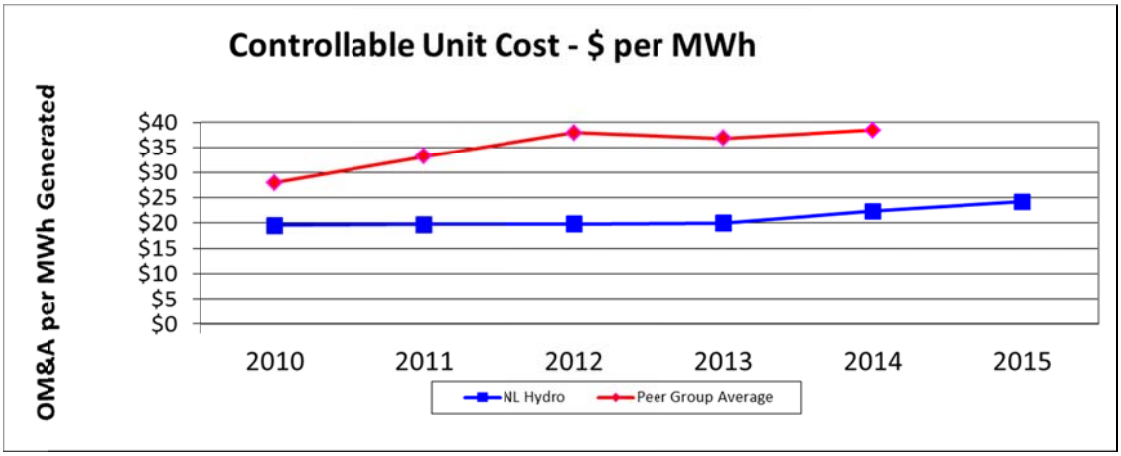
3.3.1 Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, and loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs increased from $134.2 million in 2014 to $153.8 million in 2015, resulting in a Controllable Unit Cost of $16.71 per MWh delivered for 2015.

Up to 2006, Hydro's Controllable Unit Cost was compared to the average Controllable Unit Cost for participants in the CEA COPE program as reported by Newfoundland Power. As of 2008, however, Newfoundland Power no longer uses CEA COPE benchmarking data for cost-related measures, because the composite information for these measures is no longer available for publication. Peer group results for the period 2007-2014 have therefore been restated using the same U.S. Peer Group that Hydro uses for generation financial KPIs.

For computation of Hydro's Corporate Controllable Unit Cost, normalized energy delivered is used. However, the available peer group data from the FERC database is based on net energy generated. Thus, for better comparison against the peer group, Hydro's data will also be calculated and charted on this basis. Hydro's Corporate OM&A per unit of net generation was $24.13 per MWh during 2015, higher than the computed Controllable Unit Cost, because normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost is following a very steady trend as compared to an upward trend from 2009 to 2012 and 2014, with a slight decline in 2013 for the peer group. However, it is difficult to determine specifically what factors might be impacting the expenses of the peer group participants without detailed information regarding their operations and finances.

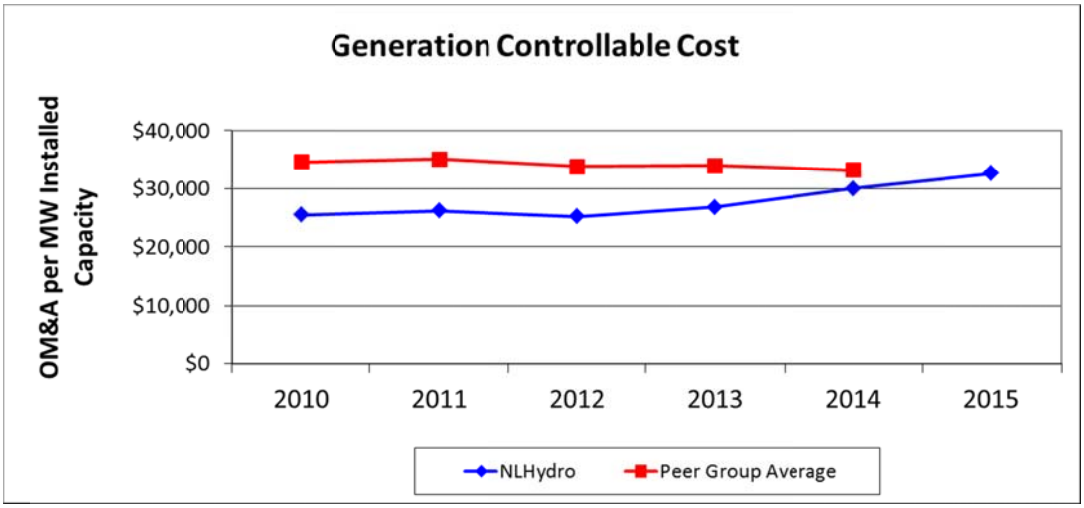


3.3.2 Financial KPI: Generation OM&A per MW Installed Capacity

3.3.2 Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $32,599 per MW for 2015 compared with $30,013 in 2014 an increase of $2,586 per MW.

The peer group used to benchmark Generation Controllable Costs appears to be experiencing a relatively steady trend in 2012 to 2014 OM&A per MW installed capacity while Hydro is showing increases for the period 2012 to 2015.

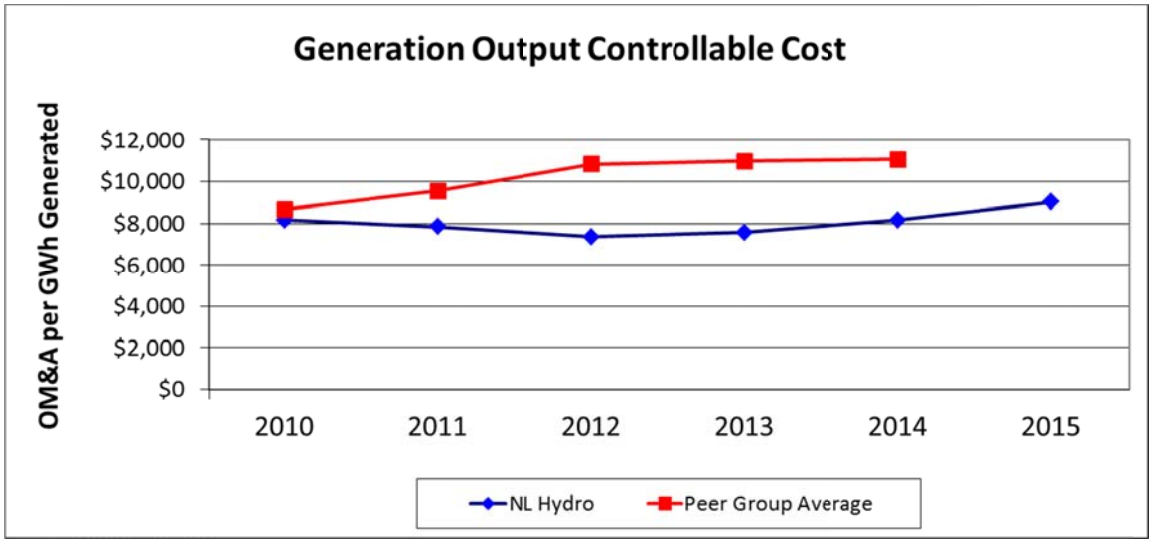


3.3.3 Generation OM&A per GWh generated

3.3.3 Generation Output Controllable Cost - *a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.*

In 2015, Hydro's Generation Output Controllable Cost of $9,010 per GWh, was higher than the $8,150 in 2014. There was an increase in the Generation Costs component of approximately $8.3 million from 2014 to 2015 coupled with an increase of 347 GWh in the Net Energy Generated.

In 2010, Hydro's Generation Output Controllable Costs were primarily in line with those of the peer group with declines showing for Hydro from 2011 and 2012 and moderate increases recorded from 2013 through 2015.

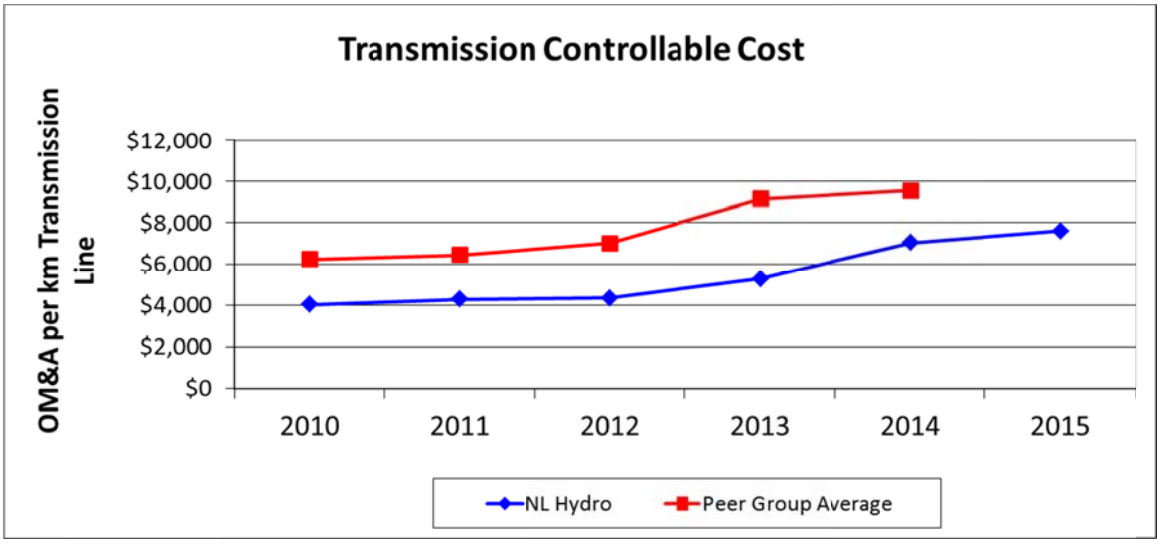


3.3.4 Financial KPI: Transmission OM&A per Transmission Circuit km

3.3.4 Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2015, Hydro's Transmission Controllable Cost was $7,615 per km of transmission, an increase of 8.1% over 2014.

Hydro's costs per km of transmission circuit are trending in a similar pattern as the peer group, although per unit cost increases appear to be increasing at a slower rate within Hydro for the period 2010 to 2013. A direct cost per unit km within the peer group is not meaningful due to differences in accounting and corporate cost allocations; however comparisons over time can highlight relevant trends.



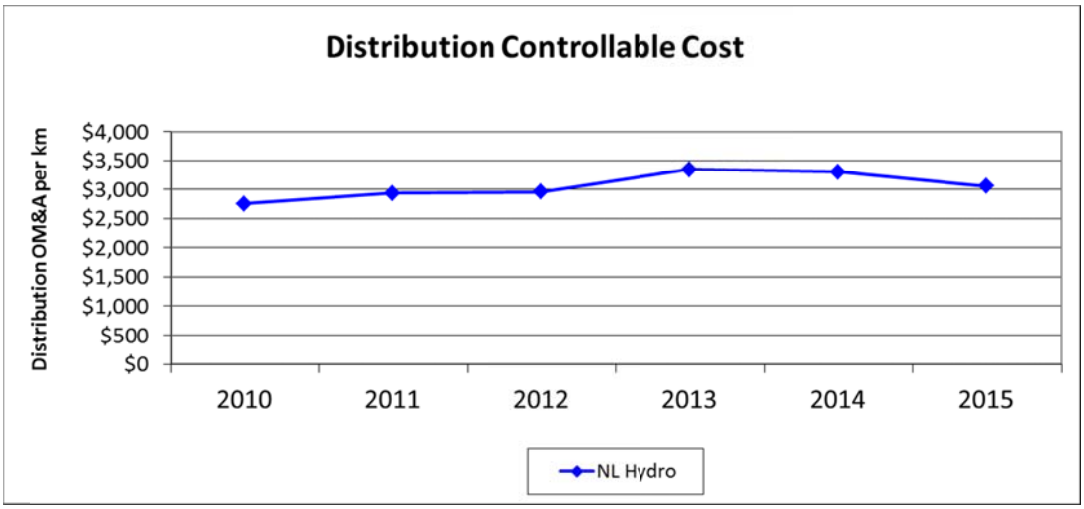
3.3.5 Financial KPI: Distribution OM&A per Distribution Circuit km

3.3.5 Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometres*[8].

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

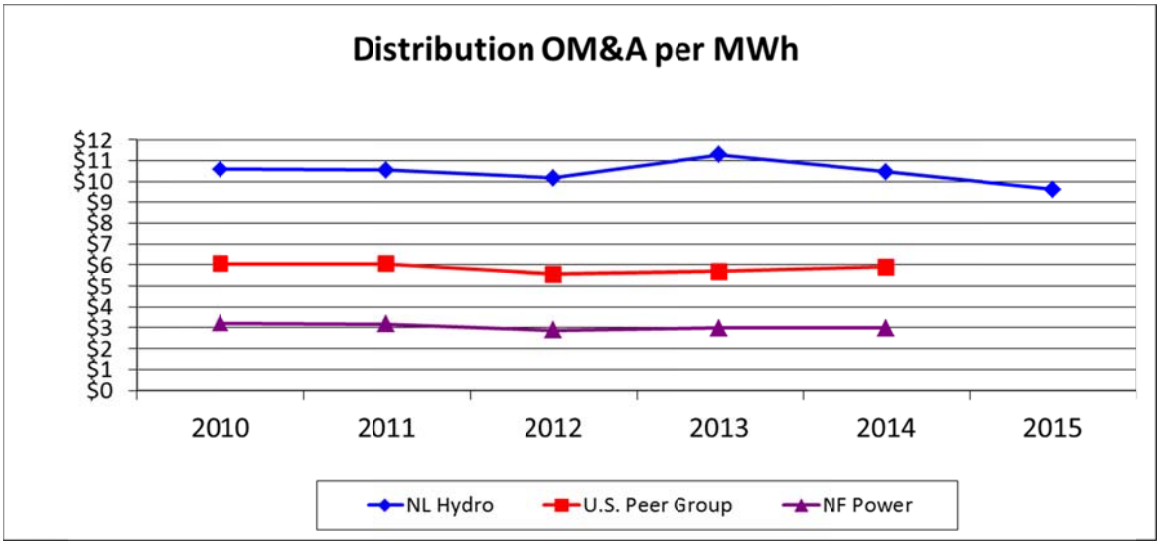
The distribution cost per km of circuit length will continue to be reported for year-over-year trend analysis.

At $3,053 per circuit km Hydro's Distribution Controllable Cost of 2015 decreased from the $3,304 that was recorded in 2014. This is a downward trend in this cost in 2015 compared to the increase trend that was seen between 2010 and 2013.



As expected, Hydro's distribution costs of $10.45 per MWh in 2014 trend higher than those of its peers in the table below. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs per MWh are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.

[8] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.



3.4 Customer-Related Performance Indicators

3.4.1 a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI*[9]*.*

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via an annual survey of Hydro's residential customers.

The 2014[10] residential customer satisfaction survey shows that 84% of customers are either very satisfied or somewhat satisfied with Hydro. When compared to 2012, customer satisfaction has increased by 4%.

[9] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.
[10] The next customer satisfaction survey is planned for Q2 2016.


Residential Customer Satisfaction
Overall Customer Satisfaction
94
92
90
88
86
84
82
80
78
76
74
2008
2009
2010
2011
2012
2014

Appendices

Appendix A: Rationale for Hydro's 2015 KPI Targets

KPI	Comment on KPI 2015 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2015 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2015 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2015 targets for forced outage performance were not set.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2015 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	The 2015 target is based on November 2014 budget for 2015 Holyrood plant operation.
Other	
Customer Satisfaction	Targeting continuous improvement.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1 - \frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance (Cont'd)

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (ten minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can arise, for example, when a unit at Holyrood is derated to remove a pump from service.
9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events – 2015

There were nine significant events in 2015. The details follow:

Event 1

On January 27, customers served by the Wiltondale, Glenburnie, and Rocky Harbour Terminal Stations experienced an unplanned power outage of two hours and 56 minutes. This was an emergency outage to make repairs to a broken crossarm on structure #273 and to re-attach a floating phase on transmission line TL226. The line had been damaged during the winter storm on January 25. The damage was detected during a line patrol of TL226 on January 27.
(Unsupplied Energy: 1,091 MW-Mins)

Event 2

On February 1, Hydro and NP customers served by the Bottom Waters Terminal Station experienced an unplanned power outage of three hours and 16 minutes. The outage occurred after transmission line 363L tripped during a winter storm due to icing on the structures crossarms. Customer restoration was delayed due a 'stuck' control relay in the auto synch circuit. This circuit controls breaker B1L363 closure at Indian River Terminal Station.
(**Unsupplied Energy: 2,193 MW-Mins)**

Event 3

On February 3, customers served by the Grandy Brook Terminal Station experienced an unplanned power outage of ten hours. The outage occurred after TL250 tripped during a winter storm due to a broken crossarm. Customer restoration was delayed due to the Burgeo Highway being closed due to poor weather conditions. The Department of Highways reopened the highway and cleared a path which allowed for a crew to perform a line patrol. The broken crossarm was located but due to the high winds (100 km/h) the crew had to wait for the wind speeds to lower before the crossarm could be replaced.
(**Unsupplied Energy: 2,040 MW-Mins)**

Event 4

On February 15, NP customers served by the Bay L'Argent Terminal Station experienced an unplanned power outage of four hours and 43 minutes, while NP customers served by the Monkstown Terminal Station experienced an unplanned power outage of six hours and 54 minutes. The outages occurred after TL212 tripped due to a burnt off jumper on disconnect switch L12-2 at Monkstown Terminal Station. **(Unsupplied Energy: 2,102 MW-Mins)**

Appendix C1: Significant Transmission Events – 2015 (Cont'd)

Event 5

On June 27, customers served by the Happy Valley and Muskrat Falls Terminal Stations experienced an unplanned power outage of two hours and 52 minutes. The outage occurred when a lighting strike hit transmission line L1301. The outage was extended due to problems with restoration of the 138 kV bus at Churchill Falls. (**Unsupplied Energy: 3,148 MW-Mins)**

Event 6/Event 7

On July 2, customers served by the Happy Valley and Muskrat Falls Terminal Stations experienced two unplanned power outages of one hour and 53 minutes and one hour and 16 minutes. The outages occurred when a lightning strike hit transmission line L1301. The outages were extended due to issues with restoration of the 138 kV bus at Churchill Falls.

Event 6: (**Unsupplied Energy: 2,091 MW-Mins)**
Event 7: (**Unsupplied Energy: 1,186 MW-Mins)**

Event 8

On September 8, NP customers served by the Western Avalon Terminal Station experienced an unplanned power outage of four hours and 55 minutes. This outage occurred after the failure of a PT on Bus B2 at Western Avalon Terminal Station. Three new PTs were installed on a planned outage in October. (**Unsupplied Energy: 1,092 MW-Mins)**

Event 9

On October 23, customers served by the Wabush Terminal Station experienced an unplanned power outage of 49 minutes. The outage was caused by a circuit breaker controls failure during switching at the Churchill Falls Generating Station. This resulted in the tripping of the two transmission lines, L23 and L24, which supply the Wabush station. (**Unsupplied Energy: 10,474 MW-Mins)**

Appendix C2: Significant Distribution Events – 2015 (Excluding Fourth Quarter)

At 1946 hours, January 4, 2015, there was a trip and reclose to Grandy Brook Terminal Station recloser, GB5-R1. Up to 120 customers in the communities of La Poile and Grand Bruit experienced the initial power interruption. Following the reclose, 66 customers in the Community of La Poile continued to experience a power outage. A Hydro crew was dispatched to the Grandy Brook Terminal Station and confirmed the correct operation of GB5-R1, however adverse weather conditions prevented travel to La Poile until later in the week. On January 7, 2015, a Hydro crew was able to fly to site and make repairs. A floating neutral conductor had made contact with the primary conductor in the distribution line. All customers were restored at 1200 hours, January 7, 2015.

At approximately 1100 hours, January 9, 2015, all customers (66) in the community of La Poile began to experience an unplanned power outage. Hydro sent a crew via helicopter on that day; however the helicopter was unable to land in La Poile due to windy weather conditions. A Hydro crew was able to fly to La Poile during the morning of January 10, 2015. Hydro had initially suspected that the sectionalizer (GB5-S2) supplying the town may have been the cause of the outage, therefore this was bypassed and the line re-energized. All customers were restored at 1146 hours, January 10, 2015. The crew continued to patrol the lines to check for additional equipment damage. During this patrol a single phase recloser (GB5-R2) was found to be making abnormal noises and this recloser was bypassed. Hydro believes this to be the root cause of the outage. Recloser GB5-R2 remains bypassed until the unit can be inspected. With sectionalizer (GB5-S2) bypassed, any future issues in La Poile will cause a recloser to trip at Hydro's Grandy Brook Terminal Station, however this station is more easily accessible for customer restoration.

On January 9, 2015 at 1422 hours, all Hydro customers (998) serviced by the L'Anse au Loup Substation experienced an unplanned power outage. The outage occurred when the supply from Hydro Québec (HQ) was interrupted due to a transformer lockout of the HQ T1 transformer. Hydro Québec switched supply to HQ T2 transformer, however not all load could be restored at once as the load was too high for the transformer. The L'Anse au Loup diesel plant was started and all customers were restored at 1507 hours. Due to the lower capacity of transformer HQ T2, Hydro has agreed that it will co-generate, using the L'Anse au Loup diesel plant, during system peak times or at the request of Hydro Québec. Hydro Québec reported the outage was caused by low gas in a breaker. It was repaired and all equipment was put back in service on February 04, 2015.

On February 16, 2015 at 1640 hours, all customers (170) in Rigolet, Labrador experienced an unplanned power outage. The outage began when heavy snow and extremely high winds caused issues with the radiator cooling systems associated with the diesel units. Hydro operators were unable to keep the radiators clear of snow and ice. Additional labourers were required to remove the ice and snow from the plant entrance as well as the radiator cooling systems which allowed for a restart of the diesel plant. At 1830 hours, February 17, power to all customers in Rigolet was restored.

On May 1, 2015 at 2025 hours, Hydro customers (141) serviced by the L'Anse au Loup feeder L2 in the communities of Pinware and Red Bay, Labrador began to experience an unplanned power outage. Crews investigated and determined that the outage was the result of conductor sleeve failures on a primary and neutral conductor in the distribution system. The problem was isolated through sectionalizing and nearly half the customers (70) were restored at 2330 hours. The remaining customers (71) were restored at 0202 hours on May 2, 2015, following completion of the repairs.

At 2129 hours, May 13, 2015, all customers (1,800) on Fogo Island and Change Islands experienced an unplanned power outage. The outage was caused by a trip of NP's line 142L which supplies the area. A NP crew was dispatched and found a faulty potential transformer at their Boyd's Cove Substation. Customers were restored at 0158 hours, May 14, 2015.

On June 9, 2015 at 1652 hours (Labrador time), 1224 customers in Labrador City, Labrador, experienced an unplanned power outage. Some customers experienced intermitted outages as Hydro was troubleshooting the problem. Hydro crews discovered the problem was caused by a primary connector coming in contact with another line. Customer outage information is as follows:

> Outage 1, Vanier Substation, Cabin Area, & Landfill Site: 474 customers, 1652 – 2000 hours, 3 hours 8 minutes.
> Outage 2, Hudson Station: 750 customers, 1652 - 2122 hours, 4 hours 30 minutes.

On June 12, 2015 at 1300 hours (Labrador time), 250 customers in Labrador City, Labrador, serviced by Quartzite Line 12 and Bartlett Line 5 experienced a planned power outage. The outage was required to safely perform upgrades to the distribution system. All customers were restored at 1800 hours.

On June 28, 2015 at 1300 hours (Labrador time), 1112 customers in Labrador City, Labrador, serviced by Lines 4, 5, and 17 experienced a planned power outage. The outage was required to safely perform upgrades to the distribution system. All customers were restored at 1815 hours.

On June 30, 2015 at 1300 hours (Labrador time), 116 customers in Labrador City, Labrador, serviced by Line 18 experienced a planned power outage. The outage was required to safely perform upgrades to the distribution system. All customers were restored at 1750 hours.

On July 5, 2015, 1916 customers supplied by Happy Valley Terminal Station Line 8 experienced an unplanned power outage. The outage occurred when Line 8 tripped due to a fault on the line. Hydro investigated, but did not determine a cause for the fault. These customers remained offline until the transmission system from Churchill Falls was returned to service following planned maintenance. The remaining customers continued to be supplied by the Happy Valley Gas Turbine.

> Outage 1: 0546 – 1424 hours, 8 hours 38 minutes, one customer (Muskrat Falls construction site - planned outage due to work on transmission system).
> Outage 2: 0651 – 1424 hours, seven hours 33 minutes, 1916 customers (Line 8).
>
> All customers were restored via the 138 kV transmission system (from Churchill Falls) at 1424 hours.

A voltage conversion is ongoing in Labrador City. Below are the outages related to safely perform that work in Q3.

> On July 18, 209 customers in Labrador City, serviced by Line 22 experienced a planned power outage.
>
> On July 25, 250 customers in Labrador City, serviced by portions of Line 2 and Line 8 experienced a planned power outage.

On July 26, 250 customers in Labrador City, serviced by portions of Line 22 and Line 23 experienced a planned power outage.

On August 06, 550 customers in Labrador City, serviced by Bartlett Substation Lines 2 & 5, and Quartzite Substation Line 12 experienced a planned power outage.

On August 15, 420 customers in Labrador City, serviced by Hudson Substation Line 18 and Quartzite Substation Line 8 experienced a planned power outage.

On August 23, 306 customers in Labrador City, serviced by Bartlett Substation Line 22 and 23 experienced a planned power outage.

On August 23, 306 customers in Labrador City, serviced by Bartlett Substation Line 22 and 23 experienced a planned power outage.

On September 2, 363 customers in Labrador City, Labrador, serviced by the Hudson Distribution System Lines 16 and 17experienced a planned power outage.

On August 15, there was a planned outage affecting customers of North West River and Sheshatshui on transmission line L7. The outage was required to safely perform maintenance to the transmission system.

On August 16, there was a planned outage affecting customers of North West River on a section of transmission line L7. The outage was required to safely perform maintenance to the transmission system.

On August 27, 14 customers, serviced by the L'Anse au Loup distribution system, began to experience an unplanned power outage. The outage was caused when one phase on a three phase tap broke off. On August 28, the 14 customers, serviced by the L'Anse au Loup distribution system were restored. The total outage duration was 19 hours and 42 minutes. The delay in restoring customers resulted from crews requiring a mandated rest period after working on the August 27 Port Hope Simpson outage before being dispatched to address the failed phase.

On September 2, all customers (170) in Rigolet, Labrador experienced a planned power outage. The outage was required to complete plant maintenance.

On September 20, 80 customers in Nain, Labrador experienced a planned power outage. The outage was required to safely complete upgrades to the distribution system.

On September 24, there was a planned outage affecting 80 customers in North West River. The outage was required to safely perform upgrades to the distribution system.

On September 26, approximately 400 customers in Nain, Labrador experienced a planned power outage. The outage was required to safely complete upgrades to the distribution system.

On September 27, approximately 478 customers in Nain, Labrador experienced a planned power outage. The outage was required to safely complete upgrades to the distribution system.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

On January 22, 2015, at 1156 hours, Holyrood Unit 1 tripped. With the removal of generation (approximately 90 MW) the system frequency dropped to 58.77 Hz resulting in the activation of the under frequency protection at NP and Corner Brook Pulp and Paper Limited. Total Island load at the time of the incident was 1271 MW. All NP customers (5,631) were reported to be restored within four minutes after the event occurred. Hydro advised Corner Brook Pulp and Paper that they could restore load within four minutes after the event occurred. **(Unsupplied Energy: 151 MW-Mins)**

Load Shed:	
Newfoundland Power:	26 MW
Corner Brook Pulp and Paper:	15 MW
Total Load Shed:	41 MW

Hydro was conducting commissioning activities on a pump motor (U1 Light Oil Pump West). One of the activities was to rewire and commission this pump motor. In the act of closing the wiring panel door, a wire knocked loose from its termination, causing a short circuit. This short circuit tripped a feeder breaker supplying critical Burner Management System (BMS) equipment. As a result, the BMS tripped Unit 1.

Hydro inspected and corrected any other loose wires in the panel. Hydro has reviewed the incident internally and conducted a non-critical work stand-down.

On March 11, 2015, at 1052 hours, Holyrood Unit 1 tripped. With the removal of generation (approximately 120 MW) the system frequency dropped to 58.57 Hz resulting in the activation of the under frequency protection at NP (14,846 customers) and Corner Brook Pulp and Paper Limited. Total Island load at the time of the incident was 1438 MW. Hydro advised NP that they could restore load within three minutes after the event occurred (NP reported all customers restored within 17 minutes). Hydro advised Corner Brook Pulp and Paper that they could restore load within ten minutes after the event occurred. **(Unsupplied Energy: 771 MW-Mins)**

Load Shed:	
Newfoundland Power:	71 MW
Corner Brook Pulp and Paper:	15 MW
Total Load Shed:	86 MW

Hydro's investigation has determined that equipment, inside a control system cabinet, was being replaced when inadvertently, an on/off power bar switch was triggered. Power was lost to a portion of the control system causing the burner management system (BMS) to trip the unit. Hydro has identified a failure to check/identify the task as the root cause.

On May 10, 2015, at 0714 hours, Holyrood Unit #1 tripped. With the removal of generation (approximately 70 MW) the system frequency dropped to 58.7 Hz resulting in the activation of the under frequency protection at NP (6,589 customers) and Corner Brook Pulp and Paper Limited. Total Island load at the time of the incident was 934 MW. NP reported all customers were restored within five minutes. Hydro advised Corner Brook Pulp and Paper that they could restore load within five minutes after the event occurred. **(Unsupplied Energy: 165 MW-Mins)**

Load Shed:	
Newfoundland Power:	18 MW
Corner Brook Pulp and Paper:	15 MW
Total Load Shed:	33 MW

In order to safely perform upgrades to a distribution panel, the power supplying the panel needed to be removed. Hydro was in the process of switching the power supply feed when the supply to the auxiliary controls of a forced draft fan on Unit 1 was inadvertently removed. This caused the unit to trip.

Hydro has reviewed the switching procedures internally and engineering is in progress to determine the feasibility of changing the supply of the control power to a more robust location.

On July 10, 2015, both Granite Canal Unit and Upper Salmon Unit tripped offline when their associated transmission line (TL234) tripped due to a lightning strike. With the removal of generation (approximately 53 MW in total on both units) the system frequency dropped to 58.65 Hz resulting in the activation of the under frequency protection at NP (4,824 customers) and Corner Brook Pulp and Paper Limited (one Industrial Customer). Total Island load at the time of the incident was 727 MW. Hydro advised NP they could restore load within three minutes after the event occurred. **(Unsupplied Energy: 102 MW-Mins)**

Load Shed:	
Newfoundland Power:	9 MW
Corner Brook Pulp and Paper:	15 MW
Total Load Shed:	24 MW

On August 05, 2015, both Bay d'Espoir Unit 7 and Transmission Line TL206 (Bay d'Espoir to Sunnyside) tripped offline due to a lightning strike in close proximity to the Bay d'Espoir Terminal Station #2. Hydro's initial investigation has determined no damage was incurred to the generation or transmission systems affected. With the removal of generation (approximately 129 MW) the system frequency dropped to 57.98 Hz resulting in the activation of the under frequency protection at NP (52,689 customers) and Hydro (4,276 customers). Total Island load at the time of the incident was 702 MW. Hydro advised NP they could restore load within six minutes after the event occurred. Hydro customers were restored by 1032 hours. **(Unsupplied Energy: 642 MW-Mins)**

Load Shed:	
Newfoundland Power:	100 MW
Hydro:	9 MW
Total Load Shed:	109 MW

Appendix C4: Other Significant Transmission System Disturbances – 2015

On the morning of March 4, 2015, Hydro was in the process of returning Unit 1 at the Holyrood Thermal Generating Station (Holyrood TGS) to service following a planned emergency maintenance outage. A

contingency plan was in place for the duration of that maintenance outage to ensure adequate electricity supply to customers. The Island Interconnected System generation reserves in the days and hours prior to the morning peak of March 4 were monitored and considered adequate for supply to customers.

At 00:28 hours on March 4, the Holyrood TGS advised Hydro's Energy Control Centre (ECC) that Unit 1 could be delayed coming on line. At 05:24 hours on March 4, the Holyrood TGS confirmed to Hydro's ECC that Unit 1 would not be on for the morning peak. The contingency plan to have the Holyrood combustion Turbine (CT) on line for the morning peak had been initiated the previous afternoon. However, shortly after 06:00 hours Hydro experienced unanticipated starting issues with the Holyrood CT, affecting reserves on the Avalon Peninsula.

The combination of both these units being unavailable as customers' morning demand rapidly increased caused system voltages to decline on the Avalon to a point where the Come by Chance capacitor banks low voltage trip setting was reached. This capacitor bank trip further reduced voltages on the Avalon, which tripped Holyrood Unit 3. Customers subsequently experienced power interruptions commencing at 07:14 hours. At the height of the power interruption, at approximately 07:20, 83,000 customers were affected.

Hydro personnel, in conjunction with NP, responded immediately to restore power in a safe and efficient manner. The Holyrood CT was brought on line at 07:25, and within 20 minutes approximately 20,000 customers were restored. By 08:15 hours a total of over 50,000 customers had been restored. By 10:30 hours, the majority of customers were restored. The remaining customers were restored by 12:32 hours.

Hydro filed a copy of its investigative report into these events with the Board in April as Power Outage/Incident Advisory - 2015-H-062.

In addition to the above Delivery Point outages and underfrequency events, there was another system event in July that impacted NP's customers. On July 1, transmission line 109L tripped at Sunnyside Terminal Station and transformer T2 tripped and locked out at Stony Brook Terminal Station. The operation of the transformer lock out separated the 230 kV and 138 kV systems at Stony Brook and the tripping of 109L isolated the 138 kV supply from Sunnyside into the Central Region. Due to major construction being carried out by NP at the Clarenville Substation, transmission lines 100L and 109L, which normally provide the 138 kV supply into the Central Region were reconfigured. Transmission line 100L was reconfigured to supply the Bonavista Peninsula radially from Sunnyside while 109L was interconnected with transmission line 124L to provide the 138 kV supply into the Central Region. With the tripping of 109L/124L and the Stony Brook 230 kV supply, the Central system was supplied radially from the 138 kV lines into to Stony Brook from Deer Lake. There were no immediate outages to customers, but at 2254 hours (six minutes after the initial trip) the 138 kV voltages decayed to the point whereNP under voltage protection operated to shed their customers at Wesleyville, Lewisporte and Norris Arm. Additionally, NP customers in Grand Falls were manually shed by NP's Control Center due to low voltages. The overall customer impact was approximately 14,600 NP customers for outage duration of between 11 and 21 minutes.

Field investigation into the transformer lock out discovered that the lightning arrestor on B-Phase on the 138 kV side of T2 had faulted. Transformer T2 was returned to service on July 6. Investigation into the tripping of transmission line 109L at Sunnyside identified that the Zone 1 ground distance protection setting had been calculated and applied incorrectly. The setting modifications were recommended by

NP and implemented by Hydro. After discussion with NP, the protection settings were corrected and new protection relay settings were issued to field personnel for implementation. These changes were completed on July 2.

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Generation and Corporate Peer Group:

Alcoa Power Generating Inc.
Allete, Inc.
Aquila, Inc.
Avista Corporation
Buckeye Power, Inc.
Cleco Power LLC
Electric Energy, Inc.
Entergy Mississippi, Inc.
Hawaiian Electric Company, Inc.
Indiana-Kentucky Electric Corporation
Kentucky Power Company
Ohio Valley Electric Corporation
Portland General Electric Company
Public Service Company of New Hampshire
Puget Sound Energy, Inc.
Savannah Electric and Power Company
Sierra Pacific Power Company
Southern Electric Generating Company
Southern Indiana Gas and Electric Company
The Empire District Electric Company

Transmission Peer Group:

AEP Texas North Company
Allete, Inc.
Aquila, Inc.
Avista Corporation
Central Illinois Public Service Company
Delmarva Power & Light Company
Entergy Mississippi, Inc.
Kentucky Utilities Company
MDU Resources Group, Inc.
Mississippi Power Company
New York State Electric & Gas Corporation
Northern Indiana Public Service Company
Northern States Power Company (Wisconsin)
Oklahoma Gas and Electric Company
Public Service Company of Colorado
Public Service Company of Oklahoma
Sierra Pacific Power Company
Southwestern Electric Power Company
Tucson Electric Power Company
Westar Energy, Inc.

A REPORT TO

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2016 ANNUAL REPORT

ON

KEY PERFORMANCE INDICATORS

Pursuant to Order No. P.U. 14 (2004)

NEWFOUNDLAND AND LABRADOR HYDRO

Table of Contents

1.0 Introduction 1

2.0 Overview of Key Performance Indicator Results 2

2.1 Overview 2

2.2 Performance in 2016 versus 2016 Target 3

3.0 Performance Indices 5

3.1 Reliability Performance Indicators 5

3.1.1 Reliability KPI: Generation 5

3.1.2 Reliability KPI: End User Performance 10

3.1.3 Reliability KPI: Transmission 14

3.1.4 Reliability KPI: Distribution 21

3.1.5 Reliability KPI: Other 28

3.2 Operating Performance Indicators 32

3.2.1 Operating KPI: Generation 32

3.3 Financial Performance Indicators 34

3.3.1 Financial KPI: Corporate Operating, Maintenance and Administrative Expense (OM&A) per MWh delivered 35

3.3.2 Financial KPI: Generation OM&A per MW Installed Capacity 37

3.3.3 Generation OM&A per GWh generated 37

3.3.4 Financial KPI: Transmission OM&A per Transmission Circuit km 38

3.3.5 Financial KPI: Distribution OM&A per Distribution Circuit km 39

3.4 Customer-Related Performance Indicators 41

Appendix A: Rationale for Hydro's 2016 KPI Targets

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Appendix C1: Significant Transmission Events – 2016

Appendix C2: Significant Distribution Events – 2016 (Excluding Fourth Quarter)

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

1.0 Introduction[1]

In Order No. P.U. 14(2004), the Board required Newfoundland and Labrador Hydro (Hydro) to file appropriate historic, current and forecast comparisons of reliability, operating, financial and other Key Performance Indicators (KPIs). These were ordered to be filed with Hydro's annual financial report, commencing in 2004.

In compliance with the above Order, Hydro has 14 individual KPIs within the following four general categories: Reliability, Operating, Financial, and Customer-Related.

Within each of these categories, KPI data is reported on a historic basis for Hydro. Where appropriate, KPIs are subcategorized based on whether they relate to generation, transmission, distribution or overall corporate activity. For most of the Reliability KPIs, data from the Canadian Electricity Association (CEA) is provided in this report, as has been the case in prior years. At the time of this report, CEA data has been published only to 2015. CEA data is unavailable for underfrequency load shedding, a reliability KPI, as this measure is unique to Hydro's Island Interconnected System. In the Operating category, the KPIs used to measure performance relate to two specific facilities within Hydro's system: Bay d'Espoir and Holyrood. For these two generation plants, performance is measured and compared on a year-over-year basis.

Section 2 of this report provides an overview of Hydro's KPI performance in 2016 compared with the prior year as well as a comparison of actual KPI results compared with targets.

Section 3 of this report provides a detailed analysis of each individual KPI within the four categories named above in Section 3. In addition, it provides fourth quarter data for transmission and distribution reliability which is routinely included in Hydro's quarterly

[1] This Report was filed with the Board on March 31, 2017 as Appendix E to the Quarterly Report (Q4). It has been reformatted; however, content has not changed.

regulatory reports. Section 3.3, Financial Performance Indicators, will be provided once Hydro's annual financial results have been audited and published.

2.0 Overview of Key Performance Indicator Results

2.1 Overview

A number of key indices measured by Hydro showed improvement when compared to 2015 or the targets for 2016. All indices are discussed in the following sections of this Appendix.

End User reliability measures improved from 2015 levels. The 2016 End User SAIFI improved to 1.30 interruptions per customer from 2.00 interruptions per customer in 2015. End User SAIDI for 2016 was 2.42 interruptions hours per customer compared to 3.07 interruptions hours per customers in 2015. Both measures were impacted by two major transmission interruptions to Newfoundland Power customers and six major transmission interruptions to Newfoundland & Labrador Hydro's distribution customers.

Generation availability did not change significantly in 2016 when compared to 2015. Hydro's overall weighted capability factor, which measures generating unit availability, declined was 77% compared to 80% in 2015. The availability of the Holyrood thermal plant was 60% in 2016, compared to 63.4% for 2015. The availability of gas turbines did not change significantly in 2016 when compared to 2015. The overall weighted capacity factor of these units was 79.3% in 2016 compared to 80% in 2015. The availability of Hydro's hydraulic plants was 85% in 2016 compared to 88% in 2015. With the exception of Units 1 and 2 at the Bay d'Espoir generating station, Hydro's hydraulic unit availability was consistent with historic performance. Impacting on the overall hydraulic unit availability were leaks in Penstock 1 which affected the performance of Bay d'Espoir Units 1 and 2.

- In the area of Derating-Adjusted Forced Outage Rate (DAFOR), performance across all generation classes was 10.0% in 2016, compared to 3.4% in 2015. The

thermal DAFOR was 19.4% in 2016 compared to 5.0% in 2015. The Hydraulic DAFOR was 5.51% in 2016 compared to 2.66% in 2015.

- The 2016 hydraulic conversion factor at Bay d'Espoir was impacted by higher reservoirs levels than experienced in previous years resulting in lower than target conversion factor.
- There were six under frequency load shedding in 2016, compared to eight events in 2015.
- Overall Transmission and Distribution reliability were impacted by an increase in unplanned outages in 2016, and offset by a reduction in the number and duration of planned outages. Both the frequency and duration of transmission delivery point outages improved in 2016, compared to 2015.

The 2016 operating KPI for energy conversion at Holyrood was primarily impacted by a higher average unit loading resulting in a lower conversion rate.

A review of all indices is contained in the following sections.

2.2 Performance in 2016 versus 2016 Target

The table below summarizes Hydro's KPI performance in 2016. The rationale for the 2016 targets was summarized in the March 2016 report to the Board entitled *2015 Annual Report on Key Performance Indicators*. The 2016 rationale is included in this report as Appendix A.

Category	KPI	Units	2016 Target	2016 Results
Reliability	Weighted Capability Factor (WCF)	%	79.9[2]	77.1
	DAFOR	%	7.1	10.0
	T-SAIDI	Minutes/Point	530	325[3]
	T-SAIFI	Number/Point	3.4	2.9
	T-SARI	Minutes/Outage	156	112
	SAIDI	Hours/Customer	12.1	15.7
	SAIFI	Number/Customer	5.5	6.6
	End User SAIDI[4]	Hours/Customer	2.2	2.4
	End User SAIFI[5]	Number/Customer	1.3	1.3
	Underfrequency Load Shedding	# of events	6	6
Operating	Hydraulic CF	GWh/MCM	0.433	0.432
	Thermal CF	kWh/bbl	607	608
Financial[6]	Controllable Unit Cost	$/MWh	N/A	N/A
Other	Customer Satisfaction (Residential)	Max=100%	80%	90%

[2] The Weighted Capability Factor target is based on planned annual maintenance outages, an allowance for other short duration maintenance outages and targeted forced outage durations.
[3] Transmission and distribution reliability performance is measured on combined planned and unplanned outages.
[4] New measure added in 2015, refer to section 3.1.2 for further details.
[5] New measure added in 2015, refer to section 3.1.2 for further details.
[6] To be provided when financial results are available.

3.0 Performance Indices

The following defines and describes detailed Key Performance Indicator data within four general categories: Reliability, Operating, Financial, and Customer-Related.

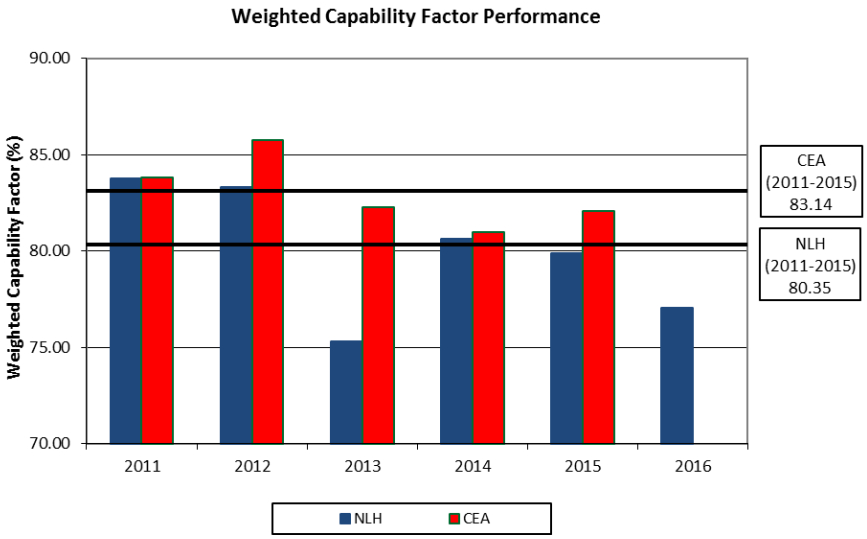
3.1 Reliability Performance Indicators

Hydro monitors reliability performance with eight separate metrics. These metrics have been divided into the following subcategories: Generation, Transmission, Distribution, and Other.

3.1.1 Reliability KPI: Generation

a) Weighted Capability Factor (WCF) – *a reliability KPI for generation assets that includes Hydro's thermal, gas turbine and hydroelectric generation assets on the Island and Labrador Interconnected Systems. The WCF measures the percentage of the time that a unit or a group of units is available to supply power at maximum continuous generating capacity. The factor is weighted to reflect the difference in generating unit sizes, meaning larger units have a greater impact on this measure.*

In 2016, Hydro's WCF was 77.1%, compared to 79.9% in 2015 and a target of 79.9%. The 2011 to 2015 Hydro five-year average (as last reported to the CEA) is 80.4%. The annual target for availability includes the time that units are out for maintenance. Therefore, the capability in any year is affected by the maintenance and capital work planned for that year. At no time in 2016 was there insufficient generation to meet customer requirements. Hydro plans required capital outages and schedules maintenance outages to ensure supply is available as required.



Thermal unit WCF was 59.9% in 2016 compared to 63.6% in 2015. The 2016 Thermal WCF target was 63.0%. Holyrood Unit 1 had a capability factor of 63.2%, Unit 2 had a capability factor of 56.0%, and Unit 3 had a capability factor of 60.5%. Holyrood Unit 1 was derated for a total of eight months through out 2016 due to airflow and reheater tube limitations, Holyrood Unit 2 was derated from February to June due to issues with the reheater section of the boiler, and Holyrood Unit 3 was derated on four occurrences in 2016 due to issues with broken generator leads, failed west fuel oil pump, air heater fouling, and fouling on the water intake.

Holyrood Unit 1 experienced a ten day maintenance outage in February to replace damaged reheater boiler tubes that had been identified during an inspection. Similar tube failures had caused two forced outages on Unit 2 in January and February, which required the replacement of the reheater tubes. In September, Unit 3 experienced a ten day maintenance outage to replace a reheater stop valve and to complete a boiler tube inspection.

Overall, Holyrood unit maintenance and planned outages were completed within the intended timeframes. Unit 3 experienced planned outages of approximately five months in total throughout the year. This extended outage was primarily required for the major

capital project to overhaul this unit as well as rewind the rotor. A Holyrood unit was operated throughout the summer months in 2016 in order to support the transmission into the Avalon Peninsula.

Overall, the hydraulic unit WCF performance was 85.2%, compared to 88.0% in 2015 and a target of 87.0%. The primary driver for the 85.2% WCF was two forced outages to Bay d'Espoir Units 1 and 2. Both of the forced outages were caused by leaks in the common Penstock no. 1. The first outage occurred on May 21, and an investigation attributed the leak to a defective weld. Repairs were completed on June 3 and both units were returned to service.

The second leak in Penstock no. 1 occurred on September 14, this leak was similar to the first and located in the same area. Investigations into the leak recommended refurbishing the welds along the upper section of the penstock between the intake and surge tank. Both units were returned to service on November 30. Removing the impact of this penstock leak on Bay d'Espoir Units 1 and 2 from the hydraulic WCF, results in an improved annual hydraulic WCF outcome of 88%.

Gas turbine availability declined slightly to 79.3% in 2016 from 80.2% in 2015. The 2016 gas turbine WCF target was 89.0%. The Hardwoods gas turbine experienced a forced outage from November 24 to December 2 due a loose connection in the circuit between the Automatic Voltage Regulator and the Exciter which prevented the unit from synchronizing to the interconnected system. The Stephenville gas turbine was impacted by a forced outage from August 2 to August 5 due to a lube oil leak in the alternator module. There was another forced outage to this unit from August 9 to August 19 due to the presence of debris on the metallic chip detectors observed during a routine inspection. The debris was subsequently analyzed and found to be minor very fine particles and not a cause of concern. The lubricating oil was analyzed and found to be in satisfactory condition for continued operation.

Calculation details for weighted capability as well as a list of factors that can impact KPI performance are included in Appendix B of this report.

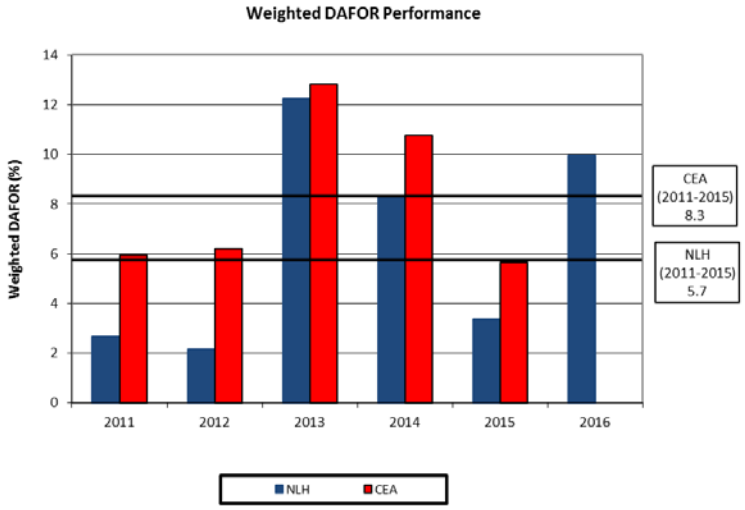
---

b) Weighted Derating-Adjusted Forced Outage Rate (DAFOR) - *a reliability KPI for generation assets that includes Hydro's thermal and hydroelectric generation assets on the interconnected systems*[7]*. DAFOR measures the percentage of the time that a unit or group of units is unable to generate at its Maximum Continuous Rating (MCR) due to forced outages. The KPI is weighted to reflect differences in generating unit sizes.*

In 2016, Hydro's weighted DAFOR was 10.0%, compared to 3.4% in 2015. The 2016 target was 7.17%. The thermal DAFOR for 2015 was 19.4%, compared to 5.0% in 2015 and a target of 19.0%. The thermal DAFOR was impacted by the boiler tubes on Holyrood Units 1 and 2. The hydraulic DAFOR was 5.5% compared to 2.7% in 2015 and a target of 0.9%. The hydraulic DAFOR was impacted by Bay d'Espoir Units 1 and 2 outage due to penstock issues. These issues contributed approximately 86% to the overall 2016 hydraulic DAFOR.

Hydro's overall weighted DAFOR for the period 2011 to 2015 is 5.7%, compared to the equivalently weighted national average of 8.3% for the same period.

[7] DAFOR is not applicable to the gas turbines because of the gas turbines' low operating hours.



c) Generation Equipment Performance

The table below highlights the various performance indices for Hydro's generation facilities. Indices for 2015 and for the latest five year CEA national average (2011-2015) are included for comparison.

Generation Performance Indices

Index		**Hydraulic**	**Thermal**	**Gas Turbine**
Failure Rate	NLH 2016	1.84	6.87	26.84
(Forced Outages per 8,760	NLH 2015	1.34	9.07	57.01
operating hours)	CEA '11-'15	2.12	8.55	90.11
Incapability	NLH 2016	14.80	40.11	20.70
Factor	NLH 2015	11.70	36.60	27.21
(Percent of Time)	CEA '11-'15	11.78	26.65	17.67
Derating Adjusted Forced	NLH 2016	5.51	19.42	
Outage Rate	NLH 2015	2.66	5.04	
(Percent of Time)	CEA '11-'15	5.56	13.75	
Utilization	NLH 2016			9.35
Forced Outage	NLH 2015			10.55
Probability (Percent of Time)	CEA '11-'15			21.17

Hydraulic Unit Performance

The forced outage to Units 1 and 2 at Bay d'Espoir, due a penstock issue impacted performance for all hydraulic unit measures in 2016. However, both the Failure Rate and DAFOR performance in 2016 remain at levels better than the national five year averages.

Thermal Unit Performance

Thermal unit performance improved considerably in 2016 in the area of Failure Rate, when compared to 2015. DAFOR and Incapability Factor performance declined in 2016, when compared to 2015, primarily due to an extended derating on Holyrood Units 1 and 2 due to airflow issues and boiler tube issues.

Gas Turbine Unit Performance

The Failure Rate, Incapability Factor and Utilization Forced Outage Probability (UFOP) performance of Hydro's gas turbines improved in 2016 when compared to 2015. Of particular importance to Hydro's gas turbines fleet is the UFOP which measure the degree to which a standby unit can be called upon to supply load when requested. The UFOP in 2016 was 9.4%, improving from 10.6% in 2015 and the CEA five year average of 21.2%.

3.1.2 Reliability KPI: End User Performance

This performance index was developed to measure the reliability of all end users of electricity in the province supplied by Newfoundland & Labrador Hydro. The measure is a combination of Hydro's service continuity data and Newfoundland Power (NP) service continuity data for Loss of Supply outages resulting from events on Hydro's transmission system. Therefore, the SAIFI and SAIDI data below is a measure of the duration and frequency of service interruptions experienced as a result of Hydro system events. This does not reflect interruptions to NLH or NP customers from issues on NP system.

Targets were developed using the past performance of Hydro and NP service continuity data. The effects of the significant interruptions on January 11, 2013, January 2 to 8, 2014, March 4, 2015 and August 5, 2015 were removed from the data and a modified 2011 to 2015 five year average was created. These events were removed due to the significant effect these events had on the five year data set. This is a normal practice of utilities to remove data associated with major events. This modified average was then compared to the 2015 CEA Region 2 Loss of Supply outcome. The 2016 target was set using the modified 2011 to 2015 average with the goal of reaching the 2015 CEA Region 2 Loss of Supply value in five years.

The SAIFI and SAIDI values add cumulatively through the year, with the final targets for SAIFI and SAIDI set at 1.29 interruptions/customer and 2.17 interruption minutes/customer, respectively.

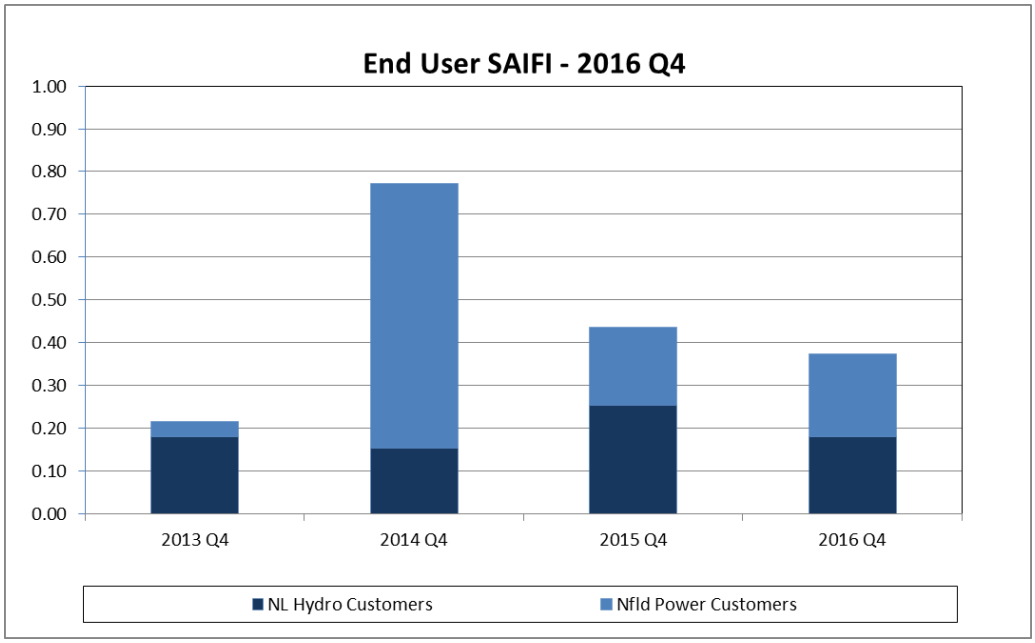
End User Service Continuity Performance

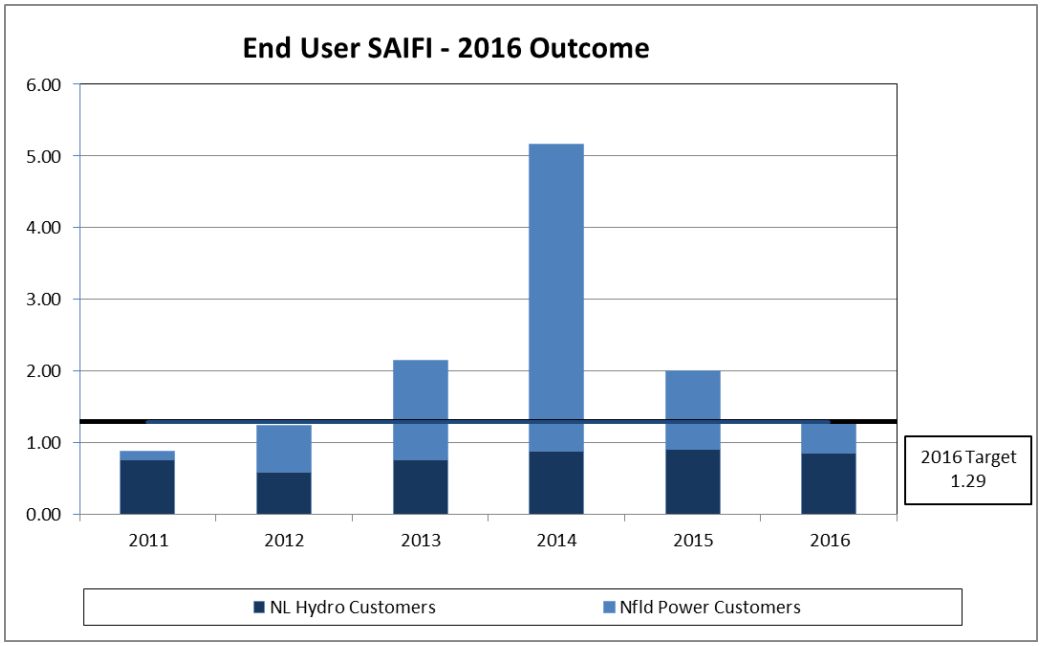
	SAIFI	SAIDI
2016 Q4	0.37	0.63
2015 Q4	0.44	0.65
2016 Outcome	1.30	2.42
Annual Target	1.29	2.17
2011 to 2015 Average	2.07	5.00

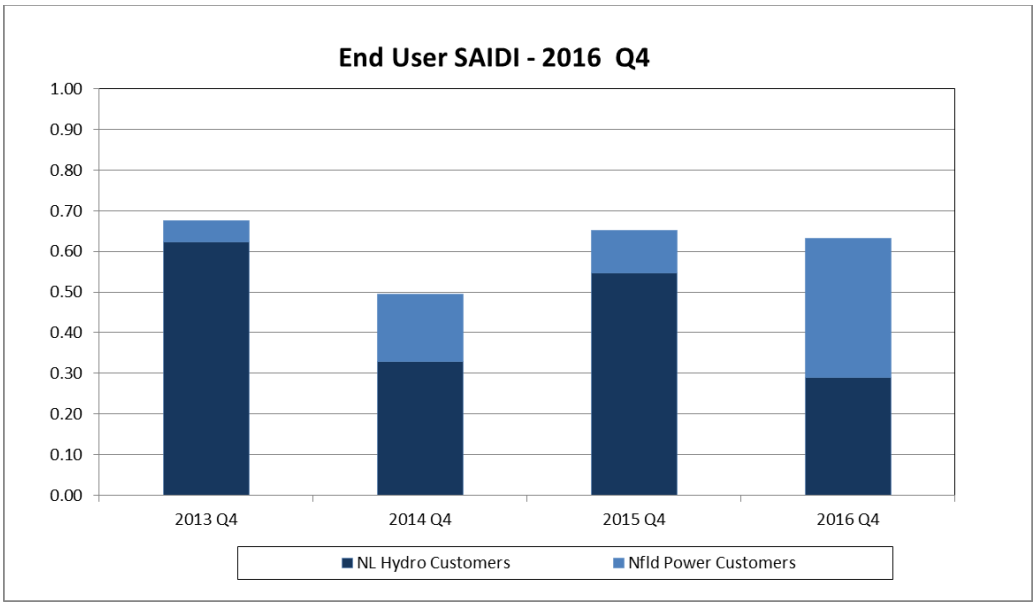
The fourth quarter performance was affected by three underfrequency events and two significant transmission outages. The under frequency events are described in detail in a later section of this report. The first significant transmission event occurred in November to transmission line TL219, effecting NP customers on the Burin Peninsula.[8] The second event effected NP customers in the Port Aux Basque area on December 16.[9] These two events contributed 81% of the total 2016 NP portion of the End User SAIDI.

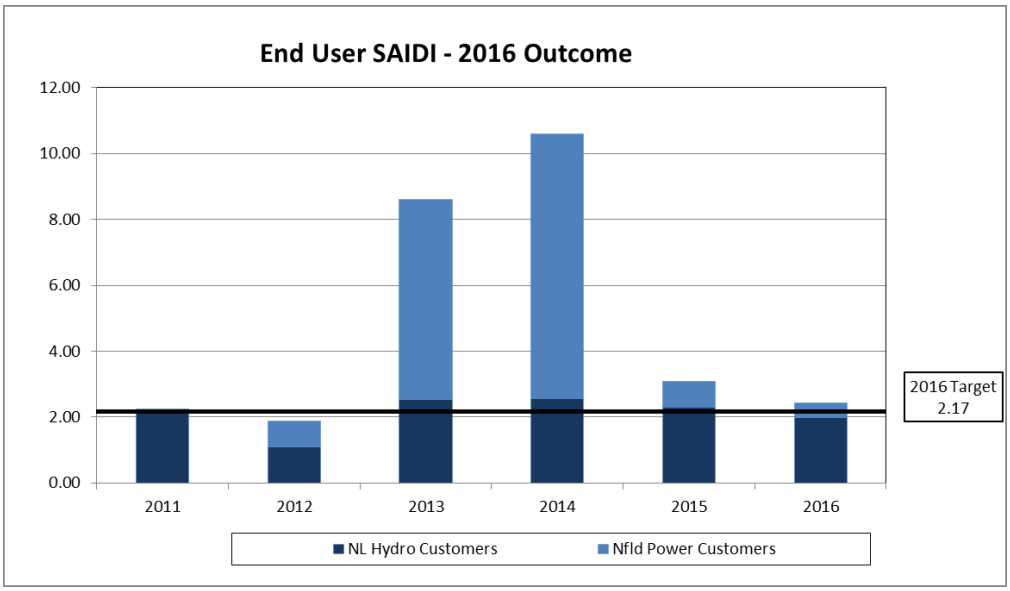
[8] Refer to Appendix C1, Event 8 for further details.
[9] Refer to Appendix C1, Event 9 for further details.

Hydro customers were affected by the significant transmission events described in Appendix C1 and the significant distribution events described in Appendix C2 and Section 3.1.4 of this report.






End User SAIDI - 2016 Q4
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
2013 Q4
2014 Q4
2015 Q4
2016 Q4
NL Hydro Customers
Nfld Power Customers

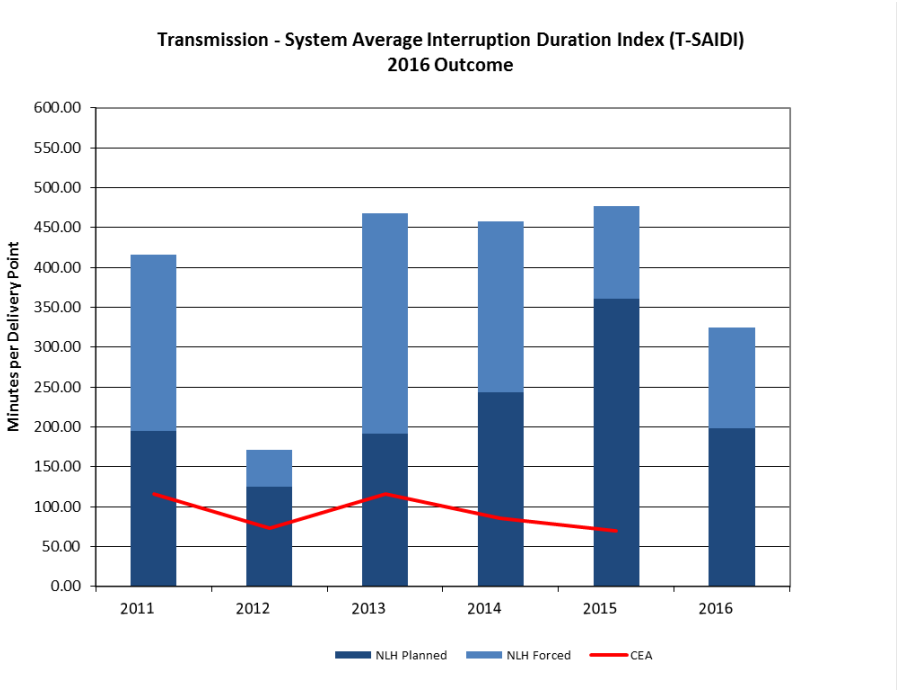

End User SAIDI - 2016 Outcome
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2011
2012
2013
2014
2015
2016
2016 Target
2.17
NL Hydro Customers
Nfld Power Customers

3.1.3 Reliability KPI: Transmission

a) Transmission System Average Interruption Duration Index (T-SAIDI) - *reliability KPI for bulk transmission assets which measures the average duration of outages in minutes per delivery point.*

The fourth quarter T-SAIDI improved to 65 minutes per delivery point (forced and planned combined) compared to 128 minutes in 2015.

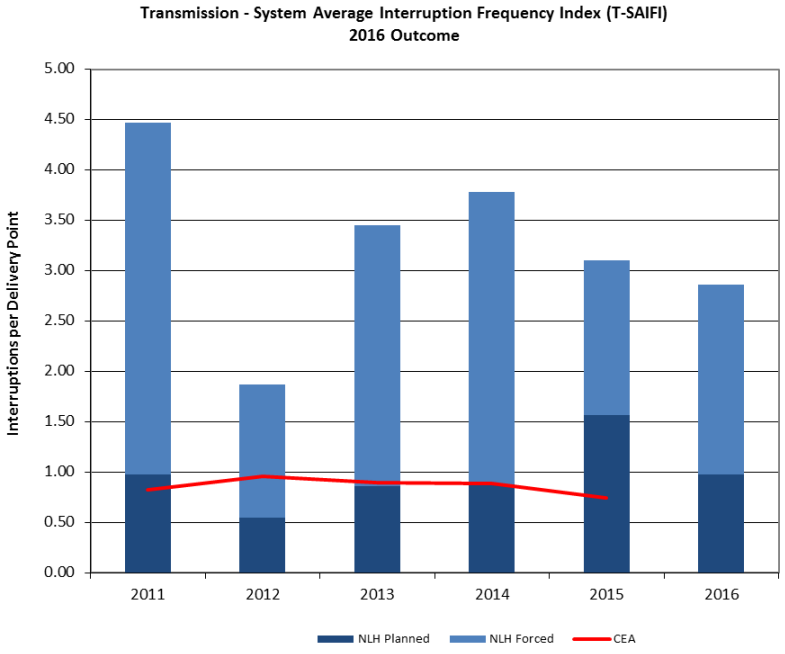
The total 2016 T-SAIDI was 325 minutes per delivery point, improved from a 2015 total T-SAIDI performance of 476 minutes per delivery point. The forced outage duration in 2016 was 127 minutes, compared to 116 minutes in 2015. The planned outage duration was 198 minutes, compared to 361 minutes in 2015. The decrease in the T-SAIDI for planned outages was the result of increased focus of reducing customer outage duration.



b) Transmission System Average Interruption Frequency Index (T-SAIFI) - *a reliability KPI for bulk transmission assets that measures the average number of sustained outages per delivery point*.

The fourth quarter T-SAIFI was 0.68 outages per bulk delivery point, with contributions of forced and planned outage frequency of 0.42 and 0.27, respectively. This compares with a 2015 fourth quarter T-SAIFI of 1.05 outages per bulk delivery point.

The 2016 T-SAIFI was 2.87 outages per bulk delivery point, improved from a 2015 T-SAIFI result of 3.10 outages per delivery point. The number of forced outages per delivery point in 2016 was 1.88, compared to 1.53 in 2015. The number of planned outages per delivery point in 2016 was 0.98 compared to 1.57 in 2015.

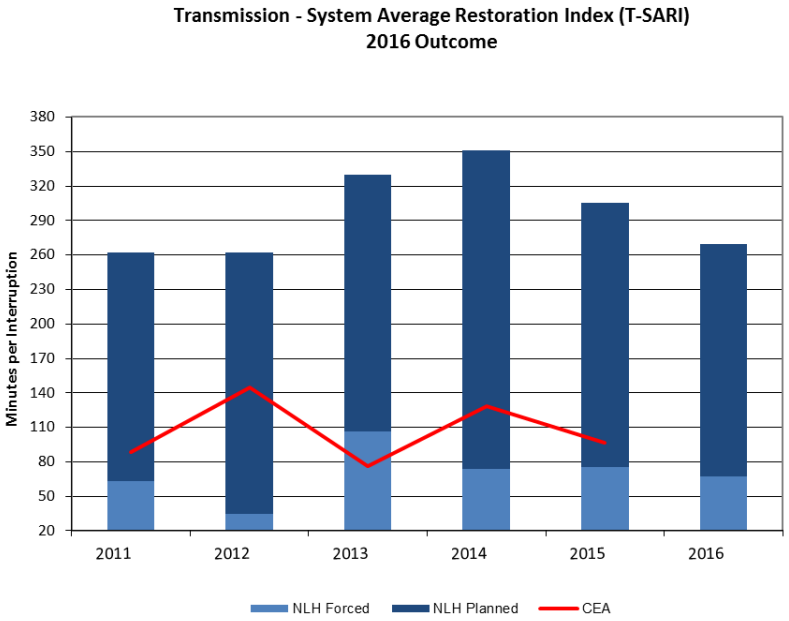


c) Transmission System Average Restoration Index (T-SARI) - *reliability KPI for bulk transmission assets which measures the average duration per transmission interruption. T-SARI is calculated by dividing T-SAIDI by T-SAIFI.*

Hydro's transmission T-SARI improved was 95 minutes per interruption for the fourth quarter of 2016, compared to 122 minutes per interruption during the same quarter in 2015. The forced outage component of T-SARI was 97 minutes per interruption, compared to 51 minutes per interruption in 2015. The planned outage component of T-SARI was 92 minutes per interruption compared to 179 minutes per interruption in 2015.

Hydro's overall transmission T-SARI for 2016 was 270 minutes per interruption, compared to 306 minutes per interruption in 2015. The forced outage component of T-SARI was 67 minutes per interruption, compared to 76 minutes per interruption in 2015. The planned outage component of T-SARI was 202 minutes per interruption, compared to 230 minutes per interruption in 2015.

Hydro's total T-SARI performance improved in 2016 compared to 2015. This is owing to a reduction in both T-SAIFI and T-SAIDI.



There were 11 forced transmission outages and nine planned transmission outages in the fourth quarter. A summary of these outages follows:

Forced

- On October 14, customers (606) supplied by the Roddickton distribution system, feeders L3 and L4, experienced an unplanned power outage of five minutes. The outage occurred during switching to complete the annual function testing on circuit breaker B1L57 at the Roddickton Terminal Station.
- On October 23, customers (5,201) supplied by the Happy Valley Terminal Station experienced an unplanned power outage of two minutes. The outage occurred during the energization process of the new power transformer - T4. A transformer differential protection relay tripped due to a set of shorted current transformers on T4.
- On November 9, NP customers (1,421) supplied by Western Avalon Terminal Station via 66 kV Bus 2, experienced an unplanned power outage of one hour and 26 minutes. The outage was caused by moisture in the gas pressure relay on transformer GT1 which operated the lockout on transformer T1 and subsequently tripped the bus.

- On November 17, customers (3,056) supplied by Plum Point, Bear Cove, Roddickton and Main Brook Terminal Stations, experienced an unplanned power outage of 12 minutes. The outage was required to interconnect the mobile substation with the Hawke's Bay Terminal Station. The mobile will be connected in Hawke's Bay during the winter.
- On November 19, customers (1,941) supplied by transmission line TL226 from the Deer Lake Terminal Station, experienced an unplanned power outage of six minutes. The outage was caused by adverse weather during a snow storm.
- On November 21, NP customers (13,135) supplied by Sunnyside Terminal Station via transmission line TL219, experienced an unplanned power outage of three hours and 34 minutes. NP restored some customers with the Greenhill gas turbine and the remaining customers were restored when TL219 was put back into service. TL219 tripped due to two lightning strikes, the second strike resulted in a flashover through breaker B3L19. This breaker is scheduled to be overhauled in 2017.
- On November 25, NP customers (1,160) supplied by the Bay L'Argent Terminal Station and 468 customers supplied by the Monkstown Terminal Station experienced an unplanned power outage of 30 minutes. The outage was caused by the failure of disconnect switch L12-1 at Monkstown to fully close during switching to restore TL212 (Monkstown to Sunnyside section).
- On November 27, all customers (7,859) north of Berry Hill Terminal Station experienced an unplanned power outage. Customer outage details are listed below. The outage was caused by a tree falling on transmission line TL239, breaking a phase conductor. The Hawke's Bay and St. Anthony Diesel plants were started to support the 66 kV system to enable customer restoration. Feeder restoration details are provided as follows:

Event - TL239 trip - Nov 27, 2016

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	22:36	23:03	27	1.1	29.7
Parson's Pond	22:36	23:04	28	0.4	11.2
Daniel's Harbour	22:36	23:04	28	0.8	22.4
Hawke's Bay	22:36	23:04	28	4	112
Plum Point	22:36	23:05	29	2.3	66.7
Bear Cove	22:36	23:16	40	3.3	132
Main Brook	22:36	23:44	68	0.4	27.2
Roddickton	22:36	23:44	68	1.6	108.8
St Anthony	22:36	23:52	51	6.4	466.1

- On December 16, NP customers (3,563) supplied by transmission line TL215 in the Port Aux Basque area experienced an unplanned power outage of 12 hours and 40 minutes due to loss of supply from Hydro. Following restoration of the line, the outage continued for NP customers due to damage on the distribution system. The line outage was caused by the failure of a crossarm pin due to extreme high winds in the area.
- On December 30, customers (269) supplied by Parson's Pond Terminal Station experienced an unplanned power outage of two hours and 12 minutes. The outage occurred after a pole broke on transmission line TL227 due to extremely high winds.
- On December 30, customers (1,317) supplied by Hawke's Bay Terminal Station experienced an unplanned power outage of 49 minutes. The outage occurred after transmission line TL259 reclosed at Berry Hill causing a voltage dip that resulted in the mobile substation tripping at Hawke's Bay.

Planned

- On October 16, customers (2,118) on the Great Northern Peninsula experienced planned power outages of various times, refer to the listing below. The outages were required to complete corrective maintenance on transmission line TL241 line hardware. Customers supplied by the St. Anthony, Main Brook and Roddickton feeders L1 and L2 were supplied by the St. Anthony Diesel Plant and did not experience power outages.

- Plum Point L1 – 343 customers – five hours and 29 minutes (329 minutes);
- Plum Point L2 – 627 customers – five hours and 29 minutes (329 minutes);
- Bear Cove L4 – 244 customers – five hours and 29 minutes (329 minutes);
- Bear Cove L6 – 698 customers – five hours and 29 minutes (329 minutes); and
- Roddickton L3 – 206 customers – three hours and 32 minutes (212 minutes).

- On October 23, customers (2,202) supplied by the South Brook Terminal Station experienced a planned power outage of up to two hours and 53 minutes. The outage was required to remove the mobile transformer (P235) after maintenance was completed on the 138 kV disconnect switches.
- On October 24, NP customers (1, 577) supplied by Western Avalon Terminal Station experienced a planned power outage of up to three hours and 48 minutes. The outage was required to complete PMs on Bus B2 disconnects, replace insulators on Bus B2, and complete CMs on disconnect switch B2T1-1.
- On November 6, NP customers (1,598) supplied by Springdale Terminal Station experienced a planned power outage of one hour and 28 minutes. The outage was required to repair the station ground grid after it was damaged by vandals. Corrective maintenance was also completed on Bus B1 potential transformers.
- On November 20, NP customers (665) supplied by the Buchans Terminal Station experienced a planned power outage of seven minutes. The outage was required to function test circuit breaker B2T1 at Buchans.

- On November 20, Duck Pond Mine experienced a planned power outage of seven minutes. The outage was required to function test circuit breaker B2T1 at Buchans.
- On December 1, customers (287) supplied by Jackson’s Arm Terminal Station (488) and Hampden Terminal Station experienced a planned power outage of five minutes. The outage was required to interconnect the new Taylor's Pond

Terminal Station. This is a single phase supply to a communications repeater site owned and operated by the Lower Churchill Project.

- On December 1, customers (1,155) supplied by Rocky Harbour Terminal Station experienced a planned power outage of 19 minutes. The outage was required to obtain an oil sample from transformer T1.
- On December 5, customers (1,317) supplied by Hawke's Bay Terminal Station experienced a planned power outage of 11 minutes. The outage was required to energize the mobile substation at Hawke's Bay for work on TL221. The mobile will be located in Hawke's Bay during the winter.

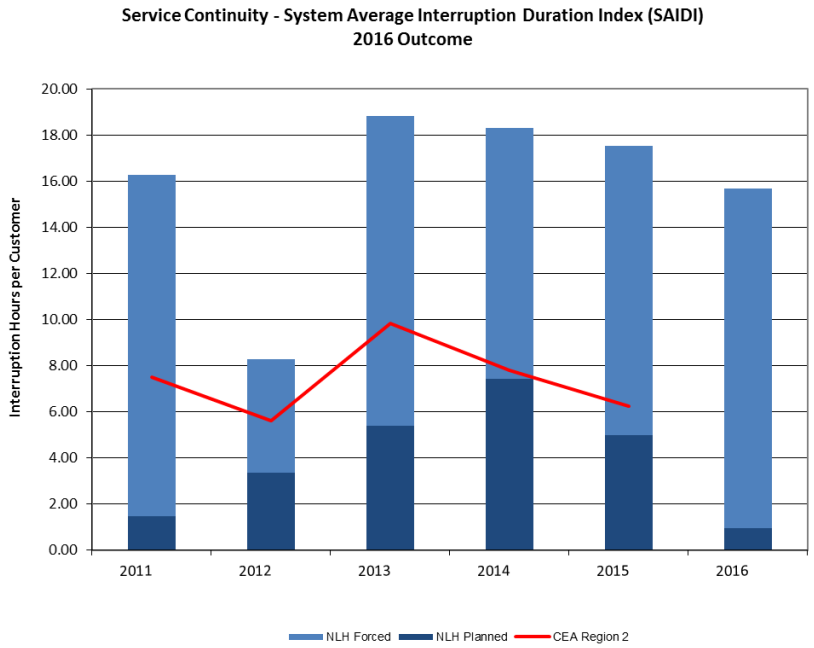
3.1.4 Reliability KPI: Distribution

a) System Average Interruption Duration Index (SAIDI) - *a reliability KPI for distribution service and it measures service continuity in terms of the average cumulative duration of outages per customer served during the year.*

In the fourth quarter of 2016, SAIDI performance was 2.32 hours per customer, compared to 4.19 hours per customer during the same quarter of 2015.

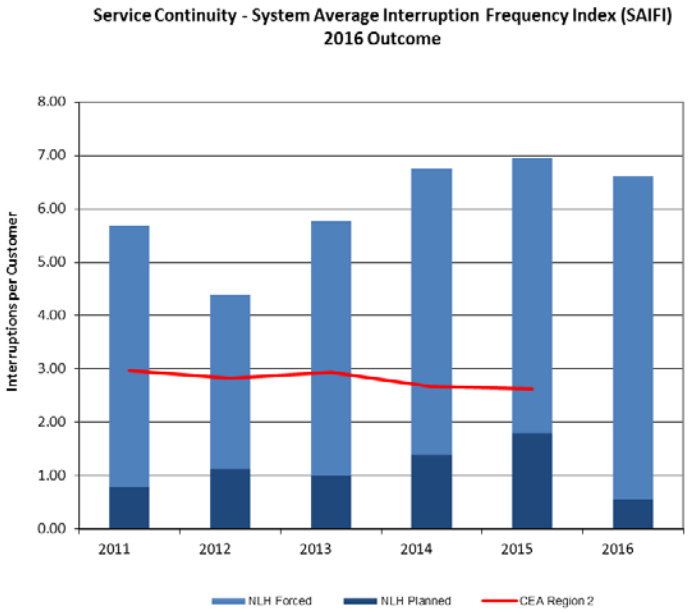
The total 2016 SAIDI was 15.68 hours per customer, compared to 17.54 hours per customer in 2015 and a target of 12.08 in 2016.

The main contributors to deteriorated SAIDI performance were unplanned outages in the Great Northern and Connaigre Peninsulas. In March, all customers north of Cow Head experienced an interruption due to a hardware failure on transmission line TL259. In May, customers on the Connaigre were affected by a forest fire under transmission line TL220 and equipment failure at the Barachoix Terminal Station.



b) System Average Interruption Frequency Index (SAIFI) - *reliability KPI for distribution service which measures the average cumulative number of sustained interruptions per customer per year.*

In the fourth quarter of 2016, SAIFI for was 1.43 interruptions per customer, compared to 1.93 interruptions per customer during the same quarter of 2015. The total 2016 SAIFI was 6.62 interruptions per customer, compared to 6.95 interruptions per customer in 2015 and compared to a target of 5.48 interruptions per customer in 2016.



The outages during the fourth quarter resulted from a variety of causes and effective most regions:

- On October 21, 855 customers supplied by the Happy Valley Distribution system feeder L7 experienced a planned outage of three hours and 49 minutes. (229 mins) The outage occurred during the energization process of new power transformer T4. The loading in the Happy Valley area had increased above the capability of the local generation and the customer on feeder L7 were shed. The remaining customers in the Happy Valley area were supplied by the gas turbine and North Plant diesel units during the outage to the Happy Valley 138 kV bus.
- On October 23, 855 customers supplied by the Happy Valley Distribution system feeder L7 experienced a planned outage of two hours and 16 minutes. (136 mins) The outage occurred during the energization process of new power transformer T4. The loading in the Happy Valley area had increased above the capability of the local generation and the customer on feeder L7 were shed. The remaining customers in the Happy Valley area were supplied by the gas turbine and North Plant diesel units during the outage to the Happy Valley 138 kV bus.
- On November 4, 225 customers supplied by Port Hope Simpson Distribution system experienced an unplanned power outage of 19 hours. The outage

occurred after the main power transformer at the diesel plant failed. A replacement transformer was bought in from Cartwright and used to restore customers.

- On November 6, 250 customers in Labrador City, Labrador, serviced by Line 3 experienced a planned power outage of two hours in 10 minutes. The outage was required to tie in a primary pole for switching a customer from underground to overhead service.
- On November 17, Bottom Waters L1 (384 customers) experienced an unplanned power outage of 7 hours and 57 mins. The outage occurred due to an insulator failure (Hendrix type) on pole #122.
- On November 27, 125 customers in Little Bay Islands experienced an unplanned power outage of 14 hours and 10 minutes. The outage occurred after a tree fell on the distribution line. The line crew arrived on site after using the ferry to access the island. Customers were restored at 1030 hours on November 28.
- On December 11, 234 customers in Goose Cove (St. Anthony Distribution System) experienced an unplanned outage of three hours. The outage was due to a phase conductor which had burnt and fell to ground.
- On December 11, 234 customers in Goose Cove (St. Anthony Distribution System) experienced a second unplanned outage of four hours and 30 minutes. Crews had found a blown fuse on the primary line.
- On December 15 (outage 2), 565 customers in Hermitage, Seal Cove and Gaultois (Barachoix Distribution System) experienced an unplanned outage of four hours and 50 minutes. The outage was caused by a broken conductor on the primary line.
- On December 15, 810 customers supplied by the English Harbour West Distribution System experienced an unplanned outage of four hours. The outage was caused by a broken conductor on the primary line.

- On December 16, 175 customers in Change Islands (Farewell Head Distribution System) experienced an unplanned outage of ten hours and 25 minutes. The outage was caused by a broken conductor on the primary line.
- On December 16, 66 customers in Lapoile experienced an unplanned outage of seven hours. The outage was caused by broken line hardware.
- On December 16, 302 customers in Trout River (Glenburine Distribution System) experienced an unplanned outage of five hours and 24 minutes. The outage was caused by a severe winter storm. A line patrol found no line damage.
- On December 17, 620 customers in Joe Batts Arm, Tilting, Shoal Bay (Farewell Head Distribution System) experienced an unplanned outage of 11 hours and 10 mins. The outage was caused by a severe winter storm. A line patrol found no line damage.
- On December 18 (outage 2), 66 customers in Lapoile experienced an unplanned outage of 35 hours and 15 minutes. A line patrol found line damage to three structures (one floating neutral and two structures with cross-arm bolts broken off). Repairs were completed and the line was restored.

A summary of the most significant distribution system interruptions for the first three quarters of 2016 (i.e., outages generally to a complete system with an extended outage duration) are contained in Appendix C2.

c) Additional Information

As per Hydro's regular quarterly report, this section provides more detailed information on distribution system interruptions with performance broken down by Area, Origin, and Type.

Rural Systems Service Continuity Performance by Area

SAIFI (Number per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2016	**2015**	**2016**	**2015**	**Average**
Central					
Interconnected	1.09	0.86	5.40	3.97	3.57
Isolated	1.21	0.41	2.35	2.34	2.89
Northern					
Interconnected	2.43	2.72	9.86	6.26	6.74
Isolated	0.95	2.00	8.19	9.05	8.74
Labrador					
Interconnected	1.01	2.30	5.08	10.45	7.84
Isolated	1.60	3.84	7.44	10.83	9.59
Total	1.43	1.93	6.62	6.95	6.12

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area

SAIDI (Hours per Period)					
Area	**Fourth Quarter**		**12 Mths to Date**		**5 Year**
	2016	**2015**	**2016**	**2015**	**Average**
Central					
Interconnected	2.85	3.12	21.88	12.78	13.94
Isolated	4.43	0.31	4.97	0.60	3.62
Northern					
Interconnected	2.70	5.69	16.18	13.65	16.11
Isolated	2.46	1.45	7.32	6.81	9.48
Labrador					
Interconnected	0.59	3.77	10.65	28.54	20.53
Isolated	5.93	10.92	12.23	23.39	14.64
Total	2.32	4.19	15.68	17.46	15.96

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Origin

SAIFI (Number per Period)

Area	Fourth Quarter 2016	Fourth Quarter 2015	12 Mths to Date 2016	12 Mths to Date 2015	5 Year Average
Loss of Supply – Transmission	0.66	0.79	4.12	2.95	2.49
Loss of Supply – NF Power	0.01	0.00	0.04	0.01	0.01
Loss of Supply – Isolated	0.07	0.08	0.41	0.39	0.47
Loss of Supply – L'Anse au Loup	0.03	0.03	0.10	0.16	0.11
Distribution	0.66	1.03	1.95	3.44	3.04
Total	1.43	1.93	6.62	6.95	6.12

Note: System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers.

SAIDI (Hours per Period)

Area	Fourth Quarter 2016	Fourth Quarter 2015	12 Mths to Date 2016	12 Mths to Date 2015	5 Year Average
Loss of Supply – Transmission	0.63	2.10	11.06	9.63	6.69
Loss of Supply – NF Power	0.05	0.00	0.16	0.04	0.07
Loss of Supply – Isolated	0.25	0.03	0.42	0.25	0.29
Loss of Supply – L'Anse au Loup	0.00	0.03	0.02	0.14	0.08
Distribution	1.39	2.03	4.02	7.40	8.83
Total	2.32	4.19	15.68	17.46	15.96

Note: System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

Rural Systems Service Continuity Performance by Type – 2016 Fourth Quarter Only

Area	Scheduled		Unscheduled		Total	
	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
Central						
Interconnected	0.03	0.14	1.06	2.71	1.09	2.85
Isolated	0.01	0.02	1.20	4.41	1.21	4.43
Northern						
Interconnected	0.41	0.55	2.02	2.15	2.43	2.70
Isolated	0.14	0.06	0.81	2.39	0.95	2.46
Labrador						
Interconnected	0.40	0.28	0.61	0.32	1.01	0.59
Isolated	0.34	0.20	1.27	5.73	1.60	5.93
Total	0.25	0.28	1.17	2.04	1.43	2.32

Note:
1. System Average Interruption Frequency Index (SAIFI) is the average number of interruptions per customer. It is calculated by dividing the number of customers that have experienced an outage by the total number of customers in an area.
2. System Average Interruption Duration Index (SAIDI) is the average interruption duration per customer. It is calculated by dividing the number of customer-outage-hours (e.g. a two-hour outage affecting 50 customers equals 100 customer-outage-hours) by the total number of customers in an area.

3.1.5 Reliability KPI: Other

a) Under Frequency Load Shedding (UFLS) - *reliability KPI that measures the number of events in which shedding of a customer load is required to counteract a generator trip. Customer loads are shed automatically depending upon the generation lost.*

There were three underfrequency events during the fourth quarter of 2016, summarized as follows:

Event No. 1

On December 08, 2016, at 1310 hours, Holyrood Unit 3 tripped. With the removal of generation (approximately 144 MW) the system frequency dropped to 58.50 Hz resulting in the activation of the under frequency protection at Newfoundland Power (12,381 customers) and Corner Brook Pulp & Paper Limited. Total island load at the time of the incident was 1294 MW. Hydro's Energy Control Center worked with

Newfoundland Power's operations group and all customers were restored within 6 minutes of the event occurring. **(315 MW-Mins)**

Load Shed:	Corner Brook Pulp and Paper	15 MW
	Newfoundland Power	40 MW
	Total Load Shed:	55 MW

At 1513 hours on December 08, 2016, Holyrood Unit 3 was returned to service. Investigation revealed that the outage was caused by tracking across the trip contact on the UST (Unit Service Transformer) oil temperature relay, which resulted in a Unit trip. After careful review, the failed output trip contact on the oil temperature relay was blocked and UST 3 and Unit 3 returned to service. The switch is scheduled to be replaced in 2017 during the unit's annual maintenance outage.

Event No. 2

On December 20, 2016, at 1805 hours the Holyrood Combustion Turbine tripped. With the removal of generation (approximately 70 MW) the system frequency dropped to 58.77 Hz resulting in the activation of the under frequency protection at Newfoundland Power (9,439 customers) and Corner Brook Pulp & Paper Limited. Total island load at the time of the incident was 1564 MW. Hydro's Energy Control Center worked with Newfoundland Power's operations group and all customers were restored within three minutes of the event occurring. **(201 MW-Mins)**

Load Shed:	Corner Brook Pulp and Paper	15 MW
	Newfoundland Power	42 MW
	Total Load Shed:	57 MW

Initial investigation revealed that the unit tripped on a "blade path temperature" alarm which occurred due to a faulty thermocouple reading. As this was a false indication, the

thermocouple was temporarily and safely bypassed which is permitted by the machine manufacturer. At 1954 hours on December 20, 2016 the Holyrood Combustion Turbine became available and was returned to service. Repairs were completed to the thermocouple circuit on December 21, 2016.

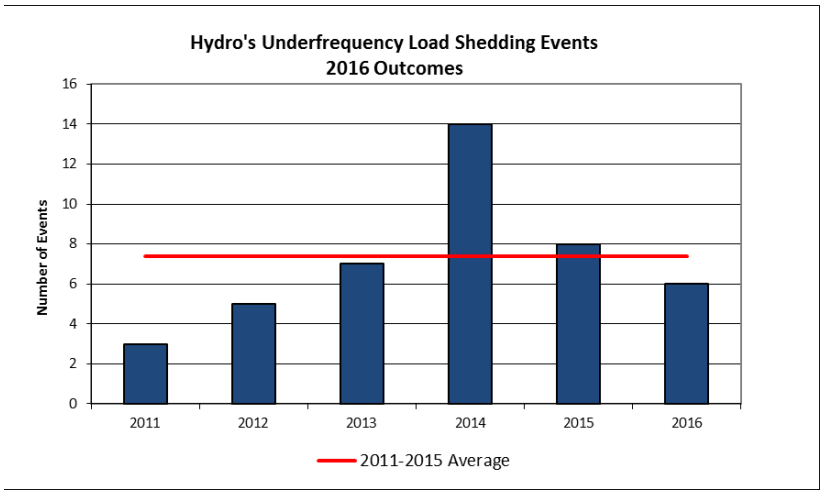
Event No. 3

On December 23, 2016, at 1032 hours the Holyrood Unit 1 tripped. With the removal of generation (approximately 110 MW) the system frequency dropped to 58.59 Hz resulting in the activation of the under frequency protection at Newfoundland Power (11,669 customers) and Corner Brook Pulp & Paper Limited. Total island load at the time of the incident was 1329 MW. Hydro's Energy Control Center gave notification to the Newfoundland Power control room within four minutes of the event to restore customers. All customers were restored within approximately nine minutes of the event occurring. **(444 MW-Mins)**

Load Shed:	Corner Brook Pulp and Paper	15 MW
	Newfoundland Power	41 MW
	Total Load Shed:	56 MW

Investigation into the trip revealed that an error occurred during the routine task of changing filters on the hydraulic system which resulted in an air bubble being trapped in the hydraulic line causing a momentary drop in pressure. All other systems were verified to be in good order and the unit was returned to service at 1111 hours on December 23, 2016. The incident was discussed with the Operator and it was determined that additional training is required for all shifts. This training will be completed in 2017.

In total, there were six UFLS events in 2016, compared to eight in 2015 and the five-year average (2011-2015) of 7.4 events. Refer to the graph below which compares the UFLS events over the past five years to this year’s performance.



1 The following table compares the UFLS events in the fourth quarter of 2016 to the same
2 quarter in 2015 in addition to the annual performance.

Underfrequency Load Shedding Number of Events

Customers	Fourth Quarter 2016	Fourth Quarter 2015	12 Mths to Date 2016	12 Mths to Date 2015	5 Year Average (2011–2015)
NF Power	3	3	6	8	7.4
Industrials	3	2	4	6	2.0
Hydro Rural*	0	1	1	2	2.0
Total Events	3	3	6	8	7.4

Underfrequency Load Shedding Unsupplied Energy (MW-min)

Customers	Fourth Quarter 2016	Fourth Quarter 2015	12 Mths to Date 2016	12 Mths to Date 2015	5 Year Average (2011–2015)
NF Power	735	831	2,304	2,245	5,096
Industrials	225	285	255	660	200
Hydro Rural*	0	30	12	72	110
Total Events	960	1,146	2,571	2,977	5,406

* Underfrequency activity affecting Hydro Rural Customers may also result in a number of delivery point outages. Outage frequency and duration are also included in totals shown in the delivery point statistics section of the report for these areas, namely the Connaigre Peninsula and Bonne Bay.

3 The details of the previous three UFLS events in 2016 are summarized in Appendix C3.

4 Refer to Appendix C4 for Other Significant Transmission System Disturbances.

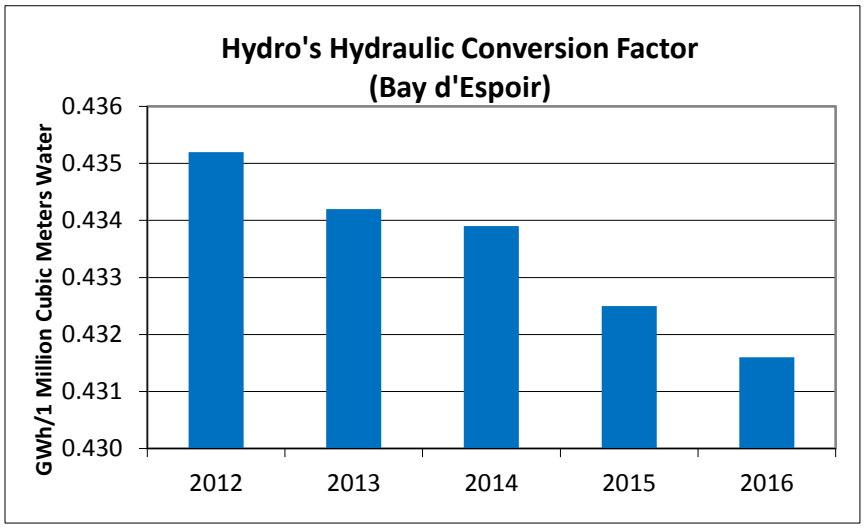
3.2 Operating Performance Indicators

This section presents information on two indicators of operating performance, both of which are associated with generation.

3.2.1 Operating KPI: Generation

a) Hydraulic Conversion Factor (Bay d'Espoir) - *a representative performance KPI for the principal hydroelectric generation assets located at Bay d'Espoir. This KPI tracks the efficiency in converting water to energy and it is calculated as the ratio of Net GWh generated for every one million cubic metres (MCM) of water consumed.*

In 2016, the hydraulic conversion factor for Bay d'Espoir was 0.432 GWh/MCM, compared to a 2016 target of 0.433 GWh/MCM.



In 2016, the inflows were 114% above average and there was a 155% increase in spillage in the Bay d'Espoir reservoir system from 2015. This was largely due to the extreme precipitation event on October 10 and 11 (Hurricane Matthew) which greatly affected the Bay d'Espoir system. The October inflows were 230% of average inflows for October. These high reservoirs levels affected water utilization at the Bay d'Espoir plant and this contributed to a lower conversion factor than previous years.

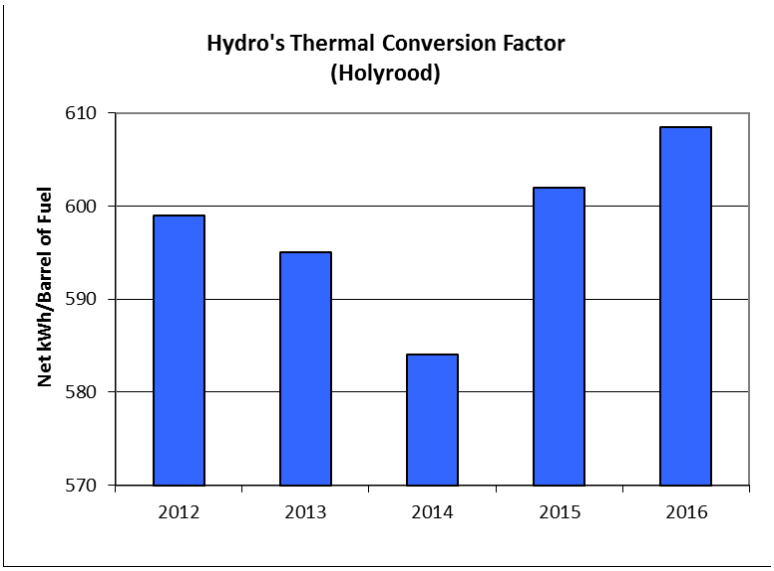
b) Thermal Conversion Factor - *a representative performance KPI for the oil-fired thermal generation assets located at Holyrood. This KPI tracks the efficiency in converting heavy fuel oil into electrical energy and is measured as the ratio of the net kWhs generated to the number of barrels of No. 6 fuel oil consumed.*

The thermal conversion factor for Holyrood is proportional to the output level of the three units, with higher averages and sustained loadings resulting in higher conversion factors. The output level of the Holyrood Thermal Generating Station will vary depending on hydraulic production on the Island, quantity of power purchases, customer energy requirements and system security requirements. The thermal conversion factor is also impacted by the heating content in the No. 6 fuel consumed at the plant, measured in BTUs/bbl.

In 2016, Hydro's net thermal conversion factor was 608 kWh per barrel compared to 602 kWh per barrel in 2015 and the 2016 target of 607 kWh per barrel. The efficiency at the Holyrood plant has remained relatively consistent with a net heat rate performance of 10,600 BTU/kWh in 2016 compared to 10,518 BTU/kWh in 2015.

In 2016, the units were dispatched as required for Avalon transmission support and system peak load considerations. The average net unit load, while operating, was 90.8 MW, up from 88.9 MW in 2015, but lower than the budget of 106 MW for 2016.

Energy production from the Holyrood Generating Station for 2016 was 1,621 GWh, an 11% increase from 2015 production levels. This is primarily due to the requirement to support the reservoirs in the first half of the year which helped to offset hydroelectric generation. Holyrood production, although higher than in 2015, was lower than planned during the winter months due to unit issues.



3.3 Financial Performance Indicators

The financial KPIs reported annually to the Board are:

1. Corporate operating, maintenance and administrative expense (OM&A) per MWh delivered;
2. Generation OM&A per MW installed capacity;
3. Generation OM&A per GWh generated;
4. Transmission OM&A per transmission circuit km; and
5. Distribution OM&A per distribution circuit km.[10]

In Order No. P.U. 8(2007), the Board ordered that Hydro file a report no later than October 31, 2007 outlining an appropriate peer group with which Hydro's financial performance at the generation and transmission levels could be compared.[11] In

[10] This KPI is not available for benchmarking from 2007 onwards. It will continue to be reported for Hydro for annual comparison purposes. Please see section 3.3.4 a) Distribution Controllable Cost for a discussion of the alternate KPI to be used for peer benchmarking.

[11] In 2007, Hydro had initially used peer benchmarking data from the Canadian Electricity Association (CEA) Committee on Performance Excellence (COPE), as published in the "Peer Group Performance Measures for Newfoundland Power" report. Since then the CEA has advised that neither the composite information for these measures nor any other cost-related CEA composite indicators are available for benchmarking purposes. As a result, Newfoundland Power reports based on a peer group of companies operating in the United States. This group of companies is not an appropriate group for Hydro to use as a peer group of companies due to Hydro's relatively small distribution component; however, in order to maintain consistency for year-over-year comparisons, Hydro uses this group of companies for the Corporate Controllable Unit KPI that Hydro uses for its generation financial benchmarking.

compliance with Board Order No. P.U. 8(2007), Hydro filed a report titled "Peer Group Benchmarking" dated October 31, 2007 which summarized Hydro's findings regarding development of a peer group for financial KPIs related to generation and transmission. In that report, Hydro identified separate peer groups for generation KPIs and transmission KPIs and proposed that, subject to data availability, the selected peers remain constant to allow for meaningful trend comparisons over time. This is the ninth year of reporting generation and transmission financial KPI peer data. The list of peers used for KPI benchmarking for Financial Performance Indicators is included as Appendix D. This peer group benchmarking data is sourced from the U.S. Federal Energy Regulatory Commission (FERC) database, to which Hydro has a subscription. All financial data for the United States-based peer group is in US dollars and all financial data for Hydro is in Canadian dollars.

Hydro has historically provided OM&A figures on a forecast basis; however, in accordance with the Settlement Agreement which was approved in Board Order No. P.U. 49(2016), Hydro has reported 2016 OM&A based on the 2015 Test Year Cost of Service Study included in its January 27, 2017 Compliance Application.

3.3.1 Financial KPI: Corporate Operating, Maintenance and Administrative Expense (OM&A) per MWh delivered

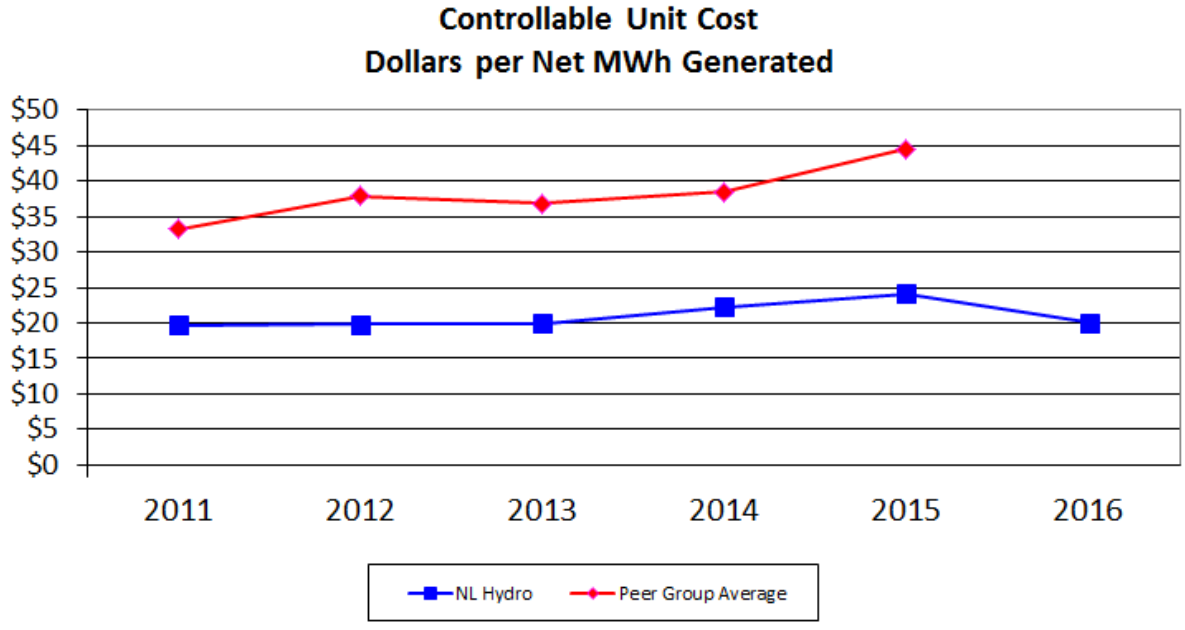
---

Controllable Unit Cost - *a high level corporate KPI that tracks Hydro's OM&A expenses in relation to its total energy delivered, expressed as dollars per MW hour. Total Corporate OM&A includes all operating labour and materials for Hydro's generation, transmission, distribution, customer-related and administrative costs, and loss on disposal of capital assets. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes.*

Hydro's OM&A costs decreased from $153.8 million in 2015 to $123.9 million in 2016, resulting in a Controllable Unit Cost of $13.39 per MWh delivered for 2016.

Hydro uses normalized energy delivered in the computation of its Corporate Controllable Unit Cost. This is not directly comparable to the peer group data from the FERC database, which is based on net energy generated. In order to provide for direct comparison with the peer group, Hydro has also calculated Controllable Unit Cost based on net energy generated. The chart below illustrates Hydro's Corporate Controllable Unit Cost for 2011 to 2016 and that of the peer group for 2011 – 2015.[12] As indicated, Hydro's Corporate OM&A per unit of net generation was $20.07 per MWh during 2016. This is higher than the computed Controllable Unit Cost of $13.39 per MWh delivered as normalized deliveries are higher than net generation due to the effect of Hydro's energy purchases.

Hydro's Corporate Controllable Unit Cost has decreased from 2015. From 2011 to 2015, Hydro's Controllable Unit Cost generally follows a similar trend as that of its peer group. As Hydro has no insight into the operations and finances of the peer group companies, it cannot determine what factors drive their individual Controllable Unit Costs.



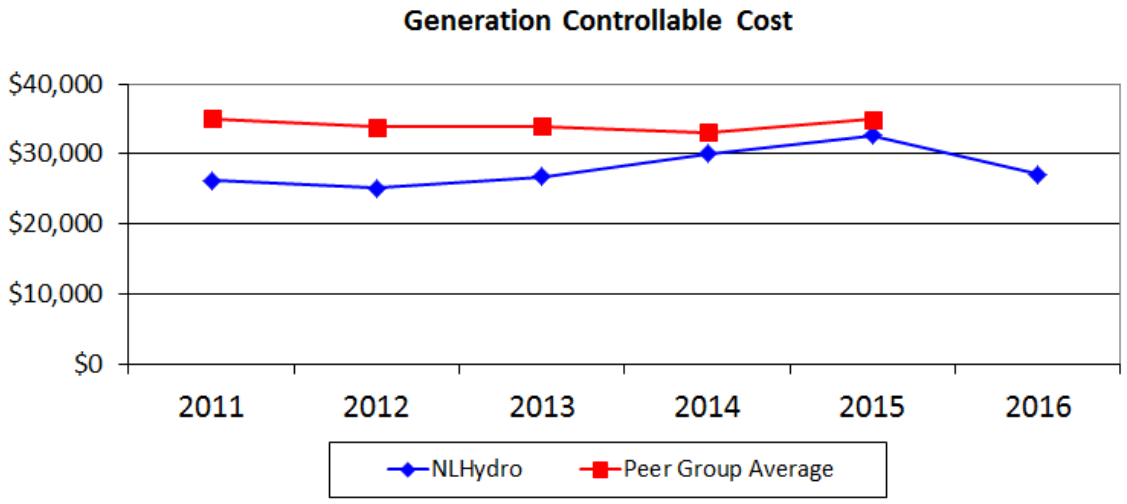
[12] Peer data for 2016 is not available at this time.

3.3.2 Financial KPI: Generation OM&A per MW Installed Capacity

Generation Controllable Cost - *a functional corporate KPI that tracks Hydro's generation costs in relation to its installed generation. It is computed by dividing generation OM&A by installed capacity as measured in MW.*

Generation Controllable Cost was $27,095 per MW for 2016 compared with $32,599 in 2015, which is a decrease of $5,503 per MW.

The peer group used to benchmark Generation Controllable Costs has generally maintained its costs between 2011 and 2015, while Hydro's Generation Controllable Cost have fluctuated, decreasing from 2011 to 2012, increasing from 2012 to 2015, and decreasing again in 2016.

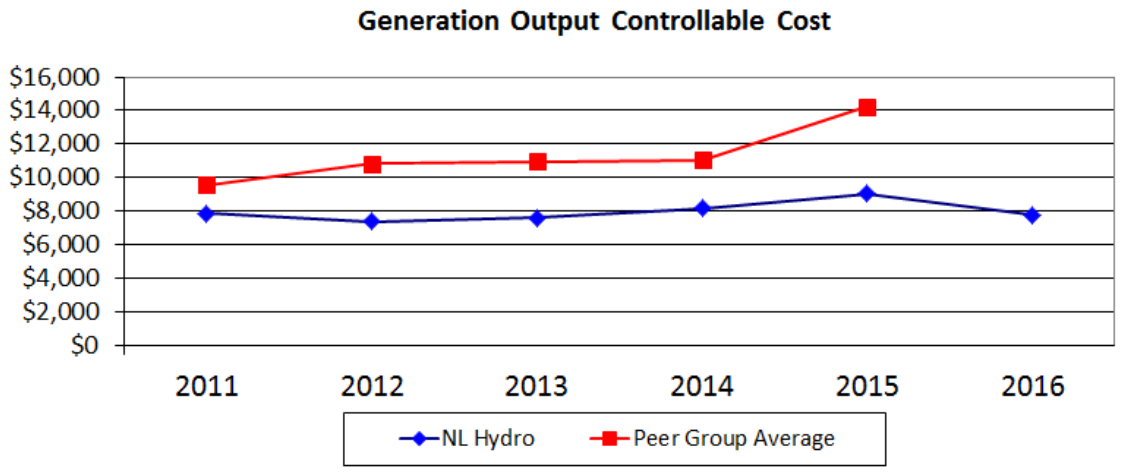


3.3.3 Generation OM&A per GWh generated

Generation Output Controllable Cost - a functional corporate KPI that tracks Hydro's generation OM&A expenses in relation to its net generation measured in GWh.

In 2016, Hydro's Generation Output Controllable Cost of $7,738 per GWh, compared to $9,010 in 2015, which is a decrease of $1,272 per GWh.

Hydro's Generation Output Controllable Cost has followed a similar trend to that of the peer group over the past five years, although the peer group experienced a bigger relative increase in 2015 than Hydro experienced.

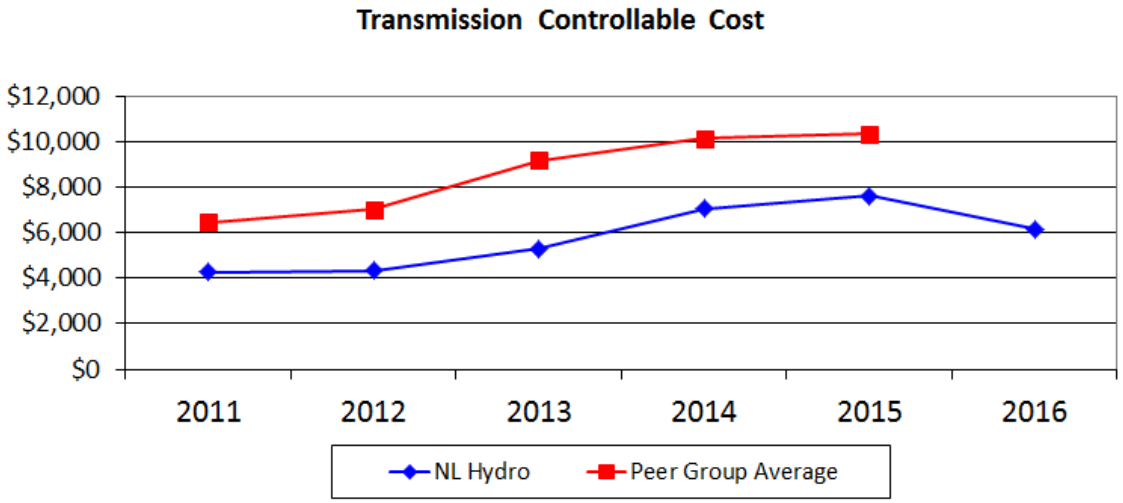


3.3.4 Financial KPI: Transmission OM&A per Transmission Circuit km

Transmission Controllable Cost - *a KPI that tracks Hydro's transmission OM&A expenses in relation to the 230 kV equivalent length of its transmission circuits (69 kV lines and above).*

In 2016, Hydro's Transmission Controllable Cost of $6,148 per km of transmission was lower than the $7,615 in 2015, which is a decrease of an increase of $1,467 per km.

Hydro's costs per km of transmission circuit from 2011 to 2015 have trended in a similar pattern as the peer group. While a comparison of direct cost per unit km between the peer group and Hydro is not meaningful due to differences in accounting treatment and corporate cost allocations, tracking trends over several years could be helpful in ensuring consistency with the industry in general.



3.3.5 Financial KPI: Distribution OM&A per Distribution Circuit km

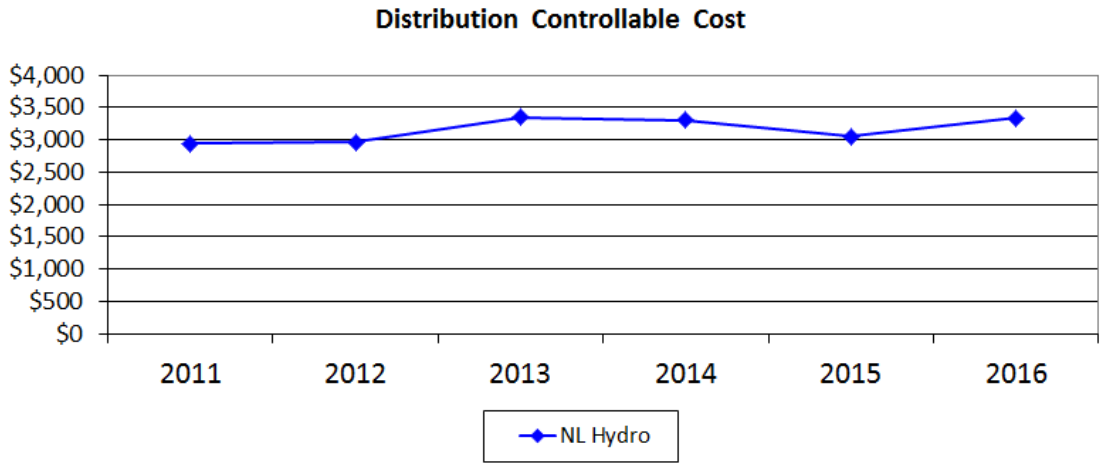
Distribution Controllable Cost - *a functional corporate KPI that tracks Hydro's distribution OM&A expenses in relation to the length of its equivalent 230 kV distribution circuits in kilometers.*[13]

The Distribution Controllable Cost KPI had previously been reported as dollars per km of distribution using the CEA COPE data. As discussed, the CEA COPE data is no longer available for benchmarking of financial KPIs. Additionally, although distribution cost data is available for the U.S.-based peer group used by Hydro for Transmission Controllable Cost, the associated km of distribution data is unavailable. In the absence of the CEA COPE data, Newfoundland Power has chosen to use a KPI that divides total Distribution OM&A by MWh of retail sales. Hydro will therefore use this same data set. However, given Hydro's relatively small quantity of retail sales, combined with the rural and remote locations of these sales, it is expected that Hydro's Distribution cost per MWh will be significantly higher than Newfoundland Power's and the peer group average.

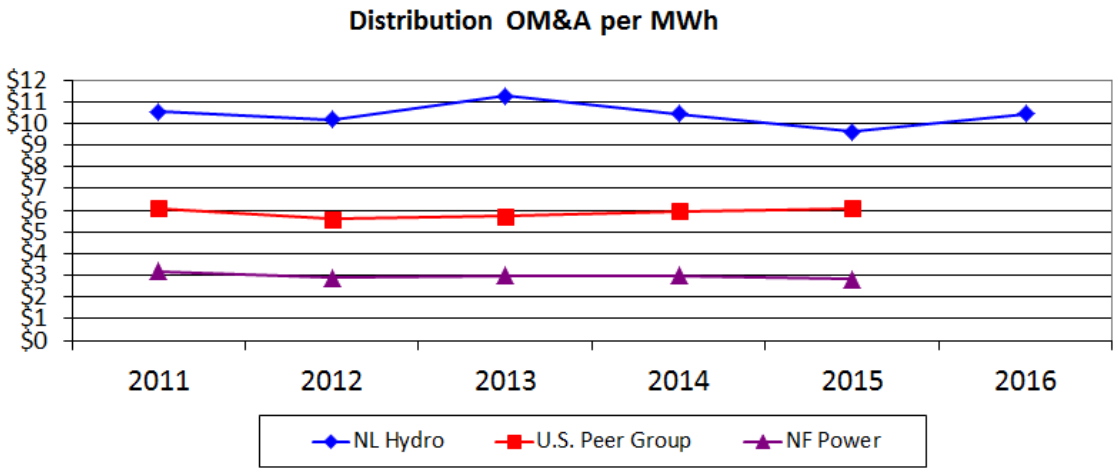
[13] CEA COPE peer data used up to 2007 excluded circuits less than 1 kV. Hydro's data has also been adjusted to exclude circuits less than 1 kV from 2003 onward.

The distribution cost per km of circuit length will continue to be reported for year-over-year trend analysis.

At $3,338 per circuit km in 2016, Hydro's Distribution Controllable Cost increased $285 per km from $3,053 per km in 2015.



As expected, Hydro's distribution costs of $9.61 in 2015 trend higher than those of the peer group, as demonstrated in the chart below. The distribution systems are a relatively small component of Hydro's total plant compared to generation and transmission plant and also compared to Newfoundland Power's distribution assets. Thus, Hydro's higher costs per MWh are likely due to the rural and geographically dispersed nature of its distribution systems and the resultant inability to achieve cost economies.



3.4 Customer-Related Performance Indicators

a) Residential Customer Satisfaction - *an indicator of Hydro's residential customers overall satisfaction level with service, which is tracked by the Percent Satisfied Customers KPI.*[14]

The Percent Satisfied Customers measure is also a corporate performance KPI that tracks the satisfaction of rural residential customers with Hydro's performance. The Percent Satisfied Customers measure is produced via regular surveys of Hydro's residential customers.

The 2016 residential customer satisfaction survey shows that 90% of customers are either very satisfied or somewhat satisfied with Hydro. When compared to 2014, customer satisfaction has increased by 6%.

[14] As of 2009, the Customer Satisfaction index (CSI) is no longer being calculated as a Customer-Related Performance Indicator.


Residential Customer Satisfaction
Overall Customer Satisfaction
94
92
90
88
86
84
82
80
78
76
74
2006
2007
2008
2009
2010
2011
2012
2014
2016

Appendices

Appendix A: Rationale for Hydro's 2016 KPI Targets

KPI	Comment on KPI 2016 Target
Reliability	Hydro has adopted a target setting approach wherein known factors that affect reliability performance are incorporated into the target setting process wherever practical. This approach also uses percentage improvements and past performance levels to set target levels for continuous improvements.
Weighted Capability Factor	The 2016 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Weighted DAFOR	The 2016 target is set using the expected annual generation unit outage schedule combined with performance improvements relative to recent history.
Transmission SAIDI, SAIFI, and SARI	The 2016 targets for forced outage performance were not set.
Distribution SAIDI & SAIFI	Improvements relative to the most recent five-year average.
Underfrequency Load Shedding	The 2016 target is based upon improvement over the most recent five-year average.
Operating	
Hydraulic Conversion Factor	Hold at the previous target value.
Thermal Conversion Factor	2016 target was 607 kWh/bbl.
Other	
Customer Satisfaction	The target for residential customers in 2016 was 80%.

Appendix B: Computation of Weighted Capability Factor and Factors Impacting Performance

Weighted Capability Factor is calculated using the following formula:

$$1 - \frac{\sum_{all\ units}\left(\frac{unit\ total\ equivalent\ outage\ time \times unit\ MCR}{unit\ hours}\right)}{\sum_{all\ units} unit\ MCR}$$

Where,

MCR = Maximum Continuous Rating, the gross maximum electrical output, measured in megawatts, for which a generating unit has been designed and/or has been shown capable of producing continuously. MCR would only change if the generating capability of a unit is permanently altered by virtue of equipment age, regulation, or capital modifications. Such changes to MCR are infrequent and have not actually taken place within Hydro since the 1980's when two units at Holyrood were uprated due to modifications made to these units.

Unit hours = the sum of hours that a unit is in commercial service. This measure includes time that a unit is operating, shut down, on maintenance, or operating under some form of derating. Unit hours will only be altered in the infrequent event that a unit is removed from commercial service for an extended period of time.

Unit total equivalent outage time = the period of time a unit is wholly or partially unavailable to generate at its MCR. For the purposes of calculating outage time, the degree to which a unit is derated is converted to an outage equivalency. Thus, a unit that is able to generate at 75% load for four days would have an equivalent outage time

of one full day out of four. Factors that can affect unit total equivalent outage time are classified by CEA under nine categories, which are outlined in Appendix A to this Report. Hydro tracks the time that each unit spends in each of these nine states and calculates the weighted capability accordingly.

Unit total equivalent outage time is the measure that is most likely to impact Weighted Capability Factor on a year-to-year basis, since MCR and unit hours are unlikely to change.

Factors that Affect Unit Total Equivalent Outage Time

1. **Sudden Forced Outage.** An occurrence wherein a unit trips or becomes immediately unavailable.
2. **Immediately Deferrable Forced Outage**. An occurrence wherein a unit must be made unavailable within a very short time (10 minutes).
3. **Deferrable Forced Outage**. An occurrence or condition wherein a unit must be made unavailable within the next week.
4. **Starting Failure**. A condition wherein a unit is unable to start.
5. **Planned Outage**. A condition where a unit is unavailable because it is on its annual inspection and maintenance.
6. **Maintenance Outage**. A condition where a unit is unavailable due to repair work. Maintenance outage time covers outages that can be deferred longer than a week, but cannot wait until the next annual planned maintenance period.
7. **Forced Derating**. A condition that limits the usable capacity of a unit to something less than MCR. The derating is forced in nature, typically because of the breakdown of a subsystem on the unit.
8. **Scheduled Derating**. A condition that limits the usable capacity of a unit to something less than MCR, but is done by virtue of the decision of the unit operator. Scheduled deratings are less common than forced deratings, but can

arise, for example, when a unit at Holyrood is de-rated to remove a pump from service.

9. **Common Mode Outages**. Common mode outages are rare, and arise when an event causes multiple units to become unavailable. An example might be the operation of multiple circuit breakers in a switchyard at Holyrood due to a lightning strike, rendering up to three units unavailable.

Note: There are hundreds of CEA equipment codes for generator subsystems that track the cause for the time spent in each of the above categories.

Appendix C1: Significant Transmission Events – 2016

There were nine significant events in 2016. The details follow:

Event 1

On January 13, all customers north of Sally's Cove on the Great Northern Peninsula experienced unplanned power outages of up to three hours and 16 minutes. The outage occurred after transformer T1 tripped at the Berry Hill Terminal Station. The transformer was isolated and all customers were restored in stages. Refer to the following table for customer outage details:

(Unsupplied Energy: 2,830 MW-Mins)

Event -BHL T1 trip - Jan 13, 2016

Delivery Point Affected	Start Time	Time of Restoration	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	16:32	17:44	72	1.6	115.2
Parson's Pond	16:32	17:40	68	0.2	13.6
Daniel's Harbour	16:32	17:40	68	0.8	54.4
Hawkes's Bay	16:32	18:33	122	5.7	586.3
Plum Point	16:32	17:42	70	3.5	245
Bear Cove	16:32	17:43	71	4.9	347.9
Main Brook	16:32	17:46	74	0.6	44.4
Roddickton	16:32	17:46	74	2.3	170.2
St Anthony	16:32	18:48	136	9.7	1252.7

Event 2

On February 4th, industrial customers Vale and Praxair at the Voisey's Bay Nickel Terminal Station experienced a load loss during switching to remove transformer T1 from service. A customer outage was required to switch loads between transformers T1 and T2. A problem was found with a burnt current transformer block in the transformer cabinet which required T1 to be removed from service immediately. Vale and Praxair reduced their loading for approximately two hours by 10 MW during this event. Repairs have been completed and T1 was energized with no load. (**Unsupplied Energy: 1,434 MW-Mins)**

Event 3

On March 22, all customers (7833) supplied by transmission line TL259 (including Parsons Pond, Daniels Harbour, Peter's Barren, Hawkes Bay, Plum Point, Bear Cove, St. Anthony Airport, St. Anthony Diesel, Main Brook, and Roddickton Terminal Stations) experienced an unplanned power outage when TL259 tripped. All customers were restored via transmission line TL227, Hawke's Bay diesel plant, and St. Anthony diesel plant. The cause of the outage was a downed conductor on A Phase of TL259 due to an eye bolt failure on structure 109. Excessive wind in the area is believed to be the root cause. **(Unsupplied Energy: 3,477 MW-Mins)**

Event -BHL TL259 trip - March 22, 2016

Delivery Point Affected	Start Time	Time of Restoration	Number of Customers	Outage Duration (mins)	Load Loss (MW)	MW-Mins
Cow Head	23:23	23:24	468	1	1.4	1.4
Parson's Pond	23:09	23:29	270	20	0.6	12
Daniel's Harbour	23:09	23:29	289	20	0.8	16
Hawkes's Bay (1)	23:09	23:29	1317	20	4.7	94
Hawkes's Bay (2)	1:42	1:52	1317	10	4.7	47
Plum Point	23:09	1:42	969	153	2.8	428.4
Bear Cove L4, L6(partial)	23:09	1:43	700	154	3.1	477.4
Bear Cove L6(partial)	23:09	5:27	244	378	1.1	415.8
Main Brook	23:09	1:59	249	170	0.8	136
Roddickton	23:09	1:59	910	170	3.1	527
St Anthony	23:09	0:55	2418	106	7.2	1370.8

Event 4

On May 20, all (1,763) customers supplied by the Bottom Waters Terminal Station experienced a planned outage of three hours and 44 minutes (224 mins). Bottom Waters transformer T1 locked out due to condensation on the winding temperature relay. This caused a short resulting in a contact closure and trip into the transformer lockout.

(Unsupplied Energy: 1,183 MW-Mins)

Event 5

On May 23, Customers served by transmission Line TL220 and the Conne River, English Harbour West, and Barachoix Distribution Systems, (2,606 customers) experienced an unplanned outage, see outage details below. A forest fire started under TL220 resulted

into a phase to phase fault that resulted in the failure of a low side (25 kV) lightning arrester on transformer T1 at Barachoix Terminal Station. The recloser supplying Gaultois had opened and had to be closed locally.

- Outage 1: Areas: Conne River and English Harbour West Distribution Systems
  Duration: 1054 to 1322 hours (May 23, 2016), 2 hours 28 minutes
  Customers: 1,226, Belleoram, English Harbour West, Pool's Cove, Rencontre East, Conne River
- Outage 2: Areas: Barachoix Distribution System (not including Gaultois)
  Duration: 1054 hours (May 23, 2016) to 0100 hours (May 24, 2016), 14 hours 6 minutes
  Customers: 1,490, Hermitage, Harbour Breton, Seal Cove (F. B.)
- Outage 3: Gaultois
  Duration: 1054 hours (May 23, 2016) to 0656 hours (May 24, 2016), 20 hours 2 minutes
  Customers: 109
  (**Unsupplied Energy: 3,319 MW-Mins)**

Event 6

On July 29, customers supplied by the St. Anthony Diesel Plant Terminal Station experienced an unplanned power outage ranging from 31 minutes to seven hours and 49 minutes. The outage occurred after lighting hit transmission line TL261 (confirmed by LTS). Circuit breaker B1L61 failed to close due a problem with the air compressor which is required to operate the closing mechanism. The fuse blown to the compressor motor. The St. Anthony Diesel Plant was used to supply customers supplied on feeders L2 and L3 while customer on L1 experienced an outage for the total duration of outage. The following outlines the customer outage information:
(Unsupplied Energy: 1,751MW-Mins)

Outage 1 - Event -STA TL261 Trip - July 29, 2016

Delivery Point Affected	Start Time	Time of Restoration	Number of Customers	Outage Duration (mins)	Load Loss (MW)	MW-Mins
St Anthony L1	5:02	12:51	1181	469	2.4	1145.3
St Anthony L2	5:02	8:27	456	205	0.9	193.3
St Anthony L3	5:02	8:01	781	179	1.6	289.1
St Anthony total	5:02	12:51	2418	469	5.0	1627.7

Outage 2 - Event -STA TL261 Trip - July 29, 2016

Delivery Point Affected	Start Time	Time of Restoration	Number of Customers	Outage Duration (mins)	Load Loss (MW)	MW-Mins
St Anthony L2	10:09	10:40	456	31	0.9	29.2
St Anthony L3	10:09	11:07	781	58	1.6	93.7

Event 7

On September 12, customers supplied by the Happy Valley (5,166) Terminal Station experienced an unplanned power outage of four hours and ten minutes. The trip occurred after L1301 tripped at the Churchill Falls Switchyard due to a damaged post insulator on disconnect switch B1T32. Attempts to start the gas turbine at Happy Valley failed. (Unsupplied Energy: 5,350 MW-Mins)

Event 8

On November 21, NP customers (13,135) supplied by Sunnyside Terminal Station and transmission line TL219, experienced an unplanned power outage of three hours and 34 minutes (214 mins). NP restored some customers with the Greenhill gas turbine and the remaining customers were restored with TL219. TL219 tripped due to two lightning strikes, the second strike resulted in the operation of the breaker failure protection on circuit Breaker B3L19. (Unsupplied Energy: 3,896 MW-Mins)

Event 9

On December 16, NP customers supplied by transmission line TL215 in the Port Aux Basque area (3,563) experienced an unplanned power outage of 12 hours and 40 minutes. The outage continued for NP customers due to distribution damage. Outage

was caused by the failure of a crossarm pin due to extreme high winds in the area.

(Unsupplied Energy: 7,650 MW-Mins)

Appendix C2: Significant Distribution Events – 2016 (Excluding Fourth Quarter)

On January 1, 2016 at 0310 hours, 552 customers serviced by the Bottom Waters Terminal Station - Line 2 experienced an unplanned power outage. The communities affected included Burlington, Middle Arm, Smith's Harbour, Nipper's Harbour and the Rambler Mine site. The outage was caused by a downed primary and neutral conductor between Nugget Pond tap and Nippers Harbour. Hydro crews responded and all customers were restored by 1545 hours.

On January 13, 2016 at 1540 hours, all customers (142) in Conche, served by the Roddickton distribution system, experienced an unplanned power outage. The outage was caused by a broken pole in the distribution system. Crews travelled to area on January 13 but could not assess the trouble due to the poor weather (snow and high winds). The issue was discovered during a morning patrol the next day. Customers were restored at 1030 hours, January 14 following completion of repairs.

On February 07, 2016 at 0900 hours, 58 customers in Happy Valley Goose Bay, Labrador supplied by Feeder 11, experienced a planned power outage. The outage was required to safely replace equipment at the terminal station. The planned work was completed and the feeder was restored at 1415 hours on February 07, 2016.

On February 13, 2016 starting at 0800, there was a planned outage affecting 400 customers in Sheshatshiu supplied by distribution line, L7. The outage was required to safely perform upgrades to the distribution system. All customers were restored at 1030 hours.

On February 15, 2016, at 0240 hours, all customers (800) serviced by the English Harbour West Terminal Station, including the communities of Boxey, Belleoram, Coombs Cove, English Harbour West, Mose Ambrose, Pools Cove, Rencontre East, St.

Jacques, and Wreck Cove experienced an unplanned power outage due to a downed conductor. At 0939 hours restorations were underway when recloser EH1-R2 tripped resulting in customer outages to Belleoram, St. Jacques, English Harbour West, Mose Ambrose, Wreck Cove, Boxey and Coombs Cove. The cause was determined to be a floating phase.

Repairs were made and customer restoration occurred as follows:

- 220 customers at Rencontre East and Pools Cove, 0240 to 0910 hours, 6 hour 30 minutes.
- 580 customers at Belleoram, St. Jacques, English Harbour West, Mose Ambrose, Wreck Cove, Boxey and Coombs Cove, 0240 to 1300 hours, 10 hours 20 minutes.

On February 16, 2016 at 1433 hours, 1110 customers in Happy Valley Goose Bay, Labrador supplied by Lines 8, 9, 10, 15, 16, and 17 experienced a planned power outage. The outage was required to safely replace equipment at the terminal station. The planned work was completed and all customers were restored by 1641 hours on February 16, 2016.

On March 16, 2016 at 1106 hours, all customers (98) in Black Tickle experienced an unplanned power outage. The outage occurred when a recloser failed to operate due to a faulted controller. All customers were restored at 1810 hours after a temporary repair was made. Hydro completed permanent repairs on March 17.

On March 23, 2016 at 1735 hours, all customers (105) in Goose Cove experienced an unplanned power outage. The outage occurred due to severe weather in the area causing issues with the distribution system. Hydro crews were delayed in making repairs due to unsafe working conditions caused by the weather. All customers were restored at 1242 hours, March, 24, 2016.

On March 27, 2016 between 0027 and 0654 hours, all customers (1317) serviced by transmission line TL221 experienced twenty five unplanned power outages when the line opened and reclosed due to ice bridging and contamination on the insulators of TL221. The total duration of these outages was 4 seconds for each occurrence.

On March 29, 2016 at 1738 hours, 374 customers serviced by the Bottom Waters Terminal Station - Line 1 experienced an unplanned power outage. The communities affected included Woodstock, Pacquet, and Mings Bight along with Rambler and Anaconda mine sites. The outage was caused by a floating phase resulting from a failed insulator string. Repairs were made and all customers were restored at 2120 hours.

On April 3, 2016 at 1045 hours, 374 customers serviced by the Bottom Waters Terminal Station - Line 1 experienced an unplanned power outage. The communities affected included Woodstock, Pacquet, and Ming's Bight along with Rambler and Anaconda mine sites. The outage was caused by a floating phase resulting from a failed insulator string. Repairs were made and all customers were restored at 1400 hours.

On April 4, 2016 at 1605 hours, 542 customers serviced by the Bottom Waters Terminal Station - Line 2 experienced an unplanned power outage. The communities affected included Nipper's Harbour, Kings Harbour, Smiths Harbour, Burlington, and Middle Arm along with Rambler Mines. The outage was caused by a downed tree on the distribution line. At the time, there were extreme wind warnings in effect. Hydro responded, made the necessary repairs and returned service to customers.

<u>Outage Details</u>

Outage 1: Nipper's Harbour and Ramble Mines, 1605 – 1845 hours, 2 hours 40 minutes, 87 customers.

Outage 2: Kings Harbour, Smiths Harbour, Burlington, and Middle Arm, 1605 – 2030 hours, 4 hours, 25 minutes, 455 customers.

On May 15, 2016 at 0600 hours, 1320 customers in Happy Valley Goose Bay, Labrador supplied by the Happy Valley Terminal Station, experienced a planned power outage. The outage was required to safely install a distribution pole on Feeder 8 as well as to make repairs to equipment in the distribution system. The line repair was completed and all customers were restored by 1150 hours. The breakdown of the 1320 customers affected by this outage is as follows:

Feeder 7

0600 to 0710 Hours (870 Customers – 1 hour, 10 mins)

Feeder 8

0900 to 1150 Hours (450 Customers – 2 hours, 50 mins)

On June 04, 2016 at 0800 hours, 93 customers in Happy Valley Goose Bay, Labrador supplied by the Happy Valley Terminal Station, Feeder L4 (partial), experienced a planned power outage to accommodate feeder upgrades. All customers were restored by 1130 hours upon completion of planned work.

On June 11, 2016 at 0700 hours (Labrador time), 650 customers in Labrador City, Labrador, serviced by Quartzite Line 11 experienced a planned power outage. The outage was required to safely tie in a midspan pole on the distribution system. All customers were restored at 0750 hours.

On June 14, 2016 at 1300 hours (Labrador time), 281 customers in Wabush, Labrador, serviced by distribution line 3 experienced a planned power outage. The outage was

required to safely perform maintenance to the distribution system. All customers were restored at 1700 hours.

On July 9, 2016 at 1300 hours (Labrador time), 450 customers in Wabush, Labrador, serviced by distribution line 12 experienced a planned power outage. The outage was required to safely replace insulators on the distribution line. All customers were restored at 1745 hours.

On July 24, 2016 at 0900 hours (Labrador time), 138 customers in Wabush, Labrador, serviced by distribution line 11 experienced a planned power outage. The outage was required to safely connect a new distribution pole and to replace insulators. All customers were restored on July 24, 2016 at 1215 hours.

On August 05, 2016 at 1700 hours (Labrador time), 1357 customers in Labrador City, Labrador, serviced by the Quartzite Substation Lines 08, 09, 10 and 11 experienced an unplanned power outage due to a lightning strike. All customers were restored at 1745 hours, August 05, 2016

On August 20, 2016 at 0700 hours (Labrador time), 320 customers in Wabush, Labrador, serviced by distribution line 12 experienced a planned power outage. The outage was required to safely replace insulators. All customers were restored on August 20, 2016 at 1200 hours.

On August 21, 2016 at 1300 hours (Labrador time), 250 customers in Wabush, Labrador, serviced by distribution line 12 experienced a planned power outage. The outage was required to safely replace insulators. All customers were restored on August 21, 2016 at 1600 hours.

On August 30, 2016 at 1300 hours (Labrador time), 100 customers in Labrador City, Labrador, serviced by Line 2 experienced a planned power outage. The outage was

required to safely install a primary conductor. All customers were restored at 1700 hours (Labrador time), August 30, 2016.

On September 03, at 1300 hours (Labrador time), 100 customers in Labrador City, Labrador, serviced by Line 2 experienced a planned power outage. The outage was required to safely install a primary conductor. All customers were restored at 1600 hours (Labrador time), September 03, 2016.

On September 12, at 1021 hours, all customers (1760) serviced by the Bottom Waters Terminal Station experienced an unplanned power outage. The communities affected included Woodstock, Pacquet, Mings Bight, Nipper's Harbour, Kings Harbour, Smiths Harbour, Burlington, Middle Arm, Brent's Cove, La Scie, Round Harbour, Snook's Arm, Shoe Cove, Tilt Cove, Rambler and Anaconda Mine sites. The outage resulted from fallen trees on Newfoundland Power's transmission line 363L at Indian River Substation. All customers were restored at 1621 hours.

On September 14, customers (442) supplied by Bottom Waters feeder L7 in the town of La Scie experienced an unplanned power outage of four hours and 26 mins. The outage was caused by an insulator failure. Repair work included a replacement crossarm, insulator and a spliced broken primary conductor on pole #189.

On September 16, customers (1,760) supplied by the Bottom Waters Terminal Station experienced a planned power outage of one hour and six mins. The outage was required for NP to remove danger trees on transmission line 363L.

Appendix C3: Underfrequency Load Shedding Events (Excluding Fourth Quarter)

On March 26, 2016 at 1102 hours, Cat Arm Generating Plant Unit 1 and Unit 2 tripped due to ice bridging and contamination on the insulators on the connecting transmission line, TL247 (Deer Lake to Cat Arm). With the removal of generation (approximately 120 MW) the system frequency dropped to 58.32 Hz resulting in the activation of the under frequency protection at Newfoundland Power (25,394 customers) and Hydro Rural (913 customers). Hydro advised Newfoundland Power they could restore load within 2 minutes after the event occurring. There was additional generation started at Bay d'Espoir and all Newfoundland Power customers were reportedly restored at 1117 hours with the exception of one feeder that the NP control room restored at 1126 hours. Total Island load at the time of the incident was 1212.7 MW. **(1,467 MW-mins)**

Load Shed:	Newfoundland Power:	97 MW
	NLH	3 MW
	Total Load Shed:	100 MW

Following the restoration of TL247 the Cat Arm Units were restored as follows:

At 1901 hours, March 26, 2016, Cat Arm Unit 2 available (67 MW).
At 1907 hours, March 26, 2016, Cat Arm Unit 1 available (67 MW).

On August 14, 2016, at 1350 hours, Holyrood Unit 3 tripped. With the removal of generation (approximately 68 MW) the system frequency dropped to 58.69 Hz resulting in the activation of the under frequency protection at Newfoundland Power (6,951 customers). Total Island load at the time of the incident was 680 MW. Hydro advised Newfoundland Power they could begin to restore load within three minutes after the event occurring. Newfoundland Power lost 11 MW of load. **(66 MW-Mins)**

Holyrood Unit 3 was restored to service by 2356 hours on August 14, 2016. Upon review of the targets in the plant and inspection of the Holyrood Unit 3 transformer, T3, it has been confirmed the unit tripped due to an over temperature on T3 transformer. This was a result of cooling controls being left in the off position and temperature alarms being blocked after work was completed to change coolers on T3 prior to returning the unit to service.

On August 24, 2016, at 1710 hours, Upper Salmon Unit tripped due to a lightning strike to its connecting 230 kV transmission line, TL234. With the removal of generation (approximately 65 MW) the system frequency dropped to 58.76 Hz resulting in the activation of the under frequency protection at Newfoundland Power (6,804 customers). Total Island load at the time of the incident was 729 MW.

Hydro advised Newfoundland Power they could begin to restore load within one minute of the event occurring. Newfoundland Power advised they had all feeders restored within four minutes with the exception of one. Corner Brook Pulp & Paper began restoring load within two minutes of the event occurring. **(78 MW-Mins)**

Load Shed:	Corner Brook Pulp and Paper:	15 MW
	Newfoundland Power:	12 MW
	Total Load Shed:	27 MW

Appendix C4: Other Significant Transmission System Disturbances – 2016

There was one other reportable system disturbance in November. On November 24, the Stephenville gas turbine tripped while in synch condense mode. This trip resulted in a high voltage spike in the Stephenville area. Over voltage protection at Newfoundland Power's Gallants Substation operated to shed load to 6,212 customers. These customers were restored in 12 minutes. **(136 MW-Mins)**

Appendix D: List of U.S.-Based Peers for Financial KPI Benchmarking

Transmission Peer Group:	**Generation and Corporate Peer Group:**
AEP Texas North Company	Alcoa Power Generating Inc.
ALLETE, Inc.	ALLETE, Inc.
Aquila, Inc.	Aquila, Inc.
Avista Corporation	Avista Corporation
Central Illinois Public Service Company	Buckeye Power, Inc.
Delmarva Power & Light Company	Cleco Power LLC
Entergy Mississippi, Inc.	Electric Energy, Inc.
Kentucky Utilities Company	Entergy Mississippi, Inc.
MDU Resources Group, Inc.	Hawaiian Electric Company, Inc.
Mississippi Power Company	Indiana-Kentucky Electric Corporation
New York State Electric & Gas Corporation	Kentucky Power Company
Northern Indiana Public Service Company	Ohio Valley Electric Corporation
Northern States Power Company (Wisconsin)	Portland General Electric Company
Oklahoma Gas and Electric Company	Public Service Company of New Hampshire
Public Service Company of Colorado	Puget Sound Energy, Inc.
Public Service Company of Oklahoma	Savannah Electric and Power Company
Sierra Pacific Power Company, d/b/a NV Energy	Sierra Pacific Power Company, d/b/a NV Energy
Southwestern Electric Power Company	SOUTHERN ELECTRIC GENERATING COMPANY
Tucson Electric Power Company	Southern Indiana Gas and Electric Company
Westar Energy, Inc.	The Empire District Electric Company

Exhibit 8 - Holyrood Decommissioning Study

Decommissioning and Demolition of the Holyrood Thermal Generating Station

Final Report

Stantec

Prepared for:
Newfoundland and Labrador Hydro
500 Columbus Drive
P. O. Box 12400
St. John's, NL A1B 4K7

Prepared by:
Stantec Consulting Ltd.
845 Prospect Street
Fredericton, NB E3B 2T7

REGISTERED PROFESSIONAL ENGINEER
PEG Newfoundland and Labrador
MARC D. VOISINE
SIGNATURE
NOV 15/16
DATE
NEWFOUNDLAND & LABRADOR

File: 133547213_23_8

November 15, 2016

Revision	Description	Author		Quality Check		Independent Review	
0 June 3/16	Draft	MEM/BDW		BET		MDV	
1 Nov 15/16	Final	MEM		BDW		MDV	

This document entitled Decommissioning and Demolition of the Holyrood Thermal Generating Station was prepared by Stantec Consulting Ltd. ("Stantec") for the account of Newfoundland and Labrador Hydro (the "Client"). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec's professional judgment in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

Table of Contents

1.0 INTRODUCTION 1
1.1 BACKGROUND 1
1.2 REPORT ORGANIZATION 2

2.0 DECOMMISSIONING AND DEMOLITION AT THE HTGS 3
2.1 REGULATORY REQUIREMENTS OF DECOMMISSIONING 3
2.2 COMPONENTS OF DECOMISSIONING AND DEMOLITON 4
2.2.1 Requirements of the Certificate of Approval to Operate 6
2.2.2 Project Execution 6
2.2.3 Demolition Risk 7
2.3 PHASING OF DECOMMISSIONING AND DEMOLITION 7
2.3.1 Phase 1 7
2.3.2 Phase 2 9

3.0 OPINION OF PROBABLE COST 13
3.1 METHODOLOGY 13
3.2 OPC ASSUMPTIONS, QUALIFICATIONS AND EXCLUSIONS 15
3.3 OPC FOR THE HTGS 16
3.3.1 Demolition Risk 17
3.3.2 OPC Details 17
3.4 PROJECTED CASH FLOW 20

4.0 APPENDICES 21

APPENDIX A DEMOLITION PLAN – SK-001 REV K
APPENDIX B DECOMMISSIONING AND DEMOLITION SCHEDULE
APPENDIX C DECOMMISSIONING AND DEMOLITION METHODOLOGY
APPENDIX D SITE PROJECT MANAGEMENT STAFFING
APPENDIX E HEAD OFFICE PROJECT MANAGEMENT STAFFING

1.0 INTRODUCTION

Newfoundland and Labrador Hydro (NLH) operates a three-unit, 490 MW (gross), thermal generating station at Holyrood, NL which supplies electricity to the Island's grid. With the planned implementation of the Muskrat Falls Generating Facility as part of the Lower Churchill Project, the electrical generation capability of the Holyrood Thermal Generating Station (HTGS) will no longer be required and selected portions of the station will be decommissioned and demolished. In order to complete long term financial planning, NLH is required to determine the cost of decommissioning and demolition the HTGS in order that an asset retirement obligation (ARO) can be estimated. As such, NLH retained the services of Stantec Consulting Ltd. (Stantec) to assist in the preparation of the ARO and this report presents that estimate as well as the assumptions and methodology utilized in developing the estimate.

In general terms, the ARO reflects a decommissioning and demolition that:

1. Complies with current environmental regulatory requirements.

2. Meets constructive obligations made by NLH to provincial regulators and neighbours of the facility.

3. Meets NLH's long term operational strategy for the HTGS.

1.1 BACKGROUND

The HTGS is located in the Town of Holyrood, approximately 50 kilometers south west of St. John's, on Conception Bay. The HTGS site is approximately 40 hectares in size and as shown on SK-001 in Appendix A, includes:

1. A powerhouse that encompasses three generation units (boiler house and turbines/generators), maintenance shops, a water treatment plant and administrative offices.

2. Two, 90 meter and one 110 meter high concrete stacks.

3. A waste water treatment system.

4. Two cooling water intake pump houses.

5. Numerous ancillary buildings and structures including a guardhouse, chemical storage buildings, hydrogen storage building, materials storage warehouse, training building, combustion gas turbine building and pipe shop.

6. A switch yard.

7. A hazardous waste landfill.

8. A Bunker C tank farm (approximately 140,000 cubic meters of storage capacity) and a day tank and diesel fuel storage (approximately 230 cubic meters of storage).

9. A marine jetty and pipeline (approximately 1400 meters in length) for offloading and transporting Bunker C to the tank farm and day tank.

The plant was constructed in two stages - Units #1 and #2 were installed in 1971 and Unit #3 was completed in 1979. In 1988 and 1989, Units #1 and #2 were modified to increase their output to 170 MW, bringing the total generating capacity of the station to 490 MW (gross).

In December 2012, the Government of Newfoundland and Labrador announced official sanction of the Muskrat Falls development as part of the Lower Churchill Falls Project (LCP). Once Muskrat Falls is brought into service in or about 2019, the HTGS will no longer be required to generate electricity; however, it will continue to be used for:

1. Synchronous condensing (SC) for grid voltage control.

2. Operational support of the 123.5 MW Combustion Turbine (CT) situated southeast of the powerhouse.

1.2 REPORT ORGANIZATION

This report presents a Class 3 Opinion of Probable Cost (OPC), for the planned decommissioning and demolition of the HTGS that can be presented to the Public Utilities Board. The OPC or ARO is based on an anticipated operating scenario at the HTGS prescribed by NLH, and is reflective of current regulatory requirements and constructive obligations made by NLH.

Section 1 provides an introduction and a brief overview of the site as it exists today and a general timetable of operations at HTGS, as the LCP comes on line.

Section 2 describes the planned operational functions at the HTGS and the regulatory framework that influences the decommissioning and demolition requirements. The general approach to decommissioning and demolition and project schedule are also presented.

Section 3 presents the OPC and an associated cash flow projection. The costing methodology, including assumptions and exclusions are also presented.

The appendices provide supporting detail.

2.0 DECOMMISSIONING AND DEMOLITION AT THE HTGS

When the LCP is brought into service in 2019, the HTGS will no longer be required to generate electricity; but it will continue to be used for SC operations and support of the CT. Based on these planned operations, NLH will have to consider: a number of federal and provincial Acts, Regulations and Guidelines; the requirements stipulated in their current Certificate of Approval (C of A) issued by the Newfoundland and Labrador Department of Environment and Conservation (NLDEC); and input from regulatory authorities, to define the exact nature, extent and requirements of decommissioning and demolition. NLH will also have to consider the constructive obligations it has made to the regulators and the public regarding the scope and timing of demolition activities. Together, the regulatory requirements and constructive obligations will shape the decommissioning and demolition plan for the HTGS.

2.1 REGULATORY REQUIREMENTS OF DECOMMISSIONING

Based on a review of environmental statutes it appears the legislation identified below will govern the scope and timing of demolition as there is no all-encompassing piece of legislation or policy that stipulates decommissioning and demolition requirements in the Province of Newfoundland and Labrador.

Preliminary discussions were held with representatives of the NLDEC as part of developing the regulatory framework, but it is suggested that additional input from regulators will be required as the project scope is finalized and as planning proceeds to ensure compliance and that all environmental issues are addressed in an appropriate manner.

Based on a review of federal legislation, the Canadian Environmental Assessment Act (CEAA) does not apply because of the nature and scope of the project; nor will an authorization from the federal Department of Fisheries and Oceans be required for the demolition of the marine jetty and causeway. This should be re-confirmed with the appropriate regulatory authorities when the project scope has been clearly defined and the demolition project is imminent.

The following acts/regulations apply:

Environmental Protection Act (SNL – 2002 c E-14.2)

Certificate of Approval to Operate for the HTGS - AA11-085563, issued to NLH pursuant to Section 83 of the Environmental Protection Act.

Appendix A – Part 16 requires compliance with the Storage and Handling of Gasoline and Associated Products Regulations 58/03 which, per Section 25. (3) mandates that the owner of a storage tank system to, within 30 days of abandonment, empty the system of all liquids and vapours and dismantle and remove or dispose of the tank system including the dyke and remove the impacted material to the satisfaction of the NLDEC.

Appendix A - Part 21 requires that a plan to restore areas disturbed by the operation be submitted to the NLDEC ten months before closure.

Appendix B – Provides general objectives for site decommissioning and elements to be included in the decommissioning and restoration plan. Specific clean-up criteria are not provided, but a phased environmental investigation to identify the type, extent and degree of impacts at the site is to be undertaken, and the site is to be restored to a condition acceptable to the NLDEC.

Environmental Assessment Regulations 54/03

Sections 34.(1) and 26 of the regulation, require that the decommissioning of an electric power generating facility be registered as an undertaking.

Storage and Handling of Gasoline and Associated Products Regulations 58/03.

Section 25.(3) of the regulation mandates cleaning and dismantling and disposal of the an above ground petroleum storage tank system.

Canadian Environmental Protection Act

PCB Regulations SOR/2008-273

This federal regulation dictates the management, storage and disposal of PCBs, and Section 19 stipulates that the owner of PCBs shall, within 30 days after they are no longer used; either send them for destruction or for storage at a PCB storage site.

Canadian Navigation Protection Act

This federal regulation requires the submission of a 'Notice of Works' to the Navigation Protection Program (Transport Canada), describing the demolition of the marine jetty and causeway. It is assumed that the work will be deemed as 'not likely to substantially interfere with navigation' and that ministerial approval will not be required.

There are a number of other acts and regulations, in addition to those described above that prescribe specific decommissioning requirements in a variety of areas – i.e. management of asbestos containing materials, or removal of halocarbons; water resource management, etc. While they are not listed, compliance with these requirements is reflected in the decommissioning methodology and the ARO presented herein.

2.2 COMPONENTS OF DECOMISSIONING AND DEMOLITON

In light of the plan to cease electrical generation at the HTGS after the LCP project comes on line, a two phase approach to demolition will be undertaken such that demolition can begin and planned SC and CT operations can continue in a safe manner.

Engineering and planning for Phase 1 will begin in early 2020 with most of the Phase 1 demolition occurring in 2021 and 2023. Phase 2 planning will begin once the SC and CT operations conclude. Once initiated, Phase 2 is expected to be completed within a five year period.

It is assumed that NLH will retain ownership of the entire HTGS site for the foreseeable future and the land use will be classified as 'Industrial'.

The key decommissioning and demolition components are listed below:

Phase 1

1. Cleaning and demolition of Bunker C Tanks #1 to #4.
2. Cleaning and demolition of the Bunker C day tank and fuel additive tank.
3. Cleaning and demolition of the Bunker C pipeline.
4. Demolition of the marine jetty and causeway.
5. Demolition of the three powerhouse stacks and breeching.
6. Demolition of the previously decommissioned 10 MW gas turbine building.
7. Cleaning and removal of seven transformers associated with Units #1 and #2.

Phase 2

1. Asbestos abatement and cleaning of the boilers and boiler house.
2. Demolition of the powerhouse and all internals and equipment.
3. Cleaning and removal of four Unit #3 transformers.
4. Demolition of the two cooling water pumphouses and associated piping.
5. Cleaning and demolition of the waste water treatment plant.
6. Cleaning and demolition of the equalization basins and building.
7. Capping of the hazardous waste landfill and decommissioning of the leachate pond.
8. Cleaning and demolition of the diesel fuel storage tanks serving the powerhouse.

At present there are no plans to demolish the ERT building, hydrogen storage building, shawmont (warehouse) building, chemical storage building, training center, pipe shop building,

the metershop building or the CT. Please refer to drawing SK-001 Rev K, in Appendix A depicting which components are to be demolished and when.

2.2.1 Requirements of the Certificate of Approval to Operate

In addition to the tasks listed above, NLH will be required, as stipulated in their current Certificate of Approval to Operate, to:

1. Complete an intrusive environmental investigation at the HTGS to identify and quantify potential contaminants of concern on the site (Phase II Environmental Site Assessment (ESA)) and to manage any impacted soils and groundwater either through remediation or risk management.

2. Prepare and submit to the NLDEC, a plan to restore areas disturbed by the HTGS operations (closure plan).

3. Register the closure of the HTGS as an undertaking as stipulated in the provincial Environmental Assessment Regulations (EA Registration).

These environmental activities are captured in the project schedule and OPC.

2.2.2 Project Execution

It is expected that the decommissioning and demolition will be planned, managed and overseen by NLH staff, at the plant and head office. In addition, HTGS staff will assist with selected decommissioning activities (chemical removals, sludge management, electrical disconnects/ isolation, boiler wash down, and contract administration, etc.), because experience has shown that this is the most efficient and effective way to complete these power plant related tasks.

It is also assumed that NLH will retain the services of an engineering consultant to assist with: project planning, preparing an EA registration and closure plan, conducting a Phase II ESA and remedial action plan, preparing decommissioning and demolition tender packages and periodic construction monitoring and support.

The demolition (including fuel tank decommissioning and asbestos abatement) will be carried out by a suitably qualified demolition contractor with a documented safety record and expertise in the required demolition components. It is also assumed that inert construction debris generated from the decommissioning and demolition work will be disposed of in a properly constructed and duly permitted on-site facility in the area of the former Bunker C tank farm.

The project task responsibilities are described in Section 2.3.

2.2.3 Demolition Risk

Based on discussions with an experienced demolition contractor, it is recommended that NLH consider the implications of Phase 1 demolition of the three stacks on planned SC and CT operations. While believed to be relatively small, there is a risk that the Phase 1 stack demolition could negatively affect SC operations. The risk can be mitigated by delaying the demolition until the end of SC operations or employing an alternate stack demolition method. This is discussed in further detail in Section 3.

2.3 PHASING OF DECOMMISSIONING AND DEMOLITION

The general sequence of events is presented below and a detailed schedule, including activity durations, is provided in Appendix B. Demolition methodology is provided in Appendix C.

2.3.1 Phase 1

Phase 1 will be conducted over a four year period and will include engineering and planning, a Phase II ESA and remediation/risk assessment, registration of the project for an environmental assessment and execution of decommissioning and demolition tasks by NLH staff and suitably qualified contractors retained through a competitive bidding process. It is envisioned that three separate tenders will be issued to complete the demolition and associated tasks in Phase 1. The majority of the demolition in Phase 1 will be completed by mechanical means with the exception of the three stacks which will be dropped using a controlled, explosive method.

2020

Engineering and planning will be initiated in 2020 and will include preparation of decommissioning and demolition tenders and submission of an environmental assessment registration and closure plan to the NLDEC.

2021

A tender will be awarded for selected demolition work and NLH staff will begin decommissioning activities including removal of:

1. Bulk surplus chemicals remaining in the powerhouse (returned to the supplier or disposed of) in accordance with regulations.

2. Surplus recoverable Bunker C and other hydrocarbons (returned to supplier or disposed of) in accordance with regulations. It is assumed that NLH will manage their fuel inventory such that only one tank will contain fuel at the lowest possible level.

3. Miscellaneous small volumes of chemicals in the powerhouse for disposal in accordance with environmental or hazardous waste regulations, as appropriate.

Once the chemicals and hydrocarbons are removed, the demolition contractor will:

1. Initiate sludge removal, cleaning and demolition of the four Bunker C tanks, the day tank and the fuel additive tank. The tank foundations shall be cleaned, but will remain in place. It is assumed that the demolition contractor will retain the services of a local, licensed petroleum contractor to complete this work.

2. Clean and dispose of the day tank enclosure (above grade knee wall), but the enclosure foundations below grade shall remain.

3. Drain and clean the Bunker C piping system from the marine jetty to the burner fronts of all three boilers.

4. Demolish the cleaned pipeline from the marine jetty to the South wall of the powerhouse and cut and remove the pipeline supports at ground level. The support foundations will remain in place.

5. Demolish and remove the previously decommissioned gas turbine building leaving the floor slab and foundation in place.

6. Drain and remove the seven transformers - including T1, UST-1, RT1, T9, T2, UST 2 and RT2 associated with Units #1 and #2.

As the demolition concludes in the fall of 2021, NLH will complete an intrusive Phase II ESA. All areas of the site that are to be decommissioned or demolished, excluding the diesel oil fuel storage tank area near the pipeline and the transformer area, will be assessed, although focus will be upon Bunker C tank farm, pipeline and area north of the powerhouse. The excluded areas will be assessed at a later date.

Impacted soils and groundwater identified in the Phase II ESA will be managed either through remediation and/or risk management.

At the same time as the intrusive investigations, NLH will also complete a hazardous building materials assessment. This will identify the extent and type of existing hazardous materials and will confirm that debris can be safely disposed of in an on-site facility. It is possible that some material identified in the hazardous building materials assessment may require special disposal at an off-site hazardous waste landfill.

Permitting for the on-site construction and debris (C&D) disposal facility will also be completed in 2021.

2022

As remediation requirements are currently unknown and will not be determined until late 2021 with the completion of a Phase II ESA, no active demolition is planned for 2022. Required soils

and groundwater remediation will be conducted at that time. However, if it is determined that soil and/or groundwater impacts can be successfully managed through risk assessment and/or minimal remedial work, it is possible that the demolition scheduled for 2023 could occur in 2022.

It is also assumed that a tender for the construction of a C&D site in the area of the former Bunker C tank farm, to permit the cost effective on-site management of inert debris, will be awarded and the facility constructed.

2023

In 2023, the final tender of Phase 1 will be awarded for the remaining demolition. This will include:

1. The marine jetty, causeway to the jetty, associated components (shed, lights, electrical, etc.) and the supports. The supports (concrete filled steel tubes) shall be cut at the seabed and the sub-seabed foundations shall remain. Demolition will follow best practices to minimize any environmental impacts on the marine environment, including the use of a silt curtain and debris will be placed in the on-site C&D facility.

2. The three stacks and breeching exterior to the plant. The concrete from the stacks shall be crushed to 6" minus and disposed of in the on-site C&D facility. The openings in the north end of the boiler house created by the removal of the breeching shall be re-sided and the building made weather tight.

Following the placement of debris in the C&D facility, it shall be covered to limit infiltration of precipitation and snow melt. The closure of the C&D facility will conclude Phase 1 activities.

2.3.2 Phase 2

Phase 2 will be conducted over a five year period and will include engineering and planning, environmental site assessment and remediation/risk assessment, and execution of decommissioning and demolition tasks by NLH staff and suitably qualified contractors retained through a competitive bidding process. It is envisioned that a single contract will be called for the demolition work described herein. Similar to Phase 1, most of the demolition work will be completed by mechanical means, but the boiler house and boilers will be dropped using explosives. A separate contract will be called, as required, for environmental remedial work.

Year 1

Engineering and planning will be initiated in year 1 and will include preparation of a decommissioning and demolition tender.

Year 2

A tender will be awarded for decommissioning and demolition and NLH staff will begin decommissioning activities in the turbine hall and balance of the powerhouse, including removal of:

1. Surplus chemicals (returned to the supplier or disposed of) in accordance with regulations.

2. Surplus recoverable diesel fuel (returned to supplier or disposed of) in accordance with regulations.

3. Miscellaneous small volumes of chemicals and ozone depleting substances for disposal in accordance with environmental or hazardous waste regulations, as appropriate.

Once the chemicals and hydrocarbons are removed by NLH, the contractor will complete environmental decommissioning and asbestos abatement tasks. During the removal of asbestos containing materials (ACM), NLH will engage the services of a specialized contractor to monitor the abatement to ensure worker safety and regulatory compliance. They will also sample suspected ACM as discovered during the demolition.

The contractor will:

1. Clean and demolish the two above ground, horizontal diesel fuel oil storage tanks and associated piping near the Bunker C tank farm. The foundations shall be cleaned, but remain in place.

2. Drain and remove the four remaining transformers T3, UST-3, SST1-2 and SST 3-4 for disposal at an approved facility.

3. Remove and dispose of mercury containing devices and lights for off-site disposal.

4. Drill low points and drain residual product, flush and clean the lines of all other oil and chemical systems previously drained in Phase 1.

5. Remove by hand, friable ACM that may be contaminated with ash (heavy metals) and could have a very low pH. The contractor will follow Type 3 removal procedures, including the off-site disposal of cladding and insulation from Boilers 1 and 2. Boiler 3 cladding and insulation is not assumed to be ACM, but must be removed as Type 3 and disposed of as ACM, due to ash contamination.

6. Manage ACMs that are discovered as demolition proceeds.

NLH staff will wash down Boilers #1 and #2 and the building interior in year 2 after asbestos abatement procedures are carried out by the contractor. Boiler #3 wash down will occur in year 3 as the ACM abatement for that particular unit will not be completed until late in year 2.

NLH will also engage a consultant to complete an intrusive Phase II ESA in the area of the diesel oil fuel storage tanks near the pipeline and in the transformer area. Impacted soils and groundwater will be managed either through remediation and/or risk management.

Year 3

NLH staff will complete the wash down of Boiler #3 and plug the floor drains/trenches in the powerhouse at grade level, and the contractor will continue to prepare for the demolition of the powerhouse. The contractor will:

1. Remove the non-friable Galbestos siding on the powerhouse. It is assumed that mechanical removal of non-friable Galbestos will be permitted and it will be disposed of in the on-site C&D site.

2. Mechanically demolish the turbine hall and equipment and equipment foundations within. The equipment footings/foundations will be removed to permit the boilers to drop to grade to facilitate their demolition. The floor slab will remain.

3. Drop the boiler building using explosives and then complete the demolition by mechanical means. The floor slab of the boiler building and equipment foundations shall remain. Concrete from demolition of the powerhouse will be crushed to 6" minus and will be placed in the on-site C&D site.

Year 4

Continuing under the same contract, the demolition contractor will clean the trenches and sumps in the power house and then move to the ancillary buildings and infrastructure situated north of the powerhouse. Specifically, the two cooling water pumphouses, the equalization basin building, and the waste water treatment building will be demolished.

NLH staff will be responsible for removing any sludge remaining in the waste water treatment and equalization basin buildings and leachate pond in advance of demolition.

The contractor will:

1. Steam clean or power wash trenches and sumps in the powerhouse.

2. Remove the non-friable Galbestos siding on cooling water pumphouse 2, for on-site disposal.

3. Demolish both cooling water pumphouses. The floor slabs, wet wells and sub surface foundations shall remain, but the wet wells and intakes will be backfilled.

4. Demolish the equalization basins and building, and the waste water treatment equipment and building. The floor slab, foundations and equipment foundations shall remain.

5. Dewater and backfill the leachate lagoon.

6. Cap and close the hazardous waste landfill.

7. Excavate, open and backfill all piping greater than 24" in diameter, including the seal pits, utilidors, oil/water separators and the wet wells.

8. Place concrete caps in the CW inlets and outlet piping. The rip rap breakwater shall remain intact.

9. Cap and close C&D facility.

Once the buildings north of the powerhouse are removed, NLH will conduct an intrusive Phase II ESA in this area.

Year 5

Any impacted soils and groundwater identified in the Phase II ESA will be managed either through remediation and/or risk management. If required, the hazardous waste landfill will be temporarily reopened for the economical on-site disposal of impacted soils and then recapped.

Final closure reporting will also be completed in year 5.

As stated earlier, based upon current assumptions, the Holyrood site is expected to remain an industrial site. As a result, at this time there are no legal or constructive requirements to remove the remaining assets in Phase 2. However, the scope of the required decommissioning could change based upon changes in assumptions, updates in regulations or directions from governing agencies such as the NLDEC. It is recommended that as the assumptions and requirements of the environmental regulators become known, the estimate be further refined for Phase 2.

3.0 OPINION OF PROBABLE COST

Section 3 presents the opinion of probable cost (OPC) of the planned decommissioning and demolition and an associated cash flow projection based upon the proposed long term operational objectives and the legislative and constructive obligations as described in Section 2. The costing methodology, including assumptions and exclusions are also presented.

3.1 METHODOLOGY

The OPC was developed by first defining the operational requirements of NLH and the legislative and constructive constraints governing decommissioning and demolition. Once these were established, an approach and schedule for the demolition was developed and budget pricing from a nationally based contractor with recent experience in demolishing two similarly sized thermal generating stations in Atlantic Canada and a 2400 MW plant in Ontario was sought. In addition to budget pricing from the demolition contractor, the OPC was developed using budget pricing from local suppliers and contractors, salary and labour burden data from NLH, and in house experience with demolition pricing.

The OPC was sub-divided into 5 groupings and the methodology for the development of the OPC within each group is presented below.

Environmental Compliance and Studies

Environmental Compliance and Studies includes those tasks to be completed to ensure the appropriate environmental permits, studies and assessments are completed, including hazardous materials surveys, asbestos monitoring, ESAs, environmental remediation, EA registration, landfill permitting and closure reporting. This grouping also includes an allowance for future studies.

Development of environmental compliance costs were based upon in house experience with similar type projects in NL, DELC requirements, and local laboratory and equipment rental costs.

No intrusive environmental studies were conducted as part of this cost estimate and only limited consultation with environmental regulators has been conducted to date. It is possible that requirements beyond those identified in current legislation may be imposed upon the project. Nevertheless, allowances to register the project under provincial environmental assessment legislation; complete Phase II ESAs, remediation and risk assessments; and to comply with existing regulatory requirements are carried in the OPC. A cost to complete a full environmental assessment is not included, as it is not known if this will be required.

Environmental Decommissioning

Environmental decommissioning includes chemical and fuel removals, tank and pipeline cleaning, asbestos abatement, development of a C&D landfill, hazardous waste management/disposal and closure of the landfills.

Development of decommissioning costs were based on the demolition contractor's experience, local contractor pricing, and estimated time and salary and labour burden costs for NLH staff to support and/or complete in plant tasks. Decommissioning includes ACM abatement, cleaning of petroleum storage tanks and removal of transformers, etc.

NLH time to support the decommissioning was also included and was based on Stantec experience with similar type demolition projects in Atlantic Canada. The following on-site staffing compliment is anticipated: shift supervisors/operators, chemical technicians/environmental management system coordinators, electricians, and utility/laborers. Staff responsible for contract administration will be full time, others will be part time. Further details on the required site support times are provided in Appendix D.

Demolition

Demolition includes the dismantling of site infrastructure for off-site recycling or disposal or on site landfilling. The infrastructure to be demolished is illustrated in SK-001 in Appendix A.

In order to develop the demolition cost, an experienced contractor visited the HTGS site and was provided with facility drawings, material quantities and photographs. The contractor pricing was supplemented by in house experience with demolition and components of the contractor's pricing were cross checked with budget pricing from local environmental and hazardous waste contractors. All sub-contractors to the general demolition contractor were assumed to be marked up at 15%, per the industry standard.

In addition, quantities and unit rates for civil works during demolition were developed, including: the C&D landfill and landfill and leachate pond capping, excavation and backfilling of voids (equalization basis, utilidors, seal pits, cooling water pumphouses buried piping) and installation of concrete caps on the cooling water intakes and discharges.

Owner's Management and Engineering Costs

Owner's management and engineering costs include direct and indirect, on site and head office project management and engineering fees associated with preparation of tender documents for the decommissioning and demolition, assistance during tendering, bid review, project planning assistance, and support during construction.

Development of Owner's costs for direct, on-site and head office project management and indirect project management were based on input from NLH and current NLH salary and labour burden costs. The direct project management staffing from site is assumed to include: a site

supervisor, administrative assistant, a safety specialist and two plant engineers. Head office direct project management staffing includes: a project manager, two project engineers, an environmental specialist, a safety hygienist, communications personnel and a scheduler, none of whom are dedicated to the project on a full time basis.

Indirect, head office, project management staff includes legal support, safety, human resources and procurement assistance at an assumed percentage of the overall project costs.

Further details on the required project management support time for direct Head Office and on-site staff is provided in Appendices D and E respectively.

Engineering costs of 15% of project costs were based on in house experience with similar decommissioning and demolition projects in New Brunswick. Full time, on-site engineering support during construction is not included in the estimate.

Contingencies

Contingencies are included in the OPC as monies that will be expended during the course of the project, but are currently unidentified. Contingencies have been added to the OPC presented herein and vary in each grouping with the degree of confidence in the estimate, the lower the contingency, the higher the anticipated accuracy.

Scrap Metal and Salvage

As directed by NLH, the OPC did not capture any value for remaining equipment or scrap. Given the current project planning horizon and the volatility in scrap metal pricing, it is believed that this is a most prudent costing approach.

3.2 OPC ASSUMPTIONS, QUALIFICATIONS AND EXCLUSIONS

The OPC presented herein is based upon the following assumptions, exclusions and/or qualifications:

1. Environmental assessment and remediation costs are based on an assumed level of effort and that on-site management of impacted soils will be permitted.

2. Environmental assessment and remediation of areas outside of the HTGS have not been included.

3. Decommissioning of the air quality monitoring stations associated with the HTGS has not been included.

4. Remaining equipment has no salvage value.

5. Metals recovered in the demolition have no assigned scrap value in the estimate.

6. NLH will capture the sunk cost of the unusable Bunker C fuel, as a write off within their internal accounting systems. The disposal cost of unusable fuel is included in the OPC.

7. All costs are presented in 2016 dollars (no escalation).

8. Union rates for labour, with no room and board allowance are used for NLH and contractor staffing.

9. Taxes are not included.

10. Maintenance and/or modifications to the water treatment, circulating cooling water system, and waste water treatment systems and equalization basins are not included.

3.3 OPC FOR THE HTGS

The OPC for the Phase 1 decommissioning and demolition of the HGTS is $15,237,000 and a breakdown of the cost is provided in Table 1 below.

Table 1: Summary of Phase 1 Decommissioning and Demolition Costs

OPC Components	Phase 1	% of Total
Environmental Compliance and Studies	$1,377,000	9
Environmental Decommissioning	$2,988,000	20
Demolition	$4,400,000	29
Owner's Management and Engineering	$4,563,000	30
Contingency	$1,909,000	12
Total	**$15,237,000**	**100**

Detailed breakdowns are provided in Section 3.3.2.

The OPC for the Phase 2 decommissioning and demolition of the HGTS is $25,839,000 and a breakdown of the cost is provided in Table 2 below.

It is noted however that, because the scope of Phase 2 activities could change based upon changes in assumptions, updates in regulations or directions from governing agencies such as the NLDEC, the Phase 2 costs are provided for information and comparative purposes only; and will not be included in the ARO submitted to the PUB.

Table 2: Summary of Phase 2 Decommissioning and Demolition Costs

OPC Components	Phase 2	% of Total
Environmental Compliance and Studies	$ 367,000	4
Environmental Decommissioning	$5,879,000	22
Demolition	$9,143,000	33
Owner's Management and Engineering	$7,368,000	29
Contingency	$3,082,000	12
Total	**$25,839,000**	**100**

Detailed breakdowns are provided in Section 3.3.2.

3.3.1 Demolition Risk

As noted in Section 2, there is a risk that the powerhouse could be damaged and SC and CT operations be impacted should the three stacks be demolished in Phase 1 as opposed to a later time at the planned end of SC operations. This is because of the potential for flying debris to damage the roof and equipment within the adjacent powerhouse. There is also a risk that the controlled explosive demolition could fail and the stacks would remain standing but in a weakened and unsafe state.

The risk of damage or failure could be mitigated by delaying the demolition until the end of SC operations or by employing an alternate stack demolition procedure utilizing specialized wall climbing scaffolding for the upper portions of the stack. It is also anticipated that windy conditions would require many starts and stops to the operations, increasing standby times and the duration of the work.

3.3.2 OPC Details

This section provides a detailed breakdown of decommissioning and demolition costs by phase and illustrates contractor and NLH costs. Table 3 provides a detailed breakdown of the Phase 1 and Table 4 provides the breakdown for Phase 2.

Table 3: Phase 1 Decommissioning and Demolition Costs

	Phase 1 - 2020 -2023	
1	**A. Environmental Compliance and Studies**	**Total**
2	Hazardous Building Materials Survey	$ 30,000
3	Permitting - EA Registration, Closure Plan and C&D Landfill Permitting	$ 60,000
4	Phase II Environmental Site Assessment	$ 239,000
5	Environmental Risk Assessment and Remediation	$ 698,000
6	Future Studies	$ 350,000
7	Sub-total	$ 1,377,000
8	**B. Environmental Decommissioning**	**Total**
9	Cleaning of Bunker C, day and additive tanks and associated pipeline	$ 2,400,000
#	Bulk, small volume chemical removal and sweep	$ 173,515
#	NLH staff support, electrical disconnects/isolation activities, contract admin	$ 116,370
#	Drain 7 transformers and dispose of oils and carcasses	$ 85,293
#	Develop C&D disposal site and parital cap	$ 180,040
#	Prep of stack fall area	$ 32,903
#	Sub-total	$ 2,988,121
#	**C. Demolition**	**Total**
#	Mobilization and demobilization	$ 75,000
#	Demolish Bunker C tanks, day and fuel additive tanks and pipeline	$ 810,000
#	Demolish marine jetty and access bridge	$ 1,650,000
#	Demolish stacks, breeching and protection of powerhouse/ancillary bldgs	$ 1,830,000
#	Repair, install new siding in boiler house wall at breeching locations	$ 9,900
#	Demolish decommissioned gas turbine building	$ 25,000
#	Sub-total	$ 4,399,900
#	**D. Owner's Management and Engineering Costs**	**Total**
#	On Site Project Management Team	$ 1,352,743
#	Head Office Project Management Team	$ 1,369,218
#	Head Office (legal, safety, HR, procurement at 6% A, B and C)	$ 525,901
#	Engineering Support (15% of A, B and C)	$ 1,314,753
#	Sub-Total	$ 4,562,615
#	**E. Contingency**	**Total**
#	Environmental Planning Contingency @ 25%	$ 344,250
#	Decommissioning Contingency @ 15%	$ 448,218
#	Demolition Contingency @ 15%	$ 659,985
#	Owner's Costs Contingency @10%	$ 456,262
#	Sub-total	$ 1,908,715
#	**Phase 1 TOTAL DECOMMISSIONING AND DEMOLITION COST**	**$ 15,236,351**

Table 4: Phase 2 Decommissioning and Demolition Costs

#	**Phase 2**	
#	**A. Environmental Compliance and Studies**	**Total**
#	Environmental Liasion	$ 50,000
#	Asbestos abatement monitoring and sampling	$ 100,000
#	Phase II Environmental Site Assessment	$ 50,000
#	Environmental Risk Assessment and Remediation	$ 117,380
#	Post closure reporting	$ 50,000
#	Sub-total	$ 367,380
#	**B. Environmental Decommissioning**	**Total**
#	Diesel fuel recovery (Credit for fuel = cost of removal)	$ -
#	Cleaning of diesel fuel tanks	$ 7,100
#	Chemical/sludge removal, drain oils, plug drains,clean oily water separators	$ 112,615
#	Washdown of boilers and building	$ 110,400
#	NLH staff support, electrical disconnects, chem techs and contract admin	$ 1,898,341
#	Drain 4 transformers and dispose of oils and carcasses	$ 48,739
#	Drilling lines, removal of chemicals and mercury containing items and lights	$ 486,736
#	Abatement of asbestos containing materials (boilers and boiler cladding)	$ 2,259,009
#	Abatement of asbestos containing materials (defined during demolition)	$ 100,000
#	Management of lead and/or zinc impacted paint	$ 50,000
#	Close C&D disposal site	$ 327,533
#	Close hazardous waste landfill and backfill lagoon	$ 478,710
#	Sub-total	$ 5,879,183
#	**C. Demolition**	**Total**
#	Contractor mobilization and demobilization	$ 306,605
#	Demolish diesel fuel tanks	$ 10,000
#	Demolish turbine hall and T/G units	$ 1,737,000
#	Demolish boiler house and units	$ 6,103,042
#	Demolish cooling water pumphouses	$ 167,000
#	Demolish WWT and equilzation basin buildings	$ 95,139
#	Backfill voids, trenches, cap cooling water intake/outlets and wetwells	$ 723,805
#	Sub-total	$ 9,142,591
#	**D. Owner's Management and Engineering Costs**	**Total**
#	On Site Project Management Team	$ 2,246,400
#	Head Office Project Management Team	$ 1,890,000
#	Head Office (legal, safety, HR, procurement at 6% A, B and C)	$ 923,349
#	Engineering Support (15% of A, B and C)	$ 2,308,373
#	Sub-Total	$ 7,368,122
#	**E. Contingency**	**Total**
#	Environmental Planning Contingency @ 25%	$ 91,845
#	Decommissioning Contingency 15%	$ 881,877
#	Demolition Contingency @ 15%	$ 1,371,389
#	Owner's Costs Contingency @10%	$ 736,812
#	Sub-total	$ 3,081,923
#	**Phase 2 TOTAL DECOMMISSIONING AND DEMOLITION COST**	**$ 25,839,200**

3.4 PROJECTED CASH FLOW

The projected cash flow for the two project phases is provided in Tables 4 and 5 below. The contingency is distributed across the duration of the project on a weighted basis.

Table 5: Phase 1 Cash Flow – 2020-2023

Year	Total
1	$1,554,000
2	$5,759,000
3	$2,255,000
4	$5,668,000
TOTAL	**$15,236,000**

Table 6: Phase 2 Cash Flow

Year	Total
1	$2,300,000
2	$6,227,000
3	$10,956,000
4	$4,237,000
5	$2,119,000
TOTAL	**$25,839,000**

4.0 APPENDICES

Appendix A Demolition Plan – SK-001 Rev K

Appendix B Decommissioning and Demolition Schedule

Appendix C Decommissioning and Demolition Methodology

Appendix D Site Project Management Staffing

Appendix E Head Office Project Management Staffing

APPENDIX A

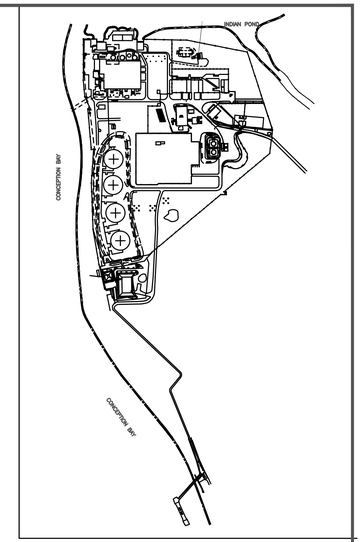
Demolition Plan – SK-001 Rev. K

PUMPHOUSE #2
INDIAN POND
WASTE WATER TREATMENT EQUALIZATION BASINS
DAY TANK
ABANDONED SEPTIC FIELD
PUMPHOUSE #1
NEW SEPTIC SYSTEM
WASTE WATER TREATMENT PLANT
#1 #2 #3
CHEMICAL STORAGE BUILDING
BOILERHOUSE TURBINE/ GENERATORS
MAINTENANCE BUILDINGS
BOILER STACKS
1 SK-001
SEE DETAIL 1 FOR TRANSFORMER DECOMMISSIONING
TRAINING CENTER
COOLING WATER DISCHARGE
ROADWAY
HYDROGEN STORAGE BUILDING
SHAWMONT BUILDING (WAREHOUSE)
ERT BUILDING
CTG
DECOMMISSIONED GAS TURBINE
BUNKER 'C' LINE BETWEEN TANK FARM AND DAY TANK
BLACK START GENERATORS
DIESEL FUEL TANKS
SWITCH YARD
TANK #1
CONCEPTION BAY
TANK FARM
16"ø BUNKER 'C' PIPELINE FROM JETTY
HAZARDOUS WASTE LANDFILL (RETAIN & CAP)
LEACHATE HOLDING POND

N

RT1 RT2
UST1 T9 UST2 SST12 UST3 SST34
T1 T2 T3
ROADWAY

DETAIL 1
SCALE: NTS SK-001
TRANSFORMER DECOMMISSIONING



KEY PLAN

16"ø BUNKER 'C' PIPELINE
CAUSEWAY
JETTY HEAD

LEGEND

- DEMOLISH AND/OR DECOMMISSION BUILDINGS AND EQUIPMENT ~PHASE 1
- DEMOLISH AND/OR DECOMMISSION BUILDINGS AND EQUIPMENT ~PHASE 2
- TO REMAIN
- MANAGED BY OTHERS TRANSMISSION ASSET

PRELIMINARY
FOR INFORMATION ONLY

DWG.NO.	TITLE
REFERENCE DRAWINGS	

NO.	DATE	DESCRIPTION	DWN.	DESIGN.	CHK.	APP'D
J	2016-06-23	GENERAL REVISION	MEO			
H	2016-06-03	GENERAL REVISION	JRC			
G	2016-05-06	GENERAL REVISION	JRL			
F	2016-05-04	GENERAL REVISION	JRL			
E	2016-04-21	GENERAL REVISION	JJB			
D	2016-04-14	GENERAL REVISION	JJB			

REVISIONS

Stantec | P.M. MEM | P.T.
JOB No. | DWG. No.

This Drawing contains intellectual property of Nalcor Energy and shall not be copied or distributed in whole or in part without prior written consent from Nalcor Energy. Use of the drawing shall be restricted to purposes of prosecution of a contract with Nalcor Energy.

newfoundland labrador hydro a nalcor energy company

Newfoundland and Labrador Hydro

HOLYROOD THERMAL GENERATING STATION DEMOLITION PLAN

ELECT.	SCALE:	NTS
CIVIL	DESIGNED:	MDV
TRANS.	DRAWN:	JJB
MECH.	DATE:	2016-04-04
P&C	CHECKED:	
TELC.	APPROVED:	

W.O. NO.
DWG. NO. SK-001
REV. K

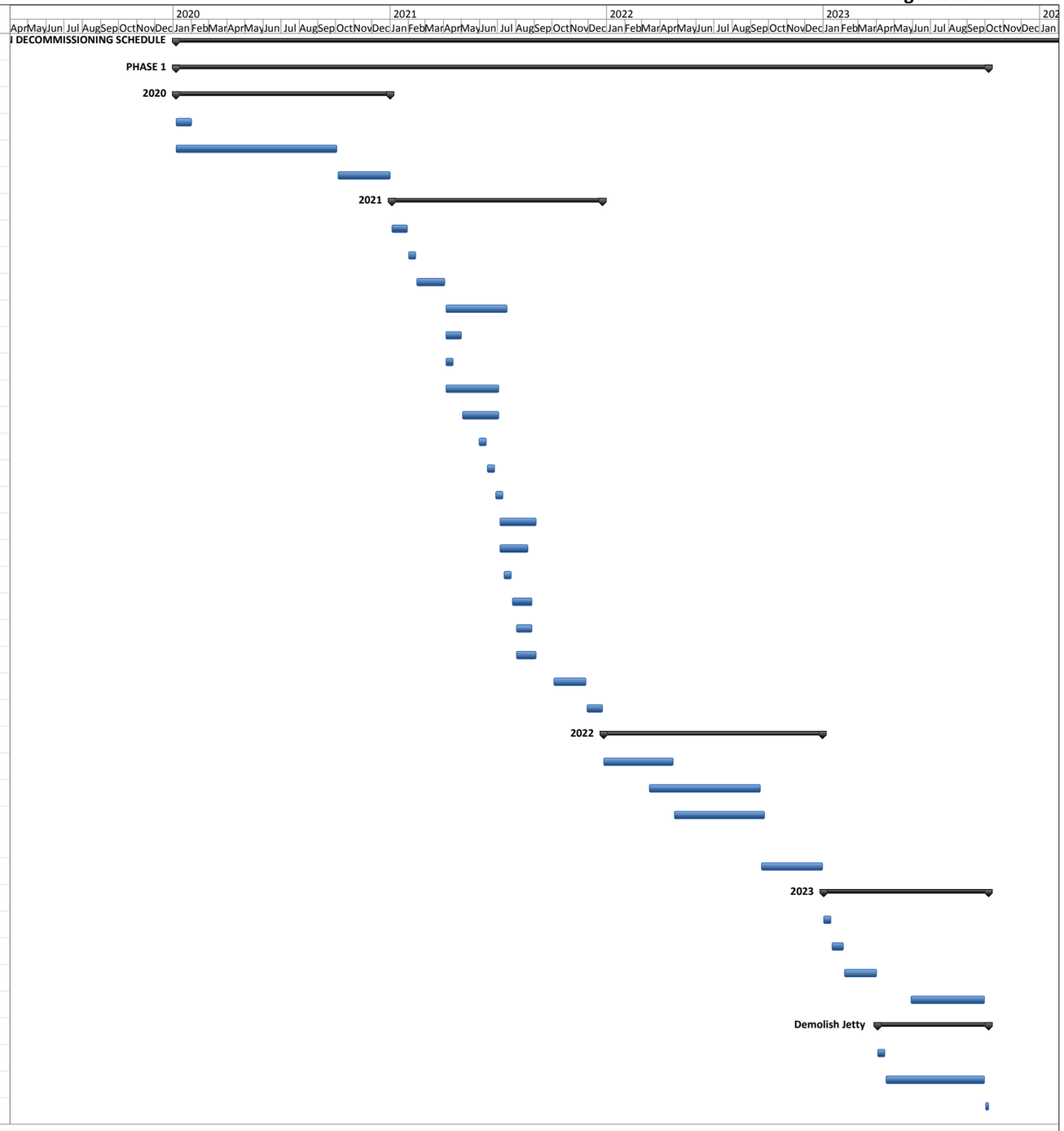
Jul 25, 2016 2:14pm jcrawford
C.A.D.

V:\1335\active\133547213\8_mechanical\3_drawing\133547213-SK001.dwg

APPENDIX B

Decommissioning and Demolition Schedule

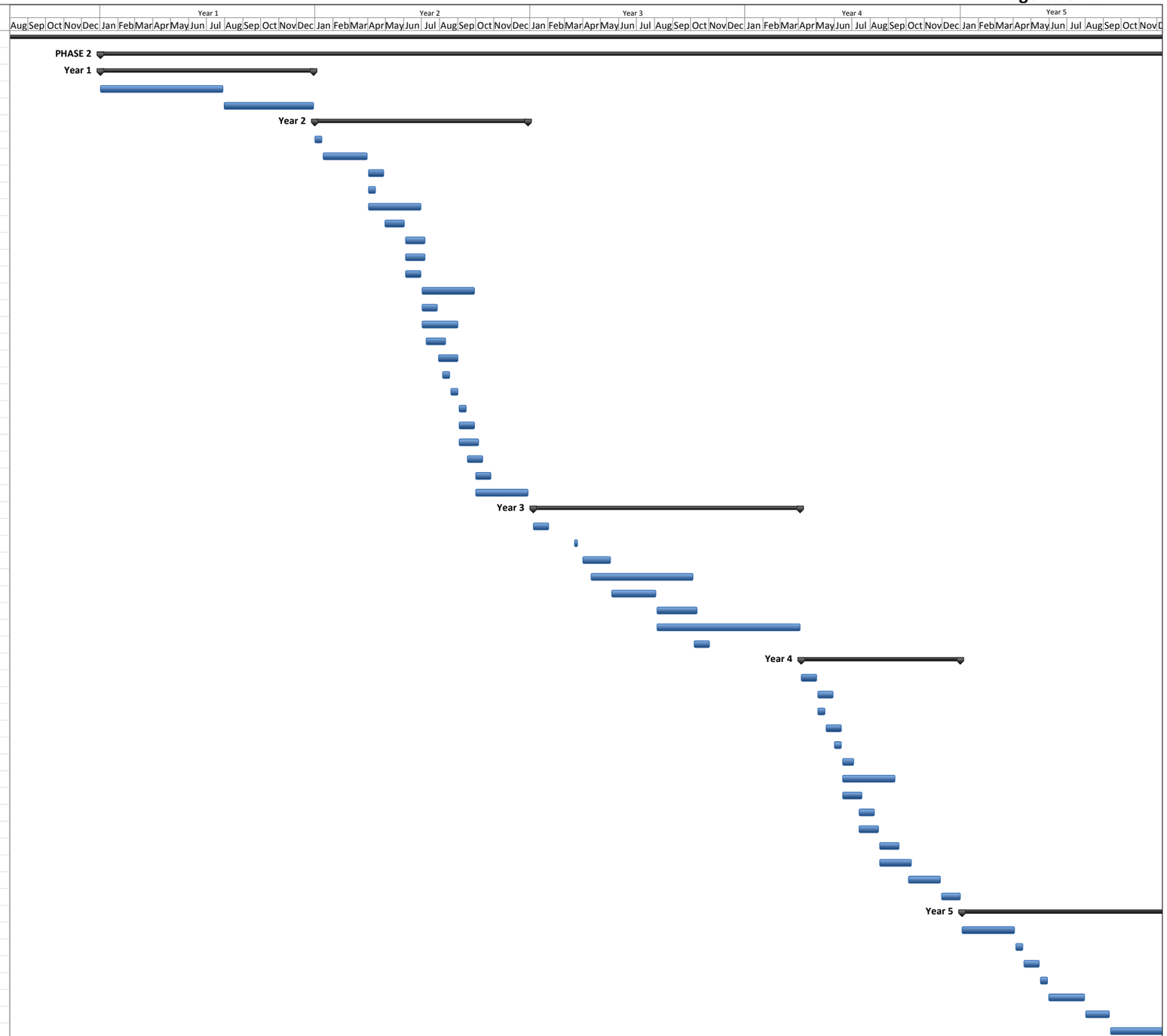
ID	Task Name	Duration	Start	Finish
1	**HOLYROOD THERMAL GENERATING STATION DECOMMISSIONING SCHEDULE**	**7825 days**	**Mon 01/06/20**	**Fri 12/31/49**
2	**PHASE 1**	**980 days**	**Mon 01/06/20**	**Fri 10/06/23**
3	**2020**	**259 days**	**Mon 01/06/20**	**Thu 12/31/20**
4	Submit Closure Plan and Register Project with Environment	4 wks	Mon 01/06/20	Fri 01/31/20
5	Engineering & Spec Development, Tank Farm & Pipeline Demolition	39 wks	Mon 01/06/20	Fri 10/02/20
6	Hydro Tender Process	12.8 wks	Mon 10/05/20	Thu 12/31/20
7	**2021**	**255 days**	**Mon 01/04/21**	**Fri 12/24/21**
8	Hydro Tender Process (Continued)	4 wks	Mon 01/04/21	Fri 01/29/21
9	Contract Signed	2 wks	Mon 02/01/21	Fri 02/12/21
10	Contractor Submittal Period	7 wks	Mon 02/15/21	Fri 04/02/21
11	Hydro Bulk Chemical Removal, Chemical Sweep, Drain Bunker C fuel, Trip Power to Select Equipment	15 wks	Mon 04/05/21	Fri 07/16/21
12	Hydro - Pumpout Bunker C Tanks	4 wks	Mon 04/05/21	Fri 04/30/21
13	Clean Day & Fuel Additive Tanks	2 wks	Mon 04/05/21	Fri 04/16/21
14	Drain & Clean Pipeline	13 wks	Mon 04/05/21	Fri 07/02/21
15	Clean Bunker Tanks 1 Through 4	9 wks	Mon 05/03/21	Fri 07/02/21
16	Demolish Day and Fuel Additive Tanks	2 wks	Mon 05/31/21	Fri 06/11/21
17	Clean Day Tank Pad Walls & Foundations	2 wks	Mon 06/14/21	Fri 06/25/21
18	Demolish Day Tank Pad Walls	2 wks	Mon 06/28/21	Fri 07/09/21
19	Demolish Pipeline	9 wks	Mon 07/05/21	Fri 09/03/21
20	Demolish Bunker Tanks 1 Through 4	7 wks	Mon 07/05/21	Fri 08/20/21
21	Demolish 10 MW CT	2 wks	Mon 07/12/21	Fri 07/23/21
22	Drain Transformers	5 wks	Mon 07/26/21	Fri 08/27/21
23	Clean Tank Foundations	4 wks	Mon 08/02/21	Fri 08/27/21
24	Disassemble Transformers & Remove From Site	5 wks	Mon 08/02/21	Fri 09/03/21
25	ESA, Entire Site Except Transformers, #2 Oil Tanks & Yard North of Stacks	8 wks	Mon 10/04/21	Fri 11/26/21
26	Prepare Tender & Award for Remedial Work (If Required) & To Convert Tank Farm to C&D Site	4 wks	Mon 11/29/21	Fri 12/24/21
27	**2022**	**265 days**	**Mon 12/27/21**	**Fri 12/30/22**
28	Prepare Tender & Award for Remedial Work, If Required & To Convert Tank Farm to C & D Site (Continued)	17 wks	Mon 12/27/21	Fri 04/22/22
29	Prepare Tender Stack & Jetty Demoltion	27 wks	Mon 03/14/22	Fri 09/16/22
30	Site Remedial Work (If Required) And Convert Tank Farm To C&D Site, Laydown Fabric & Pit Run Gravel North Of Stacks (If Required)	22 wks	Mon 04/25/22	Fri 09/23/22
31	Hydro Tender Process	15 wks	Mon 09/19/22	Fri 12/30/22
32	**2023**	**200 days**	**Mon 01/02/23**	**Fri 10/06/23**
33	Hydro Tender Process (Continued)	2 wks	Mon 01/02/23	Fri 01/13/23
34	Contract Signed	3 wks	Mon 01/16/23	Fri 02/03/23
35	Contractor Submittal Period	8 wks	Mon 02/06/23	Fri 03/31/23
36	Drop Stacks & Demolish Breeching	18 wks	Mon 05/29/23	Fri 09/29/23
37	**Demolish Jetty**	**135 days**	**Mon 04/03/23**	**Fri 10/06/23**
38	Install Silt Curtain	2 wks	Mon 04/03/23	Fri 04/14/23
39	Demolish Jetty / Access Bridge	24 wks	Mon 04/17/23	Fri 09/29/23
40	Remove Silt Curtain	1 wk	Mon 10/02/23	Fri 10/06/23



Project: sch_pvs_25072016_rev1.
Date: Mon 07/25/16

Task	Summary	External Milestone	Inactive Summary	Manual Summary Rollup	Finish-only
Split	Project Summary	Inactive Task	Manual Task	Manual Summary	Deadline
Milestone	External Tasks	Inactive Milestone	Duration-only	Start-only	Progress

ID	Task Name	Duration
1	**HOLYROOD THERMAL GENERATING STATION DECOMMISSIONING SCHEDULE**	**7825 days**
41	**PHASE 2**	**1305 days**
42	**Year 1**	**260 days**
43	Engineering & Spec Development, Powerhouse Demolition	30 wks
44	Hydro Tender Process	22 wks
45	**Year 2**	**260 days**
46	Contract Signed	2 wks
47	Contractor Submittal Period	11 wks
48	Hydro Remove Bulk Chemicals	4 wks
49	Hydro Chemical Sweep	2 wks
50	Abatement, Unit 1 Boiler	13 wks
51	Drill Low Points & Drain Oil and Chemical, Remove Haz Mat Items - Unit 2 B/B	5 wks
52	Drill Low Points & Drain Oil and Chemical, Remove Haz Mat Items - Unit 3 B/B	5 wks
53	Hyrdo Wash Turbine Building & Other Plant Areas	5 wks
54	Drain Transformer Oil & Remove From Site	4 wks
55	Abatement, Unit 2 Boiler	13 wks
56	Hydro Wash Boiler 1	4 wks
57	Shipout Transformer	9 wks
58	Drill Low Points & Drain Oil and Chemical, Remove Haz Mat Items - T/G	5 wks
59	Drill Low Points & Drain Oil and Chemical, Remove Haz Mat Items - Unit 1 B/B	5 wks
60	Clean #2 Tanks & Pads	2 wks
61	Demolish #2 Tanks	2 wks
62	Phase 2 ESA Transformer & #2 Oil Tank Area	2 wks
63	Abatement, Vacc Clean System & Transite	4 wks
64	Drill Low Points & Drain Oil and Chemical, Remove Haz Mat Items - Common	5 wks
65	Possible Remediation Transformer & #2 Oil Tank Area	4 wks
66	Hydro Wash Boiler 2	4 wks
67	Abatement, Unit 3 Boiler	13 wks
68	**Year 3**	**325 days**
69	Hydro Wash Boiler 3	4 wks
70	Hydro Plug Floor Drains	1 wk
71	Galbestos Removal T/B	7 wks
72	Demolish T/B	25 wks
73	Galbestos Removal B/B	11 wks
74	Dispose of Crushed Concrete in C&D Site	10 wks
75	Demolish B/B	35 wks
76	Drop B/B	4 wks
77	**Year 4**	**194 days**
78	Clean Powerhouse Trenches	4 wks
79	Clean Buried Piping	4 wks
80	Galbestos Removal Stage 2 CW Pumphouse	2 wks
81	Demolish CW Pumphouses	4 wks
82	Dewater Leachate Lagoon	2 wks
83	Backfill Leachate Lagoon	3 wks
84	Backfill Below Grade Structures & Burried Pipe	13 wks
85	Hydro Staff Move Sludge To Landfill	5 wks
86	Cap Hazardous Waste Landfill	4 wks
87	Demolish WWTP and EQ Basins	5 wks
88	Phase 2 ESA, Yard North Of Stacks	5 wks
89	Cap Tank Farm C&D site	8 wks
90	Engineering & Tender Preparation, Remediation Of Yard North Of Stacks	8 wks
91	Hyrdo Tender Process	4.8 wks
92	**Year 5**	**260 days**
93	Hydro Tender Process (Continued)	13 wks
94	Sign Contract	2 wks
95	Contractor Submittal Period	4 wks
96	Open Cap In Hazardous Waste Landfill	2 wks
97	Remediate Yard North Of Stacks	9 wks
98	Close Cap, Hazardous Waste Landfill	6 wks
99	Environmental Closure Reporting	15.8 wks



Project: sch_pvs_25072016_rev1.
Date: Mon 07/25/16

Task | Split | Milestone | Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | Deadline | Progress

APPENDIX C

Decommissioning and Demolition Methodology

HOLYROOD THERMAL GENERATING STATION DECOMMISSIONING

DEMOLITION METHODOLOGY

APPENDIX C

A) Phase 1 - April to December, 2021

1. Hydro staff will drain and collect bulk chemicals, fuel additive and lube oils from the plant equipment not required to maintain synchronous condenser operations or plant building integrity. These will be removed from site by a local disposal/recycle contractor.

2. Fyrquel will be drained by hydro staff and returned to the supplier.

3. Surplus recoverable Bunker C fuel will be drained from the fuel feed system by hydro staff to the extent possible and will be removed from site by a local disposal/recycle contractor.

4. Hydro staff will collect containers of surplus chemical, oils, paints and like products and have them removed from site by a local disposal/recycle contractor.

5. Hydro staff can trip power feeds to various disused pieces of equipment.

6. Completing items 2 through 6 above will result in the plant being in a safer condition from the standpoint of potential spills or accidents and fire loading.

7. Demolish all 4 Bunker C storage tanks. Assume that the contents of the tanks have been consumed to the 3 foot level. A local contractor will set up temporary piping and pumping to transfer the remaining useable bunker from the tanks to tanker trucks for sale to an offsite user. The oil level will be dropped to the sludge level which is expected to be at approx. the 1 foot level. Tanks will be cleaned by a local cleaning sub- contractor. Waste oil and sludge to be disposed of off site locally. Demolition will be by excavators with shear attachments. Plates will be sold for scrap in large sizes cut to suit trucking, not reduced to 5 foot and under. Debris will be stockpiled in the South West corner of the tank farm until this area is converted to a C&D landfill.

8. In the Fall, once the tanks have been removed from the tank farm a Phase 2 environmental assessment will be performed. Any remedial work required as well as required modifications to convert the tank farm area into a C and D landfill will be completed in 2022.

9. Day tank and fuel oil additive tanks will be demolished in a similar fashion to the large storage tanks. The concrete dike will be cleaned by steam cleaning or pressure washing and the walls will be broken to grade using excavators with crusher attachments and rock hammers. A vacuum truck will be used to remove wash water which will be disposed of offsite.

10. The bunker fuel piping system will be drained, flushed and cleaned using steam or high pressure washing and vacuum trucks from the tanker unloading arms on the jetty through to the burner fronts of all 3 units. As has been done in the past the line will be cleaned in 100 foot sections with coupons cut into the piping for cleaning wand access. Contaminated wash water will be collected in a vacuum truck for offsite disposal. The fuel pumps and heaters will be cleaned as well.

11. The piping system from the jetty to the South wall of the powerhouse will be removed, along with the supports, to grade level. The open pipe ends will be capped.

12. A phase 2 ESA will be completed in the area of demolition and any remedial work required will be completed in 2022.

13. Unit 1 and 2 main output, station service and exciter transformers and T9 (unused old CT transformer) will be drained of oil, oil to be trucked to a recycle/disposal facility and transformer carcasses to be shipped off for salvage at a licensed facility. The main output transformers are a Transmission asset therefore they will determine the final disposal of this item.

14. Decommissioned CT to be demolished using excavators with shear attachments. The concrete pad will have holes punched in it using an excavator with a rock hammer attachment.

15. Debris from the above activities will be disposed of in the South West corner of the tank farm.

B) <u>Phase 1 - 2022</u>

1. Prior to demolition work taking place in the area between the stacks and EQ basins a 6" layer of backfill material will be placed over the yard. This will prevent any possible ground contamination from being spread over the plant site during demolition activities. A phase 2 ESA will be performed in this area after final plant demolition and any remediation required will be addressed at that time.

2. The tank farm area will be converted to a C and D landfill and any remediation required will be accomplished at this time.

C) Phase 1 - 2023

1. Jetty demolition will be accomplished using a barge with integral crane. This work will take place through the summer. Delay days due to weather will have to be factored in.

2. The piles will be cut below the deck manually with a diamond wire saw. It's expected the deck is strong enough it won't cantilever over and bind the cuts.

3. The crane will then take the load of a piece of deck to be sliced and the piece will be cut with a diamond wire saw. These pieces will be 3 feet thick. The cuts will be made perpendicular to the shoreline.

4. The pieces will then be lowered into the barge.

5. For the piles, an underwater team will cut the metal pipe perimeter and also the concrete filler if rebar is present. If there is no rebar then no concrete cutting is required. The pile will be snapped off.

6. The pile will be removed after it's cut or snapped and place in the barge.

7. The concrete will be disposed of in the old tank farm. The barge will come to shore where a shore based crane will load the pieces on trucks.

8. A silt curtain will be installed around the entire in-water works.

9. The stacks will be dropped towards the East. All stacks will all be dropped on the same day with a few hours delay between drops. The stacks will be prepped for blasting by cutting a mouth in each stack on the East side, similar to how a tree would be cut to fell it. Sections of wind shell will be left in the mouth and these will be drilled and filled with dynamite. Just prior to the blast the back of the stack will be cut horizontally along the bottom. Stack concrete will be pulverized and disposed of in the old tank farm. Stack liner will be processed for scrap and insulation will go to the tank farm C&D location.

10. The breeching exterior to the boiler house will be demolished prior to the stack drops. The bricks lining the breeching are expected to be contaminated with flue gas by products therefore these will be disposed of in the hazardous waste landfill. Siding will then be installed over the breeching openings.

D) Phase 2 - Following Cessation of Synchronous Condenser Operations - Year 1

1. Planning and engineering development.

E) Phase 2 - Year 2

1. Starting in April, Hydro staff will drain and collect bulk chemicals from the WTP and powerhouse and lube oils and no. 2 fuel oil from the plant equipment that was in operation. These will be removed from site by a local disposal/recycle contractor. The WWTP will be kept operational.

2. Hydro staff will collect containers of surplus chemical, ODS, firefighting gaseous agents, oils, paints and like products and have them removed from site by a local disposal/recycle contractor.

3. Hydro staff can trip power feeds to disused pieces of equipment. Lighting panels, receptacles and the elevator will be kept operational until the abatement is complete.

4. Approx. April, the demolition contractor (DC) will have mobilized to site and will start work.

5. Hydro staff work identified in 1 through 3 above will be performed concurrent with the abatement work proceeding. The various aspects of the work will be scheduled so that they don't interfere with each other.

6. The 2 outside no. 2 fuel oil tanks will be cleaned and demolished through the summer per methodology in items 8, 10 and 11 above. The pipeline supports will be cut at grade. Insulation will be disposed of in the tank farm C and D landfill.

7. Each boiler will be abated as a type 3 ACM job, one at a time in succession. This is expected to take 9 months total. If necessary the plant will have to be kept heated until all final lock down gluing is completed. Hydro will retain an asbestos monitoring company to oversee the health and safety of the work.

8. The vacuum cleaning piping is ACM contaminated so it will be removed in sections using glove bagging, sealed and disposed of at the Robin Hood landfill. As well the remaining non friable ACM under the MCC's will be removed and wrapped in plastic and placed in the tank farm C&D site.

9. Concurrent with abatement, the demolition contractor will be drilling low points and draining the residual fluids from all plant systems.

10. These systems will then be flushed and cleaned to the point that the piping is safe to work on and the scrap is not contaminated. Oily waste water will be collected and sent offsite for disposal.

11. Hydro staff will be washing the plant in areas that the contractor is not working in and will also wash the outside and the inside of the gas path of each boiler following abatement of each boiler. Wash water will be treated in the WWTP.

12. Hydro staff will have the ODS removed by a local contractor.

13. The demo contractor will also be removing plant lighting and disposing of hazardous bulbs as well as any mercury found or PCB filled bushings that may be found.

14. The DC will drain remaining liquid filled transformers, 4 in total, and dispose of the oil at a licensed facility. The transformer carcasses will then be shipped off site to a licensed cleaning and recycling facility. As mentioned above the Unit output transformers are a transmission asset.

15. As of year-end , except for washing the unit 3 boiler area, the plant should be washed clean, abated of friable ACM and ash contaminated insulation and be free of all PCB's, hazardous products oils and chemicals.

16. A phase 2 ESA will be completed in the no. 2 fuel tank and transformer areas and any remedial work required will be completed prior to cold weather.

F) <u>Phase 2 – Year 3</u>

1. In January hydro staff will finish washing the Unit 3 boiler and boiler building area.

2. Starting approx. April demolition will commence with the turbine building first. Any remaining galbestos siding will be removed by machine. As areas of the turbine hall become exposed demolition will proceed on the building structure using excavators, both high reach and regular, with shears and crusher attachments. Heavier thickness steel will be cut by hand using torches with staff on man lifts.

3. All equipment and concrete pedestals will be removed to grade. The crushed concrete will be disposed of in the C and D landfill. Demolition of the turbine hall should be complete by the end of September.

4. Once the turbine hall galbestos is removed the boiler building galbestos removal will be completed. Galbestos will be wrapped in plastic and landfilled in the tank farm C and D landfill.

5. Following demolition of the turbine building the boiler building will be prepped for explosive charges and the boilers and boiler building will be dropped South into the turbine hall. For preparation, the lower 2 floors will have all of the equipment totally removed using machinery and by hand with torches as required. The columns will be stripped of items attached to them. Cuts will be made in select columns and shaped charges will be installed to cut and blast the columns. All gas path scrap should be kept on the turbine and boiler building concrete pad until it is determined to be free of ash otherwise precipitation will produce contaminated runoff. Runoff from the pad areas can still be treated in the WWTP.

The runoff will collect in the various sumps in the powerhouse where it will be pumped via submersible pumps to the WWTP. When the boilers and building are down the scrap will be cut up and prepped for shipping.

6. Hydro staff will plug any drains that would allow contaminated water to be routed anywhere but the WWTP.

G) <u>Phase 2 – Year 4</u>

1. The timing of demolition of the WWTP and EQ basins has to be coordinated with the capping of the hazardous waste landfill and backfilling of the leachate pond.

2. Hydro staff will remove any remaining sludge in the WWTP, EQ basins and leachate pond and dispose of it in the hazardous waste landfill. A vacuum truck will be used for this purpose and dewatering of the sludge is not considered. This will be completed just prior to demolition of the WWTP and EQ basins.

3. Remaining buildings including the 2 CW pumphouses, the WWTP and EQ basin building will be demolished and backfilled. This work will start in May and the order of demolition will be the CW pumphouses first then the WWTP and EQ basins. The WWTP and basins must be left until last so any contaminated water can be treated. The galbestos siding on the stage 2 pumphouse will be removed first and deposited in the tank farm C&D site.

4. The hazardous waste landfill site will be capped starting in May and will be completed just after the last sludge is deposited.

5. The leachate lagoon will be dewatered to the WWTP just before it's demolished and the sludge and liner will be disposed of in the hazardous waste landfill. The leachate pond will then be backfilled and hydroseeded. Any contaminated water accumulating in the landfill will have to be disposed of off-site following this time period.

6. Buried piping will be exposed by excavation, removed or broken open and backfilled. Below grade structures will be backfilled. Concrete caps will be installed on the CW pumphouse inlets and CW discharge piping. Below grade structures include the CW pumphouses, EQ basins, seal pits, utilidors and oil separators.

7. Buried piping that is contaminated will be cleaned using similar equipment to that used for bunker pipeline cleaning. Waste water from heavy metal contaminated lines will go to the WWTP prior to its demolition. Oil contaminated lines will have the waste wash water disposed of off site.

8. A phase 2 ESA will be completed on the area North of the boiler building where the pumphouses and WWTP/EQ basins were.

9. The powerhouse floor trenches and sumps will be cleaned by the DC using steam or power washers and the contaminated wash water will be disposed of off site. The floor slab will have holes hammered in it to facilitate drainage.

10. Crushed concrete from the boiler house demolition will be disposed of in the C and D landfill.

11. The tank farm C and D site will be closed and capped in the fall.

H) <u>Phase 2 – Year 5</u>

1. Remediation will be completed as required in the area North of the boiler building.

APPENDIX D

Site Project Management Staffing

Appendix D

Site Project Staff

A. Site Project Management Staff		
Position	**Year**	**Utilization**
Site Supervisor	Phase 1 - 2020 & 2023 and Phase 2 – Year 1 & Year 5	50%
	Phase 1 - 2021 & 2022 and Phase 2 – Years 2, 3,and 4	100%
Administrative Assistant	Phase 1 - 2020 & 2023 and Phase 2 – Year 1 & Year 5	50%
	Phase 2 - Years 2, 3, and 4	100%
Safety Specialist	Phase 1 - 2020 & 2023 and Phase 2 – Year 1 & Year 5	50%
	Phase 2 - Years 2, 3, and 4	100%
Plant Engineers x 2	Phase 1 - 2020 through 2023	25%
	Phase 2 – Years 1 through 5	25%

B. Site Project Plant Labour		
Position	**Staff Hours**	
	Phase 1	**Phase 2**
Shift Supervisor/Operators	420	11,420
Chemical Technicians/EMS Coordinators	410	5,200
Electricians	180	1,460
Utility/Labourers	640	8,030

APPENDIX E

Head Office Project Management Staffing

Appendix E

Head Office Project Staff

Position	Utilization
Project Manager	50%
Project Engineer x 2	50%
Environment Specialist	25%
Safety/Hygienist	10%
Communications Personnel	5%
Scheduling	5%

These positions are required in Phases 1 and 2.

Exhibit 9 - Working Capital Methodology

REVIEW

CASH WORKING CAPITAL: A REVIEW OF NEWFOUNDLAND AND LABRADOR HYDRO'S METHODOLOGY

prepared for
NEWFOUNDLAND AND LABRADOR HYDRO

review conducted by
CHRISTENSEN ASSOCIATES ENERGY CONSULTING

June 23, 2017

INTRODUCTION

This report results from Christensen Associates Energy Consulting's review of the working capital methods of Newfoundland and Labrador Hydro (NLH, Company). Working capital is a key element of a utility rate base. *Cash working capital* is a component of overall working capital, and is the focus of this review. NLH's estimates of cash working capital requirements are based on the Lead-Lag approach, a longstanding methodology. The review of NLH's cash working capital methods is timely, as the most recent review of NLH's methods reaches several years back, first put in place during the 2001-02 timeframe.

Working capital generally refers to the financial resources necessary to fund day-to-day operations. Provided by investors, working capital is underwritten by the combined financial sources of investment employed by entities to fund all resources, including debt and equity financing vehicles. The resources funded by financial sources are revealed as net assets and include fixed capital and various short-term balance sheet elements supporting routine operations; cash, cash equivalents, and inventories are typical examples.

Viewed from the perspective of public utilities, working capital is a proper component of the utility's rate base[1] for both private entities and public organizations of all types. Below is a useful definition.

> "**Working Capital.** This term refers to various rate-base funding requirements other than the utility plant in service. These funding requirement[s] would include inventories, prepayments, minimum and compensating bank balances, cash working capital, and other

[1] A utility's rate base refers to the capital employed by public utilities in the provision of public service. A utility's rate base can be defined in several ways, but typically includes net plant (gross plant minus accumulated depreciation), materials and supplies inventory including fuel stock, and working capital. However, a utility's rate base can also include construction work in progress (CWIP), plant held for future use, customer deposits, deferred income taxes, investment tax credits, and regulatory assets. The utility's rate base is generally measured in original cost terms, but fair value and trended original cost metrics are also used worldwide.

non-plant operating requirements. When these assets or operating requirements are funded by investors, they are legitimate rate-base allowances." [2]

The notion of *necessary to fund operations* refers to the ongoing differences in the timing of remittances and revenues, and is often limited to cash working capital as a matter of definition. NLH's cash working capital is the topic of the immediate review. More precisely, cash working capital is the level of internal cash on hand that a utility must have available, each day, in order to bridge the gap between the points in time when expenditures are paid and revenues are received.

METHODS TO MEASURE WORKING CAPITAL

Revenue inflows and remittance outflows are measured in terms of timeframe and level. The determination of cash working capital involves a study of the revenue and remittance timing gaps, each measured with respect to the point in time that the utility's services are delivered. Revenue timing gaps will consist of lags, more-or-less exclusively; on the other hand, remittance gaps will likely include both leads and lags. To the degree that revenue lags are greater than the net sum of the remittance leads and lags, cash working capital will be a positive amount.

While the conceptual basis for the inclusion of cash working capital within rate base is straightforward, determination of the amount involves empirical analysis and continues to be somewhat problematic, and potentially resource intensive. Consequently, alternative methods have been proposed and applied. Two general methods are used for determining the cash working capital amounts, *Default Values* and *Lead-Lag Studies*. Each is discussed below.

Default Values as the Basis for Determining Cash Working Capital: Default value approaches provide the utility with cash working capital estimates that do not require extensive analysis and have attained regulatory acceptance.

Formula Basis: The formula-based method sets cash working capital as the product of a default number of days and non-fuel operating and maintenance (O&M) expenses, including direct, administrative, and general expenses. This approach reaches back decades, first adopted by the Federal Energy Regulatory Commission (FERC) in 1939. In 1979, the FERC's Order 19A set cash working capital balances equal to 45/365, alternatively referred to as the *one-eighth of O&M* and the *45-day rule* (Rule).[3]

[2] Source: *Regulated Utilities Manual: A Service for Regulated Utilities,* c. 2012, Deloitte Development LLC., member of Deloitte Touche Tohmatsu Limited, p. 11.

[3] The one-eighth of O&M approach, otherwise referred to as the 45-day rule, remains contemporary, and is frequently applied by the FERC today including, for example, FERC Docket ER16-118-001 (January 19, 2016) regarding MISO. One-eighth of O&M, as approved by the FERC, is also referenced in several FERC electric tariffs, including that of International Transmission Company (ITC), Fourth Revised Volume No. 1. Earlier, in 2009, the

This approach has been widely adopted by regulatory authorities throughout North America where, in recent years, the Rule is applicable as a default value in the absence of a detailed lead-lag cash working capital study. Because the 45-day rule results in lag days that often exceed the lag periods suggested by formal studies, regulatory authorities in recent years have sometimes deemed shorter timeframes to be appropriates. As an example, in June 2015, the Ontario Energy Board (OEB) reduced the default days[4] for the cash working capital allowance applicable to electricity distributors from 13% (closely equivalent to 45 days) to 7.5%.

Balance Sheet Basis: The balance sheet approach uses the net balances of current assets and current liabilities, as the basis to determine cash working capital amounts for utility rate bases.[5]

Lead-Lag Approach to Cash Working Capital: Lead-lag studies explicitly account for and estimate the underlying lags in the revenue inflows and remittances covering operating expenditures.

The lead-lag methodology is a quantitative and widely preferred methodology, although the application of the methodology can be resource intensive as it involves the study of the leads and lags of actual, representative expenditure remittances (transactions). As an example, an electric utility engages an outside specialist/consultant under contract, to perform ongoing maintenance activities. The activities, viewed as inputs, are critical to the delivery of electricity services, and provided as ongoing service flows over typical months. Similarly, wholesale generation and transmission (G&T) services, viewed as outputs, are provided as ongoing flows of services to consumers by their utility. Each month's remittances are billed as inputs for consulting services and paid sometime thereafter. G&T services are measured (the read of meters), billed, and collected as revenues several days/weeks following the delivery of electricity (G&T services) to customers. In short, lags between the provision of services and payment flows are inherent to both input and output services: payments for contractor services would be remitted some time following the performance of the work (i.e., the realization of contractor services).[6] Similarly, revenues are realized with a lag, following the delivery of G&T services to consumers.

In brief, lead-lag studies involve the measurement of the leads and lags of the revenue receipts and the remittance payment. The cash working capital balance, incorporated in the rate base, is equal to the product of the various components of cash working capital and respective lead-lag days, measured as a

FERC utilized the one-eighth of O&M formula in the FERC Electric Tariff, Fifth Revised Volume No.1, for Westar under the Southwest Power Pool RTO (SPP), which covers the Southwest region of the Eastern Interconnection.

[4] The OEB, in its June 3, 2015 memorandum to All Licensed Electricity Distributors [and] All Interested Parties entitled *Allowance for Working Capital for Electricity Distribution Rate Applications*, cites several reasons for the reduction in allowance days, including the substantial completion of smart metering, wide adoption of automatic billing, customer information updates, and general process improvements. In other words, all changes are apparently attributable to reductions in revenue lags.

[5] Various reference materials will, on occasion, also mention a so-called *Rate Base Synchronization* method.

[6] Of note, the remittances for some inputs can take place prior to the receipt of the services.

share of an annual period (365 days), expressed as a percentage. The process to determine working capital balances for inclusion within rate base can be described as follows:

$$\textit{Working Capital Days}_H = \Sigma_M \textit{Transaction Weight}^H{}_M * (\textit{Lag Days}^H{}_M)$$

where,

$\textit{Working Capital Days}_H$ = *Working capital lead/lag days, expenditure category H*

$\textit{Transaction Weight}^H{}_M$ = *Amount for Transaction M, category H/* Σ_M *Transactions M*

$\textit{Lead/Lag Days}_M$ = *Lead or lag days between point in time inputs are received and rendered, and payments are completed, for each transaction M*

The transaction weighted average days for category H, $\textit{Working Capital Days}_H$, is weighted by the amounts for each category H. This result is summed across categories H. In turn, the net of revenue and expenditure categories provides the net lead-lag days. Dividing by 365 days obtains the annual lead-lag percent, as applied to the annual total cash operating expenditures – i.e., cash outflows stated annually. This lead-Lag methodology is used by NLH to determine working capital balances for inclusion within its rate base, the technical application of which is assessed herein.

NLH'S LEAD-LAG METHODOLOGY

The lead-lag analysis procedures employed by NLH are as follows:

Revenue Lag: NLH provides G&T services to Newfoundland Power, Newfoundland's large retail electricity distributor, seven industrial customers,[7] and approximately thirty-nine thousand retail electricity customers in rural areas. In addition, NLH realizes revenue from the provision of services other than general retail electricity services. Other services include electricity services provided to the Department of Transportation and Works, transport services in the form of pole attachments for telecommunication companies and other communication revenue.

For purposes of determining cash working capital, the total revenue lag consists of *service*, *billing*, and *collection* components. In the NLH Lead-Lag Study, the total revenue lag is measured from the mid-point of the month. That is, NLH assumes that the flow of services over the course of the month occurs at a more-or-less constant rate of flow. In the case of electricity services, NLH can thus use the mid-point of the month (15.2 days prior to the end of the month) as the point in time that services are rendered. The results of NLH's analysis of revenue lags are shown below.

[7] Industrial customers include Corner Brook Pulp and Paper, North Atlantic, CFB-Goose Bay, Aur Resource Praxair, Vale Inco, IOCC, and Teck Resources.

REVENUE LAG, NEWFOUNDLAND AND LABRADOR HYDRO
WORKING CAPITAL STUDY, 2015

Customer	Revenue ($ 000's)	% of Total	Lag Days				Weighted Average Lag Days
			Service	Billing	Collection	Total	
Newfoundland Powe	442,589	79.89%	15.2	6.5	15.1	36.8	29.40
Industrial Customers							
Corner Brook	2,963	0.53%	15.2	6.5	20.1	41.8	0.22
North Atlantic	11,485	2.07%	15.2	6.5	16.9	38.6	0.80
CFB - Goose Bay	3	0.00%	15.2	6.5	24.4	46.1	0.00
IOCC	3,670	0.66%	15.2	6.5	18.0	39.7	0.26
Teck Resources	2,291	0.41%	15.2	6.5	13.9	35.6	0.15
Vale inco	7,447	1.34%	15.2	6.5	26.3	48.0	0.65
Muskrat Falls	-	0.00%	15.2	4.0	0.0	19.2	0.00
Praxair Canada	1,930	0.35%	15.2	6.5	16.3	38.0	0.13
Rural	78,025	14.08%	15.2	8.0	22.1	45.3	6.38
Other	3,583	0.65%	15.2	1.6	36.7	53.5	0.35
TOTAL	553,987	100.00%					38.34

Assessment: NLH's method to determine revenue lags is correctly executed,[8] and would appear to obtain highly accurate results for much of NLH sales and revenues. Over 85% of total revenues are derived from sales to Newfoundland Power and large industrial customers (as listed above). As a result, NLH's lead-lag study does not appear to contend with sizable sampling error within the flows of G&T services and revenues. This review reveals that the collection lag days have been updated from the 2001-02 working capital study, thus reflecting the Company's contemporary lag experience. Similarly, the days for billing lags across the markets served (6.5, 4.0, and 8.0 days) reflect NLH updated sample of billing lag days compared to the previous working capital studies.

Operating Expense Lags: Direct and indirect operations and maintenance (O&M) expenditures essentially cover non-capital resources, including expenditures for labor (wages and benefits), materials and supplies, and outside services. O&M expenditures can also include purchased power. These general expenditure categories include numerous types, covering a broad array of the various resource inputs used by utilities in the provision of service. For the purposes of the Company's lead-lag study, resource inputs and the invoices for them are grouped into common categories. Samples are then drawn from each category and analyzed. The end results are time lags, measured in days, between the points when

[8] NLH's methodology presumes that the flow of electricity services is delivered at a constant rate over the course of the month—thus, the midpoint days of 15.2. This is quite plausible, providing that the flow of electricity services is not systematically skewed favoring, over the course of twelve months, either the early days or the late days of the months. Absent empirical evidence to the contrary, the mid-point-of-month delivery assumption is appropriate.

resources are utilized in the provision of G&T electricity services, and the points when the compensation for the resource inputs are remitted.

Following this general theme, the O&M expenditure categories identified within the Company's lead-lag study include *salaries and benefits, materials maintenance, professional services, travel, transportation, office supplies, equipment rentals, insurance, property rentals, customer costs, power purchases,* and other sundry items referred to as *revenue recovery*. In turn, these categories have further detailed components. The 2015 expenditure and recovery lags of NLH's working capital are shown below.

EXPENDITURE AND RECOVERY LAGS, NEWFOUNDLAND AND LABRADOR HYDRO WORKING CAPITAL STUDY, 2015

	Expenditures ($ 000's)	%	Lag Days	Weighted Average Lag Days
Salaries & Benefits	93,307	43.53%	12.5	5.4
Materials Maintenance	31,927	14.90%	52.2	7.8
Professional Services	14,408	6.72%	51.6	3.5
Miscellaneous	5,788	2.70%	46.1	1.2
Travel	3,250	1.52%	45.0	0.7
Transportation	1,649	0.77%	45.0	0.3
Office Supplies	2,762	1.29%	45.0	0.6
Equipment rentals	4,218	1.97%	45.0	0.9
Insurance	2,508	1.17%	-145.5	-1.7
Property rentals	1,497	0.70%	-30.0	-0.2
Customer costs	253	0.12%	0.0	0.0
Subtotal	161,567	75.38%		18.5
Recoveries				
CF(L)Co Recoveries	-1,701	-0.79%	30.0	-0.2
External Recoveries	-766	-0.36%	30.0	-0.1
CDM Program deferral*	0	0.00%	0.0	0.0
Interco vehicle fee	-46	-0.02%	30.0	0.0
Interco fixed fee	-581	-0.27%	30.0	-0.1
NBD Admin Fee	-4,812	-2.25%	30.0	-0.7
	-7,906	-3.69%		-1.1
Power Purchases	60,667	28.31%	42.2	11.9
Total Cash Outflow	214,328	100.00%		29.4

* CDM program deferral has no lead/lag impact, as it is an accounting deferral entry

Assessment: The Company's cash working capital methodology covering non-fuel O&M expenditures is properly designed and well executed. The general approach for determining expenditure lags is sufficiently detailed and articulate, adhering to proper sampling procedures at a detailed level. For the various resource categories, moreover, the Company's study incorporates periodic updates and appears to adequately capture the lead-lag experience between the points in time when resource inputs are provided, and when compensation is received and remittances for resources have been completed.

SUMMARY

The Company's general approach adheres to well accepted industry practices for determining its working capital requirements. Two points are worth highlighting. First, NLH updates its lead-lag study

from time to time, such that the study is contemporary, reflecting current conditions and expenditure patterns. Second, the Company employs well accepted practices to sample transactions[9] within defined expenditure categories. The Company's current lead-lag study reflects contemporary experience within small-sized categories within maintenance and non-payroll expenditures – an important consideration insofar as the transactions within these categories[10] may vary substantially from one updated study to another.

In closing, we wish to mention that the resource restructuring, currently underway. The completion of Muskrat Falls and the commence of charges for Labrador Island Link will likely have impact on the Company's working capital requirements. While the working capital methodology should remain unchanged, the lead/lag days will need to be revisited, and likely updated.

[9] The choice of sampling methodology is between random and stratified random sampling methods. As a starting point, the sample can presume that the underlying population of transactions assumes a uniform statistical distribution. Where the sample size of transactions within an expenditure category is skewed, with several large transactions dominating the total level, stratified sampling may well be the preferred approach.

[10] Selected expenditure categories include *Professional Services* (consultants, auditing, and legal groups), *Travel, Transportation, Office Supplies,* and *Equipment Rentals*.

Exhibit 10 - Average Rate Base Methodology

DISCUSSION PAPER

RATE BASE METHODS FOR DETERMINING UTILITY RATES: CONSIDERATION OF ALTERNATIVES AND RECOMMENDATIONS

discussion prepared for
NEWFOUNDLAND AND LABRADOR HYDRO

prepared by
Robert Camfield
Bruce Chapman
CHRISTENSEN ASSOCIATES ENERGY CONSULTING

July 16, 2017

INTRODUCTION

Recent conversations with Newfoundland and Labrador Hydro (NLH, Company) have precipitated two cost-of-service (COS) issues since the completion of the COS Methodology Review undertaken by Christensen Associates Energy Consulting last year. The two questions focus on the measurement of capital – essentially, the measure of plant in service for inclusion within the rate base of NLH.

Valuation of capital used by utilities in the provision of infrastructure services is not a new issue; indeed, capital valuation for setting utility rates has a rich institutional history.[1] Over recent decades, following several years of comparatively high inflation, the issue of valuation has settled on historical costs. At this point, original cost accounting is well accepted across North America for setting rates; cost theory serves only as background.

Decisions with respect to *rate base methodology* tend not to be concerns over theory so much as issues of business practice: matters of pragmatism and procedural process. Contemporary Issues of rate base methodology come down to practical concerns of frequency and timing of measurement of plant in service, for setting rates during future periods – say, the next two years forward. This discussion focuses on two specific questions regarding rate base methods, as follows:

1. How do utilities determine the value of their rate base for general rate applications? Does a generally preferred "frequency" of measurement of asset balances exist—a more-or-less commonly accepted approach by most utilities and regulatory authorities? Alternatively, do utilities apply a range of approaches? In short, is there a uniform

[1] For some time, regulatory jurisdictions used historical cost, often referred to as *Original Accounting Cost*, fair value, and other methods of capital valuation to determine the rate base and set rates for utility services. Utilities and regulatory authorities pretty much settled on original accounting cost during the years following the *Federal Power Commission v. Hope Natural Gas Company* decision of the U.S. Supreme Court (1944). Exceptions can be found. As an example, Order 154B of the Federal Energy Regulatory Commission applied a *Trended Original Cost* methodology for oil pipelines (1985).

accepted practice, or do utilities exercise a range of discretion about rate base methodology?

2. What are the main considerations for determining a utility's rate base? Should underlying circumstances including resource changes and markets served be accounted for, in decisions with respect to rate base methodology? More specifically what is the appropriate rate base approach for Newfoundland and Labrador Hydro in view of resource changes currently under way?

To provide guidance, we report herein our findings about how other utilities manage the above issues and, second, discuss how NLH should assess the problem of capital measurement (rate base) for determining utility rates in view of current resource plans.

Not surprisingly, these two questions emerge at a time when NLH is undergoing major resource restructuring, involving large additions to its rate base. For NLH, concern about rate base methodology stems from the limitations of NLH's current average balance basis of capital measurement in the face of large, within-period changes in asset value.[2] The total of gross and net asset value can increase dramatically when new, large plant assets are booked to plant-in-service accounts, thus assuming their position within a utility's rate base. In such cases, it is a matter of considerable importance that the rate base adequately captures the value of used and useful property employed in the provision of utility services.[3] In these circumstances, an average balance computation produces a value that is a combination of two very different numbers, and possibly undervaluing the rate base used to set rates over a forward period. Moreover, as we briefly touch on below, the approach to determining the weighted average cost of capital is tangentially related to rate base methodology.

ANALYSIS

Question 1: Rate Base Methods Used by Utilities: To develop a more complete understanding of industry practices with respect to this topic, we interviewed the staff of a number of Canadian and U.S. utilities. We approached and received responses from several Canadian electric utilities. We also

[2] Resources used in the provision of electricity services are often characterized by capital indivisibility: investment in large generation and transmission infrastructure facilities, owing largely to scale economies. Under the twin conditions of original cost basis for utility prices and ongoing price inflation, such projects can cause rate base levels to rise dramatically. These conditions were present in Canada and the U.S. during the 1980s. At the time, many large nuclear stations (e.g., Darlington, Pickering, Comanche Peak, South Texas, River Bend, Seabrook, Wolf Creek, Diablo Canyon, Limerick, Millstone Three, Grand Gulf, Nine Mile Point Two) were being completed and entering commercial operation status, with the sponsoring utility rate base rising dramatically, often by a factor approximating twofold.

[3] At the point in time that facilities under construction become operational, the ongoing accrual of interest during construction ceases. Absent an immediate internal cash flow offset arising from higher flows of revenue, book as well as cash returns to capital can decline significantly, possibly resulting in a major shortfall in returns to equity shareholders.

received responses from several U.S. utilities, both large and small, in a variety of market and institutional circumstances—several utilities are members in ISO/RTO regions and some not; some investor-owned and some not—in response to the same questions as those submitted to the Canadian utilities. The survey participants appear in Table 1 below. One participant, the Ontario Energy Board, is not a utility but is a repository of in-depth regulatory information filed by the numerous electric distribution utilities of the Province of Ontario.

Ownership structure of participants varies widely. Canadian utilities are predominantly Crown corporations, though Ontario's distribution utilities are municipally owned to a large extent. We also interviewed staff at two investor-owned utilities in Canada. In contrast, American utilities interviewed were predominantly investor-owned, although U.S. survey participants include a municipal utility, a cooperatively-owned utility, and two government-owned utilities, one at the federal level and another at the state level (Santee Cooper, in South Carolina).

Table 1
SURVEY PARTICIPANTS

Canada		**United States**	
Utility	Entity Control	Utility	Entity Control
BC Hydro	Gov't	Georgia Power	Shareholders
Manitoba Hydro	Gov't	Duke Energy	Shareholders
SaskPower	Gov't	Duke Energy Carolinas	
Ontario - OEB	Gov't	Duke Energy Progress	
Hydro-Quebec	Gov't	Minnesota Power	Shareholders
Nova Scotia Power	Shareholders	Xcel Energy - MN	Shareholders
Newfoundland Power	Shareholders	Souhtern California Edison	Shareholders
		Oklahoma Gas and Electric	Shareholders
		Tennessee Valley Authority	Gov't - US
		Santee Cooper	Gov't - State
		Central Electric Power Coop	Cooperative
Gov't: Crown Corporation, Municipality		Gov't - US: Corporate Agency of US Govt	
		Gov't - State: State Action Agency	
		Cooperative - Member-owned	
Shareholder: Investor-owned Utility			

Survey Results

Survey respondents use a limited set of alternatives for developing rate base values. The survey uncovered use of three methods: 13-month average balances, beginning- and end-of-year (BOY/EOY) averaging, and end-of-year (EOY) balances approaches, although variations on the EOY method are in place. The incidence of application of these alternative approaches is presented in Table 2, below.

From the survey results, there appears to be no dominant valuation method within regions, or according to utility ownership structure, public or private.[4] In Canada, four utilities use a beginning- and end-of-year average, with the other three using other forms of averaging. Hydro-Quebec uses a 13-month average while SaskPower uses an end-of-year approach which takes account of developments over the course of the year, producing an averaging effect. Ontario distributors, on the other hand, have fairly broad discretion with respect to rate base measurement methodology, where the presumed objective is to accurately represent the value of assets present in rate base for an annual period.

Table 2
FREQUENCY BASIS OF COMPUTATION OF RATE BASE

Canada				
Utility	Entity Control	13 mo. Average	BOY/EOY	EOY
BC Hydro	Gov't		X	
Manitoba Hydro	Gov't		X	
SaskPower	Gov't			Monthly Average
Ontario - OEB	Gov't			Various
Hydro-Quebec	Gov't	X		
Nova Scotia Power	Shareholders		X	
Newfoundland Power	Shareholders		X	
Gov't: Crown Corporation or Municipality				
Shareholders: Investor-owned Utility				
United States				
Utility	Entity Control	13 mo. Average	BOY/EOY	EOY
Georgia Power	Shareholders	X		
Duke Energy	Shareholders			EOY; Working
Duke Energy Carolinas				Capital is 13-mo.
Duke Energy Progress				Average.
Minnesota Power	Shareholders		X	
Xcel Energy - MN	Shareholders		X	
Southern California Edison	Shareholders	X		
Oklahoma Gas and Electric	Shareholders			X
Tennessee Valley Authority	Gov't - US			X
Santee Cooper	Gov't - State	X		
Central Electric Power Coop	Cooperative	X		
Gov't - US: Corporate Agency of US Govt				
Gov't - State: State Action Agency				
Cooperative - Member-owned				
Shareholders: Investor-owned Utility				

Operating size (MWh) appears to play a role in the determination of rate base methodology. In Ontario, for example, the preferences of electric distributors display a clear relation to size, where smaller

[4] Note that these results are related to rate case procedures. If a utility has a quarterly reporting obligation, a simpler 5-quarter average approach may serve regulatory reporting requirements well.

distributors are likely to employ beginning-and ending-balances, or end-of-year approaches. This relationship is not altogether surprising as smaller utilities may not close the books with monthly frequency, or because of software and data processing limitations. As a consequence, the beginning- and end-of-year average rate base method is favored. Larger utilities, on the other hand, tend to use 13-month (or 12-month) averaging. We note, however, that some small utilities also favor the 13-month approach.

In the United States, the 13-month average approach appears to be more widely used than in Canada, but is by no means universal, even among large utilities. For example, Xcel Energy in Minnesota uses a BOY/EOY approach and Tennessee Valley Authority uses EOY. The survey reveals anomalies driven by circumstances: for Duke Energy's operating companies in North Carolina, local tax considerations require the use of a 13-month average for working capital only.

Our prior expectations at the time of the survey were that, in view of the maturity of the industry, electric utilities would gravitate to a commonly accepted rate base valuation method, with the 13-month average method serving as the leading candidate. However, the capability to process data and information, mainly cost and revenue inputs, with sufficient expedition is a major constraint for many entities. These limitations are chiefly in the form of operating procedures and software—e.g., calculation of depreciation expense and net asset value for innumerable assets distributed across many asset classes.

Compared to the other two leading methods—average of beginning- and end-of-year values or end-of-year only—the 13-month method requires frequent entry of data and facilitating processes to manage accounting data with monthly frequency. As a consequence, the 13-month average approach better captures the value of capital used in the provision of services, at least over the course of the current year. Hydro-Quebec in Canada, and Georgia Power and Southern California Edison in the United States use this method. (Georgia Power's approach is mandated by its regulator, although Georgia Power also incorporates known and measurable cost changes within its general rate applications.) However, other large utilities across North America such as BC Hydro and Xcel Energy use alternative methods.

Question 2: Consideration of Rate Base Methods for NLH: The survey results reveal considerable variation, a consequence of context specificity. Context should be viewed broadly and, in addition to institutional legacy, can cover several important dimensions, including:

- the methods by which capital is measured, including either original cost or reproduction cost;[5]
- the path and abruptness with which plant-in-service balances are evolving;
- the timeframe for which rates are set; and,

[5] Reproduction costs net of depreciation, sometimes referred to as *fair value*, are not to be confused with replacement costs.

- offsetting changes in operating costs.[6]

In brief, the consideration of rate base methodology is highly case specific, with large mid-year changes in plant-in-service balances a central issue. This is particularly the case for small- to moderate-sized utilities. Large capital additions reflect capital indivisibility: major new facilities are often constructed in lumpy increments, necessary to realize economies of scale and least total costs over the long term. The lumpy nature of major capital additions is especially descriptive of power systems and including transmission and hydraulic generation facilities. Large capital additions are integral to the Company's current resource structuring process. Shown below are examples of new transmission facilities currently under development by NLH.

Table 3
NEWFOUNDLAND AND LABRADOR HYDRO
EXAMPLES OF LARGE TRANSMISISON CAPITAL ADDITIONS

Examples of Major Property Additions, 2017 - 2019		
Timeframe	New Facility	
October '17	*230 kV Transmission Line - BDE to WAV*	
	TL267 Towers	$116,086,141
	TL267 Tower Foundations	70,252,741
	TL267 Conductors	36,113,920
	TL267 Terminal Stations	32,799,898
	Total	$255,252,700
February '18	*230 kV Transmission Line - BDE to WAV*	
	TL267 Towers	$16,556,733
	TL267 Tower Foundations	10,019,765
	TL267 Conductors	5,150,731
	TL267 Terminal Stations	4,678,070
	Total	$36,405,300
February '18	*230kV Trans Line-TL 272 - Soldiers PD to HWD*	
	Transmission Towers	$26,560,900
	Total	$26,560,900
December '18	*Interconnection of MFA to HVY*	
	Transmission Towers	$11,756,950
	Tower Foundations	8,229,865
	Conductors	3,527,085
	Total	$23,513,900

[6] Capital can substitute for energy and, to a lesser extent, non-fuel operations and maintenance expenses. This is manifested in changes in cost structure. Marked increases in plant-in-service balances – and thus rate base – resulting from, say, the introduction of sizable generation or transmission facilities are offset, significantly, by major declines in operating costs.

The above facilities are being installed within NLH's Island Integrated and Labrador Integrated systems, and are necessary for system reliability. Viewed in isolation, the expenditure levels for the new facilities are sizable, notably the third circuit interconnecting Bay d'Espoir with the West Avalon Substation (TL267). An equally discerning view is comparative: expenditure size of new additions gauged with respect to the net book value (depreciated original cost) of the current rate base, as presented below.

Table 4
NLH EXPENDITURES FOR NEW TRANSMISISON FACILITIES
COMPARED TO CURRENT TRANSMISSION NET BOOK VALUE

		Major Capital Additions, 2017 - 2019		
System	Total Rate Base (2019)	230 kV Line - BDE to WAV	230 kV Line - Soldiers PD to HWD	Interconnection of MFA to HVY
Island Intrcnt'd	$1,927,191	$291,658	$26,561	
Labrador Intrcnt'd	$130,756			$23,514
% of Book Value		15.1%	1.4%	18.0%

The above highlights the main concern: it is essential that rate base methodology fully account for large additions including, in the example, the *230kV Line - BDE to WAV* (referred to as TL 267) and *Interconnection of MFA to HVY* facilities. On the other hand, the *230 kV Line – Soldiers PD to HWD* facility (referred to as TL 266) is comparative small scale, and may be considered a normal addition, more-or-less.

However, not all additions give rise to abrupt increases in rate base. Much of capital investment is an ongoing gradual process involving modest-sized additions along with replacement of aged equipment and facilities. This process takes place at a more-or-less steady pace over years. If total invested capital (rate base) is evolving gradually and assumes a rising path through time, increased frequency of measurement of rate base – say, 13-month average – may well provide improved accuracy. However, measurement frequency is not much of an issue, and a beginning- and ending- balances approach may work fairly well under these conditions. The larger concern is the path of total capital, measured as net book value over the relevant timeframe, either an historical or forecast test period. Both 13-month and beginning- and ending balances are forms of averaging, and often will not adequately account for additions during a forward rate year, where capital additions are sizable such as those shown in Table 3.[7]

As alluded to above, the overarching consideration with respect to rate base methodology, is ensuring that *rates reflect the costs of utility services, at the time that services are provided.* In brief, NLH and the PUB should select and implement a methodology on the basis of whether or not used and useful capital is adequately accounted for. This criterion consists of two considerations: 1) the period for which the

[7] Note that sizable mid-year capital additions can include several moderate-sized facilities on similar schedules.

rate base is being calculated, and 2) how capital employed in the provision of services is captured in rates, during the relevant rate year.

New facilities enter commercial service at any point over the course of an annual period. Mid-year additions are not particularly problematic, providing they are modest-sized. The concern is with respect to large facilities: major facilities entering service mid-year, with corresponding large additions to the rate base can lead to a significantly understated rate base for setting rates over the forward rate year. To elaborate, presume an annual test period, for which an average rate base method is used to set rates over two or three forward years. A large capital addition enters service toward mid-year, and is thus accounted for in the test year-rate base, but only during months subsequent to commercial operation. The addition is not accounted for during months prior to time that the new facility is placed in commercial service, even though the new facility is providing services during all months of the forward year. Absent offsetting effects,[8] rates over the forward years are, by design, biased downward – a direct consequence of using average balances over the test year.

Simulation analysis can help guide the determination of rate base methodology, and is particularly useful for exploring the effects of large, mid-year capital additions under alternative rate base methods. For purposes of illustration, a brief simulation study is used to better address the central issue: how best to manage large, mid-year additions. The study estimates how well alternative rate base methods capture capital costs over a future rate period, where plant-in-service balances abruptly increase during a historical test period. The study considers a large capital addition taking place during the first half and, alternatively, second half of the test period. Four rate base methods are assessed: *Beginning and Ending Balances*, *13-Month Average*, *Annualization*,[9] and *End-of-Year Balances*. Simulation results appear in Table 5, below.

(see following page)

[8] Specifically, sizable increases in sales volumes can offset the understatement of the rate base.

[9] Annualization refers to an adjustment procedure under which mid-year additions and changes to plant-in-service balances are calibrated to full-year-of-service levels. As an example, if the test year is an annual period, a capital addition taking place at the beginning of October is moved to beginning-of-year – essentially, multiplying the change by a factor of four. Annualization is a form of adjustment to an observed historical rate base referred to as *known and measurable changes*.

Table 5
ASSESSING ALTERNATIVE RATE BASE METHODS: INTRODUCING LARGE CHANGES TO PLANT-IN-SERVICE ACCOUNTS DURING MID-YEAR OF A HISTORICAL TEST PERIOD

RATE BASE*

Large Investment During 1st Half of Historical Test Year

	Methodology ($ Million)				
Plant In Service	Beginning and Ending Balances	13-Month Averge	Year-End	Annualized	Rate Period: Average Over Forecast Year
Gross Plant	$553.5	$578.5	$607.0	$598.1	$618.8
Accum. Depreciation	$308.1	$307.9	$316.3	$308.3	$325.5
Net Plant	$245.4	$270.5	$290.8	$289.8	$293.2

Large Investment During 2nd Half of Historical Test Year

	Methodology ($ Million)				
Plant In Service	Beginning and Ending Balances	13-Month Averge	Year-End	Annualized	Rate Period: Average Over Forecast Year
Gross Plant	$553.5	$539.2	$607.0	$598.1	$618.8
Accum. Depreciation	$307.5	$307.3	$315.1	$308.3	$324.3
Net Plant	$246.0	$232.0	$291.9	$289.8	$294.4

Plant Additions, Historical Test Year

Annual Additions	$ Million
Regular	$22.0
Large	$85.0

* Note that, in the simulations, net plant is used as a surrogate for rate base

As shown above, the End-of-Year and Annualization (Annualized) methods appears to provide a more accurate reflection of the capital employed (rate base) during the rate year, which for these purposes is defined as the year following the test period.[10] For investment during the 1st half of the test year, net book value[11] for Year-End and Annualized methods is $290.8 and $289.8 million, respectively, which varies only slightly from the net book value ($293.2 million) during the rate year. Similarly for large investments during the 2nd half of the test year: net book value for Year-End and Annualized methods of $291.9 and $289.8 million, respectively, closely approximates net book value for the rate year of $294.4 million. In both cases, average methods – 13-month average balances in the example – general tend understates net book value during the rate year by approximately $20 million in the case of the large investment entering service during the 1st half of the test year, and by approximately $62 million in the case of major investment entering service during the 2nd half of the test year.

[10] Note that the simulations do not take account of evolution in general sales volumes. Depending on circumstances, it may be appropriate to adjust the above analysis for expected changes in sales levels over time.

[11] Differences in measures of net book value would carry through to differences in measurement of the rate base, as other rate base elements would be held virtually unchanged.

It is useful to mention that this approach, Annualization, has precedence in the Province of Newfoundland and Labrador. In Order P.U. 22 of 2017 regarding NLH's 2013 General Rate Application Amended, the Board of Public Utilities (Board, PUB) authorized a full 12-month coverage of the capital charges on the Company's Holyrood gas turbine generating unit for rate setting purposes commencing in 2016 because it was in service for all of 2016. Whereas, the asset was only partially recovered during 2015 using the opening and closing method because it went into service in February 2015.

Capital Structure: As alluded to above, determination of the weighted average cost of capital (WACC), for purposes of setting rates, is related to rate base methodology. However, the relationship is only tangential, where the criterion "rates reflect the costs of utility services at the time that services are provided" is controlling. The carrying charges on capital – i.e., net rate base – are the product of the rate base and the WACC, and represent a large share of total costs. As a matter of consistency, it is often appropriate to determine a utility's WACC in a manner that aligns with the its determination of the rate base. Thus, if the rate base is based on 13-month average asset balances, the WACC may reflect monthly capital structure balances; similarly, beginning-of-year and end-of-year balances may be used, both for determining the rate base and the capital structure within the WACC.

The symmetry of method for determining the rate base and capital structure may not always hold. It is a matter of circumstances, and the best approach may vary from one General Rate Application to another. Much depends on financing activities and plans. Indeed, methodology symmetry may selectively break down, causing non-trivial differences between recovery of the charges on capital in rates and the weighted average cost of capital at the time that services are provided. This is particularly the case where, again, invested capital for large resource additions is introduced into rate base.[12] The WACC over the forward year, when the new facility is operating – and the capital addition is in rate base – may be substantially different from that observed for a recent historical period, particularly when the history involves construction and the mix of financing vehicles used to underwrite the investment has, at the time of commercial operation, has changed.

Similar to the approach used to gauge rate base methods, we draw on simulation analysis to illustrate and assess the effects of alternative capital structure methods. The issue at hand is the accuracy afforded by alternative capital structure methods to capture the weighted average cost of capital during

[12] Short-term debt is often used to finance large facilities during construction. Once new facilities under construction transition to commercial operating status, sizable balances of short-term debt may have accumulated, as short-term debt (or other forms of debt financing) are often used to help carry the facility projects over the course of construction. When operating status is reached – with the associated investment introduced into rate base – accumulated short-term debt balances are then rolled over into new issues of long-term mortgage debt, and infusions of equity also. In brief, sizable balances of short-term debt may be observed within the total balances of outstanding capital debt at the time of construction, with the expectation of rolling such amounts into long-term financing vehicles in the near term, perhaps only a few months forward. Also, the differences between short- and long-term interest rates – i.e., yield curve – vary from time to time; the relative level of short- and long-term rates may have impact on the schedule for conversion of short-term debt balances to longer-term financing vehicles.

the rate period, the consecutive twelve months immediately following a test period. As with the analysis of rate base methods, four capital structure methods are assessed: *Beginning and Ending Balances*, *13-Month Average*, *Annualization*, and *End-of-Year Balances*. The context, again, is the introduction of large increases to the plant-in-service balances during the first half and, alternatively, second half of the historical test period. Simulation results appear in Table 6, below.

Table 6
ASSESSING ALTERNATIVE CAPITAL STRUCTURE METHODS: INTRODUCING LARGE MID-YEAR ADDITIONS TO A HISTORICAL TEST PERIOD RATE BASE

CAPITAL STRUCTURE

Large Investment During 1st Half of Historical Test Year

	Capital Structure Weights				
Financing Vehicle	Beginning and Ending Balances	13-Month Averge	Year-End	Annualized	Rate Period: Average Over Forecast Year
Short-Term Debt	0.196	0.202	0.103	0.135	0.098
Long-Term Debt	0.401	0.399	0.443	0.434	0.440
Equity	0.402	0.399	0.454	0.431	0.462
Total	1.000	1.000	1.000	1.000	1.000

Large Investment During 2nd Half of Historical Test Year

	Capital Structure Weights				
Financing Vehicle	Beginning and Ending Balances	13-Month Averge	Year-End	Annualized	Rate Period: Average Over Forecast Year
Short-Term Debt	0.202	0.297	0.114	0.135	0.110
Long-Term Debt	0.401	0.353	0.441	0.434	0.438
Equity	0.397	0.350	0.444	0.431	0.452
Total	1.000	1.000	1.000	1.000	1.000

WEIGHTED AVERAGE COST OF CAPITAL

Large Investment During 1st Half of Historical Test Year

	Beginning and Ending Balances	13-Month Averge	Year-End	Annualized	Rate Period: Average Over Prompt Year
WACC	5.72%	5.69%	6.12%	5.95%	6.16%

Large Investment During 2nd Half of Historical Test Year

	Beginning and Ending Balances	13-Month Averge	Year-End	Annualized	Rate Period: Average Over Prompt Year
WACC	5.68%	5.31%	6.05%	5.95%	6.09%

Conclusions similar to those regarding rate base determination can be reached. The capital structure simulation results shown above suggest that, for determining rates over the prospective rate period, End-of-Year and Annualized methods better capture the weighted average cost of capital during the

forward rate year. In the case of large investment during the 1st half of the test year, Year End and Annualized methods obtain 6.12% and 5.95% WACC estimates, respectively, which closely approximate the average rate year level, 6.16%. Similarly under the 2nd half of year investment case, 6.05% and 5.95% WACC for Year End and Annualized methods, respectively, are near the 6.09% WACC level for the rate year.

In essence, it is appropriate for the rate setting process to review average methods (i.e., beginning- and end-of-year) for determination of the WACC. Other approaches may provide a more accurate reflection of the WACC during the prospective rate year. Changes to the WACC may be come about abruptly, as financings associated with major construction are manifested as capital structure changes, just as new additions enter rate base. Under such conditions, it is appropriate to consider the annualization of new financing vehicles such as long-term debt issues. However, major capital structure changes are highly case specific; in the context of setting rates over forward periods, variation from average balances to determine the capital structure is best handled on a case-by-case basis.

SUMMARY

Our survey of Canadian and US electric utilities with respect to measurement of used and useful capital residing within the rate base found that the practices in play are highly varied, with no method dominant. The focus of the survey was frequency and point in time that utilities measure capital. The applied rate base methods include 13-month averages, beginning-of-year and end-of-year averaging, and end-of-year along with several variations. No pattern of geography, size, or corporate structure appears to be determinative of the method used. This suggests that NLH should exercise broad discretion in deciding how to value its rate base.

The central objective for rate base measurement is accurate coverage of the charges on capital used in the provision of services, while also not introducing significant reporting burdens. The 13-month average approach appears to be the better approach for taking account of ongoing, routine plant additions – in essence, reflecting a more-or-less steady evolution, or path, for plant-in-service balances over time. However, 13-month averaging may present procedural limitations, in view of the financial accounting systems currently in place. Moreover, with routine additions where the rate base assumes a steady and gradual path over time, the 13-month average approach may offer only limited improvement in measurement accuracy, compared to the beginning- and ending-balances methodology. For this reason, beginning- and end-of-year average may serve quite well and, along with 13-month average, appears to be widely employed by electric utilities.

Rate base measurement practices under routine conditions, where the path of plant-in-service balance changes is gradual, does not necessarily hold for cases in which large additions in rate base take place during mid- or late-year. Large additions, including both generation and transmission facilities, may give rise to a systematic understatement of plant-in-service balances over forward rate periods, if not properly handled. For large additions, utilities employ a variety of approaches to rate base methodology

and regulatory governance. It is generally more accurate to use either an end-of-period rate base or an average rate base adjusted for known and measurable changes (annualization). Such approaches should provide the means to properly measure the capital employed in the provision of electricity services over forward periods.

RECOMMENDATION

It is recommended that Hydro and the Board adhere to the general principle: ensure coverage of the capital charges in rates at the time that capital is employed in the provision of services. To this end, Hydro and the PUB should continue to use opening and closing balances to determine the average rate base in the normal course of operation. In the event of significant capital additions, we recommend that Hydro and the PUB follow recent precedence of annualizing rate base associated with a sizable addition. As a general guideline, plausible threshold levels of investment subject to special treatment (end-of-period, annualization) appear to reside in the range of 5-7% of the cost of service systems' rate base. Second, should annualization be required for a capital addition, we recommend that the capital structure used to determine the WACC also be evaluated to gauge whether it is appropriate to annualize certain components of the capital structure.

Exhibit 11 - 2016 Depreciation Study

CONCENTRIC ADVISORS

October 5, 2017

Newfoundland and Labrador Hydro
Hydro Place, 500 Columbus Drive
P.O. Box 12400
St. John's, NL
A1B 4K7

Attention: Mr. Michael Conway, CA, CPA
Manager Regulatory Finance

Please find attached the revised 2016 Depreciation Study. The previous study had inadvertently included some incorrect wording, incorrect labeling of account titles in Section V and VI of the Depreciation Study report, and Tables 1A and Tables 1B were incorrect. This report now correctly reflects our recommendations and the calculations performed by the Company.

The following summarizes the changes.

- Revision date on the cover of the Depreciation Report changed to October 5, 2017.
- Introductory page, date changed to "October 5, 2017".
- Introductory paragraph added: "depreciation, the statistical analyses of service life and net salvage percentages and, the summary and detailed tabulations of annual and accrued depreciation."
- Signature block added: "Canada".
- Table of Contents: Various page numbers and description changes.
- Page IV, 1st paragraph, 2nd sentence "This recommendation is in response to a PUB…". Removed "Board" added "PUB"
- Page IV, last sentence: Removed "$.8M" and added "$0.8M".
- Part I, Page I-3, footnote4: Replaced "Utilities" to "utilities".
- Part I, Page I-4, middle of page. Paragraph added: "To recognize the early and complete….". This change and results are shown in Table 1A and 1B."
- Part I, page I-5, middle of first paragraph added: "NL Hydro currently records the removal…be charged to accumulated depreciation."



- Part I, Page II-12, Account G03 – Generators. First sentence investment composition changes from “4.1%” to “4.0%”.
- Part I, page I-7, first paragraph added: “expectation as NL Hydro is capitalizing a portion of the removal costs.”
- Part II, Page II-7, Account C13, first paragraph, removed: “ , the smaller communities are converting to electrical power sources so there is a need to upgrade conductor size.”
- Part II, Page II-12, first paragraph replaced “standby” to “stand by”.
- Part II, Page II-12, Account G03 replaced “4.1%” to “4.0%”.
- Part II, Page II-16, Account P05 deleted “Discussions and review with NL Hydro representatives indicated that there are no salt water issues and that the climate of NL Hydro’s territory is largely dry and cold resulting in less corrosive influences." New: “NL Hydro representatives suggest…”
- Part II, Page II-16, Account P07 – Poles – Wood. First paragraph sentence “Discussions and review with NL Hydro representatives indicated that a tower painting program is in force to extend the life. In addition, there are no salt water issues and that the climate of NL Hydro’s territory is largely dry and cold resulting in less corrosive influences” has been deleted.
- Part II, Page II-19, Account T04 – Towers. First paragraph sentence “Discussions and review with NL Hydro representatives indicated that a tower painting program is in force to extend the life. In addition, there are no salt water issues and that the climate of NL Hydro’s territory is largely dry and cold resulting in less corrosive influences” has been deleted.
- Part III, Page III-5. [Old]: "International Accounting Standard (“IAS”) #14."
  [New]: "IFRS 14." [Old]: "147."
  [New]: "14 7." (Footnote move to here)
  [Old]: "transactions 7 ," (switched where footnotes were)
  [New]: "transactions,"
- Part III, Page III-7, replaced “Combuster” with “Compressor”.
- Part IV, Page IV-2 , replaced “VI-3” to “VI-2”.
- Part IV, Page IV-3 to IV-10 – Tables 1A and 1B were incorrect and have been replaced in their entirety.
- Part V and VI, Account titles changed for:
  - Account D01 – Dams, Dykes, Canals and Tunnels
    - Pages V-75, V-76, and V-77
  - Account I02 – Instrumentation
    - Pages V-132, V-133, V134, and VI-59



- Account I03 – Insulators
  - Pages V-135, V-136, and V-137
- Account I04 – Intake Structures
  - Pages V-138, V-139, V-140
- Account I05 – Inverters
  - Pages V-141, V-142, V-143

- Part VI, pages VI-2 to VI-192, titles changed from “As of December 31, 2016” to “As of December 31, 2015”.

With the above changes, the attached report is correct to the best of our knowledge.

Sincerely,

CONCENTRIC ADVISORS ULC



Larry E. Kennedy
Vice President

LEK/bmw

NEWFOUNDLAND AND LABRADOR HYDRO

ST. JOHN'S, NEWFOUNDLAND

2016 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES APPLICABLE TO PLANT IN SERVICE

AS OF DECEMBER 31, 2015

Revised: October 5, 2017

Prepared by:

CONCENTRIC ADVISORS

Calgary. Alberta

CONCENTRIC ADVISORS

September 15, 2017

Newfoundland and Labrador Hydro
Hydro Place, 500 Columbus Drive
P.O. Box 12400
St. John's, NL
A1B 4K7

Attention: Mr. Michael Conway, CA, CPA
Manager Regulatory Finance

Ladies and Gentlemen:

Pursuant to your request, we have conducted a review and assessment of the electric generation, transmission and distribution systems of Newfoundland and Labrador Hydro ("NL Hydro") as of December 31, 2015. Our report presents a description of the methods used in the estimation of depreciation, the statistical analyses of service life and net salvage percentages and, the summary and detailed tabulations of annual and accrued depreciation.

We gratefully acknowledge the assistance of NL Hydro personnel in the completion of the review.

Respectfully submitted,

CONCENTRIC ADVISORS CANADA ULC



LARRY E. KENNEDY, CDP
Vice President

LEK/
Project: 061170

TABLE OF CONTENTS

Executive Summary III
PART I. INTRODUCTION I-1
Scope I-2
Plan of Report I-2
Basis of the Study I-3
Depreciation I-3
Service Life and Net Salvage Estimates I-6

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS II-1
Depreciation II-2
Estimation of Survivor Curves II-2
Survivor Curves II-2
Survivor Curves and Net Salvage Judgments II-3
NL Hydro Accounts II-4

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION III-1
Calculation of Annual and Accrued Depreciation III-2
Review of Conversion to a Group Accounting Method III-2
Group Depreciation Procedures III-3
International Financial Reporting Standards (IFRS) and Forecasting Purposes III-4
Calculation of Annual and Accrued Amortization III-6
Monitoring of Book Accumulated Depreciation III-7

PART IV. RESULTS OF STUDY IV-1
Qualification of Results IV-2
Description of Detailed Tabulations IV-2

Table 1A Estimated Survivor Curves, Original and Deemed Costs and Annual Accruals Related To Plant in Service as of December 31, 2015
- Life IV-4

Table 1B Estimated Survivor Curves, Original and Deemed Costs and Annual Accruals Related To Plant in Service as of December 31, 2015
- Cost of Removal IV-7

APPENDIX 1 – ADDITIONAL EVIDENCE OF LARRY KENNEDY A1-1

APPENDIX 2 – ESTIMATION OF SURVIVOR CURVES A2-1
Estimation of Survivor Curves A2-2
Average Service Life A2-2
Survivor Curves A2-2
Iowa Type Curves A2-2

TABLE OF CONTENTS, Cont'd.

Retirement Rate Method of Analysis A2-9
Schedules of Annual Transactions in Plant Records A2-9
Schedule of Plant Exposed to Retirement A2-12
Original Life Table A2-14
Smoothing the Original Survivor Curve A2-16

NEWFOUNDLAND AND LABRADOR HYDRO
DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Newfoundland and Labrador Hydro's ("NL Hydro" or "Company") request, Concentric Advisors Canada ULC ("Concentric Advisors") conducted a depreciation study related to generation, transmission, distribution, and general plant accounts as of December 31, 2015.

Concentric Advisors is proposing changes from NL Hydro's last approved depreciation study. The first change is applicable to 2015 investment only. For all vintages up to and including 2014, depreciation rates are based on the straight line method using the Average Service Life (ASL) group procedure and applied on a remaining life basis consistent with the previous depreciation study. For current plant (i.e. 2015 vintage) the depreciation rates are based on the straight line method using the Equal Life Group (ELG) procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life.

Secondly, this study makes provision for the recovery of the original cost of investment (net of anticipated gross salvage proceeds) and for the cost of removal[1] to be collected through depreciation expense, as compared to the current collection of cost of removal in the year of occurrence.

Third, to recognize the early and complete retirement of a large portion of the Holyrood Generating Station assets, the assets that are anticipated to be retired have been identified by NL Hydro and have been subjected to a truncation date of March 31, 2021. The truncation date results in a corresponding increase in each account's depreciation rate to reflect the complete recovery of the Holyrood assets that will be retired by the recommended truncation date of March 31, 2021. This change and results are shown in Table 1A and 1B.

Fourth, to recognize that NL Hydro utilizes deemed cost in its accounting systems for financial disclosure purposes, Concentric Advisors has developed deemed cost

[1] Does not include the expected costs of retirement that are included in Asset Retirement Obligation calculations

accrual rates for each depreciable account as shown on Tables 1A and 1B. For post 2015 additions Concentric Advisors recommends and has provided whole life accrual rates that do not reflect the booked depreciation deficiency or surplus position as of December 31, 2015. These deemed cost accrual rates will then ensure the accurate recovery of NL Hydro's deemed cost investment as of December 31, 2015.

Fifth, in this report Concentric Advisors recommends the conversion to a more traditional group accounting concept. This recommendation is in response to a PUB directive resulting from the last depreciation study and negotiated settlement application relating to the historical NL Hydro departure from the use of typical regulated group depreciation accounting. Concentric Advisors has prepared a report titled "Evidence of Larry E. Kennedy Related To The Conversion To Group Accounting Methods" which is attached as Appendix 1 to this report. This evidence discusses the issues and concepts related to Group Depreciation and provides a recommendation to convert to Group Depreciation accounting. Under Group Depreciation no gain or loss on disposal is recognized since the accumulated depreciation relates to the entire group rather than to specific assets within the group. This recommendation was used in the development of the depreciation rates that are determined in the Concentric Advisors Depreciation Study.

The effect of the proposed partial incorporation of the ELG procedure, the changes to the average service lives, the introduction of the recovery of cost of removal related to the final retirement of assets and the elimination of losses on retirements[2], when applied to 2015 original cost is an approximate $0.8M increase in annual depreciation expense as detailed below.

	Expense	Change
Previous Parameters	$60,623,582	
Life Parameter Change	$56,736,099	-$3,887,483
Net Salvage Change	$64,912,188	$8,176,089
ELG Change	$66,402,637	$1,490,449
Losses on Retirements[3]		-$4,969,000

[2] Includes costs associated with loss on retirement, disposal costs, and salvage proceeds that were previously charged to NL Hydro's income statement.
[3] For the period 2012 to 2015.

Total Change	$ 810,055

Concentric Advisors recommends the calculated annual depreciation accrual rates set forth herein as summarized by Tables 1A and 1B of the study by account detail. Supporting data and calculations are provided in Parts V and VI in the Supporting Documents.

PART I. INTRODUCTION

NEWFOUNDLAND AND LABRADOR HYDRO
DEPRECIATION STUDY
PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for NL Hydro to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of NL Hydro's generation, transmission, distribution, and general plant assets as of December 31, 2015. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the electric plant in service.

The service life and net salvage estimates resulting from the study were based on: consideration of current practice in the electric generation, transmission and distribution industry, including knowledge of service lives used for other electric utilities; a review of company practice and outlook as they relate to plant operation and retirement; a review of the company's upcoming capital and retirement projects; and informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2015.

PLAN OF REPORT

Part I. Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II. Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life and net salvage studies. Part III. Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation. Part IV. Results of Study, presents summaries by depreciable group of annual and accrued depreciation. The Additional Evidence of Larry Kennedy Related to the Conversion to Group Accounting Methods is presented in Appendix 1. An overview of Iowa curves and the Retirement Rate Analysis are set forth in Appendix 2 of the report. Parts V and VI of this report are found in the Supporting Documents. Part V presents the results of the Retirement Rate

and Service Life Statistics and detailed tabulations of annual and accrued depreciation are presented in Part VI.

BASIS OF THE STUDY

Depreciation

As mentioned in the Executive Summary, Concentric Advisors is proposing a change in procedure for current plant from the ASL procedure to the ELG procedure. Concentric Advisors is proposing a gradual phased in approach to the ELG procedure which will result in a more accurate alignment of the depreciation expense to the consumption of the service value of the assets providing utility service. The Board of Commissioners of Public Utilities (the "Board") has long accepted the better accuracy of ELG depreciation rates for Newfoundland Power. In the circumstances of Newfoundland Power, the Board first accepted ELG rates for new plant in their 1978 general rate hearing. Following the 1982 general rate hearing, the Board accepted that ELG rates would be used for all plant, and since 1983 the procedure has been in place for Newfoundland Power. Concentric Advisors recommends a similar gradual phased in process as described above in order to minimize the impact to current customers while implementing a change that will benefit future customers.

Other jurisdictions in Canada and the United States have also concluded that ELG procedure is the most appropriate depreciation procedure[4]. In the United States, more utilities use ASL, although ELG is still used in some states. However, in Canada the use of ELG is much more pronounced. The ELG procedure is widely accepted for depreciation rates in Canada, and is the long-standing practice of Newfoundland Power. Its use for more than three decades by Newfoundland Power provides a net benefit to current customers and the transition of NL Hydro to ELG provides a net benefit for future customers for NL Hydro as well.

The incorporation of ELG procedure in the depreciation rate calculation is in compliance with the International Financial Reporting Standards (IFRS) when using group

[4] In Canada, this includes most utilities in Alberta and Saskatchewan, in addition to Gaz Metro and Yukon Electrical Company Limited

accounting methods. External Auditors have generally been very accepting of the group accounting process when the ELG procedure is used by utilities reporting under the IFRS. The acceptance is based on the better and proper matching of the depreciation expense to the consumption of service value of the assets with the ELG procedure. Both the ASL and ELG procedures will result in 100% recovery of original costs. However, the ASL procedure utilizes an averaging principle which under recovers the original cost on assets that retire prior to the average service life while over recovering the original cost on assets that retire after the average service life. This inherent assumption results in an under recovery during the early years of a fixed asset account (or UOP) compensated by an over recovery in the later years but still reflecting complete recovery over the fixed asset account's life. The ELG procedure, however, recognizes that some assets retire before and after the average service. By recognizing the actual physical life retirements through its inherent calculations, the ELG procedure more accurately reflects each asset's original cost recovery to its physical life.

To recognize the early and complete retirement of a large portion of the Holyrood Generating Station assets, the assets that are anticipated to be retired have been identified by NL Hydro and have been subjected to a truncation date of March 31, 2021. This represents a small update from the previous Depreciation study where a truncation date of 2020 was identified. The current truncation date results in a corresponding increase in each account's depreciation rate to reflect the complete recovery of the Holyrood assets that will be retired by the recommended truncation date of March 31, 2021. This change and results are shown in Table 1A and 1B.

For most accounts, the annual and accrued depreciation were calculated by the straight line method ASL procedure for all vintages up to and including 2014 and the straight line method ELG procedure for 2015 vintages. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required to track small assets in these accounts. Many regulated utilities in North America have received approval to adopt amortization accounting for these accounts. All the calculations were based on original cost, attained ages, and estimates of service lives and salvage.

This study also recommends the incorporation of the anticipated cost of removal within the depreciation rate calculations. However, the cost of removal percentage recommendations were moderated to ensure continuity of the past practices of NL Hydro. NL Hydro policy is to capitalize site preparation costs to the new assets in replacement projects. NL Hydro has indicated that they will continue with this practice which results in a less cost of removal percentage as compared to a number of the industry peers including Newfoundland Power. The NL Hydro policy reflects the IFRS view that the replacement of an asset is dependent upon the removal of the existing asset and thus should be capitalized to the new replacement asset. However, if there are no replacement assets (i.e. meaning replacement in the exact same location), NL Hydro currently records the removal costs to an income statement account in the year occurred. This practice has required that the removal entries be forecast for all test periods which requires estimation and inclusion in the test year's revenue requirement. Given the current practices requirement to estimate forecast removal costs, there exists a potential of material over or under recovery of NL Hydro's net income. Therefore Concentric Advisors recommends that cost of removal be charged to accumulated depreciation. The inclusion of an allowance for cost of removal in this manner provides for the proper matching of expenses to revenues, without any double counting of the estimates in revenue requirement request. The recovery of cost of removal in the depreciation rates is widely accepted throughout North America[5], including Newfoundland Power for many decades. Delaying collection until such costs are incurred results in a charge to customers for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to cost of removal. The appropriateness and accuracy of including cost of removal into NL Hydro's rates should be reviewed during each depreciation study to ensure they reflect that the most up to date information has been incorporated into net salvage rate development.

Gross salvage (i.e. proceeds upon retirement) have been incorporated into the Life component of depreciation rates (i.e. Table 1A-Life) and cost of removal (i.e. removal

[5] For example, Canadian jurisdictions such as Alberta, British Columbia, Saskatchewan, Manitoba, Ontario, Quebec, Northwest Territories, Nova Scotia, and many jurisdictions in the United States.

expenditures upon retirement) into the Cost of Removal component of depreciation rates (i.e. Table 1B-Cost of Removal). This delineation of gross salvage and cost of removal is consistent with financial disclosure requirements of IFRS.

Service Life and Cost of Removal Estimates

The service life and cost of removal estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and cost of removal estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for electric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future, which included reviews of detailed upcoming project business cases and operational staff interviews. Additionally, detailed asset retirement information (where known) for upcoming retirement projects was incorporated into the data files for the analysis of average service life. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The procedure for estimating cost of removal considered to a large extent the approved cost of removal parameters for Newfoundland Power's 2015 depreciation study. However, due to differing accounting policies related to cost of removal between NL Hydro and Newfoundland Power, adjustments to NL Hydro's recommended cost of removal were required. Since at least the early 1980's, Newfoundland Power charges all cost of removal to accumulated depreciation (in accordance with Newfoundland Power's financial disclosure under Canadian and USGAAP) whereas NL Hydro's policy is to capitalize cost of removal to the new assets in replacement projects (in accordance with the IFRS requirements) and NL Hydro has indicated that they will continue with this

practice. This reflects NL Hydro's view that the replacement of an asset is dependent upon the removal of the existing asset and thus should be capitalized to the new replacement asset. However, if there are no replacement assets (i.e. meaning replacement in the exact same location), then Concentric Advisors recommends that cost of removal will be charged to accumulated depreciation. The effect of this policy is a reduced cost of removal expectation as NL Hydro is capitalizing a portion of the removal costs. NL Hydro does not have account specific cost of removal results however corporate removal costs are available and have been provided for the past four years. To reflect this recent corporate cost of removal experience, Concentric Advisors has applied a reduced percentage to all cost of removal accounts accordingly.

The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

PART II. DEVELOPMENT OF DEPRECIATION PARAMETERS

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, and obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

The calculation of annual and accrued depreciation based on the straight line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed in Part III of this report.

ESTIMATION OF SURVIVOR CURVES

Survivor Curves

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and relative height of the modes. The left-moded curves are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical-moded curves are those in which the greatest frequency of retirement occurs at average service life. The right-moded curves are those in which the greatest frequency occurs to the right of, or after, the average service life. The origin-moded curves are those in which the greatest frequency of retirement occurs at the origin, or immediately after age 0. The letter designation of each family of curves (L, S, R or O) represents the mode of the associated frequency curve with respect to the average service life. The numerical subscripts represent the relative heights of the modes of the frequency curves within each family.

A discussion of the general concept of survivor curves and retirement rate method is presented in Appendix 2 of this report.

Survivor Curve and Net Salvage Judgments

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined during conversations with management personnel, knowledge and review of upcoming capital projects, which included reviews of detailed upcoming project business cases and operational staff interviews. The average service life analysis also included a review of the impact of large retirements caused by forces of nature, and on the knowledge Concentric Advisors developed through the completion of numerous electric utility studies. Additionally, detailed asset retirement information (where known) for upcoming retirement projects was incorporated into the data files for the analysis of average service life in order to ensure that all known impacts of retirements could be considered.

NL Hydro has indicated that there is minimal historical net salvage data. As such, the initial estimates of net salvage were based on peer comparison and on the knowledge and experience of Concentric Advisors.

NL Hydro Accounts

Account B02 – Boiler System - The investment in Boiler System comprises 2.2% of the total depreciable plant. The investment in this account mainly consists of steam generator, boiler structure & boiler secondary super-heater. The currently approved average service life estimate is the Iowa 35-R3. The retirement rate analysis prepared in this study reviewed the plant installed over the period of 1968 through 2015 and the retirement experience covering the period of 1968 through 2015. Over this period this account has experienced $11,281,692 of retirements over a widely sparse range of ages as summarized on the observed life table provided on pages V-12 and V-13 of this report. An analysis of the currently approved Iowa 35-R3 did not provide a good fit over the observed data. To better fit the data a five-year increase to the average service life was deemed appropriate. As shown on the fitted smooth curve on page V-11, an Iowa 40-R3 provides a better fit to the observed data. Discussions and review with NL Hydro representatives suggested that the recommended 40-R3 was reasonable for this account. Therefore, the current approved Iowa 40-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has used its knowledge and experience, peer comparisons, knowledge of NL Hydro's capitalization and removal policies, and discussions with NL Hydro representatives to recommend negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is a reasonable for this account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account B05 – Buildings - Other - The investment in Buildings - Other comprises 2.7% of the total depreciable plant. The investment in this account mainly consists of building structures and components including HVAC systems, security, etc. The currently approved average service life estimate is the Iowa 50-R0.5. The retirement rate analysis prepared in this study reviewed the plant over the period of 1965 through 2015. Over this period this account has experienced $11,256,905 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-21 and V-22 of this report. As shown on the fitted smooth curve on page V-20, the currently approved Iowa 50-R0.5 provides a reasonable fit to the complete observed data. A peer

comparison of Canadian utilities produced a wide range from 20 to 70 years. Discussions and review with NL Hydro representatives suggested that the currently approved Iowa 50-R0.5 is a reasonable expectation for this account. Based on the above, the current approved Iowa 50-R0.5 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 30 percent for their Hydro Production Structures, negative 35 percent for their Diesel Structures, 0 percent for their Substation Structures, negative 5 percent for their Distribution Structures, and 5 percent and 15 percent for their small and large General Plant Structures respectively. Nova Scotia Power Inc. utilizes negative 5 percentage for their Distribution Structures and for their General Plant Structures. Newfoundland Power Inc. has a net salvage percentage of negative 10 percent for their Hydro Production Structures, negative 20% for their Diesel Structures, negative 15 percent for their Transmission Substation Structures, and negative 10 percent and 0 percent for their small and large buildings respectively. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 3 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 3 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 3 percent to best represent the future expectations for the equipment in this account.

Account B06 – Buildings - Metal - The investment in Buildings - Metal comprises 1.3% of the total depreciable plant. The investment in this account mainly consists of powerhouse and pump-house structures and components, and metal control buildings in stations. The currently approved average service life estimate is the Iowa 55-R3. The retirement rate analysis prepared in this study reviewed the plant over the period of 1965 through 2015. Over this period this account has experienced $1,895,706 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-24 and V-25 of this report. As shown on the fitted smooth curve on page V-23, the currently approved Iowa 55-R3 still provides a reasonable fit to the complete observed data. A peer comparison of Canadian utilities produced a wide range from 20

to 70 years. Discussions and review with NL Hydro representatives suggested that the currently approved Iowa 55-R3 is a reasonable expectation for this account. Based on the above, the currently approved Iowa 55-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of 5 percent and 15 percent for their small and large buildings respectively. Nova Scotia Power Inc. utilizes negative 5 percentage. Newfoundland Power Inc. has a net salvage percentage of negative 10 percent and 0 percent for their small and large buildings respectively. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 3 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 3 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 3 percent to best represent the future expectations for the equipment in this account.

Account C09 – Circuit Breakers - The investment in Circuit Breakers comprises 1.5% of the total depreciable plant. The investment in this account mainly consists of breakers & upgrades, switches and switchgear. The currently approved average service life estimate is the Iowa 55-R3. The retirement rate analysis prepared in this study reviewed the plant over the period of 1965 through 2015. Over this period this account has experienced $2,751,415 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-49 and V-50 of this report. A significant amount of retirements have occurred relatively early at ages 0.0 to 9.5. Concentric Advisors has placed less emphasis on this early retirement activity. An analysis of the currently approved Iowa 55-R3 did not provide a good fit over the observed data. As shown on the fitted smooth curve on page V-48, an Iowa 60-R2.5 provides an excellent fit to the observed data. Discussions and review with NL Hydro representatives agreed that the recommended Iowa 60-R2.5 is a reasonable expectation for this account. Based on the above, the current approved Iowa 60-R2.5 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has used its knowledge and experience, peer comparisons, knowledge of NL Hydro's capitalization and removal policies, and discussions with NL

Hydro representatives to recommend negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is a reasonable for this account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account C13 – Conductor - Transmission - The investment in Conductor - Transmission account comprises 2.6% of the total depreciable plant. The investment in this account mainly consists of transmission conductor. The currently approved average service life estimate is the Iowa 60-R3. The retirement rate analysis prepared in this study reviewed the plant over the period of 1967 through 2015. Over this period this account has experienced $3,158,000 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-58 and V-59 of this report. As shown on the fitted smooth curve on page V-57, the currently approved Iowa 60-R3 provides a good fit over the available observed data. A peer comparison of Canadian utilities produced a range from 45 to 80 years. Discussions and review with NL Hydro representatives indicated that there are no major issues with conductor. They also indicated that existing conductor is mainly bare but there is some coated conductor and that there are no salt water issues. NL Hydro representatives suggested that the current 60-R3 was reasonable for this account. Based on the above, the current approved Iowa 60-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 25 percent. Nova Scotia Power Inc. utilizes negative 10 percentage for their Transmission Conductor. Newfoundland Power Inc. utilizes negative 35 percentage for their Transmission Conductor. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 20 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 20 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 20 percent to best represent the future expectations for the equipment in this account.

Account C14 – Conductor - Distribution - The investment in Conductor - Distribution comprises 1.3% of the total depreciable plant. The investment in this account mainly consists of distribution conductors at 25 kV and below including primary, secondary and service drop conductors. The currently approved average service life estimate is the Iowa 55-R3. The retirement rate analysis prepared in this study reviewed the plant over the period of 1971 through 2015. Over this period this account has experienced $2,500,908 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-61 and V-62 of this report. An analysis of the currently approved Iowa 55-R3 did not provide a good fit to the observed data. As shown on the fitted smooth curve on page V-60, an Iowa 45-R3 provides an excellent fit over the available observed data. A peer comparison of Canadian utilities produced a wide range from 29 to 60 years. Discussions and review with NL Hydro representatives indicated that there are no major issues with conductor, the smaller communities are converting to electrical power sources so there is a need to upgrade conductor size. They also indicated that existing conductor is mainly bare but there is some coated conductor and that there are no salt water issues. NL Hydro representatives agreed that the recommended 45-R3 was reasonable for this account. Based on the above, the currently approved Iowa 45-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 25 percent. Nova Scotia Power Inc. utilizes negative 15 percentage for their Distribution Conductor. Newfoundland Power Inc. utilizes a range of negative 25 percent to negative 35 percent for their Distribution Conductor. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 14 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 14 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 14 percent to best represent the future expectations for the equipment in this account.

Account C15 – Control, Meter, Relaying - The investment in Control, Meter, Relaying account comprises 1.1% of the total depreciable plant. The investment in this

account mainly consists of plant and turbine protection, control meter/relay including revenue metering, station controls and protection. The currently approved average service life estimate is the Iowa 30-R1. The retirement rate analysis prepared in this study reviewed the plant over the period of 1966 through 2015. Over this period this account has experienced $2,594,863 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-64 and V-65 of this report. An analysis of the currently approved Iowa 30-R1 did not provide a good fit to the observed data. As shown on the fitted smooth curve on page V-63, a recommended Iowa 40-R2.5 provides a good fit to the observed data. Discussions and review with NL Hydro representatives suggested that the recommended Iowa 40-R2.5 is a reasonable expectation for this account. Based on the above, the currently approved Iowa 40-R2.5 is recommended to best represent the future expectations for the equipment in this account.

NL Hydro representatives have indicated that 0 percent is a reasonable net salvage expectation for this account. Based on these comments, Concentric Advisors recommends 0 percent to best represent the future expectations for the equipment in this account.

Account D01 – Dams, Dykes, Canals and Tunnels – The investment in Dams, Dykes, Canals and Tunnels is the largest account and comprises approximately 13.8% of the total depreciable plant. The investment in this account mainly consists of dams, dykes, canals, and tunnels. The currently approved average service life estimate is an Iowa 100-R4. The retirement experience has been very small and as such has not resulted in any reliable historical indications. As such, the average service life recommendations were based primarily on the comments received from the NL Hydro operational staff, and on the experience of Concentric Advisors. A peer comparison of Canadian utilities was conducted which indicated a range from 70 years to 125 years. Discussions and review with NL Hydro representatives indicated that an active condition assessment program along with routine surveillance is utilized. No large capital programs are forecasted other than for routine maintenance. There was also general agreement that a 110-year life was reasonable for this account. Based on these comments and on

the peer comparison of Canadian utilities, an Iowa 110-R4 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 30 percent with Nova Scotia Power Inc. utilizing a range for all Hydro accounts of negative 20 percentage to negative 445 percent with an investment weighted average of negative 69 percent. Newfoundland Power Inc. has a net salvage percentage of negative 25 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account D02 – Diesel Systems and Engines - The investment in Diesel Systems and Engines comprises 1.6% of the total depreciable plant. The investment in this account mainly consists of engines, generators, cooling systems, and switchgear. The currently approved average service life estimate is the Iowa 25-S0.5. The retirement rate analysis prepared in this study reviewed the plant over the period of 1965 through 2015. Over this period this account has experienced $20,478,011 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-79 and V-80 of this report. An analysis of the currently approved Iowa 25-S0.5 did not provide a good fit over the observed data. As shown on the fitted smooth curve on page V-78, an Iowa 25-L0.5 provides an excellent fit over the observed data. Discussions and review with NL Hydro representatives indicated that the historical indications and recommended 25-L0.5 was reasonable for this account. Therefore, an Iowa 25-L0.5 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from two electric utilities. Northwest Territories Power Corporation has a recommendation of negative 25 percent and negative 5 percent for their Diesel Primer Movers and Generators respectively. Newfoundland Power Inc. has a net salvage percentage range of negative 20 percent to negative 65 percent for their Primer Movers and Generators. In

consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 11 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 11 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 11 percent to best represent the future expectations for the equipment in this account.

Account F06 – Fuel Systems - The investment in Fuel Systems comprises 1.6% of the total depreciable plant. The investment in this account mainly consists of fuel systems including storage tanks. The currently approved average service life estimate is the Iowa 50-R1.5. The retirement rate analysis prepared in this study reviewed the plant over the period of 1956 through 2015. Over this period this account has experienced $4,654,704 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-109 and V-110 of this report. As shown on the fitted smooth curve on page V-108, an Iowa 50-R1.5 still provides a good fit over the observed data. Discussions and review with NL Hydro representatives indicated that the historical indications and recommended 50-R1.5 was reasonable for this account. Therefore, an Iowa 50-R1.5 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from two electric utilities. Northwest Territories Power Corporation has a recommendation of negative 75 percent. Newfoundland Power Inc. has a net salvage range of negative 20 percent to negative 65 percentage. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 11 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 11 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 11 percent to best represent the future expectations for the equipment in this account.

Account G01 – Gas Turbine Systems - The investment in Gas Turbine Systems comprises 2.6% of the total depreciable plant. The investment in this account mainly consists of turbine engine and generators. The currently approved average service life estimate is the Iowa 35-R4. The retirement rate analysis prepared in this study reviewed the plant over the period of 1968 through 2015. Over this period this account has

experienced $5,403,986 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-112 and V-113 of this report. An analysis of the currently approved Iowa 35-R4 did not provide a good fit over the observed data. As shown on the fitted smooth curve on page V-111, an Iowa 45-R3 provides a good fit over the observed data. A peer comparison of Canadian utilities produced a range from 30 to 55 years. Discussions and review with NL Hydro representatives indicated that there are four Gas Turbines in NL Hydro's system. These turbines are mainly used for stand by and peaking purposes and that there has been little historical use and that this will likely continue in the near future. Discussions and review with NL Hydro representatives suggested that the current 35-year average service life appeared short and that the recommended 45-R3 was reasonable for this account. Therefore, the current approved Iowa 45-R3 is recommended to best represent the future expectations for the equipment in this account.

Newfoundland Power Inc. has a net salvage of negative 3 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 2 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 2 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 2 percent to best represent the future expectations for the equipment in this account.

Account G03 – Generators - The investment in Generators comprises 4.0% of the total depreciable plant. The investment in this account mainly consists of the electric power generator and assembly including rotor, bearings and excitation systems. The currently approved average service life estimate is the Iowa 60-S4. The retirement rate analysis prepared in this study reviewed plant over the period of 1966 through 2015. Over this period this account has experienced $2,804,759 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-118 and V-119 of this report. The currently approved Iowa 60-S4 did not fit the observed data as well as the Iowa 65-S3. A peer comparison of Canadian utilities indicated a range from 50 years to 70 years. Discussions and review with NL Hydro representatives suggested that the current 60-S4 appeared a little short and that an increase to a 65 year average service life was more reasonable for the equipment in this account. Based on

the above and the peer comparison of Canadian utilities, an Iowa 65-S3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 15 percent with Nova Scotia Power Inc. utilizing a range for all Hydro accounts of negative 20 percentage to negative 445 with an investment average of negative 69 percent. Newfoundland Power Inc. has a net salvage percentage of negative 25 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account I03 – Insulators - The investment in Insulators comprises 1.6% of the total depreciable plant. The investment in this account mainly consists of insulators for transmission lines and stations. The currently approved average service life estimate is the Iowa 30-L3. The retirement rate analysis prepared in this study reviewed the plant over the period of 1966 through 2015. Over this period this account has experienced $6,332,763 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-136 and V-137 of this report. An analysis of the currently approved Iowa 30-L3 did not provide a good fit over the observed data. As shown on the fitted smooth curve on page V-135, an Iowa 35-L3 provides an excellent fit over the observed data. A peer comparison of Canadian utilities produced a range from 31 to 37 years. Discussions and review with NL Hydro representatives indicated that porcelain and glass insulators are used in NL Hydro's system. They also viewed that the historical indications of a recommended 35-L3 was reasonable for this account. Therefore, an Iowa 35-L3 is recommended to best represent the future expectations for the equipment in this account.

NL Hydro representatives have indicated an expectation of 0 percent as a reasonable net salvage expectation for this account. Based on these comments, Concentric Advisors recommends 0 percent to best represent the future expectations for the equipment in this account.

Account M10 – Miscellaneous Units of Property - The investment in Miscellaneous Units of Property comprises 1.0% of the total depreciable plant. The investment in this account mainly consists of studies and assessments. The currently approved average service life estimate is the Iowa 20-R1. The retirement rate analysis prepared in this study reviewed the plant over the period of 1966 through 2015. Over this period this account has experienced $3,507,943 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-176 and V-177 of this report. As shown on the fitted smooth curve on page V-175, a recommended Iowa 22-R1.5 provides a good fit to the observed data. Discussions and review with NL Hydro representatives suggested that the recommended Iowa 22-R1.5 is a reasonable expectation for this account. Based on the above, the current approved Iowa 22-R1.5 is recommended to best represent the future expectations for the equipment in this account.

NL Hydro representatives have indicated that 0 percent is a reasonable net salvage expectation for this account. Based on these comments, Concentric Advisors recommends 0 percent to best represent the future expectations for the equipment in this account.

Account P03 – Penstock - The investment in Penstock comprises 2.2% of the total depreciable plant. The investment in this account mainly consists of penstock. The currently approved average service life estimate is an Iowa 70-R4. The retirement experience has been very small and as such has not resulted in reliable historical indications. A peer comparison of Canadian utilities indicated a 60-year average service life. Discussions and review with NL Hydro representatives suggested that the current 70-R4 was reasonable for this account. Therefore, the currently approved Iowa 70-R4 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from two electric utilities. Nova Scotia Power Inc. utilizes a range for all Hydro accounts of negative 20 percentage to negative 445 with an investment average of negative 69 percent. Newfoundland Power Inc. has a net salvage percentage of negative 25 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is reasonable for this

account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account P04 – Pole Cribs and Pole Hardware - The investment in Pole Cribs and Pole Hardware comprises 4.5% of the total depreciable plant. The investment in this account mainly consists of pole cribs and pole hardware at the distribution level including cross arms, insulators, brackets, pole gains, and cut-outs/fuse assemblies. The currently approved average service life estimate is the Iowa 50-L2. The retirement rate analysis prepared in this study reviewed plant over the years 1966 through 2015. Over this period this account has experienced $9,700,360 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-196 and V-197 of this report. The currently approved Iowa 50-L2 provided a good fit up to age 15, but does not fit to the ages afterwards. The Iowa 35-S2.5 provides a more appropriate fit to the complete observed data. A peer comparison of Canadian utilities produced a range from 31 to 85 years. Discussions and review with NL Hydro representatives suggested that the historical experience and the recommended Iowa 35-S2.5 is a reasonable expectation for this account. Based on the above and the peer comparison of Canadian utilities, the Iowa 35-S2.5 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized the net salvage recommendation of Account P05 of negative 20 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 20 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 20 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 20 percent to best represent the future expectations for the equipment in this account.

Account P05 – Pole Structures - Wood - The investment in Pole Structures – Wood comprises 4.9% of the total depreciable plant. The investment in this account mainly consists of wood pole structures including inspection and refurbishment at the transmission level (46 kV and above). The currently approved average service life estimate is an Iowa 53-R4. The retirement rate analysis prepared in this study reviewed the plant installed over the period of 1960 through 2015 and the retirement experience

covering the period of 1965 through 2015. Over this period this account has experienced $11,310,961 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-199 to V-200 of this report. The currently approved Iowa 53-R4 did not provide a good fit to the observed data. As shown on the fitted smooth curve on page V-198, the Iowa 57-R3 provides an excellent fit to the observed data. A peer comparison of Canadian utilities produced a range from 40 to 65 years. NL Hydro representatives suggested that the historical experience and resultant Iowa 57-R3 are reasonable expectations for this account. Based on the above, the Iowa 57-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 25 percent. Nova Scotia Power Inc. utilizes negative 35 percentage. Newfoundland Power Inc. has a net salvage percentage of negative 35 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 20 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 20 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 20 percent to best represent the future expectations for the equipment in this account.

Account P07 – Poles - Wood - The investment in Poles - Wood comprises 2.8% of the total depreciable plant. The investment in this account mainly consists of wood poles generally at the distribution level 25 kV and below**.** The currently approved average service life estimate is the Iowa 37-R3. The retirement rate analysis prepared in this study reviewed the plant over the period of 1967 through 2015. Over this period this account has experienced $11,072,192 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-204 and V-205 of this report. The currently approved Iowa 37-R3 provided a poor fit on the observed data. A peer comparison of Canadian utilities produced a range from 38 to 65 years. NL Hydro representatives indicated that the historical life for this account appeared too short. They indicated that the purchase previously owned facilities and subsequent retirements (with an original vintage equal to the acquisition date) has resulted in a short average service

life. Based on this, it was agreed that a peer comparison of Canadian utilities, Iowa 43-R1 would be a more appropriate estimate. As such, the Iowa 43-R1 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation for their station equipment of negative 25 percent with Nova Scotia Power Inc. utilizing a negative 40 percent. Newfoundland Power Inc. has a net salvage percentage of negative 35 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 20 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 20 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 20 percent to best represent the future expectations for the equipment in this account.

Account P10 – Powerhouse - The investment in Powerhouse comprises 3.9% of the total depreciable plant. The investment in this account mainly consists of powerhouse structures**.** The currently approved average service life estimate is an Iowa 75-R3. The retirement experience has been very small and as such has not resulted in any reliable historical indications. A peer comparison produced a life of 75 years. Discussions and review with NL Hydro representatives suggested that the current 75-R3 was reasonable for the equipment in this account. Based on the above and the peer comparison, an Iowa 75-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 30 percent with Nova Scotia Power Inc. utilizing a range for all Hydro accounts of negative 20 percentage to negative 445 with an investment average for all their Hydro accounts of negative 69 percent. Newfoundland Power Inc. has a net salvage percentage of negative 10 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is reasonable for this account. Based on the above, Concentric Advisors recommends

negative 8 percent to best represent the future expectations for the equipment in this account.

Account R13 – Roads - The investment in Roads comprises 3.2% of the total depreciable plant. The investment in this account mainly consists of gravel and access roads. The currently approved average service life estimate is the Iowa 50-R4. The retirement experience has been very small and as such has not resulted in any reliable historical indications. A peer comparison of Canadian utilities produced a range from 40 years to 65 years. Discussions and review with NL Hydro representatives suggested that the current 50-year average service life appeared a little short and that an increase to a 60 year average service life was more reasonable for the equipment in this account. Based on the above and the peer comparison of Canadian utilities, an Iowa 60-R4 is recommended to best represent the future expectation for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation for their station equipment of negative 5 percent with Nova Scotia Power Inc. utilizing a range for all Hydro accounts of negative 20 percentage to negative 445 with an investment average of negative 69 percent. Newfoundland Power Inc. has a net salvage percentage of negative 15 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account T04 – Towers - The investment in Towers comprises 3.0% of the total depreciable plant. The investment in this account mainly consists of steel towers including inspection and refurbishment. The currently approved average service life estimate is the Iowa 65-R3. The retirement rate analysis prepared in this study reviewed plant over the period of 1967 through 2015. Over this period this account has experienced $1,861,164 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-301 and V-302 of this report. Although the historical data is limited, it did indicate that a slightly higher Iowa curve of R4 did provide

a better fit to the historical data than the currently approved R3 curve. A peer comparison of Canadian utilities produced a range from 55 years to 85 years. Discussions and review with NL Hydro representatives suggested that the recommended 65-R4 was reasonable for this account. Based on the above, an Iowa 65-R4 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation for their station equipment of negative 25 percent with Nova Scotia Power Inc. utilizing a negative 35 percent. Newfoundland Power Inc. has a net salvage percentage of negative 35 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 20 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 20 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 20 percent to best represent the future expectations for the equipment in this account.

Account T05 – Transformers - Other - The investment in Transformers - Other comprises 3.4% of the total depreciable plant. The investment in this account mainly consists of transformers including power transformers, autotransformers and generator step-up transformers. The currently approved average service life estimate is the Iowa 55-R3. The retirement rate analysis prepared in this study reviewed plant over the period of 1964 through 2015. Over this period this account has experienced $6,447,435 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-304 and V-305 of this report. As shown on the fitted smooth curve on page V-303, the currently approved Iowa 55-R3 provides a good fit over the observed data. A peer comparison of Canadian utilities produced a range from 40 to 50 years. Discussions and review with NL Hydro representatives suggested that the historical experience and currently approved Iowa 55-R3 are reasonable expectations for this account. Based on the above, the current approved Iowa 55-R3 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation for their station equipment of negative 20 percent with Nova Scotia Power Inc. utilizing a negative 69

percent. Newfoundland Power Inc. has a net salvage percentage of negative 15 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 6 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 6 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 6 percent to best represent the future expectations for the equipment in this account.

Account T07 – Transformers – Pole Mounted - The investment in Distribution Transformers – Pole Mounted comprises 1.4% of the total depreciable plant. The investment in this account mainly consists of pole mounted distribution transformers**.** The currently approved average service life estimate is the Iowa 30-R2. The retirement rate analysis prepared in this study reviewed plant over the period of 1965 through 2015. Over this period this account has experienced $7,011,936 of retirements over a widely dispersed range of ages as summarized on the observed life table provided on pages V-310 and V-311 of this report. An analysis of the currently approved Iowa 30-R2 did not provide a good fit to the observed data. As shown on the fitted smooth curve on page V-309, an Iowa 30-L1 provides an excellent fit over the observed data. A peer comparison of Canadian utilities produced a range from 33 to 40 years. Discussions and review with NL Hydro representatives suggested that the historical experience of an Iowa 30-L1 is a reasonable expectation for this account. Based on the above, the currently approved Iowa 30-L1 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 20 percent. Nova Scotia Power Inc. utilizes negative 5 percentage for their Substation Equipment. Newfoundland Power Inc. utilizes negative 15 percentage for their Substation Equipment. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 8 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 8 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 8 percent to best represent the future expectations for the equipment in this account.

Account T09 – Turbines - The investment in Turbines comprises 3.5% of the total depreciable plant. The investment in this account mainly consists of turbines. The currently approved average service life estimate is the Iowa 50-R3. The retirement experience has been very small and as such has not resulted in any reliable historical indications. A peer comparison of Canadian utilities produced a range of 30 to 55 years. Discussions and review with NL Hydro representatives indicated that there are four gas turbines utilized for mainly stand-by and peaking purposes and have little historical usage. Discussions and review with NL Hydro representatives also suggested that the current 50-year average service life appeared a little short and that an increase to a 55-year average service life was more reasonable for the equipment in this account. Based on the above and the peer comparison of Canadian utilities, an Iowa 55-R2.5 is recommended to best represent the future expectations for the equipment in this account.

Concentric Advisors has utilized net salvage recommendations from three electric utilities. Northwest Territories Power Corporation has a recommendation of negative 15 percent with Nova Scotia Power Inc. utilizing a range for all Hydro accounts of negative 20 percentage to negative 445 with an investment average for all their Hydro accounts of negative 69 percent. Newfoundland Power Inc. has a net salvage percentage of negative 25 percent. In consideration of the above and knowledge of NL Hydro's capitalization and removal policies, Concentric Advisors views negative 14 percent as a net salvage expectation. NL Hydro representatives have indicated that negative 14 percent is reasonable for this account. Based on the above, Concentric Advisors recommends negative 14 percent to best represent the future expectations for the equipment in this account.

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART III. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

Review of Conversion to a Group Accounting Method

In the Public Utilities Board Order No P.U. 40(2012), the Board directed as follows:

> *"In accordance with the terms of the Settlement Agreement Hydro has agreed to provide, at the time of its next depreciation study, a report, on a limited number of groups of property, comparing the agreed methodology to the application of depreciation on a pure group basis. The Board notes that the findings of this report would not be applied retroactively but rather would provide information for future rate making purposes. In the Board's view this is a reasonable approach to resolve what appears to have been a difference in expert opinion on this specific issue. The Board will accept this recommendation."*[6]

Attached as Appendix 1 to this report is the "Evidence of Larry E. Kennedy Related to the Conversion to Group Accounting Methods" (Additional Evidence of Larry Kennedy"). This Evidence provides the detailed response to the above PUB directive resulting from the last depreciation study and negotiated settlement application relating to the historical NL Hydro departure from the use of typical regulated group depreciation accounting.

Group depreciation refers to the widely accepted procedure for rate regulated utilities where, rather than depreciating each item by itself (unit depreciation), a group containing homogenous units of plant which are alike in character, used in the same manner throughout the utilities service territory, and operated under the same general conditions is formed. Group depreciation recognizes that there will be differing lives for individual units within the group. For example, poles are often combined into a single group. Some poles will be retired due to storms or third party damage (for example automobile accidents, for strikes by farm equipment, etc.). Others will decay, while some will be displaced due to road relocations, and some will be replaced due to the need to provide underground service. However they are combined into the same group because they are homogenous units. With group depreciation, the entire group is considered as

[6] Order No. P.U. 40(2012), page 3, lines 28-35.

the asset being depreciated, therefore, one depreciation rate is applied to the entire group and only one accumulated depreciation account is tracked for the entire group.

Under group depreciation no gain or loss is recognized for retirement of individual assets, as only one depreciation calculation is made on the entire group. Upon retirement of an asset from the group, the total original cost of the asset is debited to the accumulated depreciation account and credited to the asset account. Gross salvage received (if applicable) for the retired asset is credited to the accumulated depreciation account and cost of removal is debited to the accumulated depreciation account. Under group depreciation, since the accumulated depreciation relates to the entire group rather than to specific assets within the group, no gain or loss is recognized. This assumes that the group depreciation rate is accurate for the group as a whole and that the cost of the retired asset, net of gross salvage and cost of removal, is being fully provided for in the accumulated depreciation account.

A full description of the review is provided in the Additional Evidence of Larry Kennedy. Based on the review it is noted that long life accounts such as Wood Poles and Conductor are virtually neutral as to the use of the current hybrid approach versus traditional grouping accounting approaches. The Additional Evidence of Larry Kennedy recommends that:

- NL Hydro convert to a more traditional Group Accounting and Depreciation Practice for all accounts other than Amortized accounts as discussed below;

- That Amortized accounts (as noted with a Square or SQ Iowa curve) be subjected to a pure amortization procedure wherein the investment in these accounts is retired when it reaches its full amortization period. All retirements in these accounts should be made only at the expiration of the amortization period.

Group Depreciation Procedures

Based on the recommended conversion to Group Accounting, the selection of a group depreciation procedure is required. When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because normally

all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, Average Service Life (ASL) and Equal Life Group (ELG).

In the average service life procedure, the rate of annual depreciation is based on the average service life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the ELG procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group.

In the determination of the depreciation rates in this study, the use of the average service life procedure has been continued for all vintages up to and including 2014. For current plant (i.e. 2015 vintages), the use of the equal life group procedure will be utilized providing an enhanced matching of depreciation expense to the consumption of service value.

Impact of the International Financial Reporting Standards (IFRS) in this Study

In the determination of the depreciation rates for Regulatory purposes Concentric Advisors has applied its depreciation parameters on an original cost basis. However, upon implementation of IFRS NL Hydro's reported asset values are calculated on a deemed cost basis in the disclosure of the plant in service in its accounting systems for financial disclosure purposes. Therefore the depreciation rates need to recognize that the cost basis is a deemed cost rather than an original cost. To ensure proper and accurate recovery, Concentric Advisors has applied its developed depreciation expense (as determined from an original cost base) to NL Hydro's deemed costs to develop

deemed cost accrual rates for each depreciable account as shown on Table 1. Concentric Advisors notes that the deemed cost depreciation rates are for financial disclosure purposes only. These deemed cost accrual rates will then ensure the accurate recovery of NL Hydro's deemed cost investment as of December 31, 2015.

The above deemed cost accrual rates reflect the position of each account's booked depreciation reserve as of December 31, 2015. If an account's booked depreciation reserve is in a deficiency or surplus position, the resultant accrual rate reflects an adjustment to correct this deficiency or surplus over the applicable account's composite remaining life. However, for future additions (i.e. post 2015), the application of the developed deemed cost accrual rates will incorrectly adjust the post 2015 addition's depreciation expense due to the above 2015 book depreciation reserve adjustment for each applicable account. As such, Concentric Advisors recommends, and has provided whole life accrual rates that do not reflect the booked depreciation deficiency or surplus position as of December 31, 2015. This will more accurately reflect the correct depreciation expense on post 2015 additions.

The Concentric Advisors recommendation of including an accrual provision for the recovery of future costs of removal in the depreciation expense, and to implement traditional group accounting practices are in accordance with the IFRS 14. However, in order to rely upon IFRS 14, the cost of removal component being recovered through depreciation expense needs to be specifically identified and tracked in accordance with IFRS 14. Therefore, this study separately provides for the depreciation rates associated with the recovery of future cost of removal in Table 1B provided in the Results section of this report. Additionally, the impacts of the conversion to traditional group accounting will also require the tracking of gains or losses on retirements through the reporting as directed under IFRS 14[7]. While Concentric Advisors notes that the use of the ELG procedure and accruing for cost of removal will ultimately eliminate the need to calculate gains and losses on most retirement transactions, it will take a number of years of use of

[7] Including gains and losses associated with original costs of retirements, costs of removal and gross salvage proceeds

the ELG procedure and cost of removal accrual before the tracking of gains and losses through IFRS 14 can be eliminated.

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period through the use of a square Iowa curve, which assumes no retirement over the life of the investment through to its final retirement at the end of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

For the purpose of calculating annual amortization amounts as of December 31, 2015, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

Amortization accounting is proposed for a number of accounts that represent a small portion of depreciable December 31, 2015 plant in service. The accounts and their amortization periods are as follows:

ACCOUNT	TITLE	AMORTIZATION PERIOD, YEARS
C11	Computers	5
O01	Office Equipment	20
O02	Office Furniture	20
P11	Printers	6
R14	Routers and LAN	5
S03	Servers	7
S05	Software	7
T02	Test Equipment	20
T03	Tools and Equipment	20
T10	Holyrood Turbines – Combuster Overhaul	3
T11	Holyrood Turbines – Turbine Overhaul	6
T12	Holyrood Turbine – Compressor Overhaul	12

For the above accounts where amortization accounting is proposed, Concentric Advisors recommends that for each vintage, for each applicable account, the complete amortization period be utilized irrespective of whether the related fixed asset equipment is removed from active service. Likewise, Concentric Advisors further recommends that when each vintage for each applicable account reaches the complete amortization period, that vintage be fully retired irrespective of whether the associated equipment is still in service.

MONITORING OF BOOK ACCUMULATED DEPRECIATION

The calculated accrued depreciation or amortization represents that portion of the depreciable cost which will not be allocated to expense through future depreciation accruals, if current forecasts of service life characteristics and net salvage materialize and are used as a basis for depreciation accounting. Thus, the calculated accrued depreciation provides a measure of the book accumulated depreciation. The use of this measure is recommended in the amortization of book accumulated depreciation variances to insure complete recovery of capital over the life of the property.

The recommended amortization of the variance between the book accumulated depreciation and the calculated accrued depreciation is based on an amortization period

equal to the composite remaining life for each property group where the variance exceeds five percent of the calculated accrued depreciation.

The composite remaining life for use in the calculation of accumulated depreciation variances is derived by developing the composite sum of the individual equal life group remaining lives in accordance with the following equation:

The book costs and lives of the several equal life groups, which are summed in the foregoing equation, are defined by the estimated future survivor curve. Inasmuch as book cost divided by life equals the whole life annual accrual, the foregoing equation reduces to the following form:

Or

$$\text{Composite Remaining Life} = \frac{\sum \text{Book Cost - Calc. Reserve}}{\sum \text{Whole Life Annual Accrual}}.$$

PART IV. RESULTS OF STUDY

PART IV. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the straight line method, using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

DESCRIPTION OF DETAILED TABULATIONS

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions and review with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in Part V beginning on V-2 of the Supporting Documents.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2015 are presented in account sequence starting on page VI-2 of the

Supporting Documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

NEWFOUNDLAND AND LABRADOR HYDRO
DEPRECIATION STUDY

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1A. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
LIFE

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
A01.	AIRCRAFT LANDING STRIP	33-R2	0	475,498	447,118	28,380	1,156	0.24	22.5	106,867	1.08	4.27
A04.	AUXILIARY POWER SYSTEMS	30-R4	0	6,054,939	2,863,282	3,191,657	142,690	2.36	21.0	3,875,070	3.68	3.55
B01.	BATTERY AND POWER SYSTEMS	26-L1.5	0	11,399,996	5,831,921	5,568,076	281,160	2.47	19.7	6,859,869	4.10	5.37
B02.	BOILER SYSTEM	40-R3	0	23,876,046	22,173,735	1,702,310	51,390	0.22	23.1	1,848,235	2.78	2.92
B03.	BOOMS - TIMBER	25-R2	0	175,556	68,815	106,740	12,386	7.06	8.6	112,339	11.03	5.52
B04.	BRIDGES	65-R4	0	4,254,290	3,356,067	898,223	19,633	0.46	42.7	965,004	2.03	1.64
B05.	BUILDINGS - OTHER	50-R0.5	0	69,176,761	31,590,131	37,586,631	954,632	1.38	39.3	40,332,978	2.37	4.42
B06.	BUILDINGS - METAL	55-R3	0	34,029,073	18,159,493	15,869,581	384,804	1.13	40.5	16,435,007	2.34	2.13
B07.	BUS DUCT GENERATOR	40-R4	0	1,456,108	546,113	909,995	30,373	2.09	29.1	985,315	3.08	2.66
B08.	BUSWORK AND HARDWARE	50-R4	0	7,307,906	4,510,152	2,797,755	86,974	1.19	30.4	3,340,456	2.60	2.13
C01.	CABLES - TELECONTROL	30-R4	0	2,643,339	2,286,539	356,800	13,452	0.51	26.5	393,321	3.42	3.55
C02.	CABLE - SUBMARINE	45-R4	0	8,901,116	6,446,852	2,454,264	113,135	1.27	20.9	2,776,722	4.07	2.37
C03.	CABLES - UNDERGROUND	60-S4	0	2,837,546	1,019,407	1,818,138	36,892	1.30	46.1	1,905,314	1.94	1.72
C04.	CABLES - ABOVE GROUND	60-R4	0	10,550,929	6,547,333	4,003,596	100,721	0.95	36.8	4,494,725	2.24	1.77
C06.	CAPACITORS	35-R3	0	994,744	457,993	536,751	64,049	6.44	8.3	690,109	9.28	3.33
C07.	CHEMICAL FEED SYSTEMS	45-R4	0	509,132	495,386	13,747	338	0.07	20.6	18,552	1.82	2.37
C09.	CIRCUIT BREAKERS	60-R2.5	0	39,656,672	9,636,653	30,020,020	678,934	1.71	43.6	31,594,197	2.15	2.21
C10.	COMPRESSED AIR SYSTEMS	41-R1.5	0	16,666,710	3,115,906	13,550,805	505,554	3.03	26.8	14,222,905	3.55	4.00
C11.	COMPUTERS	5-SQ	0	4,899,775	2,343,713	2,556,063	633,911	12.94	4.0	4,407,813	14.38	20.00
C12.	CONDENSERS	55-R3	0	125,930	125,930	0	0	0.00	15.1	0	-	2.13
C13.	CONDUCTOR - TRANSMISSION	60-R3	0	67,322,774	28,952,047	38,370,727	1,185,060	1.76	31.8	42,025,239	2.82	1.96
C14.	CONDUCTOR - DISTRIBUTION	45-R3	0	34,320,050	16,853,643	17,466,406	547,899	1.60	30.2	18,601,762	2.95	2.60
C15.	CONTROL, METERING, RELAYING	40-R3	0	29,645,208	13,067,444	16,577,763	599,361	2.02	27.7	18,702,830	3.20	2.92
C16.	COOLING SYSTEMS	40-R1.5	0	10,007,038	2,674,586	7,332,452	261,458	2.61	28.0	7,732,067	3.38	4.10
C17.	COUNTERPOISE	55-R2.5	0	3,623,089	1,556,773	2,066,316	63,340	1.75	32.2	2,310,209	2.74	2.39
C18.	CRANES	70-R3	0	6,902,142	1,299,150	5,602,992	133,894	1.94	41.8	6,044,509	2.22	1.69
D01.	DAMS, DYKES, CANALS AND TUNNELS	110-R4	0	361,909,256	35,352,203	326,557,053	4,330,896	1.20	75.4	340,976,393	1.27	0.97
D02.	DIESEL SYSTEMS AND ENGINES	25-L0.5	0	41,897,351	18,893,624	23,003,727	1,182,488	2.82	19.1	27,128,109	4.36	6.96
D03.	DISCONNECT SWITCHES	55-R2.5	0	20,883,528	6,740,368	14,143,160	336,802	1.61	41.5	15,314,119	2.20	2.39
D04.	DYKES AND LINERS	42-L1.5	0	2,477,333	1,799,505	677,828	21,022	0.85	30.1	745,693	2.82	3.36
E01.	ELEVATORS	45-S5	0	89,800	89,800	0	0	0.00	4.5	0	-	2.25
E02.	EMS EQUIPMENT	35-R2.5	0	12,917,219	12,757,417	159,802	6,392	0.05	25.0	189,571	3.37	3.68
E03.	ENVIRONMENTAL EQUIPMENT	45-R2.5	0	935,876	678,187	257,689	11,409	1.22	22.6	349,053	3.27	2.90
F01.	FALL ARREST EQUIPMENT	15-R4	0	2,509,020	1,215,404	1,293,616	123,050	4.90	10.5	2,007,509	6.13	7.09
F02.	FENCING	52-R3	0	7,555,589	3,627,286	3,928,303	93,592	1.24	41.4	4,183,349	2.24	2.25
F03.	FIRE FIGHTING EQUIPMENT	50-R4	0	13,906,919	5,568,798	8,338,121	194,950	1.40	42.8	8,924,743	2.18	2.13
F04.	FOOTINGS AND FOUNDATIONS	65-R3	0	20,413,239	8,981,394	11,431,845	263,514	1.29	42.5	12,276,179	2.15	1.81
F05.	FREQUENCY CONVERSION	45-S4	0	2,453,577	1,758,713	694,864	19,595	0.80	35.5	755,877	2.59	2.30
F06.	FUEL SYSTEMS	50-R1.5	0	28,513,898	9,915,217	18,598,681	542,202	1.90	34.3	19,575,128	2.77	3.36
G01.	GAS TURBINE SYSTEMS	45-R3	0	69,325,761	25,791,118	43,534,643	1,160,219	1.67	37.3	46,097,528	2.52	2.60
G02.	GATES	80-R4	0	19,048,533	3,368,711	15,679,823	320,794	1.68	48.8	16,550,695	1.94	1.[illegible]
G03.	GENERATORS	65-S3	0	105,132,875	30,681,141	74,451,734	1,613,265	1.53	45.4	79,119,107	2.04	1.[illegible]
G04.	GENERATOR - WINDINGS	50-S3	0	24,614,758	9,576,304	15,038,454	321,672	1.31	46.7	17,789,053	1.81	2.[illegible]
G05.	GLYCOL SYSTEMS	40-S3	0	530,654	446,507	84,147	4,831	0.91	17.4	98,436	4.91	2.[illegible]
G06.	GOVENORS	45-S4	0	7,840,659	2,139,962	5,700,697	303,354	3.87	18.5	6,562,987	4.62	2.[illegible]
G07.	GROUND WIRE SYSTEM	55-R4	0	10,370,352	3,450,583	6,919,769	182,386	1.76	37.3	7,515,444	2.43	1.[illegible]
I02.	INSTRUMENTATION	30-L0.5	0	5,967,398	5,010,716	956,682	38,194	0.64	25.0	1,113,173	3.43	5.[illegible]
I03.	INSULATORS	35-L3	0	41,988,322	20,326,481	21,661,840	1,002,854	2.39	21.6	25,983,406	3.86	3.23
I04.	INTAKE STRUCTURES	110-R4	0	19,436,445	1,973,440	17,463,005	231,764	1.19	75.3	18,225,951	1.27	0.97
I05.	INVERTERS	25-S1.5	0	521,505	371,033	150,471	12,485	2.39	6.4	176,682	7.07	4.[illegible]
L03.	LAND IMPROVEMENTS	75-R3	0	14,196,794	9,017,193	5,179,601	96,403	0.68	53.7	5,735,273	1.68	1.[illegible]
L04.	LIGHTING SYSTEMS	50-R4	0	926,303	557,052	369,251	8,923	0.96	41.4	483,472	1.85	2.[illegible]
L05.	LIGHTNING ARRESTORS	58-R3	0	6,193,610	2,439,676	3,753,934	84,364	1.36	44.5	3,984,825	2.12	2.[illegible]
L06.	LINE COUPLING EQUIPMENT	24-R5	0	11,226	11,226	0	0	0.00	0.0	0	-	4.[illegible]
M01.	MAIN BREAKERS	42-R0.5	0	552,940	289,587	263,353	7,867	1.42	33.2	288,042	2.73	5.[illegible]
M02.	MARINE TERMINAL	65-R4	0	3,833,871	3,229,543	604,328	9,669	0.25	62.5	860,754	1.12	1.[illegible]
M03.	METALCLAD SWITCHGEAR CUB/EQU 4kv/600	45-R4	0	2,233,645	1,718,481	515,163	14,823	0.66	31.5	669,662	2.21	2.[illegible]
M04.	METER TEST SWITCHES	35-R5	0	58,301	47,500	10,800	928	1.59	11.6	13,519	6.86	2.[illegible]
M05.	METERING TANKS	37-R3	0	660,416	283,977	376,440	12,873	1.95	29.2	438,378	2.94	3.[illegible]
M06.	METERS - DIGITAL	20-L3	0	5,874,668	2,181,741	3,692,927	285,363	4.86	12.9	4,566,868	6.25	5.[illegible]
M07.	METERS - ANALOGUE	25-L2	0	698,384	659,749	38,635	4,235	0.61	9.1	76,225	5.56	5.[illegible]
M08.	METERS - OTHER	22-L4	0	262,853	144,342	118,512	10,414	3.96	11.4	166,747	6.25	4.[illegible]
M10.	MISCELLANEOUS UNITS OF PROPERTY	22-R1.5	0	25,815,956	10,083,214	15,732,742	887,243	3.44	17.7	24,143,424	3.67	6.[illegible]

Revision 2 - October 16, 2017
Exhibit 11 - Depreciation Study
Page 50 of 633

NEWFOUNDLAND AND LABRADOR HYDRO
DEPRECIATION STUDY

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1A. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
LIFE

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
M11.	MOBILE - A.T.V.'S AND SNOWMOBILES	6-L3	20	1,906,739	988,839	536,552	132,832	6.97	4.0	1,630,167	8.15	15.02
M12.	MOBILE - AIR COMPRESSOR ATTACHMENT AND BOAT	20-L0	20	432,046	322,829	22,807	1,321	0.31	17.3	131,898	1.00	7.59
M13.	MOBILE - ARGO'S	9-R5	20	287,287	270,068	(40,239)	0	0.00	0.0	180,781	-	9.08
M14.	MOBILE - FLEX/FORK/LOAD/GRADE/MUSK/TRAILER	18-L3	20	10,581,312	4,436,000	4,029,050	299,132	2.83	13.5	7,185,044	4.16	5.03
M16.	MULTIPLEX EQUIPMENT	18-S1.5	0	2,812,217	2,220,728	591,489	52,487	1.87	11.3	822,074	6.38	6.67
O01.	OFFICE EQUIPMENT	20-SQ	0	1,286,440	670,958	615,481	40,943	3.18	15.0	731,009	5.60	5.00
O02.	OFFICE FURNITURE	20-SQ	0	1,477,990	866,277	611,713	45,350	3.07	13.5	743,513	6.10	5.00
P01.	P.C.B. STORAGE CONTAINER	30-R4	0	42,480	41,427	1,052	137	0.32	7.7	1,483	9.24	3.55
P02.	PABX - PRIVATE AUTO BRANCH EXCHANGE	20-R4	0	1,181,009	955,817	225,191	21,221	1.80	10.6	277,879	7.64	5.32
P03.	PENSTOCK	70-R4	0	58,908,421	16,867,332	42,041,089	1,255,120	2.13	33.4	44,875,320	2.80	1.52
P04.	POLE CRIBS AND POLE HARDWARE	35-S2.5	0	118,371,156	40,540,863	77,830,293	3,088,060	2.61	24.0	82,813,901	3.73	3.15
P05.	POLE STRUCTURES - WOOD	57-R3	0	129,790,285	48,775,465	81,014,821	2,175,325	1.68	36.3	89,077,051	2.44	2.06
P06.	POLES - CONCRETE	25-R4	0	333,760	307,440	26,320	1,240	0.37	3.0	55,346	2.24	4.26
P07.	POLES - WOOD	43-R1	0	72,604,630	27,332,178	45,272,452	1,392,688	1.92	32.2	49,437,902	2.82	4.34
P08.	POWER LINE CARRIER	25-R3	0	4,971,572	4,329,788	641,785	40,639	0.82	14.6	798,185	5.09	4.64
P09.	POWER SYSTEMS	20-L3	0	664,592	342,360	322,232	31,737	4.78	10.0	457,452	6.94	5.66
P10.	POWERHOUSE	75-R3	0	93,718,745	20,425,400	73,293,346	1,617,203	1.73	45.2	77,547,345	2.09	1.57
P11.	PRINTERS	6-SQ	0	1,038,001	818,313	219,688	50,319	4.85	4.4	968,970	5.19	16.67
P12.	PROTECTIVE CONTROL AND RELAY PANELS	35-R3	0	9,507,129	3,266,574	6,240,555	214,367	2.25	29.1	7,232,549	2.96	3.33
R01.	RADIO TOWERS (WOOD OR STEEL)	48-R3	0	9,759,106	7,079,596	2,679,510	71,439	0.73	37.0	3,006,850	2.38	2.44
R02.	RADIOS - FIXED MICROWAVE EQUIPMENT	19-R5	0	6,212,764	4,646,541	1,566,223	159,307	2.56	9.8	1,854,531	8.59	5.37
R03.	RADIOS - FIXED UHF EQUIPMENT	15-L0.5	0	101,662	36,875	64,787	6,085	5.99	10.6	81,822	7.44	11.00
R04.	RADIOS - FIXED VHF EQUIPMENT	19-R3	0	560,166	448,857	111,309	10,243	1.83	10.9	153,938	6.65	6.08
R05.	RADIOS - MOBILE VHF BASE STATION	15-R4	0	7,278,664	5,004,461	2,274,203	326,656	4.49	7.0	3,124,097	10.46	7.09
R06.	RAMPS - YARD STORAGE	25-R3	0	1,593,558	784,653	808,905	48,198	3.02	16.8	935,272	5.15	4.64
R07.	REACTORS AND RESISTORS	40-S4	0	1,225,065	415,447	809,618	37,859	3.09	21.4	903,491	4.19	2.58
R08.	RECLOSERS	48-R3	0	7,158,607	3,012,684	4,145,922	105,835	1.48	38.1	4,572,762	2.31	2.44
R09.	REGULATORS	40-S0.5	0	5,667,640	2,392,726	3,274,914	108,120	1.91	29.3	3,706,121	2.92	3.56
R11.	REVENUE METERING	35-R3	0	1,242,916	495,989	746,926	35,790	2.88	20.9	849,542	4.21	3.33
R12.	RIGHT-OF-WAYS	65-R4	0	21,729,649	10,327,231	11,402,418	296,842	1.37	38.4	12,488,097	2.38	1.64
R13.	ROADS	60-R4	0	84,440,747	16,404,114	68,036,633	2,225,706	2.64	30.5	75,174,354	2.96	1.77
R14.	ROUTERS AND LAN	5-SQ	0	2,730,978	1,833,487	897,491	216,573	7.93	4.1	2,448,737	8.84	20.00
R15.	RUNNER	55-R5	0	11,669,844	6,299,567	5,370,277	424,434	3.64	12.7	6,821,838	6.22	1.86
S01.	SCADA EQUIPMENT	20-L3	0	4,929,933	2,829,101	2,100,832	154,652	3.14	13.6	2,481,772	6.23	5.66
S02.	SECTIONALIZERS	25-R5	0	154,009	126,212	27,797	6,911	4.49	4.0	45,666	15.13	4.08
S03.	SERVERS	7-SQ	0	3,019,204	2,756,280	262,924	47,011	1.56	5.6	1,643,300	2.86	14.29
S04.	SEWAGE DISPOSAL SYSTEM	55-R4	0	2,919,319	1,894,968	1,024,351	24,407	0.84	41.4	1,121,167	2.18	1.94
S05.	SOFTWARE	7-SQ	0	10,081,799	3,806,822	6,274,977	1,826,510	18.12	3.4	8,980,374	20.34	14.29
S06.	SPILLWAY STRUCTURES	110-R4	0	28,120,270	3,203,543	24,916,728	331,244	1.18	75.2	26,004,636	1.27	0.97
S07.	STACKS	55-R4	0	7,850,850	3,172,485	4,678,365	93,981	1.20	48.2	4,868,525	1.93	1.94
S08.	STATIC EXCITATION SYSTEM	32-R4	0	8,333,065	3,979,751	4,353,314	576,637	6.92	6.5	5,117,789	11.27	3.[illegible]
S09.	STATIC EXCITATION - TRANSFORMERS	45-R4	0	734,327	727,391	6,936	429	0.06	15.7	16,538	2.59	2.[illegible]
S10.	STATION SERVICE	50-R4	0	5,233,336	1,741,249	3,492,087	120,651	2.31	28.1	3,966,436	3.04	2.[illegible]
S11.	STOP LOGS	65-R4	0	3,114,097	643,196	2,470,901	72,339	2.32	34.2	2,650,931	2.73	1.[illegible]
S12.	STORAGE PALLETS AND RACKINGS	30-R3	0	14,403	14,403	0	0	0.00	0.0	0	-	3.[illegible]
S13.	STORM AND YARD DRAINAGE	55-R4	0	1,308,713	1,054,925	253,788	6,537	0.50	38.8	283,067	2.31	1.94
S14.	STREET LIGHTS	20-R2	0	3,874,989	1,657,192	2,217,797	172,083	4.44	12.5	2,805,557	6.13	6.[illegible]
S15.	STRUCTURAL SUPPORTS (WOOD OR STEEL)	55-R4	0	11,677,609	6,274,387	5,403,222	147,181	1.26	35.4	6,251,538	2.35	1.94
S17.	SUMP SYSTEMS	35-R4	0	667,245	135,218	532,027	29,713	4.45	17.9	561,992	5.29	3.04
S18.	SURGE SYSTEMS	60-R4	0	6,972,889	3,352,973	3,619,917	96,658	1.39	37.5	4,069,890	2.37	1.[illegible]
S19.	STATION SWITCHING	38-S0.5	0	11,650,032	4,719,809	6,930,224	267,874	2.30	25.9	7,525,863	3.56	3.[illegible]
S20.	SWITCHING SYSTEMS - L.V.	60-R5	0	2,304,609	396,950	1,907,659	59,963	2.60	31.8	2,071,699	2.89	1.[illegible]
T01.	TELECONTROL SYSTEM	25-L1.5	0	12,429,279	6,824,711	5,604,568	304,406	2.45	18.4	6,362,279	4.78	5.[illegible]
T02.	TEST EQUIPMENT	20-SQ	0	1,955,314	1,128,984	826,330	55,804	2.85	14.8	955,358	5.84	5.[illegible]
T03.	TOOLS AND EQUIPMENT	20-SQ	0	11,434,328	6,018,424	5,415,904	378,698	3.31	14.3	6,366,862	5.95	5.[illegible]
T04.	TOWERS	65-R4	0	77,739,424	27,526,269	50,213,155	1,256,447	1.62	38.9	54,042,115	2.32	1.[illegible]
T05.	TRANSFORMERS - OTHER	55-R3	0	89,255,274	37,368,104	51,887,170	1,599,600	1.79	31.8	55,908,373	2.86	2.[illegible]
T06.	TRANSFORMERS - PAD MOUNT	40-R1.5	0	17,723,652	2,188,073	15,535,579	420,766	2.37	36.8	16,335,856	2.58	4.[illegible]
T07.	TRANSFORMERS - POLE MOUNTED	30-L1	0	37,040,457	10,664,694	26,375,763	1,145,163	3.09	22.9	29,543,794	3.88	5.[illegible]
T09.	TURBINES	55-R2.5	0	65,159,636	27,353,903	37,805,733	1,233,955	1.89	29.9	42,271,663	2.92	2.[illegible]

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1A. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
LIFE

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
T10.	HOLYROOD GAS TURBINE - COMBUSTOR OVERHAUL	3-SQ	0	2,206,062	40,444	2,165,618	866,247	39.27	2.5	2,206,062	39.27	33.33
T11.	HOLYROOD GAS TURBINE - TURBINE OVERHAUL	6-SQ	0	2,206,062	40,444	2,165,618	393,749	17.85	5.5	2,206,062	17.85	16.67
T12.	HOLYROOD GAS TURBINE - COMPRESSOR OVERHAUL	12-SQ	0	3,088,487	56,622	3,031,865	263,640	8.54	11.5	3,088,487	8.54	8.33
V01.	VACUUM CLEANING SYSTEM	60-R4	0	72,451	66,980	5,471	212	0.29	25.8	6,099	3.48	1.77
V02.	VALVES - PENSTOCK	65-R3	0	7,567,760	2,366,964	5,200,796	128,332	1.70	40.1	5,558,323	2.31	1.81
V03.	VEHICLES - 1 TON	8-L4	15	51,648	16,140	27,761	5,047	9.77	5.5	51,648	9.77	11.29
V04.	VEHICLES - 3/4 TON AND UNDER	7-L3	15	5,167,170	3,260,796	1,131,298	203,617	3.94	5.6	4,033,711	5.05	13.71
V05.	VEHICLES - BOOMS/BODIES/CRANES/CAB/CHASSIS	12-L3	15	14,954,546	5,943,877	6,767,488	839,148	5.61	8.1	10,855,821	7.73	8.02
V06.	VEHICLES - CARS, STATION WAGONS AND VAN	6-L3	15	1,795,372	1,516,681	9,385	2,081	0.12	4.5	1,134,905	0.18	15.96
V07.	VEHICLES - DUMP TRUCKS	10-L5	15	11,535	11,535	(1,730)	0	0.00	0.0	0	-	10.28
W01.	WATER REGULATING STRUCTURES	65-S4	0	22,451,738	5,101,189	17,350,549	415,932	1.85	41.3	18,454,117	2.25	1.59
W02.	WATER SUPPLY SYSTEMS	30-L4	0	3,394,554	1,790,681	1,603,873	105,993	3.12	14.0	1,972,019	5.37	3.53
W03.	WATER SYSTEMS - FEED	55-R2.5	0	6,531,260	3,595,245	2,936,015	74,656	1.14	37.0	3,023,065	2.47	2.39
W04.	WATER TREATMENT	55-R2.5	0	11,921,573	6,449,340	5,472,233	134,521	1.13	40.3	6,307,665	2.13	2.39
	Sub-Total			2,458,776,655	852,381,210	1,600,456,929	49,040,034	1.99		1,756,107,129	2.79	

NEWFOUNDLAND AND LABRADOR HYDRO
DEPRECIATION STUDY

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1A. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
LIFE

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
HOLYROOD ASSETS	**TRUCATION DATE**	**3/31/2021**										
A04.1	AUXILIARY POWER SYSTEMS	30-R4	0	620,866	313,020	307,846	58,749	9.46	5.2	492,554	11.93	24.32
B01.1	BATTERY AND POWER SYSTEMS	26-L1.5	0	106,627	45,121	61,506	13,957	13.09	4.4	86,099	16.21	24.53
B02.1	BOILER SYSTEM	40-R3	0	35,073,430	27,260,865	7,812,565	1,538,636	4.39	5.0	12,295,071	12.51	24.37
B05.1	BUILDINGS - OTHER	50-R0.5	0	1,300,250	763,274	536,976	104,628	8.05	5.1	859,162	12.18	25.12
B06.1	BUILDINGS - METAL	55-R3	0	72,011	39,551	32,460	6,195	8.60	5.2	51,935	11.93	24.35
C01.1	CABLES - TELECONTROL	30-R4	0	89,750	63,121	26,629	5,121	5.71	5.2	42,606	12.02	24.32
C03.1	CABLES - UNDERGROUND	60-S4	0	544,049	481,561	62,488	12,017	2.21	5.2	68,519	17.54	24.31
C04.1	CABLES - ABOVE GROUND	60-R4	0	629,827	560,583	69,244	13,419	2.13	5.2	78,084	17.19	24.32
C07.1	CHEMICAL FEED SYSTEMS	45-R4	0	77,164	66,656	10,508	2,024	2.62	5.2	16,813	12.04	24.32
C12.1	CONDENSERS	55-R3	0	2,329,667	2,087,816	241,851	46,983	2.02	5.1	386,962	12.14	24.35
C15.1	CONTROL, METERING, RELAYING	40-R3	0	119,880	48,437	71,443	13,634	11.37	5.2	115,036	11.85	24.37
E03.1	ENVIRONMENTAL EQUIPMENT	45-R2.5	0	1,280,261	883,404	396,857	76,415	5.97	5.2	624,419	12.24	24.45
F03.1	FIRE FIGHTING EQUIPMENT	50-R4	0	797,150	545,433	251,716	49,563	6.22	5.1	290,151	17.08	24.32
F04.1	FOOTINGS AND FOUNDATIONS	65-R3	0	56,613	46,927	9,685	1,866	3.30	5.2	10,668	17.49	24.34
F06.1	FUEL SYSTEMS	50-R1.5	0	13,309,152	7,877,261	5,431,891	1,050,852	7.90	5.2	8,233,153	12.76	24.70
G01.1	GAS TURBINE SYSTEMS	45-R3	0	24,645	23,906	739	146	0.59	5.0	887	16.46	24.36
G03.1	GENERATORS	65-S3	0	1,067,438	367,373	700,064	133,346	12.49	5.3	1,228,857	10.85	24.31
G06.1	GOVENORS	45-S4	0	2,144,383	1,652,526	491,857	94,078	4.39	5.2	773,352	12.16	24.31
I02.1	INSTRUMENTATION	30-L0.5	0	6,727,326	4,902,728	1,824,598	379,394	5.64	4.8	2,327,089	16.30	24.94
I05.1	INVERTERS	25-S1.5	0	24,417	17,670	6,747	1,391	5.70	4.8	10,794	12.89	24.35
L03.1	LAND IMPROVEMENTS	75-R3	0	5,766	4,965	801	153	2.65	5.2	1,281	11.94	24.34
M02.1	MARINE TERMINAL	65-R4	0	468,523	358,934	109,589	20,895	4.46	5.2	175,342	11.92	24.32
M10.1	MISCELLANEOUS UNITS OF PROPERTY	22-R1.5	0	1,611,947	407,422	1,204,525	236,325	14.66	5.1	1,583,560	14.92	25.26
O02.1	OFFICE FURNITURE	20-SQ	0	58,975	48,674	10,302	4,121	6.99	2.5	16,483	25.00	24.31
P10.1	POWERHOUSE	75-R3	0	8,903,432	7,852,132	1,051,300	202,559	2.28	5.2	1,133,208	17.87	24.34
P12.1	PROTECTIVE CONTROL AND RELAY PANELS	35-R3	0	106,685	65,531	41,154	7,899	7.40	5.2	65,847	12.00	24.38
R13.1	ROADS	60-R4	0	1,859	1,635	224	43	2.31	5.2	248	17.35	24.32
S07.1	STACKS	55-R4	0	9,202,119	6,183,907	3,018,212	582,779	6.33	5.2	4,786,711	12.17	24.32
S08.1	STATIC EXCITATION SYSTEM	32-R4	0	1,461,435	1,004,244	457,191	332,027	22.72	1.4	729,359	45.52	24.32
T03.1	TOOLS AND EQUIPMENT	20-SQ	0	351,262	183,716	167,546	31,914	9.09	5.2	268,073	11.90	24.31
T05.1	TRANSFORMERS	55-R3	0	126,690	38,007	88,683	16,924	13.36	5.2	126,690	13.36	24.35
T09.1	TURBINES	55-R2.5	0	27,077,372	12,977,563	14,099,810	2,700,859	9.97	5.2	20,041,663	13.48	24.43
W03.1	WATER SYSTEMS - FEED	55-R2.5	0	2,818,634	1,772,494	1,046,140	203,526	7.22	5.1	1,270,349	16.02	24.43
W04.1	WATER TREATMENT	55-R2.5	0	2,792,962	1,648,626	1,144,336	219,631	7.86	5.2	1,772,842	12.39	24.43
	Sub-Total			121,382,565	80,595,081	40,787,483	8,162,069	6.72		59,963,868	13.61	
	TOTAL			2,580,159,221	932,976,291	1,641,244,412	57,202,103	2.22		1,816,070,997	3.15	

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1B. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
COST OF REMOVAL

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
A01.	AIRCRAFT LANDING STRIP	33-R2	(6)	475,498	0	28,530	1,374	0.29	22.5	106,867	1.29	0.43
A04.	AUXILIARY POWER SYSTEMS	30-R4	(3)	6,054,939	0	181,648	17,864	0.29	21.0	3,875,070	0.46	0.18
B01.	BATTERY AND POWER SYSTEMS	26-L1.5	(3)	11,399,996	0	342,000	18,808	0.16	19.7	6,859,869	0.27	0.27
B02.	BOILER SYSTEM	40-R3	(8)	23,876,046	0	1,910,084	104,912	0.43	23.1	1,848,235	5.68	0.44
B03.	BOOMS - TIMBER	25-R2	0	175,556	0	0	0	0.00	8.6	112,339	-	-
B04.	BRIDGES	65-R4	(11)	4,254,290	0	467,972	12,358	0.29	42.7	965,004	1.28	0.33
B05.	BUILDINGS - OTHER	50-R0.5	(3)	69,176,761	0	2,075,302	55,540	0.08	39.3	40,332,978	0.14	0.22
B06.	BUILDINGS - METAL	55-R3	(3)	34,029,073	0	1,020,872	32,294	0.10	40.5	16,435,007	0.20	0.11
B07.	BUS DUCT GENERATOR	40-R4	(3)	1,456,108	0	43,683	2,358	0.16	29.1	985,315	0.24	0.13
B08.	BUSWORK AND HARDWARE	50-R4	(8)	7,307,906	0	584,632	24,380	0.33	30.4	3,340,456	0.73	0.32
C01.	CABLES - TELECONTROL	30-R4	(3)	2,643,339	0	79,301	3,021	0.11	26.5	393,321	0.77	0.18
C02.	CABLE - SUBMARINE	45-R4	(14)	8,901,116	0	1,246,156	64,114	0.72	20.9	2,776,722	2.31	0.59
C03.	CABLES - UNDERGROUND	60-S4	(14)	2,837,546	0	397,257	11,201	0.39	46.1	1,905,314	0.59	0.43
C04.	CABLES - ABOVE GROUND	60-R4	(14)	10,550,929	0	1,477,130	48,135	0.46	36.8	4,494,725	1.07	0.44
C06.	CAPACITORS	35-R3	(3)	994,744	0	29,843	4,297	0.43	8.3	690,109	0.62	0.17
C07.	CHEMICAL FEED SYSTEMS	45-R4	(6)	509,132	0	30,548	1,808	0.35	20.6	18,552	9.75	0.24
C09.	CIRCUIT BREAKERS	60-R2.5	(8)	39,656,672	0	3,172,534	82,172	0.21	43.6	31,594,197	0.26	0.33
C10.	COMPRESSED AIR SYSTEMS	41-R1.5	0	16,666,710	0	0	0	0.00	26.8	14,222,905	-	-
C11.	COMPUTERS	5-SQ	0	4,899,775	0	0	0	0.00	4.0	4,407,813	-	-
C12.	CONDENSERS	55-R3	(3)	125,930	0	3,778	250	0.20	15.1	0	-	0.11
C13.	CONDUCTOR - TRANSMISSION	60-R3	(20)	67,322,774	0	13,464,554	443,858	0.66	31.8	42,025,239	1.06	0.68
C14.	CONDUCTOR - DISTRIBUTION	45-R3	(14)	34,320,050	0	4,804,807	190,688	0.55	30.2	18,601,762	1.03	0.65
C15.	CONTROL, METERING, RELAYING	40-R3	0	29,645,208	0	0	0	0.00	27.7	18,702,830	-	-
C16.	COOLING SYSTEMS	40-R1.5	(3)	10,007,038	0	300,211	11,276	0.12	28.0	7,732,067	0.15	0.20
C17.	COUNTERPOISE	55-R2.5	(6)	3,623,089	0	217,385	7,511	0.21	32.2	2,310,209	0.33	0.24
C18.	CRANES	70-R3	(3)	6,902,142	0	207,064	5,088	0.07	41.8	6,044,509	0.08	0.09
D01.	DAMS, DYKES, CANALS AND TUNNELS	110-R4	(8)	361,909,256	0	28,952,740	385,472	0.10	75.4	340,976,393	0.11	0.15
D02.	DIESEL SYSTEMS AND ENGINES	25-L0.5	(11)	41,897,351	0	4,608,708	265,556	0.64	19.1	27,128,109	0.98	1.39
D03.	DISCONNECT SWITCHES	55-R2.5	(3)	20,883,528	0	626,505	19,129	0.09	41.5	15,314,119	0.12	0.12
D04.	DYKES AND LINERS	42-L1.5	(8)	2,477,333	0	198,186	8,047	0.32	30.1	745,693	1.08	0.50
E01.	ELEVATORS	45-S5	(3)	89,800	0	2,694	604	0.67	4.5	0	-	0.11
E02.	EMS EQUIPMENT	35-R2.5	0	12,917,219	0	0	0	0.00	25.0	189,571	-	-
E03.	ENVIRONMENTAL EQUIPMENT	45-R2.5	0	935,876	0	0	0	0.00	22.6	349,053	-	-
F01.	FALL ARREST EQUIPMENT	15-R4	0	2,509,020	0	0	0	0.00	10.5	2,007,509	-	-
F02.	FENCING	52-R3	(3)	7,555,589	0	226,668	6,653	0.09	41.4	4,183,349	0.16	0.11
F03.	FIRE FIGHTING EQUIPMENT	50-R4	0	13,906,919	0	0	0	0.00	42.8	8,924,743	-	-
F04.	FOOTINGS AND FOUNDATIONS	65-R3	(8)	20,413,239	0	1,633,059	43,987	0.22	42.5	12,276,179	0.36	0.27
F05.	FREQUENCY CONVERSION	45-S4	0	2,453,577	0	0	0	0.00	35.5	755,877	-	-
F06.	FUEL SYSTEMS	50-R1.5	(11)	28,513,898	0	3,136,529	91,557	0.32	34.3	19,575,128	0.47	0.67
G01.	GAS TURBINE SYSTEMS	45-R3	(2)	69,325,761	0	1,386,515	43,819	0.07	37.3	46,097,528	0.10	0.08
G02.	GATES	80-R4	(8)	19,048,533	0	1,523,882	32,043	0.17	48.8	16,550,695	0.19	0.20
G03.	GENERATORS	65-S3	(8)	105,132,875	0	8,410,630	211,119	0.21	45.4	79,119,107	0.27	0.35
G04.	GENERATOR - WINDINGS	50-S3	(8)	24,614,758	0	1,969,180	42,361	0.17	46.7	17,789,053	0.24	0.32
G05.	GLYCOL SYSTEMS	40-S3	(8)	530,654	0	42,452	2,440	0.46	17.4	98,436	2.48	2.48
G06.	GOVENORS	45-S4	(14)	7,840,659	0	1,097,693	64,598	0.82	18.5	6,562,987	0.98	0.98
G07.	GROUND WIRE SYSTEM	55-R4	(6)	10,370,352	0	622,221	19,634	0.19	37.3	7,515,444	0.26	0.29
I02.	INSTRUMENTATION	30-L0.5	0	5,967,398	0	0	0	0.00	25.0	1,113,173	-	-
I03.	INSULATORS	35-L3	0	41,988,322	0	0	0	0.00	21.6	25,983,406	-	-
I04.	INTAKE STRUCTURES	110-R4	(8)	19,436,445	0	1,554,916	20,774	0.11	75.3	18,225,951	0.11	0.15
I05.	INVERTERS	25-S1.5	(8)	521,505	0	41,721	17,362	3.33	6.4	176,682	9.83	0.72
L03.	LAND IMPROVEMENTS	75-R3	0	14,196,794	0	0	0	0.00	53.7	5,735,273	-	-
L04.	LIGHTING SYSTEMS	50-R4	0	926,303	0	0	0	0.00	41.4	483,472	-	-
L05.	LIGHTNING ARRESTORS	58-R3	0	6,193,610	0	0	0	0.00	44.5	3,984,825	-	-
L06.	LINE COUPLING EQUIPMENT	24-R5	0	11,226	0	0	0	0.00	0.0	0	-	-
M01.	MAIN BREAKERS	42-R0.5	(8)	552,940	0	44,235	1,395	0.26	33.2	288,042	0.48	0.66
M02.	MARINE TERMINAL	65-R4	(6)	3,833,871	0	230,032	3,681	0.10	62.5	860,754	0.43	0.66
M03.	METALCLAD SWITCHGEAR CUB/EQU 4kv/600	45-R4	(6)	2,233,645	0	134,019	5,817	0.26	31.5	669,662	0.87	0.94
M04.	METER TEST SWITCHES	35-R5	0	58,301	0	0	0	0.00	11.6	13,519	-	-
M05.	METERING TANKS	37-R3	0	660,416	0	0	0	0.00	29.2	438,378	-	-
M06.	METERS - DIGITAL	20-L3	0	5,874,668	0	0	0	0.00	12.9	4,566,868	-	-
M07.	METERS - ANALOGUE	25-L2	0	698,384	0	0	0	0.00	9.1	76,225	-	-
M08.	METERS - OTHER	22-L4	0	262,853	0	0	0	0.00	11.4	166,747	-	-
M10.	MISCELLANEOUS UNITS OF PROPERTY	22-R1.5	0	25,815,956	0	0	0	0.00	17.7	24,143,424	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1B. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
COST OF REMOVAL

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
M11.	MOBILE - A.T.V.'S AND SNOWMOBILES	6-L3	0	1,906,739	0	0	0	0.00	4.0	1,630,167	-	-
M12.	MOBILE - AIR COMPRESSOR ATTACHMENT AND BOAT	20-L0	0	432,046	0	0	0	0.00	17.3	131,898	-	-
M13.	MOBILE - ARGO'S	9-R5	0	287,287	0	0	0	0.00	0.0	180,781	-	-
M14.	MOBILE - FLEX/FORK/LOAD/GRADE/MUSK/TRAILER	18-L3	0	10,581,312	0	0	0	0.00	13.5	7,185,044	-	-
M16.	MULTIPLEX EQUIPMENT	18-S1.5	0	2,812,217	0	0	0	0.00	11.3	822,074	-	-
O01.	OFFICE EQUIPMENT	20-SQ	0	1,286,440	0	0	0	0.00	15.0	731,009	-	-
O02.	OFFICE FURNITURE	20-SQ	0	1,477,990	0	0	0	0.00	13.5	743,513	-	-
P01.	P.C.B. STORAGE CONTAINER	30-R4	0	42,480	0	0	0	0.00	7.7	1,483	-	-
P02.	PABX - PRIVATE AUTO BRANCH EXCHANGE	20-R4	0	1,181,009	0	0	0	0.00	10.6	277,879	-	-
P03.	PENSTOCK	70-R4	(8)	58,908,421	0	4,712,674	145,974	0.25	33.4	44,875,320	0.33	0.23
P04.	POLE CRIBS AND POLE HARDWARE	35-S2.5	(20)	118,371,156	0	23,674,231	1,142,374	0.96	24.0	82,813,901	1.38	1.10
P05.	POLE STRUCTURES - WOOD	57-R3	(20)	129,790,285	0	25,958,057	771,662	0.59	36.3	89,077,051	0.87	0.72
P06.	POLES - CONCRETE	25-R4	(20)	333,760	0	66,752	29,693	8.90	3.0	55,346	53.65	1.49
P07.	POLES - WOOD	43-R1	(20)	72,604,630	0	14,520,926	464,761	0.64	32.2	49,437,902	0.94	1.52
P08.	POWER LINE CARRIER	25-R3	(6)	4,971,572	0	298,294	23,858	0.48	14.6	798,185	2.99	0.46
P09.	POWER SYSTEMS	20-L3	(6)	664,592	0	39,876	4,300	0.64	10.0	457,452	0.94	0.57
P10.	POWERHOUSE	75-R3	(8)	93,718,745	0	7,497,499	169,522	0.18	45.2	77,547,345	0.22	0.24
P11.	PRINTERS	6-SQ	0	1,038,001	0	0	0	0.00	4.4	968,970	-	-
P12.	PROTECTIVE CONTROL AND RELAY PANELS	35-R3	0	9,507,129	0	0	0	0.00	29.1	7,232,549	-	-
R01.	RADIO TOWERS (WOOD OR STEEL)	48-R3	(14)	9,759,106	0	1,366,275	37,759	0.39	37.0	3,006,850	1.26	0.61
R02.	RADIOS - FIXED MICROWAVE EQUIPMENT	19-R5	0	6,212,764	0	0	0	0.00	9.8	1,854,531	-	-
R03.	RADIOS - FIXED UHF EQUIPMENT	15-L0.5	0	101,662	0	0	0	0.00	10.6	81,822	-	-
R04.	RADIOS - FIXED VHF EQUIPMENT	19-R3	0	560,166	0	0	0	0.00	10.9	153,938	-	-
R05.	RADIOS - MOBILE VHF BASE STATION	15-R4	0	7,278,664	0	0	0	0.00	7.0	3,124,097	-	-
R06.	RAMPS - YARD STORAGE	25-R3	0	1,593,558	0	0	0	0.00	16.8	935,272	-	-
R07.	REACTORS AND RESISTORS	40-S4	0	1,225,065	0	0	0	0.00	21.4	903,491	-	-
R08.	RECLOSERS	48-R3	(8)	7,158,607	0	572,689	18,065	0.25	38.1	4,572,762	0.40	0.36
R09.	REGULATORS	40-S0.5	(8)	5,667,640	0	453,411	18,933	0.33	29.3	3,706,121	0.51	0.53
R11.	REVENUE METERING	35-R3	0	1,242,916	0	0	0	0.00	20.9	849,542	-	-
R12.	RIGHT-OF-WAYS	65-R4	0	21,729,649	0	0	0	0.00	38.4	12,488,097	-	-
R13.	ROADS	60-R4	(8)	84,440,747	0	6,755,260	223,049	0.26	30.5	75,174,354	0.30	0.27
R14.	ROUTERS AND LAN	5-SQ	0	2,730,978	0	0	0	0.00	4.1	2,448,737	-	-
R15.	RUNNER	55-R5	0	11,669,844	0	0	0	0.00	12.7	6,821,838	-	-
S01.	SCADA EQUIPMENT	20-L3	0	4,929,933	0	0	0	0.00	13.6	2,481,772	-	-
S02.	SECTIONALIZERS	25-R5	0	154,009	0	0	0	0.00	4.0	45,666	-	-
S03.	SERVERS	7-SQ	0	3,019,204	0	0	0	0.00	5.6	1,643,300	-	-
S04.	SEWAGE DISPOSAL SYSTEM	55-R4	(6)	2,919,319	0	175,159	4,593	0.15	41.4	1,121,167	0.41	0.19
S05.	SOFTWARE	7-SQ	0	10,081,799	0	0	0	0.00	3.4	8,980,374	-	-
S06.	SPILLWAY STRUCTURES	110-R4	(8)	28,120,270	0	2,249,621	30,004	0.10	75.2	26,004,636	0.12	0.15
S07.	STACKS	55-R4	(8)	7,850,850	0	628,068	16,058	0.20	48.2	4,868,525	0.33	0.29
S08.	STATIC EXCITATION SYSTEM	32-R4	(6)	8,333,065	0	499,984	167,515	2.01	6.5	5,117,789	3.27	0.33
S09.	STATIC EXCITATION - TRANSFORMERS	45-R4	(6)	734,327	0	44,059	2,827	0.38	15.7	16,538	17.09	0.64
S10.	STATION SERVICE	50-R4	(6)	5,233,336	0	314,000	14,642	0.28	28.1	3,966,436	0.37	0.41
S11.	STOP LOGS	65-R4	0	3,114,097	0	0	0	0.00	34.2	2,650,931	-	-
S12.	STORAGE PALLETS AND RACKINGS	30-R3	0	14,403	0	0	0	0.00	0.0	0	-	-
S13.	STORM AND YARD DRAINAGE	55-R4	0	1,308,713	0	0	0	0.00	38.8	283,067	-	-
S14.	STREET LIGHTS	20-R2	(6)	3,874,989	0	232,500	23,891	0.62	12.5	2,805,557	0.85	0.68
S15.	STRUCTURAL SUPPORTS (WOOD OR STEEL)	55-R4	(6)	11,677,609	0	700,657	25,273	0.22	35.4	6,251,538	0.40	0.39
S17.	SUMP SYSTEMS	35-R4	0	667,245	0	0	0	0.00	17.9	561,992	-	-
S18.	SURGE SYSTEMS	60-R4	0	6,972,889	0	0	0	0.00	37.5	4,069,890	-	-
S19.	STATION SWITCHING	38-S0.5	0	11,650,032	0	0	0	0.00	25.9	7,525,863	-	-
S20.	SWITCHING SYSTEMS - L.V.	60-R5	0	2,304,609	0	0	0	0.00	31.8	2,071,699	-	-
T01.	TELECONTROL SYSTEM	25-L1.5	0	12,429,279	0	0	0	0.00	18.4	6,362,279	-	-
T02.	TEST EQUIPMENT	20-SQ	0	1,955,314	0	0	0	0.00	14.8	955,358	-	-
T03.	TOOLS AND EQUIPMENT	20-SQ	0	11,434,328	0	0	0	0.00	14.3	6,366,862	-	-
T04.	TOWERS	65-R4	(20)	77,739,424	0	15,547,885	432,964	0.55	38.9	54,042,115	0.80	0.67
T05.	TRANSFORMERS - OTHER	55-R3	(6)	89,255,274	0	5,355,317	201,653	0.23	31.8	55,908,373	0.36	0.41
T06.	TRANSFORMERS - PAD MOUNT	40-R1.5	(8)	17,723,652	0	1,417,893	40,372	0.23	36.8	16,335,856	0.25	0.31
T07.	TRANSFORMERS - POLE MOUNTED	30-L1	(8)	37,040,457	0	2,963,236	136,116	0.37	22.9	29,543,794	0.46	0.47
T09.	TURBINES	55-R2.5	(14)	65,159,636	0	9,122,349	333,332	0.52	29.9	42,271,663	0.79	0.80

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1B. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
COST OF REMOVAL

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
T10.	HOLYROOD GAS TURBINE - COMBUSTOR OVERHAUL	3-SQ	0	2,206,062	0	0	0	0.00	2.5	2,206,062	-	-
T11.	HOLYROOD GAS TURBINE - TURBINE OVERHAUL	6-SQ	0	2,206,062	0	0	0	0.00	5.5	2,206,062	-	-
T12.	HOLYROOD GAS TURBINE - COMPRESSOR OVERHAUL	12-SQ	0	3,088,487	0	0	0	0.00	11.5	3,088,487	-	-
V01.	VACUUM CLEANING SYSTEM	60-R4	0	72,451	0	0	0	0.00	25.8	6,099	-	-
V02.	VALVES - PENSTOCK	65-R3	(8)	7,567,760	0	605,421	16,573	0.21	40.1	5,558,323	0.30	0.27
V03.	VEHICLES - 1 TON	8-L4	0	51,648	0	0	0	0.00	5.5	51,648	-	-
V04.	VEHICLES - 3/4 TON AND UNDER	7-L3	0	5,167,170	0	0	0	0.00	5.6	4,033,711	-	-
V05.	VEHICLES - BOOMS/BODIES/CRANES/CAB/CHASSIS	12-L3	0	14,954,546	0	0	0	0.00	8.1	10,855,821	-	-
V06.	VEHICLES - CARS, STATION WAGONS AND VAN	6-L3	0	1,795,372	0	0	0	0.00	4.5	1,134,905	-	-
V07.	VEHICLES - DUMP TRUCKS	10-L5	0	11,535	0	0	0	0.00	0.0	0	-	-
W01.	WATER REGULATING STRUCTURES	65-S4	(8)	22,451,738	0	1,796,139	47,213	0.21	41.3	18,454,117	0.26	0.24
W02.	WATER SUPPLY SYSTEMS	30-L4	(8)	3,394,554	0	271,564	28,124	0.83	14.0	1,972,019	1.43	0.53
W03.	WATER SYSTEMS - FEED	55-R2.5	(8)	6,531,260	0	522,501	18,729	0.29	37.0	3,023,065	0.62	0.36
W04.	WATER TREATMENT	55-R2.5	(6)	11,921,573	0	715,295	18,997	0.16	40.3	6,307,665	0.30	0.24
	Sub-Total			2,458,776,655	0	217,605,468	7,038,181	0.29		1,756,107,129	0.40	

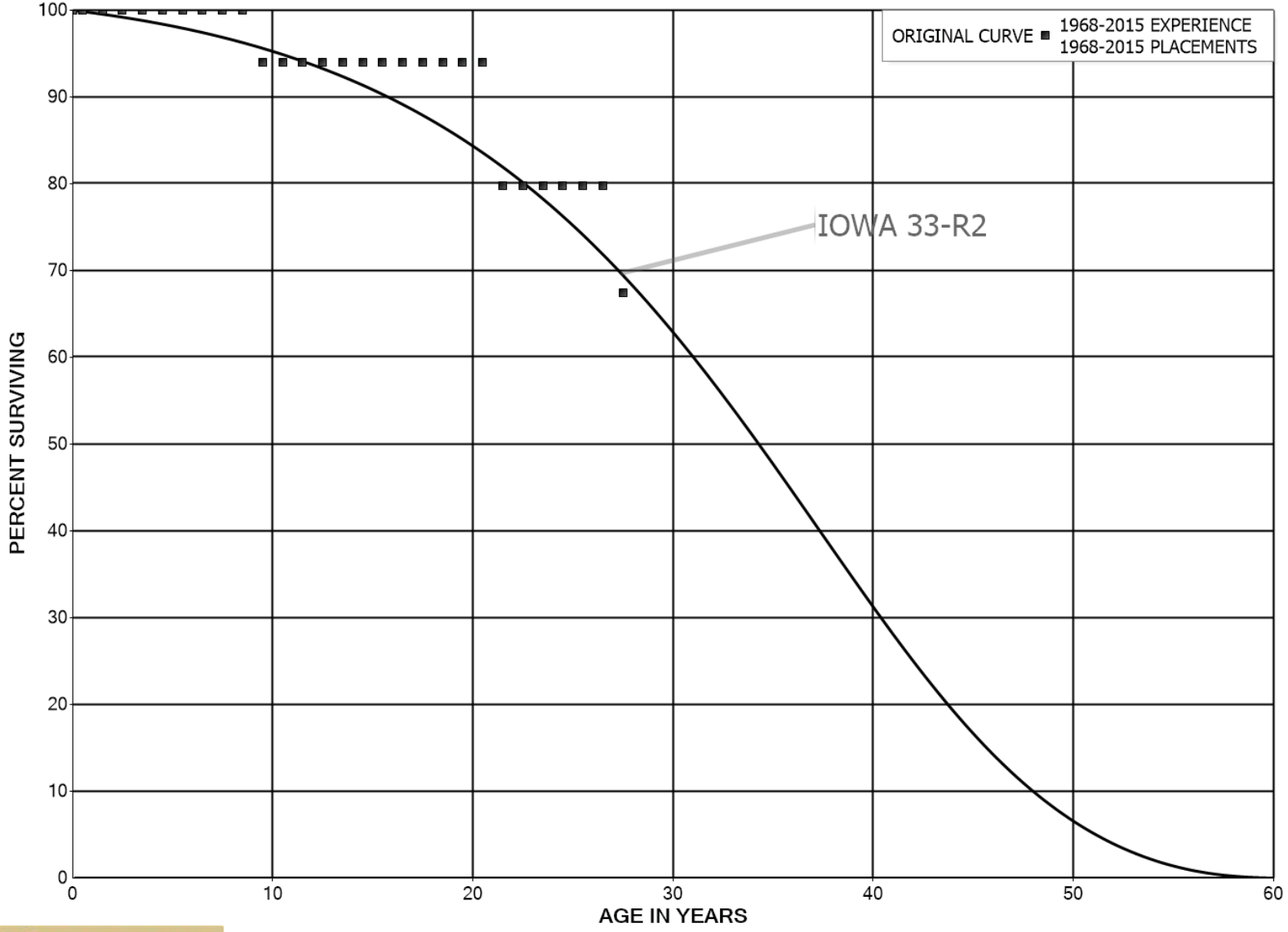
NEWFOUNDLAND AND LABRADOR HYDRO
DEPRECIATION STUDY

NEWFOUNDLAND AND LABRADOR HYDRO
TABLE 1B. ESTIMATED SURVIVOR CURVES,ORIGINAL AND DEEMED COST AND ANNUAL ACCRUALS
RELATED TO PLANT IN SERVICE AS OF DECEMBER 31, 2015
COST OF REMOVAL

ACCOUNT	ACCOUNT DESCRIPTION	SURVIVOR CURVE	NET SALVAGE PERCENTAGE	ORIGINAL COST DECEMBER 31, 2015	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ACCRUAL AMOUNT	ORIGINAL COST ACCRUAL RATE	COMPOSITE REMAINING LIFE	DEEMED COST DECEMBER 31, 2015	DEEMED COST ACCRUAL RATE	WHOLE LIFE ACCRUAL RATE
HOLYROOD ASSETS	**TRUCATION DATE**	**3/31/2021**										
A04.1	AUXILIARY POWER SYSTEMS	30-R4	(3)	620,866	0	18,626	3,555	0.58	5.2	492,554	0.72	1.21
B01.1	BATTERY AND POWER SYSTEMS	26-L1.5	(3)	106,627	0	3,199	764	0.72	4.4	86,099	0.89	1.22
B02.1	BOILER SYSTEM	40-R3	(8)	35,073,430	0	2,805,875	576,238	1.64	5.0	12,295,071	4.69	3.65
B05.1	BUILDINGS - OTHER	50-R0.5	(3)	1,300,250	0	39,007	7,601	0.58	5.1	859,162	0.88	1.26
B06.1	BUILDINGS - METAL	55-R3	(3)	72,011	0	2,160	412	0.57	5.2	51,935	0.79	1.22
C01.1	CABLES - TELECONTROL	30-R4	(3)	89,750	0	2,692	518	0.57	5.2	42,606	1.22	1.21
C03.1	CABLES - UNDERGROUND	60-S4	(14)	544,049	0	76,167	14,647	2.69	5.2	68,519	21.38	6.08
C04.1	CABLES - ABOVE GROUND	60-R4	(14)	629,827	0	88,176	17,089	2.71	5.2	78,084	21.89	6.08
C07.1	CHEMICAL FEED SYSTEMS	45-R4	(6)	77,164	0	4,630	893	1.16	5.2	16,813	5.31	2.43
C12.1	CONDENSERS	55-R3	(3)	2,329,667	0	69,890	13,684	0.58	5.1	386,962	3.54	1.22
C15.1	CONTROL, METERING, RELAYING	40-R3	0	119,880	0	0	0	0.00	5.2	115,036	-	-
E03.1	ENVIRONMENTAL EQUIPMENT	45-R2.5	0	1,280,261	0	0	0	0.00	5.2	624,419	-	-
F03.1	FIRE FIGHTING EQUIPMENT	50-R4	0	797,150	0	0	0	0.00	5.1	290,151	-	-
F04.1	FOOTINGS AND FOUNDATIONS	65-R3	(8)	56,613	0	4,529	873	1.54	5.2	10,668	8.18	3.65
F06.1	FUEL SYSTEMS	50-R1.5	(11)	13,309,152	0	1,464,007	285,329	2.14	5.2	8,233,153	3.47	4.94
G01.1	GAS TURBINE SYSTEMS	45-R3	(2)	24,645	0	493	98	0.40	5.0	887	11.05	0.73
G03.1	GENERATORS	65-S3	(8)	1,067,438	0	85,395	16,264	1.53	5.3	1,228,857	1.32	3.65
G06.1	GOVENORS	45-S4	(14)	2,144,383	0	300,214	57,784	2.69	5.2	773,352	7.47	6.08
I02.1	INSTRUMENTATION	30-L0.5	0	6,727,326	0	0	0	0.00	4.8	2,327,089	-	-
I05.1	INVERTERS	25-S1.5	(8)	24,417	0	1,953	405	1.66	4.8	10,794	3.75	3.66
L03.1	LAND IMPROVEMENTS	75-R3	0	5,766	0	0	0	0.00	5.2	1,281	-	-
M02.1	MARINE TERMINAL	65-R4	(6)	468,523	0	28,111	5,363	1.14	5.2	175,342	3.06	2.43
M10.1	MISCELLANEOUS UNITS OF PROPERTY	22-R1.5	0	1,611,947	0	0	0	0.00	5.1	1,583,560	-	-
O02.1	OFFICE FURNITURE	20-SQ	0	58,975	0	0	0	0.00	2.5	16,483	-	-
P10.1	POWERHOUSE	75-R3	(8)	8,903,432	0	712,275	137,239	1.54	5.2	1,133,208	12.11	3.65
P12.1	PROTECTIVE CONTROL AND RELAY PANELS	35-R3	0	106,685	0	0	0	0.00	5.2	65,847	-	-
R13.1	ROADS	60-R4	(8)	1,859	0	149	29	1.56	5.2	248	11.70	3.65
S07.1	STACKS	55-R4	(8)	9,202,119	0	736,169	144,478	1.57	5.2	4,786,711	3.02	3.65
S08.1	STATIC EXCITATION SYSTEM	32-R4	(6)	1,461,435	0	87,686	70,971	4.86	1.4	729,359	9.73	2.43
T03.1	TOOLS AND EQUIPMENT	20-SQ	0	351,262	0	0	0	0.00	5.2	268,073	-	-
T05.1	TRANSFORMERS	55-R3	(6)	126,690	0	7,602	1,451	1.14	5.2	126,690	1.15	2.43
T09.1	TURBINES	55-R2.5	(14)	27,077,372	0	3,790,832	730,053	2.70	5.2	20,041,663	3.64	6.11
W03.1	WATER SYSTEMS - FEED	55-R2.5	(8)	2,818,634	0	225,491	44,198	1.57	5.1	1,270,349	3.48	3.66
W04.1	WATER TREATMENT	55-R2.5	(6)	2,792,962	0	167,578	32,417	1.16	5.2	1,772,842	1.83	2.44
	Sub-Total			121,382,565	0	10,722,906	2,162,353	1.78		59,963,868	3.61	
	TOTAL			2,580,159,221	0	228,328,374	9,200,534	0.36		1,816,070,997	0.51	

PART V. SERVICE LIFE STATISTICS

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT A01 - AIRCRAFT LANDING STRIP
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT A01 - AIRCRAFT LANDING STRIP

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	583,066		0.0000	1.0000	100.00
0.5	580,763		0.0000	1.0000	100.00
1.5	580,763		0.0000	1.0000	100.00
2.5	580,763		0.0000	1.0000	100.00
3.5	580,763		0.0000	1.0000	100.00
4.5	580,763		0.0000	1.0000	100.00
5.5	580,763		0.0000	1.0000	100.00
6.5	580,763		0.0000	1.0000	100.00
7.5	580,763		0.0000	1.0000	100.00
8.5	580,763	35,373	0.0609	0.9391	100.00
9.5	467,000		0.0000	1.0000	93.91
10.5	467,000		0.0000	1.0000	93.91
11.5	467,000		0.0000	1.0000	93.91
12.5	467,000		0.0000	1.0000	93.91
13.5	467,000		0.0000	1.0000	93.91
14.5	467,000		0.0000	1.0000	93.91
15.5	467,000		0.0000	1.0000	93.91
16.5	467,000		0.0000	1.0000	93.91
17.5	467,000		0.0000	1.0000	93.91
18.5	467,000		0.0000	1.0000	93.91
19.5	467,000		0.0000	1.0000	93.91
20.5	467,000	70,746	0.1515	0.8485	93.91
21.5	201,633		0.0000	1.0000	79.68
22.5	9,425		0.0000	1.0000	79.68
23.5	9,425		0.0000	1.0000	79.68
24.5	9,425		0.0000	1.0000	79.68
25.5	9,425		0.0000	1.0000	79.68
26.5	9,425	1,449	0.1537	0.8463	79.68
27.5	7,976		0.0000	1.0000	67.43
28.5	7,976		0.0000	1.0000	67.43
29.5	7,976		0.0000	1.0000	67.43
30.5	7,976		0.0000	1.0000	67.43
31.5	7,976		0.0000	1.0000	67.43
32.5	7,976		0.0000	1.0000	67.43
33.5	7,976		0.0000	1.0000	67.43
34.5	7,976		0.0000	1.0000	67.43
35.5	7,976		0.0000	1.0000	67.43
36.5	7,976		0.0000	1.0000	67.43
37.5	7,976		0.0000	1.0000	67.43
38.5	7,976		0.0000	1.0000	67.43

NEWFOUNDLAND AND LABRADOR HYDRO

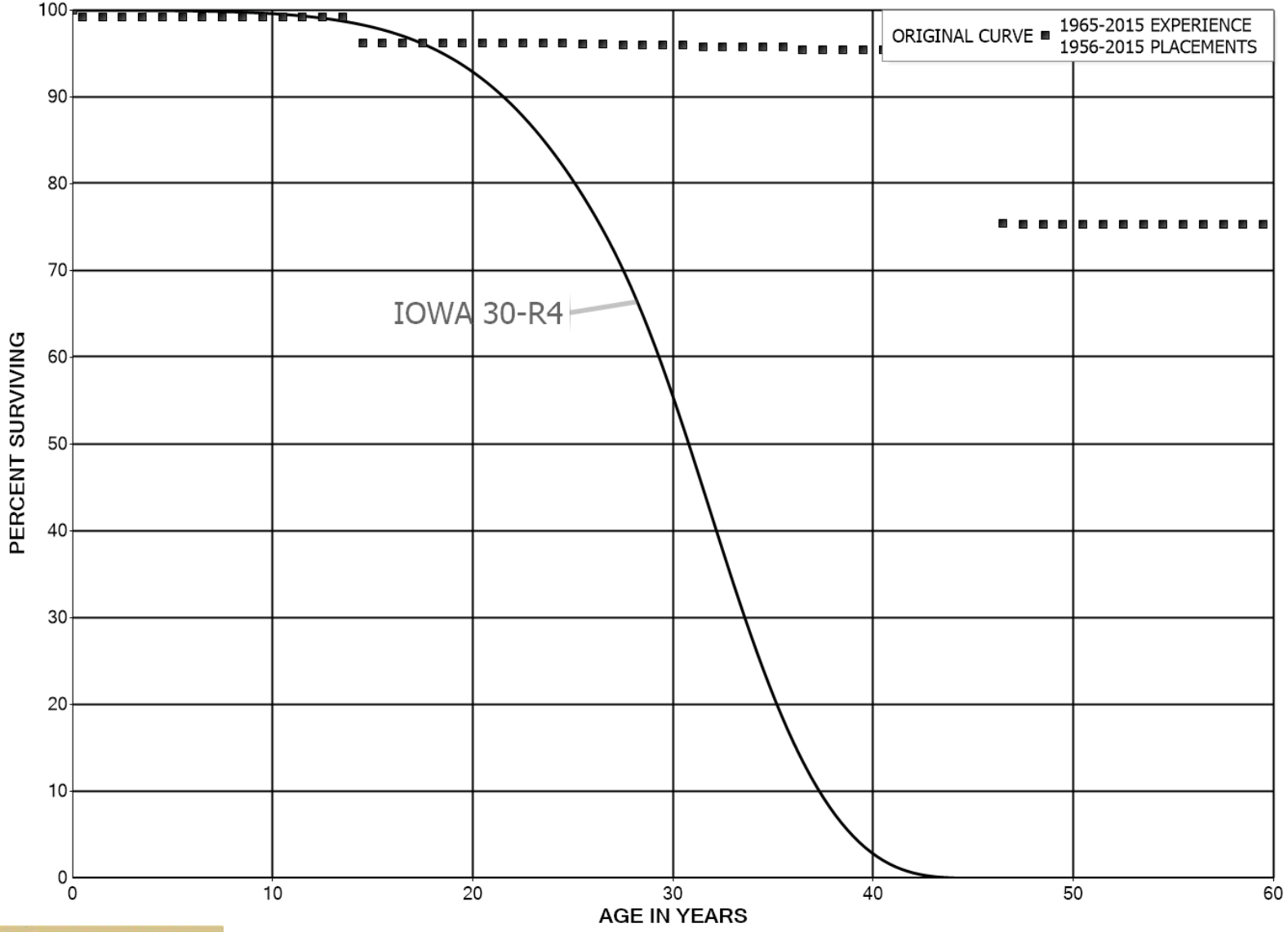
ACCOUNT A01 - AIRCRAFT LANDING STRIP

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	7,976		0.0000	1.0000	67.43
40.5	7,976		0.0000	1.0000	67.43
41.5					67.43

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT A04 - AUXILIARY POWER SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT A04 - AUXILIARY POWER SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,844,251	56,321	0.0082	0.9918	100.00
0.5	5,450,620		0.0000	1.0000	99.18
1.5	5,450,620		0.0000	1.0000	99.18
2.5	4,648,143		0.0000	1.0000	99.18
3.5	4,435,128		0.0000	1.0000	99.18
4.5	4,375,301		0.0000	1.0000	99.18
5.5	3,417,839		0.0000	1.0000	99.18
6.5	3,417,839		0.0000	1.0000	99.18
7.5	3,417,839		0.0000	1.0000	99.18
8.5	3,503,309		0.0000	1.0000	99.18
9.5	3,503,309		0.0000	1.0000	99.18
10.5	3,405,766		0.0000	1.0000	99.18
11.5	3,405,766		0.0000	1.0000	99.18
12.5	2,957,369		0.0000	1.0000	99.18
13.5	2,957,369	88,784	0.0300	0.9700	99.18
14.5	2,500,316		0.0000	1.0000	96.20
15.5	2,336,231		0.0000	1.0000	96.20
16.5	2,320,175		0.0000	1.0000	96.20
17.5	2,320,175		0.0000	1.0000	96.20
18.5	2,320,175		0.0000	1.0000	96.20
19.5	2,320,175		0.0000	1.0000	96.20
20.5	2,320,175		0.0000	1.0000	96.20
21.5	2,320,175		0.0000	1.0000	96.20
22.5	2,320,175		0.0000	1.0000	96.20
23.5	2,256,451		0.0000	1.0000	96.20
24.5	2,256,451	4,435	0.0020	0.9980	96.20
25.5	2,252,016		0.0000	1.0000	96.01
26.5	1,571,875	1,465	0.0009	0.9991	96.01
27.5	1,404,505		0.0000	1.0000	95.92
28.5	1,404,505		0.0000	1.0000	95.92
29.5	1,404,505		0.0000	1.0000	95.92
30.5	1,404,505	2,233	0.0016	0.9984	95.92
31.5	1,181,198		0.0000	1.0000	95.77
32.5	1,137,700		0.0000	1.0000	95.77
33.5	724,162		0.0000	1.0000	95.77
34.5	724,162		0.0000	1.0000	95.77
35.5	588,602	2,388	0.0041	0.9959	95.77
36.5	486,440		0.0000	1.0000	95.38
37.5	484,440		0.0000	1.0000	95.38
38.5	484,440		0.0000	1.0000	95.38

NEWFOUNDLAND AND LABRADOR HYDRO

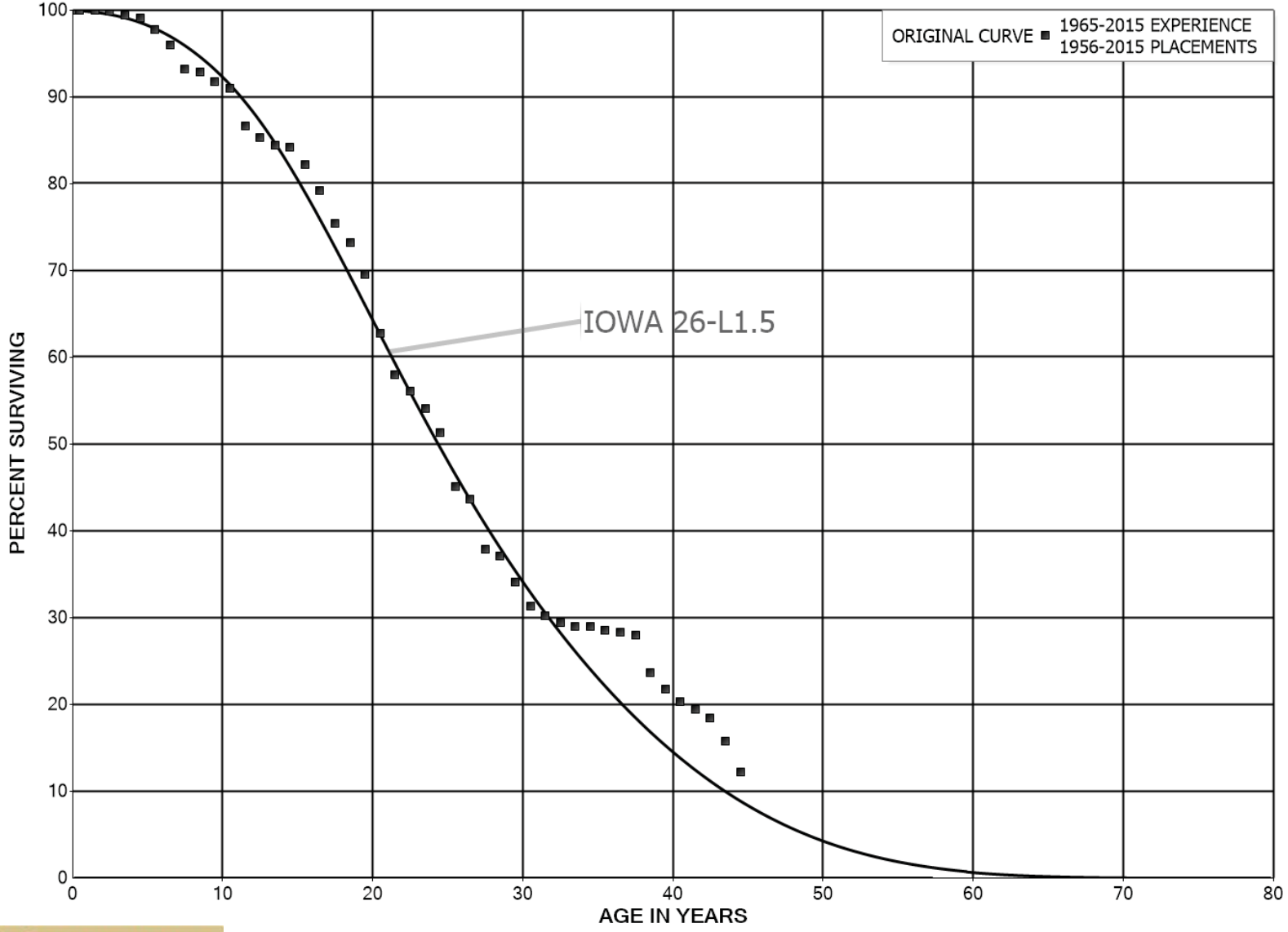
ACCOUNT A04 - AUXILIARY POWER SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	484,440		0.0000	1.0000	95.38
40.5	484,440		0.0000	1.0000	95.38
41.5	479,390		0.0000	1.0000	95.38
42.5	479,390		0.0000	1.0000	95.38
43.5	479,390		0.0000	1.0000	95.38
44.5	479,390		0.0000	1.0000	95.38
45.5	467,390	98,000	0.2097	0.7903	95.38
46.5	369,390	289	0.0008	0.9992	75.38
47.5	369,101		0.0000	1.0000	75.32
48.5	369,101		0.0000	1.0000	75.32
49.5	85,470		0.0000	1.0000	75.32
50.5	85,470		0.0000	1.0000	75.32
51.5	85,470		0.0000	1.0000	75.32
52.5	85,470		0.0000	1.0000	75.32
53.5	85,470		0.0000	1.0000	75.32
54.5	85,470		0.0000	1.0000	75.32
55.5	85,470		0.0000	1.0000	75.32
56.5	85,470		0.0000	1.0000	75.32
57.5	85,470		0.0000	1.0000	75.32
58.5	85,470		0.0000	1.0000	75.32
59.5					75.32

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B01 - BATTERY AND POWER SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B01 - BATTERY AND POWER SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,741,039		0.0000	1.0000	100.00
0.5	14,914,911		0.0000	1.0000	100.00
1.5	14,548,815	31,712	0.0022	0.9978	100.00
2.5	13,711,017	47,671	0.0035	0.9965	99.78
3.5	12,451,002	40,274	0.0032	0.9968	99.44
4.5	11,702,891	159,679	0.0136	0.9864	99.11
5.5	10,984,190	207,966	0.0189	0.9811	97.76
6.5	10,009,380	288,121	0.0288	0.9712	95.91
7.5	9,362,565	34,448	0.0037	0.9963	93.15
8.5	8,847,535	107,713	0.0122	0.9878	92.81
9.5	8,339,058	67,934	0.0081	0.9919	91.68
10.5	7,835,000	371,208	0.0474	0.9526	90.93
11.5	7,037,952	106,152	0.0151	0.9849	86.62
12.5	5,559,047	59,727	0.0107	0.9893	85.32
13.5	5,492,709	13,768	0.0025	0.9975	84.40
14.5	4,629,876	108,926	0.0235	0.9765	84.19
15.5	4,336,216	161,634	0.0373	0.9627	82.21
16.5	4,154,340	195,177	0.0470	0.9530	79.14
17.5	3,769,965	115,058	0.0305	0.9695	75.42
18.5	3,643,147	180,715	0.0496	0.9504	73.12
19.5	3,280,050	320,349	0.0977	0.9023	69.49
20.5	2,887,798	221,046	0.0765	0.9235	62.71
21.5	2,641,652	85,451	0.0323	0.9677	57.91
22.5	2,556,201	90,249	0.0353	0.9647	56.03
23.5	2,300,838	117,643	0.0511	0.9489	54.06
24.5	2,183,195	266,372	0.1220	0.8780	51.29
25.5	1,635,643	52,049	0.0318	0.9682	45.03
26.5	1,569,780	208,599	0.1329	0.8671	43.60
27.5	1,354,635	25,667	0.0189	0.9811	37.81
28.5	1,326,794	107,122	0.0807	0.9193	37.09
29.5	1,219,672	100,855	0.0827	0.9173	34.10
30.5	1,006,195	35,619	0.0354	0.9646	31.28
31.5	970,576	23,696	0.0244	0.9756	30.17
32.5	946,881	17,400	0.0184	0.9816	29.43
33.5	851,124		0.0000	1.0000	28.89
34.5	851,124	10,357	0.0122	0.9878	28.89
35.5	530,788	5,270	0.0099	0.9901	28.54
36.5	516,555	6,470	0.0125	0.9875	28.26
37.5	470,539	72,512	0.1541	0.8459	27.90
38.5	398,027	32,393	0.0814	0.9186	23.60

NEWFOUNDLAND AND LABRADOR HYDRO

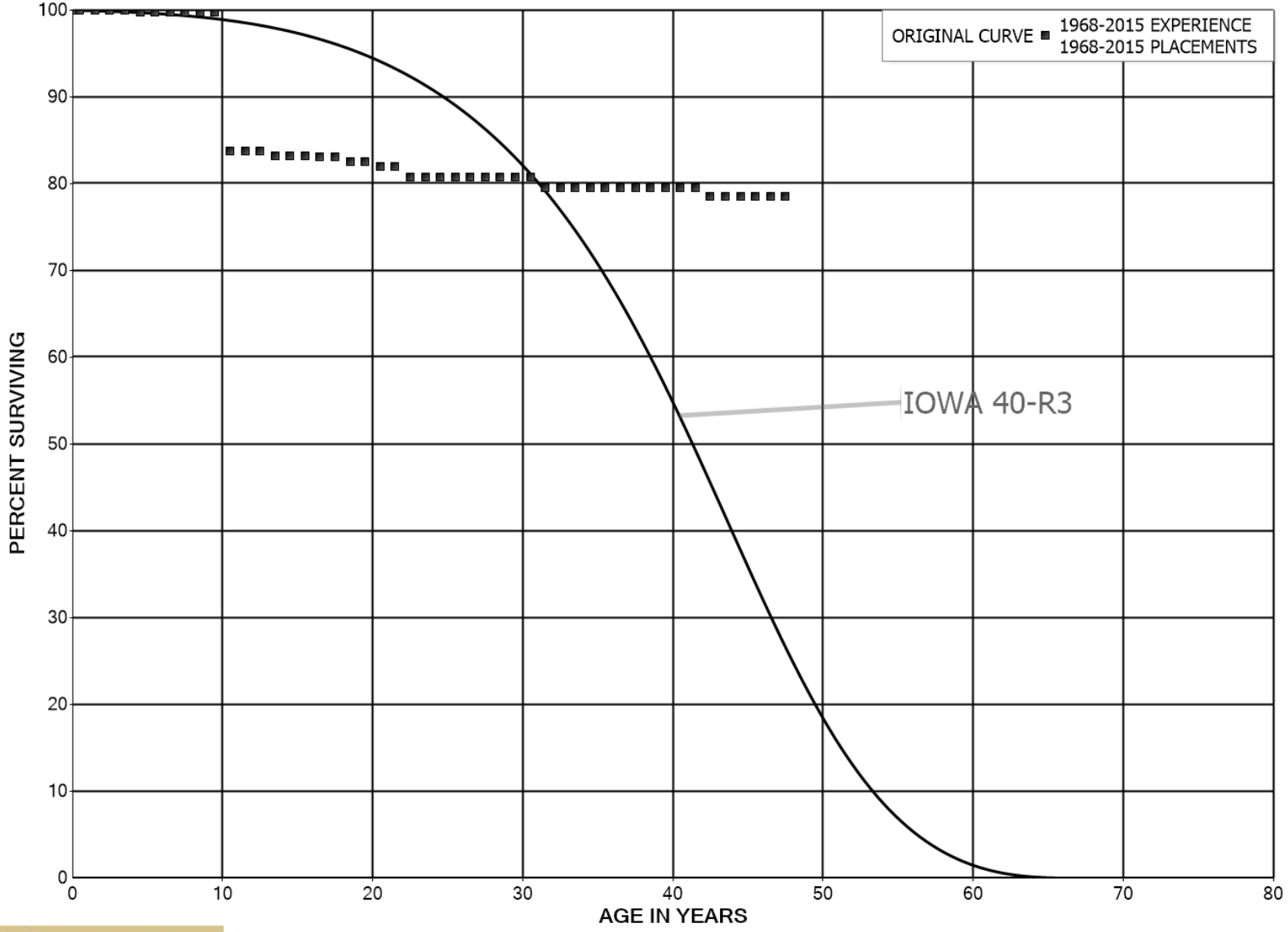
ACCOUNT B01 - BATTERY AND POWER SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	365,634	23,740	0.0649	0.9351	21.68
40.5	335,847	13,700	0.0408	0.9592	20.27
41.5	322,147	17,094	0.0531	0.9469	19.45
42.5	304,702	44,588	0.1463	0.8537	18.42
43.5	242,923	55,185	0.2272	0.7728	15.72
44.5	126,300		0.0000	1.0000	12.15
45.5	122,665	12,425	0.1013	0.8987	12.15
46.5	110,240		0.0000	1.0000	10.92
47.5	1,466		0.0000	1.0000	10.92
48.5	1,466		0.0000	1.0000	10.92
49.5	1,466		0.0000	1.0000	10.92
50.5	1,466		0.0000	1.0000	10.92
51.5	1,466		0.0000	1.0000	10.92
52.5	1,466		0.0000	1.0000	10.92
53.5	1,466		0.0000	1.0000	10.92
54.5	1,466		0.0000	1.0000	10.92
55.5	1,466		0.0000	1.0000	10.92
56.5	1,466		0.0000	1.0000	10.92
57.5	1,466		0.0000	1.0000	10.92
58.5	1,466		0.0000	1.0000	10.92
59.5					10.92

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B02 - BOILER SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B02 - BOILER SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	70,231,168		0.0000	1.0000	100.00
0.5	70,137,735		0.0000	1.0000	100.00
1.5	69,218,304		0.0000	1.0000	100.00
2.5	69,135,617		0.0000	1.0000	100.00
3.5	67,758,844	180,285	0.0027	0.9973	100.00
4.5	66,863,796		0.0000	1.0000	99.73
5.5	65,506,295		0.0000	1.0000	99.73
6.5	64,184,236		0.0000	1.0000	99.73
7.5	59,966,281		0.0000	1.0000	99.73
8.5	54,489,872		0.0000	1.0000	99.73
9.5	54,489,872	8,721,695	0.1601	0.8399	99.73
10.5	45,768,177		0.0000	1.0000	83.77
11.5	45,768,177		0.0000	1.0000	83.77
12.5	45,768,177	328,432	0.0072	0.9928	83.77
13.5	45,439,745		0.0000	1.0000	83.17
14.5	45,031,090		0.0000	1.0000	83.17
15.5	45,031,090	42,746	0.0009	0.9991	83.17
16.5	44,714,746		0.0000	1.0000	83.09
17.5	44,714,746	292,387	0.0065	0.9935	83.09
18.5	43,412,932		0.0000	1.0000	82.55
19.5	43,383,798	338,428	0.0078	0.9922	82.55
20.5	43,045,370		0.0000	1.0000	81.90
21.5	43,045,370	629,544	0.0146	0.9854	81.90
22.5	42,231,334		0.0000	1.0000	80.71
23.5	42,066,888		0.0000	1.0000	80.71
24.5	42,066,888		0.0000	1.0000	80.71
25.5	42,066,888		0.0000	1.0000	80.71
26.5	37,715,238		0.0000	1.0000	80.71
27.5	37,234,903		0.0000	1.0000	80.71
28.5	37,066,712		0.0000	1.0000	80.71
29.5	36,922,122		0.0000	1.0000	80.71
30.5	36,885,398	564,681	0.0153	0.9847	80.71
31.5	36,231,939		0.0000	1.0000	79.47
32.5	34,026,361		0.0000	1.0000	79.47
33.5	33,958,330		0.0000	1.0000	79.47
34.5	33,644,077		0.0000	1.0000	79.47
35.5	15,993,526		0.0000	1.0000	79.47
36.5	15,971,096		0.0000	1.0000	79.47
37.5	15,971,096		0.0000	1.0000	79.47
38.5	15,971,096		0.0000	1.0000	79.47

NEWFOUNDLAND AND LABRADOR HYDRO

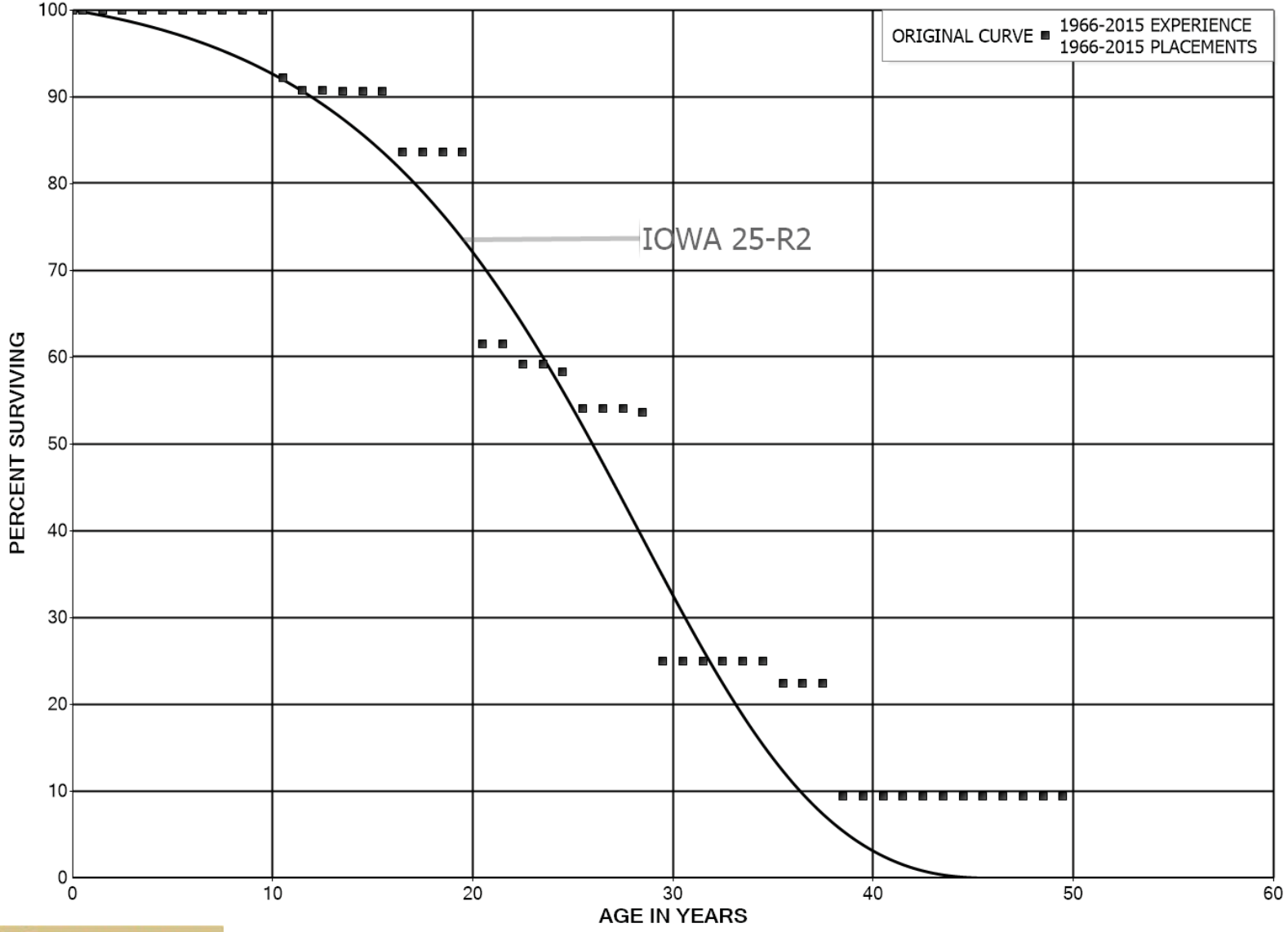
ACCOUNT B02 - BOILER SYSTEM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,964,723		0.0000	1.0000	79.47
40.5	15,964,723		0.0000	1.0000	79.47
41.5	15,964,723	183,493	0.0115	0.9885	79.47
42.5	15,781,230		0.0000	1.0000	78.56
43.5	15,781,230		0.0000	1.0000	78.56
44.5	14,985,641		0.0000	1.0000	78.56
45.5	14,985,641		0.0000	1.0000	78.56
46.5	14,985,641		0.0000	1.0000	78.56
47.5					78.56

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B03 - BOOMS - TIMBER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B03 - BOOMS - TIMBER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	723,485		0.0000	1.0000	100.00
0.5	671,923		0.0000	1.0000	100.00
1.5	634,914		0.0000	1.0000	100.00
2.5	634,914		0.0000	1.0000	100.00
3.5	634,914		0.0000	1.0000	100.00
4.5	634,914		0.0000	1.0000	100.00
5.5	634,914		0.0000	1.0000	100.00
6.5	634,914		0.0000	1.0000	100.00
7.5	634,914		0.0000	1.0000	100.00
8.5	634,914		0.0000	1.0000	100.00
9.5	634,914	50,000	0.0788	0.9212	100.00
10.5	584,914	8,673	0.0148	0.9852	92.12
11.5	576,242		0.0000	1.0000	90.76
12.5	576,242	818	0.0014	0.9986	90.76
13.5	575,423		0.0000	1.0000	90.63
14.5	575,423		0.0000	1.0000	90.63
15.5	575,423	44,401	0.0772	0.9228	90.63
16.5	531,022		0.0000	1.0000	83.64
17.5	531,022		0.0000	1.0000	83.64
18.5	531,022		0.0000	1.0000	83.64
19.5	531,022	140,269	0.2641	0.7359	83.64
20.5	390,753		0.0000	1.0000	61.54
21.5	390,753	14,962	0.0383	0.9617	61.54
22.5	375,791		0.0000	1.0000	59.19
23.5	375,791	5,428	0.0144	0.9856	59.19
24.5	370,363	26,774	0.0723	0.9277	58.33
25.5	343,589		0.0000	1.0000	54.12
26.5	343,589		0.0000	1.0000	54.12
27.5	343,589	3,034	0.0088	0.9912	54.12
28.5	340,555	182,066	0.5346	0.4654	53.64
29.5	158,489		0.0000	1.0000	24.96
30.5	158,489		0.0000	1.0000	24.96
31.5	158,489		0.0000	1.0000	24.96
32.5	158,489		0.0000	1.0000	24.96
33.5	158,489		0.0000	1.0000	24.96
34.5	158,489	16,064	0.1014	0.8986	24.96
35.5	142,425		0.0000	1.0000	22.43
36.5	95,631		0.0000	1.0000	22.43
37.5	95,631	55,440	0.5797	0.4203	22.43
38.5	40,191		0.0000	1.0000	9.43

NEWFOUNDLAND AND LABRADOR HYDRO

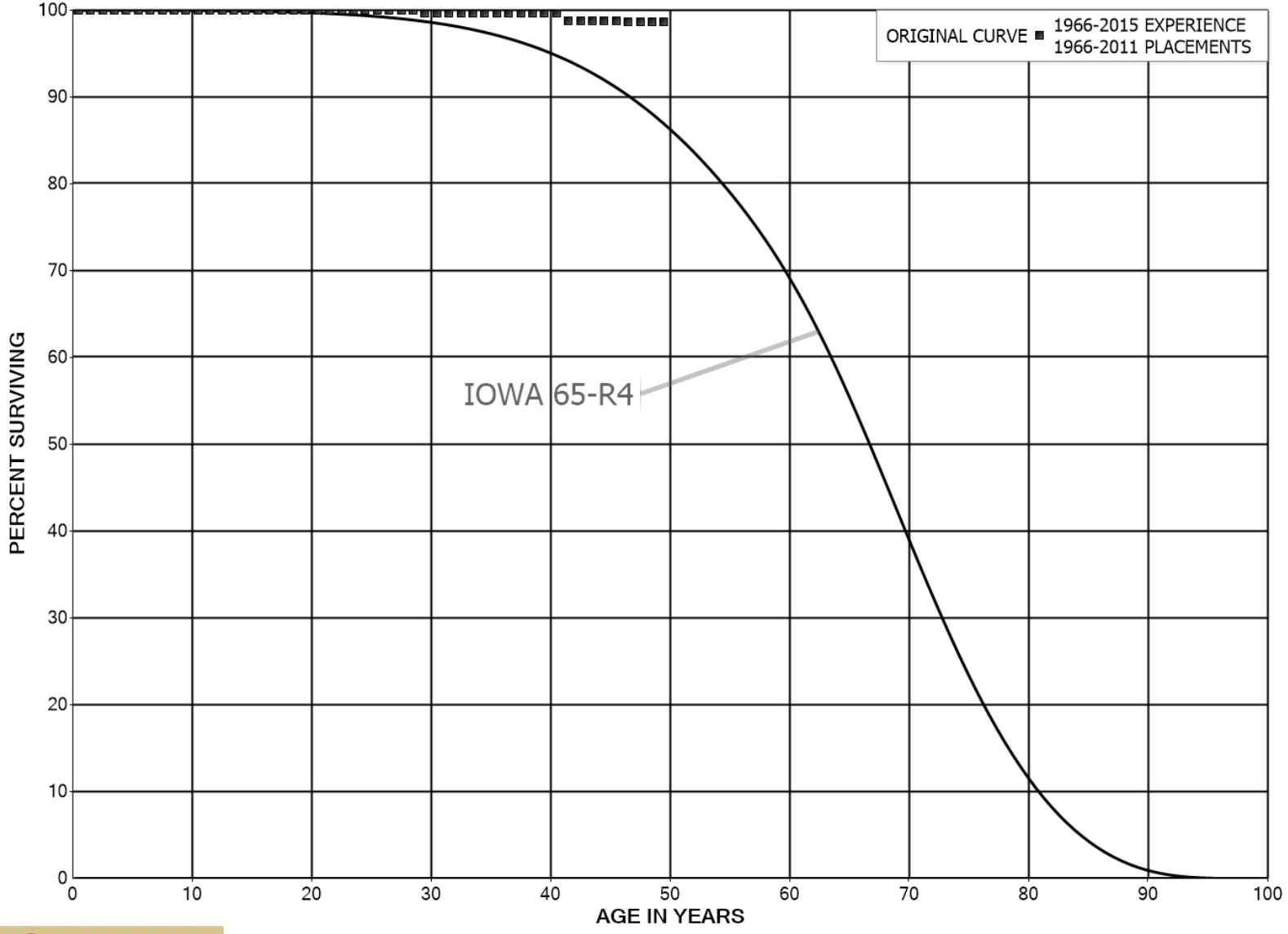
ACCOUNT B03 - BOOMS - TIMBER

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	40,191		0.0000	1.0000	9.43
40.5	40,191		0.0000	1.0000	9.43
41.5	40,191		0.0000	1.0000	9.43
42.5	40,191		0.0000	1.0000	9.43
43.5	40,191		0.0000	1.0000	9.43
44.5	40,191		0.0000	1.0000	9.43
45.5	38,209		0.0000	1.0000	9.43
46.5	38,209		0.0000	1.0000	9.43
47.5	38,209		0.0000	1.0000	9.43
48.5	38,209		0.0000	1.0000	9.43
49.5					9.43

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B04 - BRIDGES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B04 - BRIDGES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2011 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,270,789		0.0000	1.0000	100.00
0.5	4,270,789		0.0000	1.0000	100.00
1.5	4,270,789		0.0000	1.0000	100.00
2.5	4,270,789		0.0000	1.0000	100.00
3.5	4,270,789		0.0000	1.0000	100.00
4.5	4,251,595		0.0000	1.0000	100.00
5.5	4,251,595		0.0000	1.0000	100.00
6.5	4,251,595		0.0000	1.0000	100.00
7.5	4,251,595		0.0000	1.0000	100.00
8.5	3,914,583		0.0000	1.0000	100.00
9.5	3,914,583		0.0000	1.0000	100.00
10.5	3,914,583		0.0000	1.0000	100.00
11.5	3,914,583		0.0000	1.0000	100.00
12.5	3,602,553		0.0000	1.0000	100.00
13.5	3,602,553		0.0000	1.0000	100.00
14.5	3,602,553		0.0000	1.0000	100.00
15.5	3,602,553		0.0000	1.0000	100.00
16.5	3,602,553		0.0000	1.0000	100.00
17.5	3,602,553		0.0000	1.0000	100.00
18.5	3,538,953		0.0000	1.0000	100.00
19.5	3,502,566		0.0000	1.0000	100.00
20.5	3,502,566		0.0000	1.0000	100.00
21.5	3,447,001		0.0000	1.0000	100.00
22.5	3,447,001		0.0000	1.0000	100.00
23.5	2,817,693		0.0000	1.0000	100.00
24.5	2,817,693		0.0000	1.0000	100.00
25.5	2,817,693		0.0000	1.0000	100.00
26.5	2,817,693		0.0000	1.0000	100.00
27.5	2,817,693		0.0000	1.0000	100.00
28.5	2,817,693	11,000	0.0039	0.9961	100.00
29.5	2,806,693		0.0000	1.0000	99.61
30.5	2,806,693		0.0000	1.0000	99.61
31.5	818,463		0.0000	1.0000	99.61
32.5	791,716		0.0000	1.0000	99.61
33.5	791,716		0.0000	1.0000	99.61
34.5	791,716		0.0000	1.0000	99.61
35.5	570,290		0.0000	1.0000	99.61
36.5	570,290		0.0000	1.0000	99.61
37.5	570,290		0.0000	1.0000	99.61
38.5	570,290		0.0000	1.0000	99.61

NEWFOUNDLAND AND LABRADOR HYDRO

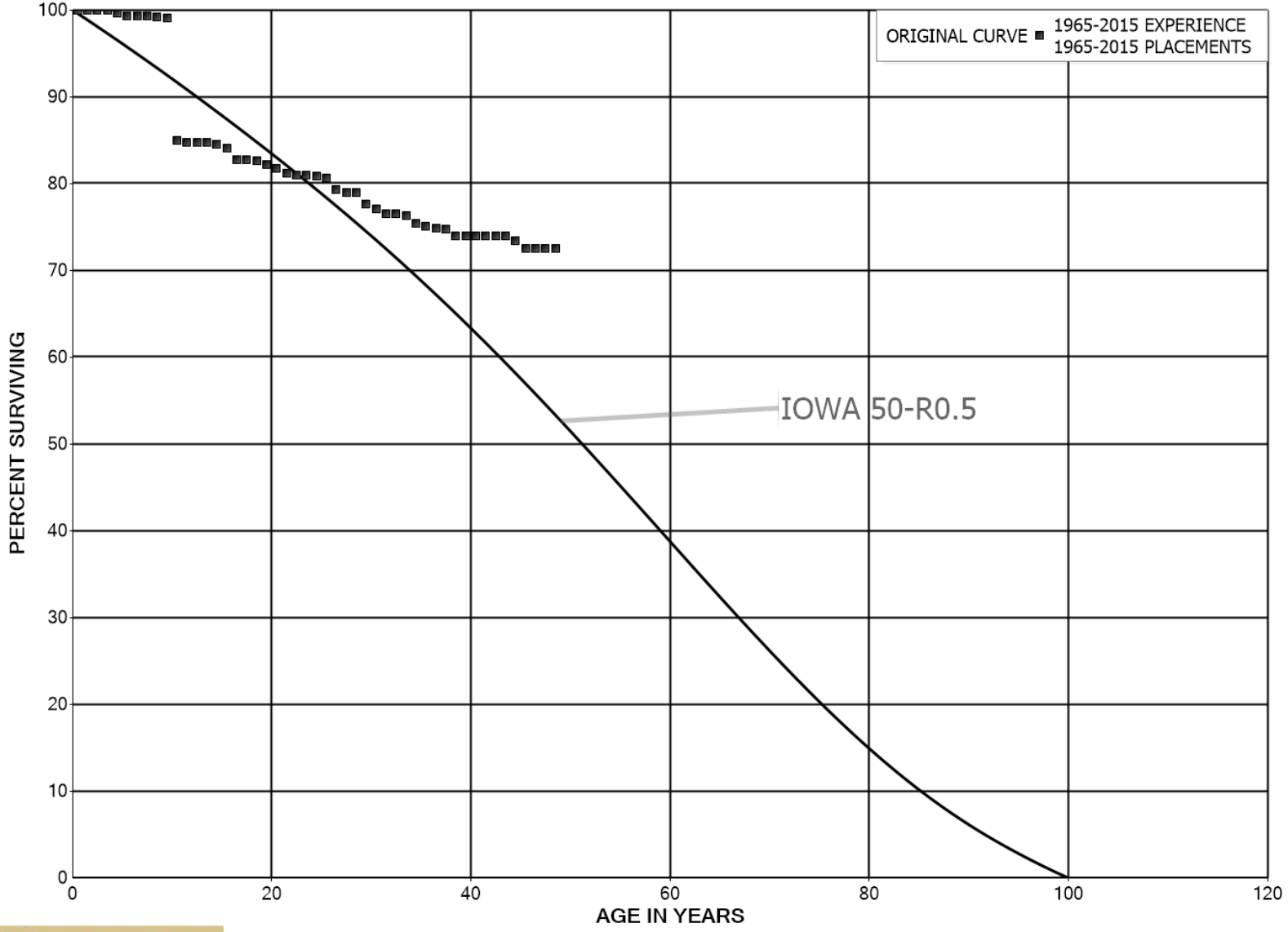
ACCOUNT B04 - BRIDGES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2011 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	570,290		0.0000	1.0000	99.61
40.5	570,290	5,021	0.0088	0.9912	99.61
41.5	565,270		0.0000	1.0000	98.73
42.5	565,270		0.0000	1.0000	98.73
43.5	565,270		0.0000	1.0000	98.73
44.5	565,270		0.0000	1.0000	98.73
45.5	565,270	479	0.0008	0.9992	98.73
46.5	564,791		0.0000	1.0000	98.65
47.5	564,791		0.0000	1.0000	98.65
48.5	564,791		0.0000	1.0000	98.65
49.5					98.65

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B05 - BUILDINGS - OTHER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B05 - BUILDINGS - OTHER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	81,733,917		0.0000	1.0000	100.00
0.5	79,467,544		0.0000	1.0000	100.00
1.5	77,165,990		0.0000	1.0000	100.00
2.5	75,417,722	76,705	0.0010	0.9990	100.00
3.5	73,220,560	204,506	0.0028	0.9972	99.90
4.5	69,160,675	199,241	0.0029	0.9971	99.62
5.5	62,203,059	18,672	0.0003	0.9997	99.33
6.5	61,310,444	10,000	0.0002	0.9998	99.30
7.5	60,347,764	69,496	0.0012	0.9988	99.29
8.5	59,310,893	78,986	0.0013	0.9987	99.17
9.5	54,131,652	7,733,707	0.1429	0.8571	99.04
10.5	45,260,382	59,708	0.0013	0.9987	84.89
11.5	44,413,636		0.0000	1.0000	84.78
12.5	40,998,859	25,765	0.0006	0.9994	84.78
13.5	40,933,193	132,098	0.0032	0.9968	84.72
14.5	38,775,766	158,952	0.0041	0.9959	84.45
15.5	38,080,243	634,408	0.0167	0.9833	84.11
16.5	37,082,626	13,958	0.0004	0.9996	82.70
17.5	37,008,045	10,389	0.0003	0.9997	82.67
18.5	36,051,567	220,139	0.0061	0.9939	82.65
19.5	34,768,422	180,807	0.0052	0.9948	82.15
20.5	34,024,736	238,434	0.0070	0.9930	81.72
21.5	33,292,621	66,910	0.0020	0.9980	81.15
22.5	33,080,894	35,887	0.0011	0.9989	80.98
23.5	32,821,223	34,419	0.0010	0.9990	80.89
24.5	32,650,258	66,998	0.0021	0.9979	80.81
25.5	30,874,977	526,647	0.0171	0.9829	80.64
26.5	8,899,240	33,373	0.0038	0.9962	79.27
27.5	8,611,291		0.0000	1.0000	78.97
28.5	7,364,753	126,226	0.0171	0.9829	78.97
29.5	6,738,268	44,289	0.0066	0.9934	77.62
30.5	6,471,512	46,983	0.0073	0.9927	77.11
31.5	6,173,052	3,730	0.0006	0.9994	76.55
32.5	6,052,164	14,175	0.0023	0.9977	76.50
33.5	5,143,479	58,976	0.0115	0.9885	76.32
34.5	4,896,879	27,511	0.0056	0.9944	75.45
35.5	4,261,803	13,489	0.0032	0.9968	75.02
36.5	4,115,454	5,307	0.0013	0.9987	74.79
37.5	4,093,941	40,283	0.0098	0.9902	74.69
38.5	3,616,834		0.0000	1.0000	73.95

NEWFOUNDLAND AND LABRADOR HYDRO

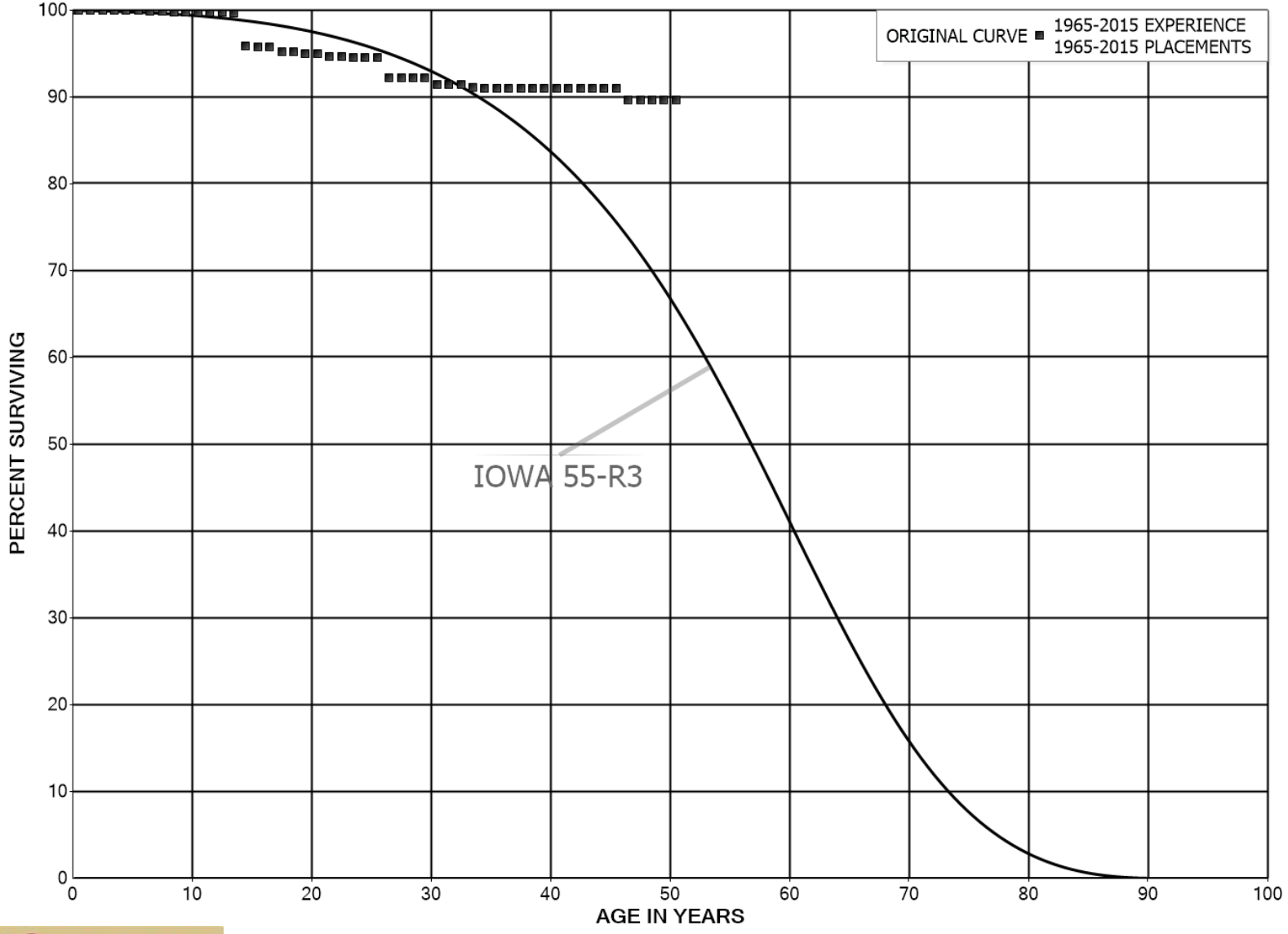
ACCOUNT B05 - BUILDINGS - OTHER

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,616,834		0.0000	1.0000	73.95
40.5	2,711,994		0.0000	1.0000	73.95
41.5	2,686,482		0.0000	1.0000	73.95
42.5	2,409,250		0.0000	1.0000	73.95
43.5	2,345,598	18,731	0.0080	0.9920	73.95
44.5	2,277,587	27,000	0.0119	0.9881	73.36
45.5	2,128,116		0.0000	1.0000	72.49
46.5	2,025,591		0.0000	1.0000	72.49
47.5	321,303		0.0000	1.0000	72.49
48.5					72.49

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B06 - BUILDINGS - METAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B06 - BUILDINGS - METAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	35,996,791		0.0000	1.0000	100.00
0.5	25,168,176		0.0000	1.0000	100.00
1.5	24,278,983		0.0000	1.0000	100.00
2.5	24,278,983		0.0000	1.0000	100.00
3.5	24,278,983		0.0000	1.0000	100.00
4.5	24,247,337		0.0000	1.0000	100.00
5.5	24,247,337	41,104	0.0017	0.9983	100.00
6.5	24,058,787		0.0000	1.0000	99.83
7.5	24,040,969	18,990	0.0008	0.9992	99.83
8.5	23,972,589	15,545	0.0006	0.9994	99.75
9.5	23,957,044		0.0000	1.0000	99.69
10.5	23,672,091		0.0000	1.0000	99.69
11.5	23,621,849		0.0000	1.0000	99.69
12.5	23,454,997	14,030	0.0006	0.9994	99.69
13.5	22,659,992	864,917	0.0382	0.9618	99.63
14.5	21,685,002	29,906	0.0014	0.9986	95.82
15.5	21,655,096		0.0000	1.0000	95.69
16.5	21,655,096	112,921	0.0052	0.9948	95.69
17.5	21,365,644		0.0000	1.0000	95.19
18.5	21,365,644	54,966	0.0026	0.9974	95.19
19.5	20,800,414		0.0000	1.0000	94.95
20.5	20,696,799	76,056	0.0037	0.9963	94.95
21.5	20,608,897		0.0000	1.0000	94.60
22.5	20,117,742	26,025	0.0013	0.9987	94.60
23.5	19,159,276	0	0.0000	1.0000	94.48
24.5	17,668,718		0.0000	1.0000	94.48
25.5	16,093,101	393,729	0.0245	0.9755	94.48
26.5	15,552,437		0.0000	1.0000	92.17
27.5	15,116,988		0.0000	1.0000	92.17
28.5	14,832,765		0.0000	1.0000	92.17
29.5	14,816,075	115,181	0.0078	0.9922	92.17
30.5	14,613,697		0.0000	1.0000	91.45
31.5	14,205,534		0.0000	1.0000	91.45
32.5	12,806,433	57,461	0.0045	0.9955	91.45
33.5	10,823,937	5,733	0.0005	0.9995	91.04
34.5	10,234,044		0.0000	1.0000	90.99
35.5	7,095,177		0.0000	1.0000	90.99
36.5	6,847,351		0.0000	1.0000	90.99
37.5	6,163,042	6,800	0.0011	0.9989	90.99
38.5	6,043,170		0.0000	1.0000	90.89

NEWFOUNDLAND AND LABRADOR HYDRO

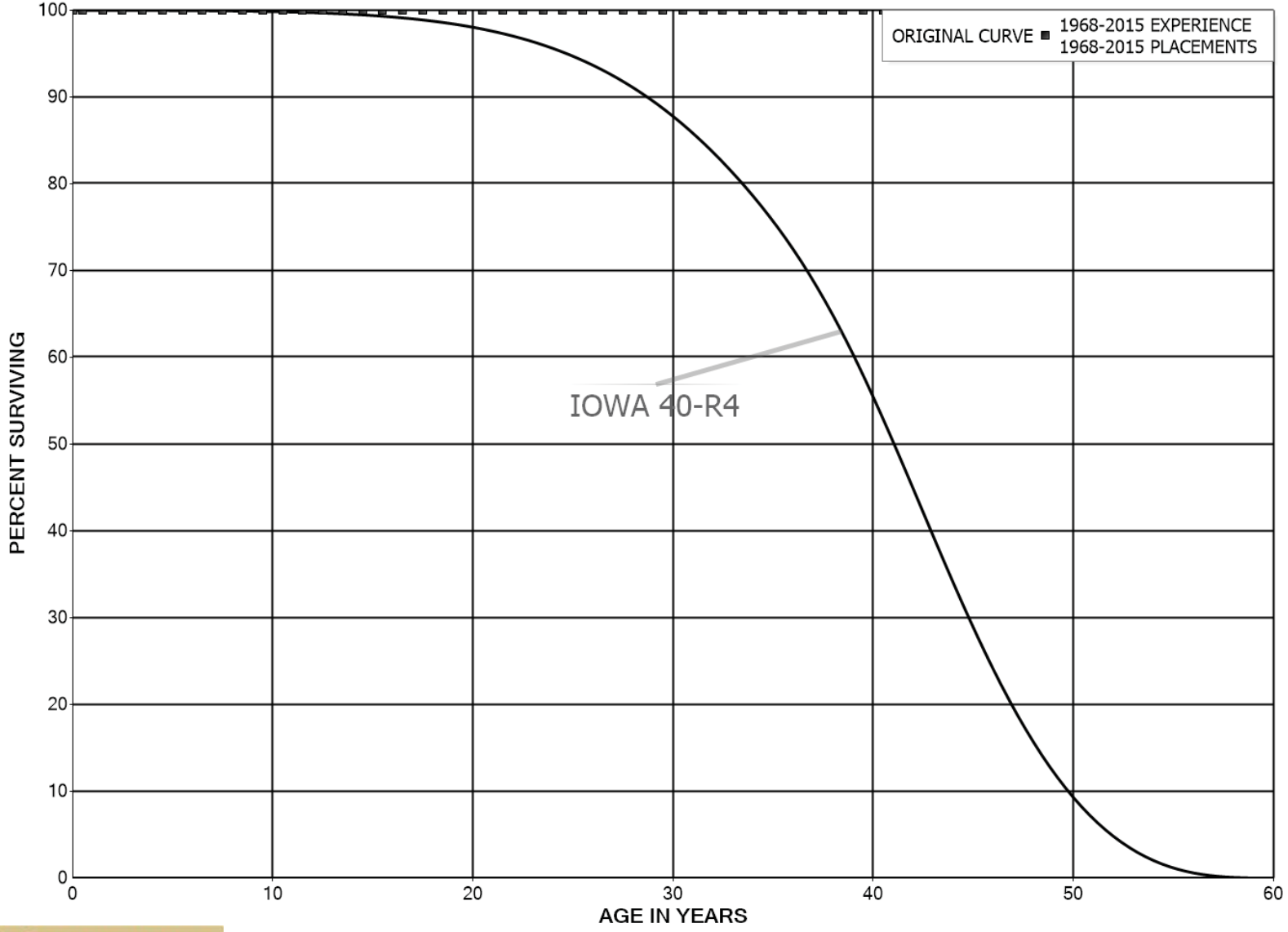
ACCOUNT B06 - BUILDINGS - METAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,731,924		0.0000	1.0000	90.89
40.5	5,180,227		0.0000	1.0000	90.89
41.5	5,180,227		0.0000	1.0000	90.89
42.5	5,180,227		0.0000	1.0000	90.89
43.5	5,180,227		0.0000	1.0000	90.89
44.5	4,480,030		0.0000	1.0000	90.89
45.5	4,332,844	62,342	0.0144	0.9856	90.89
46.5	2,926,199		0.0000	1.0000	89.58
47.5	1,577,877		0.0000	1.0000	89.58
48.5	781,601		0.0000	1.0000	89.58
49.5	496,681		0.0000	1.0000	89.58
50.5					89.58

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B07 - BUS DUCT GENERATOR
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B07 - BUS DUCT GENERATOR

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,456,108		0.0000	1.0000	100.00
0.5	825,804		0.0000	1.0000	100.00
1.5	825,804		0.0000	1.0000	100.00
2.5	825,804		0.0000	1.0000	100.00
3.5	825,804		0.0000	1.0000	100.00
4.5	825,804		0.0000	1.0000	100.00
5.5	825,804		0.0000	1.0000	100.00
6.5	825,804		0.0000	1.0000	100.00
7.5	825,804		0.0000	1.0000	100.00
8.5	825,804		0.0000	1.0000	100.00
9.5	825,804		0.0000	1.0000	100.00
10.5	825,804		0.0000	1.0000	100.00
11.5	825,804		0.0000	1.0000	100.00
12.5	459,833		0.0000	1.0000	100.00
13.5	459,833		0.0000	1.0000	100.00
14.5	459,833		0.0000	1.0000	100.00
15.5	459,833		0.0000	1.0000	100.00
16.5	459,833		0.0000	1.0000	100.00
17.5	459,833		0.0000	1.0000	100.00
18.5	459,833		0.0000	1.0000	100.00
19.5	459,833		0.0000	1.0000	100.00
20.5	459,833		0.0000	1.0000	100.00
21.5	459,833		0.0000	1.0000	100.00
22.5	459,833		0.0000	1.0000	100.00
23.5	459,833		0.0000	1.0000	100.00
24.5	459,833		0.0000	1.0000	100.00
25.5	459,833		0.0000	1.0000	100.00
26.5	459,833		0.0000	1.0000	100.00
27.5	338,955		0.0000	1.0000	100.00
28.5	338,955		0.0000	1.0000	100.00
29.5	338,955		0.0000	1.0000	100.00
30.5	338,955		0.0000	1.0000	100.00
31.5	338,955		0.0000	1.0000	100.00
32.5	338,955		0.0000	1.0000	100.00
33.5	338,955		0.0000	1.0000	100.00
34.5	338,955		0.0000	1.0000	100.00
35.5	27,238		0.0000	1.0000	100.00
36.5	27,238		0.0000	1.0000	100.00
37.5	27,238		0.0000	1.0000	100.00
38.5	27,238		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

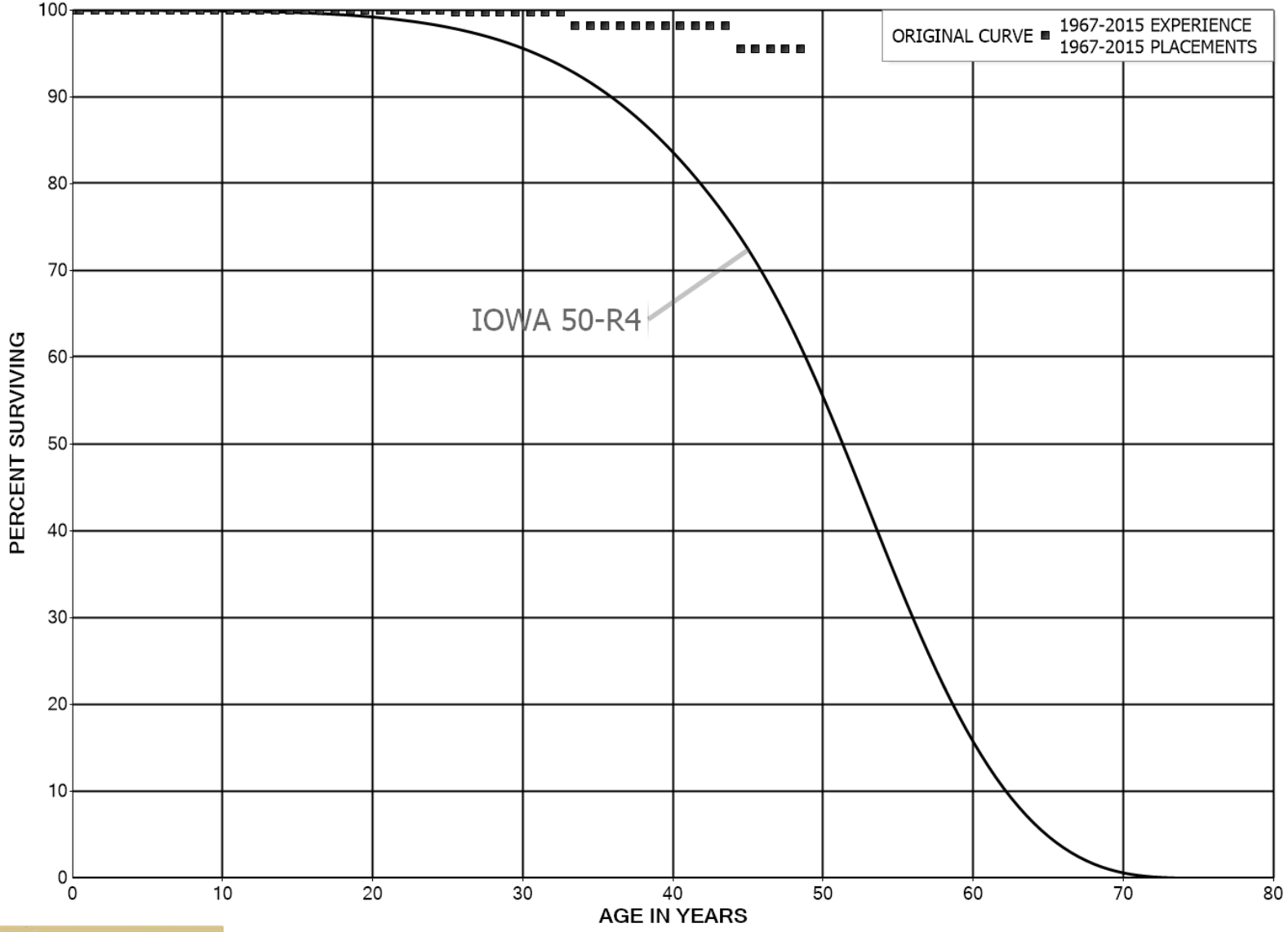
ACCOUNT B07 - BUS DUCT GENERATOR

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	27,238		0.0000	1.0000	100.00
40.5	27,238		0.0000	1.0000	100.00
41.5	27,238		0.0000	1.0000	100.00
42.5	27,238		0.0000	1.0000	100.00
43.5	27,238		0.0000	1.0000	100.00
44.5	27,238		0.0000	1.0000	100.00
45.5	27,238		0.0000	1.0000	100.00
46.5	27,238		0.0000	1.0000	100.00
47.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT B08 - BUSWORK AND HARDWARE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B08 - BUSWORK AND HARDWARE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,379,408		0.0000	1.0000	100.00
0.5	7,333,002		0.0000	1.0000	100.00
1.5	7,286,779		0.0000	1.0000	100.00
2.5	7,286,779		0.0000	1.0000	100.00
3.5	6,251,243		0.0000	1.0000	100.00
4.5	6,251,243		0.0000	1.0000	100.00
5.5	6,251,243		0.0000	1.0000	100.00
6.5	6,217,568		0.0000	1.0000	100.00
7.5	6,217,568		0.0000	1.0000	100.00
8.5	6,217,568		0.0000	1.0000	100.00
9.5	6,217,568		0.0000	1.0000	100.00
10.5	6,211,235		0.0000	1.0000	100.00
11.5	6,099,010		0.0000	1.0000	100.00
12.5	6,061,904		0.0000	1.0000	100.00
13.5	6,013,333		0.0000	1.0000	100.00
14.5	6,013,333		0.0000	1.0000	100.00
15.5	5,713,849		0.0000	1.0000	100.00
16.5	5,713,849		0.0000	1.0000	100.00
17.5	5,387,459		0.0000	1.0000	100.00
18.5	5,331,543		0.0000	1.0000	100.00
19.5	5,232,676		0.0000	1.0000	100.00
20.5	4,767,022		0.0000	1.0000	100.00
21.5	4,617,644		0.0000	1.0000	100.00
22.5	4,584,516		0.0000	1.0000	100.00
23.5	4,029,183		0.0000	1.0000	100.00
24.5	3,321,720	10,856	0.0033	0.9967	100.00
25.5	3,160,022		0.0000	1.0000	99.67
26.5	2,759,996		0.0000	1.0000	99.67
27.5	2,737,453		0.0000	1.0000	99.67
28.5	2,626,785		0.0000	1.0000	99.67
29.5	2,542,611		0.0000	1.0000	99.67
30.5	2,518,812		0.0000	1.0000	99.67
31.5	2,518,812		0.0000	1.0000	99.67
32.5	2,352,400	35,777	0.0152	0.9848	99.67
33.5	2,078,238		0.0000	1.0000	98.16
34.5	1,866,029		0.0000	1.0000	98.16
35.5	1,733,264		0.0000	1.0000	98.16
36.5	1,577,519		0.0000	1.0000	98.16
37.5	1,254,807		0.0000	1.0000	98.16
38.5	1,016,669		0.0000	1.0000	98.16

NEWFOUNDLAND AND LABRADOR HYDRO

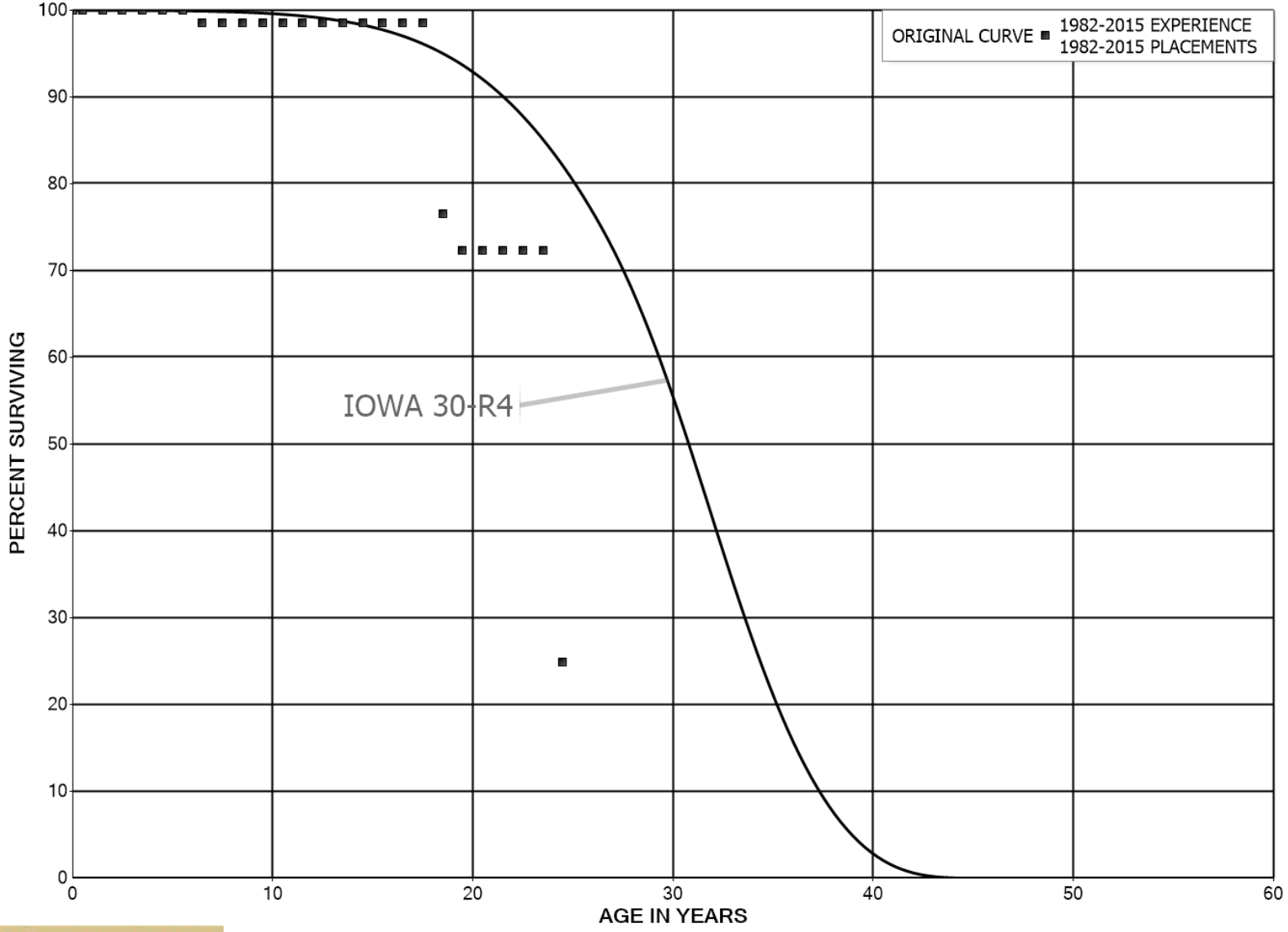
ACCOUNT B08 - BUSWORK AND HARDWARE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,014,371		0.0000	1.0000	98.16
40.5	946,331		0.0000	1.0000	98.16
41.5	937,636		0.0000	1.0000	98.16
42.5	937,636		0.0000	1.0000	98.16
43.5	937,636	24,869	0.0265	0.9735	98.16
44.5	912,767		0.0000	1.0000	95.55
45.5	391,137		0.0000	1.0000	95.55
46.5	373,137		0.0000	1.0000	95.55
47.5	268,548		0.0000	1.0000	95.55
48.5					95.55

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C01 - CABLES - TELECONTROL
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

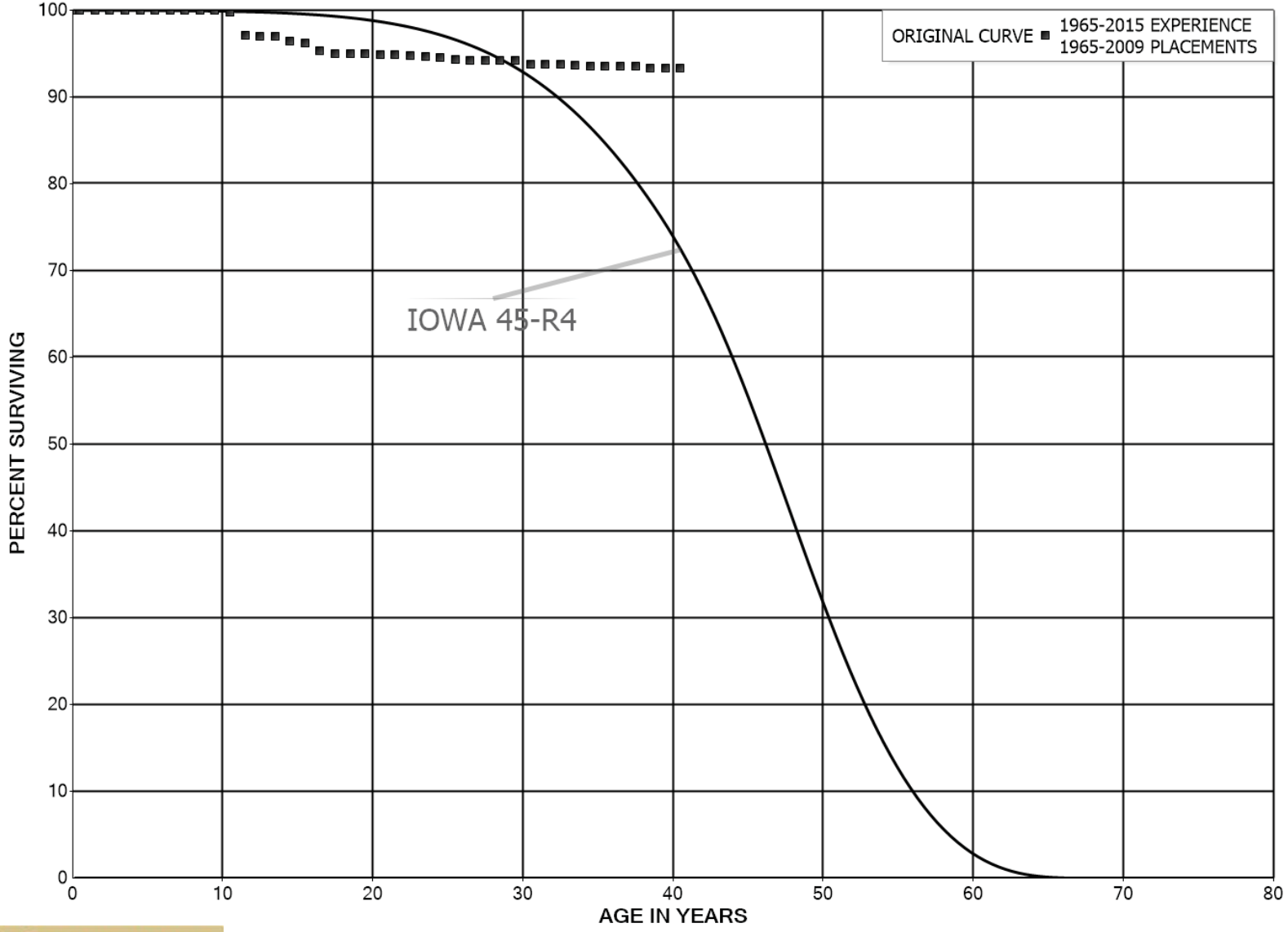
ACCOUNT C01 - CABLES - TELECONTROL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1982-2015 EXPERIENCE BAND 1982-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,838,620	0	0.0000	1.0000	100.00
0.5	2,836,079	0	0.0000	1.0000	100.00
1.5	2,836,079		0.0000	1.0000	100.00
2.5	2,824,227		0.0000	1.0000	100.00
3.5	1,900,728		0.0000	1.0000	100.00
4.5	1,900,728		0.0000	1.0000	100.00
5.5	1,801,277	27,391	0.0152	0.9848	100.00
6.5	1,773,885		0.0000	1.0000	98.48
7.5	1,773,885		0.0000	1.0000	98.48
8.5	1,773,885		0.0000	1.0000	98.48
9.5	1,773,885		0.0000	1.0000	98.48
10.5	1,773,885		0.0000	1.0000	98.48
11.5	1,684,136		0.0000	1.0000	98.48
12.5	791,888		0.0000	1.0000	98.48
13.5	531,510		0.0000	1.0000	98.48
14.5	401,932		0.0000	1.0000	98.48
15.5	379,901		0.0000	1.0000	98.48
16.5	203,293		0.0000	1.0000	98.48
17.5	203,293	45,443	0.2235	0.7765	98.48
18.5	157,849	8,519	0.0540	0.9460	76.47
19.5	149,330		0.0000	1.0000	72.34
20.5	149,330		0.0000	1.0000	72.34
21.5	149,330		0.0000	1.0000	72.34
22.5	36,789		0.0000	1.0000	72.34
23.5	36,789	24,177	0.6572	0.3428	72.34
24.5	12,612		0.0000	1.0000	24.80
25.5	12,612		0.0000	1.0000	24.80
26.5	12,612		0.0000	1.0000	24.80
27.5	12,612		0.0000	1.0000	24.80
28.5	12,612		0.0000	1.0000	24.80
29.5	12,612		0.0000	1.0000	24.80
30.5	12,612		0.0000	1.0000	24.80
31.5	12,612		0.0000	1.0000	24.80
32.5	12,612		0.0000	1.0000	24.80
33.5					24.80

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C02 - CABLE - SUBMARINE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

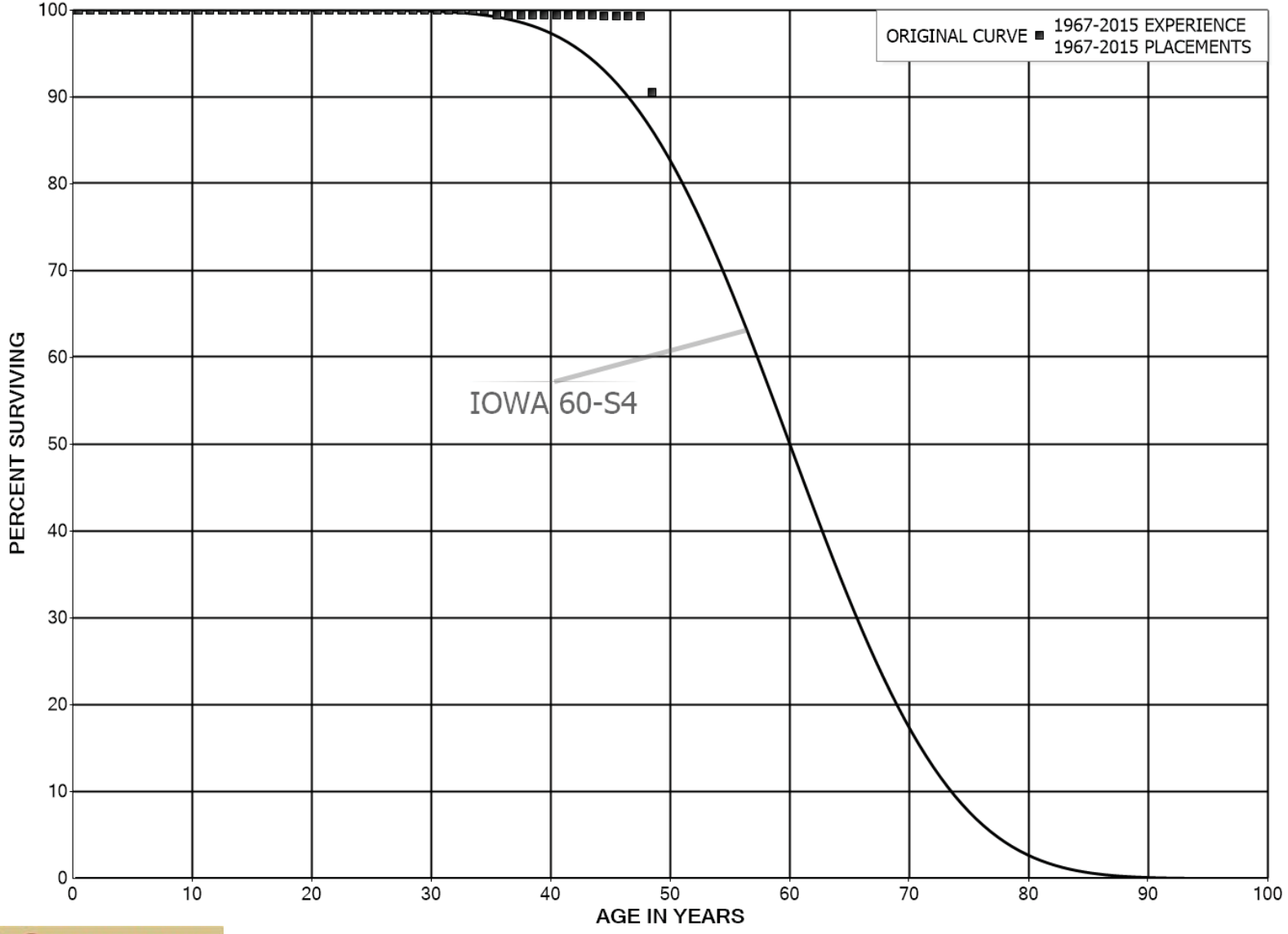
ACCOUNT C02 - CABLE - SUBMARINE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2009 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,425,415		0.0000	1.0000	100.00
0.5	9,425,415		0.0000	1.0000	100.00
1.5	9,425,415		0.0000	1.0000	100.00
2.5	9,425,415		0.0000	1.0000	100.00
3.5	9,425,415		0.0000	1.0000	100.00
4.5	9,425,415		0.0000	1.0000	100.00
5.5	9,425,415		0.0000	1.0000	100.00
6.5	9,344,728	262	0.0000	1.0000	100.00
7.5	9,302,171		0.0000	1.0000	100.00
8.5	9,197,890		0.0000	1.0000	100.00
9.5	9,197,890	24,789	0.0027	0.9973	100.00
10.5	9,173,102	245,126	0.0267	0.9733	99.73
11.5	8,927,976	10,786	0.0012	0.9988	97.06
12.5	8,917,190	2,233	0.0003	0.9997	96.95
13.5	8,914,958	48,195	0.0054	0.9946	96.92
14.5	8,866,762	19,777	0.0022	0.9978	96.40
15.5	8,846,986	87,216	0.0099	0.9901	96.18
16.5	7,837,422	21,424	0.0027	0.9973	95.23
17.5	7,815,998		0.0000	1.0000	94.97
18.5	7,815,998	5,358	0.0007	0.9993	94.97
19.5	7,810,640	1,990	0.0003	0.9997	94.91
20.5	7,808,650	1,297	0.0002	0.9998	94.88
21.5	7,807,353	13,145	0.0017	0.9983	94.87
22.5	7,794,208	4,245	0.0005	0.9995	94.71
23.5	7,789,963	8,605	0.0011	0.9989	94.66
24.5	7,781,358	17,612	0.0023	0.9977	94.55
25.5	4,784,397	5,538	0.0012	0.9988	94.34
26.5	2,325,408		0.0000	1.0000	94.23
27.5	775,017		0.0000	1.0000	94.23
28.5	775,017		0.0000	1.0000	94.23
29.5	775,017	4,602	0.0059	0.9941	94.23
30.5	770,414		0.0000	1.0000	93.67
31.5	770,414		0.0000	1.0000	93.67
32.5	770,414	39	0.0001	0.9999	93.67
33.5	646,975	968	0.0015	0.9985	93.67
34.5	646,007	443	0.0007	0.9993	93.53
35.5	476,448		0.0000	1.0000	93.46
36.5	476,448		0.0000	1.0000	93.46
37.5	476,448	651	0.0014	0.9986	93.46
38.5	475,797		0.0000	1.0000	93.33
39.5	475,797		0.0000	1.0000	93.33
40.5					93.33

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C03 - CABLE - UNDERGROUND
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C03 - CABLE - UNDERGROUND

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,395,635		0.0000	1.0000	100.00
0.5	2,844,830		0.0000	1.0000	100.00
1.5	2,379,940		0.0000	1.0000	100.00
2.5	2,270,771		0.0000	1.0000	100.00
3.5	1,947,270		0.0000	1.0000	100.00
4.5	1,947,270		0.0000	1.0000	100.00
5.5	1,947,270		0.0000	1.0000	100.00
6.5	1,947,270		0.0000	1.0000	100.00
7.5	1,947,270		0.0000	1.0000	100.00
8.5	1,947,270		0.0000	1.0000	100.00
9.5	1,947,270		0.0000	1.0000	100.00
10.5	1,947,270		0.0000	1.0000	100.00
11.5	1,947,270		0.0000	1.0000	100.00
12.5	1,947,270		0.0000	1.0000	100.00
13.5	1,947,270		0.0000	1.0000	100.00
14.5	1,929,618		0.0000	1.0000	100.00
15.5	1,861,337		0.0000	1.0000	100.00
16.5	1,861,337		0.0000	1.0000	100.00
17.5	1,839,011		0.0000	1.0000	100.00
18.5	1,839,011		0.0000	1.0000	100.00
19.5	1,829,125		0.0000	1.0000	100.00
20.5	1,663,088		0.0000	1.0000	100.00
21.5	1,663,088		0.0000	1.0000	100.00
22.5	1,656,465		0.0000	1.0000	100.00
23.5	1,604,291		0.0000	1.0000	100.00
24.5	1,510,195		0.0000	1.0000	100.00
25.5	1,429,264		0.0000	1.0000	100.00
26.5	1,351,971		0.0000	1.0000	100.00
27.5	1,351,971		0.0000	1.0000	100.00
28.5	1,307,375		0.0000	1.0000	100.00
29.5	1,307,375		0.0000	1.0000	100.00
30.5	1,307,375		0.0000	1.0000	100.00
31.5	1,307,375		0.0000	1.0000	100.00
32.5	1,274,153		0.0000	1.0000	100.00
33.5	1,174,801		0.0000	1.0000	100.00
34.5	1,127,018	7,281	0.0065	0.9935	100.00
35.5	513,619		0.0000	1.0000	99.35
36.5	429,332		0.0000	1.0000	99.35
37.5	344,220		0.0000	1.0000	99.35
38.5	337,437		0.0000	1.0000	99.35

NEWFOUNDLAND AND LABRADOR HYDRO

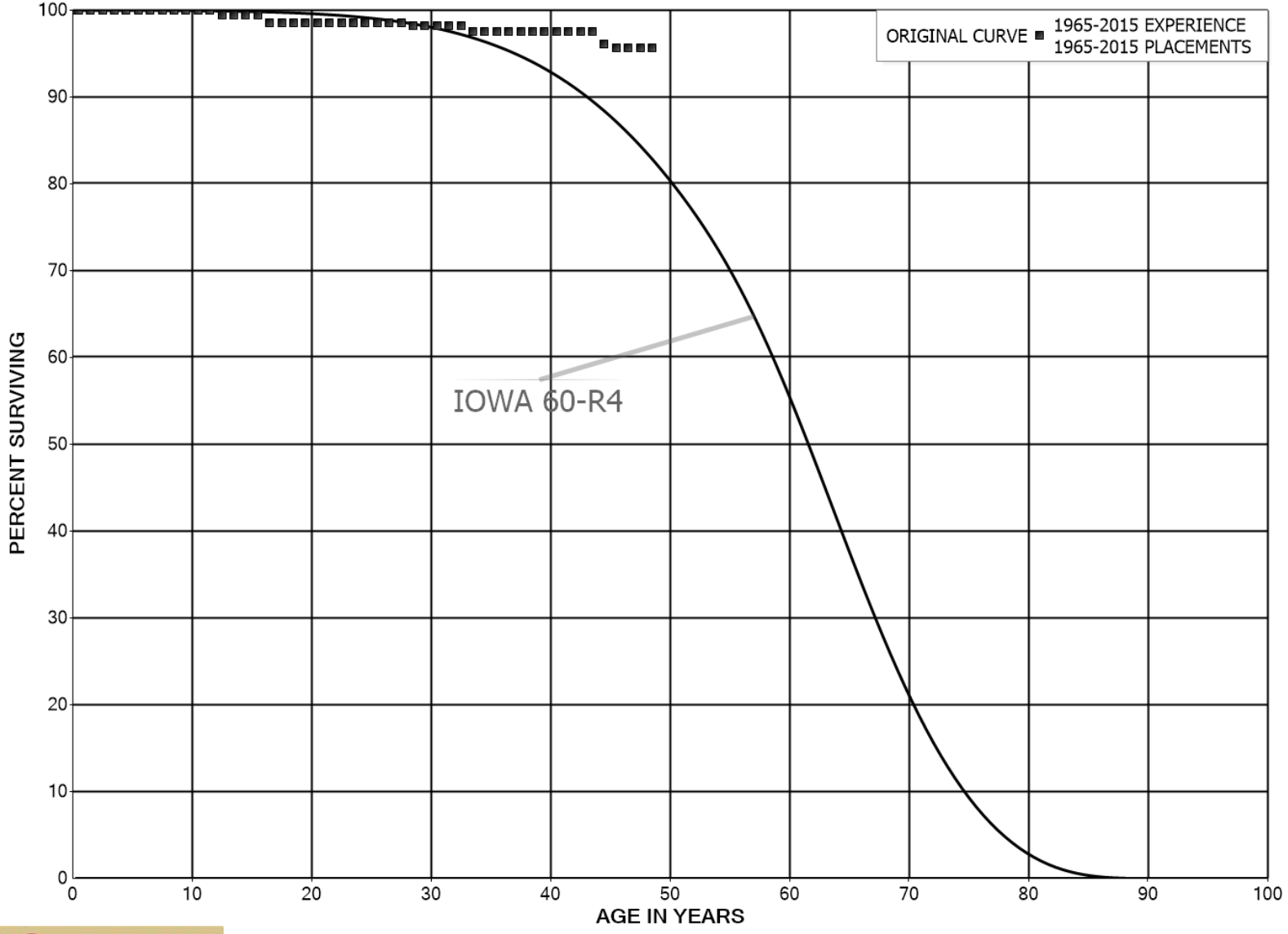
ACCOUNT C03 - CABLE - UNDERGROUND

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	333,739		0.0000	1.0000	99.35
40.5	318,436		0.0000	1.0000	99.35
41.5	318,436		0.0000	1.0000	99.35
42.5	318,436		0.0000	1.0000	99.35
43.5	305,575	188	0.0006	0.9994	99.35
44.5	276,579		0.0000	1.0000	99.29
45.5	141,503		0.0000	1.0000	99.29
46.5	141,503		0.0000	1.0000	99.29
47.5	74,406	6,571	0.0883	0.9117	99.29
48.5					90.52

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C04 - CABLE - ABOVE GROUND
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C04 - CABLE - ABOVE GROUND

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,401,564		0.0000	1.0000	100.00
0.5	11,299,810		0.0000	1.0000	100.00
1.5	11,299,810		0.0000	1.0000	100.00
2.5	11,137,698		0.0000	1.0000	100.00
3.5	10,286,672		0.0000	1.0000	100.00
4.5	9,987,308		0.0000	1.0000	100.00
5.5	9,926,759		0.0000	1.0000	100.00
6.5	9,926,759		0.0000	1.0000	100.00
7.5	9,926,759		0.0000	1.0000	100.00
8.5	9,926,759		0.0000	1.0000	100.00
9.5	9,884,286		0.0000	1.0000	100.00
10.5	9,769,662		0.0000	1.0000	100.00
11.5	9,769,662	63,219	0.0065	0.9935	100.00
12.5	9,614,621		0.0000	1.0000	99.35
13.5	9,580,028		0.0000	1.0000	99.35
14.5	9,464,487		0.0000	1.0000	99.35
15.5	9,346,771	84,913	0.0091	0.9909	99.35
16.5	9,174,365		0.0000	1.0000	98.45
17.5	8,884,088		0.0000	1.0000	98.45
18.5	8,863,231		0.0000	1.0000	98.45
19.5	8,769,635		0.0000	1.0000	98.45
20.5	8,542,287		0.0000	1.0000	98.45
21.5	7,870,443		0.0000	1.0000	98.45
22.5	7,815,792		0.0000	1.0000	98.45
23.5	7,433,724		0.0000	1.0000	98.45
24.5	6,964,552		0.0000	1.0000	98.45
25.5	6,674,759		0.0000	1.0000	98.45
26.5	6,267,887		0.0000	1.0000	98.45
27.5	6,150,181	19,117	0.0031	0.9969	98.45
28.5	5,978,081		0.0000	1.0000	98.14
29.5	5,893,892		0.0000	1.0000	98.14
30.5	4,979,674		0.0000	1.0000	98.14
31.5	4,952,895		0.0000	1.0000	98.14
32.5	4,388,615	27,298	0.0062	0.9938	98.14
33.5	4,088,745	134	0.0000	1.0000	97.53
34.5	4,023,163		0.0000	1.0000	97.53
35.5	2,236,296		0.0000	1.0000	97.53
36.5	2,091,333		0.0000	1.0000	97.53
37.5	1,565,100		0.0000	1.0000	97.53
38.5	1,447,446		0.0000	1.0000	97.53

NEWFOUNDLAND AND LABRADOR HYDRO

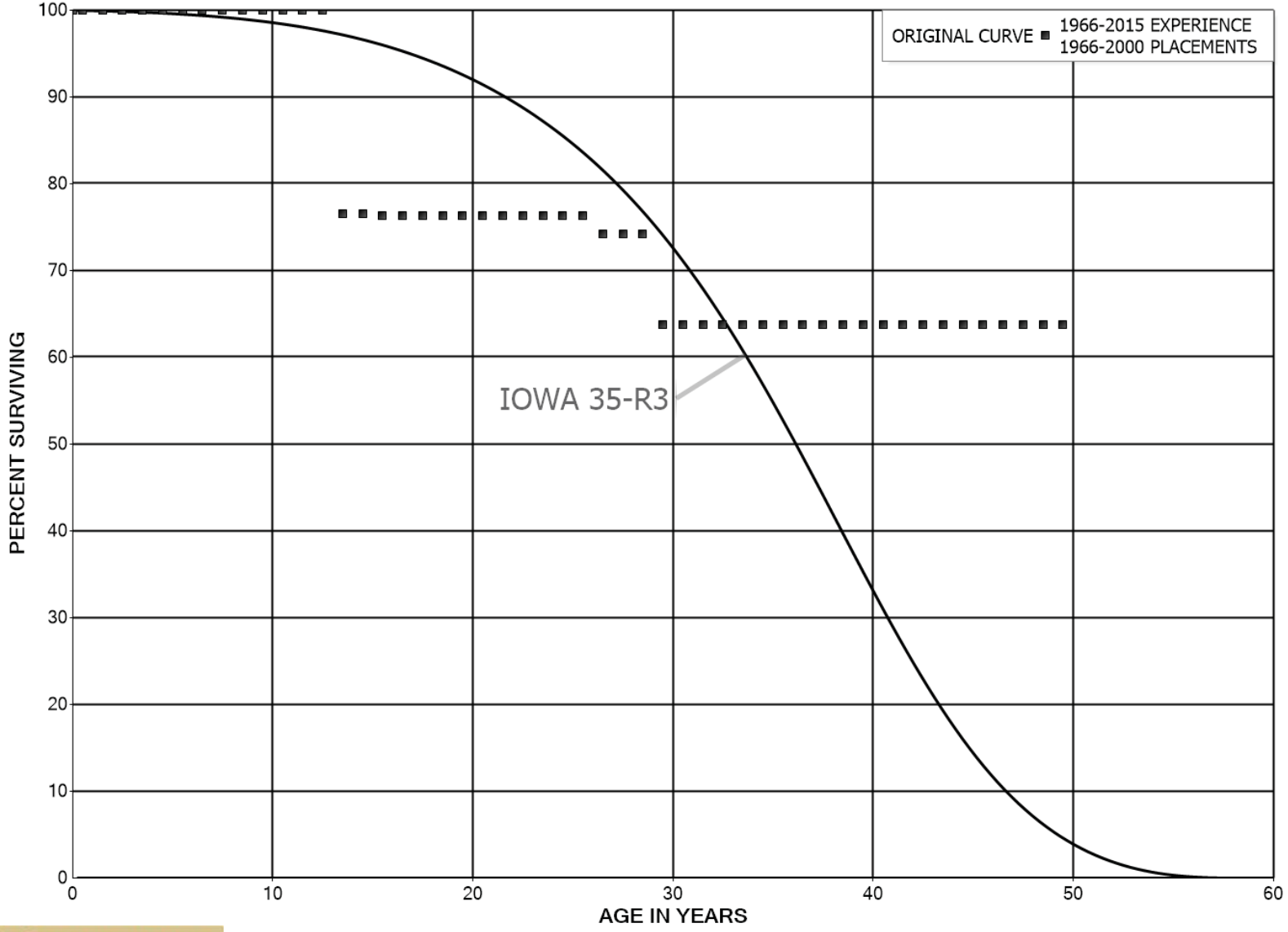
ACCOUNT C04 - CABLE - ABOVE GROUND

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,429,253		0.0000	1.0000	97.53
40.5	1,415,740		0.0000	1.0000	97.53
41.5	1,360,687		0.0000	1.0000	97.53
42.5	1,359,668		0.0000	1.0000	97.53
43.5	1,359,668	20,755	0.0153	0.9847	97.53
44.5	1,145,684	5,372	0.0047	0.9953	96.04
45.5	808,553		0.0000	1.0000	95.59
46.5	808,553		0.0000	1.0000	95.59
47.5	176,786		0.0000	1.0000	95.59
48.5					95.59

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C06 - CAPACITORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C06 - CAPACITORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2000 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,417,922		0.0000	1.0000	100.00
0.5	1,417,922		0.0000	1.0000	100.00
1.5	1,417,922		0.0000	1.0000	100.00
2.5	1,417,922		0.0000	1.0000	100.00
3.5	1,417,922		0.0000	1.0000	100.00
4.5	1,417,922		0.0000	1.0000	100.00
5.5	1,417,922		0.0000	1.0000	100.00
6.5	1,417,922		0.0000	1.0000	100.00
7.5	1,417,922		0.0000	1.0000	100.00
8.5	1,417,922		0.0000	1.0000	100.00
9.5	1,417,922		0.0000	1.0000	100.00
10.5	1,417,922		0.0000	1.0000	100.00
11.5	1,417,922		0.0000	1.0000	100.00
12.5	1,417,922	332,373	0.2344	0.7656	100.00
13.5	1,085,549		0.0000	1.0000	76.56
14.5	1,085,549	4,448	0.0041	0.9959	76.56
15.5	924,455		0.0000	1.0000	76.25
16.5	924,455		0.0000	1.0000	76.25
17.5	924,455		0.0000	1.0000	76.25
18.5	924,455		0.0000	1.0000	76.25
19.5	608,625		0.0000	1.0000	76.25
20.5	599,093		0.0000	1.0000	76.25
21.5	599,093		0.0000	1.0000	76.25
22.5	599,093		0.0000	1.0000	76.25
23.5	599,093		0.0000	1.0000	76.25
24.5	599,093		0.0000	1.0000	76.25
25.5	599,093	16,678	0.0278	0.9722	76.25
26.5	582,416		0.0000	1.0000	74.12
27.5	582,416		0.0000	1.0000	74.12
28.5	498,690	69,680	0.1397	0.8603	74.12
29.5	429,010		0.0000	1.0000	63.77
30.5	429,010		0.0000	1.0000	63.77
31.5	429,010		0.0000	1.0000	63.77
32.5	429,010		0.0000	1.0000	63.77
33.5	405,743		0.0000	1.0000	63.77
34.5	405,743		0.0000	1.0000	63.77
35.5	332,630		0.0000	1.0000	63.77
36.5	332,630		0.0000	1.0000	63.77
37.5	332,630		0.0000	1.0000	63.77
38.5	332,630		0.0000	1.0000	63.77

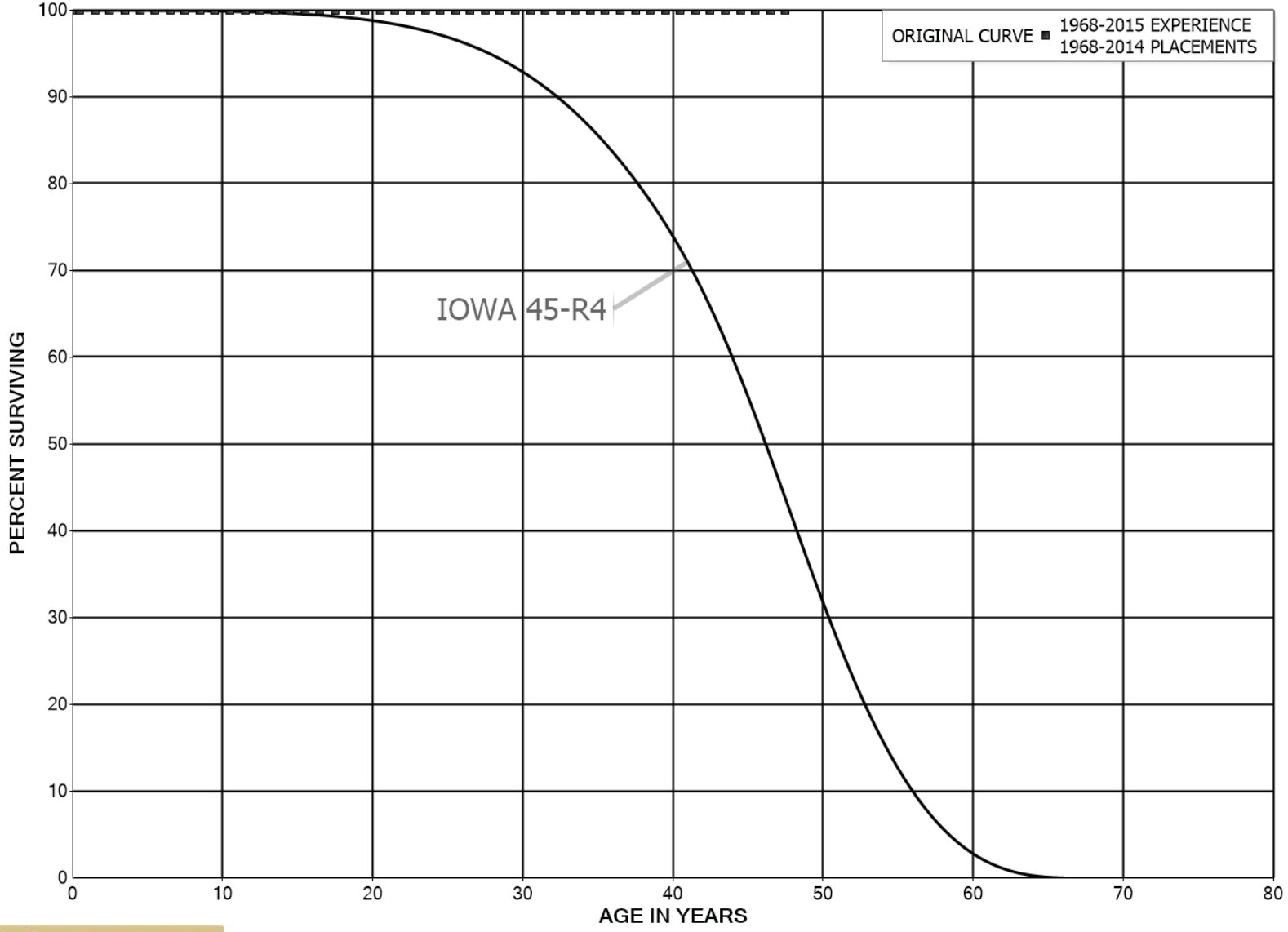
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C06 - CAPACITORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2000			EXPERIENCE BAND 1966-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	308,195		0.0000	1.0000	63.77
40.5	308,195		0.0000	1.0000	63.77
41.5	308,195		0.0000	1.0000	63.77
42.5	308,195		0.0000	1.0000	63.77
43.5	308,195		0.0000	1.0000	63.77
44.5	47,294		0.0000	1.0000	63.77
45.5	44,471		0.0000	1.0000	63.77
46.5	44,471		0.0000	1.0000	63.77
47.5	44,471		0.0000	1.0000	63.77
48.5	44,471		0.0000	1.0000	63.77
49.5					63.77

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C07 - CHEMICAL FEED SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C07 - CHEMICAL FEED SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2014 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	586,296		0.0000	1.0000	100.00
0.5	586,296		0.0000	1.0000	100.00
1.5	573,005		0.0000	1.0000	100.00
2.5	573,005		0.0000	1.0000	100.00
3.5	573,005		0.0000	1.0000	100.00
4.5	573,005		0.0000	1.0000	100.00
5.5	573,005		0.0000	1.0000	100.00
6.5	573,005		0.0000	1.0000	100.00
7.5	573,005		0.0000	1.0000	100.00
8.5	573,005		0.0000	1.0000	100.00
9.5	573,005		0.0000	1.0000	100.00
10.5	573,005		0.0000	1.0000	100.00
11.5	573,005		0.0000	1.0000	100.00
12.5	573,005		0.0000	1.0000	100.00
13.5	573,005		0.0000	1.0000	100.00
14.5	573,005		0.0000	1.0000	100.00
15.5	573,005		0.0000	1.0000	100.00
16.5	573,005		0.0000	1.0000	100.00
17.5	573,005		0.0000	1.0000	100.00
18.5	544,329		0.0000	1.0000	100.00
19.5	544,329		0.0000	1.0000	100.00
20.5	476,006		0.0000	1.0000	100.00
21.5	476,006		0.0000	1.0000	100.00
22.5	476,006		0.0000	1.0000	100.00
23.5	476,006		0.0000	1.0000	100.00
24.5	476,006		0.0000	1.0000	100.00
25.5	476,006		0.0000	1.0000	100.00
26.5	476,006		0.0000	1.0000	100.00
27.5	476,006		0.0000	1.0000	100.00
28.5	467,165		0.0000	1.0000	100.00
29.5	467,165		0.0000	1.0000	100.00
30.5	467,165		0.0000	1.0000	100.00
31.5	467,165		0.0000	1.0000	100.00
32.5	467,165		0.0000	1.0000	100.00
33.5	467,165		0.0000	1.0000	100.00
34.5	467,165		0.0000	1.0000	100.00
35.5	417,847		0.0000	1.0000	100.00
36.5	367,295		0.0000	1.0000	100.00
37.5	367,295		0.0000	1.0000	100.00
38.5	367,295		0.0000	1.0000	100.00

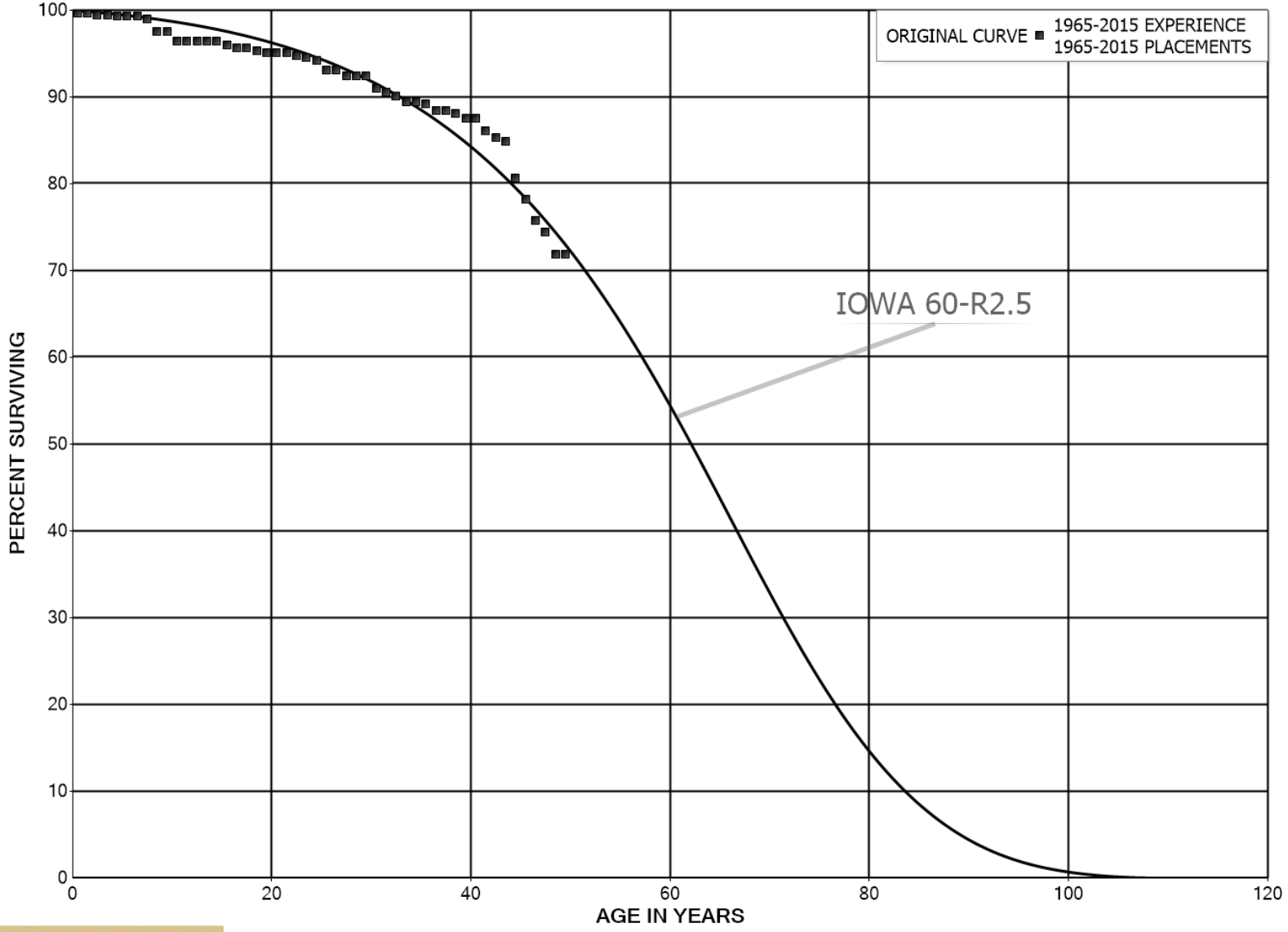
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C07 - CHEMICAL FEED SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2014			EXPERIENCE BAND 1968-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	367,295		0.0000	1.0000	100.00
40.5	367,295		0.0000	1.0000	100.00
41.5	367,295		0.0000	1.0000	100.00
42.5	367,295		0.0000	1.0000	100.00
43.5	367,295		0.0000	1.0000	100.00
44.5	295,111		0.0000	1.0000	100.00
45.5	295,111		0.0000	1.0000	100.00
46.5	50,552		0.0000	1.0000	100.00
47.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C09 - CIRCUIT BREAKERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C09 - CIRCUIT BREAKERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	42,408,089	160,899	0.0038	0.9962	100.00
0.5	28,938,215		0.0000	1.0000	99.62
1.5	27,073,477	51,514	0.0019	0.9981	99.62
2.5	23,420,774		0.0000	1.0000	99.43
3.5	20,102,925	27,294	0.0014	0.9986	99.43
4.5	19,123,433	7,293	0.0004	0.9996	99.30
5.5	18,642,875		0.0000	1.0000	99.26
6.5	18,034,521	60,978	0.0034	0.9966	99.26
7.5	17,678,078	249,244	0.0141	0.9859	98.92
8.5	17,139,665		0.0000	1.0000	97.53
9.5	16,953,058	200,915	0.0119	0.9881	97.53
10.5	16,702,131		0.0000	1.0000	96.37
11.5	16,621,648		0.0000	1.0000	96.37
12.5	16,272,210		0.0000	1.0000	96.37
13.5	15,850,732		0.0000	1.0000	96.37
14.5	15,832,173	67,355	0.0043	0.9957	96.37
15.5	15,499,963	58,294	0.0038	0.9962	95.96
16.5	15,441,670		0.0000	1.0000	95.60
17.5	15,287,303	50,464	0.0033	0.9967	95.60
18.5	15,043,281	40,862	0.0027	0.9973	95.29
19.5	14,573,151		0.0000	1.0000	95.03
20.5	13,743,654		0.0000	1.0000	95.03
21.5	13,718,206	47,162	0.0034	0.9966	95.03
22.5	13,398,595	20,279	0.0015	0.9985	94.70
23.5	12,287,999	45,251	0.0037	0.9963	94.56
24.5	12,137,656	149,323	0.0123	0.9877	94.21
25.5	11,610,539		0.0000	1.0000	93.05
26.5	11,025,638	72,655	0.0066	0.9934	93.05
27.5	10,808,151		0.0000	1.0000	92.44
28.5	10,733,766		0.0000	1.0000	92.44
29.5	10,696,675	173,483	0.0162	0.9838	92.44
30.5	10,483,633	46,776	0.0045	0.9955	90.94
31.5	10,436,857	56,847	0.0054	0.9946	90.53
32.5	10,067,873	75,026	0.0075	0.9925	90.04
33.5	8,982,702		0.0000	1.0000	89.37
34.5	8,780,905	22,391	0.0025	0.9975	89.37
35.5	8,005,967	65,599	0.0082	0.9918	89.14
36.5	7,862,991		0.0000	1.0000	88.41
37.5	7,494,955	32,264	0.0043	0.9957	88.41
38.5	6,871,566	43,798	0.0064	0.9936	88.03

NEWFOUNDLAND AND LABRADOR HYDRO

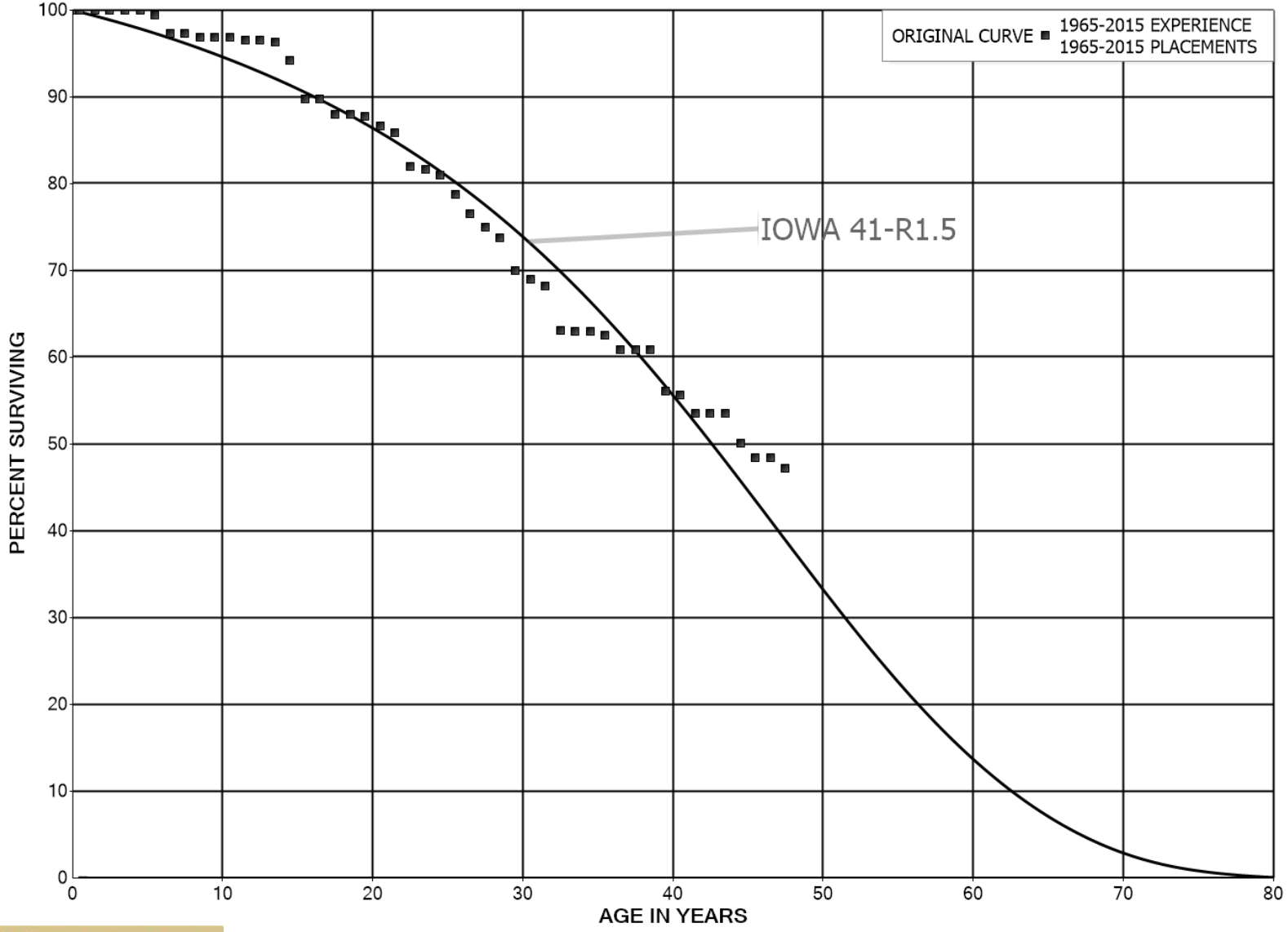
ACCOUNT C09 - CIRCUIT BREAKERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,781,445		0.0000	1.0000	87.47
40.5	6,497,180	102,890	0.0158	0.9842	87.47
41.5	6,251,013	54,215	0.0087	0.9913	86.08
42.5	6,196,798	32,682	0.0053	0.9947	85.34
43.5	5,594,010	278,870	0.0499	0.9501	84.89
44.5	4,868,135	149,825	0.0308	0.9692	80.65
45.5	3,050,359	94,629	0.0310	0.9690	78.17
46.5	2,843,847	49,956	0.0176	0.9824	75.75
47.5	1,997,293	68,207	0.0341	0.9659	74.42
48.5	886,988		0.0000	1.0000	71.87
49.5	519,843	94,176	0.1812	0.8188	71.87
50.5					58.85

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C10 - COMPRESSED AIR SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C10 - COMPRESSED AIR SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	18,045,846		0.0000	1.0000	100.00
0.5	9,907,229		0.0000	1.0000	100.00
1.5	7,959,480		0.0000	1.0000	100.00
2.5	6,442,427		0.0000	1.0000	100.00
3.5	6,442,427		0.0000	1.0000	100.00
4.5	5,847,852	32,529	0.0056	0.9944	100.00
5.5	5,674,885	125,289	0.0221	0.9779	99.44
6.5	5,380,906		0.0000	1.0000	97.25
7.5	4,943,013	19,135	0.0039	0.9961	97.25
8.5	4,678,473		0.0000	1.0000	96.87
9.5	4,647,855		0.0000	1.0000	96.87
10.5	4,647,855	17,971	0.0039	0.9961	96.87
11.5	4,629,884		0.0000	1.0000	96.50
12.5	4,429,884	10,656	0.0024	0.9976	96.50
13.5	4,377,956	96,947	0.0221	0.9779	96.27
14.5	4,133,050	192,426	0.0466	0.9534	94.13
15.5	3,745,763	1,766	0.0005	0.9995	89.75
16.5	3,579,639	70,987	0.0198	0.9802	89.71
17.5	3,425,631		0.0000	1.0000	87.93
18.5	3,397,099	8,231	0.0024	0.9976	87.93
19.5	3,378,212	43,863	0.0130	0.9870	87.72
20.5	3,205,312	27,663	0.0086	0.9914	86.58
21.5	2,943,004	132,489	0.0450	0.9550	85.83
22.5	2,766,426	13,168	0.0048	0.9952	81.97
23.5	2,237,625	16,940	0.0076	0.9924	81.58
24.5	2,185,057	59,522	0.0272	0.9728	80.96
25.5	2,083,992	58,872	0.0282	0.9718	78.75
26.5	1,949,912	39,150	0.0201	0.9799	76.53
27.5	1,796,026	29,172	0.0162	0.9838	74.99
28.5	1,730,649	91,004	0.0526	0.9474	73.77
29.5	1,639,645	22,151	0.0135	0.9865	69.89
30.5	1,617,494	17,783	0.0110	0.9890	68.95
31.5	1,433,255	107,523	0.0750	0.9250	68.19
32.5	1,269,188	1,504	0.0012	0.9988	63.08
33.5	1,114,126		0.0000	1.0000	63.00
34.5	1,114,126	9,569	0.0086	0.9914	63.00
35.5	876,987	23,423	0.0267	0.9733	62.46
36.5	811,553		0.0000	1.0000	60.79
37.5	749,163		0.0000	1.0000	60.79
38.5	610,688	47,584	0.0779	0.9221	60.79

NEWFOUNDLAND AND LABRADOR HYDRO

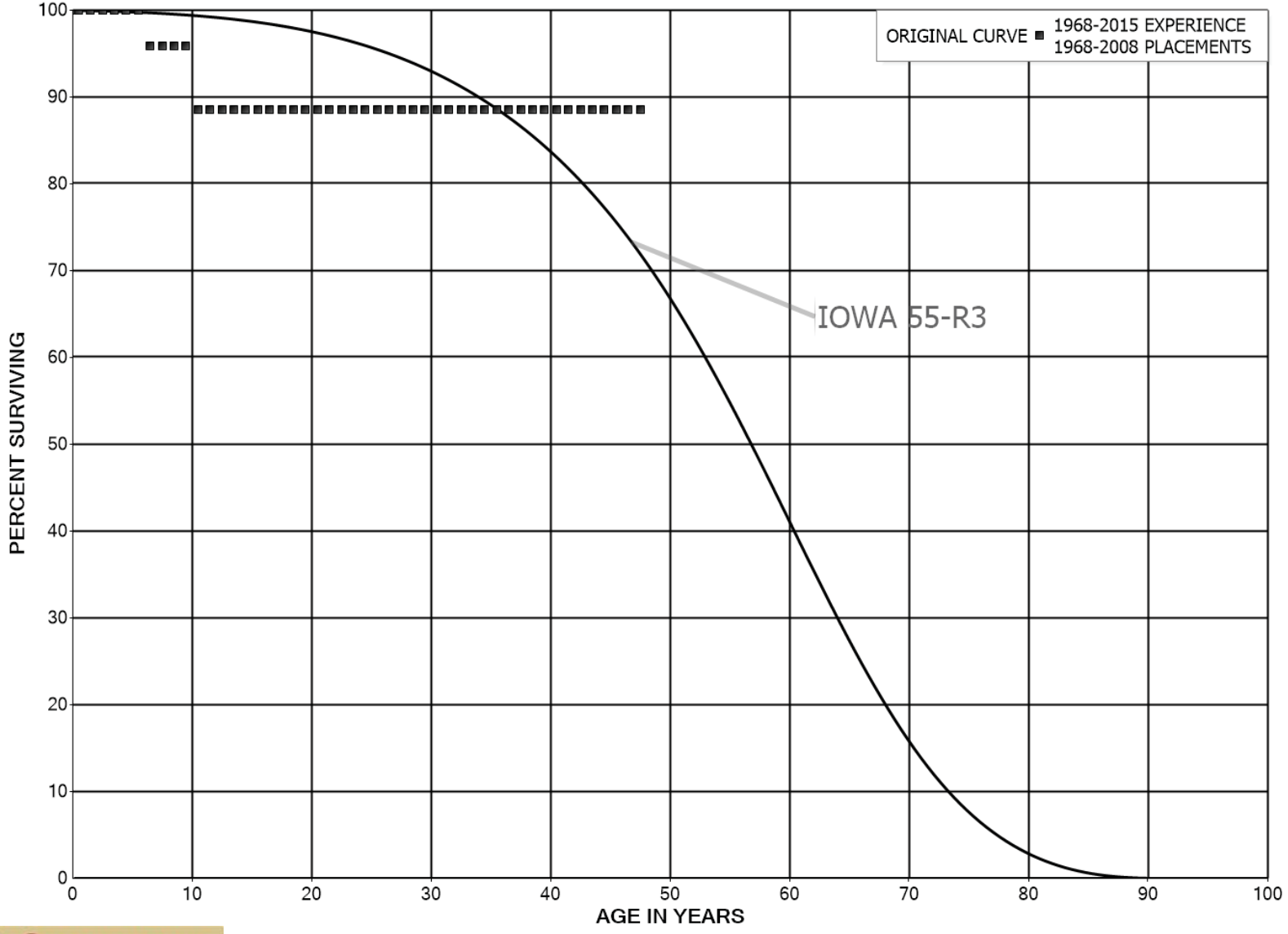
ACCOUNT C10 - COMPRESSED AIR SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	521,153	4,512	0.0087	0.9913	56.06
40.5	506,641	18,589	0.0367	0.9633	55.57
41.5	391,903		0.0000	1.0000	53.53
42.5	391,903		0.0000	1.0000	53.53
43.5	391,903	25,370	0.0647	0.9353	53.53
44.5	251,208	8,181	0.0326	0.9674	50.07
45.5	237,023		0.0000	1.0000	48.44
46.5	195,996	5,167	0.0264	0.9736	48.44
47.5	170,490		0.0000	1.0000	47.16
48.5	36,402		0.0000	1.0000	47.16
49.5					47.16

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C12 - CONDENSERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C12 - CONDENSERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2008 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,754,393		0.0000	1.0000	100.00
0.5	2,754,393		0.0000	1.0000	100.00
1.5	2,754,393		0.0000	1.0000	100.00
2.5	2,754,393		0.0000	1.0000	100.00
3.5	2,754,393		0.0000	1.0000	100.00
4.5	2,754,393		0.0000	1.0000	100.00
5.5	2,754,393	113,499	0.0412	0.9588	100.00
6.5	2,640,894		0.0000	1.0000	95.88
7.5	2,405,299		0.0000	1.0000	95.88
8.5	2,405,299		0.0000	1.0000	95.88
9.5	2,405,299	185,297	0.0770	0.9230	95.88
10.5	2,220,002		0.0000	1.0000	88.49
11.5	2,220,002		0.0000	1.0000	88.49
12.5	2,220,002		0.0000	1.0000	88.49
13.5	2,220,002		0.0000	1.0000	88.49
14.5	2,220,002		0.0000	1.0000	88.49
15.5	2,220,002		0.0000	1.0000	88.49
16.5	2,220,002		0.0000	1.0000	88.49
17.5	2,220,002		0.0000	1.0000	88.49
18.5	2,168,448		0.0000	1.0000	88.49
19.5	2,168,448		0.0000	1.0000	88.49
20.5	2,168,448		0.0000	1.0000	88.49
21.5	2,168,448		0.0000	1.0000	88.49
22.5	2,168,448		0.0000	1.0000	88.49
23.5	2,168,448		0.0000	1.0000	88.49
24.5	2,168,448		0.0000	1.0000	88.49
25.5	2,168,448		0.0000	1.0000	88.49
26.5	2,168,448		0.0000	1.0000	88.49
27.5	2,168,448		0.0000	1.0000	88.49
28.5	2,168,448		0.0000	1.0000	88.49
29.5	2,168,448		0.0000	1.0000	88.49
30.5	2,168,448		0.0000	1.0000	88.49
31.5	2,168,448		0.0000	1.0000	88.49
32.5	2,168,448		0.0000	1.0000	88.49
33.5	2,168,448		0.0000	1.0000	88.49
34.5	2,168,448		0.0000	1.0000	88.49
35.5	125,930		0.0000	1.0000	88.49
36.5	125,930		0.0000	1.0000	88.49
37.5	125,930		0.0000	1.0000	88.49
38.5	125,930		0.0000	1.0000	88.49

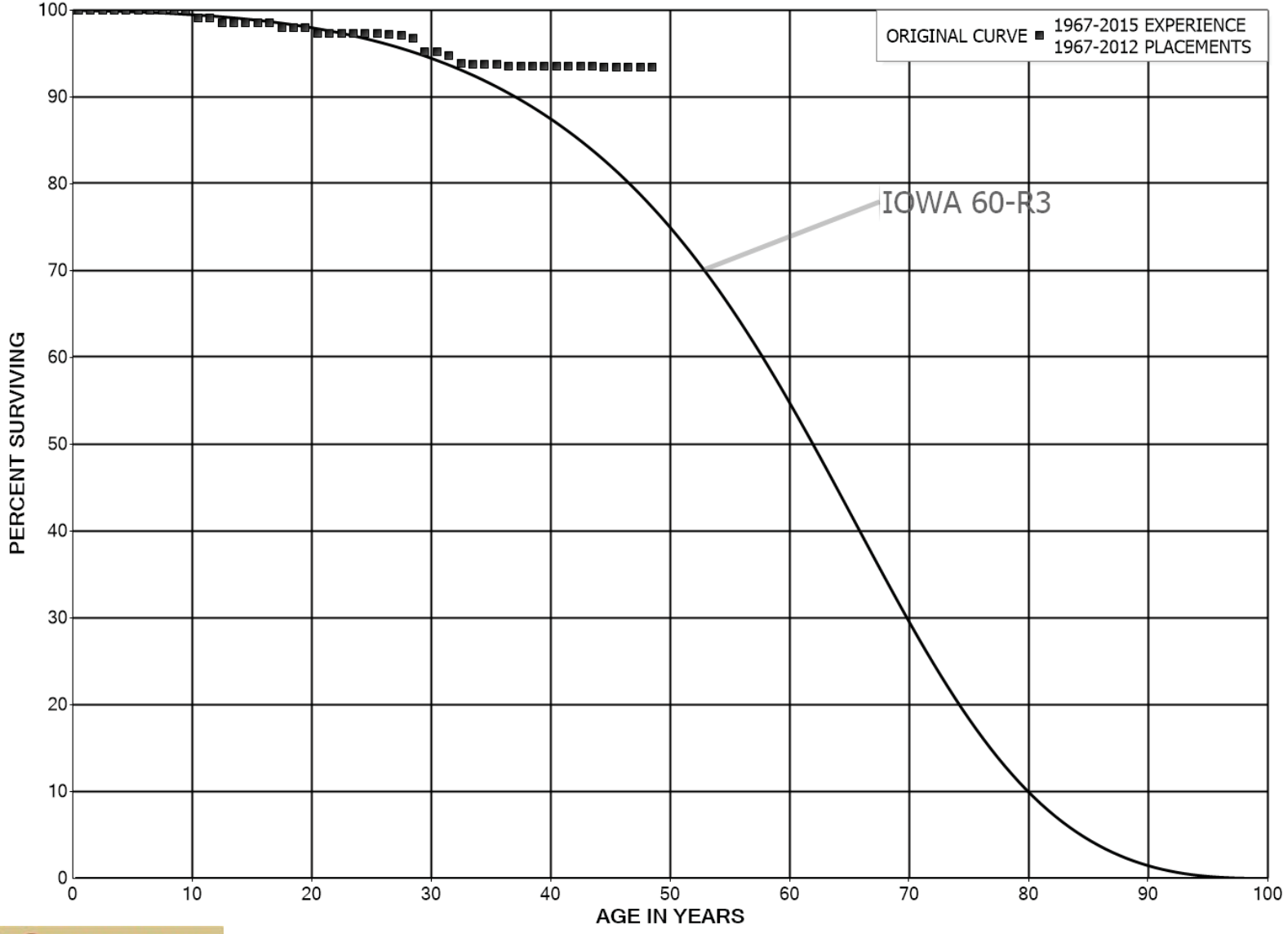
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C12 - CONDENSERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2008			EXPERIENCE BAND 1968-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	125,930		0.0000	1.0000	88.49
40.5	125,930		0.0000	1.0000	88.49
41.5	125,930		0.0000	1.0000	88.49
42.5	125,930		0.0000	1.0000	88.49
43.5	125,930		0.0000	1.0000	88.49
44.5	125,930		0.0000	1.0000	88.49
45.5	125,930		0.0000	1.0000	88.49
46.5	125,930		0.0000	1.0000	88.49
47.5					88.49

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C13 - CONDUCTOR
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C13 - CONDUCTOR

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2012 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	70,480,775		0.0000	1.0000	100.00
0.5	70,480,775		0.0000	1.0000	100.00
1.5	70,480,775		0.0000	1.0000	100.00
2.5	70,480,775		0.0000	1.0000	100.00
3.5	70,181,749		0.0000	1.0000	100.00
4.5	70,181,749		0.0000	1.0000	100.00
5.5	70,181,749		0.0000	1.0000	100.00
6.5	70,069,982	67,979	0.0010	0.9990	100.00
7.5	70,002,002		0.0000	1.0000	99.90
8.5	70,002,002		0.0000	1.0000	99.90
9.5	69,296,481	578,547	0.0083	0.9917	99.90
10.5	68,717,933	26,504	0.0004	0.9996	99.07
11.5	68,257,032	370,056	0.0054	0.9946	99.03
12.5	67,665,869	12,891	0.0002	0.9998	98.49
13.5	65,058,158		0.0000	1.0000	98.48
14.5	62,746,193		0.0000	1.0000	98.48
15.5	59,738,827		0.0000	1.0000	98.48
16.5	59,717,138	285,994	0.0048	0.9952	98.48
17.5	57,857,546	63,133	0.0011	0.9989	98.00
18.5	56,648,660		0.0000	1.0000	97.90
19.5	55,424,640	341,068	0.0062	0.9938	97.90
20.5	53,661,174		0.0000	1.0000	97.29
21.5	53,600,351		0.0000	1.0000	97.29
22.5	53,558,762		0.0000	1.0000	97.29
23.5	53,558,762	14,600	0.0003	0.9997	97.29
24.5	53,458,029	990	0.0000	1.0000	97.27
25.5	42,935,498	25,135	0.0006	0.9994	97.27
26.5	42,910,364	85,533	0.0020	0.9980	97.21
27.5	41,350,890	119,028	0.0029	0.9971	97.02
28.5	38,513,640	625,623	0.0162	0.9838	96.74
29.5	37,888,017		0.0000	1.0000	95.16
30.5	32,483,669	133,501	0.0041	0.9959	95.16
31.5	32,302,920	324,580	0.0100	0.9900	94.77
32.5	25,980,143	24,442	0.0009	0.9991	93.82
33.5	22,557,226		0.0000	1.0000	93.73
34.5	18,394,525		0.0000	1.0000	93.73
35.5	18,213,456	53,158	0.0029	0.9971	93.73
36.5	18,160,298		0.0000	1.0000	93.46
37.5	13,235,211		0.0000	1.0000	93.46
38.5	10,190,032		0.0000	1.0000	93.46

NEWFOUNDLAND AND LABRADOR HYDRO

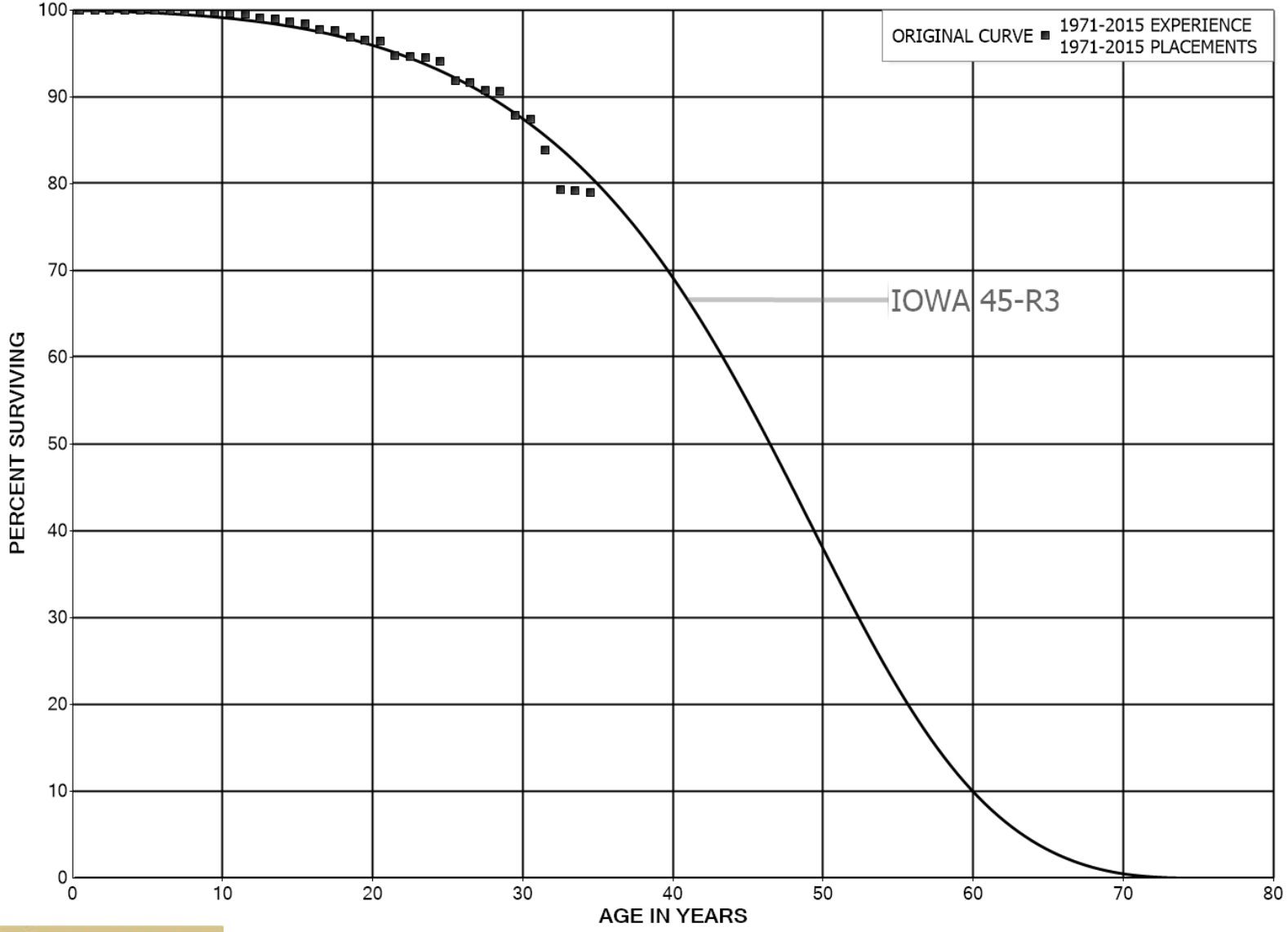
ACCOUNT C13 - CONDUCTOR

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2012 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	10,074,089		0.0000	1.0000	93.46
40.5	10,074,089		0.0000	1.0000	93.46
41.5	8,354,258		0.0000	1.0000	93.46
42.5	8,354,258		0.0000	1.0000	93.46
43.5	8,354,258	5,238	0.0006	0.9994	93.46
44.5	8,349,019		0.0000	1.0000	93.40
45.5	7,575,829		0.0000	1.0000	93.40
46.5	7,323,183		0.0000	1.0000	93.40
47.5	4,914,311		0.0000	1.0000	93.40
48.5					93.40

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C14 - CONDUCTOR - DISTRIBUTION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C14 - CONDUCTOR - DISTRIBUTION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2015 EXPERIENCE BAND 1971-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	36,819,940		0.0000	1.0000	100.00
0.5	35,645,992	479	0.0000	1.0000	100.00
1.5	33,936,800	544	0.0000	1.0000	100.00
2.5	31,408,042	1,531	0.0000	1.0000	100.00
3.5	29,890,463	4,045	0.0001	0.9999	99.99
4.5	29,206,735	8,981	0.0003	0.9997	99.98
5.5	28,940,399	13,474	0.0005	0.9995	99.95
6.5	28,226,144	4,465	0.0002	0.9998	99.90
7.5	27,708,336	25,140	0.0009	0.9991	99.89
8.5	27,179,759	16,412	0.0006	0.9994	99.79
9.5	26,327,109	18,031	0.0007	0.9993	99.73
10.5	26,097,119	33,970	0.0013	0.9987	99.67
11.5	25,761,069	122,738	0.0048	0.9952	99.54
12.5	25,181,970	33,062	0.0013	0.9987	99.06
13.5	21,302,356	59,365	0.0028	0.9972	98.93
14.5	20,663,414	60,355	0.0029	0.9971	98.66
15.5	19,912,890	123,096	0.0062	0.9938	98.37
16.5	19,283,755	28,595	0.0015	0.9985	97.76
17.5	18,725,840	154,385	0.0082	0.9918	97.62
18.5	17,183,862	59,009	0.0034	0.9966	96.81
19.5	16,388,655	23,093	0.0014	0.9986	96.48
20.5	15,598,113	260,829	0.0167	0.9833	96.34
21.5	14,806,008	13,268	0.0009	0.9991	94.73
22.5	14,073,831	19,353	0.0014	0.9986	94.65
23.5	13,845,454	69,553	0.0050	0.9950	94.52
24.5	13,101,525	305,608	0.0233	0.9767	94.04
25.5	11,985,146	25,544	0.0021	0.9979	91.85
26.5	10,692,019	106,506	0.0100	0.9900	91.65
27.5	9,672,675	13,277	0.0014	0.9986	90.74
28.5	8,730,110	270,431	0.0310	0.9690	90.61
29.5	7,794,514	35,049	0.0045	0.9955	87.81
30.5	6,628,324	272,343	0.0411	0.9589	87.41
31.5	5,486,386	295,579	0.0539	0.9461	83.82
32.5	4,824,825	9,868	0.0020	0.9980	79.31
33.5	4,490,644	11,911	0.0027	0.9973	79.14
34.5	684,485		0.0000	1.0000	78.93
35.5	4,409		0.0000	1.0000	78.93
36.5	4,409		0.0000	1.0000	78.93
37.5	4,409		0.0000	1.0000	78.93
38.5	3,753		0.0000	1.0000	78.93

NEWFOUNDLAND AND LABRADOR HYDRO

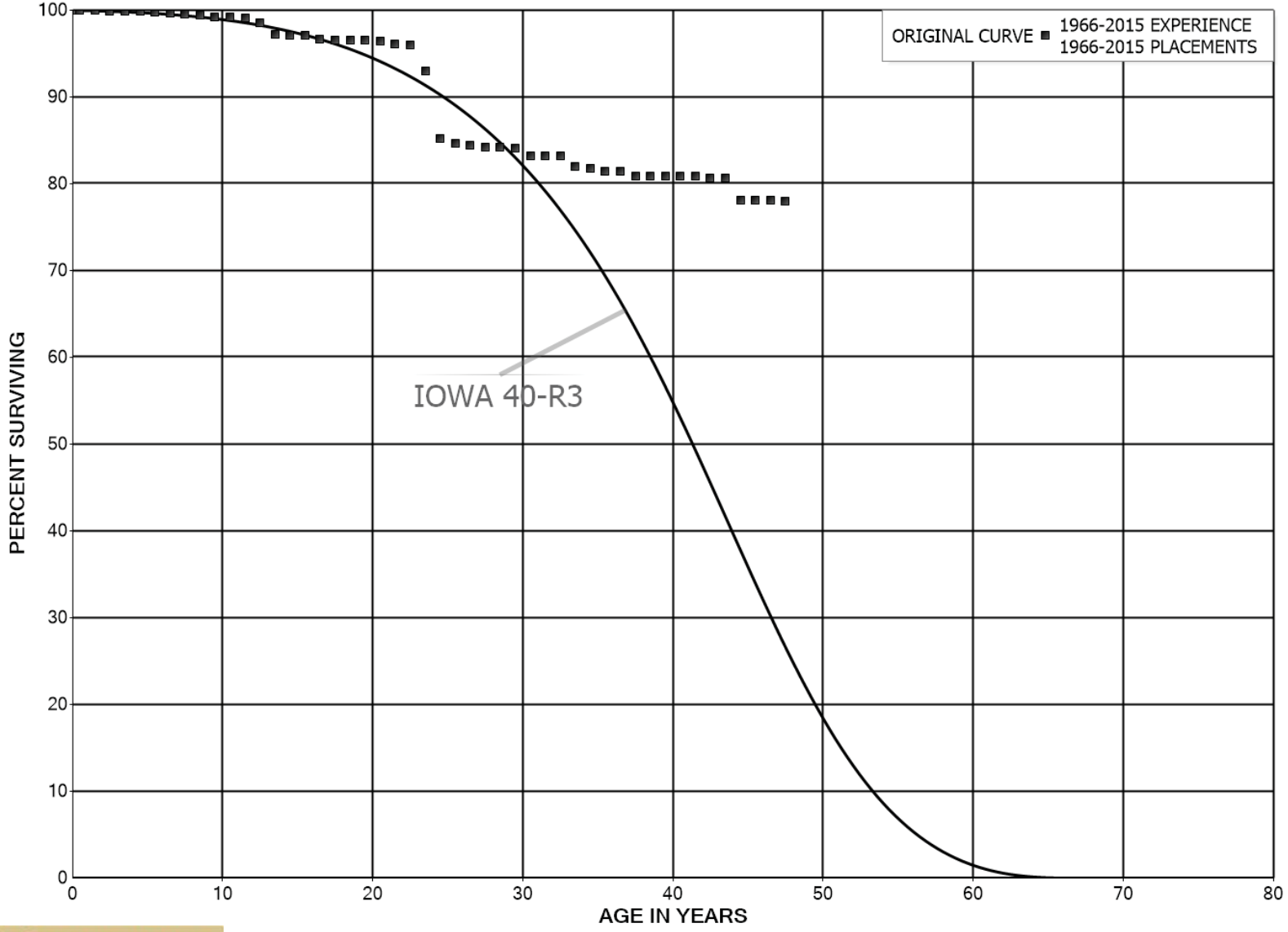
ACCOUNT C14 - CONDUCTOR - DISTRIBUTION

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1971-2015 EXPERIENCE BAND 1971-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,753		0.0000	1.0000	78.93
40.5	3,753		0.0000	1.0000	78.93
41.5	3,753		0.0000	1.0000	78.93
42.5	3,753		0.0000	1.0000	78.93
43.5	3,753		0.0000	1.0000	78.93
44.5					78.93

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C15 - CONTROL, METER / RELAYING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C15 - CONTROL, METER / RELAYING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	32,359,950		0.0000	1.0000	100.00
0.5	25,771,532	13,320	0.0005	0.9995	100.00
1.5	25,058,141	34,993	0.0014	0.9986	99.95
2.5	24,421,940		0.0000	1.0000	99.81
3.5	23,172,790	6,163	0.0003	0.9997	99.81
4.5	22,753,741	788	0.0000	1.0000	99.78
5.5	22,213,253	44,781	0.0020	0.9980	99.78
6.5	21,274,185	12,423	0.0006	0.9994	99.58
7.5	21,038,684	25,993	0.0012	0.9988	99.52
8.5	20,930,332	51,041	0.0024	0.9976	99.40
9.5	20,469,755		0.0000	1.0000	99.15
10.5	20,042,613	10,665	0.0005	0.9995	99.15
11.5	19,586,316	111,002	0.0057	0.9943	99.10
12.5	19,028,560	268,994	0.0141	0.9859	98.54
13.5	18,520,510	10,359	0.0006	0.9994	97.15
14.5	17,559,692	9,026	0.0005	0.9995	97.09
15.5	16,727,758	80,152	0.0048	0.9952	97.04
16.5	16,117,217	13,444	0.0008	0.9992	96.58
17.5	15,372,825		0.0000	1.0000	96.50
18.5	14,807,238		0.0000	1.0000	96.50
19.5	14,402,480	13,424	0.0009	0.9991	96.50
20.5	13,323,080	45,052	0.0034	0.9966	96.41
21.5	12,679,908	18,113	0.0014	0.9986	96.08
22.5	12,475,358	395,390	0.0317	0.9683	95.94
23.5	10,815,343	903,684	0.0836	0.9164	92.90
24.5	9,593,893	55,378	0.0058	0.9942	85.14
25.5	8,683,391	30,154	0.0035	0.9965	84.65
26.5	8,180,693	13,142	0.0016	0.9984	84.35
27.5	7,887,390	2,980	0.0004	0.9996	84.22
28.5	7,515,959	12,667	0.0017	0.9983	84.19
29.5	7,143,772	74,334	0.0104	0.9896	84.05
30.5	6,816,996	3,704	0.0005	0.9995	83.17
31.5	6,712,760		0.0000	1.0000	83.13
32.5	6,324,697	88,202	0.0139	0.9861	83.13
33.5	5,577,905	15,672	0.0028	0.9972	81.97
34.5	5,391,777	21,753	0.0040	0.9960	81.74
35.5	4,914,807		0.0000	1.0000	81.41
36.5	4,538,826	33,134	0.0073	0.9927	81.41
37.5	4,132,037		0.0000	1.0000	80.81
38.5	3,885,274		0.0000	1.0000	80.81

NEWFOUNDLAND AND LABRADOR HYDRO

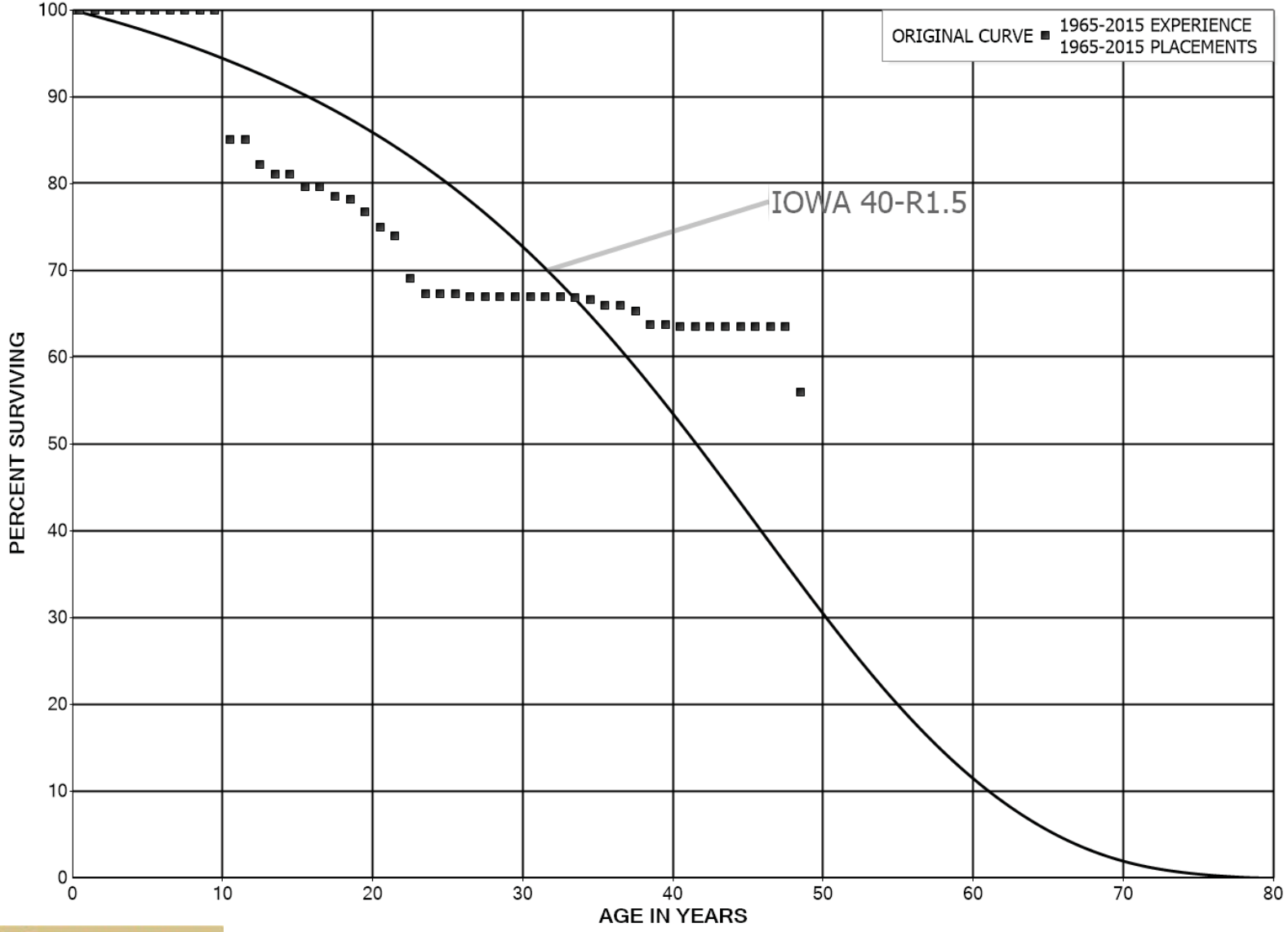
ACCOUNT C15 - CONTROL, METER / RELAYING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,869,706		0.0000	1.0000	80.81
40.5	3,268,599		0.0000	1.0000	80.81
41.5	3,147,635	6,881	0.0022	0.9978	80.81
42.5	3,140,755		0.0000	1.0000	80.64
43.5	3,140,755	99,116	0.0316	0.9684	80.64
44.5	3,041,639		0.0000	1.0000	78.09
45.5	2,507,838		0.0000	1.0000	78.09
46.5	2,492,160	6,399	0.0026	0.9974	78.09
47.5	2,298,558	62,541	0.0272	0.9728	77.89
48.5	36,521		0.0000	1.0000	75.77
49.5					75.77

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C16 - COOLING SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C16 - COOLING SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,150,185		0.0000	1.0000	100.00
0.5	7,898,071		0.0000	1.0000	100.00
1.5	7,340,820		0.0000	1.0000	100.00
2.5	5,631,985		0.0000	1.0000	100.00
3.5	5,615,933		0.0000	1.0000	100.00
4.5	5,169,926		0.0000	1.0000	100.00
5.5	4,821,164		0.0000	1.0000	100.00
6.5	4,340,913		0.0000	1.0000	100.00
7.5	3,999,987		0.0000	1.0000	100.00
8.5	3,920,744		0.0000	1.0000	100.00
9.5	3,785,623	566,030	0.1495	0.8505	100.00
10.5	3,190,712		0.0000	1.0000	85.05
11.5	3,190,712	106,045	0.0332	0.9668	85.05
12.5	2,998,348	42,775	0.0143	0.9857	82.22
13.5	2,916,218		0.0000	1.0000	81.05
14.5	2,916,218	51,412	0.0176	0.9824	81.05
15.5	2,712,372		0.0000	1.0000	79.62
16.5	2,605,704	36,863	0.0141	0.9859	79.62
17.5	2,255,278	7,884	0.0035	0.9965	78.49
18.5	2,247,395	42,898	0.0191	0.9809	78.22
19.5	2,204,497	50,693	0.0230	0.9770	76.73
20.5	1,991,939	27,142	0.0136	0.9864	74.96
21.5	1,612,007	107,059	0.0664	0.9336	73.94
22.5	1,495,645	36,960	0.0247	0.9753	69.03
23.5	1,420,769		0.0000	1.0000	67.32
24.5	1,420,769		0.0000	1.0000	67.32
25.5	1,420,769	8,192	0.0058	0.9942	67.32
26.5	1,283,107		0.0000	1.0000	66.94
27.5	1,250,535		0.0000	1.0000	66.94
28.5	1,250,535		0.0000	1.0000	66.94
29.5	1,250,535		0.0000	1.0000	66.94
30.5	1,250,535		0.0000	1.0000	66.94
31.5	1,001,226		0.0000	1.0000	66.94
32.5	992,289	1,500	0.0015	0.9985	66.94
33.5	824,036	3,274	0.0040	0.9960	66.83
34.5	795,673	7,916	0.0099	0.9901	66.57
35.5	761,282		0.0000	1.0000	65.91
36.5	623,479	6,231	0.0100	0.9900	65.91
37.5	617,248	14,120	0.0229	0.9771	65.25
38.5	319,207		0.0000	1.0000	63.76

NEWFOUNDLAND AND LABRADOR HYDRO

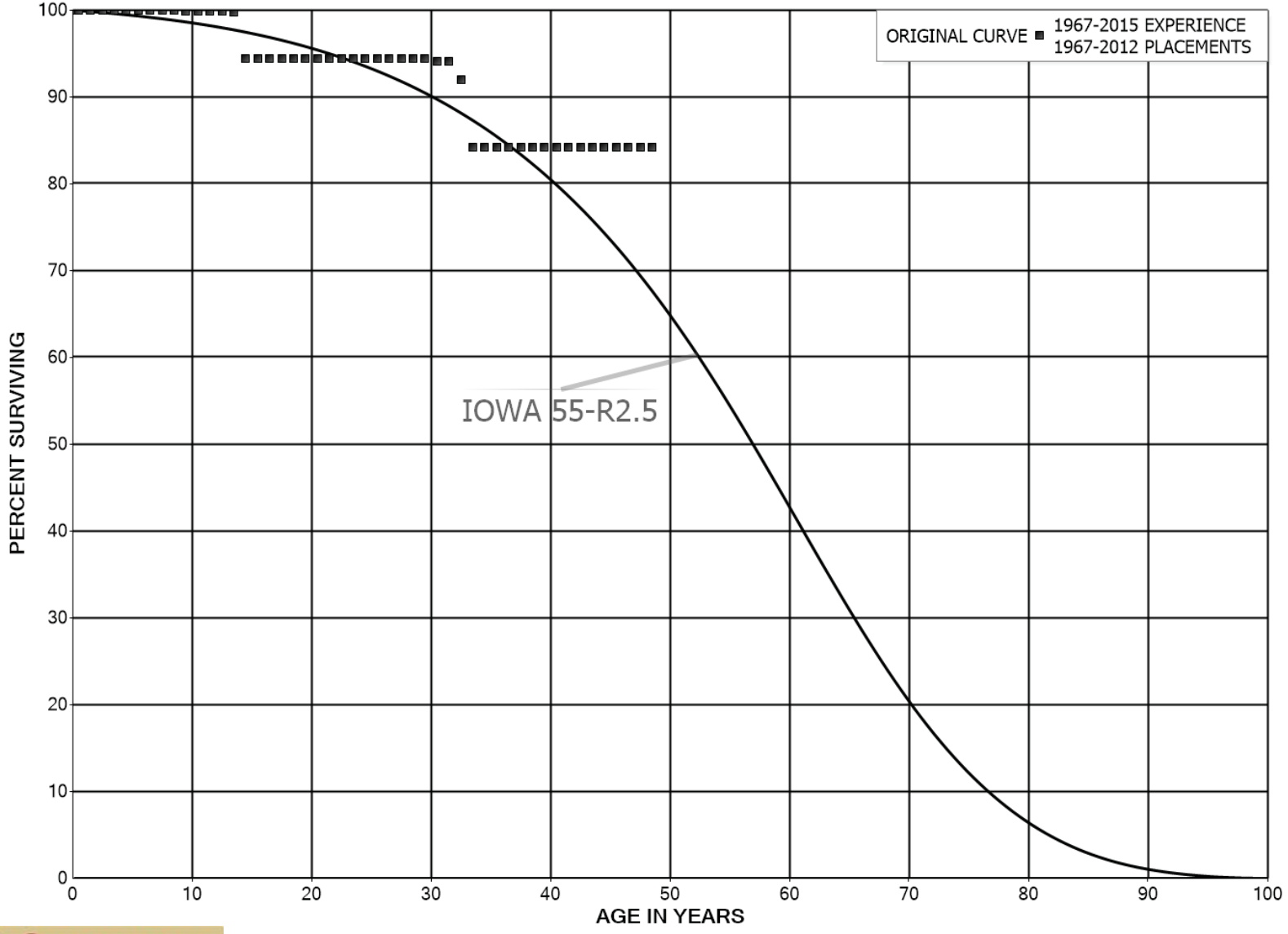
ACCOUNT C16 - COOLING SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	319,207	1,155	0.0036	0.9964	63.76
40.5	318,052		0.0000	1.0000	63.52
41.5	318,052		0.0000	1.0000	63.52
42.5	298,713		0.0000	1.0000	63.52
43.5	298,713		0.0000	1.0000	63.52
44.5	262,697		0.0000	1.0000	63.52
45.5	262,697		0.0000	1.0000	63.52
46.5	213,556		0.0000	1.0000	63.52
47.5	210,322	25,000	0.1189	0.8811	63.52
48.5	185,322		0.0000	1.0000	55.97
49.5	49,715		0.0000	1.0000	55.97
50.5					55.97

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C17 - COUNTERPOISE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C17 - COUNTERPOISE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2012 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,915,332		0.0000	1.0000	100.00
0.5	3,915,332		0.0000	1.0000	100.00
1.5	3,915,332		0.0000	1.0000	100.00
2.5	3,915,332		0.0000	1.0000	100.00
3.5	3,871,953		0.0000	1.0000	100.00
4.5	3,871,953		0.0000	1.0000	100.00
5.5	3,871,953		0.0000	1.0000	100.00
6.5	3,871,953		0.0000	1.0000	100.00
7.5	3,871,953		0.0000	1.0000	100.00
8.5	3,871,953	5,928	0.0015	0.9985	100.00
9.5	3,866,025		0.0000	1.0000	99.85
10.5	3,866,025		0.0000	1.0000	99.85
11.5	3,866,025		0.0000	1.0000	99.85
12.5	3,513,115	5,192	0.0015	0.9985	99.85
13.5	3,326,719	176,142	0.0529	0.9471	99.70
14.5	2,933,725		0.0000	1.0000	94.42
15.5	2,652,937		0.0000	1.0000	94.42
16.5	2,649,779		0.0000	1.0000	94.42
17.5	2,649,779		0.0000	1.0000	94.42
18.5	2,601,336		0.0000	1.0000	94.42
19.5	2,583,450		0.0000	1.0000	94.42
20.5	2,564,439		0.0000	1.0000	94.42
21.5	2,233,040		0.0000	1.0000	94.42
22.5	1,867,771		0.0000	1.0000	94.42
23.5	1,705,947		0.0000	1.0000	94.42
24.5	1,705,388		0.0000	1.0000	94.42
25.5	1,671,216		0.0000	1.0000	94.42
26.5	1,523,554		0.0000	1.0000	94.42
27.5	1,308,437		0.0000	1.0000	94.42
28.5	1,297,319		0.0000	1.0000	94.42
29.5	1,190,515	4,514	0.0038	0.9962	94.42
30.5	971,350		0.0000	1.0000	94.06
31.5	971,350	21,504	0.0221	0.9779	94.06
32.5	934,320	78,963	0.0845	0.9155	91.98
33.5	827,814		0.0000	1.0000	84.21
34.5	818,308		0.0000	1.0000	84.21
35.5	818,308		0.0000	1.0000	84.21
36.5	818,308		0.0000	1.0000	84.21
37.5	694,989		0.0000	1.0000	84.21
38.5	694,989		0.0000	1.0000	84.21

NEWFOUNDLAND AND LABRADOR HYDRO

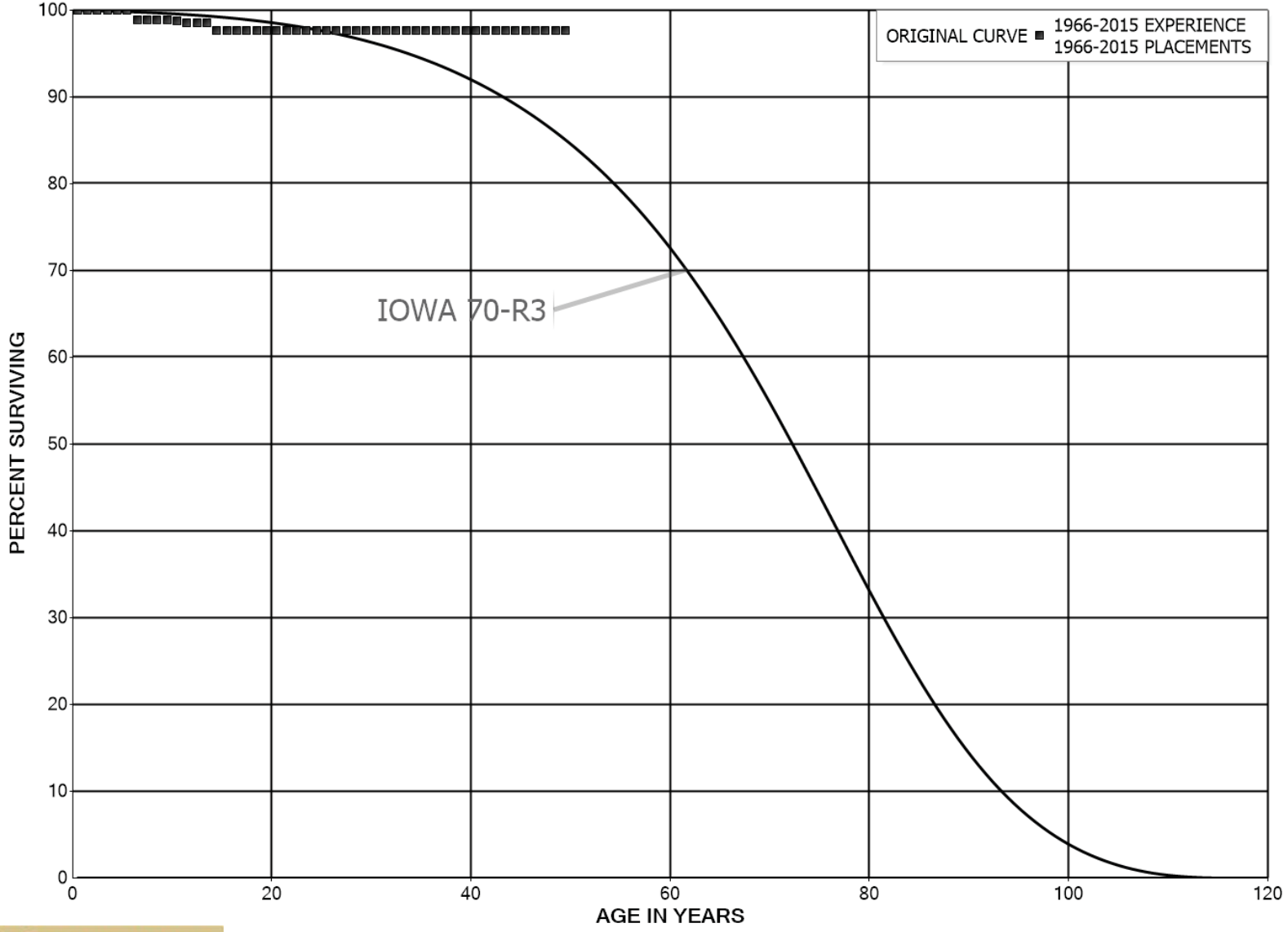
ACCOUNT C17 - COUNTERPOISE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2012 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	694,989		0.0000	1.0000	84.21
40.5	694,989		0.0000	1.0000	84.21
41.5	679,437		0.0000	1.0000	84.21
42.5	679,437		0.0000	1.0000	84.21
43.5	679,437		0.0000	1.0000	84.21
44.5	679,437		0.0000	1.0000	84.21
45.5	678,891		0.0000	1.0000	84.21
46.5	678,891		0.0000	1.0000	84.21
47.5	431,098		0.0000	1.0000	84.21
48.5					84.21

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT C18 - CRANES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C18 - CRANES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,041,523		0.0000	1.0000	100.00
0.5	7,028,081		0.0000	1.0000	100.00
1.5	6,964,914		0.0000	1.0000	100.00
2.5	6,749,075		0.0000	1.0000	100.00
3.5	6,749,075		0.0000	1.0000	100.00
4.5	6,605,709		0.0000	1.0000	100.00
5.5	6,605,709	75,734	0.0115	0.9885	100.00
6.5	6,529,974		0.0000	1.0000	98.85
7.5	6,514,785		0.0000	1.0000	98.85
8.5	6,514,785		0.0000	1.0000	98.85
9.5	6,420,884	4,823	0.0008	0.9992	98.85
10.5	6,416,061	16,543	0.0026	0.9974	98.78
11.5	6,399,518		0.0000	1.0000	98.52
12.5	4,839,368		0.0000	1.0000	98.52
13.5	4,830,953	42,281	0.0088	0.9912	98.52
14.5	4,788,672		0.0000	1.0000	97.66
15.5	4,788,672		0.0000	1.0000	97.66
16.5	4,788,672		0.0000	1.0000	97.66
17.5	4,788,672		0.0000	1.0000	97.66
18.5	4,788,672		0.0000	1.0000	97.66
19.5	4,782,465		0.0000	1.0000	97.66
20.5	4,778,683		0.0000	1.0000	97.66
21.5	4,778,683		0.0000	1.0000	97.66
22.5	4,763,241		0.0000	1.0000	97.66
23.5	4,763,241		0.0000	1.0000	97.66
24.5	4,763,241		0.0000	1.0000	97.66
25.5	4,763,241		0.0000	1.0000	97.66
26.5	4,739,441		0.0000	1.0000	97.66
27.5	4,434,835		0.0000	1.0000	97.66
28.5	4,434,835		0.0000	1.0000	97.66
29.5	4,434,835		0.0000	1.0000	97.66
30.5	4,311,217		0.0000	1.0000	97.66
31.5	3,317,260		0.0000	1.0000	97.66
32.5	3,317,260		0.0000	1.0000	97.66
33.5	1,815,849		0.0000	1.0000	97.66
34.5	1,815,849		0.0000	1.0000	97.66
35.5	1,679,562		0.0000	1.0000	97.66
36.5	1,081,985		0.0000	1.0000	97.66
37.5	1,081,985		0.0000	1.0000	97.66
38.5	1,081,985		0.0000	1.0000	97.66

NEWFOUNDLAND AND LABRADOR HYDRO

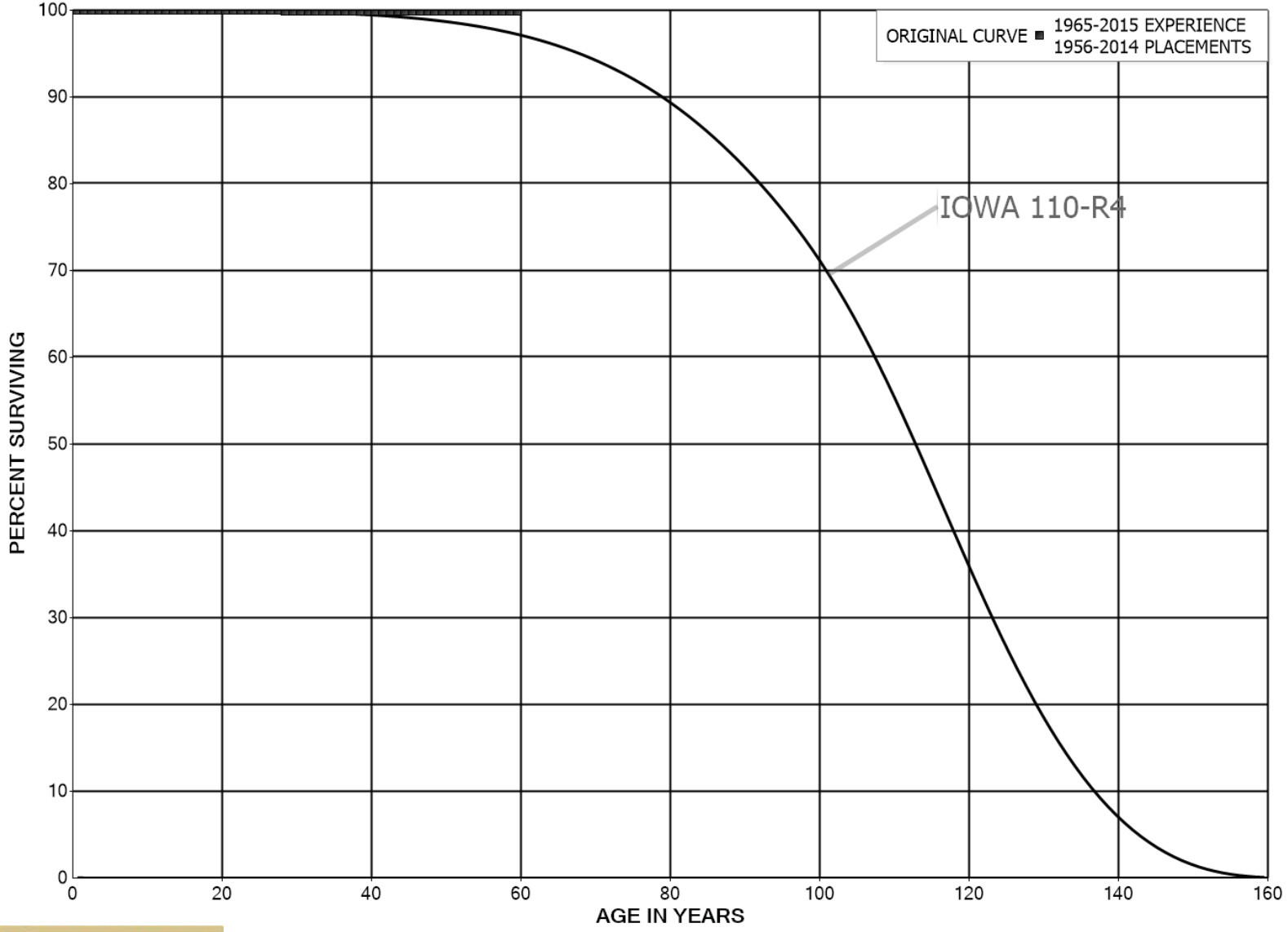
ACCOUNT C18 - CRANES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,081,985		0.0000	1.0000	97.66
40.5	1,081,985		0.0000	1.0000	97.66
41.5	1,081,985		0.0000	1.0000	97.66
42.5	1,081,985		0.0000	1.0000	97.66
43.5	1,081,985		0.0000	1.0000	97.66
44.5	1,081,985		0.0000	1.0000	97.66
45.5	1,081,985		0.0000	1.0000	97.66
46.5	847,978		0.0000	1.0000	97.66
47.5	847,978		0.0000	1.0000	97.66
48.5	658,978		0.0000	1.0000	97.66
49.5					97.66

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT D01 - DAMS, DIKES, CANALS AND TUNNELS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D01 - DAMS, DYKES, CANALS AND TUNNELS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2014 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	361,974,611		0.0000	1.0000	100.00
0.5	361,974,611		0.0000	1.0000	100.00
1.5	361,816,305		0.0000	1.0000	100.00
2.5	361,816,305		0.0000	1.0000	100.00
3.5	360,513,319		0.0000	1.0000	100.00
4.5	360,513,319		0.0000	1.0000	100.00
5.5	360,016,433		0.0000	1.0000	100.00
6.5	359,312,256		0.0000	1.0000	100.00
7.5	359,312,256		0.0000	1.0000	100.00
8.5	359,927,562		0.0000	1.0000	100.00
9.5	359,927,562		0.0000	1.0000	100.00
10.5	357,064,279		0.0000	1.0000	100.00
11.5	357,064,279		0.0000	1.0000	100.00
12.5	328,845,243		0.0000	1.0000	100.00
13.5	328,845,243		0.0000	1.0000	100.00
14.5	328,845,243		0.0000	1.0000	100.00
15.5	328,845,243		0.0000	1.0000	100.00
16.5	328,845,243		0.0000	1.0000	100.00
17.5	328,845,243		0.0000	1.0000	100.00
18.5	328,845,243		0.0000	1.0000	100.00
19.5	328,845,243		0.0000	1.0000	100.00
20.5	328,845,243		0.0000	1.0000	100.00
21.5	328,845,243		0.0000	1.0000	100.00
22.5	328,840,531		0.0000	1.0000	100.00
23.5	328,802,521		0.0000	1.0000	100.00
24.5	328,802,521		0.0000	1.0000	100.00
25.5	328,802,521		0.0000	1.0000	100.00
26.5	328,299,433		0.0000	1.0000	100.00
27.5	316,297,101	677,266	0.0021	0.9979	100.00
28.5	315,619,835		0.0000	1.0000	99.79
29.5	315,571,032		0.0000	1.0000	99.79
30.5	304,575,473	134	0.0000	1.0000	99.79
31.5	191,450,701		0.0000	1.0000	99.79
32.5	169,766,434		0.0000	1.0000	99.79
33.5	114,996,228		0.0000	1.0000	99.79
34.5	114,996,228		0.0000	1.0000	99.79
35.5	106,262,617		0.0000	1.0000	99.79
36.5	79,308,072		0.0000	1.0000	99.79
37.5	75,663,686		0.0000	1.0000	99.79
38.5	75,663,686		0.0000	1.0000	99.79

NEWFOUNDLAND AND LABRADOR HYDRO

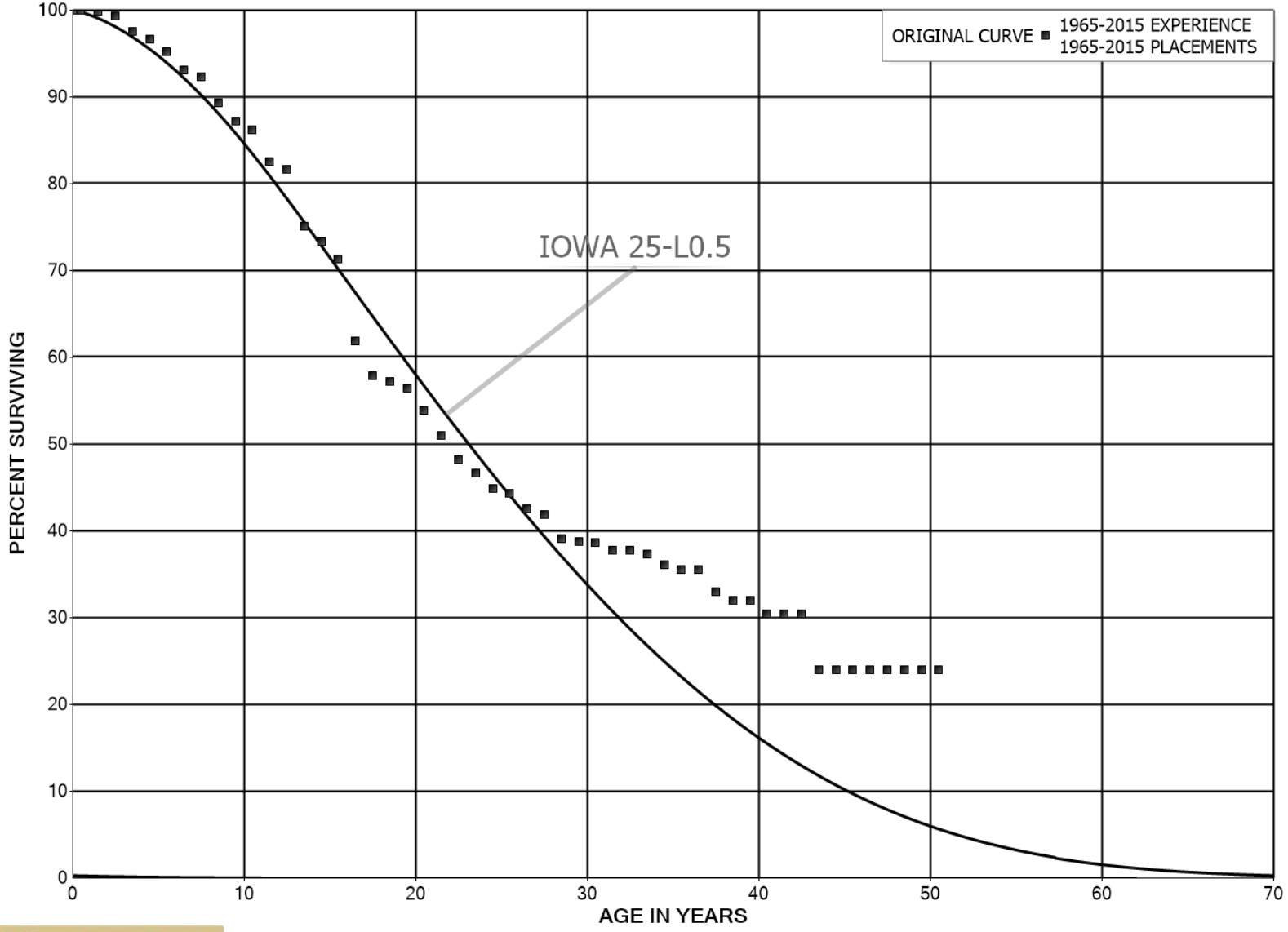
ACCOUNT D01 - DAMS, DIKES, CANALS AND TUNNELS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2014 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	75,663,686		0.0000	1.0000	99.79
40.5	75,663,686		0.0000	1.0000	99.79
41.5	75,663,686		0.0000	1.0000	99.79
42.5	75,663,686		0.0000	1.0000	99.79
43.5	75,663,686		0.0000	1.0000	99.79
44.5	75,663,686	3,146	0.0000	1.0000	99.79
45.5	70,760,716		0.0000	1.0000	99.78
46.5	70,614,492		0.0000	1.0000	99.78
47.5	70,614,492		0.0000	1.0000	99.78
48.5	43,482,527	116	0.0000	1.0000	99.78
49.5	615,306		0.0000	1.0000	99.78
50.5	615,306		0.0000	1.0000	99.78
51.5	615,306		0.0000	1.0000	99.78
52.5	615,306		0.0000	1.0000	99.78
53.5	615,306		0.0000	1.0000	99.78
54.5	615,306		0.0000	1.0000	99.78
55.5	615,306		0.0000	1.0000	99.78
56.5	615,306		0.0000	1.0000	99.78
57.5	615,306		0.0000	1.0000	99.78
58.5	615,306		0.0000	1.0000	99.78
59.5					99.78

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT D02 - DIESEL SYSTEMS AND ENGINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D02 - DIESEL SYSTEMS AND ENGINES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	60,908,369		0.0000	1.0000	100.00
0.5	58,476,998	126,086	0.0022	0.9978	100.00
1.5	51,717,002	280,669	0.0054	0.9946	99.78
2.5	49,925,783	863,917	0.0173	0.9827	99.24
3.5	46,654,770	449,035	0.0096	0.9904	97.53
4.5	42,463,182	624,574	0.0147	0.9853	96.59
5.5	39,066,836	852,864	0.0218	0.9782	95.17
6.5	35,576,464	301,402	0.0085	0.9915	93.09
7.5	35,166,050	1,135,416	0.0323	0.9677	92.30
8.5	33,113,977	797,058	0.0241	0.9759	89.32
9.5	31,958,993	373,543	0.0117	0.9883	87.17
10.5	30,479,328	1,275,308	0.0418	0.9582	86.15
11.5	29,204,020	323,119	0.0111	0.9889	82.55
12.5	28,638,070	2,294,762	0.0801	0.9199	81.63
13.5	24,704,152	587,844	0.0238	0.9762	75.09
14.5	22,153,380	608,581	0.0275	0.9725	73.31
15.5	20,064,729	2,668,955	0.1330	0.8670	71.29
16.5	17,163,010	1,093,659	0.0637	0.9363	61.81
17.5	14,959,659	166,917	0.0112	0.9888	57.87
18.5	13,363,449	201,359	0.0151	0.9849	57.22
19.5	12,632,012	555,987	0.0440	0.9560	56.36
20.5	11,445,530	617,375	0.0539	0.9461	53.88
21.5	9,299,615	517,598	0.0557	0.9443	50.97
22.5	8,673,038	277,348	0.0320	0.9680	48.14
23.5	8,367,321	313,199	0.0374	0.9626	46.60
24.5	7,670,193	100,631	0.0131	0.9869	44.85
25.5	7,097,159	286,403	0.0404	0.9596	44.27
26.5	6,746,698	95,097	0.0141	0.9859	42.48
27.5	6,567,795	436,304	0.0664	0.9336	41.88
28.5	6,089,567	63,530	0.0104	0.9896	39.10
29.5	5,871,542	9,325	0.0016	0.9984	38.69
30.5	5,862,217	133,451	0.0228	0.9772	38.63
31.5	5,391,672		0.0000	1.0000	37.75
32.5	4,153,672	48,702	0.0117	0.9883	37.75
33.5	3,171,517	105,997	0.0334	0.9666	37.31
34.5	2,612,444	41,778	0.0160	0.9840	36.06
35.5	1,432,816		0.0000	1.0000	35.48
36.5	1,432,816	100,048	0.0698	0.9302	35.48
37.5	1,332,768	42,474	0.0319	0.9681	33.01
38.5	1,290,294		0.0000	1.0000	31.95

NEWFOUNDLAND AND LABRADOR HYDRO

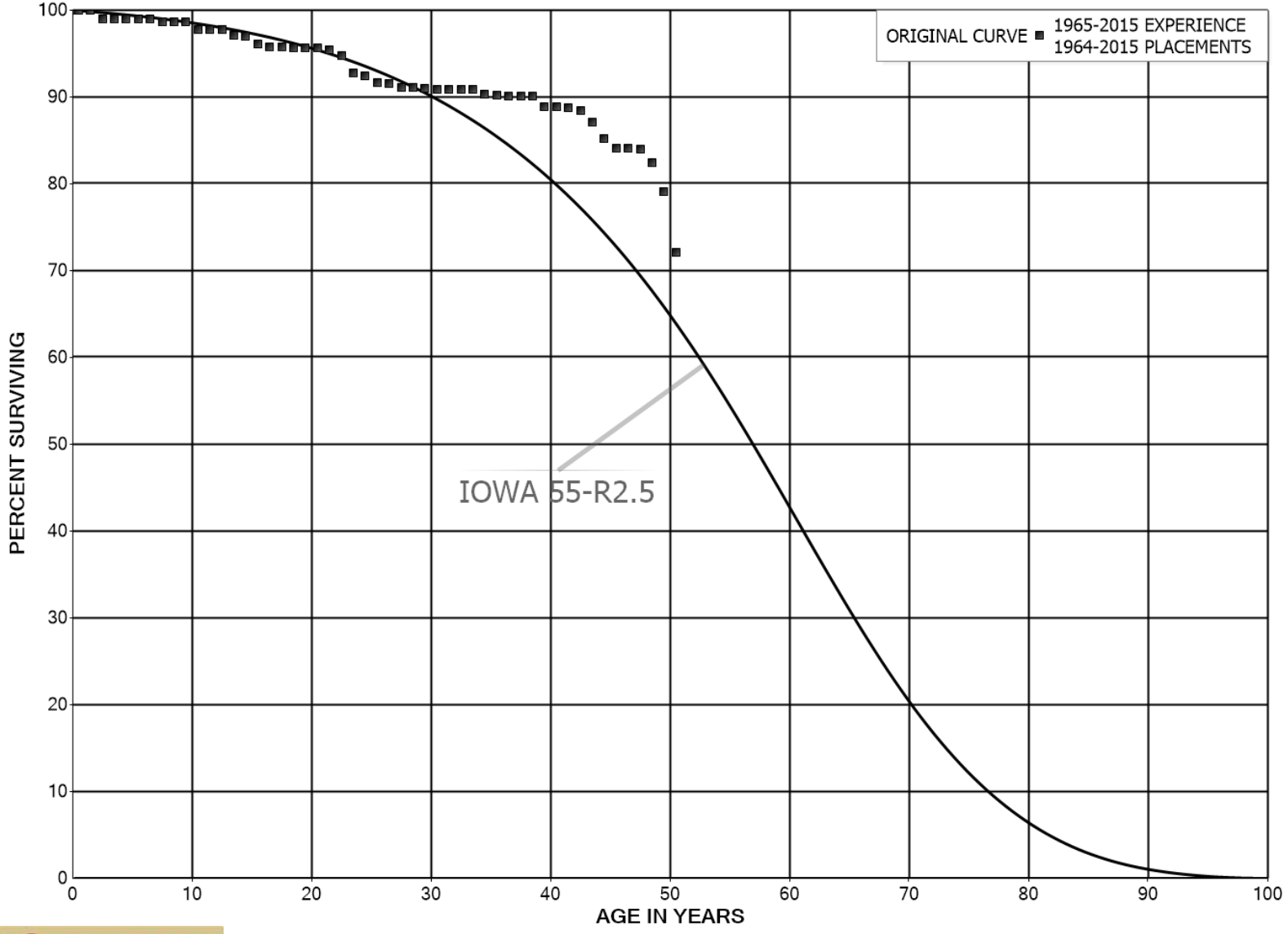
ACCOUNT D02 - DIESEL SYSTEMS AND ENGINES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,290,294	63,514	0.0492	0.9508	31.95
40.5	1,226,781		0.0000	1.0000	30.38
41.5	1,226,781		0.0000	1.0000	30.38
42.5	831,977	177,189	0.2130	0.7870	30.38
43.5	654,787		0.0000	1.0000	23.91
44.5	654,787		0.0000	1.0000	23.91
45.5	654,787		0.0000	1.0000	23.91
46.5	654,787		0.0000	1.0000	23.91
47.5	644,462		0.0000	1.0000	23.91
48.5	644,462		0.0000	1.0000	23.91
49.5	644,462		0.0000	1.0000	23.91
50.5					23.91

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT D03 - DISCONNECT SWITCHES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D03 - DISCONNECT SWITCHES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1964-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,095,900		0.0000	1.0000	100.00
0.5	17,474,940		0.0000	1.0000	100.00
1.5	14,553,456	152,196	0.0105	0.9895	100.00
2.5	13,319,299		0.0000	1.0000	98.95
3.5	11,785,456		0.0000	1.0000	98.95
4.5	10,687,854		0.0000	1.0000	98.95
5.5	10,630,784		0.0000	1.0000	98.95
6.5	10,098,449	33,780	0.0033	0.9967	98.95
7.5	10,064,669	5,835	0.0006	0.9994	98.62
8.5	10,058,833		0.0000	1.0000	98.57
9.5	10,023,738	86,743	0.0087	0.9913	98.57
10.5	9,749,421		0.0000	1.0000	97.71
11.5	9,591,623		0.0000	1.0000	97.71
12.5	9,461,971	65,466	0.0069	0.9931	97.71
13.5	9,208,933	5,635	0.0006	0.9994	97.04
14.5	9,106,778	85,267	0.0094	0.9906	96.98
15.5	8,851,445	34,139	0.0039	0.9961	96.07
16.5	8,817,307	525	0.0001	0.9999	95.70
17.5	8,650,640	4,171	0.0005	0.9995	95.69
18.5	8,615,939		0.0000	1.0000	95.65
19.5	8,314,559		0.0000	1.0000	95.65
20.5	7,892,188	16,500	0.0021	0.9979	95.65
21.5	7,839,960	59,725	0.0076	0.9924	95.45
22.5	7,675,252	165,724	0.0216	0.9784	94.72
23.5	7,278,498	24,416	0.0034	0.9966	92.67
24.5	7,217,752	57,499	0.0080	0.9920	92.36
25.5	6,678,456	10,004	0.0015	0.9985	91.63
26.5	6,165,686	29,781	0.0048	0.9952	91.49
27.5	6,003,213		0.0000	1.0000	91.05
28.5	5,851,512	4,308	0.0007	0.9993	91.05
29.5	5,815,459	9,658	0.0017	0.9983	90.98
30.5	5,789,888		0.0000	1.0000	90.83
31.5	5,745,574		0.0000	1.0000	90.83
32.5	5,701,491	1,339	0.0002	0.9998	90.83
33.5	5,418,574	29,924	0.0055	0.9945	90.81
34.5	5,253,728	9,267	0.0018	0.9982	90.31
35.5	4,970,406	2,913	0.0006	0.9994	90.15
36.5	4,925,181	1,802	0.0004	0.9996	90.10
37.5	4,680,873	1,368	0.0003	0.9997	90.06
38.5	4,283,650	55,197	0.0129	0.9871	90.04

NEWFOUNDLAND AND LABRADOR HYDRO

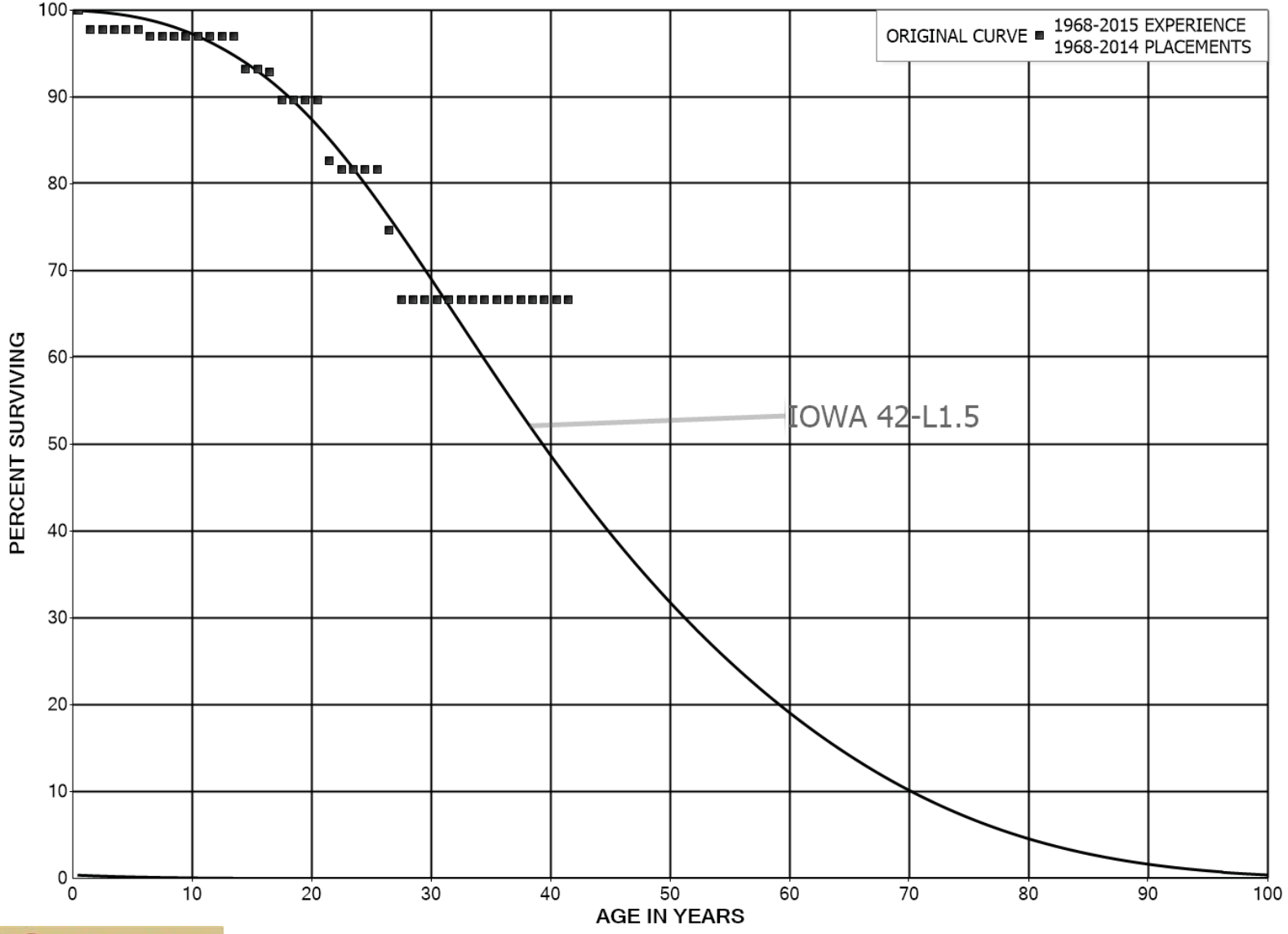
ACCOUNT D03 - DISCONNECT SWITCHES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1964-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,206,628		0.0000	1.0000	88.88
40.5	4,034,274	5,338	0.0013	0.9987	88.88
41.5	3,868,789	15,233	0.0039	0.9961	88.76
42.5	3,853,556	58,335	0.0151	0.9849	88.41
43.5	3,515,199	75,906	0.0216	0.9784	87.07
44.5	3,207,262	43,610	0.0136	0.9864	85.19
45.5	1,890,413		0.0000	1.0000	84.03
46.5	1,682,694	1,656	0.0010	0.9990	84.03
47.5	1,198,598	21,486	0.0179	0.9821	83.95
48.5	462,249	18,789	0.0406	0.9594	82.44
49.5	265,793	23,522	0.0885	0.9115	79.09
50.5					72.09

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT D04 - DYKES AND LINERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D04 - DYKES AND LINERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2014 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,257,663		0.0000	1.0000	100.00
0.5	3,257,663	75,464	0.0232	0.9768	100.00
1.5	3,132,304		0.0000	1.0000	97.68
2.5	3,132,304		0.0000	1.0000	97.68
3.5	3,132,304		0.0000	1.0000	97.68
4.5	2,653,521		0.0000	1.0000	97.68
5.5	2,653,521	19,425	0.0073	0.9927	97.68
6.5	2,634,096		0.0000	1.0000	96.97
7.5	2,634,096		0.0000	1.0000	96.97
8.5	2,634,096		0.0000	1.0000	96.97
9.5	2,634,096		0.0000	1.0000	96.97
10.5	2,617,582		0.0000	1.0000	96.97
11.5	2,617,582		0.0000	1.0000	96.97
12.5	2,617,582		0.0000	1.0000	96.97
13.5	2,541,694	98,455	0.0387	0.9613	96.97
14.5	2,443,238		0.0000	1.0000	93.21
15.5	2,443,238	9,704	0.0040	0.9960	93.21
16.5	2,299,051	81,055	0.0353	0.9647	92.84
17.5	2,178,399		0.0000	1.0000	89.57
18.5	2,178,399		0.0000	1.0000	89.57
19.5	2,178,399		0.0000	1.0000	89.57
20.5	2,178,399	168,684	0.0774	0.9226	89.57
21.5	2,009,715	25,156	0.0125	0.9875	82.63
22.5	1,984,559		0.0000	1.0000	81.60
23.5	1,767,499		0.0000	1.0000	81.60
24.5	1,767,499		0.0000	1.0000	81.60
25.5	1,503,267	128,562	0.0855	0.9145	81.60
26.5	1,374,705	147,344	0.1072	0.8928	74.62
27.5	1,227,361		0.0000	1.0000	66.62
28.5	1,045,371		0.0000	1.0000	66.62
29.5	1,045,371		0.0000	1.0000	66.62
30.5	833,860		0.0000	1.0000	66.62
31.5	833,860		0.0000	1.0000	66.62
32.5	765,383		0.0000	1.0000	66.62
33.5	675,487		0.0000	1.0000	66.62
34.5	462,303		0.0000	1.0000	66.62
35.5	408,403		0.0000	1.0000	66.62
36.5	408,403		0.0000	1.0000	66.62
37.5	408,403		0.0000	1.0000	66.62
38.5	408,403		0.0000	1.0000	66.62

NEWFOUNDLAND AND LABRADOR HYDRO

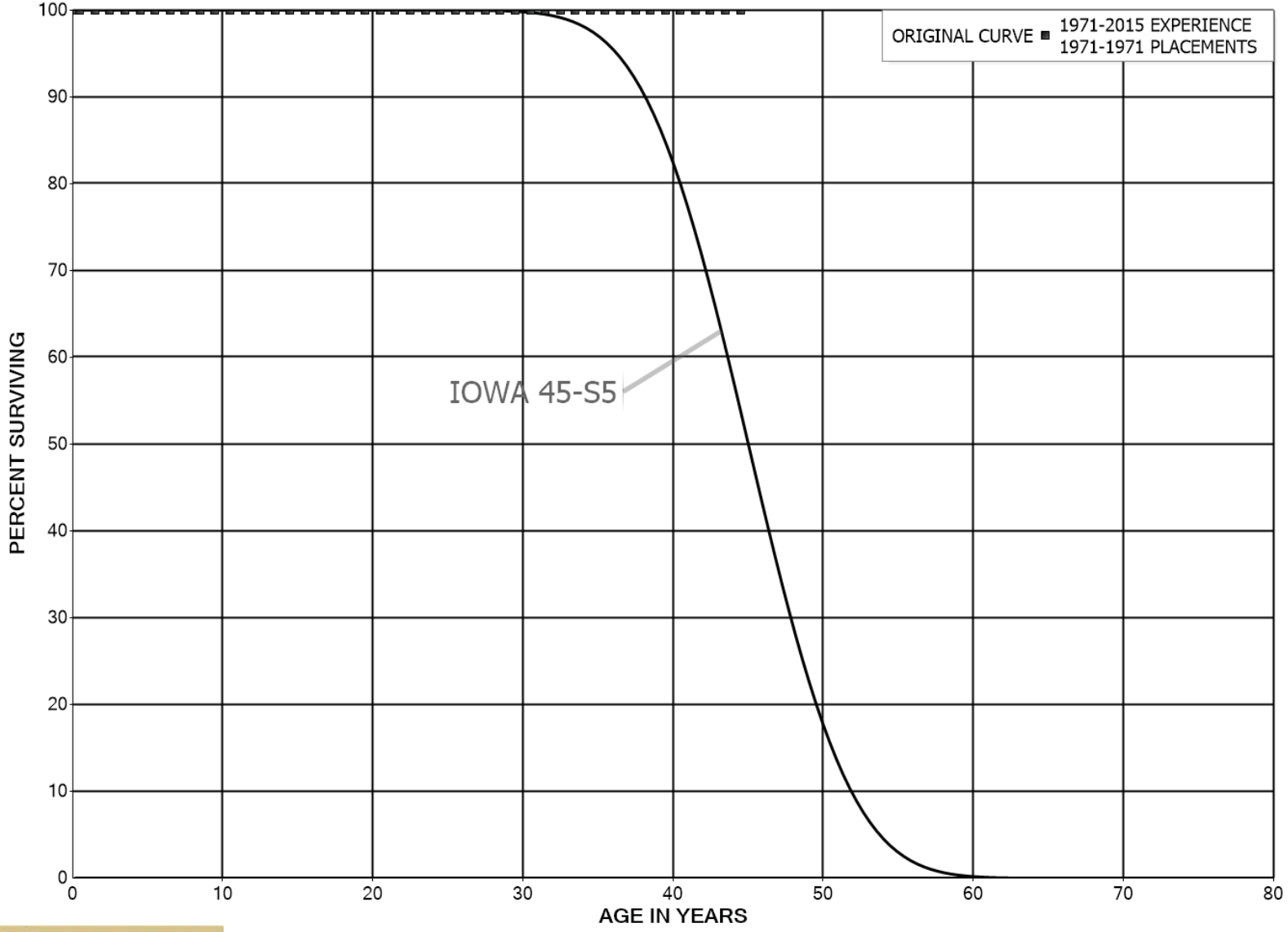
ACCOUNT D04 - DYKES AND LINERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2014 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	408,403		0.0000	1.0000	66.62
40.5	195,060		0.0000	1.0000	66.62
41.5	52,960		0.0000	1.0000	66.62
42.5	52,960	26,480	0.5000	0.5000	66.62
43.5	26,480		0.0000	1.0000	33.31
44.5	26,480		0.0000	1.0000	33.31
45.5	26,480		0.0000	1.0000	33.31
46.5	26,480		0.0000	1.0000	33.31
47.5					33.31

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT E01 - ELEVATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT E01 - ELEVATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-1971 EXPERIENCE BAND 1971-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	89,800		0.0000	1.0000	100.00
0.5	89,800		0.0000	1.0000	100.00
1.5	89,800		0.0000	1.0000	100.00
2.5	89,800		0.0000	1.0000	100.00
3.5	89,800		0.0000	1.0000	100.00
4.5	89,800		0.0000	1.0000	100.00
5.5	89,800		0.0000	1.0000	100.00
6.5	89,800		0.0000	1.0000	100.00
7.5	89,800		0.0000	1.0000	100.00
8.5	89,800		0.0000	1.0000	100.00
9.5	89,800		0.0000	1.0000	100.00
10.5	89,800		0.0000	1.0000	100.00
11.5	89,800		0.0000	1.0000	100.00
12.5	89,800		0.0000	1.0000	100.00
13.5	89,800		0.0000	1.0000	100.00
14.5	89,800		0.0000	1.0000	100.00
15.5	89,800		0.0000	1.0000	100.00
16.5	89,800		0.0000	1.0000	100.00
17.5	89,800		0.0000	1.0000	100.00
18.5	89,800		0.0000	1.0000	100.00
19.5	89,800		0.0000	1.0000	100.00
20.5	89,800		0.0000	1.0000	100.00
21.5	89,800		0.0000	1.0000	100.00
22.5	89,800		0.0000	1.0000	100.00
23.5	89,800		0.0000	1.0000	100.00
24.5	89,800		0.0000	1.0000	100.00
25.5	89,800		0.0000	1.0000	100.00
26.5	89,800		0.0000	1.0000	100.00
27.5	89,800		0.0000	1.0000	100.00
28.5	89,800		0.0000	1.0000	100.00
29.5	89,800		0.0000	1.0000	100.00
30.5	89,800		0.0000	1.0000	100.00
31.5	89,800		0.0000	1.0000	100.00
32.5	89,800		0.0000	1.0000	100.00
33.5	89,800		0.0000	1.0000	100.00
34.5	89,800		0.0000	1.0000	100.00
35.5	89,800		0.0000	1.0000	100.00
36.5	89,800		0.0000	1.0000	100.00
37.5	89,800		0.0000	1.0000	100.00
38.5	89,800		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

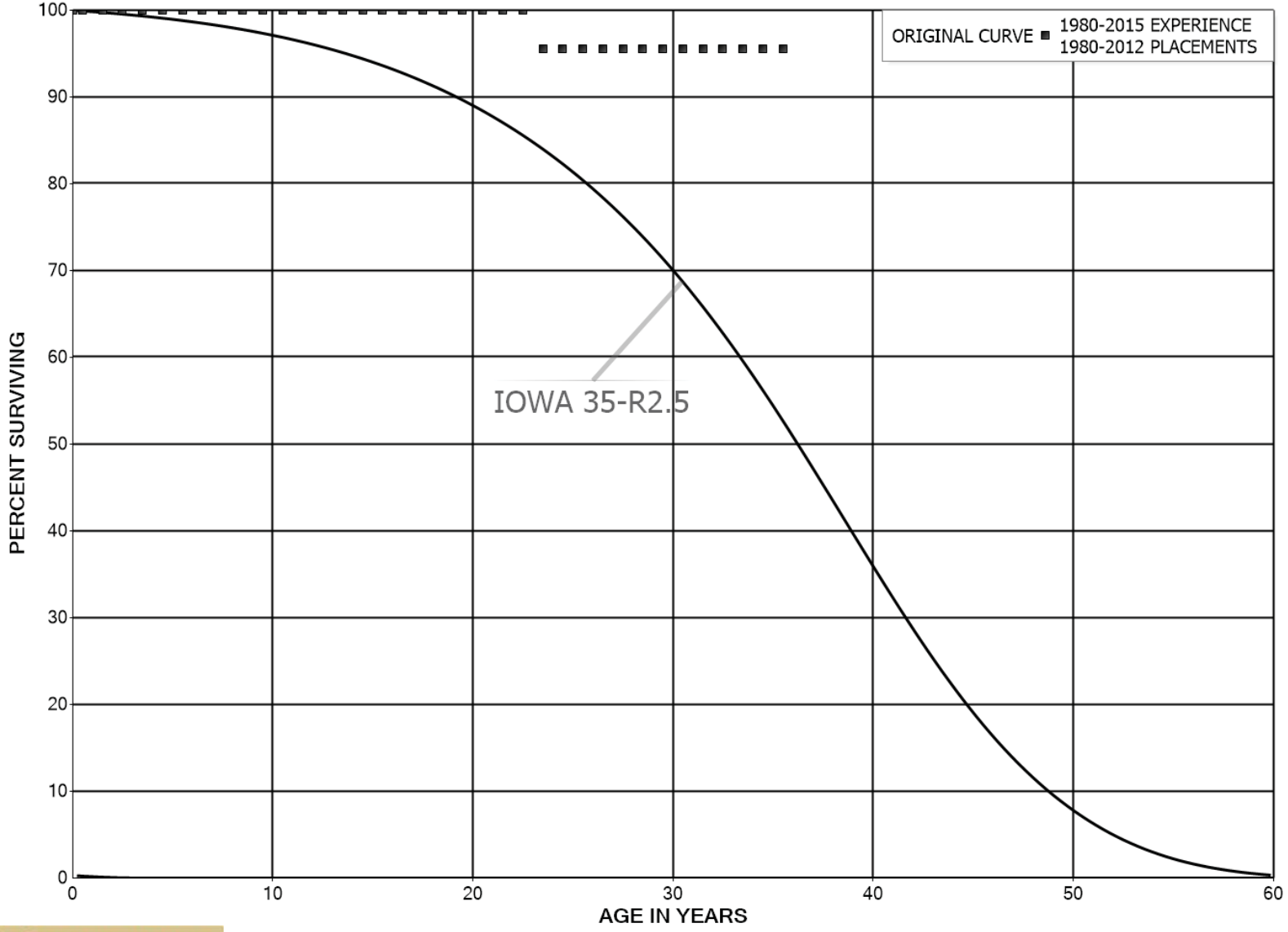
ACCOUNT E01 - ELEVATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1971-1971 EXPERIENCE BAND 1971-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	89,800		0.0000	1.0000	100.00
40.5	89,800		0.0000	1.0000	100.00
41.5	89,800		0.0000	1.0000	100.00
42.5	89,800		0.0000	1.0000	100.00
43.5	89,800		0.0000	1.0000	100.00
44.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT E02 - EMS EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

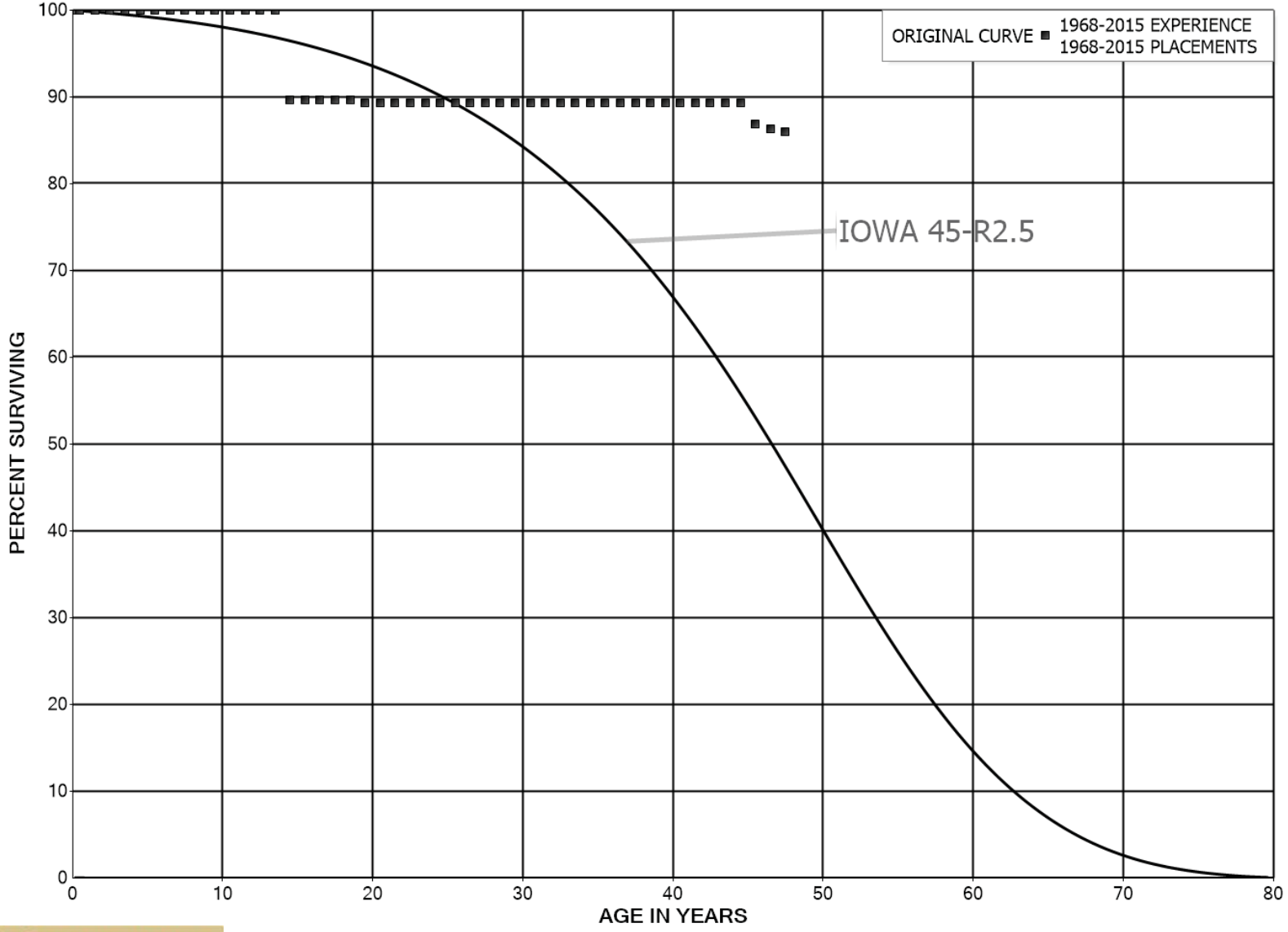
ACCOUNT E02 - EMS EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2012 EXPERIENCE BAND 1980-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,468,716		0.0000	1.0000	100.00
0.5	13,468,716		0.0000	1.0000	100.00
1.5	13,468,716		0.0000	1.0000	100.00
2.5	13,468,716		0.0000	1.0000	100.00
3.5	13,458,915		0.0000	1.0000	100.00
4.5	13,446,886		0.0000	1.0000	100.00
5.5	13,446,886		0.0000	1.0000	100.00
6.5	13,424,526		0.0000	1.0000	100.00
7.5	13,424,526		0.0000	1.0000	100.00
8.5	13,424,526		0.0000	1.0000	100.00
9.5	13,424,526	1,069	0.0001	0.9999	100.00
10.5	13,187,338		0.0000	1.0000	99.99
11.5	13,179,305		0.0000	1.0000	99.99
12.5	13,179,305		0.0000	1.0000	99.99
13.5	13,179,305		0.0000	1.0000	99.99
14.5	12,879,444		0.0000	1.0000	99.99
15.5	12,762,329		0.0000	1.0000	99.99
16.5	12,716,366		0.0000	1.0000	99.99
17.5	12,617,281		0.0000	1.0000	99.99
18.5	12,617,281		0.0000	1.0000	99.99
19.5	12,617,281		0.0000	1.0000	99.99
20.5	12,617,281		0.0000	1.0000	99.99
21.5	12,387,941		0.0000	1.0000	99.99
22.5	12,339,009	550,428	0.0446	0.9554	99.99
23.5	11,775,720		0.0000	1.0000	95.53
24.5	11,775,720		0.0000	1.0000	95.53
25.5	16,461		0.0000	1.0000	95.53
26.5	16,461		0.0000	1.0000	95.53
27.5	16,461		0.0000	1.0000	95.53
28.5	16,461		0.0000	1.0000	95.53
29.5	16,461		0.0000	1.0000	95.53
30.5	16,461		0.0000	1.0000	95.53
31.5	16,461		0.0000	1.0000	95.53
32.5	16,461		0.0000	1.0000	95.53
33.5	16,461		0.0000	1.0000	95.53
34.5	16,461		0.0000	1.0000	95.53
35.5					95.53

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT E03 - ENVIRONMENTAL EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT E03 - ENVIRONMENTAL EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,373,439		0.0000	1.0000	100.00
0.5	2,353,273		0.0000	1.0000	100.00
1.5	2,305,102		0.0000	1.0000	100.00
2.5	2,305,102		0.0000	1.0000	100.00
3.5	2,305,102		0.0000	1.0000	100.00
4.5	2,305,102		0.0000	1.0000	100.00
5.5	2,305,102		0.0000	1.0000	100.00
6.5	2,305,102		0.0000	1.0000	100.00
7.5	2,083,160		0.0000	1.0000	100.00
8.5	2,083,160		0.0000	1.0000	100.00
9.5	2,083,160		0.0000	1.0000	100.00
10.5	2,083,160		0.0000	1.0000	100.00
11.5	2,083,160		0.0000	1.0000	100.00
12.5	1,267,384		0.0000	1.0000	100.00
13.5	1,267,384	131,792	0.1040	0.8960	100.00
14.5	1,132,912		0.0000	1.0000	89.60
15.5	869,328		0.0000	1.0000	89.60
16.5	869,328		0.0000	1.0000	89.60
17.5	869,328		0.0000	1.0000	89.60
18.5	740,085	3,002	0.0041	0.9959	89.60
19.5	737,083		0.0000	1.0000	89.24
20.5	707,136		0.0000	1.0000	89.24
21.5	607,037		0.0000	1.0000	89.24
22.5	607,037		0.0000	1.0000	89.24
23.5	607,037		0.0000	1.0000	89.24
24.5	607,037		0.0000	1.0000	89.24
25.5	607,037		0.0000	1.0000	89.24
26.5	607,037		0.0000	1.0000	89.24
27.5	607,037		0.0000	1.0000	89.24
28.5	607,037		0.0000	1.0000	89.24
29.5	607,037		0.0000	1.0000	89.24
30.5	607,037		0.0000	1.0000	89.24
31.5	607,037		0.0000	1.0000	89.24
32.5	607,037		0.0000	1.0000	89.24
33.5	607,037		0.0000	1.0000	89.24
34.5	607,037		0.0000	1.0000	89.24
35.5	607,037		0.0000	1.0000	89.24
36.5	607,037		0.0000	1.0000	89.24
37.5	607,037		0.0000	1.0000	89.24
38.5	607,037		0.0000	1.0000	89.24

NEWFOUNDLAND AND LABRADOR HYDRO

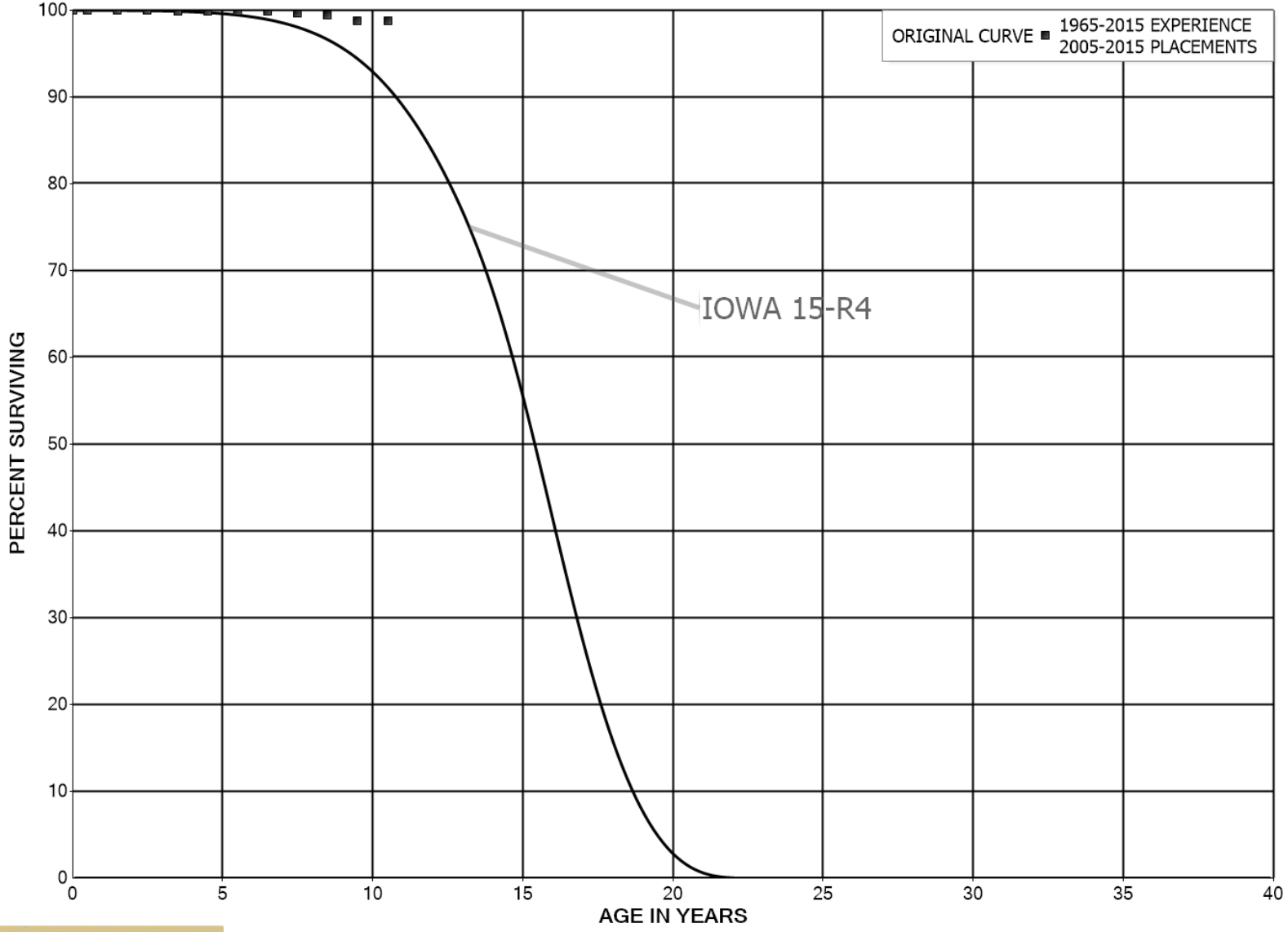
ACCOUNT E03 - ENVIRONMENTAL EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	607,037		0.0000	1.0000	89.24
40.5	607,037		0.0000	1.0000	89.24
41.5	607,037		0.0000	1.0000	89.24
42.5	607,037		0.0000	1.0000	89.24
43.5	607,037		0.0000	1.0000	89.24
44.5	607,037	16,308	0.0269	0.9731	89.24
45.5	590,730	4,000	0.0068	0.9932	86.84
46.5	586,730	2,200	0.0037	0.9963	86.25
47.5					85.93

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT F01 - FALL ARREST EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

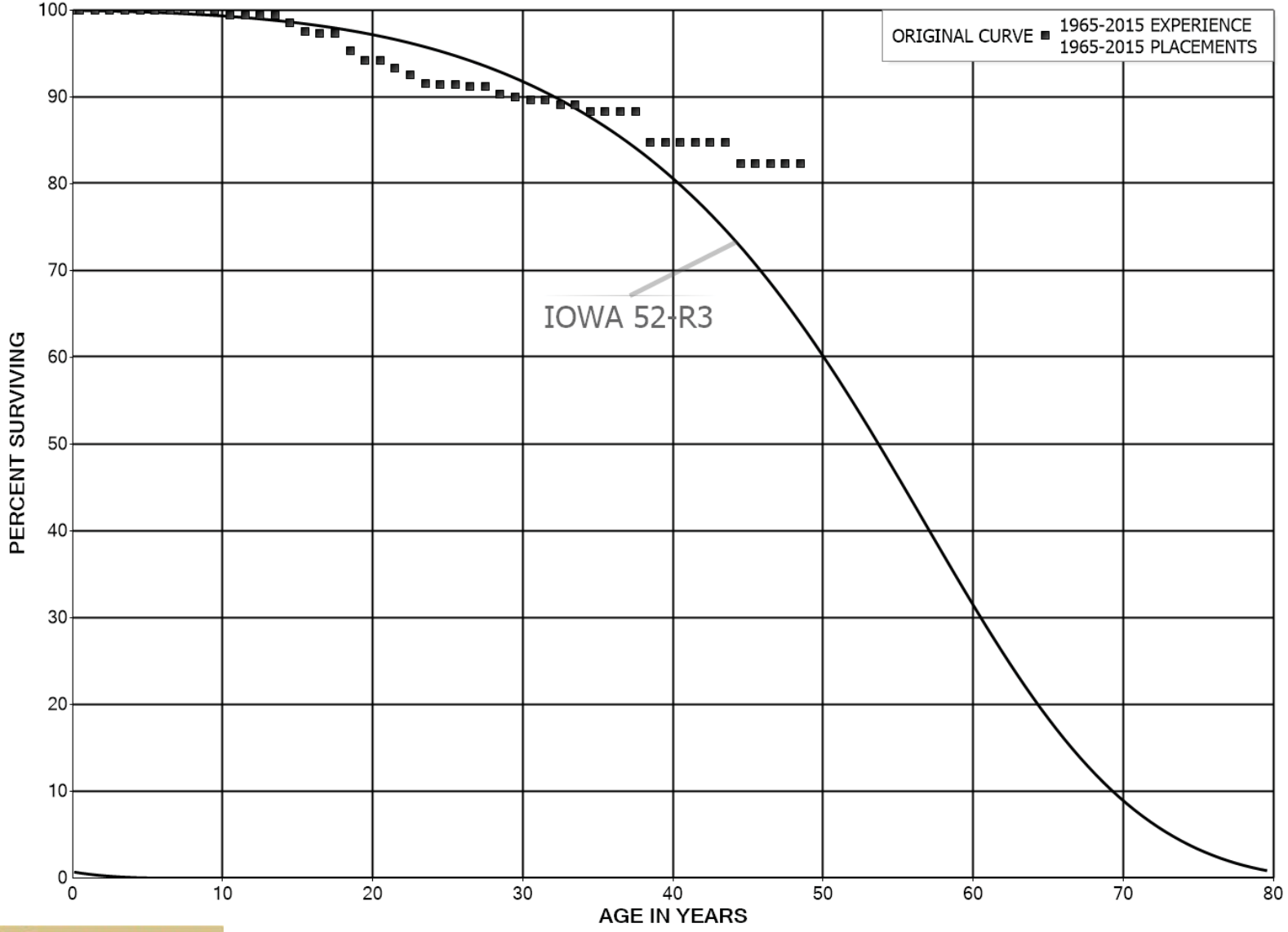
ACCOUNT F01 - FALL ARREST EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 2005-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,517,730		0.0000	1.0000	100.00
0.5	2,337,058		0.0000	1.0000	100.00
1.5	2,000,093		0.0000	1.0000	100.00
2.5	1,753,322	2,237	0.0013	0.9987	100.00
3.5	1,566,843		0.0000	1.0000	99.87
4.5	1,361,713		0.0000	1.0000	99.87
5.5	1,318,612		0.0000	1.0000	99.87
6.5	817,528	1,824	0.0022	0.9978	99.87
7.5	616,425	1,824	0.0030	0.9970	99.65
8.5	418,787	2,824	0.0067	0.9933	99.35
9.5	198,105		0.0000	1.0000	98.68
10.5					98.68

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT F02 - FENCING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F02 - FENCING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,961,463		0.0000	1.0000	100.00
0.5	7,022,742		0.0000	1.0000	100.00
1.5	6,652,096		0.0000	1.0000	100.00
2.5	6,541,634		0.0000	1.0000	100.00
3.5	6,244,965		0.0000	1.0000	100.00
4.5	5,431,072	1,912	0.0004	0.9996	100.00
5.5	5,429,160	2,071	0.0004	0.9996	99.96
6.5	5,171,316		0.0000	1.0000	99.93
7.5	5,112,854		0.0000	1.0000	99.93
8.5	5,112,854		0.0000	1.0000	99.93
9.5	5,107,400	26,114	0.0051	0.9949	99.93
10.5	4,965,283		0.0000	1.0000	99.42
11.5	4,932,835		0.0000	1.0000	99.42
12.5	3,916,965		0.0000	1.0000	99.42
13.5	3,866,679	36,546	0.0095	0.9905	99.42
14.5	3,666,545	37,467	0.0102	0.9898	98.48
15.5	3,576,253	8,160	0.0023	0.9977	97.47
16.5	3,524,231		0.0000	1.0000	97.25
17.5	3,391,217	70,232	0.0207	0.9793	97.25
18.5	3,263,809	37,468	0.0115	0.9885	95.23
19.5	3,181,332		0.0000	1.0000	94.14
20.5	3,098,467	29,848	0.0096	0.9904	94.14
21.5	2,984,763	23,138	0.0078	0.9922	93.23
22.5	2,917,682	31,996	0.0110	0.9890	92.51
23.5	2,762,852	1,507	0.0005	0.9995	91.50
24.5	2,623,746	995	0.0004	0.9996	91.45
25.5	2,510,515	7,120	0.0028	0.9972	91.41
26.5	2,320,720	311	0.0001	0.9999	91.15
27.5	2,244,565	21,240	0.0095	0.9905	91.14
28.5	2,009,953	7,243	0.0036	0.9964	90.28
29.5	1,976,843	6,454	0.0033	0.9967	89.95
30.5	1,725,332		0.0000	1.0000	89.66
31.5	1,640,234	10,169	0.0062	0.9938	89.66
32.5	1,347,668		0.0000	1.0000	89.10
33.5	1,158,044	10,359	0.0089	0.9911	89.10
34.5	1,062,416		0.0000	1.0000	88.31
35.5	782,663		0.0000	1.0000	88.31
36.5	764,382		0.0000	1.0000	88.31
37.5	618,632	25,113	0.0406	0.9594	88.31
38.5	574,277		0.0000	1.0000	84.72

NEWFOUNDLAND AND LABRADOR HYDRO

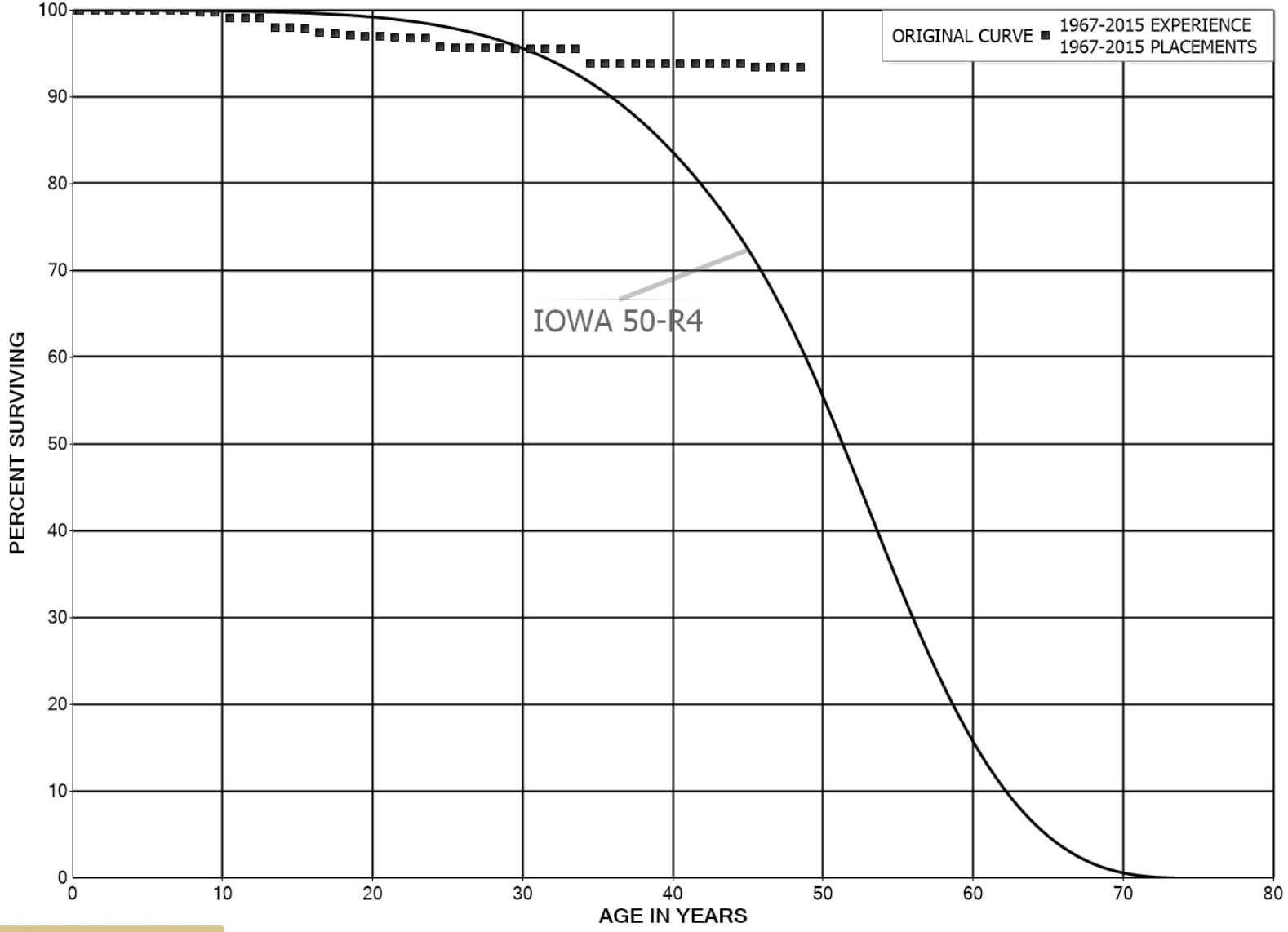
ACCOUNT F02 - FENCING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	514,981		0.0000	1.0000	84.72
40.5	503,692		0.0000	1.0000	84.72
41.5	451,743		0.0000	1.0000	84.72
42.5	427,075		0.0000	1.0000	84.72
43.5	361,336	10,413	0.0288	0.9712	84.72
44.5	337,611		0.0000	1.0000	82.28
45.5	220,329		0.0000	1.0000	82.28
46.5	154,156		0.0000	1.0000	82.28
47.5	95,308		0.0000	1.0000	82.28
48.5					82.28

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT F03 - FIRE FIGHTING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F03 - FIRE FIGHTING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	15,017,245		0.0000	1.0000	100.00
0.5	11,895,429		0.0000	1.0000	100.00
1.5	10,944,270		0.0000	1.0000	100.00
2.5	10,386,193		0.0000	1.0000	100.00
3.5	9,799,981		0.0000	1.0000	100.00
4.5	9,589,416		0.0000	1.0000	100.00
5.5	9,585,000	7,480	0.0008	0.9992	100.00
6.5	7,447,725		0.0000	1.0000	99.92
7.5	7,209,032	12,437	0.0017	0.9983	99.92
8.5	7,196,595		0.0000	1.0000	99.75
9.5	7,196,595	45,673	0.0063	0.9937	99.75
10.5	7,095,680		0.0000	1.0000	99.12
11.5	7,095,680		0.0000	1.0000	99.12
12.5	6,437,931	72,271	0.0112	0.9888	99.12
13.5	5,736,420	2,972	0.0005	0.9995	98.00
14.5	5,517,383	8,917	0.0016	0.9984	97.95
15.5	5,508,466	23,592	0.0043	0.9957	97.79
16.5	5,390,836	2,414	0.0004	0.9996	97.38
17.5	5,319,903	16,189	0.0030	0.9970	97.33
18.5	5,123,461	6,509	0.0013	0.9987	97.04
19.5	5,116,952	203	0.0000	1.0000	96.91
20.5	5,092,231	4,691	0.0009	0.9991	96.91
21.5	5,087,540	3,269	0.0006	0.9994	96.82
22.5	5,084,271	92	0.0000	1.0000	96.76
23.5	4,935,098	54,919	0.0111	0.9889	96.76
24.5	4,880,179	2,170	0.0004	0.9996	95.68
25.5	4,813,682	406	0.0001	0.9999	95.64
26.5	4,050,609		0.0000	1.0000	95.63
27.5	3,833,130		0.0000	1.0000	95.63
28.5	3,736,336	4,710	0.0013	0.9987	95.63
29.5	3,578,679		0.0000	1.0000	95.51
30.5	3,392,687		0.0000	1.0000	95.51
31.5	2,808,935		0.0000	1.0000	95.51
32.5	2,714,260		0.0000	1.0000	95.51
33.5	2,307,362	40,186	0.0174	0.9826	95.51
34.5	2,257,774		0.0000	1.0000	93.84
35.5	1,536,580		0.0000	1.0000	93.84
36.5	1,421,399		0.0000	1.0000	93.84
37.5	1,229,262		0.0000	1.0000	93.84
38.5	1,200,404		0.0000	1.0000	93.84

NEWFOUNDLAND AND LABRADOR HYDRO

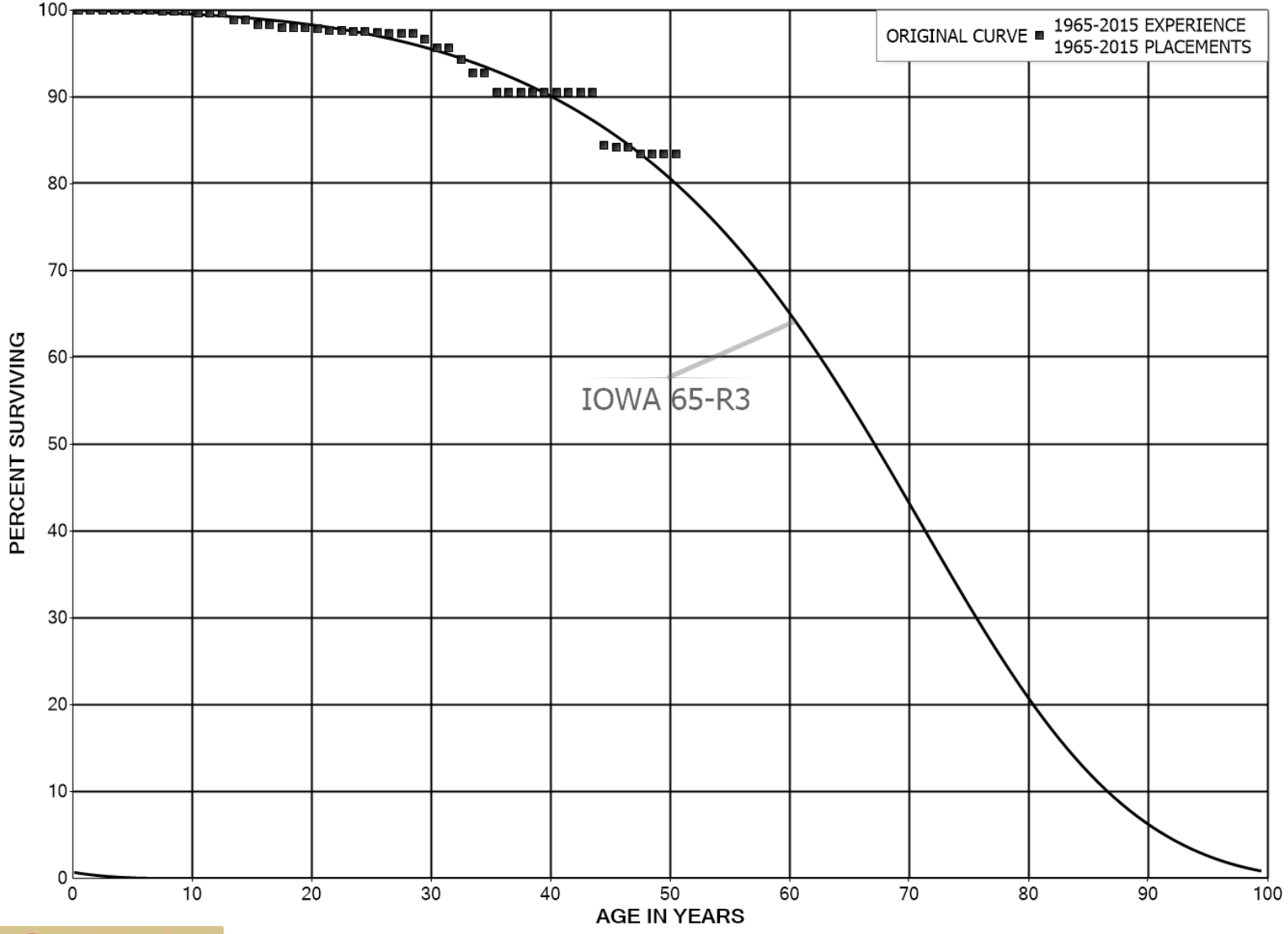
ACCOUNT F03 - FIRE FIGHTING EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,142,056		0.0000	1.0000	93.84
40.5	1,132,055		0.0000	1.0000	93.84
41.5	1,132,055		0.0000	1.0000	93.84
42.5	1,110,366		0.0000	1.0000	93.84
43.5	1,110,366		0.0000	1.0000	93.84
44.5	828,411	4,076	0.0049	0.9951	93.84
45.5	815,131		0.0000	1.0000	93.38
46.5	713,899		0.0000	1.0000	93.38
47.5	597,273		0.0000	1.0000	93.38
48.5					93.38

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT F04 - FOOTINGS AND FOUNDATIONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F04 - FOOTINGS AND FOUNDATIONS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	21,754,410		0.0000	1.0000	100.00
0.5	18,902,176		0.0000	1.0000	100.00
1.5	18,221,916		0.0000	1.0000	100.00
2.5	18,221,916		0.0000	1.0000	100.00
3.5	18,199,235		0.0000	1.0000	100.00
4.5	18,158,647		0.0000	1.0000	100.00
5.5	18,158,647		0.0000	1.0000	100.00
6.5	18,158,647	26,848	0.0015	0.9985	100.00
7.5	18,102,476		0.0000	1.0000	99.85
8.5	18,102,476	291	0.0000	1.0000	99.85
9.5	18,102,185	36,626	0.0020	0.9980	99.85
10.5	18,065,559		0.0000	1.0000	99.65
11.5	18,055,845	100	0.0000	1.0000	99.65
12.5	17,010,811	140,699	0.0083	0.9917	99.65
13.5	14,244,637		0.0000	1.0000	98.82
14.5	14,210,780	81,410	0.0057	0.9943	98.82
15.5	14,098,878		0.0000	1.0000	98.26
16.5	14,033,306	47,046	0.0034	0.9966	98.26
17.5	13,872,129		0.0000	1.0000	97.93
18.5	13,872,129	1,380	0.0001	0.9999	97.93
19.5	13,721,794	11,757	0.0009	0.9991	97.92
20.5	13,242,979	24,525	0.0019	0.9981	97.83
21.5	13,213,028	10,261	0.0008	0.9992	97.65
22.5	13,118,028	4,866	0.0004	0.9996	97.58
23.5	12,486,548	11,384	0.0009	0.9991	97.54
24.5	11,462,453	12,531	0.0011	0.9989	97.45
25.5	10,137,769	4,864	0.0005	0.9995	97.35
26.5	9,792,032	6,265	0.0006	0.9994	97.30
27.5	9,669,954		0.0000	1.0000	97.24
28.5	9,306,278	62,933	0.0068	0.9932	97.24
29.5	9,195,697	87,255	0.0095	0.9905	96.58
30.5	9,082,596	9,145	0.0010	0.9990	95.66
31.5	9,065,633	117,521	0.0130	0.9870	95.57
32.5	8,181,919	137,940	0.0169	0.9831	94.33
33.5	7,572,102		0.0000	1.0000	92.74
34.5	7,272,645	172,290	0.0237	0.9763	92.74
35.5	6,560,246	331	0.0001	0.9999	90.54
36.5	6,225,772	241	0.0000	1.0000	90.54
37.5	5,118,947		0.0000	1.0000	90.53
38.5	3,852,682		0.0000	1.0000	90.53

NEWFOUNDLAND AND LABRADOR HYDRO

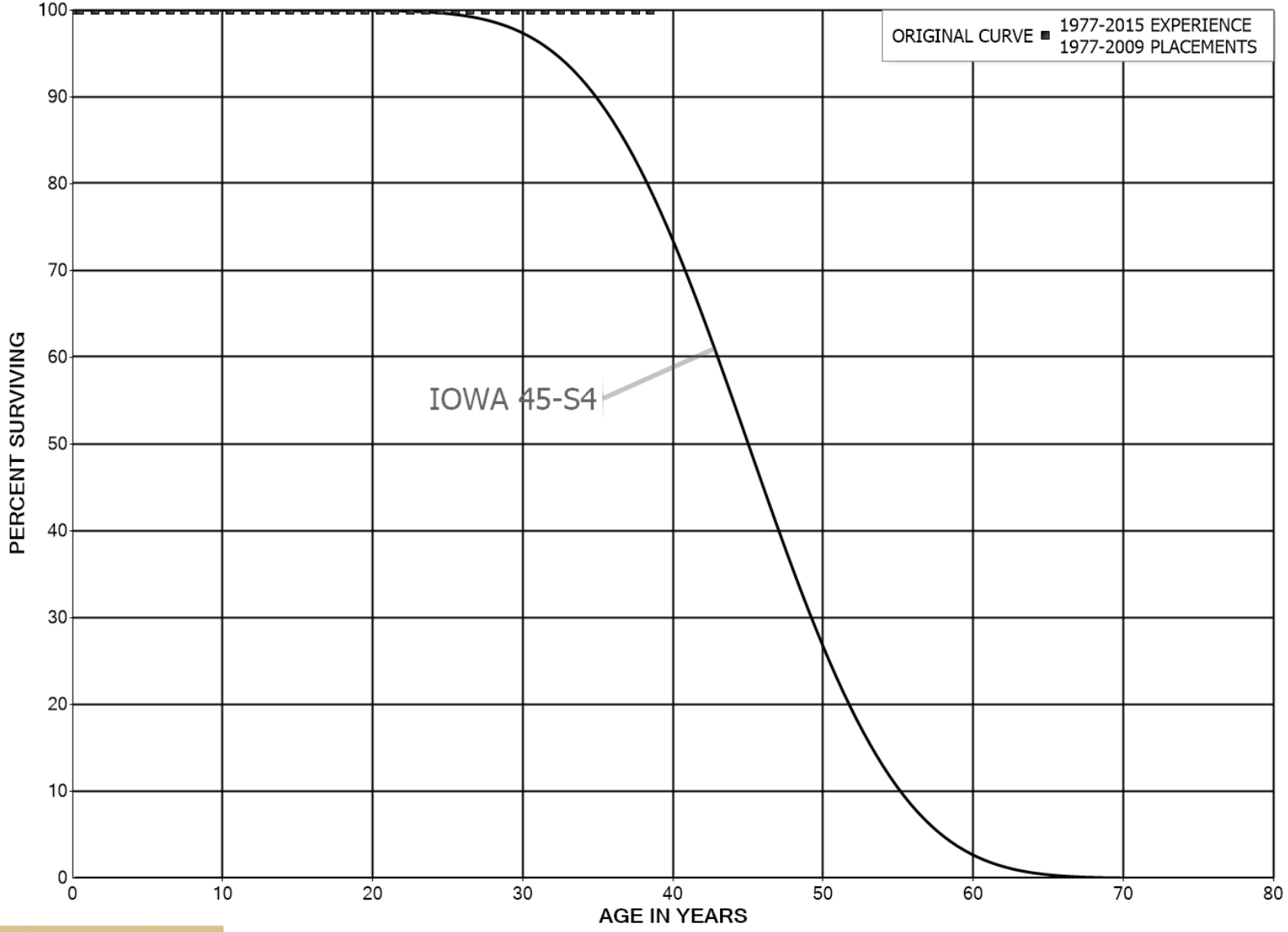
ACCOUNT F04 - FOOTINGS AND FOUNDATIONS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,739,616		0.0000	1.0000	90.53
40.5	3,631,175		0.0000	1.0000	90.53
41.5	3,562,891		0.0000	1.0000	90.53
42.5	3,548,308		0.0000	1.0000	90.53
43.5	3,548,308	240,679	0.0678	0.9322	90.53
44.5	3,307,629	9,345	0.0028	0.9972	84.39
45.5	2,808,082		0.0000	1.0000	84.15
46.5	2,808,082	26,026	0.0093	0.9907	84.15
47.5	1,890,964		0.0000	1.0000	83.37
48.5	167,301		0.0000	1.0000	83.37
49.5	167,301		0.0000	1.0000	83.37
50.5					83.37

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT F05 - FREQUENCY CONVERSION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

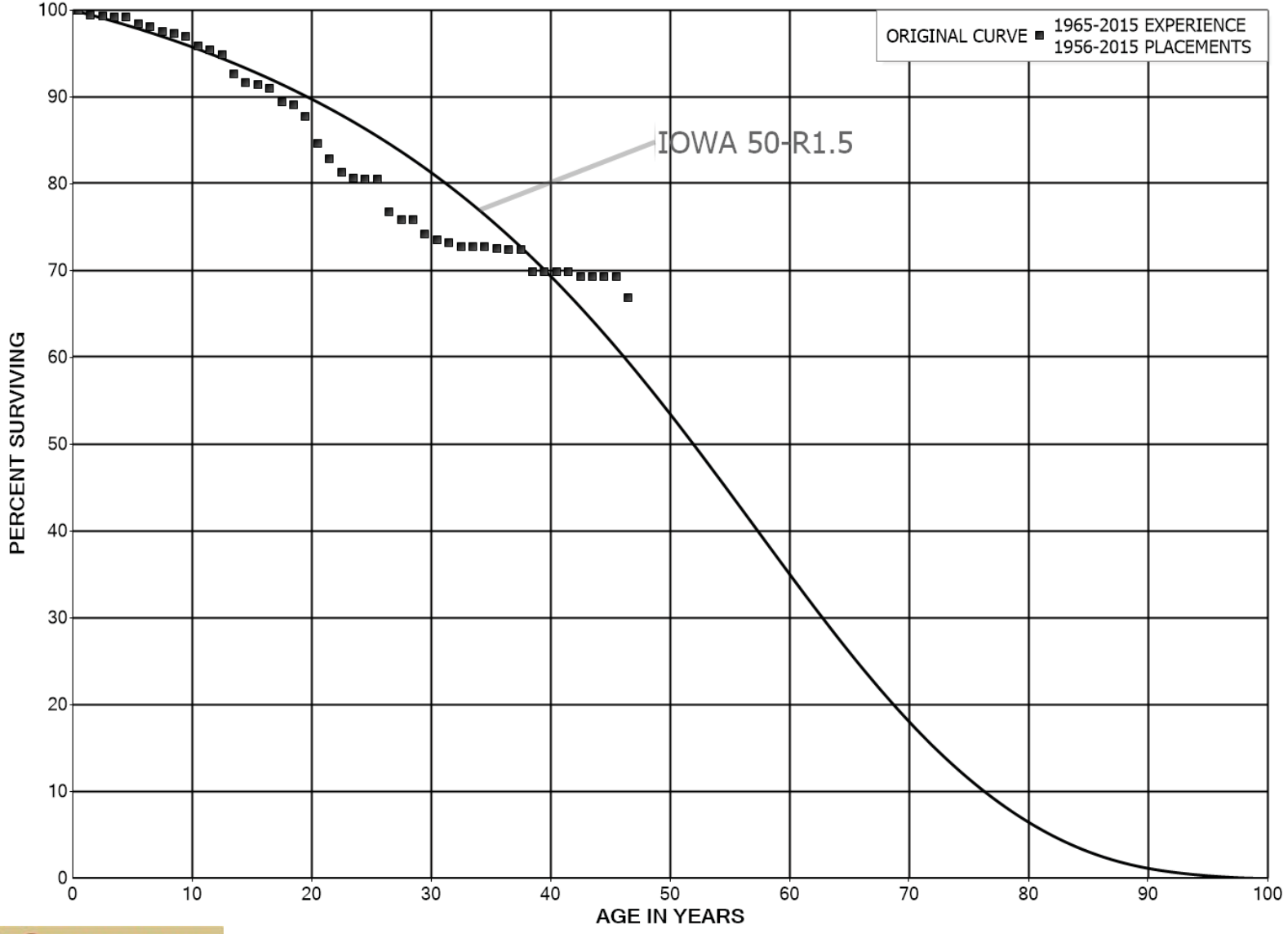
ACCOUNT F05 - FREQUENCY CONVERSION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1977-2009 EXPERIENCE BAND 1977-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,453,577		0.0000	1.0000	100.00
0.5	2,453,577		0.0000	1.0000	100.00
1.5	2,453,577		0.0000	1.0000	100.00
2.5	2,453,577		0.0000	1.0000	100.00
3.5	2,453,577		0.0000	1.0000	100.00
4.5	2,453,577		0.0000	1.0000	100.00
5.5	2,453,577		0.0000	1.0000	100.00
6.5	1,694,970		0.0000	1.0000	100.00
7.5	1,694,970		0.0000	1.0000	100.00
8.5	1,666,961		0.0000	1.0000	100.00
9.5	1,666,961		0.0000	1.0000	100.00
10.5	1,619,259		0.0000	1.0000	100.00
11.5	1,619,259		0.0000	1.0000	100.00
12.5	1,619,259		0.0000	1.0000	100.00
13.5	1,619,259		0.0000	1.0000	100.00
14.5	1,619,259		0.0000	1.0000	100.00
15.5	1,619,259		0.0000	1.0000	100.00
16.5	1,619,259		0.0000	1.0000	100.00
17.5	1,619,259		0.0000	1.0000	100.00
18.5	1,619,259		0.0000	1.0000	100.00
19.5	1,619,259		0.0000	1.0000	100.00
20.5	1,619,259		0.0000	1.0000	100.00
21.5	1,619,259		0.0000	1.0000	100.00
22.5	1,619,259		0.0000	1.0000	100.00
23.5	1,619,259		0.0000	1.0000	100.00
24.5	1,619,259		0.0000	1.0000	100.00
25.5	1,619,259		0.0000	1.0000	100.00
26.5	1,619,259		0.0000	1.0000	100.00
27.5	1,619,259		0.0000	1.0000	100.00
28.5	1,619,259		0.0000	1.0000	100.00
29.5	1,619,259		0.0000	1.0000	100.00
30.5	1,619,259		0.0000	1.0000	100.00
31.5	1,619,259		0.0000	1.0000	100.00
32.5	1,619,259		0.0000	1.0000	100.00
33.5	1,607,215		0.0000	1.0000	100.00
34.5	1,607,215		0.0000	1.0000	100.00
35.5	1,607,215		0.0000	1.0000	100.00
36.5	1,607,215		0.0000	1.0000	100.00
37.5	1,607,215		0.0000	1.0000	100.00
38.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT F06 - FUEL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F06 - FUEL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	46,436,130		0.0000	1.0000	100.00
0.5	37,579,279	244,046	0.0065	0.9935	100.00
1.5	35,743,238	25,840	0.0007	0.9993	99.35
2.5	33,302,159	30,932	0.0009	0.9991	99.28
3.5	29,303,216	16,568	0.0006	0.9994	99.19
4.5	27,562,051	197,053	0.0071	0.9929	99.13
5.5	24,463,713	82,926	0.0034	0.9966	98.42
6.5	22,071,903	119,683	0.0054	0.9946	98.09
7.5	20,827,974	50,544	0.0024	0.9976	97.56
8.5	20,030,715	86,687	0.0043	0.9957	97.32
9.5	19,398,058	208,578	0.0108	0.9892	96.90
10.5	18,409,008	83,498	0.0045	0.9955	95.86
11.5	18,325,510	113,661	0.0062	0.9938	95.42
12.5	17,941,686	424,782	0.0237	0.9763	94.83
13.5	17,080,407	187,859	0.0110	0.9890	92.58
14.5	15,448,635	22,641	0.0015	0.9985	91.57
15.5	15,181,320	78,987	0.0052	0.9948	91.43
16.5	14,692,087	251,530	0.0171	0.9829	90.96
17.5	14,356,823	47,942	0.0033	0.9967	89.40
18.5	14,219,187	217,848	0.0153	0.9847	89.10
19.5	13,597,437	484,629	0.0356	0.9644	87.74
20.5	12,851,694	267,371	0.0208	0.9792	84.61
21.5	12,213,145	223,790	0.0183	0.9817	82.85
22.5	11,650,530	109,204	0.0094	0.9906	81.33
23.5	10,843,133	4,557	0.0004	0.9996	80.57
24.5	10,391,654		0.0000	1.0000	80.53
25.5	9,618,285	456,005	0.0474	0.9526	80.53
26.5	8,879,299	96,528	0.0109	0.9891	76.72
27.5	8,768,843	2,100	0.0002	0.9998	75.88
28.5	8,306,579	180,152	0.0217	0.9783	75.86
29.5	8,101,753	83,242	0.0103	0.9897	74.22
30.5	7,813,484	27,816	0.0036	0.9964	73.46
31.5	7,785,668	48,759	0.0063	0.9937	73.19
32.5	7,719,714	1,500	0.0002	0.9998	72.74
33.5	7,613,667	3,600	0.0005	0.9995	72.72
34.5	7,114,455	15,000	0.0021	0.9979	72.69
35.5	2,624,538	3,113	0.0012	0.9988	72.53
36.5	2,621,425		0.0000	1.0000	72.45
37.5	2,493,155	89,532	0.0359	0.9641	72.45
38.5	2,387,033	100	0.0000	1.0000	69.85

NEWFOUNDLAND AND LABRADOR HYDRO

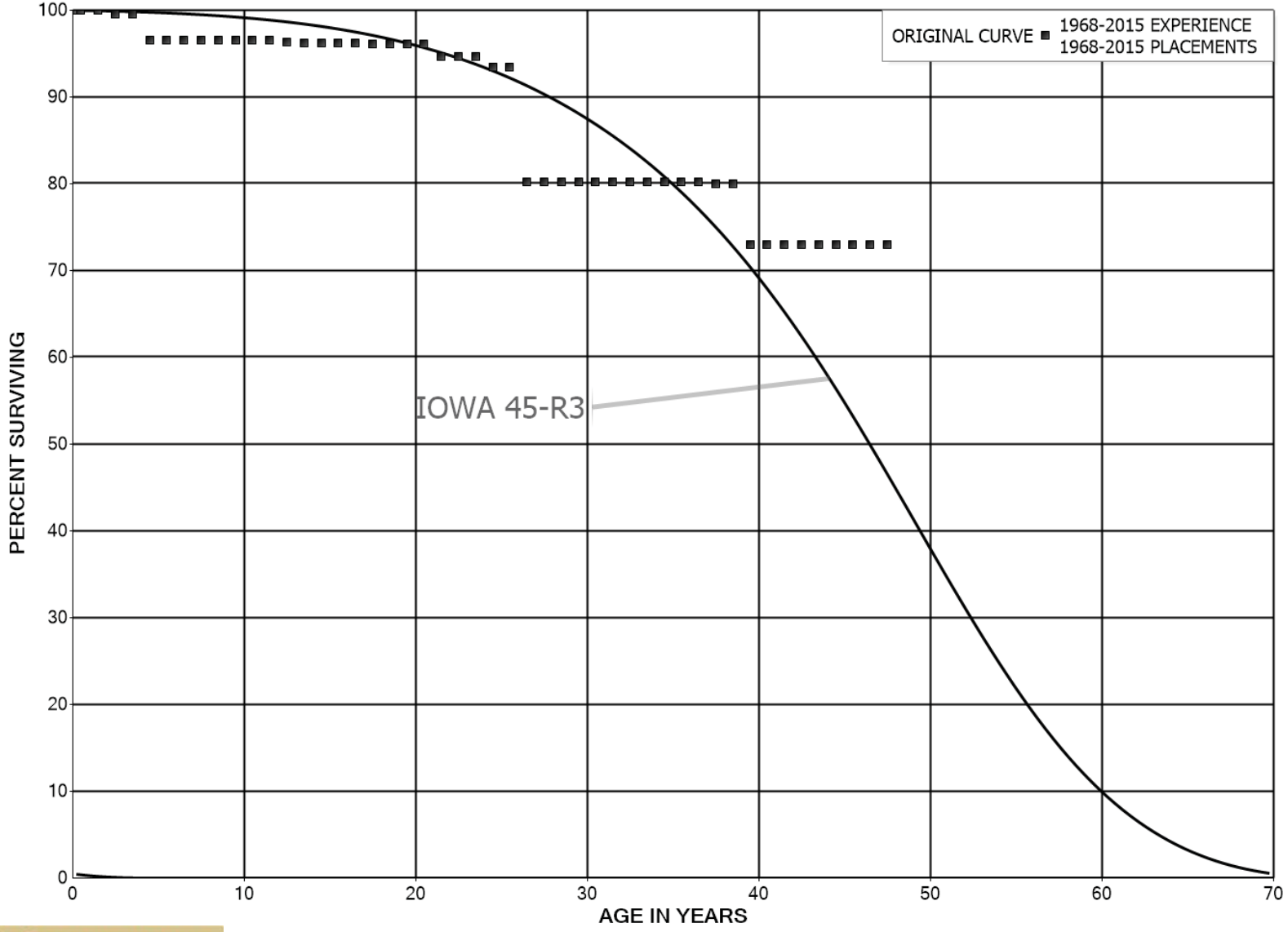
ACCOUNT F06 - FUEL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,174,446		0.0000	1.0000	69.84
40.5	2,130,030		0.0000	1.0000	69.84
41.5	1,839,417	13,277	0.0072	0.9928	69.84
42.5	1,822,895		0.0000	1.0000	69.34
43.5	1,822,895		0.0000	1.0000	69.34
44.5	1,735,607		0.0000	1.0000	69.34
45.5	1,734,807	63,382	0.0365	0.9635	69.34
46.5	913,885		0.0000	1.0000	66.81
47.5	85,268		0.0000	1.0000	66.81
48.5	85,268		0.0000	1.0000	66.81
49.5	11,786		0.0000	1.0000	66.81
50.5	11,786		0.0000	1.0000	66.81
51.5	11,786		0.0000	1.0000	66.81
52.5	11,786		0.0000	1.0000	66.81
53.5	11,786		0.0000	1.0000	66.81
54.5	11,786		0.0000	1.0000	66.81
55.5	11,786		0.0000	1.0000	66.81
56.5	11,786		0.0000	1.0000	66.81
57.5	11,786		0.0000	1.0000	66.81
58.5	11,786		0.0000	1.0000	66.81
59.5					66.81

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G01 - GAS TURBINE SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G01 - GAS TURBINE SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	74,754,391		0.0000	1.0000	100.00
0.5	43,459,283		0.0000	1.0000	100.00
1.5	41,367,811	185,109	0.0045	0.9955	100.00
2.5	33,371,915		0.0000	1.0000	99.55
3.5	32,995,571	1,011,679	0.0307	0.9693	99.55
4.5	31,761,027		0.0000	1.0000	96.50
5.5	30,492,331		0.0000	1.0000	96.50
6.5	30,362,697		0.0000	1.0000	96.50
7.5	30,362,697		0.0000	1.0000	96.50
8.5	30,331,597		0.0000	1.0000	96.50
9.5	30,331,597		0.0000	1.0000	96.50
10.5	30,331,597		0.0000	1.0000	96.50
11.5	30,331,597	57,145	0.0019	0.9981	96.50
12.5	30,274,452	48,384	0.0016	0.9984	96.32
13.5	30,226,068		0.0000	1.0000	96.16
14.5	30,164,230		0.0000	1.0000	96.16
15.5	30,164,230	2,141	0.0001	0.9999	96.16
16.5	30,153,001	18,390	0.0006	0.9994	96.16
17.5	30,134,611		0.0000	1.0000	96.10
18.5	29,586,371		0.0000	1.0000	96.10
19.5	29,586,371		0.0000	1.0000	96.10
20.5	29,586,371	459,085	0.0155	0.9845	96.10
21.5	29,127,286		0.0000	1.0000	94.61
22.5	29,127,286		0.0000	1.0000	94.61
23.5	16,056,519	203,409	0.0127	0.9873	94.61
24.5	15,853,110		0.0000	1.0000	93.41
25.5	15,853,110	2,243,280	0.1415	0.8585	93.41
26.5	13,526,225		0.0000	1.0000	80.19
27.5	13,526,225		0.0000	1.0000	80.19
28.5	13,501,580		0.0000	1.0000	80.19
29.5	13,501,580		0.0000	1.0000	80.19
30.5	13,501,580		0.0000	1.0000	80.19
31.5	13,501,580		0.0000	1.0000	80.19
32.5	13,501,580		0.0000	1.0000	80.19
33.5	13,501,580		0.0000	1.0000	80.19
34.5	13,290,970		0.0000	1.0000	80.19
35.5	13,290,970		0.0000	1.0000	80.19
36.5	13,290,970	30,595	0.0023	0.9977	80.19
37.5	13,260,375		0.0000	1.0000	80.01
38.5	12,876,356	1,144,769	0.0889	0.9111	80.01

NEWFOUNDLAND AND LABRADOR HYDRO

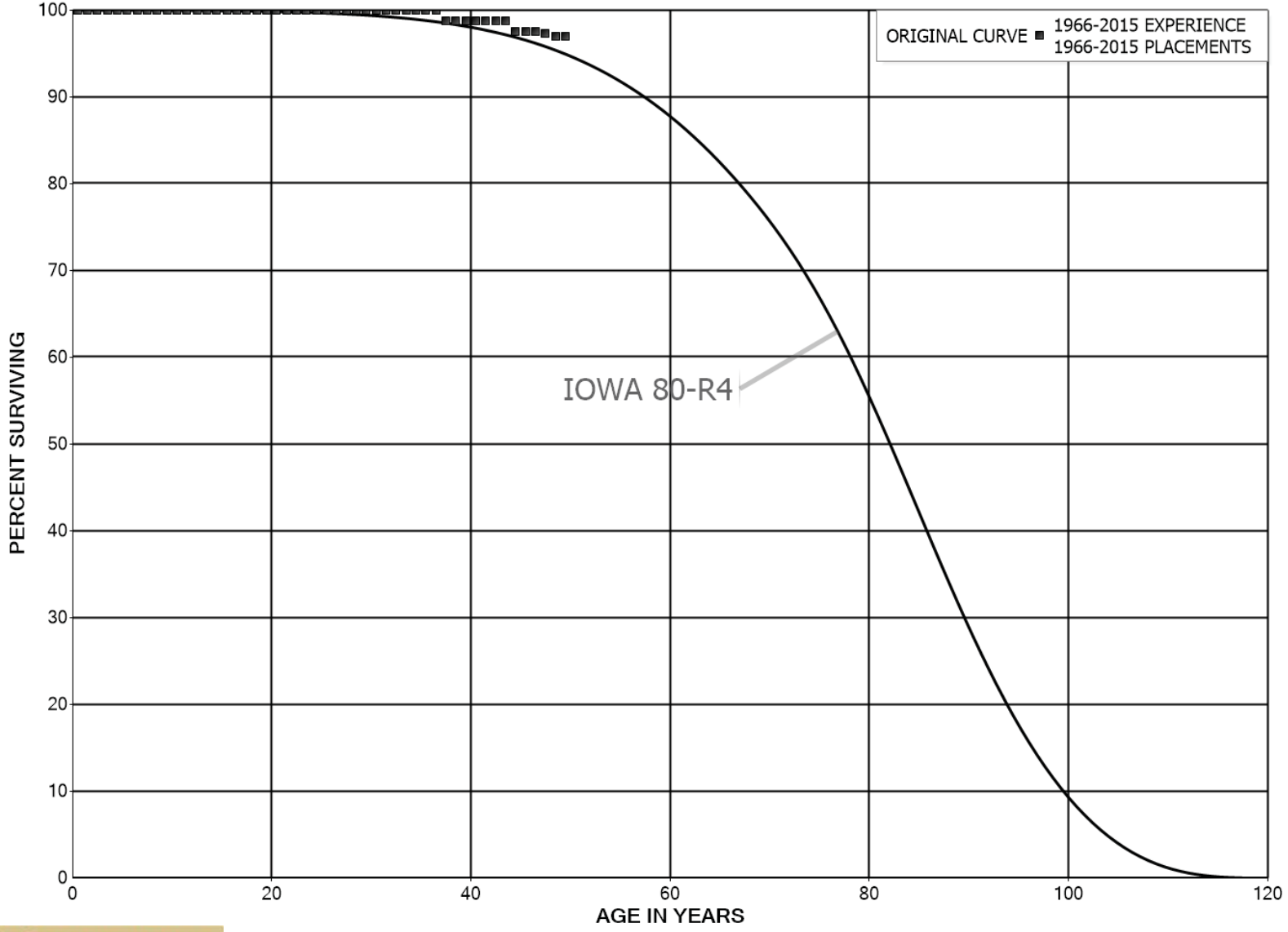
ACCOUNT G01 - GAS TURBINE SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,731,587		0.0000	1.0000	72.89
40.5	5,699,814		0.0000	1.0000	72.89
41.5	995,759		0.0000	1.0000	72.89
42.5	995,759		0.0000	1.0000	72.89
43.5	995,759		0.0000	1.0000	72.89
44.5	995,759		0.0000	1.0000	72.89
45.5	995,759		0.0000	1.0000	72.89
46.5	995,759		0.0000	1.0000	72.89
47.5					72.89

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G02 - GATES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G02 - GATES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,165,290		0.0000	1.0000	100.00
0.5	17,747,770		0.0000	1.0000	100.00
1.5	17,426,122		0.0000	1.0000	100.00
2.5	15,500,388		0.0000	1.0000	100.00
3.5	15,468,388		0.0000	1.0000	100.00
4.5	15,468,388		0.0000	1.0000	100.00
5.5	15,468,388		0.0000	1.0000	100.00
6.5	15,468,388		0.0000	1.0000	100.00
7.5	15,468,388		0.0000	1.0000	100.00
8.5	15,468,388		0.0000	1.0000	100.00
9.5	15,468,388		0.0000	1.0000	100.00
10.5	15,468,388		0.0000	1.0000	100.00
11.5	15,029,276		0.0000	1.0000	100.00
12.5	15,029,276	9,500	0.0006	0.9994	100.00
13.5	15,019,776		0.0000	1.0000	99.94
14.5	15,019,776		0.0000	1.0000	99.94
15.5	15,019,776		0.0000	1.0000	99.94
16.5	15,019,776		0.0000	1.0000	99.94
17.5	15,019,776		0.0000	1.0000	99.94
18.5	15,019,776		0.0000	1.0000	99.94
19.5	15,019,776		0.0000	1.0000	99.94
20.5	15,019,776		0.0000	1.0000	99.94
21.5	15,019,776		0.0000	1.0000	99.94
22.5	15,019,776		0.0000	1.0000	99.94
23.5	15,019,776		0.0000	1.0000	99.94
24.5	15,019,776		0.0000	1.0000	99.94
25.5	15,019,776		0.0000	1.0000	99.94
26.5	14,839,446		0.0000	1.0000	99.94
27.5	13,824,563		0.0000	1.0000	99.94
28.5	13,824,563		0.0000	1.0000	99.94
29.5	13,685,101		0.0000	1.0000	99.94
30.5	13,499,888	170	0.0000	1.0000	99.94
31.5	12,379,584		0.0000	1.0000	99.94
32.5	10,403,078		0.0000	1.0000	99.94
33.5	6,279,829		0.0000	1.0000	99.94
34.5	6,279,829		0.0000	1.0000	99.94
35.5	5,228,337		0.0000	1.0000	99.94
36.5	3,809,007	46,760	0.0123	0.9877	99.94
37.5	3,494,554		0.0000	1.0000	98.71
38.5	3,494,554		0.0000	1.0000	98.71

NEWFOUNDLAND AND LABRADOR HYDRO

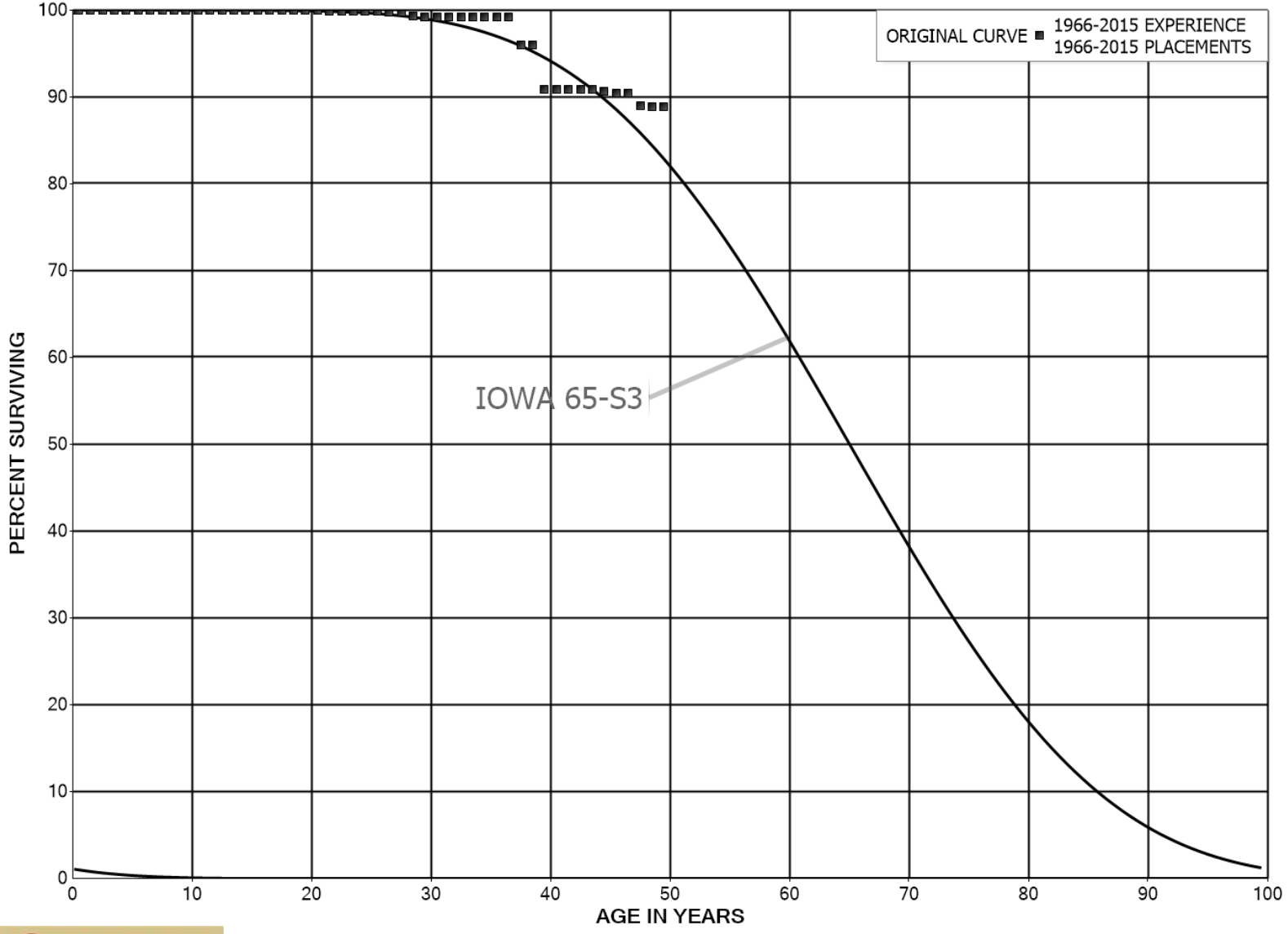
ACCOUNT G02 - GATES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,494,554		0.0000	1.0000	98.71
40.5	3,494,554		0.0000	1.0000	98.71
41.5	3,494,554		0.0000	1.0000	98.71
42.5	3,494,554		0.0000	1.0000	98.71
43.5	3,494,554	42,000	0.0120	0.9880	98.71
44.5	3,452,554	425	0.0001	0.9999	97.52
45.5	3,055,727	1,218	0.0004	0.9996	97.51
46.5	3,054,510	5,408	0.0018	0.9982	97.47
47.5	3,049,102	10,366	0.0034	0.9966	97.30
48.5	1,987,063	910	0.0005	0.9995	96.97
49.5					96.92

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G03 - GENERATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G03 - GENERATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	111,858,702		0.0000	1.0000	100.00
0.5	79,442,981		0.0000	1.0000	100.00
1.5	72,374,115		0.0000	1.0000	100.00
2.5	69,234,533		0.0000	1.0000	100.00
3.5	67,267,295	4,146	0.0001	0.9999	100.00
4.5	66,812,388	0	0.0000	1.0000	99.99
5.5	64,860,626		0.0000	1.0000	99.99
6.5	64,625,861		0.0000	1.0000	99.99
7.5	62,337,507		0.0000	1.0000	99.99
8.5	62,309,499	844	0.0000	1.0000	99.99
9.5	62,308,654		0.0000	1.0000	99.99
10.5	62,308,654		0.0000	1.0000	99.99
11.5	62,308,654		0.0000	1.0000	99.99
12.5	52,323,128		0.0000	1.0000	99.99
13.5	52,286,260		0.0000	1.0000	99.99
14.5	52,189,246	1,025	0.0000	1.0000	99.99
15.5	52,188,221		0.0000	1.0000	99.99
16.5	52,022,321		0.0000	1.0000	99.99
17.5	52,022,321		0.0000	1.0000	99.99
18.5	52,022,321	16,211	0.0003	0.9997	99.99
19.5	52,006,109		0.0000	1.0000	99.96
20.5	52,006,109	64,978	0.0012	0.9988	99.96
21.5	51,941,131	7,928	0.0002	0.9998	99.83
22.5	51,933,202		0.0000	1.0000	99.82
23.5	46,839,338		0.0000	1.0000	99.82
24.5	46,839,338		0.0000	1.0000	99.82
25.5	46,666,228	52,026	0.0011	0.9989	99.82
26.5	45,412,789		0.0000	1.0000	99.71
27.5	45,335,797	214,354	0.0047	0.9953	99.71
28.5	45,120,595	43,627	0.0010	0.9990	99.24
29.5	45,076,969	1,839	0.0000	1.0000	99.14
30.5	35,850,861		0.0000	1.0000	99.14
31.5	35,850,861		0.0000	1.0000	99.14
32.5	35,673,506		0.0000	1.0000	99.14
33.5	30,001,748	2,961	0.0001	0.9999	99.14
34.5	29,998,786		0.0000	1.0000	99.13
35.5	17,961,479		0.0000	1.0000	99.13
36.5	17,175,463	554,625	0.0323	0.9677	99.13
37.5	16,349,838		0.0000	1.0000	95.93
38.5	13,164,067	698,546	0.0531	0.9469	95.93

NEWFOUNDLAND AND LABRADOR HYDRO

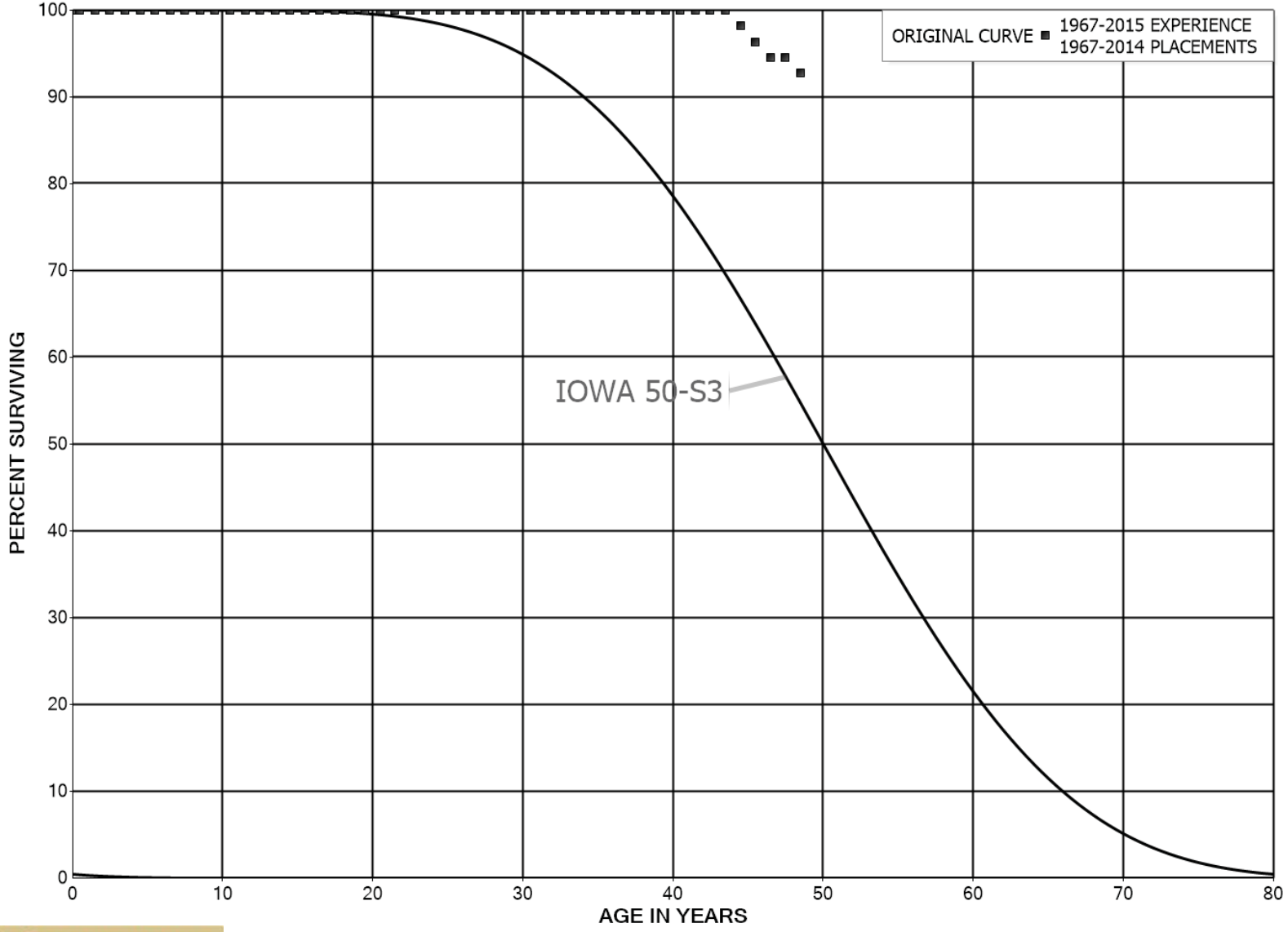
ACCOUNT G03 - GENERATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,465,521		0.0000	1.0000	90.84
40.5	12,465,521		0.0000	1.0000	90.84
41.5	12,465,521		0.0000	1.0000	90.84
42.5	12,465,521		0.0000	1.0000	90.84
43.5	12,465,521	32,540	0.0026	0.9974	90.84
44.5	10,845,051	20,889	0.0019	0.9981	90.60
45.5	7,376,884		0.0000	1.0000	90.42
46.5	7,376,884	124,689	0.0169	0.9831	90.42
47.5	1,723,534	734	0.0004	0.9996	88.90
48.5	18,140		0.0000	1.0000	88.86
49.5					88.86

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G04 - GENERATORS - WINDINGS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G04 - GENERATORS - WINDINGS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2014 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	25,122,055		0.0000	1.0000	100.00
0.5	25,122,055		0.0000	1.0000	100.00
1.5	22,989,529		0.0000	1.0000	100.00
2.5	15,242,801		0.0000	1.0000	100.00
3.5	11,360,350		0.0000	1.0000	100.00
4.5	11,360,350		0.0000	1.0000	100.00
5.5	6,924,795		0.0000	1.0000	100.00
6.5	6,924,795		0.0000	1.0000	100.00
7.5	6,924,795		0.0000	1.0000	100.00
8.5	6,924,795		0.0000	1.0000	100.00
9.5	6,924,795		0.0000	1.0000	100.00
10.5	6,924,795		0.0000	1.0000	100.00
11.5	6,924,795		0.0000	1.0000	100.00
12.5	6,924,795		0.0000	1.0000	100.00
13.5	6,924,795		0.0000	1.0000	100.00
14.5	6,924,795		0.0000	1.0000	100.00
15.5	6,924,795		0.0000	1.0000	100.00
16.5	6,924,795		0.0000	1.0000	100.00
17.5	6,924,795		0.0000	1.0000	100.00
18.5	6,924,795		0.0000	1.0000	100.00
19.5	6,924,795		0.0000	1.0000	100.00
20.5	6,924,795		0.0000	1.0000	100.00
21.5	6,924,795		0.0000	1.0000	100.00
22.5	6,924,795		0.0000	1.0000	100.00
23.5	6,924,795		0.0000	1.0000	100.00
24.5	6,924,795		0.0000	1.0000	100.00
25.5	6,924,795		0.0000	1.0000	100.00
26.5	6,924,795		0.0000	1.0000	100.00
27.5	6,924,795		0.0000	1.0000	100.00
28.5	6,924,795		0.0000	1.0000	100.00
29.5	6,924,795		0.0000	1.0000	100.00
30.5	6,924,795		0.0000	1.0000	100.00
31.5	6,924,795		0.0000	1.0000	100.00
32.5	6,924,795		0.0000	1.0000	100.00
33.5	6,924,795		0.0000	1.0000	100.00
34.5	6,924,795		0.0000	1.0000	100.00
35.5	6,924,795		0.0000	1.0000	100.00
36.5	6,924,795		0.0000	1.0000	100.00
37.5	6,924,795		0.0000	1.0000	100.00
38.5	6,924,795		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

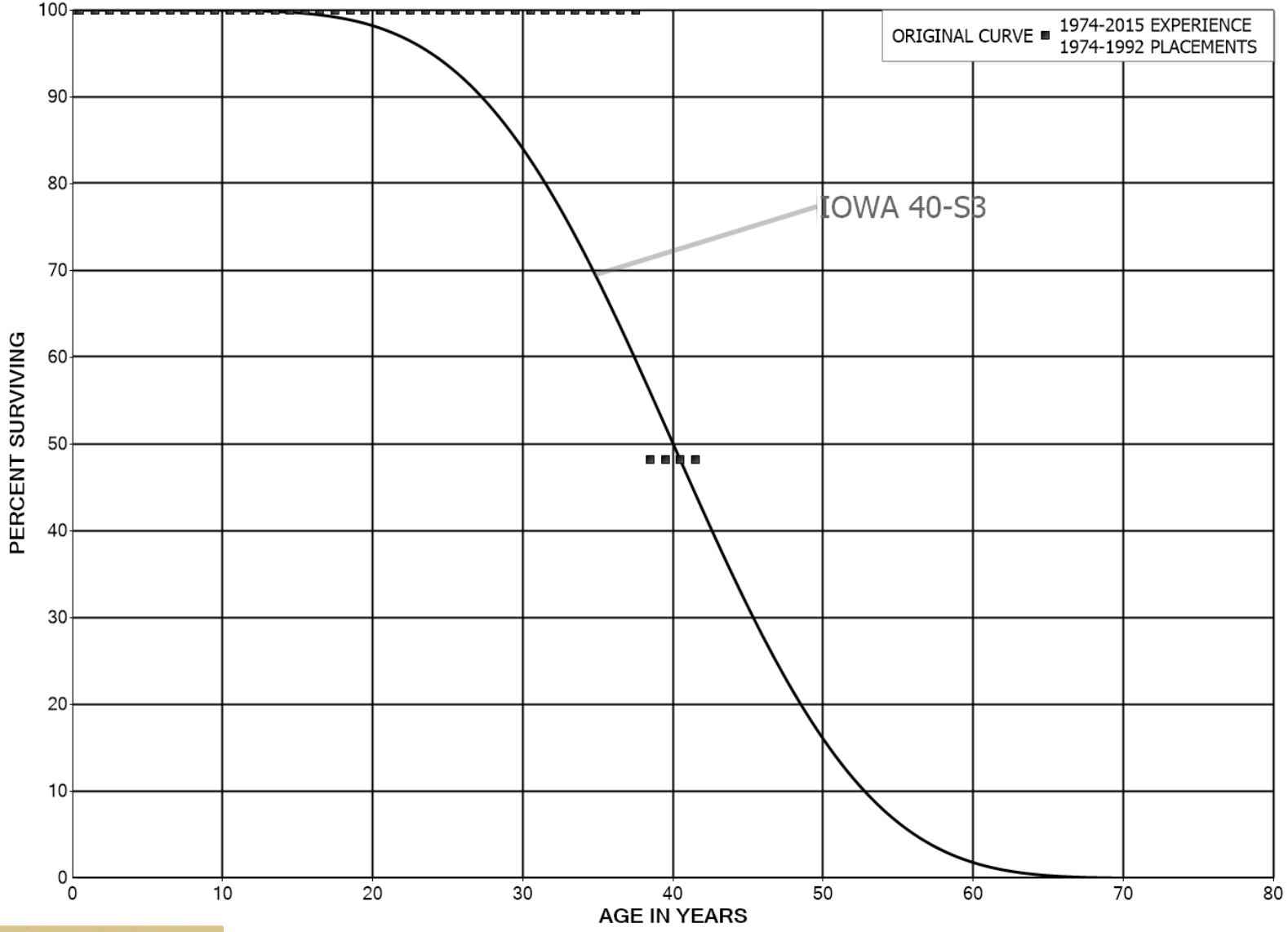
ACCOUNT G04 - GENERATORS - WINDINGS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2014 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,924,795		0.0000	1.0000	100.00
40.5	6,924,795		0.0000	1.0000	100.00
41.5	6,924,795		0.0000	1.0000	100.00
42.5	6,924,795		0.0000	1.0000	100.00
43.5	6,924,795	126,824	0.0183	0.9817	100.00
44.5	6,797,971	126,824	0.0187	0.9813	98.17
45.5	6,671,146	126,824	0.0190	0.9810	96.34
46.5	6,544,322		0.0000	1.0000	94.51
47.5	6,544,322	126,824	0.0194	0.9806	94.51
48.5					92.67

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G05 - GLYCOL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G05 - GLYCOL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1974-1992 EXPERIENCE BAND 1974-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	620,704		0.0000	1.0000	100.00
0.5	620,704		0.0000	1.0000	100.00
1.5	620,704		0.0000	1.0000	100.00
2.5	620,704		0.0000	1.0000	100.00
3.5	620,704		0.0000	1.0000	100.00
4.5	620,704		0.0000	1.0000	100.00
5.5	620,704		0.0000	1.0000	100.00
6.5	620,704		0.0000	1.0000	100.00
7.5	620,704		0.0000	1.0000	100.00
8.5	620,704		0.0000	1.0000	100.00
9.5	620,704		0.0000	1.0000	100.00
10.5	620,704		0.0000	1.0000	100.00
11.5	620,704		0.0000	1.0000	100.00
12.5	620,704		0.0000	1.0000	100.00
13.5	620,704		0.0000	1.0000	100.00
14.5	620,704		0.0000	1.0000	100.00
15.5	620,704		0.0000	1.0000	100.00
16.5	620,704		0.0000	1.0000	100.00
17.5	620,704		0.0000	1.0000	100.00
18.5	620,704		0.0000	1.0000	100.00
19.5	620,704		0.0000	1.0000	100.00
20.5	620,704		0.0000	1.0000	100.00
21.5	620,704		0.0000	1.0000	100.00
22.5	620,704		0.0000	1.0000	100.00
23.5	183,019		0.0000	1.0000	100.00
24.5	183,019		0.0000	1.0000	100.00
25.5	183,019		0.0000	1.0000	100.00
26.5	173,749		0.0000	1.0000	100.00
27.5	173,749		0.0000	1.0000	100.00
28.5	173,749		0.0000	1.0000	100.00
29.5	173,749		0.0000	1.0000	100.00
30.5	173,749		0.0000	1.0000	100.00
31.5	173,749		0.0000	1.0000	100.00
32.5	173,749		0.0000	1.0000	100.00
33.5	173,749		0.0000	1.0000	100.00
34.5	173,749		0.0000	1.0000	100.00
35.5	173,749		0.0000	1.0000	100.00
36.5	173,749		0.0000	1.0000	100.00
37.5	173,749	90,050	0.5183	0.4817	100.00
38.5	83,699		0.0000	1.0000	48.17

NEWFOUNDLAND AND LABRADOR HYDRO

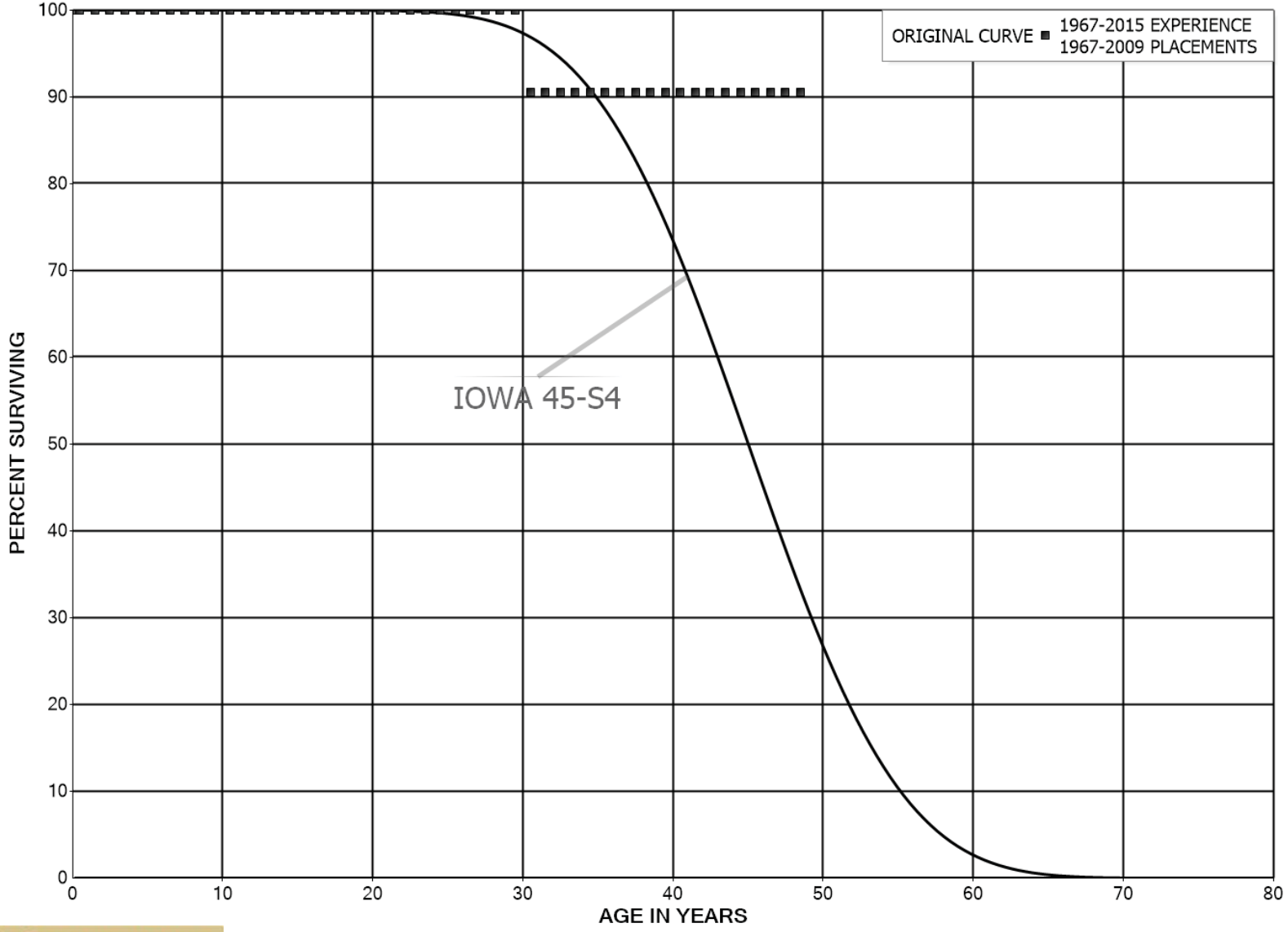
ACCOUNT G05 - GLYCOL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1974-1992 EXPERIENCE BAND 1974-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	83,699		0.0000	1.0000	48.17
40.5	83,699		0.0000	1.0000	48.17
41.5					48.17

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G06 - GOVENORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G06 - GOVENORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2009 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,471,294		0.0000	1.0000	100.00
0.5	10,471,294		0.0000	1.0000	100.00
1.5	10,471,294		0.0000	1.0000	100.00
2.5	10,471,294		0.0000	1.0000	100.00
3.5	10,471,294		0.0000	1.0000	100.00
4.5	10,471,294		0.0000	1.0000	100.00
5.5	10,471,294		0.0000	1.0000	100.00
6.5	9,176,079		0.0000	1.0000	100.00
7.5	9,176,079		0.0000	1.0000	100.00
8.5	9,176,079		0.0000	1.0000	100.00
9.5	8,263,566		0.0000	1.0000	100.00
10.5	8,263,566		0.0000	1.0000	100.00
11.5	8,263,566		0.0000	1.0000	100.00
12.5	6,637,157		0.0000	1.0000	100.00
13.5	6,042,522		0.0000	1.0000	100.00
14.5	6,042,522		0.0000	1.0000	100.00
15.5	6,042,522		0.0000	1.0000	100.00
16.5	5,119,741		0.0000	1.0000	100.00
17.5	5,119,741		0.0000	1.0000	100.00
18.5	5,119,741		0.0000	1.0000	100.00
19.5	5,108,302		0.0000	1.0000	100.00
20.5	5,108,302		0.0000	1.0000	100.00
21.5	5,108,302		0.0000	1.0000	100.00
22.5	5,108,302		0.0000	1.0000	100.00
23.5	5,108,302		0.0000	1.0000	100.00
24.5	5,108,302		0.0000	1.0000	100.00
25.5	5,108,302		0.0000	1.0000	100.00
26.5	5,108,302		0.0000	1.0000	100.00
27.5	5,108,302		0.0000	1.0000	100.00
28.5	5,108,302		0.0000	1.0000	100.00
29.5	5,108,302	486,252	0.0952	0.9048	100.00
30.5	3,199,933		0.0000	1.0000	90.48
31.5	3,199,933		0.0000	1.0000	90.48
32.5	3,199,933		0.0000	1.0000	90.48
33.5	894,084		0.0000	1.0000	90.48
34.5	894,084		0.0000	1.0000	90.48
35.5	424,738		0.0000	1.0000	90.48
36.5	424,738		0.0000	1.0000	90.48
37.5	424,738		0.0000	1.0000	90.48
38.5	281,513		0.0000	1.0000	90.48

NEWFOUNDLAND AND LABRADOR HYDRO

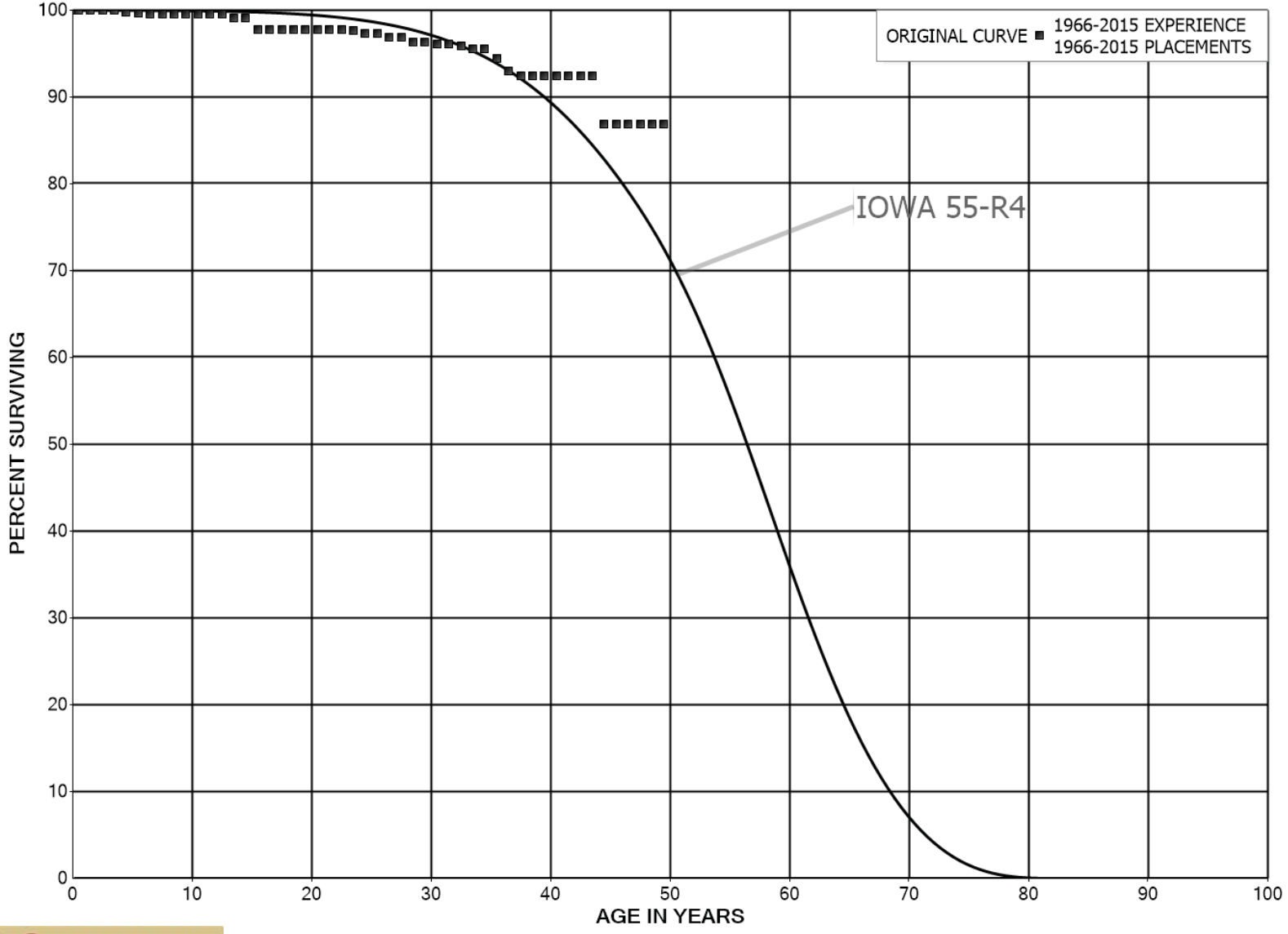
ACCOUNT G06 - GOVENORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2009 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	281,513		0.0000	1.0000	90.48
40.5	281,513		0.0000	1.0000	90.48
41.5	281,513		0.0000	1.0000	90.48
42.5	281,513		0.0000	1.0000	90.48
43.5	281,513		0.0000	1.0000	90.48
44.5	203,784		0.0000	1.0000	90.48
45.5	139,962		0.0000	1.0000	90.48
46.5	139,962		0.0000	1.0000	90.48
47.5	62,233		0.0000	1.0000	90.48
48.5					90.48

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT G07 - GROUND WIRE SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G07 - GROUND WIRE SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,655,699		0.0000	1.0000	100.00
0.5	10,087,501		0.0000	1.0000	100.00
1.5	9,546,185		0.0000	1.0000	100.00
2.5	8,903,324	2,405	0.0003	0.9997	100.00
3.5	8,158,963	23,099	0.0028	0.9972	99.97
4.5	7,858,588	2,351	0.0003	0.9997	99.69
5.5	7,588,514	11,099	0.0015	0.9985	99.66
6.5	7,402,576	2,960	0.0004	0.9996	99.51
7.5	6,346,757		0.0000	1.0000	99.47
8.5	6,346,757		0.0000	1.0000	99.47
9.5	6,276,529	510	0.0001	0.9999	99.47
10.5	6,256,087		0.0000	1.0000	99.47
11.5	6,246,646		0.0000	1.0000	99.47
12.5	5,838,094	21,116	0.0036	0.9964	99.47
13.5	5,753,109		0.0000	1.0000	99.11
14.5	5,399,745	73,158	0.0135	0.9865	99.11
15.5	5,217,387	51	0.0000	1.0000	97.76
16.5	5,217,336	806	0.0002	0.9998	97.76
17.5	5,188,571		0.0000	1.0000	97.75
18.5	5,160,918		0.0000	1.0000	97.75
19.5	5,018,364		0.0000	1.0000	97.75
20.5	4,602,965		0.0000	1.0000	97.75
21.5	4,597,352		0.0000	1.0000	97.75
22.5	4,586,032	6,802	0.0015	0.9985	97.75
23.5	4,364,218	12,497	0.0029	0.9971	97.60
24.5	3,830,834	230	0.0001	0.9999	97.32
25.5	3,361,807	17,549	0.0052	0.9948	97.32
26.5	3,061,231		0.0000	1.0000	96.81
27.5	3,017,215	16,470	0.0055	0.9945	96.81
28.5	2,856,723	194	0.0001	0.9999	96.28
29.5	2,826,921	6,426	0.0023	0.9977	96.27
30.5	2,364,792	773	0.0003	0.9997	96.06
31.5	2,364,019	4,607	0.0019	0.9981	96.02
32.5	2,007,180	6,833	0.0034	0.9966	95.84
33.5	1,653,358	281	0.0002	0.9998	95.51
34.5	1,580,951	19,030	0.0120	0.9880	95.49
35.5	1,192,468	17,206	0.0144	0.9856	94.35
36.5	1,098,806	6,546	0.0060	0.9940	92.98
37.5	854,782		0.0000	1.0000	92.43
38.5	810,716		0.0000	1.0000	92.43

NEWFOUNDLAND AND LABRADOR HYDRO

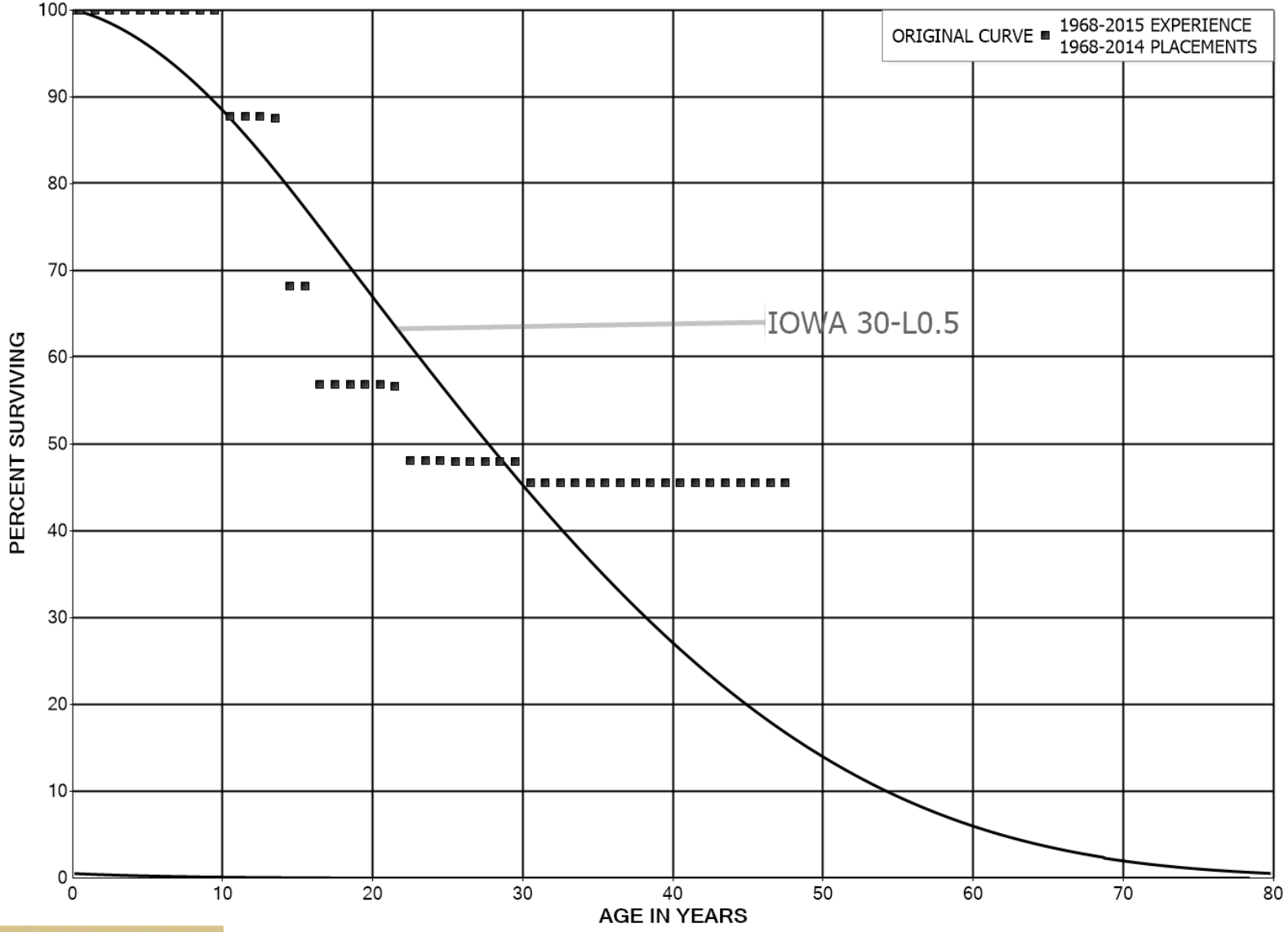
ACCOUNT G07 - GROUND WIRE SYSTEM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	806,093	23	0.0000	1.0000	92.43
40.5	758,178	20	0.0000	1.0000	92.43
41.5	536,557		0.0000	1.0000	92.43
42.5	536,557		0.0000	1.0000	92.43
43.5	536,557	32,306	0.0602	0.9398	92.43
44.5	451,178		0.0000	1.0000	86.86
45.5	278,958		0.0000	1.0000	86.86
46.5	278,958		0.0000	1.0000	86.86
47.5	184,040		0.0000	1.0000	86.86
48.5	2,824		0.0000	1.0000	86.86
49.5					86.86

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT I02 - INSTRUMENTATION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I02 - INSTRUMENTATION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2014 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,261,230		0.0000	1.0000	100.00
0.5	22,261,230		0.0000	1.0000	100.00
1.5	21,913,559		0.0000	1.0000	100.00
2.5	21,913,559		0.0000	1.0000	100.00
3.5	21,868,188		0.0000	1.0000	100.00
4.5	21,868,188		0.0000	1.0000	100.00
5.5	21,868,188	3,719	0.0002	0.9998	100.00
6.5	21,446,139		0.0000	1.0000	99.98
7.5	21,101,401		0.0000	1.0000	99.98
8.5	21,101,401		0.0000	1.0000	99.98
9.5	20,604,043	2,527,190	0.1227	0.8773	99.98
10.5	16,873,034		0.0000	1.0000	87.72
11.5	15,233,831		0.0000	1.0000	87.72
12.5	15,233,831	45,673	0.0030	0.9970	87.72
13.5	15,169,709	3,351,016	0.2209	0.7791	87.46
14.5	11,818,693		0.0000	1.0000	68.14
15.5	11,818,693	1,953,783	0.1653	0.8347	68.14
16.5	9,508,569	798	0.0001	0.9999	56.87
17.5	9,507,771	7,009	0.0007	0.9993	56.87
18.5	9,500,762		0.0000	1.0000	56.83
19.5	9,500,762		0.0000	1.0000	56.83
20.5	9,500,762	39,474	0.0042	0.9958	56.83
21.5	8,701,521	1,309,202	0.1505	0.8495	56.59
22.5	7,392,319		0.0000	1.0000	48.08
23.5	7,372,386	1,036	0.0001	0.9999	48.08
24.5	7,371,350	18,112	0.0025	0.9975	48.07
25.5	6,834,830		0.0000	1.0000	47.95
26.5	6,783,761		0.0000	1.0000	47.95
27.5	6,499,007		0.0000	1.0000	47.95
28.5	6,008,757		0.0000	1.0000	47.95
29.5	6,008,757	309,494	0.0515	0.9485	47.95
30.5	5,699,263		0.0000	1.0000	45.48
31.5	5,699,263		0.0000	1.0000	45.48
32.5	5,699,263		0.0000	1.0000	45.48
33.5	5,699,263		0.0000	1.0000	45.48
34.5	5,699,263		0.0000	1.0000	45.48
35.5	3,391,604		0.0000	1.0000	45.48
36.5	3,366,271		0.0000	1.0000	45.48
37.5	3,366,271		0.0000	1.0000	45.48
38.5	3,366,271		0.0000	1.0000	45.48

NEWFOUNDLAND AND LABRADOR HYDRO

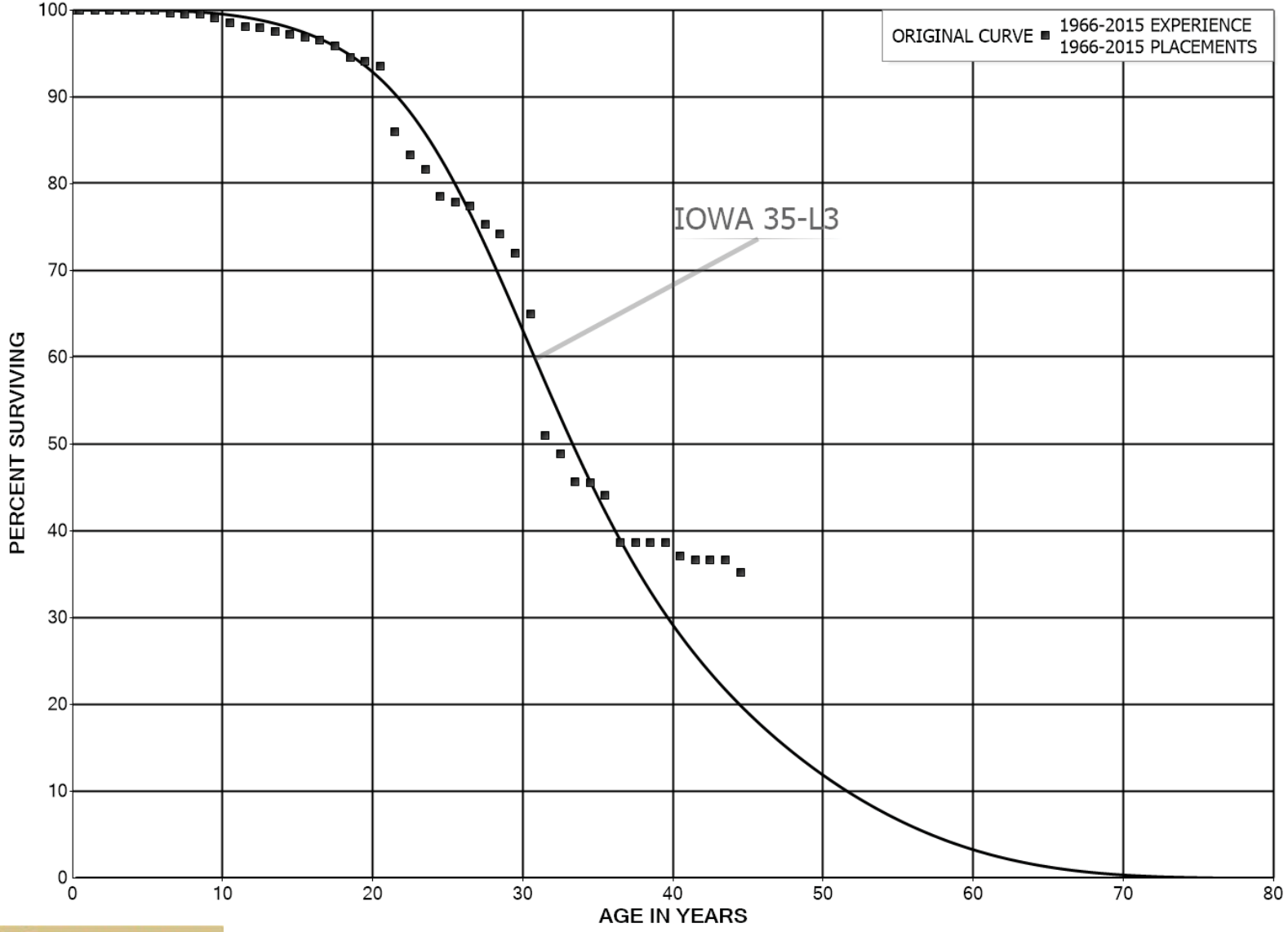
ACCOUNT I02 - INSTRUMENTATION

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2014 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,366,271		0.0000	1.0000	45.48
40.5	3,366,271		0.0000	1.0000	45.48
41.5	3,366,271		0.0000	1.0000	45.48
42.5	3,366,271		0.0000	1.0000	45.48
43.5	3,366,271		0.0000	1.0000	45.48
44.5	1,803,443		0.0000	1.0000	45.48
45.5	1,803,443		0.0000	1.0000	45.48
46.5	1,270,122		0.0000	1.0000	45.48
47.5					45.48

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT I03 - INSULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I03 - INSULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	48,242,343		0.0000	1.0000	100.00
0.5	48,174,385	324	0.0000	1.0000	100.00
1.5	45,488,327		0.0000	1.0000	100.00
2.5	45,382,692		0.0000	1.0000	100.00
3.5	44,388,624		0.0000	1.0000	100.00
4.5	43,897,849		0.0000	1.0000	100.00
5.5	43,573,959	160,151	0.0037	0.9963	100.00
6.5	41,290,216	43,594	0.0011	0.9989	99.63
7.5	40,437,876	13,964	0.0003	0.9997	99.53
8.5	37,286,948	146,912	0.0039	0.9961	99.49
9.5	35,815,777	230,244	0.0064	0.9936	99.10
10.5	35,252,361	161,496	0.0046	0.9954	98.46
11.5	32,314,895	21,157	0.0007	0.9993	98.01
12.5	30,452,396	151,853	0.0050	0.9950	97.95
13.5	28,313,477	77,779	0.0027	0.9973	97.46
14.5	27,554,054	102,287	0.0037	0.9963	97.19
15.5	23,559,738	66,360	0.0028	0.9972	96.83
16.5	22,472,689	160,058	0.0071	0.9929	96.56
17.5	21,592,182	305,202	0.0141	0.9859	95.87
18.5	20,397,103	95,844	0.0047	0.9953	94.52
19.5	18,514,891	116,445	0.0063	0.9937	94.07
20.5	16,639,757	1,340,429	0.0806	0.9194	93.48
21.5	14,330,008	448,710	0.0313	0.9687	85.95
22.5	12,691,805	258,205	0.0203	0.9797	83.26
23.5	11,665,780	439,868	0.0377	0.9623	81.56
24.5	9,525,743	75,091	0.0079	0.9921	78.49
25.5	6,237,944	38,748	0.0062	0.9938	77.87
26.5	5,598,358	149,312	0.0267	0.9733	77.39
27.5	4,873,463	73,191	0.0150	0.9850	75.32
28.5	4,266,325	132,011	0.0309	0.9691	74.19
29.5	4,126,752	396,364	0.0960	0.9040	71.90
30.5	2,731,213	591,635	0.2166	0.7834	64.99
31.5	2,069,541	85,526	0.0413	0.9587	50.91
32.5	1,353,535	88,424	0.0653	0.9347	48.81
33.5	838,678	1,295	0.0015	0.9985	45.62
34.5	768,363	24,135	0.0314	0.9686	45.55
35.5	732,916	90,713	0.1238	0.8762	44.12
36.5	627,421		0.0000	1.0000	38.66
37.5	591,994		0.0000	1.0000	38.66
38.5	541,711		0.0000	1.0000	38.66

NEWFOUNDLAND AND LABRADOR HYDRO

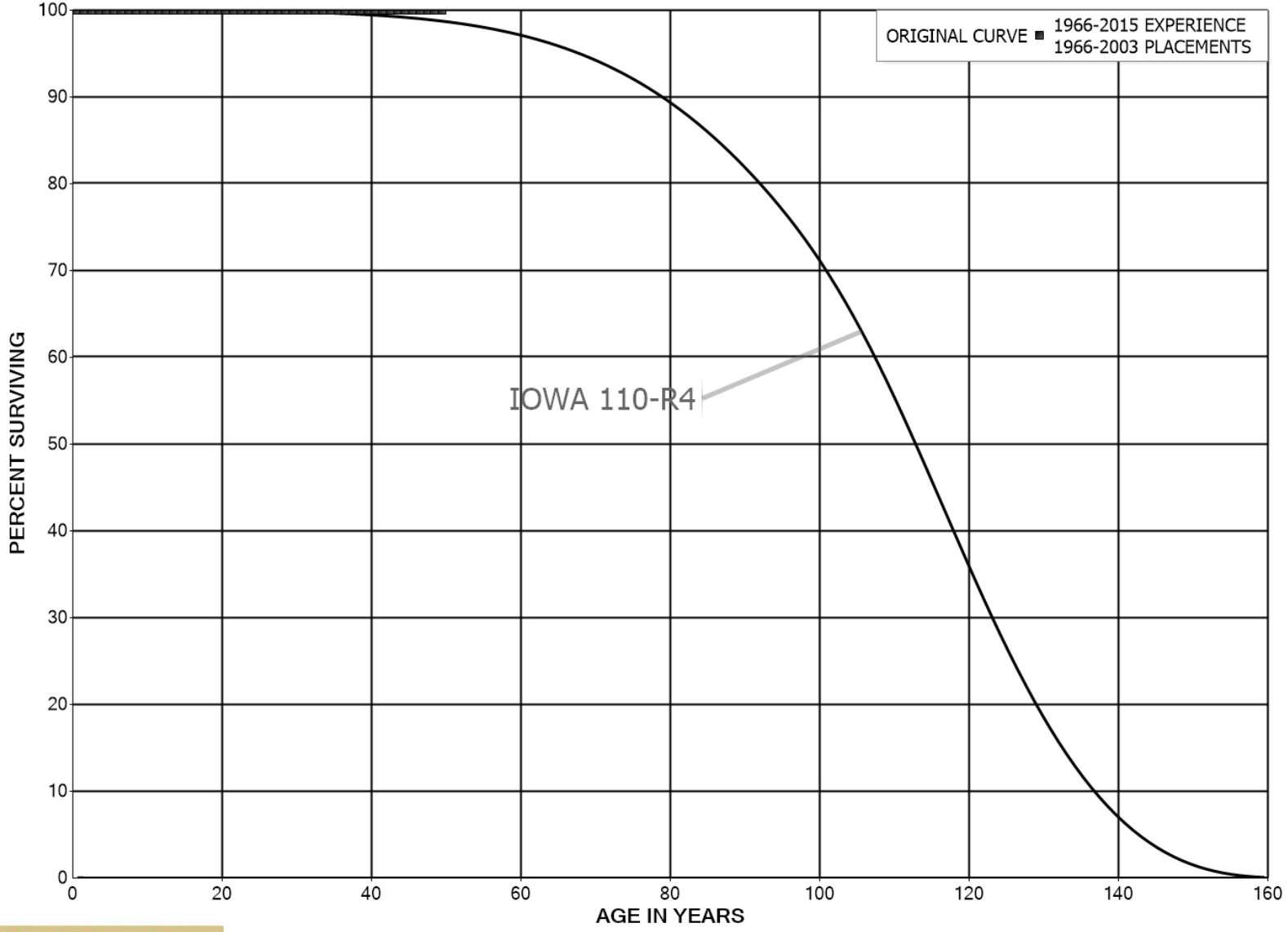
ACCOUNT I03 - INSULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	529,369	21,991	0.0415	0.9585	38.66
40.5	506,864	5,271	0.0104	0.9896	37.05
41.5	489,114		0.0000	1.0000	36.67
42.5	489,114	1,243	0.0025	0.9975	36.67
43.5	487,870	18,088	0.0371	0.9629	36.57
44.5	469,783		0.0000	1.0000	35.22
45.5	373,407		0.0000	1.0000	35.22
46.5	323,008	120,099	0.3718	0.6282	35.22
47.5	88,701		0.0000	1.0000	22.12
48.5					22.12

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT I04 - INTAKE STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I04 - INTAKE STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2003 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,436,445		0.0000	1.0000	100.00
0.5	19,436,445		0.0000	1.0000	100.00
1.5	19,436,445		0.0000	1.0000	100.00
2.5	19,436,445		0.0000	1.0000	100.00
3.5	19,436,445		0.0000	1.0000	100.00
4.5	19,436,445		0.0000	1.0000	100.00
5.5	19,436,445		0.0000	1.0000	100.00
6.5	19,436,445		0.0000	1.0000	100.00
7.5	19,436,445		0.0000	1.0000	100.00
8.5	19,436,445		0.0000	1.0000	100.00
9.5	19,436,445		0.0000	1.0000	100.00
10.5	19,436,445		0.0000	1.0000	100.00
11.5	19,436,445		0.0000	1.0000	100.00
12.5	15,526,631		0.0000	1.0000	100.00
13.5	15,502,585		0.0000	1.0000	100.00
14.5	15,502,585		0.0000	1.0000	100.00
15.5	15,502,585		0.0000	1.0000	100.00
16.5	15,502,585		0.0000	1.0000	100.00
17.5	15,502,585		0.0000	1.0000	100.00
18.5	15,492,014		0.0000	1.0000	100.00
19.5	15,492,014		0.0000	1.0000	100.00
20.5	15,492,014		0.0000	1.0000	100.00
21.5	15,486,773		0.0000	1.0000	100.00
22.5	15,486,773		0.0000	1.0000	100.00
23.5	15,486,773		0.0000	1.0000	100.00
24.5	15,486,773		0.0000	1.0000	100.00
25.5	15,486,773		0.0000	1.0000	100.00
26.5	15,480,004		0.0000	1.0000	100.00
27.5	15,480,004		0.0000	1.0000	100.00
28.5	15,480,004		0.0000	1.0000	100.00
29.5	15,480,004		0.0000	1.0000	100.00
30.5	15,480,004		0.0000	1.0000	100.00
31.5	12,078,221		0.0000	1.0000	100.00
32.5	12,062,216		0.0000	1.0000	100.00
33.5	7,022,641		0.0000	1.0000	100.00
34.5	7,022,641		0.0000	1.0000	100.00
35.5	7,022,641		0.0000	1.0000	100.00
36.5	5,568,392		0.0000	1.0000	100.00
37.5	5,568,392		0.0000	1.0000	100.00
38.5	5,568,392		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

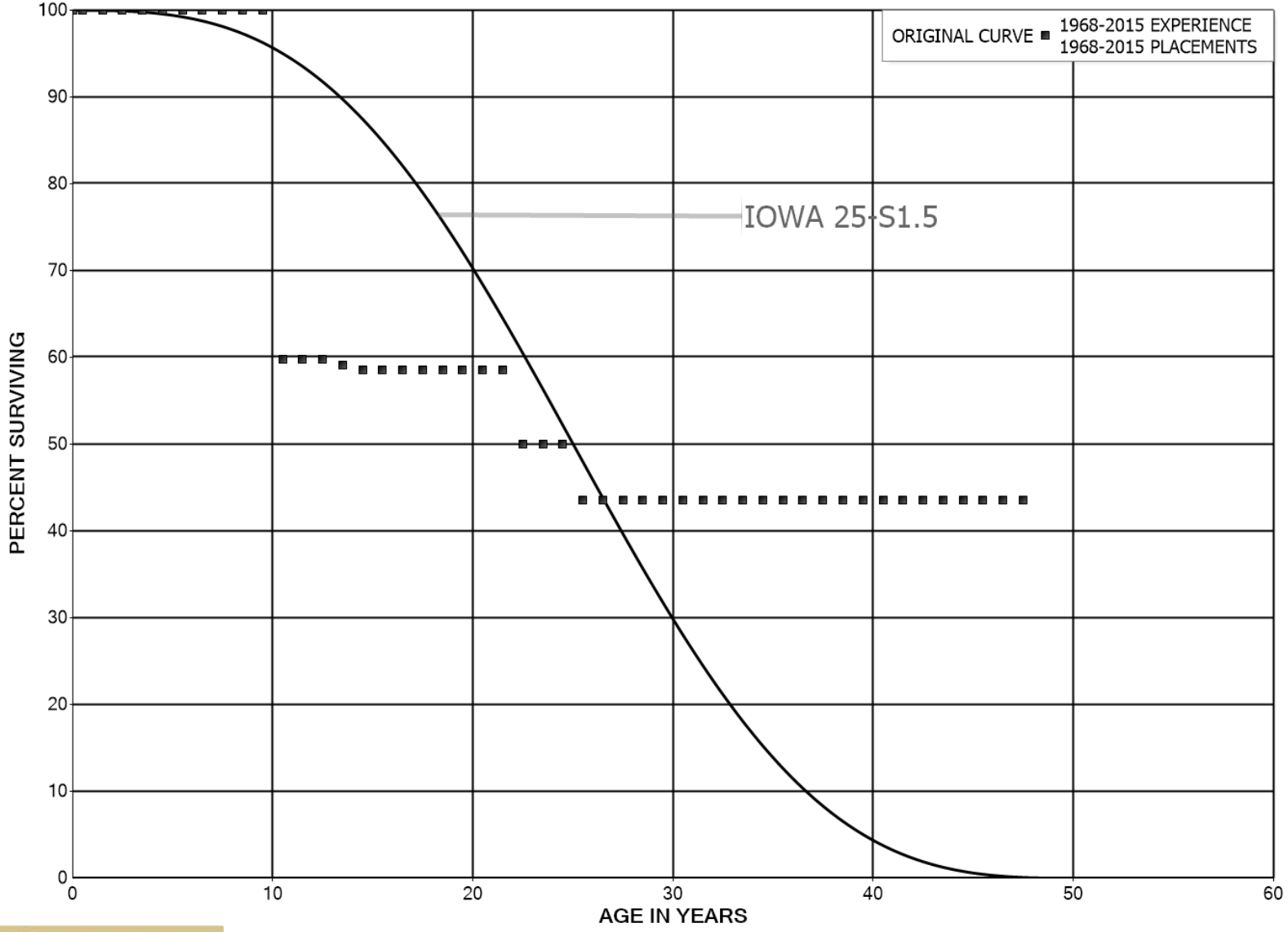
ACCOUNT I04 - INTAKE STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2003 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,568,392		0.0000	1.0000	100.00
40.5	5,568,392		0.0000	1.0000	100.00
41.5	5,568,392		0.0000	1.0000	100.00
42.5	5,568,392		0.0000	1.0000	100.00
43.5	5,568,392		0.0000	1.0000	100.00
44.5	5,568,392		0.0000	1.0000	100.00
45.5	5,568,392		0.0000	1.0000	100.00
46.5	5,568,392		0.0000	1.0000	100.00
47.5	5,568,392		0.0000	1.0000	100.00
48.5	3,784,392		0.0000	1.0000	100.00
49.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT I05 - INVERTERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I05 – INVERTERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,046,068		0.0000	1.0000	100.00
0.5	996,264		0.0000	1.0000	100.00
1.5	990,621		0.0000	1.0000	100.00
2.5	990,621		0.0000	1.0000	100.00
3.5	985,656		0.0000	1.0000	100.00
4.5	985,656		0.0000	1.0000	100.00
5.5	985,656		0.0000	1.0000	100.00
6.5	985,656		0.0000	1.0000	100.00
7.5	974,645		0.0000	1.0000	100.00
8.5	974,645		0.0000	1.0000	100.00
9.5	958,372	385,595	0.4023	0.5977	100.00
10.5	570,437		0.0000	1.0000	59.77
11.5	570,437		0.0000	1.0000	59.77
12.5	570,437	6,319	0.0111	0.9889	59.77
13.5	564,119	5,824	0.0103	0.9897	59.10
14.5	447,339		0.0000	1.0000	58.49
15.5	416,460		0.0000	1.0000	58.49
16.5	416,460		0.0000	1.0000	58.49
17.5	416,460		0.0000	1.0000	58.49
18.5	416,460		0.0000	1.0000	58.49
19.5	398,855		0.0000	1.0000	58.49
20.5	398,855		0.0000	1.0000	58.49
21.5	398,855	58,409	0.1464	0.8536	58.49
22.5	340,446		0.0000	1.0000	49.93
23.5	340,446		0.0000	1.0000	49.93
24.5	340,446	44,000	0.1292	0.8708	49.93
25.5	296,446		0.0000	1.0000	43.47
26.5	296,446		0.0000	1.0000	43.47
27.5	296,446		0.0000	1.0000	43.47
28.5	296,446		0.0000	1.0000	43.47
29.5	296,446		0.0000	1.0000	43.47
30.5	296,446		0.0000	1.0000	43.47
31.5	296,446		0.0000	1.0000	43.47
32.5	296,446		0.0000	1.0000	43.47
33.5	296,446		0.0000	1.0000	43.47
34.5	296,446		0.0000	1.0000	43.47
35.5	296,446		0.0000	1.0000	43.47
36.5	182,291		0.0000	1.0000	43.47
37.5	182,291		0.0000	1.0000	43.47
38.5	182,291		0.0000	1.0000	43.47

NEWFOUNDLAND AND LABRADOR HYDRO

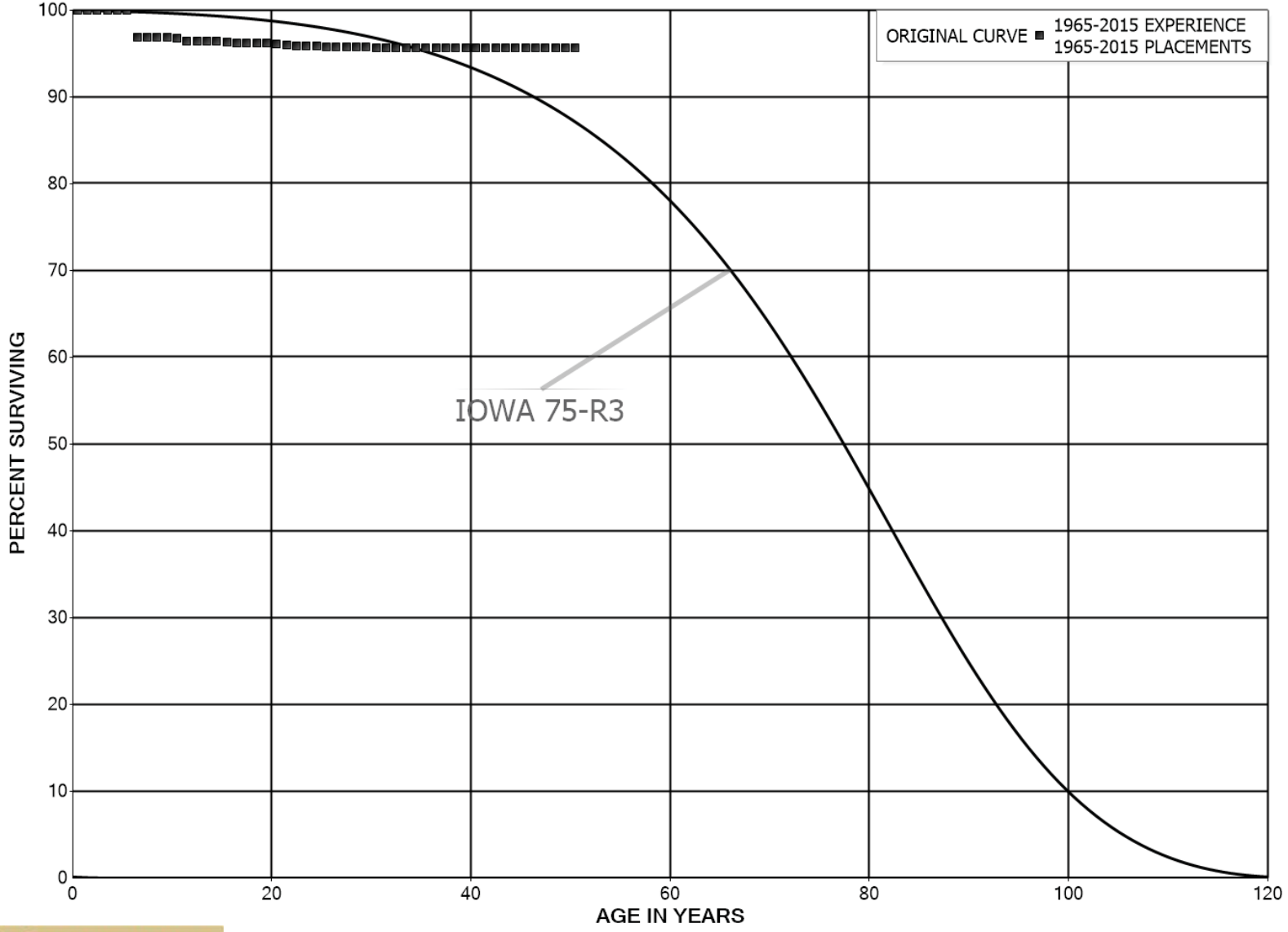
ACCOUNT I05 - INVERTERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	182,291		0.0000	1.0000	43.47
40.5	182,291		0.0000	1.0000	43.47
41.5	182,291		0.0000	1.0000	43.47
42.5	182,291		0.0000	1.0000	43.47
43.5	182,291		0.0000	1.0000	43.47
44.5	182,291		0.0000	1.0000	43.47
45.5	182,291		0.0000	1.0000	43.47
46.5	182,291		0.0000	1.0000	43.47
47.5					43.47

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT L03 - LAND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L03 - LAND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,785,580		0.0000	1.0000	100.00
0.5	14,405,219		0.0000	1.0000	100.00
1.5	14,035,436		0.0000	1.0000	100.00
2.5	14,035,436		0.0000	1.0000	100.00
3.5	13,985,752		0.0000	1.0000	100.00
4.5	13,920,972		0.0000	1.0000	100.00
5.5	13,907,588	434,171	0.0312	0.9688	100.00
6.5	13,205,053		0.0000	1.0000	96.88
7.5	13,140,512	3,813	0.0003	0.9997	96.88
8.5	13,136,698		0.0000	1.0000	96.85
9.5	13,026,208	18,971	0.0015	0.9985	96.85
10.5	12,919,808	42,480	0.0033	0.9967	96.71
11.5	12,774,710		0.0000	1.0000	96.39
12.5	12,546,047		0.0000	1.0000	96.39
13.5	12,373,363		0.0000	1.0000	96.39
14.5	12,373,363	15,446	0.0012	0.9988	96.39
15.5	12,284,887	6,107	0.0005	0.9995	96.27
16.5	12,161,087	9,618	0.0008	0.9992	96.22
17.5	11,829,964	2,739	0.0002	0.9998	96.15
18.5	11,802,786		0.0000	1.0000	96.12
19.5	11,546,911	6,476	0.0006	0.9994	96.12
20.5	11,195,645	12,318	0.0011	0.9989	96.07
21.5	10,996,065	11,197	0.0010	0.9990	95.96
22.5	10,758,006	6,203	0.0006	0.9994	95.87
23.5	10,182,136		0.0000	1.0000	95.81
24.5	9,741,386	5,711	0.0006	0.9994	95.81
25.5	8,969,860		0.0000	1.0000	95.76
26.5	6,750,871		0.0000	1.0000	95.76
27.5	6,562,113		0.0000	1.0000	95.76
28.5	5,992,954		0.0000	1.0000	95.76
29.5	5,907,424	7,420	0.0013	0.9987	95.76
30.5	5,647,615		0.0000	1.0000	95.64
31.5	5,550,842		0.0000	1.0000	95.64
32.5	5,290,586		0.0000	1.0000	95.64
33.5	4,774,341		0.0000	1.0000	95.64
34.5	4,502,387		0.0000	1.0000	95.64
35.5	3,449,183		0.0000	1.0000	95.64
36.5	3,412,057		0.0000	1.0000	95.64
37.5	2,634,287		0.0000	1.0000	95.64
38.5	2,242,772	350	0.0002	0.9998	95.64

NEWFOUNDLAND AND LABRADOR HYDRO

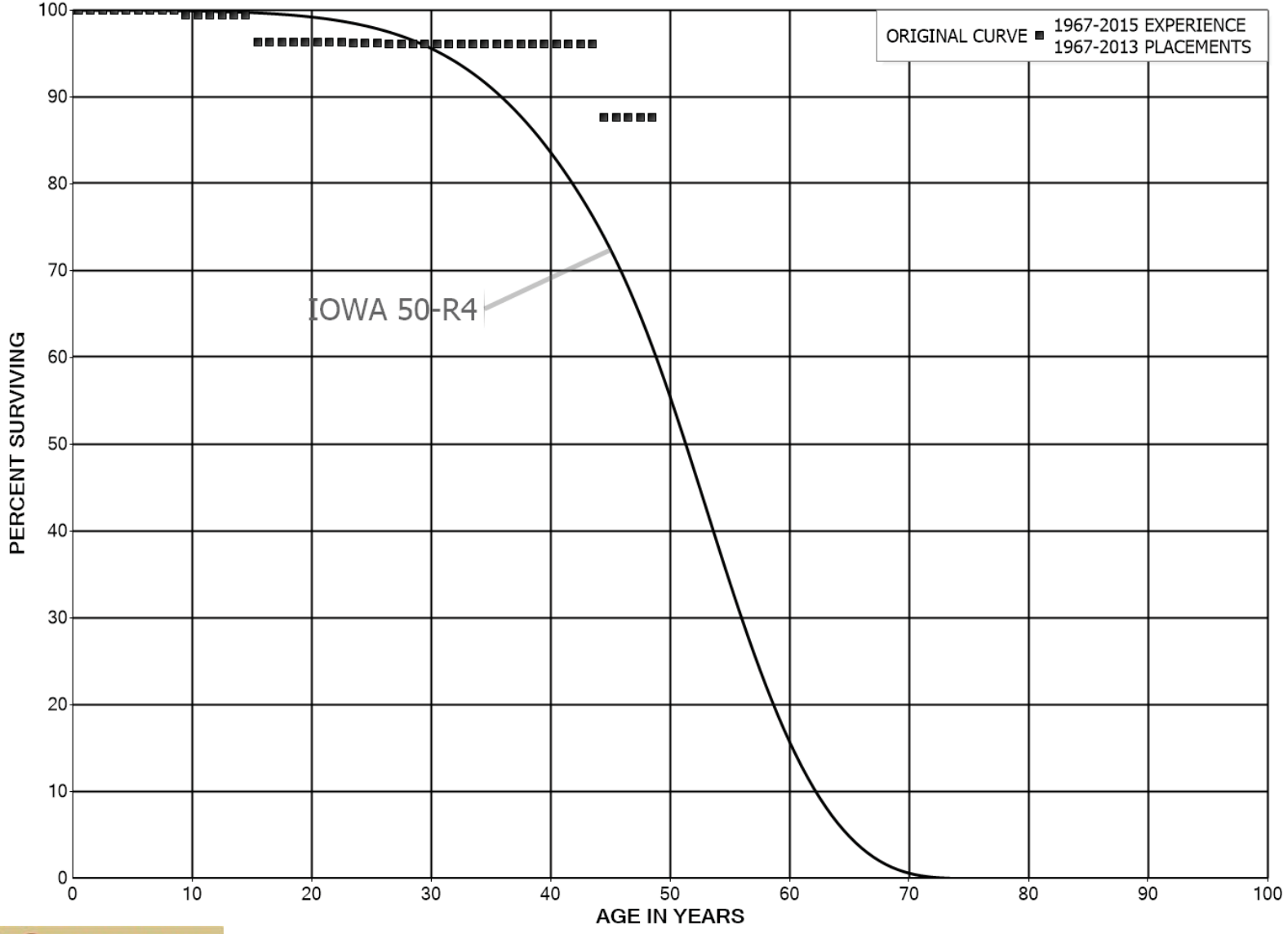
ACCOUNT L03 - LAND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,181,133		0.0000	1.0000	95.62
40.5	2,121,180		0.0000	1.0000	95.62
41.5	1,858,787		0.0000	1.0000	95.62
42.5	1,858,787		0.0000	1.0000	95.62
43.5	1,572,568		0.0000	1.0000	95.62
44.5	575,791		0.0000	1.0000	95.62
45.5	262,197		0.0000	1.0000	95.62
46.5	262,197		0.0000	1.0000	95.62
47.5	180,098		0.0000	1.0000	95.62
48.5	5,754		0.0000	1.0000	95.62
49.5	5,754		0.0000	1.0000	95.62
50.5					95.62

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT L04 - LIGHTING SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L04 - LIGHTING SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2013 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	961,466		0.0000	1.0000	100.00
0.5	961,466		0.0000	1.0000	100.00
1.5	961,466		0.0000	1.0000	100.00
2.5	703,475		0.0000	1.0000	100.00
3.5	610,448		0.0000	1.0000	100.00
4.5	610,448		0.0000	1.0000	100.00
5.5	610,448		0.0000	1.0000	100.00
6.5	610,448		0.0000	1.0000	100.00
7.5	610,448		0.0000	1.0000	100.00
8.5	610,448	3,887	0.0064	0.9936	100.00
9.5	606,561		0.0000	1.0000	99.36
10.5	606,561		0.0000	1.0000	99.36
11.5	606,561		0.0000	1.0000	99.36
12.5	606,561		0.0000	1.0000	99.36
13.5	606,561		0.0000	1.0000	99.36
14.5	606,561	18,968	0.0313	0.9687	99.36
15.5	587,593		0.0000	1.0000	96.26
16.5	587,593		0.0000	1.0000	96.26
17.5	587,593		0.0000	1.0000	96.26
18.5	587,593		0.0000	1.0000	96.26
19.5	587,593		0.0000	1.0000	96.26
20.5	587,593		0.0000	1.0000	96.26
21.5	587,593		0.0000	1.0000	96.26
22.5	587,593	251	0.0004	0.9996	96.26
23.5	584,606		0.0000	1.0000	96.21
24.5	565,775		0.0000	1.0000	96.21
25.5	530,168	548	0.0010	0.9990	96.21
26.5	511,596		0.0000	1.0000	96.12
27.5	501,759		0.0000	1.0000	96.12
28.5	462,437		0.0000	1.0000	96.12
29.5	456,580		0.0000	1.0000	96.12
30.5	453,017		0.0000	1.0000	96.12
31.5	453,017		0.0000	1.0000	96.12
32.5	442,026		0.0000	1.0000	96.12
33.5	408,180		0.0000	1.0000	96.12
34.5	398,291		0.0000	1.0000	96.12
35.5	372,390		0.0000	1.0000	96.12
36.5	288,819		0.0000	1.0000	96.12
37.5	220,924		0.0000	1.0000	96.12
38.5	190,964		0.0000	1.0000	96.12

NEWFOUNDLAND AND LABRADOR HYDRO

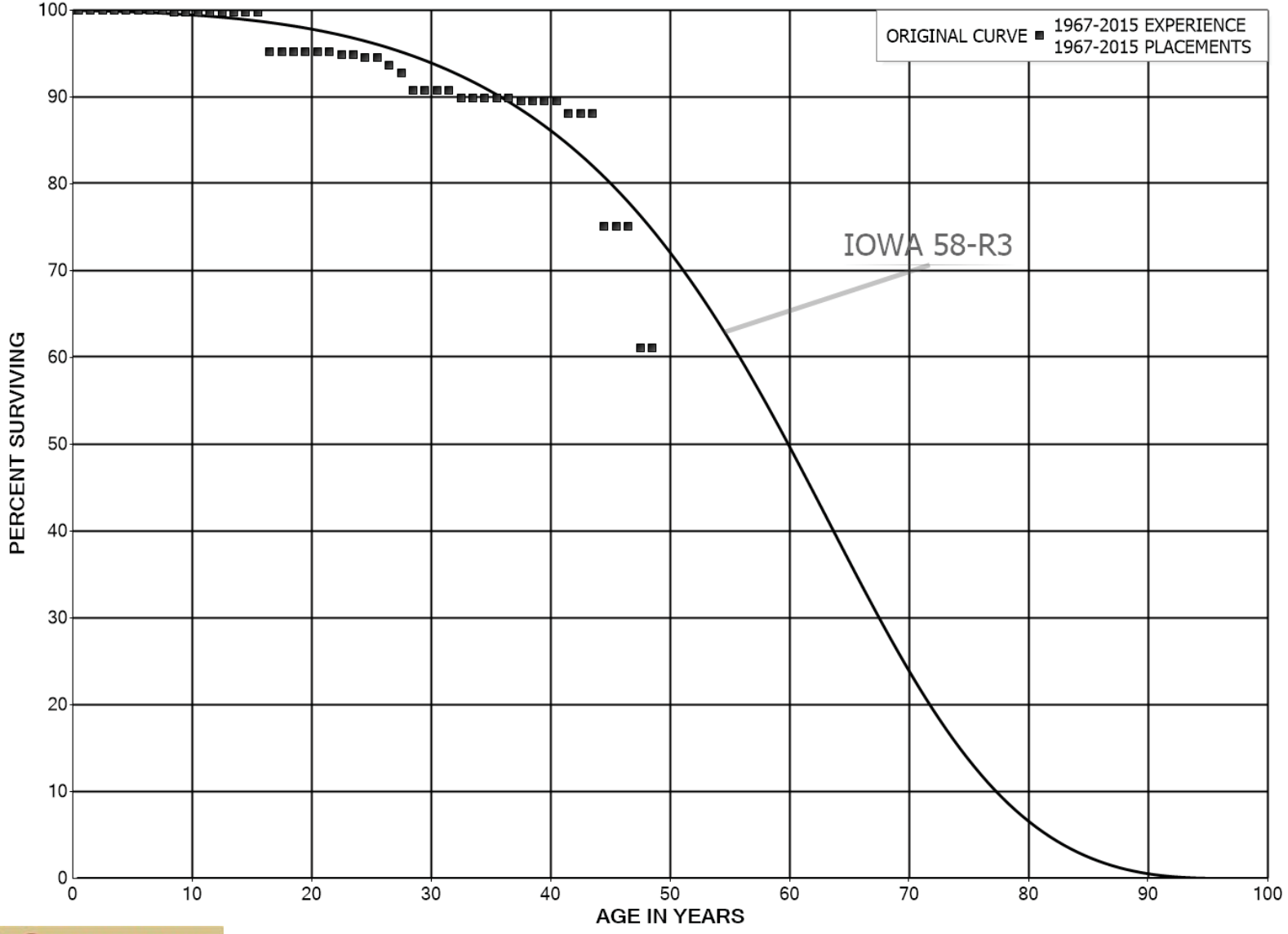
ACCOUNT L04 - LIGHTING SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2013 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	186,557		0.0000	1.0000	96.12
40.5	146,805		0.0000	1.0000	96.12
41.5	130,187		0.0000	1.0000	96.12
42.5	130,187		0.0000	1.0000	96.12
43.5	130,187	11,509	0.0884	0.9116	96.12
44.5	90,452		0.0000	1.0000	87.62
45.5	47,965		0.0000	1.0000	87.62
46.5	47,965		0.0000	1.0000	87.62
47.5	45,238		0.0000	1.0000	87.62
48.5					87.62

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT L05 - LIGHTNING ARRESTORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L05 - LIGHTNING ARRESTORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,294,940	6,388	0.0010	0.9990	100.00
0.5	5,967,202	314	0.0001	0.9999	99.90
1.5	5,876,747		0.0000	1.0000	99.89
2.5	5,859,055		0.0000	1.0000	99.89
3.5	5,772,890		0.0000	1.0000	99.89
4.5	5,715,551		0.0000	1.0000	99.89
5.5	5,692,652		0.0000	1.0000	99.89
6.5	5,612,650		0.0000	1.0000	99.89
7.5	5,560,060	8,235	0.0015	0.9985	99.89
8.5	5,538,693		0.0000	1.0000	99.75
9.5	5,448,583		0.0000	1.0000	99.75
10.5	5,368,864		0.0000	1.0000	99.75
11.5	5,357,424		0.0000	1.0000	99.75
12.5	5,357,424		0.0000	1.0000	99.75
13.5	5,357,424		0.0000	1.0000	99.75
14.5	5,357,424		0.0000	1.0000	99.75
15.5	301,716	13,947	0.0462	0.9538	99.75
16.5	287,769		0.0000	1.0000	95.13
17.5	287,769		0.0000	1.0000	95.13
18.5	287,769		0.0000	1.0000	95.13
19.5	285,304		0.0000	1.0000	95.13
20.5	285,304		0.0000	1.0000	95.13
21.5	282,713	944	0.0033	0.9967	95.13
22.5	281,769		0.0000	1.0000	94.82
23.5	281,769	892	0.0032	0.9968	94.82
24.5	280,877		0.0000	1.0000	94.52
25.5	280,877	2,829	0.0101	0.9899	94.52
26.5	277,708	2,538	0.0091	0.9909	93.56
27.5	274,358	5,754	0.0210	0.9790	92.71
28.5	268,310		0.0000	1.0000	90.76
29.5	262,608		0.0000	1.0000	90.76
30.5	262,608		0.0000	1.0000	90.76
31.5	262,608	2,692	0.0103	0.9897	90.76
32.5	259,916		0.0000	1.0000	89.83
33.5	234,230		0.0000	1.0000	89.83
34.5	232,163		0.0000	1.0000	89.83
35.5	231,873		0.0000	1.0000	89.83
36.5	231,873	755	0.0033	0.9967	89.83
37.5	211,893		0.0000	1.0000	89.54
38.5	211,828		0.0000	1.0000	89.54

NEWFOUNDLAND AND LABRADOR HYDRO

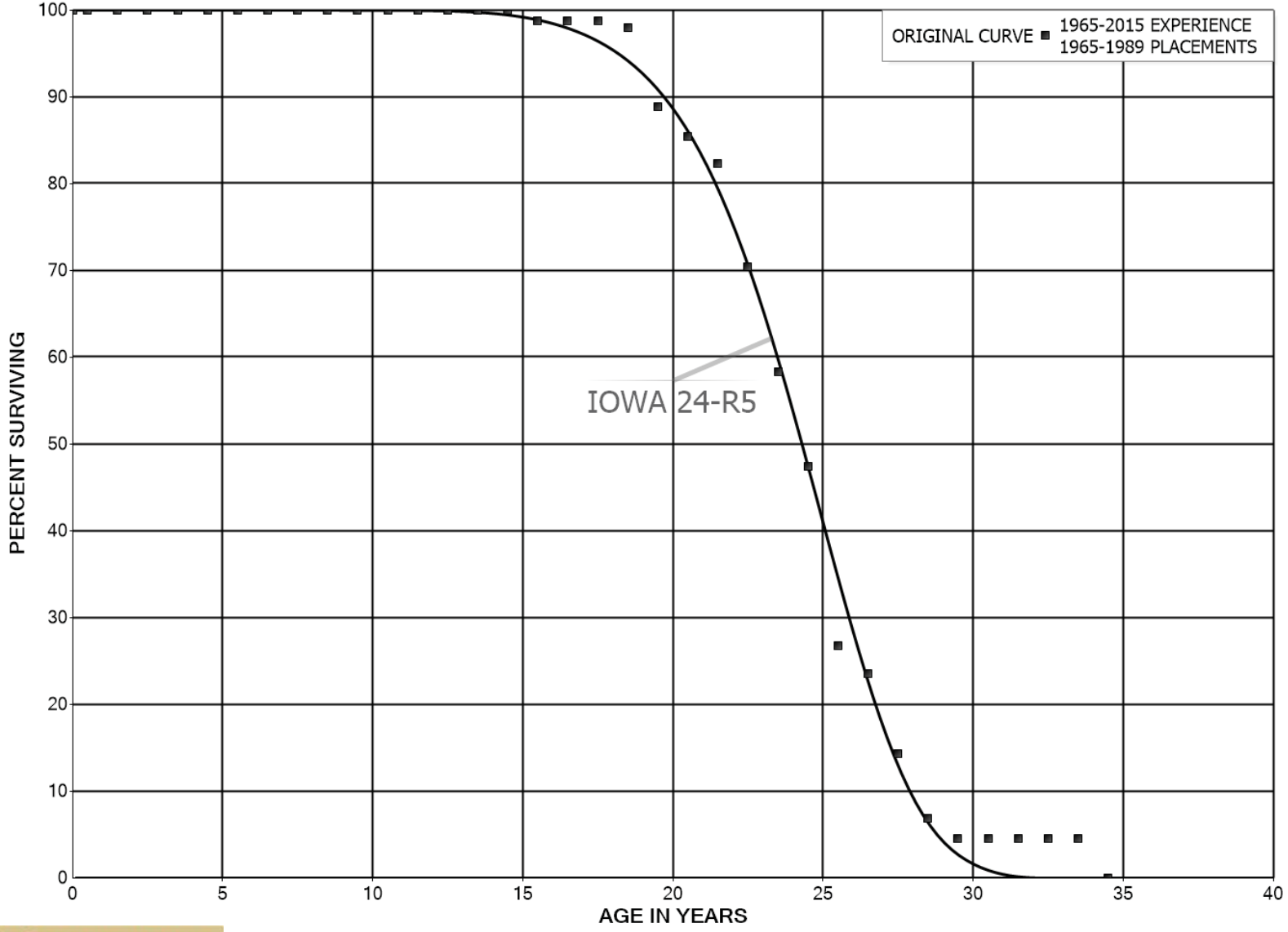
ACCOUNT L05 - LIGHTNING ARRESTORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	211,828		0.0000	1.0000	89.54
40.5	211,828	3,471	0.0164	0.9836	89.54
41.5	208,357		0.0000	1.0000	88.07
42.5	208,357		0.0000	1.0000	88.07
43.5	208,357	30,755	0.1476	0.8524	88.07
44.5	177,602		0.0000	1.0000	75.07
45.5	116,585		0.0000	1.0000	75.07
46.5	116,585	21,815	0.1871	0.8129	75.07
47.5	44,408		0.0000	1.0000	61.03
48.5					61.03

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT L06 - LINE COUPLING EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

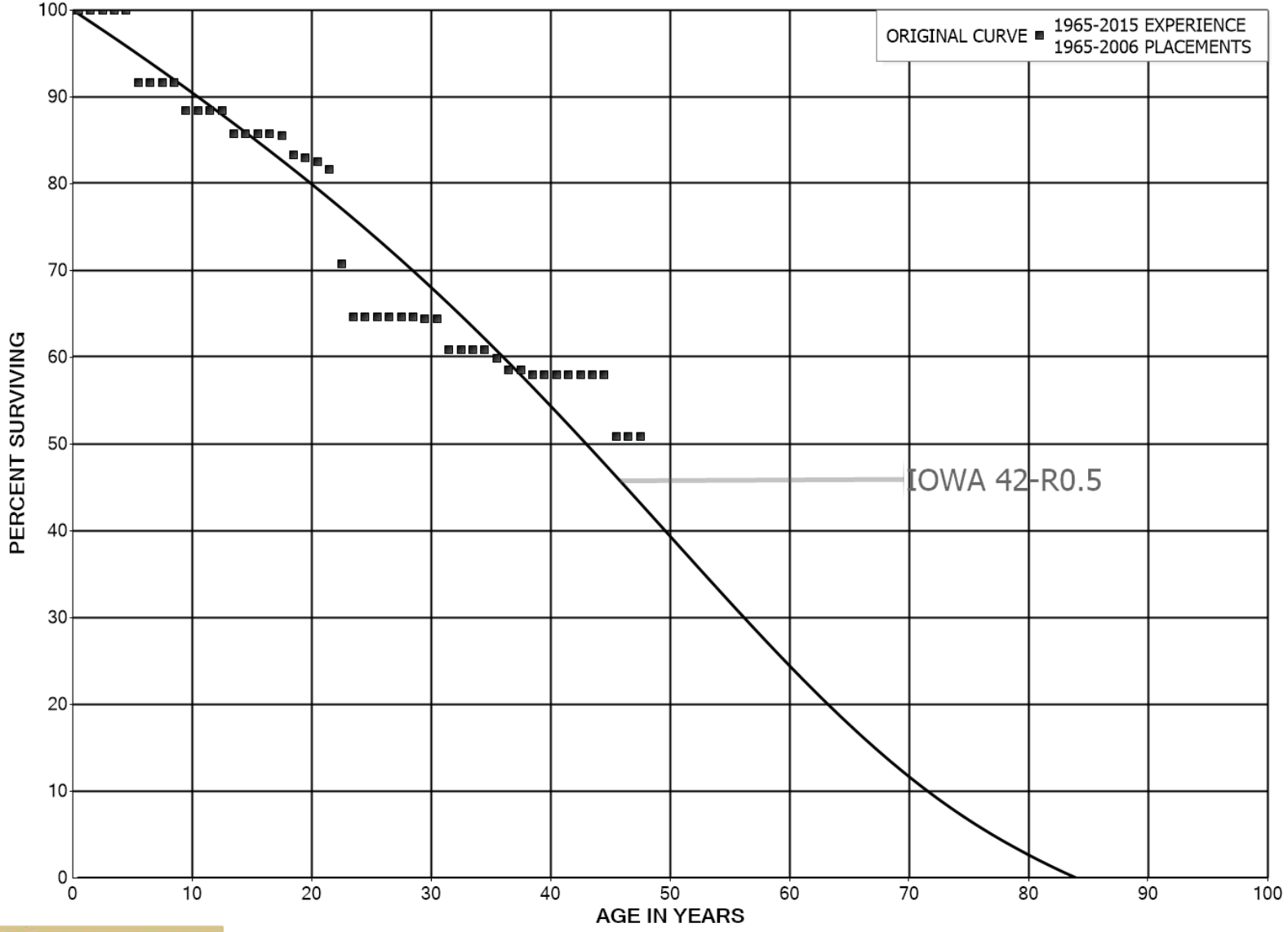
ACCOUNT L06 - LINE COUPLING EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-1989 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	283,845		0.0000	1.0000	100.00
0.5	283,845		0.0000	1.0000	100.00
1.5	283,845		0.0000	1.0000	100.00
2.5	283,845		0.0000	1.0000	100.00
3.5	283,845		0.0000	1.0000	100.00
4.5	283,845		0.0000	1.0000	100.00
5.5	283,845		0.0000	1.0000	100.00
6.5	283,845		0.0000	1.0000	100.00
7.5	283,845		0.0000	1.0000	100.00
8.5	283,845		0.0000	1.0000	100.00
9.5	283,845		0.0000	1.0000	100.00
10.5	283,845		0.0000	1.0000	100.00
11.5	283,845		0.0000	1.0000	100.00
12.5	283,845		0.0000	1.0000	100.00
13.5	283,845		0.0000	1.0000	100.00
14.5	283,845	3,500	0.0123	0.9877	100.00
15.5	280,345		0.0000	1.0000	98.77
16.5	280,345		0.0000	1.0000	98.77
17.5	280,345	2,288	0.0082	0.9918	98.77
18.5	278,057	25,956	0.0933	0.9067	97.96
19.5	252,101	9,613	0.0381	0.9619	88.82
20.5	242,488	8,841	0.0365	0.9635	85.43
21.5	233,647	33,900	0.1451	0.8549	82.32
22.5	199,747	34,202	0.1712	0.8288	70.37
23.5	165,546	31,132	0.1881	0.8119	58.32
24.5	134,414	58,470	0.4350	0.5650	47.35
25.5	75,945	9,291	0.1223	0.8777	26.76
26.5	66,654	26,127	0.3920	0.6080	23.48
27.5	40,527	21,273	0.5249	0.4751	14.28
28.5	19,254	6,528	0.3391	0.6609	6.78
29.5	12,726		0.0000	1.0000	4.48
30.5	12,726		0.0000	1.0000	4.48
31.5	1,500		0.0000	1.0000	4.48
32.5	1,500		0.0000	1.0000	4.48
33.5	1,500	1,500	1.0000		4.48
34.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M01 - MAIN BREAKERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M01 - MAIN BREAKERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2006 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	736,754		0.0000	1.0000	100.00
0.5	736,754		0.0000	1.0000	100.00
1.5	736,754		0.0000	1.0000	100.00
2.5	736,754		0.0000	1.0000	100.00
3.5	736,754		0.0000	1.0000	100.00
4.5	736,754	62,132	0.0843	0.9157	100.00
5.5	674,622		0.0000	1.0000	91.57
6.5	674,622		0.0000	1.0000	91.57
7.5	674,622		0.0000	1.0000	91.57
8.5	674,622	23,698	0.0351	0.9649	91.57
9.5	531,730		0.0000	1.0000	88.35
10.5	531,730		0.0000	1.0000	88.35
11.5	503,834		0.0000	1.0000	88.35
12.5	411,286	12,000	0.0292	0.9708	88.35
13.5	399,286		0.0000	1.0000	85.77
14.5	351,328		0.0000	1.0000	85.77
15.5	351,328		0.0000	1.0000	85.77
16.5	351,328	1,200	0.0034	0.9966	85.77
17.5	326,517	8,319	0.0255	0.9745	85.48
18.5	313,682	1,200	0.0038	0.9962	83.30
19.5	216,280	1,200	0.0055	0.9945	82.98
20.5	215,080	2,400	0.0112	0.9888	82.52
21.5	212,680	28,313	0.1331	0.8669	81.60
22.5	184,367	15,852	0.0860	0.9140	70.74
23.5	168,515		0.0000	1.0000	64.66
24.5	163,837		0.0000	1.0000	64.66
25.5	163,837		0.0000	1.0000	64.66
26.5	163,837		0.0000	1.0000	64.66
27.5	163,837		0.0000	1.0000	64.66
28.5	163,837	798	0.0049	0.9951	64.66
29.5	148,265		0.0000	1.0000	64.34
30.5	148,265	8,161	0.0550	0.9450	64.34
31.5	140,104		0.0000	1.0000	60.80
32.5	126,104		0.0000	1.0000	60.80
33.5	126,104		0.0000	1.0000	60.80
34.5	126,104	1,941	0.0154	0.9846	60.80
35.5	109,962	2,400	0.0218	0.9782	59.86
36.5	107,562		0.0000	1.0000	58.56
37.5	107,562	1,200	0.0112	0.9888	58.56
38.5	106,362		0.0000	1.0000	57.90

NEWFOUNDLAND AND LABRADOR HYDRO

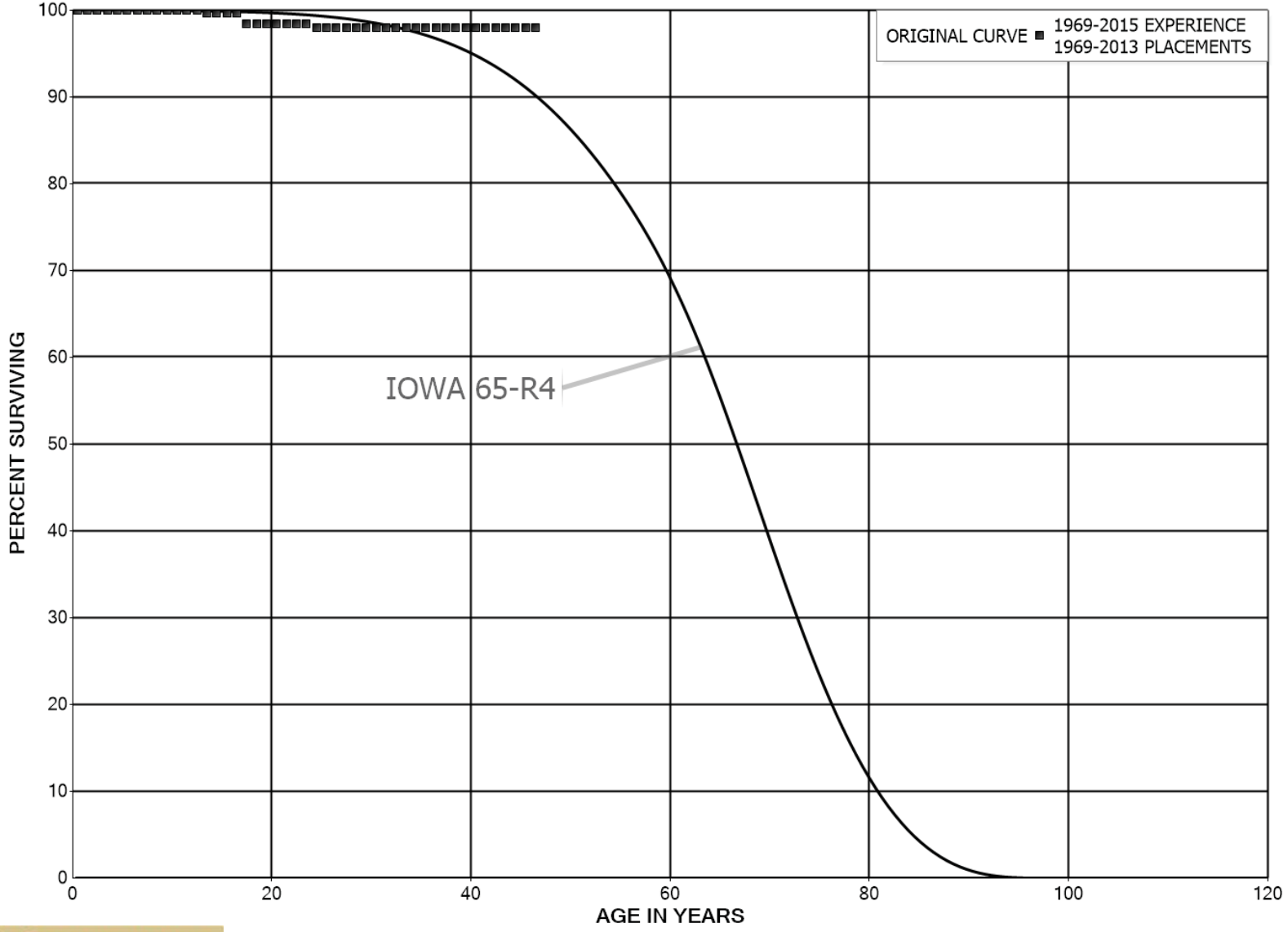
ACCOUNT M01 - MAIN BREAKERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2006 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	106,362		0.0000	1.0000	57.90
40.5	106,362		0.0000	1.0000	57.90
41.5	106,362		0.0000	1.0000	57.90
42.5	106,362		0.0000	1.0000	57.90
43.5	106,362		0.0000	1.0000	57.90
44.5	106,362	13,000	0.1222	0.8778	57.90
45.5	87,097		0.0000	1.0000	50.83
46.5	87,097		0.0000	1.0000	50.83
47.5					50.83

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M02 - MARINE TERMINAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M02 - MARINE TERMINAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-2013 EXPERIENCE BAND 1969-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,370,678		0.0000	1.0000	100.00
0.5	4,370,678		0.0000	1.0000	100.00
1.5	4,370,678		0.0000	1.0000	100.00
2.5	3,513,142		0.0000	1.0000	100.00
3.5	3,513,142		0.0000	1.0000	100.00
4.5	3,513,142		0.0000	1.0000	100.00
5.5	3,513,142		0.0000	1.0000	100.00
6.5	3,391,551		0.0000	1.0000	100.00
7.5	3,391,551		0.0000	1.0000	100.00
8.5	3,391,551		0.0000	1.0000	100.00
9.5	3,391,551		0.0000	1.0000	100.00
10.5	3,391,551		0.0000	1.0000	100.00
11.5	3,391,551		0.0000	1.0000	100.00
12.5	3,391,551	12,192	0.0036	0.9964	100.00
13.5	3,379,359		0.0000	1.0000	99.64
14.5	3,379,359		0.0000	1.0000	99.64
15.5	3,379,359	1,114	0.0003	0.9997	99.64
16.5	3,378,245	39,909	0.0118	0.9882	99.61
17.5	3,338,336		0.0000	1.0000	98.43
18.5	3,338,336		0.0000	1.0000	98.43
19.5	2,991,404		0.0000	1.0000	98.43
20.5	2,991,404		0.0000	1.0000	98.43
21.5	2,991,404		0.0000	1.0000	98.43
22.5	2,991,404		0.0000	1.0000	98.43
23.5	2,991,404	15,069	0.0050	0.9950	98.43
24.5	2,976,335		0.0000	1.0000	97.94
25.5	2,976,335		0.0000	1.0000	97.94
26.5	2,976,335		0.0000	1.0000	97.94
27.5	2,976,335		0.0000	1.0000	97.94
28.5	2,976,335		0.0000	1.0000	97.94
29.5	2,976,335		0.0000	1.0000	97.94
30.5	2,976,335		0.0000	1.0000	97.94
31.5	2,689,521		0.0000	1.0000	97.94
32.5	2,678,149		0.0000	1.0000	97.94
33.5	2,678,149		0.0000	1.0000	97.94
34.5	2,678,149		0.0000	1.0000	97.94
35.5	2,665,300		0.0000	1.0000	97.94
36.5	2,665,300		0.0000	1.0000	97.94
37.5	2,665,300		0.0000	1.0000	97.94
38.5	2,665,300		0.0000	1.0000	97.94

NEWFOUNDLAND AND LABRADOR HYDRO

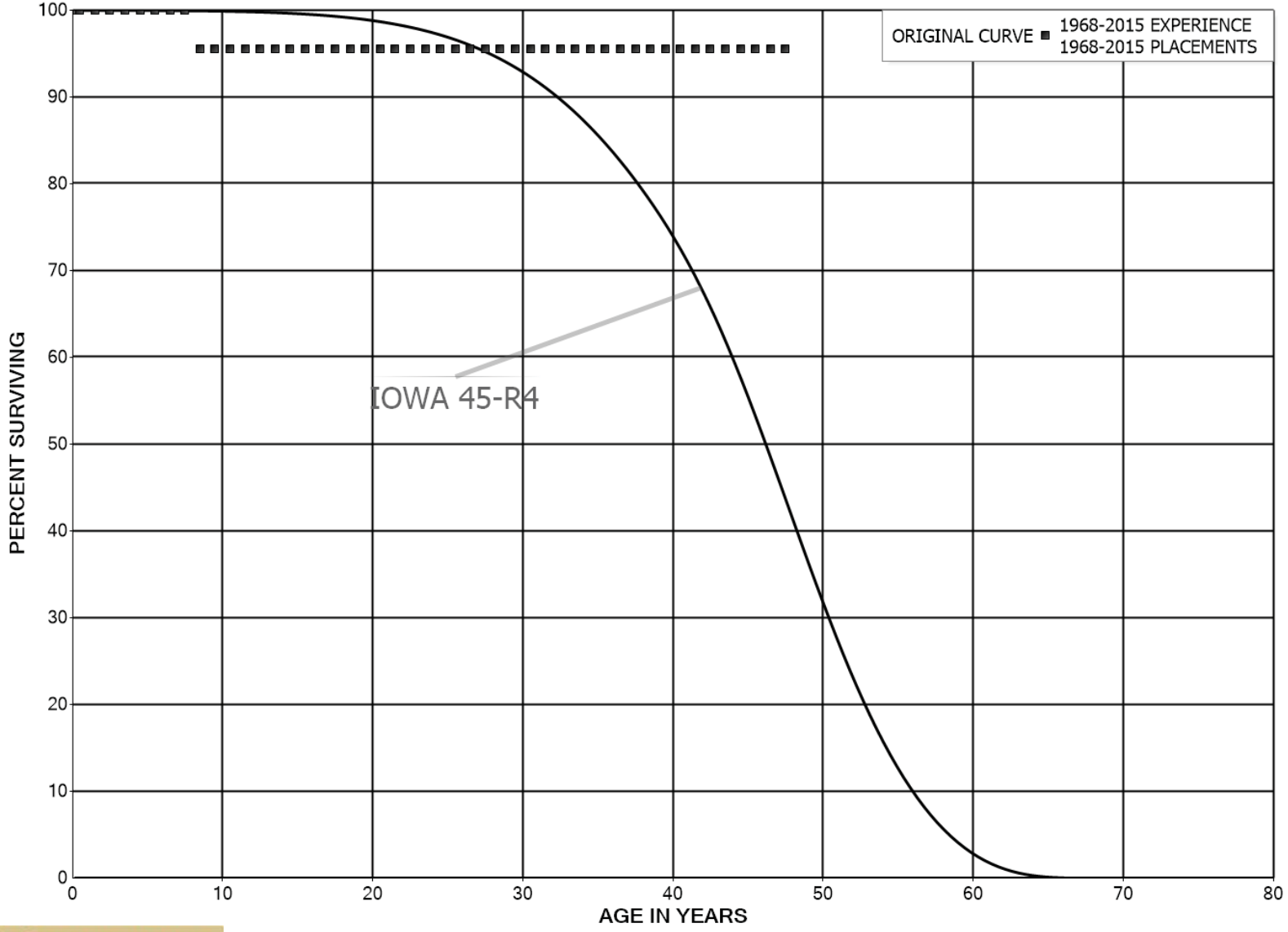
ACCOUNT M02 - MARINE TERMINAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-2013 EXPERIENCE BAND 1969-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,665,300		0.0000	1.0000	97.94
40.5	2,665,300		0.0000	1.0000	97.94
41.5	2,665,300		0.0000	1.0000	97.94
42.5	2,665,300		0.0000	1.0000	97.94
43.5	2,665,300		0.0000	1.0000	97.94
44.5	2,596,300		0.0000	1.0000	97.94
45.5	2,596,300		0.0000	1.0000	97.94
46.5					97.94

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M03 - METALCLAD SWITCHGEAR CUB/EQU 4kv/600
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M03 - METALCLAD SWITCHGEAR CUB/EQU 4kv/600

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,321,761		0.0000	1.0000	100.00
0.5	1,937,987		0.0000	1.0000	100.00
1.5	1,937,987		0.0000	1.0000	100.00
2.5	1,937,987		0.0000	1.0000	100.00
3.5	1,937,987		0.0000	1.0000	100.00
4.5	1,937,987		0.0000	1.0000	100.00
5.5	1,937,987		0.0000	1.0000	100.00
6.5	1,937,987		0.0000	1.0000	100.00
7.5	1,937,987	88,117	0.0455	0.9545	100.00
8.5	1,849,870		0.0000	1.0000	95.45
9.5	1,849,870		0.0000	1.0000	95.45
10.5	1,849,870		0.0000	1.0000	95.45
11.5	1,849,870		0.0000	1.0000	95.45
12.5	1,849,870		0.0000	1.0000	95.45
13.5	1,849,870		0.0000	1.0000	95.45
14.5	1,849,870		0.0000	1.0000	95.45
15.5	1,849,870		0.0000	1.0000	95.45
16.5	1,849,870		0.0000	1.0000	95.45
17.5	1,849,870		0.0000	1.0000	95.45
18.5	1,849,870		0.0000	1.0000	95.45
19.5	1,849,870		0.0000	1.0000	95.45
20.5	1,835,582		0.0000	1.0000	95.45
21.5	1,268,370		0.0000	1.0000	95.45
22.5	1,268,370		0.0000	1.0000	95.45
23.5	1,268,370		0.0000	1.0000	95.45
24.5	1,268,370		0.0000	1.0000	95.45
25.5	1,268,370		0.0000	1.0000	95.45
26.5	1,268,370		0.0000	1.0000	95.45
27.5	1,268,370		0.0000	1.0000	95.45
28.5	1,211,961		0.0000	1.0000	95.45
29.5	1,211,961		0.0000	1.0000	95.45
30.5	1,211,961		0.0000	1.0000	95.45
31.5	1,211,961		0.0000	1.0000	95.45
32.5	1,211,961		0.0000	1.0000	95.45
33.5	1,211,961		0.0000	1.0000	95.45
34.5	1,211,961		0.0000	1.0000	95.45
35.5	431,573		0.0000	1.0000	95.45
36.5	431,573		0.0000	1.0000	95.45
37.5	431,573		0.0000	1.0000	95.45
38.5	431,573		0.0000	1.0000	95.45

NEWFOUNDLAND AND LABRADOR HYDRO

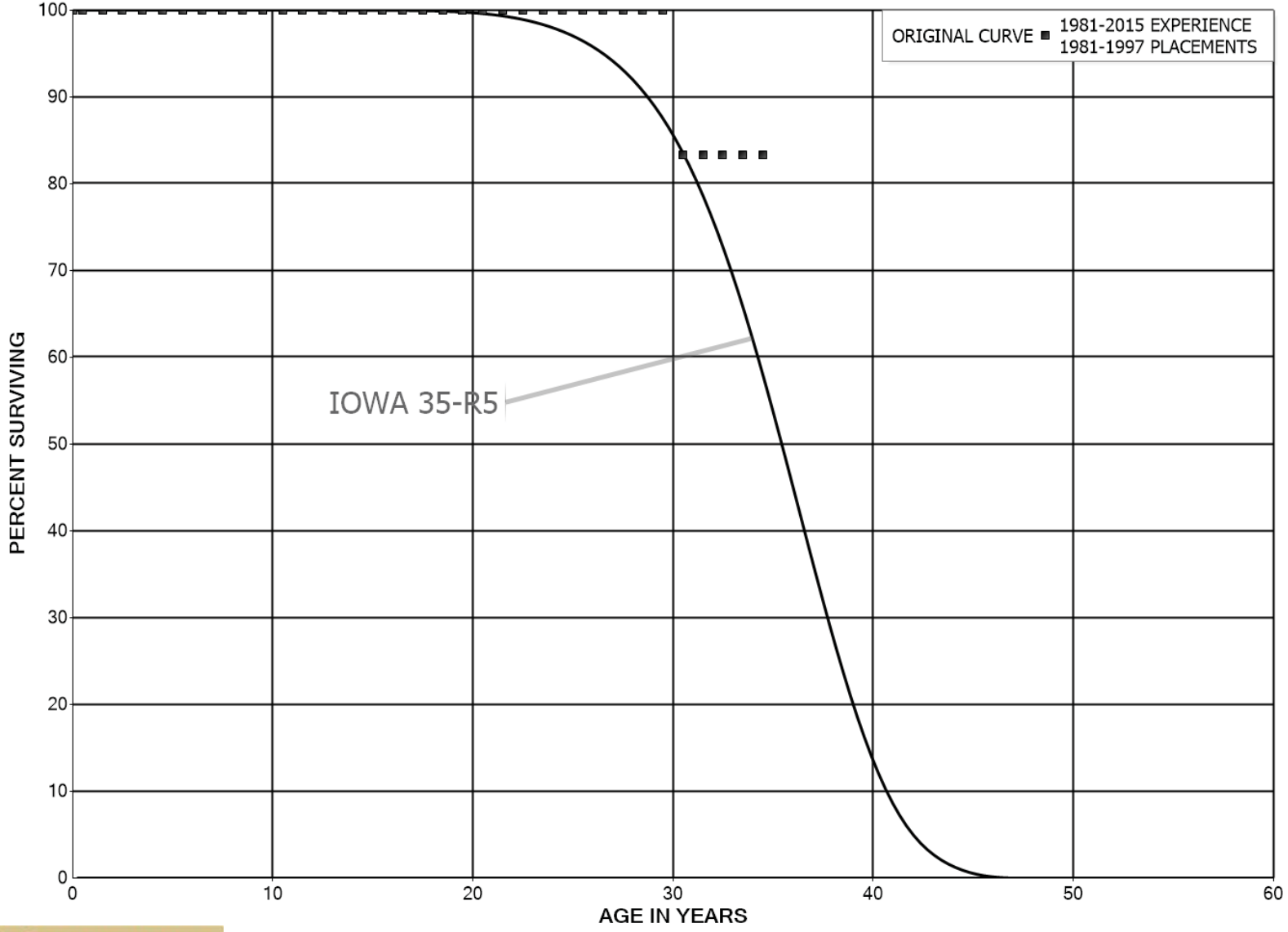
ACCOUNT M03 - METALCLAD SWITCHGEAR CUB/EQU 4kv/600

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	431,573		0.0000	1.0000	95.45
40.5	431,573		0.0000	1.0000	95.45
41.5	431,573		0.0000	1.0000	95.45
42.5	431,573		0.0000	1.0000	95.45
43.5	431,573		0.0000	1.0000	95.45
44.5	431,573		0.0000	1.0000	95.45
45.5	431,573		0.0000	1.0000	95.45
46.5	431,573		0.0000	1.0000	95.45
47.5					95.45

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M04 - METER TEST SWITCHES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

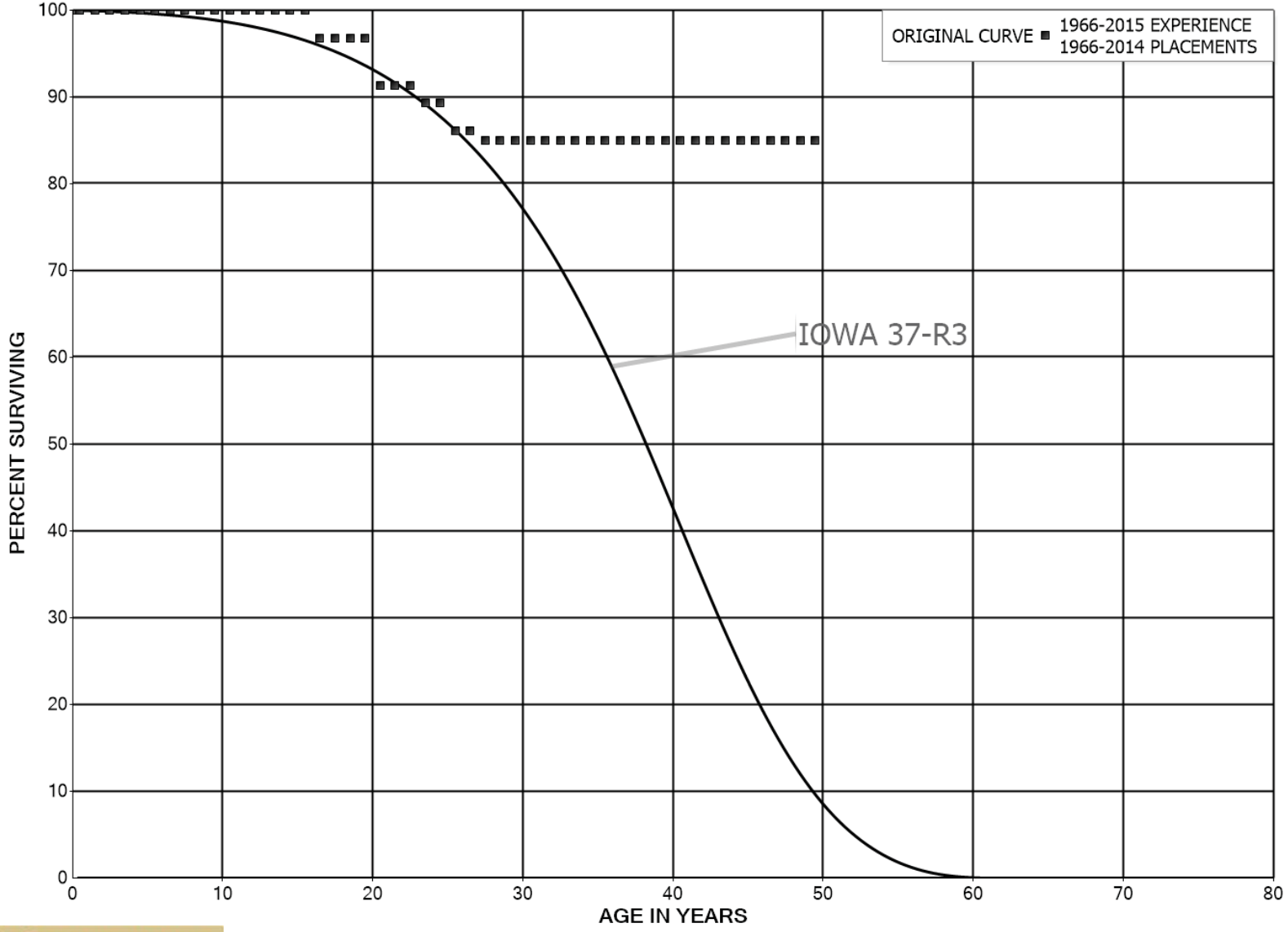
ACCOUNT M04 - METER TEST SWITCHES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-1997 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	60,735		0.0000	1.0000	100.00
0.5	60,735		0.0000	1.0000	100.00
1.5	60,735		0.0000	1.0000	100.00
2.5	60,735		0.0000	1.0000	100.00
3.5	60,735		0.0000	1.0000	100.00
4.5	60,735		0.0000	1.0000	100.00
5.5	60,735		0.0000	1.0000	100.00
6.5	60,735		0.0000	1.0000	100.00
7.5	60,735		0.0000	1.0000	100.00
8.5	60,735		0.0000	1.0000	100.00
9.5	60,735		0.0000	1.0000	100.00
10.5	60,735		0.0000	1.0000	100.00
11.5	60,735		0.0000	1.0000	100.00
12.5	60,735		0.0000	1.0000	100.00
13.5	60,735		0.0000	1.0000	100.00
14.5	60,735		0.0000	1.0000	100.00
15.5	60,735		0.0000	1.0000	100.00
16.5	60,735		0.0000	1.0000	100.00
17.5	60,735		0.0000	1.0000	100.00
18.5	55,044		0.0000	1.0000	100.00
19.5	55,044		0.0000	1.0000	100.00
20.5	55,044		0.0000	1.0000	100.00
21.5	43,701		0.0000	1.0000	100.00
22.5	42,485		0.0000	1.0000	100.00
23.5	42,485		0.0000	1.0000	100.00
24.5	29,763		0.0000	1.0000	100.00
25.5	29,763		0.0000	1.0000	100.00
26.5	29,763		0.0000	1.0000	100.00
27.5	26,459		0.0000	1.0000	100.00
28.5	14,602		0.0000	1.0000	100.00
29.5	14,602	2,434	0.1667	0.8333	100.00
30.5	12,168		0.0000	1.0000	83.33
31.5	11,271		0.0000	1.0000	83.33
32.5	11,271		0.0000	1.0000	83.33
33.5	9,278		0.0000	1.0000	83.33
34.5					83.33

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M05 - METERING TANKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M05 - METERING TANKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2014 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	705,132		0.0000	1.0000	100.00
0.5	705,132		0.0000	1.0000	100.00
1.5	565,098		0.0000	1.0000	100.00
2.5	469,655		0.0000	1.0000	100.00
3.5	409,740		0.0000	1.0000	100.00
4.5	343,171		0.0000	1.0000	100.00
5.5	343,171		0.0000	1.0000	100.00
6.5	343,171		0.0000	1.0000	100.00
7.5	343,171		0.0000	1.0000	100.00
8.5	343,171		0.0000	1.0000	100.00
9.5	343,171		0.0000	1.0000	100.00
10.5	343,171		0.0000	1.0000	100.00
11.5	343,171		0.0000	1.0000	100.00
12.5	343,171		0.0000	1.0000	100.00
13.5	343,171		0.0000	1.0000	100.00
14.5	343,171		0.0000	1.0000	100.00
15.5	343,171	11,420	0.0333	0.9667	100.00
16.5	331,751		0.0000	1.0000	96.67
17.5	331,751		0.0000	1.0000	96.67
18.5	330,505		0.0000	1.0000	96.67
19.5	316,174	17,609	0.0557	0.9443	96.67
20.5	298,565		0.0000	1.0000	91.29
21.5	277,148		0.0000	1.0000	91.29
22.5	241,006	5,184	0.0215	0.9785	91.29
23.5	218,320		0.0000	1.0000	89.32
24.5	218,320	8,002	0.0367	0.9633	89.32
25.5	210,318		0.0000	1.0000	86.05
26.5	198,433	2,500	0.0126	0.9874	86.05
27.5	182,108		0.0000	1.0000	84.97
28.5	182,108		0.0000	1.0000	84.97
29.5	182,108		0.0000	1.0000	84.97
30.5	182,108		0.0000	1.0000	84.97
31.5	170,992		0.0000	1.0000	84.97
32.5	165,644		0.0000	1.0000	84.97
33.5	165,644		0.0000	1.0000	84.97
34.5	34,552		0.0000	1.0000	84.97
35.5	34,552		0.0000	1.0000	84.97
36.5	26,391		0.0000	1.0000	84.97
37.5	20,957		0.0000	1.0000	84.97
38.5	20,957		0.0000	1.0000	84.97

NEWFOUNDLAND AND LABRADOR HYDRO

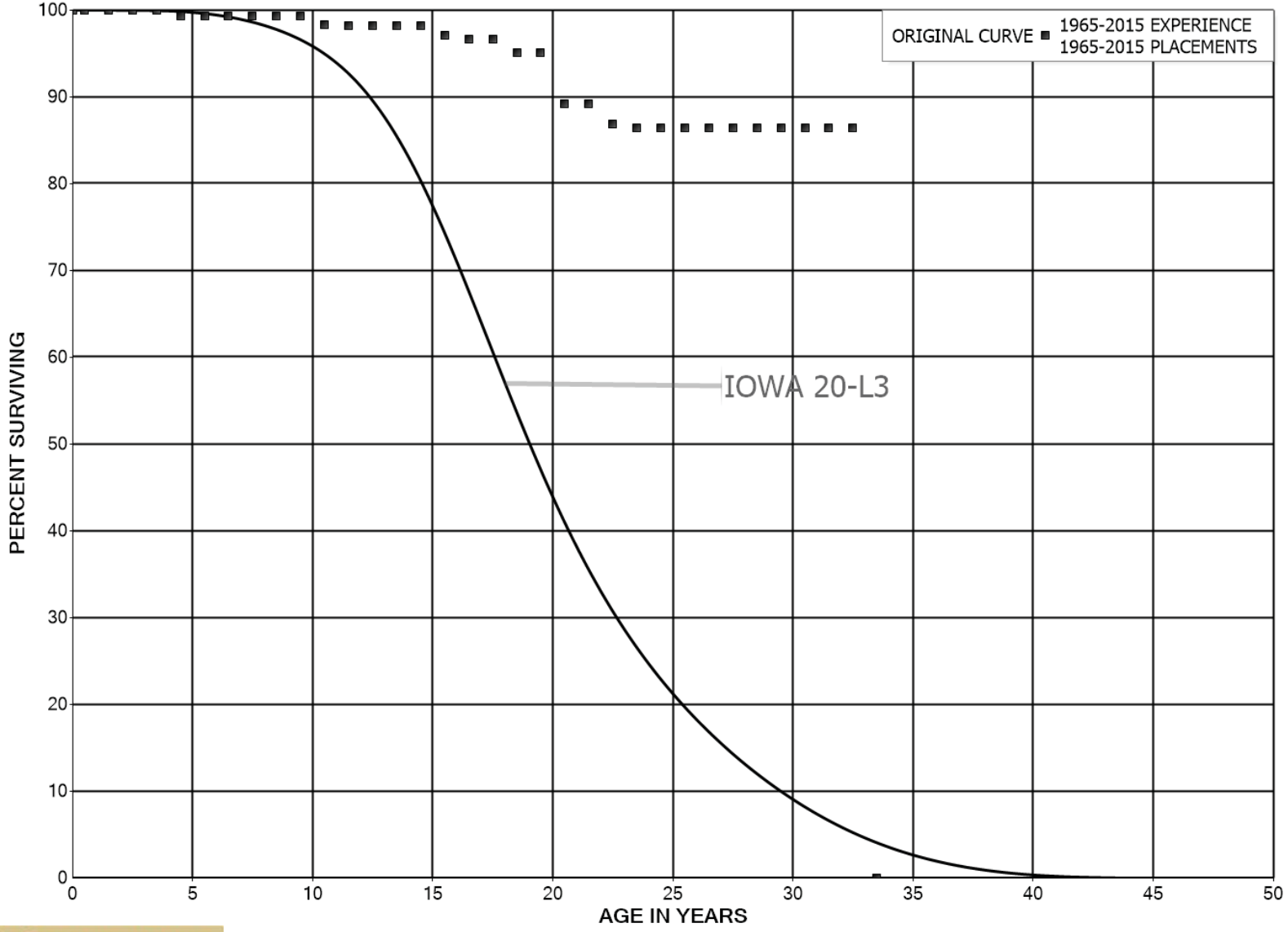
ACCOUNT M05 - METERING TANKS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2014 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,957		0.0000	1.0000	84.97
40.5	20,957		0.0000	1.0000	84.97
41.5	20,957		0.0000	1.0000	84.97
42.5	20,957		0.0000	1.0000	84.97
43.5	13,595		0.0000	1.0000	84.97
44.5	13,595		0.0000	1.0000	84.97
45.5	9,614		0.0000	1.0000	84.97
46.5	9,614		0.0000	1.0000	84.97
47.5	2,500		0.0000	1.0000	84.97
48.5	2,500		0.0000	1.0000	84.97
49.5					84.97

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M06 - METERS - DIGITAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

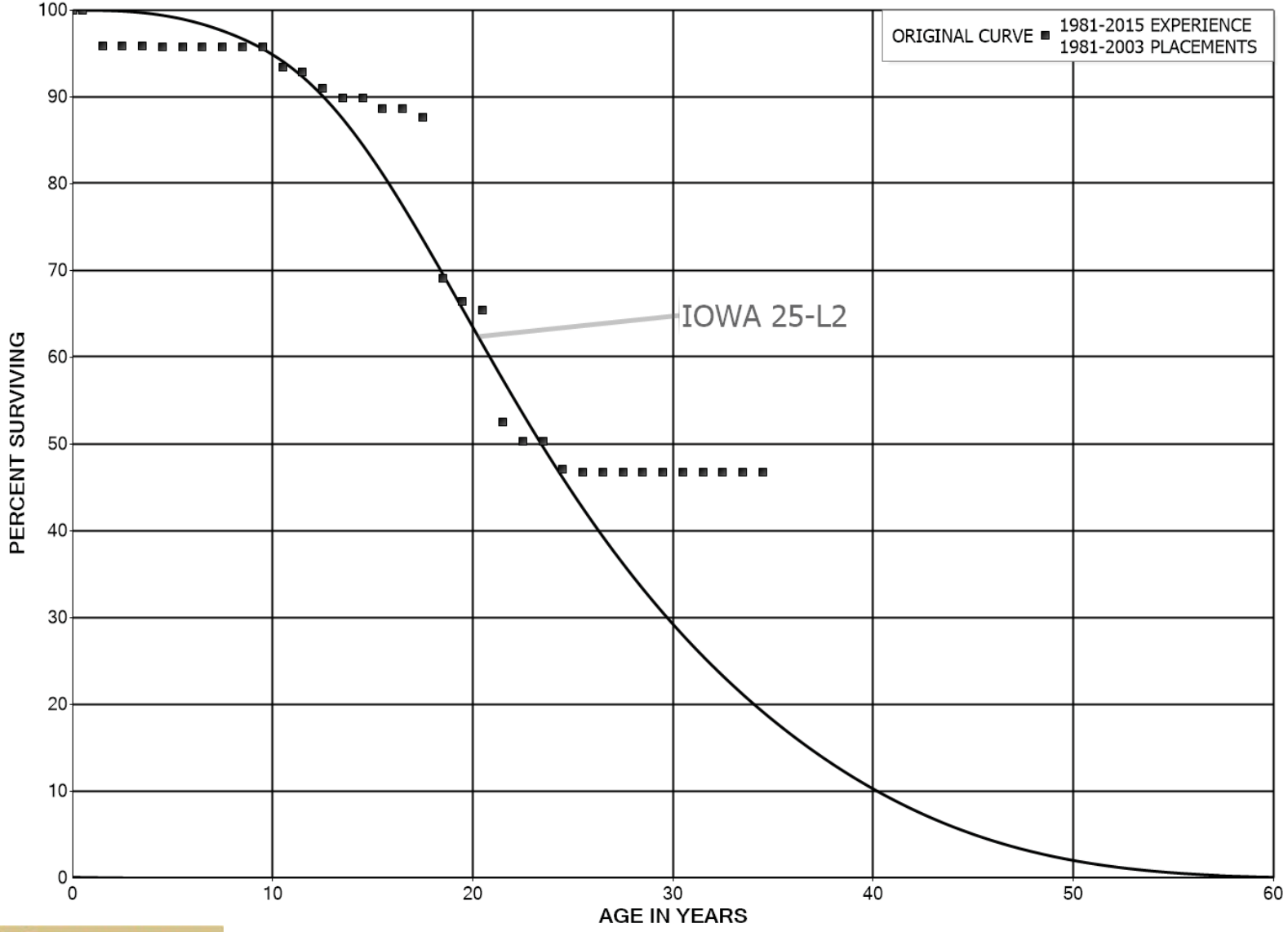
ACCOUNT M06 - METERS - DIGITAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,037,293		0.0000	1.0000	100.00
0.5	5,625,739		0.0000	1.0000	100.00
1.5	5,536,167		0.0000	1.0000	100.00
2.5	4,824,333		0.0000	1.0000	100.00
3.5	4,303,225	30,980	0.0072	0.9928	100.00
4.5	3,964,086		0.0000	1.0000	99.28
5.5	3,569,971		0.0000	1.0000	99.28
6.5	2,133,272		0.0000	1.0000	99.28
7.5	2,060,513		0.0000	1.0000	99.28
8.5	1,972,191		0.0000	1.0000	99.28
9.5	1,913,144	19,570	0.0102	0.9898	99.28
10.5	1,793,295	1,202	0.0007	0.9993	98.26
11.5	1,589,911		0.0000	1.0000	98.20
12.5	1,525,115		0.0000	1.0000	98.20
13.5	1,331,321		0.0000	1.0000	98.20
14.5	1,181,881	13,761	0.0116	0.9884	98.20
15.5	1,145,185	5,442	0.0048	0.9952	97.06
16.5	1,050,035		0.0000	1.0000	96.59
17.5	900,361	14,155	0.0157	0.9843	96.59
18.5	770,061		0.0000	1.0000	95.08
19.5	718,143	44,781	0.0624	0.9376	95.08
20.5	654,314		0.0000	1.0000	89.15
21.5	567,605	14,687	0.0259	0.9741	89.15
22.5	549,560	2,907	0.0053	0.9947	86.84
23.5	412,318		0.0000	1.0000	86.38
24.5	37,966		0.0000	1.0000	86.38
25.5	15,141		0.0000	1.0000	86.38
26.5	15,141		0.0000	1.0000	86.38
27.5	15,141		0.0000	1.0000	86.38
28.5	15,141		0.0000	1.0000	86.38
29.5	15,141		0.0000	1.0000	86.38
30.5	15,141		0.0000	1.0000	86.38
31.5	15,141		0.0000	1.0000	86.38
32.5	15,141	15,141	1.0000		86.38
33.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M07 - METERS - ANALOGUE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

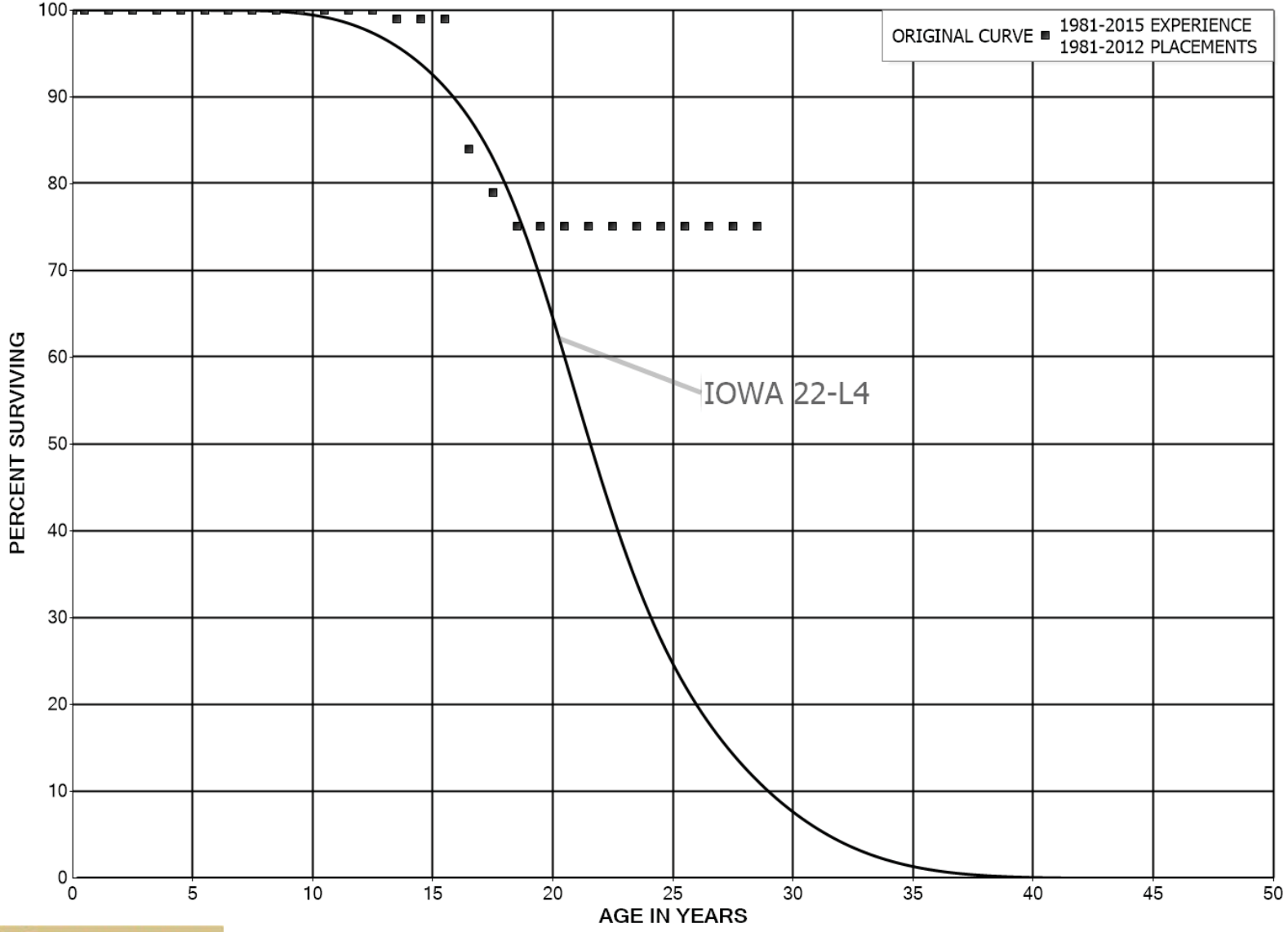
ACCOUNT M07 - METERS - ANALOGUE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-2003 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,493,442		0.0000	1.0000	100.00
0.5	1,493,442	62,730	0.0420	0.9580	100.00
1.5	1,430,712		0.0000	1.0000	95.80
2.5	1,430,712		0.0000	1.0000	95.80
3.5	1,430,712	399	0.0003	0.9997	95.80
4.5	1,430,314		0.0000	1.0000	95.77
5.5	1,430,314		0.0000	1.0000	95.77
6.5	1,430,314	344	0.0002	0.9998	95.77
7.5	1,429,970	290	0.0002	0.9998	95.75
8.5	1,429,679		0.0000	1.0000	95.73
9.5	1,429,679	35,356	0.0247	0.9753	95.73
10.5	1,394,323	8,069	0.0058	0.9942	93.36
11.5	1,386,254	28,092	0.0203	0.9797	92.82
12.5	1,358,162	15,803	0.0116	0.9884	90.94
13.5	1,342,359		0.0000	1.0000	89.88
14.5	1,342,359	19,057	0.0142	0.9858	89.88
15.5	1,323,302	204	0.0002	0.9998	88.61
16.5	1,323,098	13,890	0.0105	0.9895	88.59
17.5	1,309,208	277,503	0.2120	0.7880	87.66
18.5	1,031,705	39,340	0.0381	0.9619	69.08
19.5	992,365	15,494	0.0156	0.9844	66.45
20.5	976,871	193,449	0.1980	0.8020	65.41
21.5	783,422	32,848	0.0419	0.9581	52.46
22.5	750,574		0.0000	1.0000	50.26
23.5	750,574	46,989	0.0626	0.9374	50.26
24.5	703,585	5,201	0.0074	0.9926	47.11
25.5	698,384		0.0000	1.0000	46.76
26.5	549,645		0.0000	1.0000	46.76
27.5	352,574		0.0000	1.0000	46.76
28.5	206,618		0.0000	1.0000	46.76
29.5	206,618		0.0000	1.0000	46.76
30.5	206,618		0.0000	1.0000	46.76
31.5	150,111		0.0000	1.0000	46.76
32.5	138,968		0.0000	1.0000	46.76
33.5	138,968		0.0000	1.0000	46.76
34.5					46.76

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M08 - METERS - OTHER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

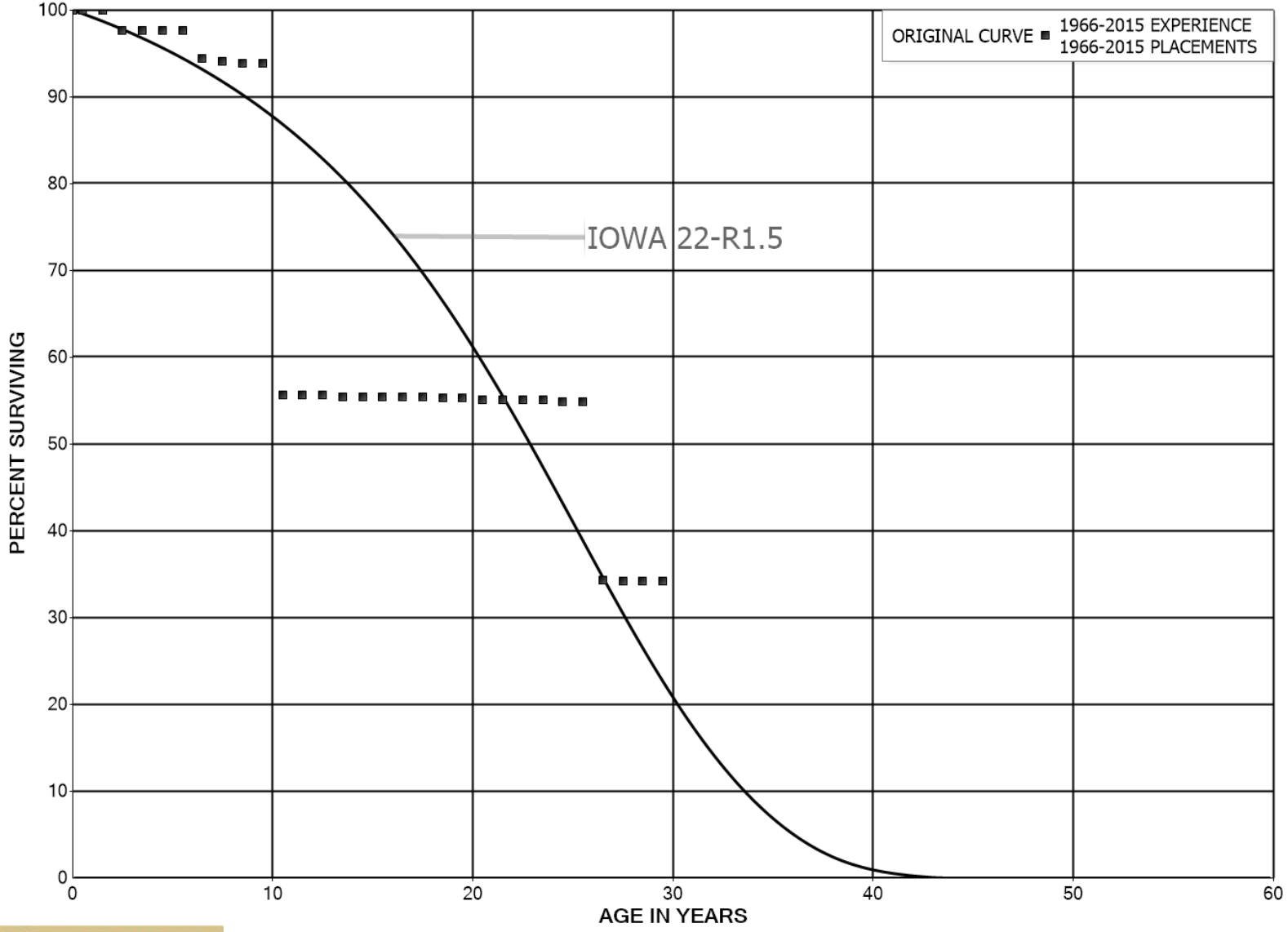
ACCOUNT M08 - METERS - OTHER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-2012 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	300,408		0.0000	1.0000	100.00
0.5	300,408		0.0000	1.0000	100.00
1.5	300,408		0.0000	1.0000	100.00
2.5	300,408		0.0000	1.0000	100.00
3.5	221,165		0.0000	1.0000	100.00
4.5	221,165		0.0000	1.0000	100.00
5.5	221,165		0.0000	1.0000	100.00
6.5	221,165		0.0000	1.0000	100.00
7.5	221,165		0.0000	1.0000	100.00
8.5	221,165		0.0000	1.0000	100.00
9.5	199,415		0.0000	1.0000	100.00
10.5	171,757		0.0000	1.0000	100.00
11.5	168,002		0.0000	1.0000	100.00
12.5	152,181	1,588	0.0104	0.9896	100.00
13.5	150,594		0.0000	1.0000	98.96
14.5	150,594		0.0000	1.0000	98.96
15.5	148,829	22,487	0.1511	0.8489	98.96
16.5	126,342	7,513	0.0595	0.9405	84.01
17.5	117,996	5,967	0.0506	0.9494	79.01
18.5	72,459		0.0000	1.0000	75.01
19.5	56,346		0.0000	1.0000	75.01
20.5	34,155		0.0000	1.0000	75.01
21.5	21,023		0.0000	1.0000	75.01
22.5	12,210		0.0000	1.0000	75.01
23.5	12,210		0.0000	1.0000	75.01
24.5	12,210		0.0000	1.0000	75.01
25.5	12,210		0.0000	1.0000	75.01
26.5	12,210		0.0000	1.0000	75.01
27.5	450		0.0000	1.0000	75.01
28.5					75.01

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M10 - MISCELLANEOUS UNITS OF PROPERTY
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M10 - MISCELLANEOUS UNITS OF PROPERTY

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	30,935,849		0.0000	1.0000	100.00
0.5	30,615,702	21,599	0.0007	0.9993	100.00
1.5	29,046,158	663,327	0.0228	0.9772	99.93
2.5	26,800,997		0.0000	1.0000	97.65
3.5	26,800,997		0.0000	1.0000	97.65
4.5	25,286,937	1,987	0.0001	0.9999	97.65
5.5	4,846,873	163,508	0.0337	0.9663	97.64
6.5	4,683,364	14,534	0.0031	0.9969	94.35
7.5	4,668,830	10,016	0.0021	0.9979	94.05
8.5	4,641,691		0.0000	1.0000	93.85
9.5	4,641,691	1,889,486	0.4071	0.5929	93.85
10.5	2,752,205		0.0000	1.0000	55.65
11.5	2,736,621		0.0000	1.0000	55.65
12.5	2,736,621	9,946	0.0036	0.9964	55.65
13.5	2,726,675		0.0000	1.0000	55.45
14.5	2,726,675		0.0000	1.0000	55.45
15.5	2,726,675		0.0000	1.0000	55.45
16.5	2,726,675	1,631	0.0006	0.9994	55.45
17.5	2,725,043	4,926	0.0018	0.9982	55.41
18.5	2,720,118	2,024	0.0007	0.9993	55.31
19.5	2,718,093	8,444	0.0031	0.9969	55.27
20.5	2,709,649		0.0000	1.0000	55.10
21.5	2,709,649	920	0.0003	0.9997	55.10
22.5	2,708,729		0.0000	1.0000	55.08
23.5	2,708,729	12,800	0.0047	0.9953	55.08
24.5	2,645,492		0.0000	1.0000	54.82
25.5	1,819,518	682,013	0.3748	0.6252	54.82
26.5	342,222	600	0.0018	0.9982	34.27
27.5	341,622		0.0000	1.0000	34.21
28.5	341,622		0.0000	1.0000	34.21
29.5	341,622		0.0000	1.0000	34.21
30.5	26,368	3,006	0.1140	0.8860	34.21
31.5	23,361		0.0000	1.0000	30.31
32.5	23,361		0.0000	1.0000	30.31
33.5	23,361		0.0000	1.0000	30.31
34.5	23,361		0.0000	1.0000	30.31
35.5	23,361	17,176	0.7352	0.2648	30.31
36.5	6,185		0.0000	1.0000	8.02
37.5	6,185		0.0000	1.0000	8.02
38.5	6,185		0.0000	1.0000	8.02

NEWFOUNDLAND AND LABRADOR HYDRO

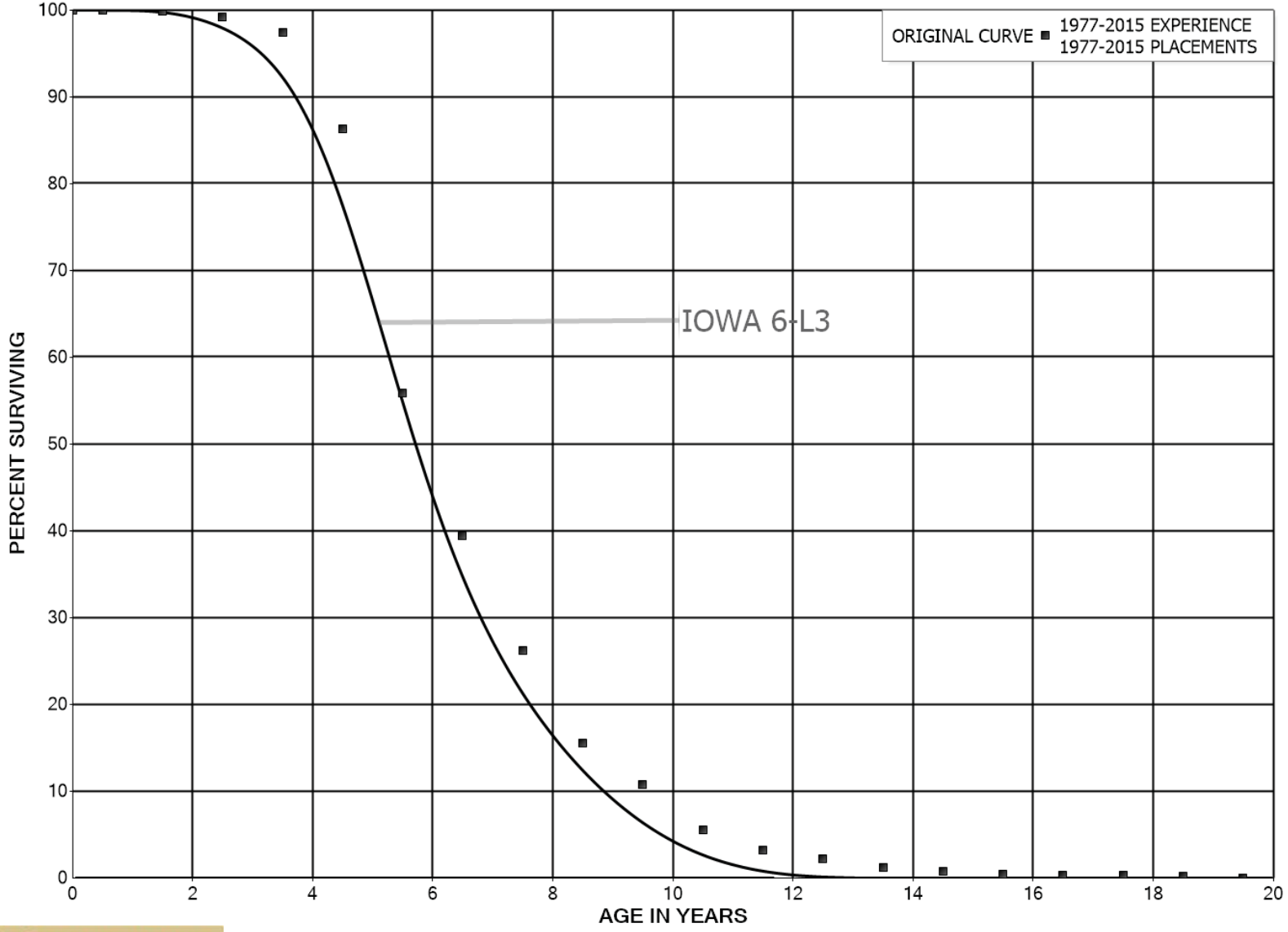
ACCOUNT M10 - MISCELLANEOUS UNITS OF PROPERTY

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,185		0.0000	1.0000	8.02
40.5	6,185		0.0000	1.0000	8.02
41.5	6,185		0.0000	1.0000	8.02
42.5	6,185		0.0000	1.0000	8.02
43.5	6,185		0.0000	1.0000	8.02
44.5	6,185		0.0000	1.0000	8.02
45.5					8.02

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M11 - MOBILE - A.T.V.'S AND SNOWMOBILES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

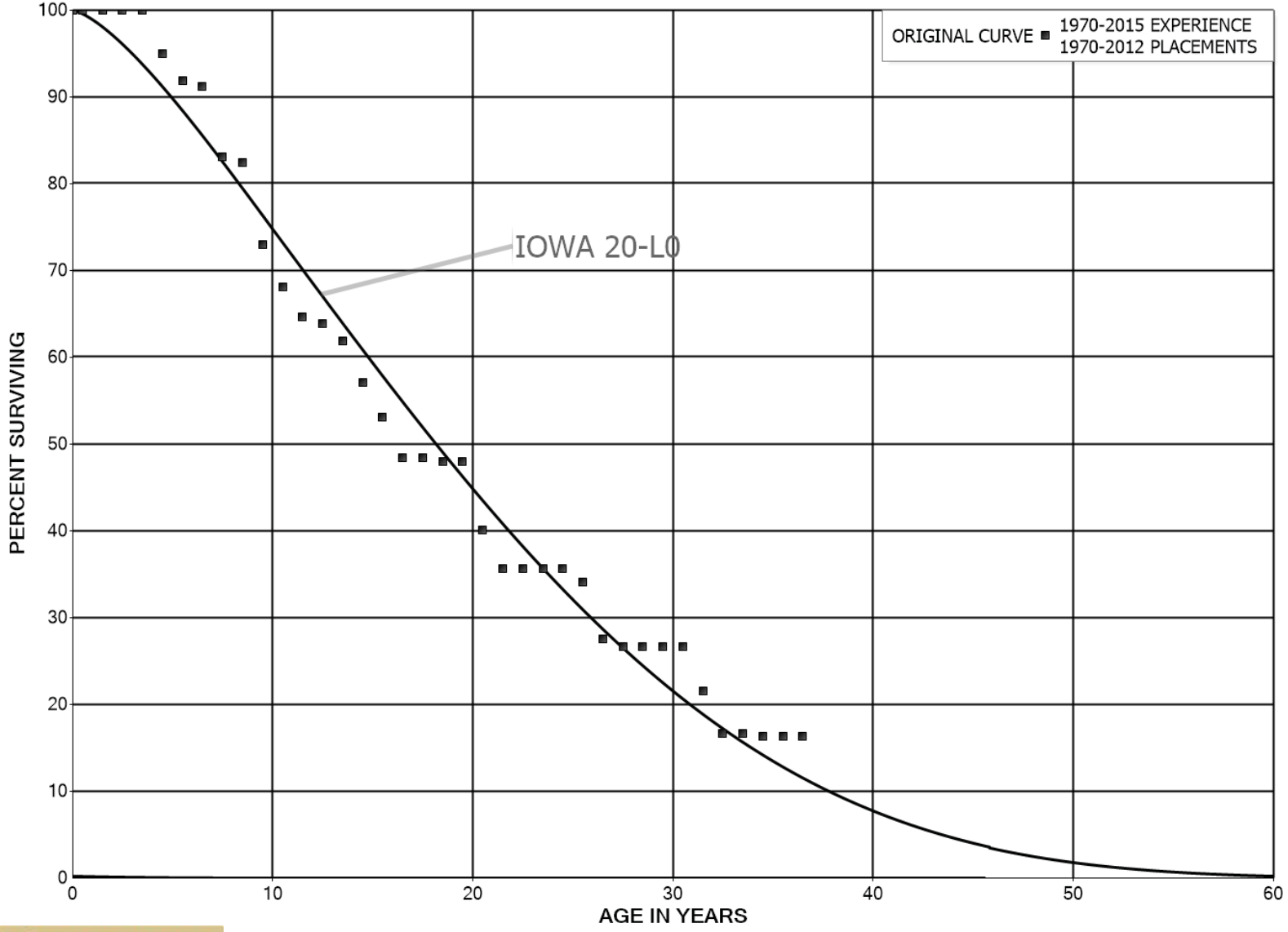
ACCOUNT M11 - MOBILE - A.T.V.'S AND SNOWMOBILES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1977-2015 EXPERIENCE BAND 1977-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,061,677		0.0000	1.0000	100.00
0.5	5,845,920	9,689	0.0017	0.9983	100.00
1.5	5,557,216	37,144	0.0067	0.9933	99.83
2.5	4,716,380	82,946	0.0176	0.9824	99.17
3.5	4,549,851	519,232	0.1141	0.8859	97.42
4.5	3,873,671	1,366,461	0.3528	0.6472	86.30
5.5	2,415,547	712,674	0.2950	0.7050	55.86
6.5	1,545,938	516,406	0.3340	0.6660	39.38
7.5	957,240	392,250	0.4098	0.5902	26.23
8.5	518,137	159,155	0.3072	0.6928	15.48
9.5	358,982	176,273	0.4910	0.5090	10.72
10.5	182,710	77,992	0.4269	0.5731	5.46
11.5	104,718	31,186	0.2978	0.7022	3.13
12.5	73,531	33,933	0.4615	0.5385	2.20
13.5	39,598	14,207	0.3588	0.6412	1.18
14.5	25,391	13,188	0.5194	0.4806	0.76
15.5	12,203	1,071	0.0877	0.9123	0.36
16.5	11,133		0.0000	1.0000	0.33
17.5	11,133	4,833	0.4341	0.5659	0.33
18.5	6,300	6,300	1.0000		0.19
19.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M12 - MOBILE - MIR COMPRESSOR, ATTACHMENT AND BOAT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

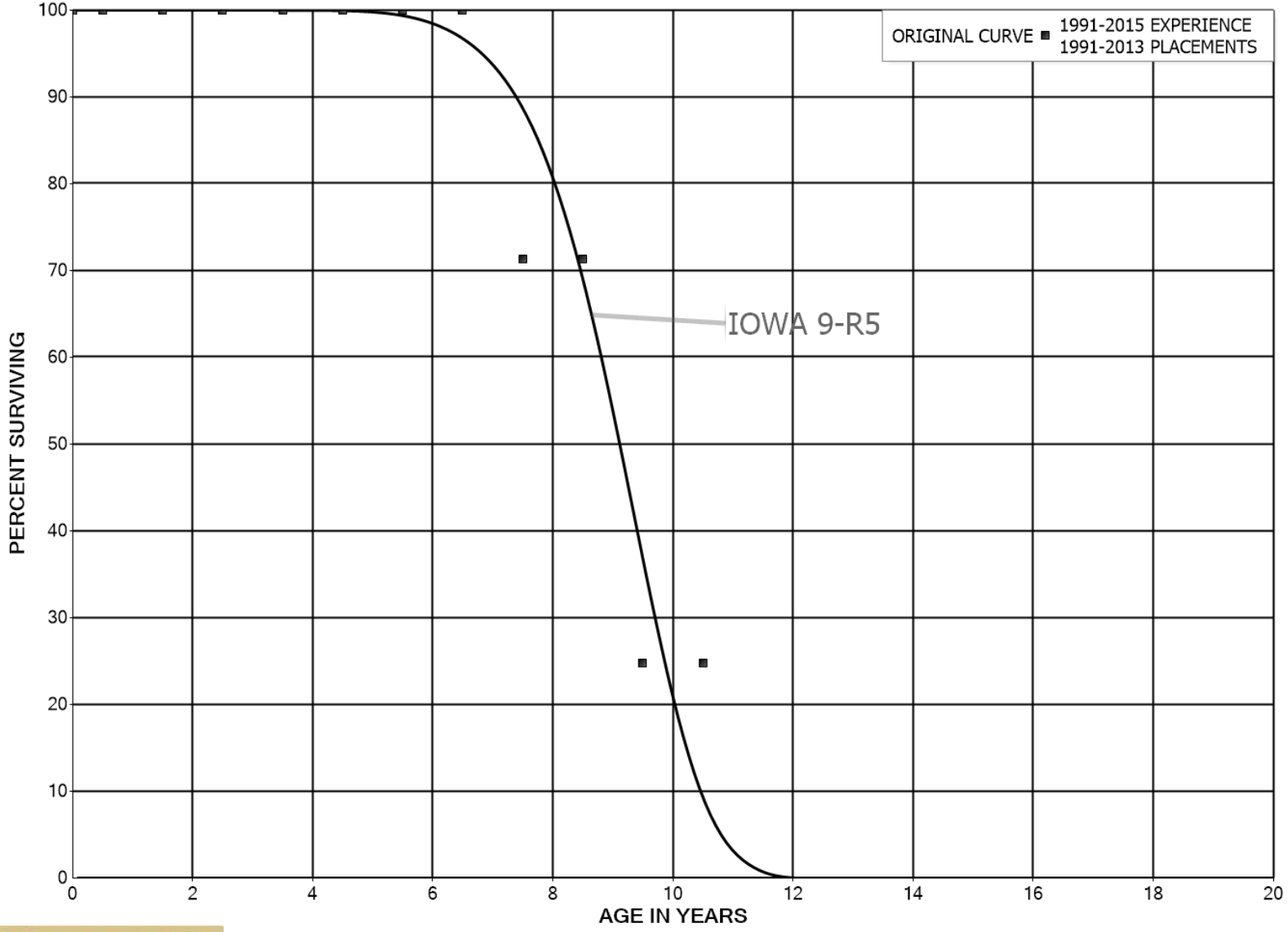
ACCOUNT M12 - MOBILE - MIR COMPRESSOR, ATTACHMENT AND BOAT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2012 EXPERIENCE BAND 1970-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,224,589		0.0000	1.0000	100.00
0.5	1,224,589		0.0000	1.0000	100.00
1.5	1,224,589		0.0000	1.0000	100.00
2.5	1,224,589		0.0000	1.0000	100.00
3.5	1,188,949	59,529	0.0501	0.9499	100.00
4.5	1,105,020	37,266	0.0337	0.9663	94.99
5.5	1,045,065	7,416	0.0071	0.9929	91.79
6.5	959,775	84,500	0.0880	0.9120	91.14
7.5	875,275	8,022	0.0092	0.9908	83.11
8.5	867,253	98,926	0.1141	0.8859	82.35
9.5	755,728	50,889	0.0673	0.9327	72.96
10.5	704,839	35,526	0.0504	0.9496	68.05
11.5	669,313	7,614	0.0114	0.9886	64.62
12.5	661,699	21,388	0.0323	0.9677	63.88
13.5	640,312	49,093	0.0767	0.9233	61.82
14.5	591,218	41,556	0.0703	0.9297	57.08
15.5	531,667	47,217	0.0888	0.9112	53.06
16.5	453,233		0.0000	1.0000	48.35
17.5	450,858	3,364	0.0075	0.9925	48.35
18.5	434,593		0.0000	1.0000	47.99
19.5	422,611	69,632	0.1648	0.8352	47.99
20.5	352,979	39,071	0.1107	0.8893	40.08
21.5	309,846		0.0000	1.0000	35.65
22.5	296,362		0.0000	1.0000	35.65
23.5	296,362		0.0000	1.0000	35.65
24.5	296,362	12,913	0.0436	0.9564	35.65
25.5	283,449	54,660	0.1928	0.8072	34.09
26.5	203,120	6,463	0.0318	0.9682	27.52
27.5	163,907		0.0000	1.0000	26.64
28.5	163,907		0.0000	1.0000	26.64
29.5	148,497		0.0000	1.0000	26.64
30.5	148,497	28,470	0.1917	0.8083	26.64
31.5	120,027	27,712	0.2309	0.7691	21.54
32.5	92,316		0.0000	1.0000	16.56
33.5	92,316	1,318	0.0143	0.9857	16.56
34.5	87,567		0.0000	1.0000	16.33
35.5	87,567		0.0000	1.0000	16.33
36.5					16.33

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M13 - MOBILE - ARGO'S
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

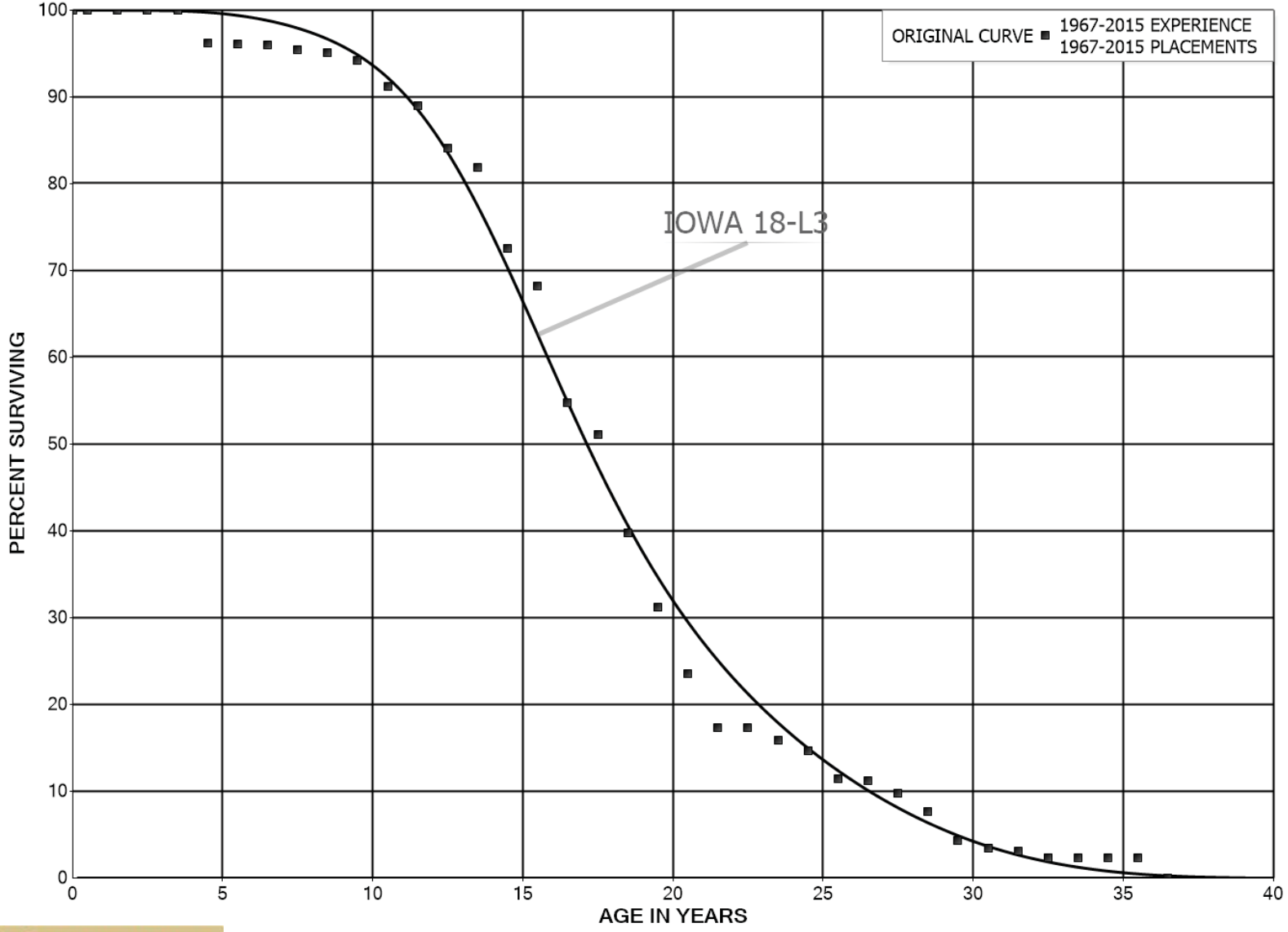
ACCOUNT M13 - MOBILE - ARGO'S

ORIGINAL LIFE TABLE

PLACEMENT BAND 1991-2013 EXPERIENCE BAND 1991-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	343,875		0.0000	1.0000	100.00
0.5	343,875		0.0000	1.0000	100.00
1.5	343,875		0.0000	1.0000	100.00
2.5	255,321		0.0000	1.0000	100.00
3.5	195,827		0.0000	1.0000	100.00
4.5	173,588		0.0000	1.0000	100.00
5.5	56,588		0.0000	1.0000	100.00
6.5	56,588	16,220	0.2866	0.7134	100.00
7.5	40,368		0.0000	1.0000	71.34
8.5	40,368	26,377	0.6534	0.3466	71.34
9.5	13,991		0.0000	1.0000	24.72
10.5	13,991		0.0000	1.0000	24.72
11.5	13,991		0.0000	1.0000	24.72
12.5	13,991		0.0000	1.0000	24.72
13.5	13,991		0.0000	1.0000	24.72
14.5	13,991		0.0000	1.0000	24.72
15.5	13,991		0.0000	1.0000	24.72
16.5	13,991	13,991	1.0000		24.72
17.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M14 - MOBILE - FLEX/FORK/LOAD/GRADE/MUSK/TRAILER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

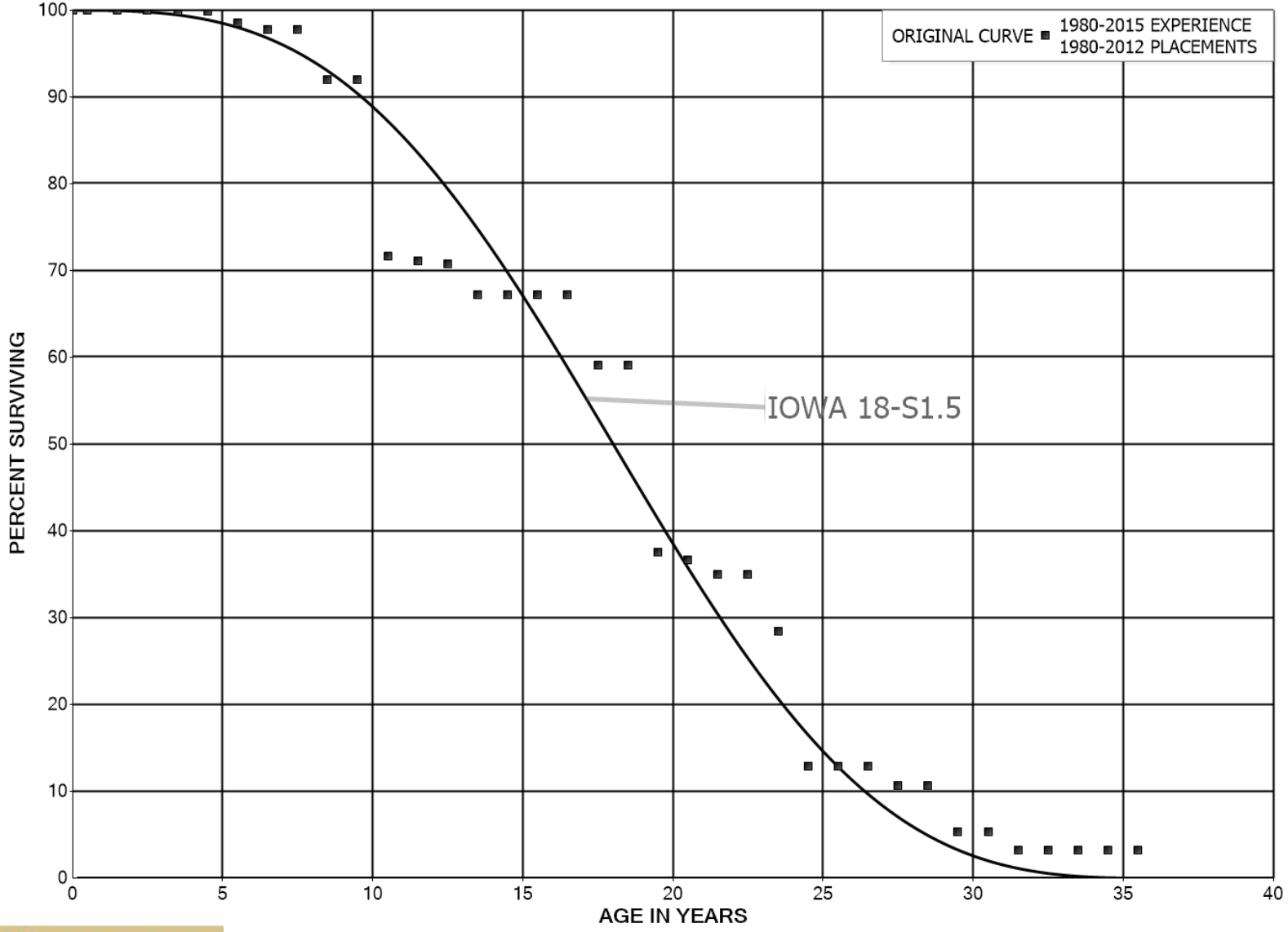
ACCOUNT M14 - MOBILE - FLEX/FORK/LOAD/GRADE/MUSK/TRAILER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,876,198		0.0000	1.0000	100.00
0.5	17,492,063		0.0000	1.0000	100.00
1.5	16,005,972	0	0.0000	1.0000	100.00
2.5	15,642,741	9,892	0.0006	0.9994	100.00
3.5	14,813,600	559,521	0.0378	0.9622	99.94
4.5	12,476,888	11,479	0.0009	0.9991	96.16
5.5	12,113,243	11,947	0.0010	0.9990	96.07
6.5	11,249,730	73,783	0.0066	0.9934	95.98
7.5	10,011,091	27,984	0.0028	0.9972	95.35
8.5	9,586,856	95,432	0.0100	0.9900	95.08
9.5	8,869,152	279,013	0.0315	0.9685	94.14
10.5	8,261,883	197,041	0.0238	0.9762	91.17
11.5	7,928,206	440,074	0.0555	0.9445	89.00
12.5	7,472,133	200,225	0.0268	0.9732	84.06
13.5	7,092,222	810,533	0.1143	0.8857	81.81
14.5	5,998,929	353,540	0.0589	0.9411	72.46
15.5	5,423,264	1,070,658	0.1974	0.8026	68.19
16.5	4,068,796	270,498	0.0665	0.9335	54.73
17.5	3,427,048	763,964	0.2229	0.7771	51.09
18.5	2,663,084	571,122	0.2145	0.7855	39.70
19.5	2,091,962	518,478	0.2478	0.7522	31.19
20.5	1,543,051	404,290	0.2620	0.7380	23.46
21.5	1,138,762	4,981	0.0044	0.9956	17.31
22.5	1,096,786	90,283	0.0823	0.9177	17.24
23.5	861,199	66,170	0.0768	0.9232	15.82
24.5	795,030	175,879	0.2212	0.7788	14.60
25.5	575,470	10,742	0.0187	0.9813	11.37
26.5	478,531	59,596	0.1245	0.8755	11.16
27.5	284,228	62,203	0.2188	0.7812	9.77
28.5	222,025	97,733	0.4402	0.5598	7.63
29.5	124,292	26,479	0.2130	0.7870	4.27
30.5	97,813	7,383	0.0755	0.9245	3.36
31.5	77,352	21,478	0.2777	0.7223	3.11
32.5	55,874	0	0.0000	1.0000	2.25
33.5	45,230		0.0000	1.0000	2.25
34.5	2,486		0.0000	1.0000	2.25
35.5	2,486	2,486	1.0000	0.0000	2.25
36.5	0		0.0000	1.0000	0.00
37.5	0	0	1.0000		0.00
38.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT M16 - MULTIPLEX EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

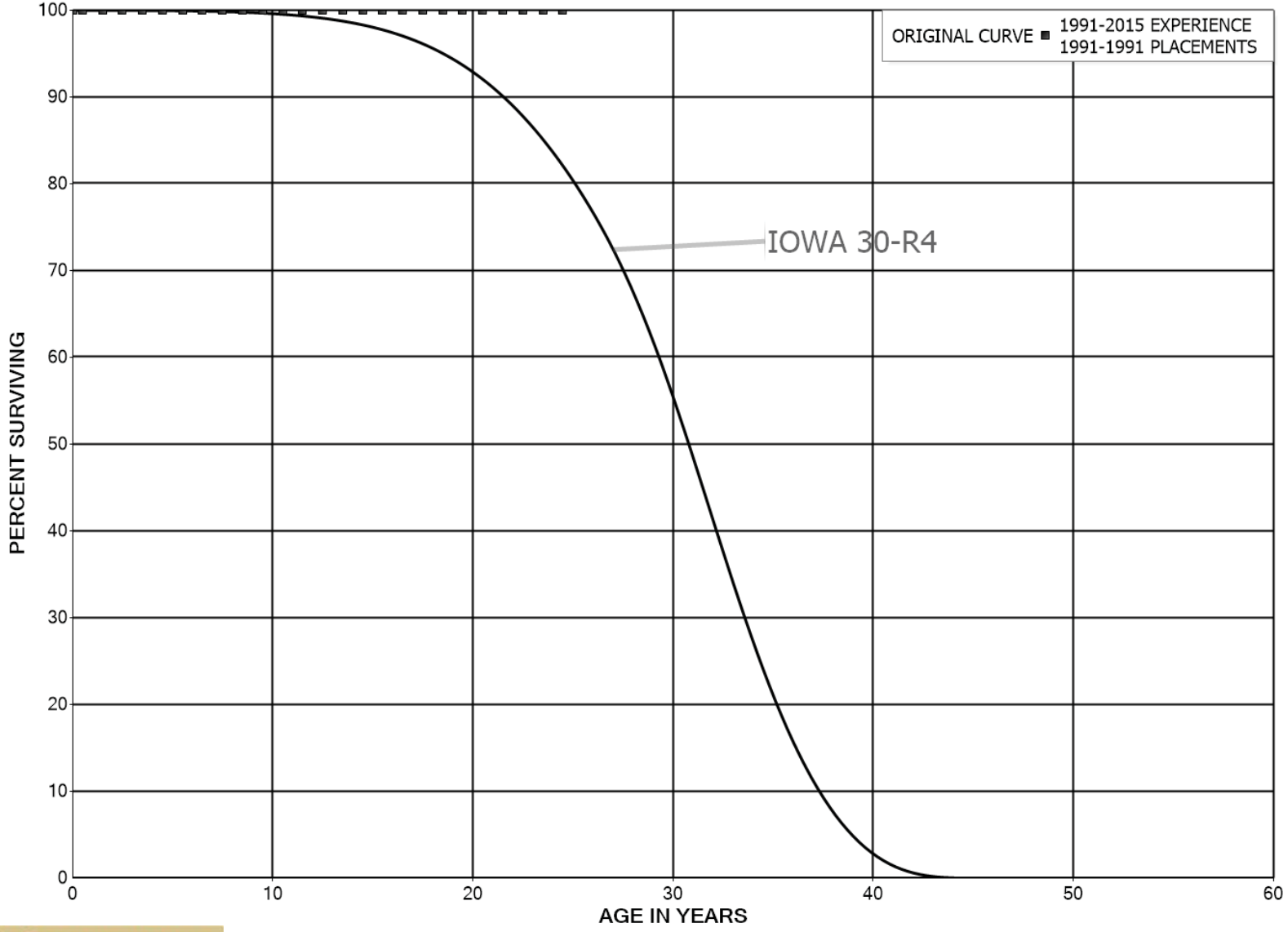
ACCOUNT M16 - MULTIPLEX EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2012 EXPERIENCE BAND 1980-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,919,915		0.0000	1.0000	100.00
0.5	5,919,915		0.0000	1.0000	100.00
1.5	5,919,915		0.0000	1.0000	100.00
2.5	5,919,915	9,167	0.0015	0.9985	100.00
3.5	5,730,526		0.0000	1.0000	99.85
4.5	5,718,497	74,748	0.0131	0.9869	99.85
5.5	5,148,445	43,977	0.0085	0.9915	98.54
6.5	5,104,468		0.0000	1.0000	97.70
7.5	4,965,470	290,128	0.0584	0.9416	97.70
8.5	4,675,342		0.0000	1.0000	91.99
9.5	4,675,342	1,033,622	0.2211	0.7789	91.99
10.5	3,578,900	29,019	0.0081	0.9919	71.65
11.5	3,545,061	15,324	0.0043	0.9957	71.07
12.5	2,920,159	149,749	0.0513	0.9487	70.76
13.5	2,416,439		0.0000	1.0000	67.14
14.5	1,679,635		0.0000	1.0000	67.14
15.5	1,571,171		0.0000	1.0000	67.14
16.5	1,533,979	184,775	0.1205	0.8795	67.14
17.5	1,349,204		0.0000	1.0000	59.05
18.5	1,349,204	492,737	0.3652	0.6348	59.05
19.5	856,467	20,354	0.0238	0.9762	37.48
20.5	836,113	37,588	0.0450	0.9550	36.59
21.5	798,525		0.0000	1.0000	34.95
22.5	798,525	149,665	0.1874	0.8126	34.95
23.5	648,861	354,510	0.5464	0.4536	28.40
24.5	294,351		0.0000	1.0000	12.88
25.5	294,351		0.0000	1.0000	12.88
26.5	294,351	52,098	0.1770	0.8230	12.88
27.5	242,253		0.0000	1.0000	10.60
28.5	242,253	121,314	0.5008	0.4992	10.60
29.5	120,939		0.0000	1.0000	5.29
30.5	120,939	48,924	0.4045	0.5955	5.29
31.5	72,015		0.0000	1.0000	3.15
32.5	72,015		0.0000	1.0000	3.15
33.5	72,015		0.0000	1.0000	3.15
34.5	72,015		0.0000	1.0000	3.15
35.5					3.15

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P01 - P.C.B. STORAGE CONTAINER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

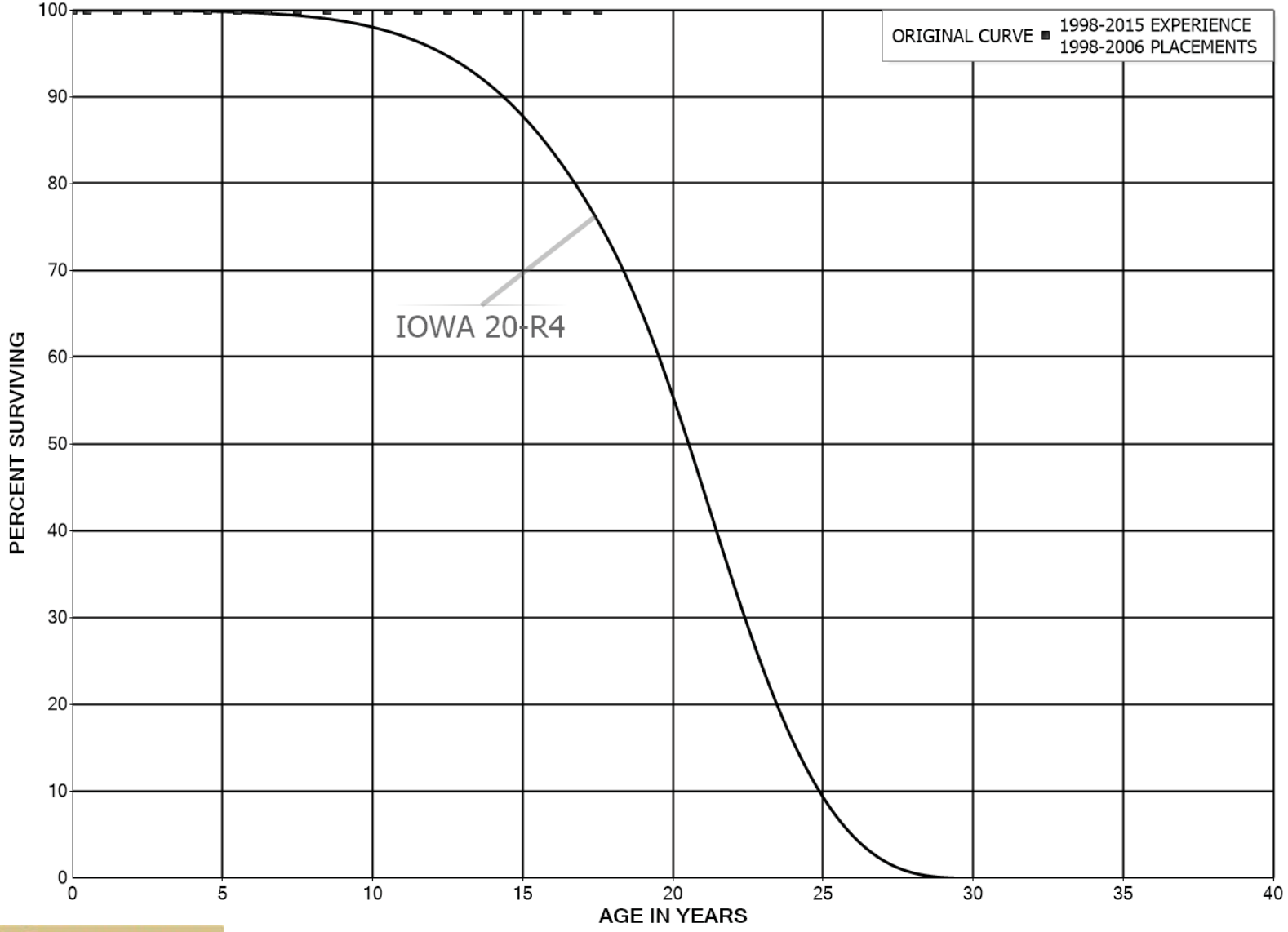
ACCOUNT P01 - P.C.B. STORAGE CONTAINER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1991-1991 EXPERIENCE BAND 1991-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	42,480		0.0000	1.0000	100.00
0.5	42,480		0.0000	1.0000	100.00
1.5	42,480		0.0000	1.0000	100.00
2.5	42,480		0.0000	1.0000	100.00
3.5	42,480		0.0000	1.0000	100.00
4.5	42,480		0.0000	1.0000	100.00
5.5	42,480		0.0000	1.0000	100.00
6.5	42,480		0.0000	1.0000	100.00
7.5	42,480		0.0000	1.0000	100.00
8.5	42,480		0.0000	1.0000	100.00
9.5	42,480		0.0000	1.0000	100.00
10.5	42,480		0.0000	1.0000	100.00
11.5	42,480		0.0000	1.0000	100.00
12.5	42,480		0.0000	1.0000	100.00
13.5	42,480		0.0000	1.0000	100.00
14.5	42,480		0.0000	1.0000	100.00
15.5	42,480		0.0000	1.0000	100.00
16.5	42,480		0.0000	1.0000	100.00
17.5	42,480		0.0000	1.0000	100.00
18.5	42,480		0.0000	1.0000	100.00
19.5	42,480		0.0000	1.0000	100.00
20.5	42,480		0.0000	1.0000	100.00
21.5	42,480		0.0000	1.0000	100.00
22.5	42,480		0.0000	1.0000	100.00
23.5	42,480		0.0000	1.0000	100.00
24.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P02 - PRIVATE AUTO BRANCH EXCHANGE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

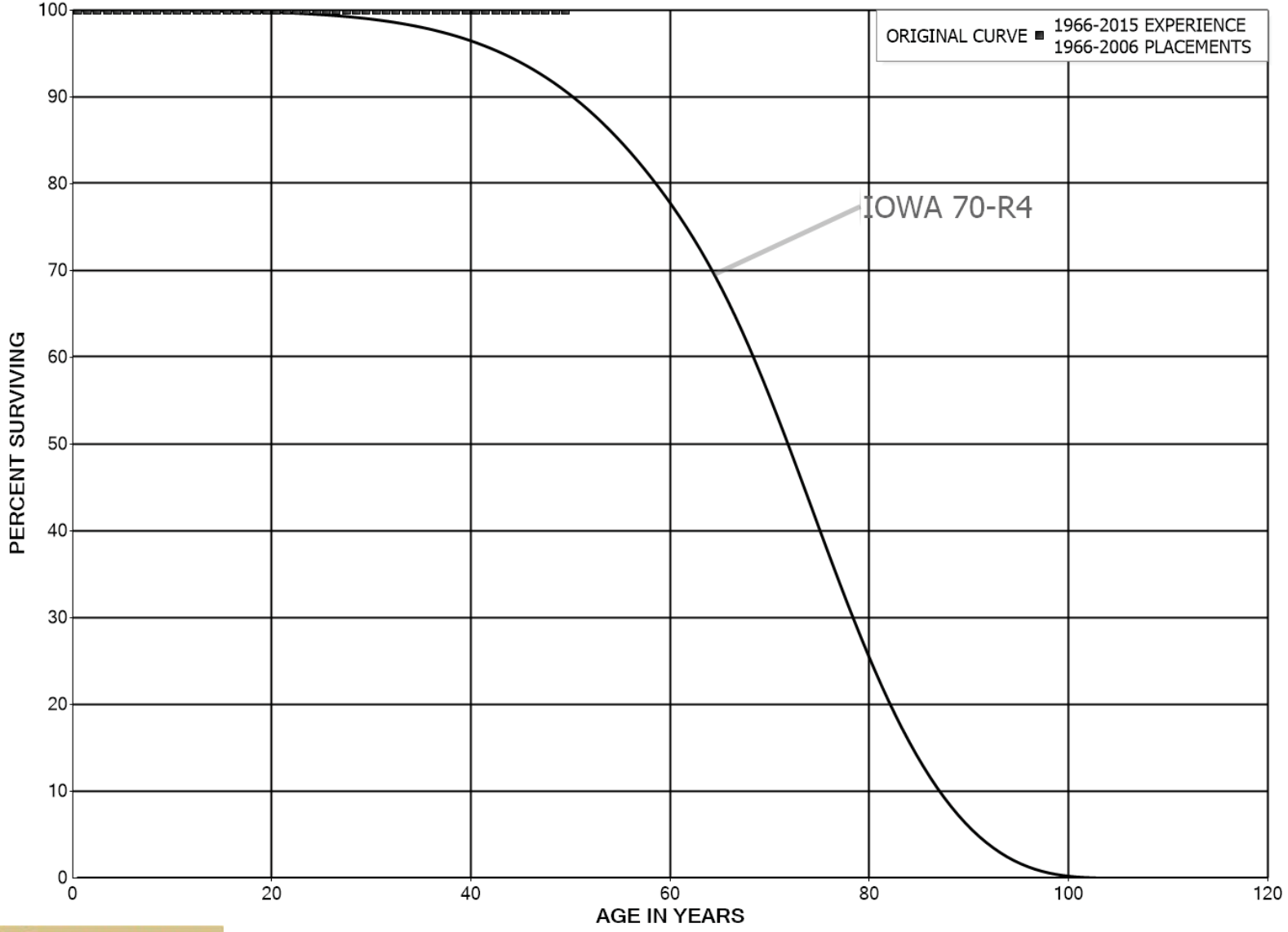
ACCOUNT P02 - PRIVATE AUTO BRANCH EXCHANGE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1998-2006 EXPERIENCE BAND 1998-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,181,009		0.0000	1.0000	100.00
0.5	1,181,009		0.0000	1.0000	100.00
1.5	1,181,009		0.0000	1.0000	100.00
2.5	1,181,009		0.0000	1.0000	100.00
3.5	1,181,009		0.0000	1.0000	100.00
4.5	1,181,009		0.0000	1.0000	100.00
5.5	1,181,009		0.0000	1.0000	100.00
6.5	1,181,009		0.0000	1.0000	100.00
7.5	1,181,009		0.0000	1.0000	100.00
8.5	1,181,009		0.0000	1.0000	100.00
9.5	380,481		0.0000	1.0000	100.00
10.5	380,481		0.0000	1.0000	100.00
11.5	380,481		0.0000	1.0000	100.00
12.5	296,149		0.0000	1.0000	100.00
13.5	296,149		0.0000	1.0000	100.00
14.5	296,149		0.0000	1.0000	100.00
15.5	37,492		0.0000	1.0000	100.00
16.5	37,492		0.0000	1.0000	100.00
17.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P03 - PENSTOCK
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P03 - PENSTOCK

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2006 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	58,908,421		0.0000	1.0000	100.00
0.5	58,908,421		0.0000	1.0000	100.00
1.5	58,908,421		0.0000	1.0000	100.00
2.5	58,908,421		0.0000	1.0000	100.00
3.5	58,908,421		0.0000	1.0000	100.00
4.5	58,908,421		0.0000	1.0000	100.00
5.5	58,908,421		0.0000	1.0000	100.00
6.5	58,908,421		0.0000	1.0000	100.00
7.5	58,908,421		0.0000	1.0000	100.00
8.5	58,908,421		0.0000	1.0000	100.00
9.5	56,760,952		0.0000	1.0000	100.00
10.5	56,760,952		0.0000	1.0000	100.00
11.5	56,760,952		0.0000	1.0000	100.00
12.5	50,028,727		0.0000	1.0000	100.00
13.5	50,028,727		0.0000	1.0000	100.00
14.5	50,028,727		0.0000	1.0000	100.00
15.5	50,028,727		0.0000	1.0000	100.00
16.5	50,028,727		0.0000	1.0000	100.00
17.5	50,028,727		0.0000	1.0000	100.00
18.5	50,028,727		0.0000	1.0000	100.00
19.5	50,028,727		0.0000	1.0000	100.00
20.5	50,028,727		0.0000	1.0000	100.00
21.5	50,028,727		0.0000	1.0000	100.00
22.5	50,028,727		0.0000	1.0000	100.00
23.5	50,028,727		0.0000	1.0000	100.00
24.5	50,028,727		0.0000	1.0000	100.00
25.5	50,028,727		0.0000	1.0000	100.00
26.5	49,614,170		0.0000	1.0000	100.00
27.5	49,614,170		0.0000	1.0000	100.00
28.5	49,614,170		0.0000	1.0000	100.00
29.5	49,614,170		0.0000	1.0000	100.00
30.5	44,923,599		0.0000	1.0000	100.00
31.5	44,923,599		0.0000	1.0000	100.00
32.5	44,923,599		0.0000	1.0000	100.00
33.5	31,951,196		0.0000	1.0000	100.00
34.5	31,951,196		0.0000	1.0000	100.00
35.5	31,951,196		0.0000	1.0000	100.00
36.5	20,920,528		0.0000	1.0000	100.00
37.5	20,920,528		0.0000	1.0000	100.00
38.5	20,920,528		0.0000	1.0000	100.00

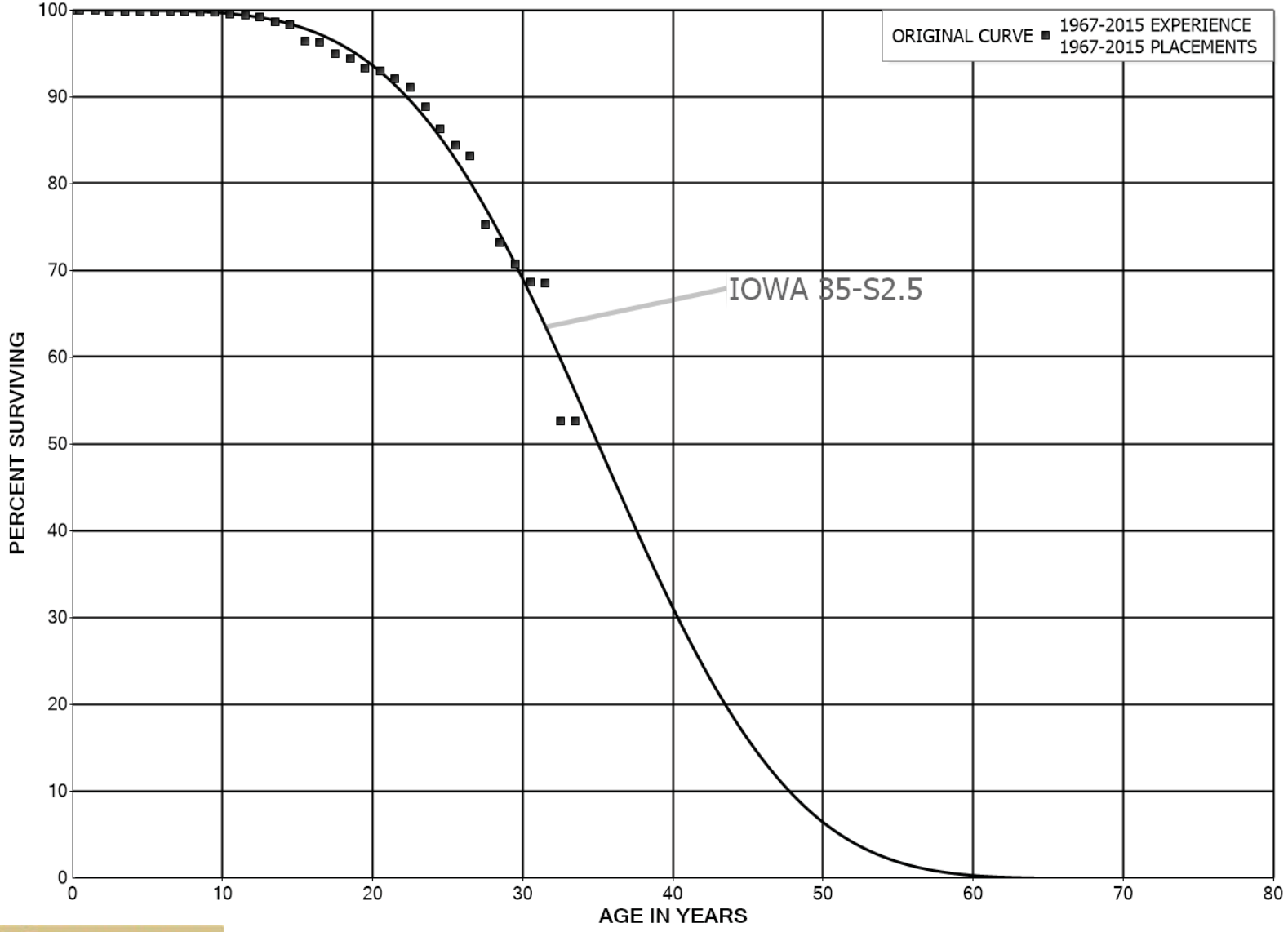
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P03 - PENSTOCK

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2006			EXPERIENCE BAND 1966-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,920,528		0.0000	1.0000	100.00
40.5	20,920,528		0.0000	1.0000	100.00
41.5	20,920,528		0.0000	1.0000	100.00
42.5	20,920,528		0.0000	1.0000	100.00
43.5	20,920,528		0.0000	1.0000	100.00
44.5	20,920,528		0.0000	1.0000	100.00
45.5	20,569,173		0.0000	1.0000	100.00
46.5	20,569,173		0.0000	1.0000	100.00
47.5	20,569,173		0.0000	1.0000	100.00
48.5	13,597,173		0.0000	1.0000	100.00
49.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P04 - POLE CRIBS AND POLE HARDWARE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P04 - POLE CRIBS AND POLE HARDWARE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	128,071,519	13,079	0.0001	0.9999	100.00
0.5	119,928,189	1,409	0.0000	1.0000	99.99
1.5	118,045,861	168,412	0.0014	0.9986	99.99
2.5	101,937,882	334	0.0000	1.0000	99.85
3.5	94,281,980	3,838	0.0000	1.0000	99.85
4.5	87,193,005	1,365	0.0000	1.0000	99.84
5.5	82,148,886	2,253	0.0000	1.0000	99.84
6.5	76,504,284	10,701	0.0001	0.9999	99.84
7.5	70,791,042	47,163	0.0007	0.9993	99.82
8.5	66,769,994	4,606	0.0001	0.9999	99.76
9.5	62,228,255	136,209	0.0022	0.9978	99.75
10.5	58,629,230	49,983	0.0009	0.9991	99.53
11.5	54,976,388	178,942	0.0033	0.9967	99.45
12.5	51,531,940	269,870	0.0052	0.9948	99.12
13.5	46,527,439	128,839	0.0028	0.9972	98.60
14.5	43,999,472	853,523	0.0194	0.9806	98.33
15.5	41,095,562	77,359	0.0019	0.9981	96.42
16.5	39,645,688	527,125	0.0133	0.9867	96.24
17.5	37,239,882	236,143	0.0063	0.9937	94.96
18.5	32,118,454	361,539	0.0113	0.9887	94.36
19.5	29,123,498	90,892	0.0031	0.9969	93.30
20.5	27,171,095	266,486	0.0098	0.9902	93.01
21.5	25,324,911	281,449	0.0111	0.9889	92.09
22.5	23,751,430	587,323	0.0247	0.9753	91.07
23.5	22,068,413	627,221	0.0284	0.9716	88.82
24.5	19,674,036	431,812	0.0219	0.9781	86.29
25.5	17,480,564	263,135	0.0151	0.9849	84.40
26.5	15,521,387	1,473,870	0.0950	0.9050	83.13
27.5	12,892,687	360,356	0.0280	0.9720	75.24
28.5	10,381,049	345,037	0.0332	0.9668	73.13
29.5	8,842,401	255,623	0.0289	0.9711	70.70
30.5	7,850,257	18,235	0.0023	0.9977	68.66
31.5	6,935,636	1,604,104	0.2313	0.7687	68.50
32.5	4,603,834	621	0.0001	0.9999	52.66
33.5	3,174,930	2,029	0.0006	0.9994	52.65
34.5	111,582	10,434	0.0935	0.9065	52.62
35.5	101,148		0.0000	1.0000	47.70
36.5	99,734	4,429	0.0444	0.9556	47.70
37.5	83,544	3,452	0.0413	0.9587	45.58
38.5	80,092		0.0000	1.0000	43.69

NEWFOUNDLAND AND LABRADOR HYDRO

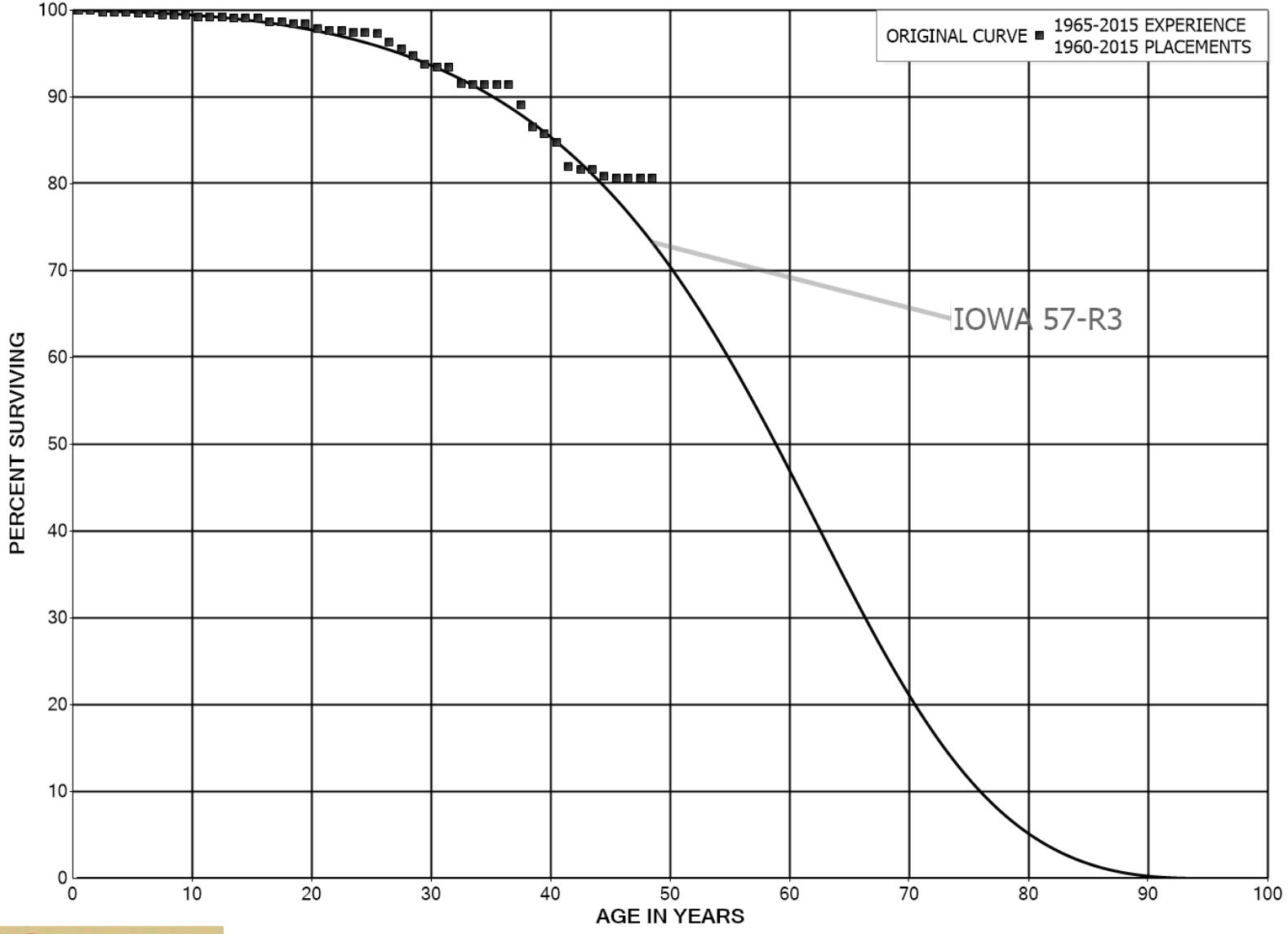
ACCOUNT P04 - POLE CRIBS AND POLE HARDWARE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	80,092	1,160	0.0145	0.9855	43.69
40.5	78,932		0.0000	1.0000	43.06
41.5	78,932		0.0000	1.0000	43.06
42.5	78,932		0.0000	1.0000	43.06
43.5	78,932		0.0000	1.0000	43.06
44.5	78,932		0.0000	1.0000	43.06
45.5	1,845		0.0000	1.0000	43.06
46.5	1,845		0.0000	1.0000	43.06
47.5					43.06

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P05 - POLE STRUCTURES - WOOD
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P05 - POLE STRUCTURES - WOOD

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	135,794,090		0.0000	1.0000	100.00
0.5	131,957,484		0.0000	1.0000	100.00
1.5	127,172,604	337,672	0.0027	0.9973	100.00
2.5	124,343,720		0.0000	1.0000	99.73
3.5	121,844,733	12,298	0.0001	0.9999	99.73
4.5	118,272,859	112,436	0.0010	0.9990	99.72
5.5	117,568,751	13,981	0.0001	0.9999	99.63
6.5	114,509,260	212,848	0.0019	0.9981	99.62
7.5	111,437,597	16,188	0.0001	0.9999	99.43
8.5	110,933,863	35,151	0.0003	0.9997	99.42
9.5	106,346,800	234,549	0.0022	0.9978	99.39
10.5	103,596,673		0.0000	1.0000	99.17
11.5	103,141,550		0.0000	1.0000	99.17
12.5	98,855,866	102,297	0.0010	0.9990	99.17
13.5	97,646,721		0.0000	1.0000	99.06
14.5	93,443,406		0.0000	1.0000	99.06
15.5	86,662,267	418,135	0.0048	0.9952	99.06
16.5	86,162,302		0.0000	1.0000	98.59
17.5	82,915,154	166,301	0.0020	0.9980	98.59
18.5	82,464,363	28,403	0.0003	0.9997	98.39
19.5	76,421,769	444,290	0.0058	0.9942	98.36
20.5	72,949,918	96,255	0.0013	0.9987	97.78
21.5	72,737,944	28,205	0.0004	0.9996	97.65
22.5	72,582,415	127,411	0.0018	0.9982	97.62
23.5	72,311,898	75,469	0.0010	0.9990	97.45
24.5	72,013,176	67,071	0.0009	0.9991	97.34
25.5	48,011,423	463,896	0.0097	0.9903	97.25
26.5	46,962,028	380,463	0.0081	0.9919	96.31
27.5	43,941,372	368,422	0.0084	0.9916	95.53
28.5	38,765,136	428,013	0.0110	0.9890	94.73
29.5	38,167,539	100,429	0.0026	0.9974	93.69
30.5	36,025,707	6,855	0.0002	0.9998	93.44
31.5	35,575,825	731,323	0.0206	0.9794	93.42
32.5	29,055,987	21,318	0.0007	0.9993	91.50
33.5	22,184,602	7,549	0.0003	0.9997	91.43
34.5	16,158,260	2,301	0.0001	0.9999	91.40
35.5	15,288,343	1,480	0.0001	0.9999	91.39
36.5	15,282,951	380,974	0.0249	0.9751	91.38
37.5	9,302,607	268,297	0.0288	0.9712	89.10
38.5	8,744,708	82,696	0.0095	0.9905	86.53

NEWFOUNDLAND AND LABRADOR HYDRO

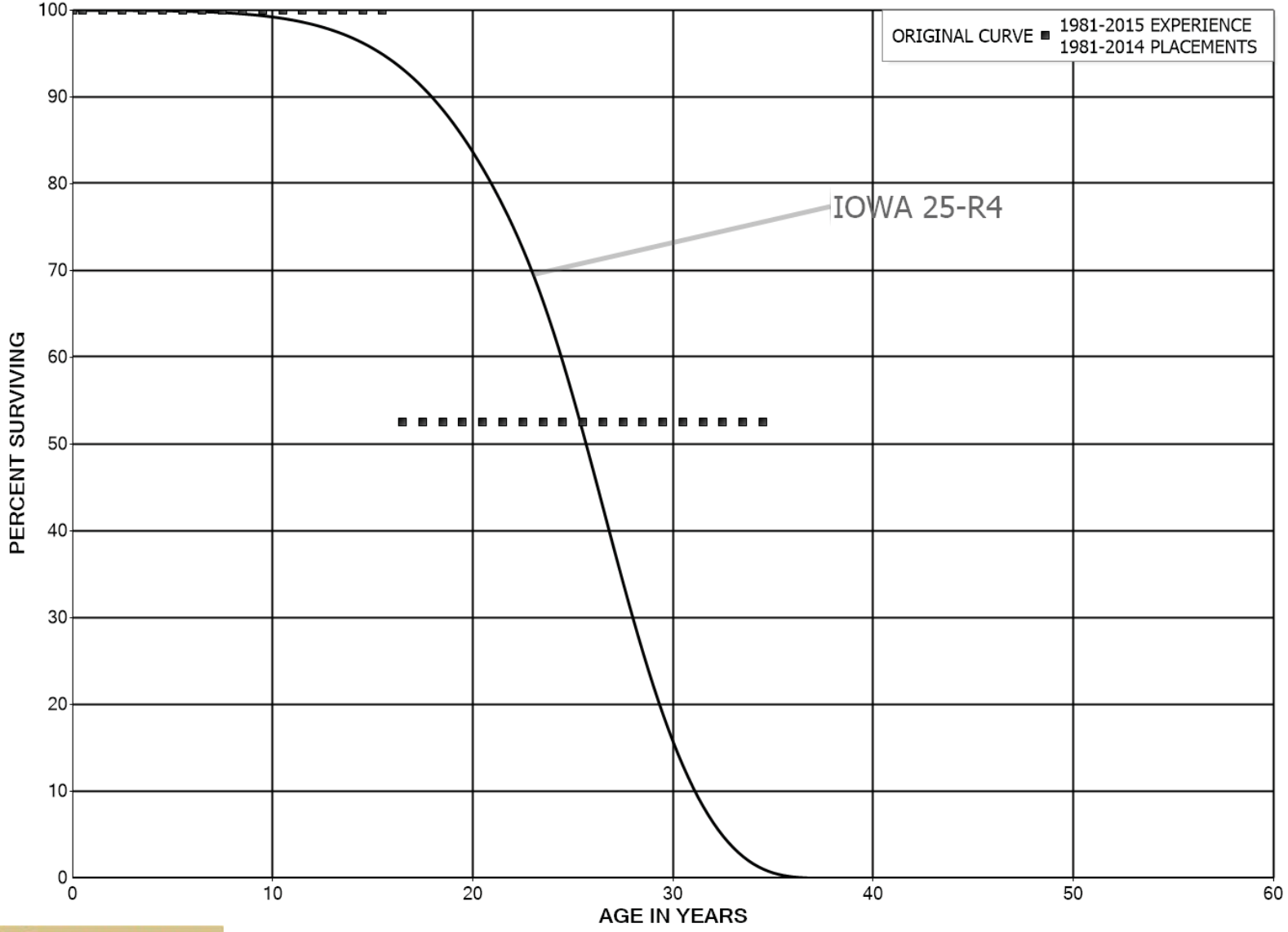
ACCOUNT P05 - POLE STRUCTURES - WOOD

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,550,283	97,486	0.0114	0.9886	85.71
40.5	8,448,254	277,795	0.0329	0.9671	84.74
41.5	5,360,936	24,278	0.0045	0.9955	81.95
42.5	5,336,658		0.0000	1.0000	81.58
43.5	5,336,658	46,880	0.0088	0.9912	81.58
44.5	5,269,090	12,661	0.0024	0.9976	80.86
45.5	2,475,936		0.0000	1.0000	80.67
46.5	2,055,270		0.0000	1.0000	80.67
47.5	1,368,472		0.0000	1.0000	80.67
48.5					80.67

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P06 - POLES - CONCRETE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

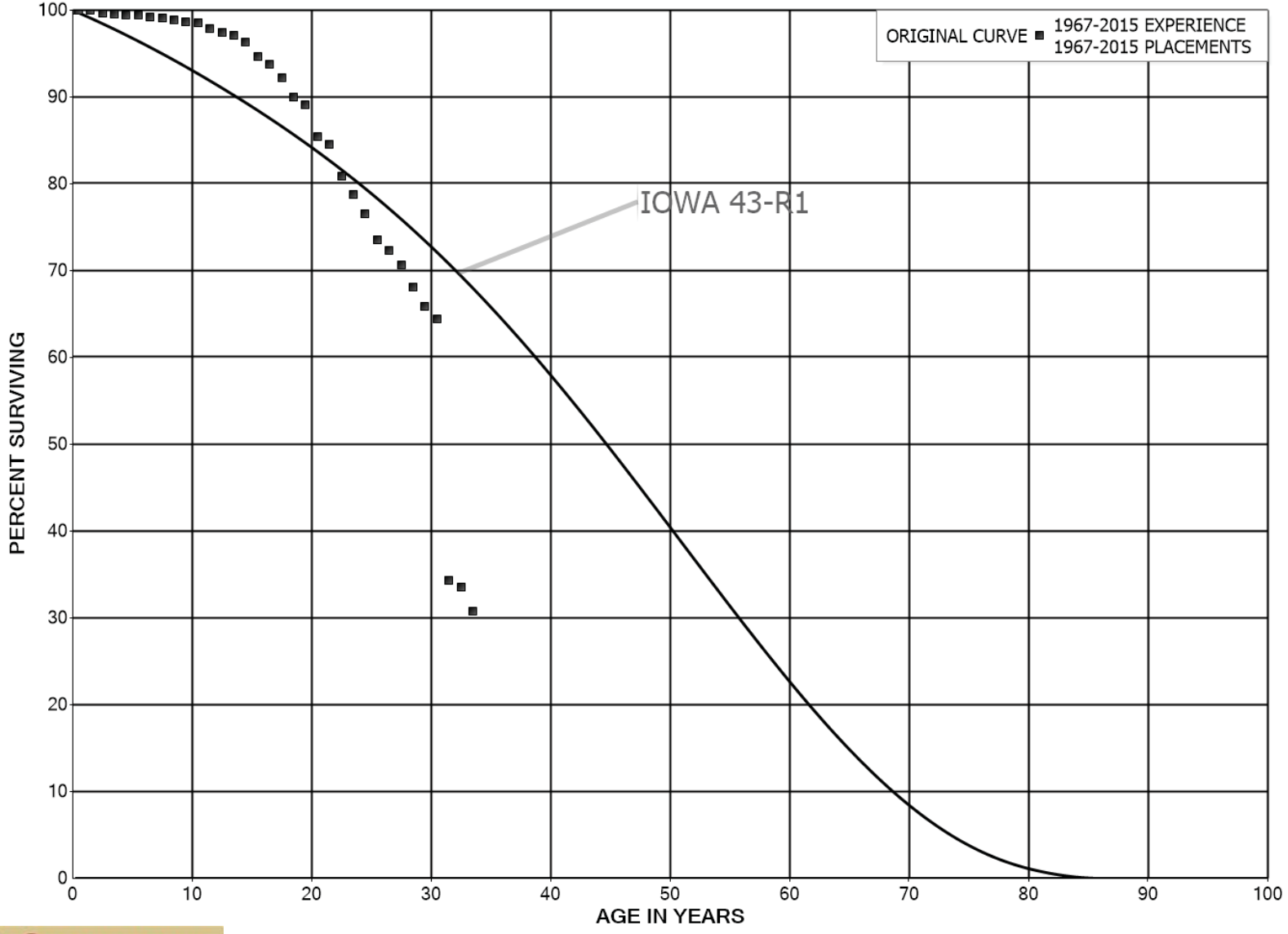
ACCOUNT P06 - POLES - CONCRETE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-2014 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	599,885		0.0000	1.0000	100.00
0.5	599,885		0.0000	1.0000	100.00
1.5	575,788		0.0000	1.0000	100.00
2.5	575,788		0.0000	1.0000	100.00
3.5	575,788		0.0000	1.0000	100.00
4.5	575,788		0.0000	1.0000	100.00
5.5	575,788		0.0000	1.0000	100.00
6.5	575,788		0.0000	1.0000	100.00
7.5	575,788		0.0000	1.0000	100.00
8.5	575,788		0.0000	1.0000	100.00
9.5	575,788		0.0000	1.0000	100.00
10.5	560,013		0.0000	1.0000	100.00
11.5	560,013		0.0000	1.0000	100.00
12.5	560,013		0.0000	1.0000	100.00
13.5	560,013		0.0000	1.0000	100.00
14.5	560,013		0.0000	1.0000	100.00
15.5	560,013	266,125	0.4752	0.5248	100.00
16.5	293,316		0.0000	1.0000	52.48
17.5	293,316		0.0000	1.0000	52.48
18.5	291,677		0.0000	1.0000	52.48
19.5	291,677		0.0000	1.0000	52.48
20.5	291,677		0.0000	1.0000	52.48
21.5	257,201		0.0000	1.0000	52.48
22.5	257,201		0.0000	1.0000	52.48
23.5	257,201		0.0000	1.0000	52.48
24.5	257,201		0.0000	1.0000	52.48
25.5	234,066		0.0000	1.0000	52.48
26.5	234,066		0.0000	1.0000	52.48
27.5	234,066		0.0000	1.0000	52.48
28.5	223,750		0.0000	1.0000	52.48
29.5	154,611		0.0000	1.0000	52.48
30.5	154,611		0.0000	1.0000	52.48
31.5	95,671		0.0000	1.0000	52.48
32.5	95,671		0.0000	1.0000	52.48
33.5	23,208		0.0000	1.0000	52.48
34.5					52.48

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P07 - POLES - WOOD
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P07 - POLES - WOOD

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	83,580,934	40,059	0.0005	0.9995	100.00
0.5	75,308,999	28,423	0.0004	0.9996	99.95
1.5	70,556,380	208,455	0.0030	0.9970	99.91
2.5	65,541,762	68,646	0.0010	0.9990	99.62
3.5	61,689,873	67,574	0.0011	0.9989	99.51
4.5	59,162,963	26,767	0.0005	0.9995	99.41
5.5	52,735,804	71,829	0.0014	0.9986	99.36
6.5	51,224,152	103,083	0.0020	0.9980	99.23
7.5	49,210,897	111,679	0.0023	0.9977	99.03
8.5	47,056,044	84,825	0.0018	0.9982	98.80
9.5	42,734,152	66,534	0.0016	0.9984	98.62
10.5	40,720,690	260,085	0.0064	0.9936	98.47
11.5	39,030,080	156,707	0.0040	0.9960	97.84
12.5	37,359,461	164,429	0.0044	0.9956	97.45
13.5	30,921,577	246,717	0.0080	0.9920	97.02
14.5	29,403,583	510,161	0.0174	0.9826	96.24
15.5	27,747,417	251,517	0.0091	0.9909	94.57
16.5	26,544,727	447,461	0.0169	0.9831	93.72
17.5	24,944,338	607,529	0.0244	0.9756	92.14
18.5	22,387,909	205,456	0.0092	0.9908	89.89
19.5	20,605,159	861,043	0.0418	0.9582	89.07
20.5	18,792,449	196,789	0.0105	0.9895	85.35
21.5	17,257,295	728,894	0.0422	0.9578	84.45
22.5	15,575,912	423,108	0.0272	0.9728	80.89
23.5	14,395,418	399,475	0.0278	0.9722	78.69
24.5	13,166,348	510,198	0.0388	0.9612	76.51
25.5	11,654,551	199,912	0.0172	0.9828	73.54
26.5	9,848,035	224,445	0.0228	0.9772	72.28
27.5	8,679,615	312,730	0.0360	0.9640	70.63
28.5	7,265,878	235,291	0.0324	0.9676	68.09
29.5	6,128,894	142,688	0.0233	0.9767	65.88
30.5	5,854,651	2,737,687	0.4676	0.5324	64.35
31.5	2,686,461	55,829	0.0208	0.9792	34.26
32.5	2,282,571	191,717	0.0840	0.9160	33.55
33.5	1,604,053	25,151	0.0157	0.9843	30.73
34.5	25,456		0.0000	1.0000	30.25
35.5	25,456		0.0000	1.0000	30.25
36.5	25,169	954	0.0379	0.9621	30.25
37.5	21,294	1,929	0.0906	0.9094	29.10
38.5	19,365	527	0.0272	0.9728	26.46

NEWFOUNDLAND AND LABRADOR HYDRO

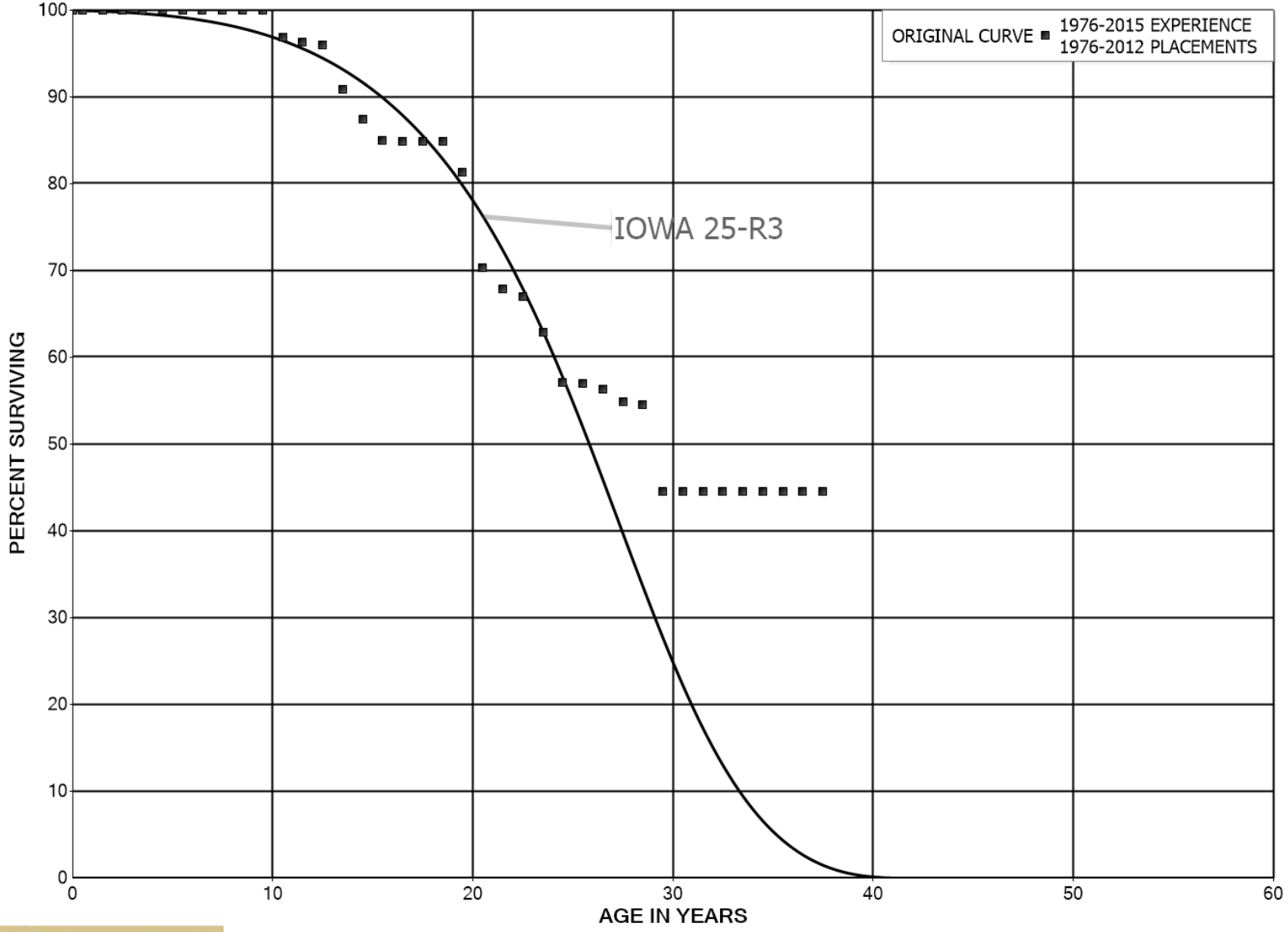
ACCOUNT P07 - POLES - WOOD

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,839		0.0000	1.0000	25.75
40.5	18,839		0.0000	1.0000	25.75
41.5	18,839		0.0000	1.0000	25.75
42.5	18,839		0.0000	1.0000	25.75
43.5	18,839		0.0000	1.0000	25.75
44.5	18,839		0.0000	1.0000	25.75
45.5	1,430		0.0000	1.0000	25.75
46.5	1,430		0.0000	1.0000	25.75
47.5					25.75

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P08 - POWER LINE CARRIER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

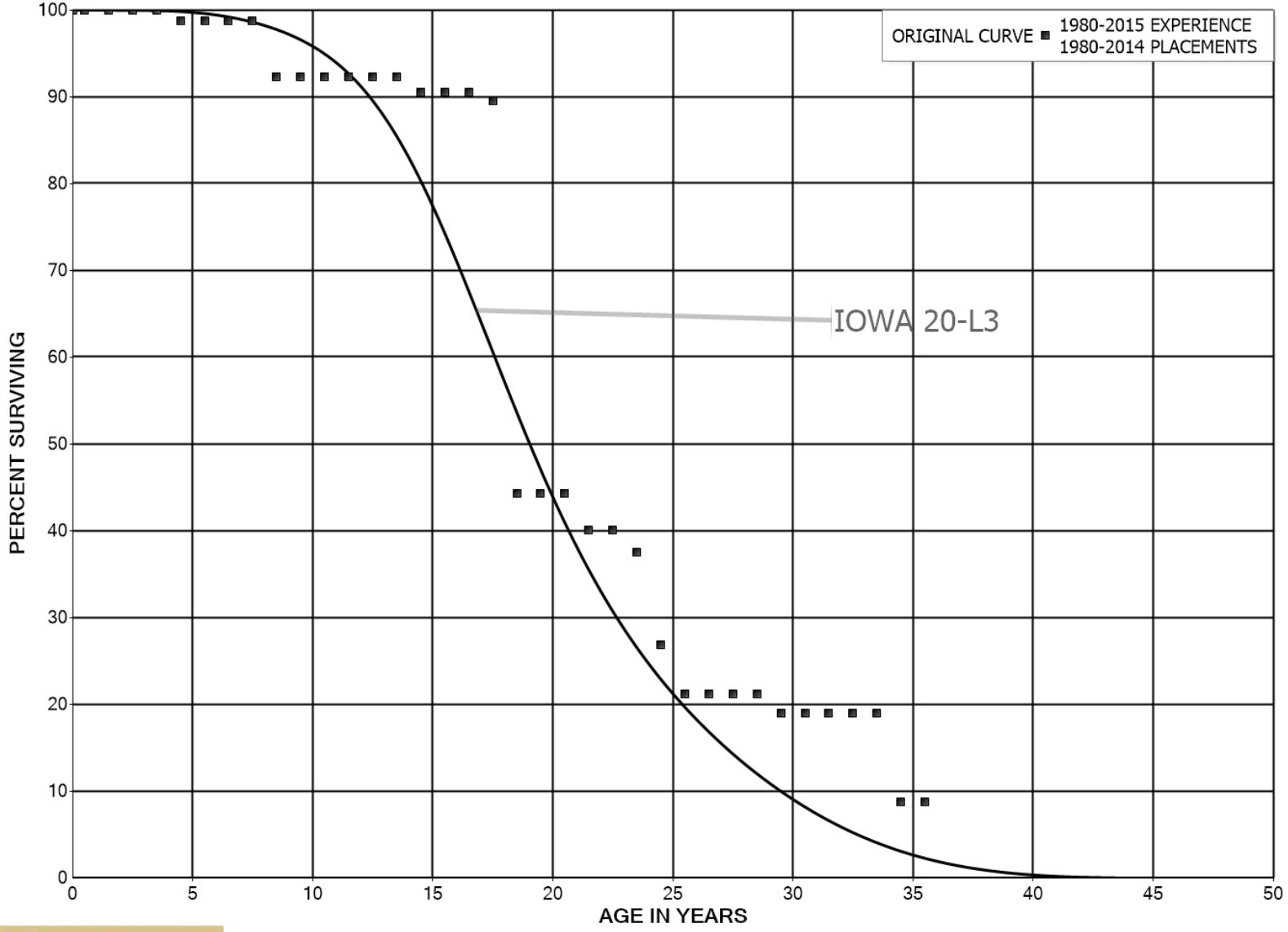
ACCOUNT P08 - POWER LINE CARRIER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1976-2012 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,720,295		0.0000	1.0000	100.00
0.5	6,720,295		0.0000	1.0000	100.00
1.5	6,720,295		0.0000	1.0000	100.00
2.5	6,720,295		0.0000	1.0000	100.00
3.5	6,709,545		0.0000	1.0000	100.00
4.5	6,709,545		0.0000	1.0000	100.00
5.5	6,709,545		0.0000	1.0000	100.00
6.5	6,358,277		0.0000	1.0000	100.00
7.5	5,989,724	744	0.0001	0.9999	100.00
8.5	5,988,980		0.0000	1.0000	99.99
9.5	5,988,980	185,763	0.0310	0.9690	99.99
10.5	5,803,217	34,114	0.0059	0.9941	96.89
11.5	5,482,029	20,092	0.0037	0.9963	96.32
12.5	5,203,757	280,286	0.0539	0.9461	95.96
13.5	4,328,816	161,080	0.0372	0.9628	90.79
14.5	4,167,736	116,380	0.0279	0.9721	87.42
15.5	2,882,813	4,683	0.0016	0.9984	84.98
16.5	2,345,658		0.0000	1.0000	84.84
17.5	2,345,658		0.0000	1.0000	84.84
18.5	2,345,658	97,722	0.0417	0.9583	84.84
19.5	2,132,112	288,410	0.1353	0.8647	81.30
20.5	1,524,034	54,146	0.0355	0.9645	70.31
21.5	1,469,888	17,575	0.0120	0.9880	67.81
22.5	1,452,313	89,404	0.0616	0.9384	67.00
23.5	1,362,910	125,054	0.0918	0.9082	62.87
24.5	1,237,856	3,286	0.0027	0.9973	57.10
25.5	1,232,572	14,196	0.0115	0.9885	56.95
26.5	1,218,377	30,612	0.0251	0.9749	56.30
27.5	1,187,764	6,999	0.0059	0.9941	54.88
28.5	1,180,765	216,792	0.1836	0.8164	54.56
29.5	963,973	1,384	0.0014	0.9986	44.54
30.5	962,588		0.0000	1.0000	44.48
31.5	962,588		0.0000	1.0000	44.48
32.5	962,588		0.0000	1.0000	44.48
33.5	952,437		0.0000	1.0000	44.48
34.5	952,437		0.0000	1.0000	44.48
35.5	50,795		0.0000	1.0000	44.48
36.5	50,795		0.0000	1.0000	44.48
37.5					44.48

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P09 - POWER SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

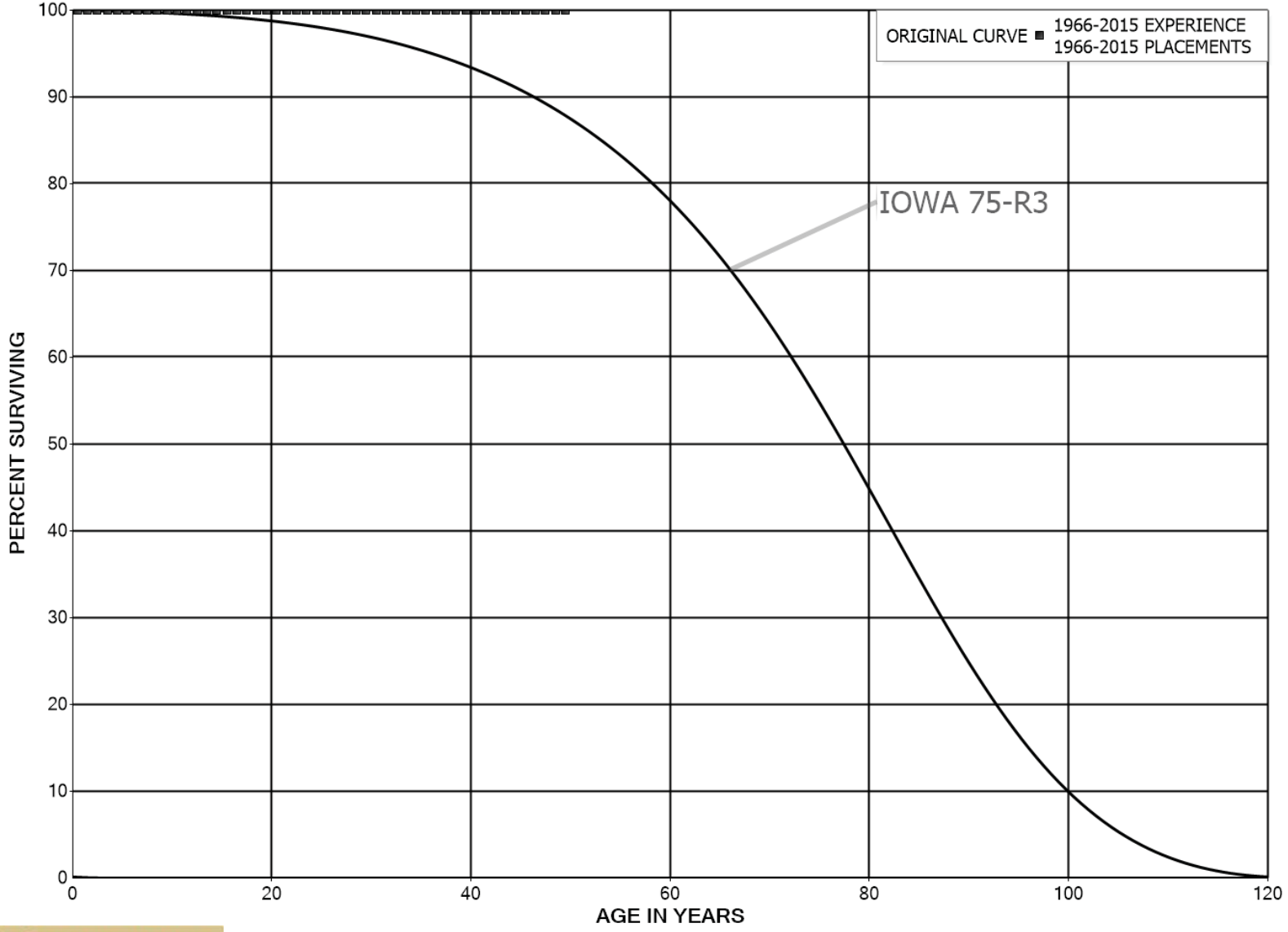
ACCOUNT P09 - POWER SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2014 EXPERIENCE BAND 1980-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	804,033		0.0000	1.0000	100.00
0.5	804,033		0.0000	1.0000	100.00
1.5	790,242		0.0000	1.0000	100.00
2.5	742,503		0.0000	1.0000	100.00
3.5	719,393	8,858	0.0123	0.9877	100.00
4.5	710,534		0.0000	1.0000	98.77
5.5	710,534		0.0000	1.0000	98.77
6.5	710,534		0.0000	1.0000	98.77
7.5	685,630	45,059	0.0657	0.9343	98.77
8.5	639,484		0.0000	1.0000	92.28
9.5	543,189		0.0000	1.0000	92.28
10.5	543,189		0.0000	1.0000	92.28
11.5	513,756		0.0000	1.0000	92.28
12.5	139,320		0.0000	1.0000	92.28
13.5	139,320	2,673	0.0192	0.9808	92.28
14.5	136,647		0.0000	1.0000	90.51
15.5	129,219		0.0000	1.0000	90.51
16.5	124,816	1,456	0.0117	0.9883	90.51
17.5	120,687	60,879	0.5044	0.4956	89.45
18.5	30,507		0.0000	1.0000	44.33
19.5	30,507		0.0000	1.0000	44.33
20.5	30,507	2,900	0.0951	0.9049	44.33
21.5	27,607		0.0000	1.0000	40.11
22.5	27,607	1,774	0.0643	0.9357	40.11
23.5	23,483	6,712	0.2858	0.7142	37.54
24.5	16,771	3,531	0.2105	0.7895	26.81
25.5	9,538		0.0000	1.0000	21.16
26.5	9,538		0.0000	1.0000	21.16
27.5	9,538		0.0000	1.0000	21.16
28.5	9,538	1,000	0.1048	0.8952	21.16
29.5	8,538		0.0000	1.0000	18.95
30.5	8,538		0.0000	1.0000	18.95
31.5	8,538		0.0000	1.0000	18.95
32.5	8,538		0.0000	1.0000	18.95
33.5	8,538	4,598	0.5386	0.4614	18.95
34.5	3,940		0.0000	1.0000	8.74
35.5					8.74

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P10 - POWERHOUSE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P10 - POWERHOUSE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	102,700,817		0.0000	1.0000	100.00
0.5	101,734,797		0.0000	1.0000	100.00
1.5	101,329,090		0.0000	1.0000	100.00
2.5	101,192,787		0.0000	1.0000	100.00
3.5	101,192,787		0.0000	1.0000	100.00
4.5	101,192,787		0.0000	1.0000	100.00
5.5	101,192,787		0.0000	1.0000	100.00
6.5	101,192,787		0.0000	1.0000	100.00
7.5	101,082,001		0.0000	1.0000	100.00
8.5	101,082,001		0.0000	1.0000	100.00
9.5	100,998,712		0.0000	1.0000	100.00
10.5	100,998,712		0.0000	1.0000	100.00
11.5	100,998,712		0.0000	1.0000	100.00
12.5	80,149,101		0.0000	1.0000	100.00
13.5	80,149,101		0.0000	1.0000	100.00
14.5	80,149,101	1,408	0.0000	1.0000	100.00
15.5	80,040,055	63,094	0.0008	0.9992	100.00
16.5	79,976,960		0.0000	1.0000	99.92
17.5	79,967,397		0.0000	1.0000	99.92
18.5	79,960,122		0.0000	1.0000	99.92
19.5	79,960,122		0.0000	1.0000	99.92
20.5	79,811,859		0.0000	1.0000	99.92
21.5	79,766,978		0.0000	1.0000	99.92
22.5	77,059,323		0.0000	1.0000	99.92
23.5	77,059,323		0.0000	1.0000	99.92
24.5	77,048,404		0.0000	1.0000	99.92
25.5	77,009,543		0.0000	1.0000	99.92
26.5	75,938,104		0.0000	1.0000	99.92
27.5	74,445,854		0.0000	1.0000	99.92
28.5	74,196,993		0.0000	1.0000	99.92
29.5	74,186,988	12,517	0.0002	0.9998	99.92
30.5	68,169,254		0.0000	1.0000	99.90
31.5	56,183,499		0.0000	1.0000	99.90
32.5	51,612,776		0.0000	1.0000	99.90
33.5	39,057,174		0.0000	1.0000	99.90
34.5	38,814,548	1,272	0.0000	1.0000	99.90
35.5	27,784,412		0.0000	1.0000	99.90
36.5	21,227,034		0.0000	1.0000	99.90
37.5	20,143,559		0.0000	1.0000	99.90
38.5	20,143,559		0.0000	1.0000	99.90

NEWFOUNDLAND AND LABRADOR HYDRO

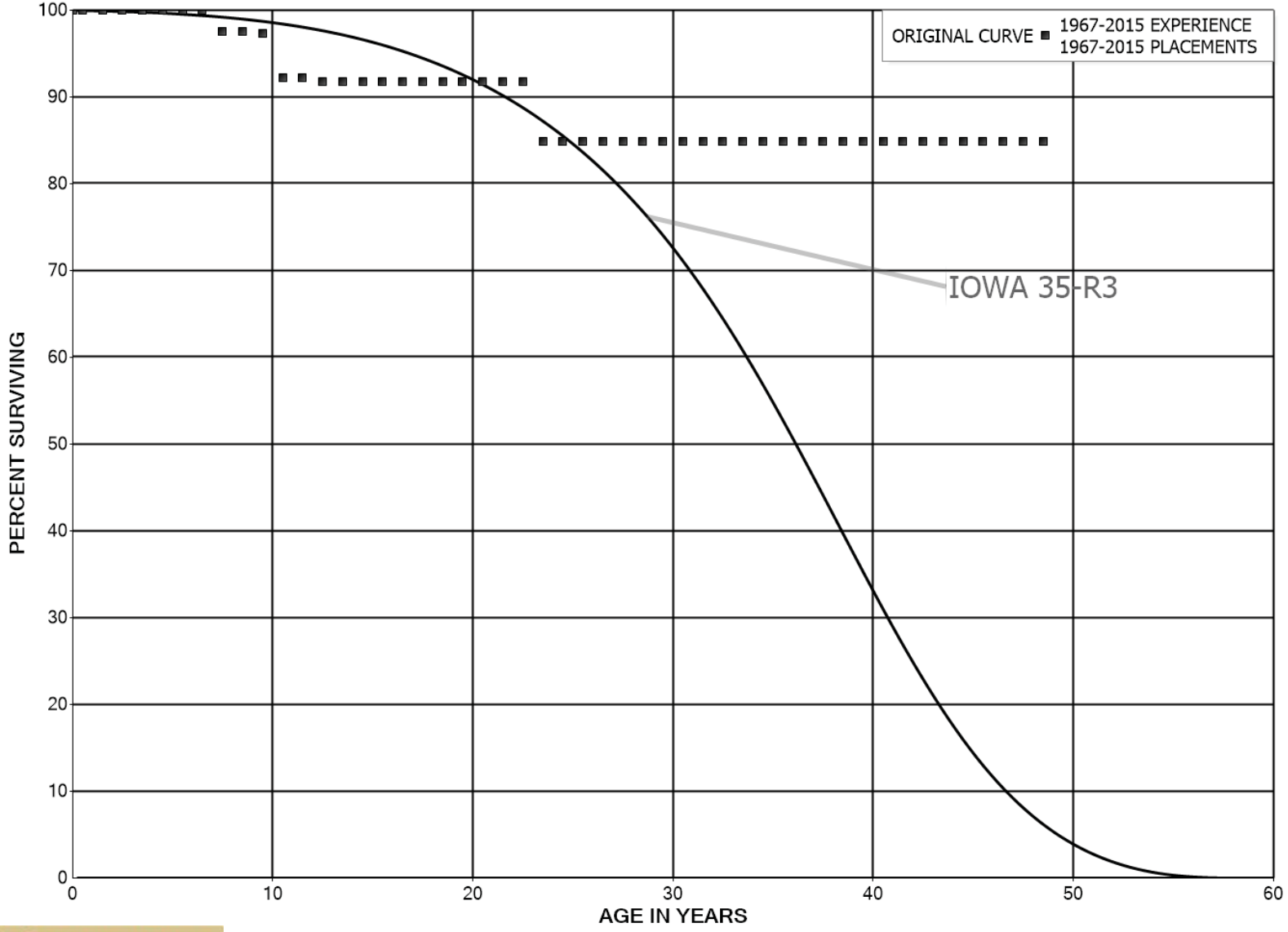
ACCOUNT P10 - POWERHOUSE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,138,559		0.0000	1.0000	99.90
40.5	20,138,559		0.0000	1.0000	99.90
41.5	20,138,559		0.0000	1.0000	99.90
42.5	20,138,559	349	0.0000	1.0000	99.90
43.5	20,138,210		0.0000	1.0000	99.90
44.5	16,547,132		0.0000	1.0000	99.90
45.5	13,734,007		0.0000	1.0000	99.90
46.5	10,881,494		0.0000	1.0000	99.90
47.5	10,881,494		0.0000	1.0000	99.90
48.5	6,311,169		0.0000	1.0000	99.90
49.5					99.90

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT P12 - PROTECTIVE CONTROL AND RELAY PANELS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P12 - PROTECTIVE CONTROL AND RELAY PANELS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,018,336		0.0000	1.0000	100.00
0.5	9,215,365	289	0.0000	1.0000	100.00
1.5	8,790,412		0.0000	1.0000	100.00
2.5	6,915,111		0.0000	1.0000	100.00
3.5	5,112,300		0.0000	1.0000	100.00
4.5	4,840,285		0.0000	1.0000	100.00
5.5	4,762,333		0.0000	1.0000	100.00
6.5	4,618,882	116,342	0.0252	0.9748	100.00
7.5	4,328,679		0.0000	1.0000	97.48
8.5	3,910,908	7,102	0.0018	0.9982	97.48
9.5	3,819,666	200,000	0.0524	0.9476	97.30
10.5	3,482,721		0.0000	1.0000	92.21
11.5	3,214,837	16,280	0.0051	0.9949	92.21
12.5	1,482,888		0.0000	1.0000	91.74
13.5	1,482,888		0.0000	1.0000	91.74
14.5	1,482,888		0.0000	1.0000	91.74
15.5	1,482,888		0.0000	1.0000	91.74
16.5	1,359,099		0.0000	1.0000	91.74
17.5	1,359,099		0.0000	1.0000	91.74
18.5	1,359,099		0.0000	1.0000	91.74
19.5	936,582		0.0000	1.0000	91.74
20.5	854,646		0.0000	1.0000	91.74
21.5	854,646		0.0000	1.0000	91.74
22.5	854,646	64,494	0.0755	0.9245	91.74
23.5	790,153		0.0000	1.0000	84.82
24.5	790,153		0.0000	1.0000	84.82
25.5	790,153		0.0000	1.0000	84.82
26.5	790,153		0.0000	1.0000	84.82
27.5	779,116	15	0.0000	1.0000	84.82
28.5	681,158		0.0000	1.0000	84.81
29.5	681,158		0.0000	1.0000	84.81
30.5	681,158		0.0000	1.0000	84.81
31.5	615,525		0.0000	1.0000	84.81
32.5	615,525		0.0000	1.0000	84.81
33.5	615,525		0.0000	1.0000	84.81
34.5	615,525		0.0000	1.0000	84.81
35.5	341,524		0.0000	1.0000	84.81
36.5	341,524		0.0000	1.0000	84.81
37.5	341,524		0.0000	1.0000	84.81
38.5	341,524		0.0000	1.0000	84.81

NEWFOUNDLAND AND LABRADOR HYDRO

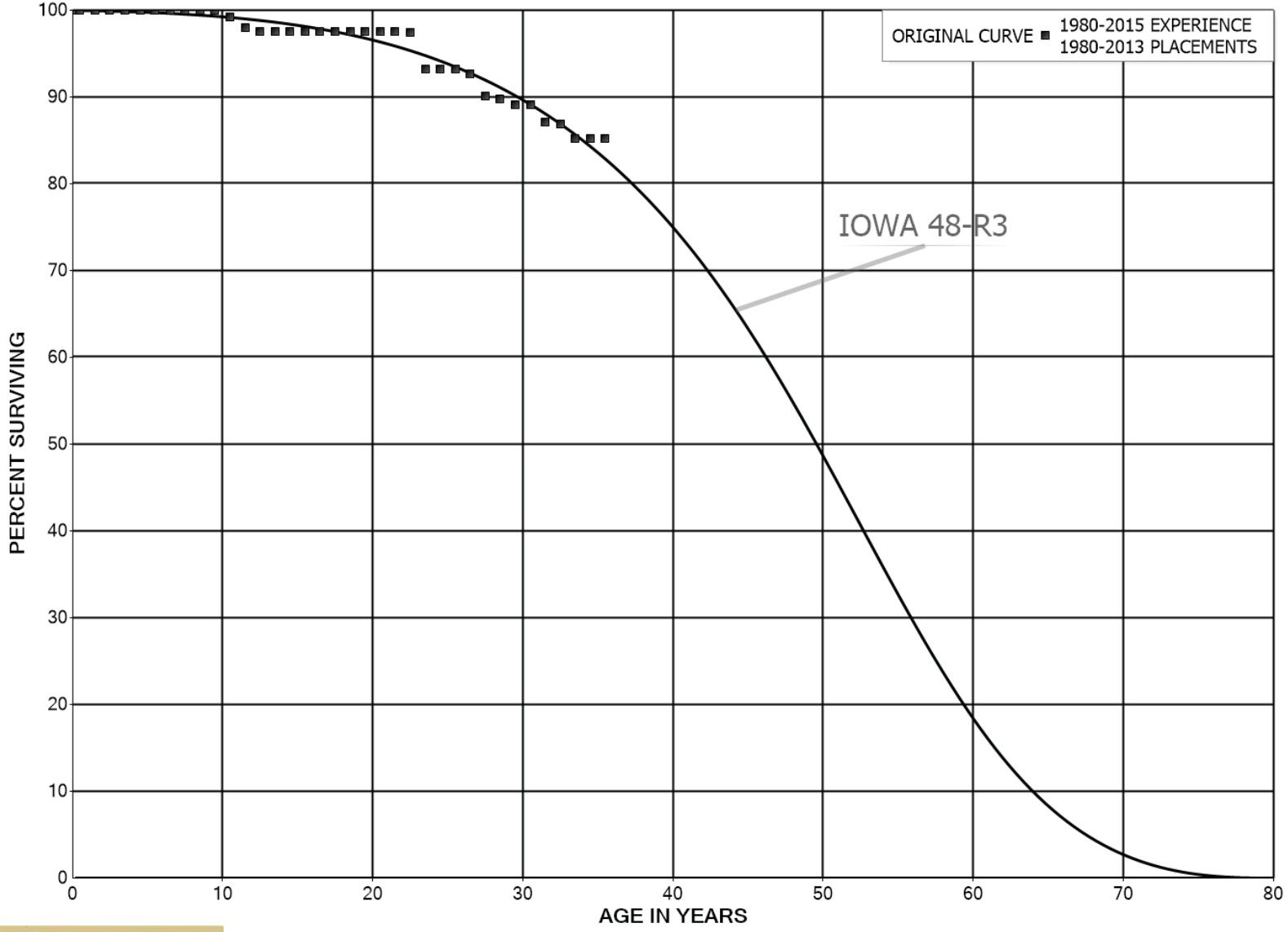
ACCOUNT P12 - PROTECTIVE CONTROL AND RELAY PANELS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	341,524		0.0000	1.0000	84.81
40.5	341,524		0.0000	1.0000	84.81
41.5	341,524		0.0000	1.0000	84.81
42.5	341,524		0.0000	1.0000	84.81
43.5	341,524		0.0000	1.0000	84.81
44.5	341,524		0.0000	1.0000	84.81
45.5	341,524		0.0000	1.0000	84.81
46.5	341,524		0.0000	1.0000	84.81
47.5	284,442		0.0000	1.0000	84.81
48.5					84.81

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R01 - RADIO TOWERS (WOOD OR STEEL)
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

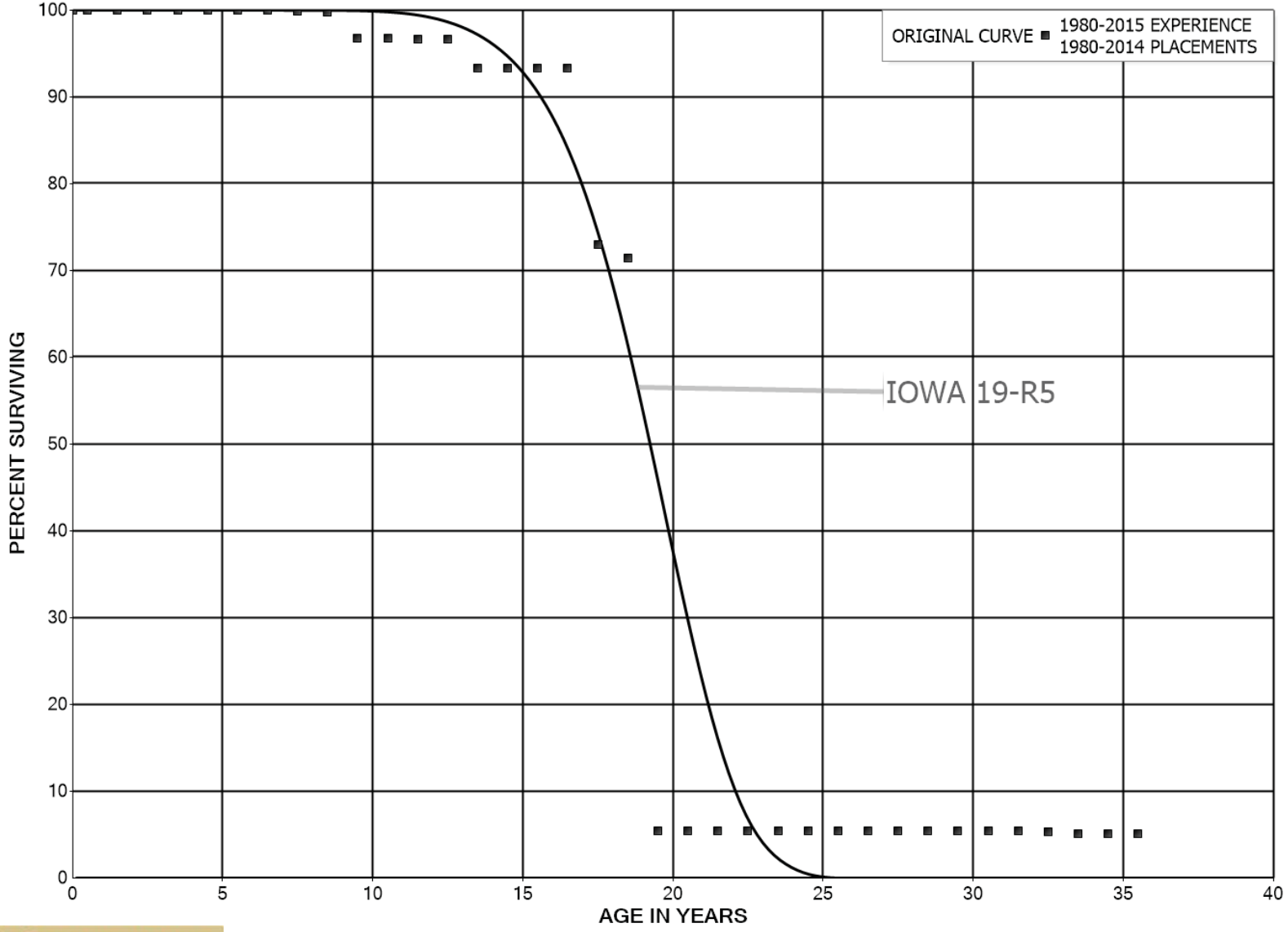
ACCOUNT R01 - RADIO TOWERS (WOOD OR STEEL)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2013 EXPERIENCE BAND 1980-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,210,442		0.0000	1.0000	100.00
0.5	10,210,442		0.0000	1.0000	100.00
1.5	10,210,442		0.0000	1.0000	100.00
2.5	9,947,473		0.0000	1.0000	100.00
3.5	9,790,093		0.0000	1.0000	100.00
4.5	9,790,093		0.0000	1.0000	100.00
5.5	9,575,446		0.0000	1.0000	100.00
6.5	9,393,802		0.0000	1.0000	100.00
7.5	9,393,802		0.0000	1.0000	100.00
8.5	9,028,332	1,887	0.0002	0.9998	100.00
9.5	9,026,445	71,491	0.0079	0.9921	99.98
10.5	8,723,764	113,599	0.0130	0.9870	99.19
11.5	8,610,165	32,144	0.0037	0.9963	97.90
12.5	4,170,732		0.0000	1.0000	97.53
13.5	4,170,732		0.0000	1.0000	97.53
14.5	1,951,585		0.0000	1.0000	97.53
15.5	1,951,585		0.0000	1.0000	97.53
16.5	1,951,585		0.0000	1.0000	97.53
17.5	1,951,585		0.0000	1.0000	97.53
18.5	1,951,585	511	0.0003	0.9997	97.53
19.5	1,951,074		0.0000	1.0000	97.50
20.5	1,951,074		0.0000	1.0000	97.50
21.5	1,951,074	2,042	0.0010	0.9990	97.50
22.5	1,928,684	84,079	0.0436	0.9564	97.40
23.5	1,844,605		0.0000	1.0000	93.16
24.5	1,844,605		0.0000	1.0000	93.16
25.5	1,783,733	11,183	0.0063	0.9937	93.16
26.5	1,772,550	48,007	0.0271	0.9729	92.57
27.5	1,724,543	6,445	0.0037	0.9963	90.07
28.5	1,718,098	13,493	0.0079	0.9921	89.73
29.5	1,704,605		0.0000	1.0000	89.02
30.5	1,704,605	37,301	0.0219	0.9781	89.02
31.5	1,321,553	2,832	0.0021	0.9979	87.08
32.5	1,318,721	26,322	0.0200	0.9800	86.89
33.5	1,129,316		0.0000	1.0000	85.15
34.5	1,129,316		0.0000	1.0000	85.15
35.5					85.15

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R02 - RADIOS - FIXED MICROWAVE EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

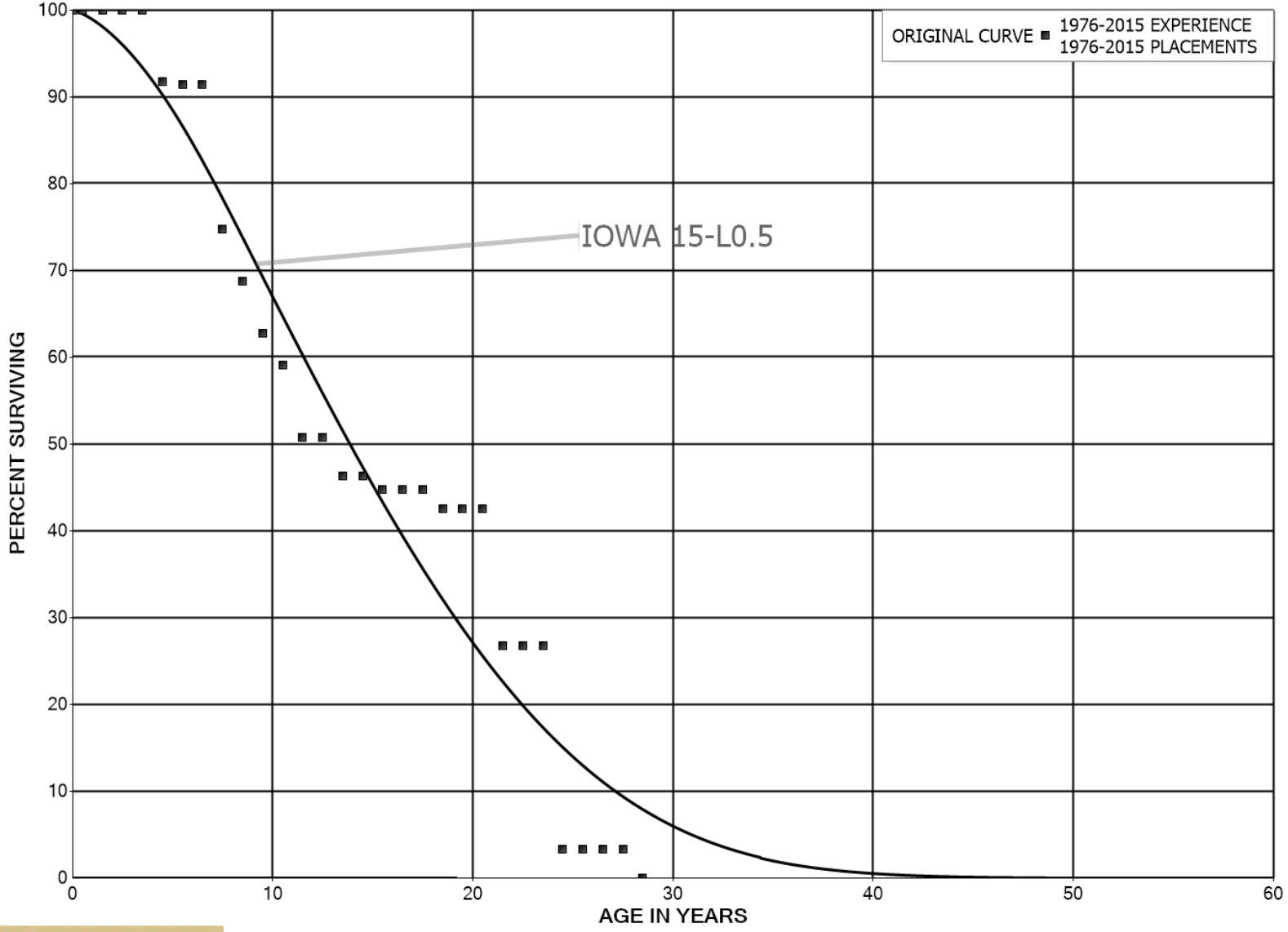
ACCOUNT R02 - RADIOS - FIXED MICROWAVE EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2014 EXPERIENCE BAND 1980-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,015,572		0.0000	1.0000	100.00
0.5	9,015,572		0.0000	1.0000	100.00
1.5	8,079,697		0.0000	1.0000	100.00
2.5	8,079,697		0.0000	1.0000	100.00
3.5	8,037,253		0.0000	1.0000	100.00
4.5	8,037,253		0.0000	1.0000	100.00
5.5	7,984,806	5,955	0.0007	0.9993	100.00
6.5	7,978,851	5,955	0.0007	0.9993	99.93
7.5	7,972,896	11,911	0.0015	0.9985	99.85
8.5	7,776,559	229,080	0.0295	0.9705	99.70
9.5	7,547,479		0.0000	1.0000	96.76
10.5	7,547,479	8,953	0.0012	0.9988	96.76
11.5	7,538,526		0.0000	1.0000	96.65
12.5	5,602,065	196,602	0.0351	0.9649	96.65
13.5	5,405,463		0.0000	1.0000	93.26
14.5	2,478,110		0.0000	1.0000	93.26
15.5	2,478,110		0.0000	1.0000	93.26
16.5	2,478,110	541,022	0.2183	0.7817	93.26
17.5	1,937,088	38,530	0.0199	0.9801	72.90
18.5	1,898,558	1,755,806	0.9248	0.0752	71.45
19.5	142,752		0.0000	1.0000	5.37
20.5	142,752		0.0000	1.0000	5.37
21.5	142,752		0.0000	1.0000	5.37
22.5	142,752		0.0000	1.0000	5.37
23.5	142,752		0.0000	1.0000	5.37
24.5	142,752		0.0000	1.0000	5.37
25.5	142,752		0.0000	1.0000	5.37
26.5	142,752		0.0000	1.0000	5.37
27.5	142,752		0.0000	1.0000	5.37
28.5	142,752		0.0000	1.0000	5.37
29.5	142,752		0.0000	1.0000	5.37
30.5	142,752		0.0000	1.0000	5.37
31.5	142,752	1,124	0.0079	0.9921	5.37
32.5	141,628	7,869	0.0556	0.9444	5.33
33.5	133,759		0.0000	1.0000	5.03
34.5	133,759		0.0000	1.0000	5.03
35.5					5.03

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R03 - RADIOS - FIXED UHF EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

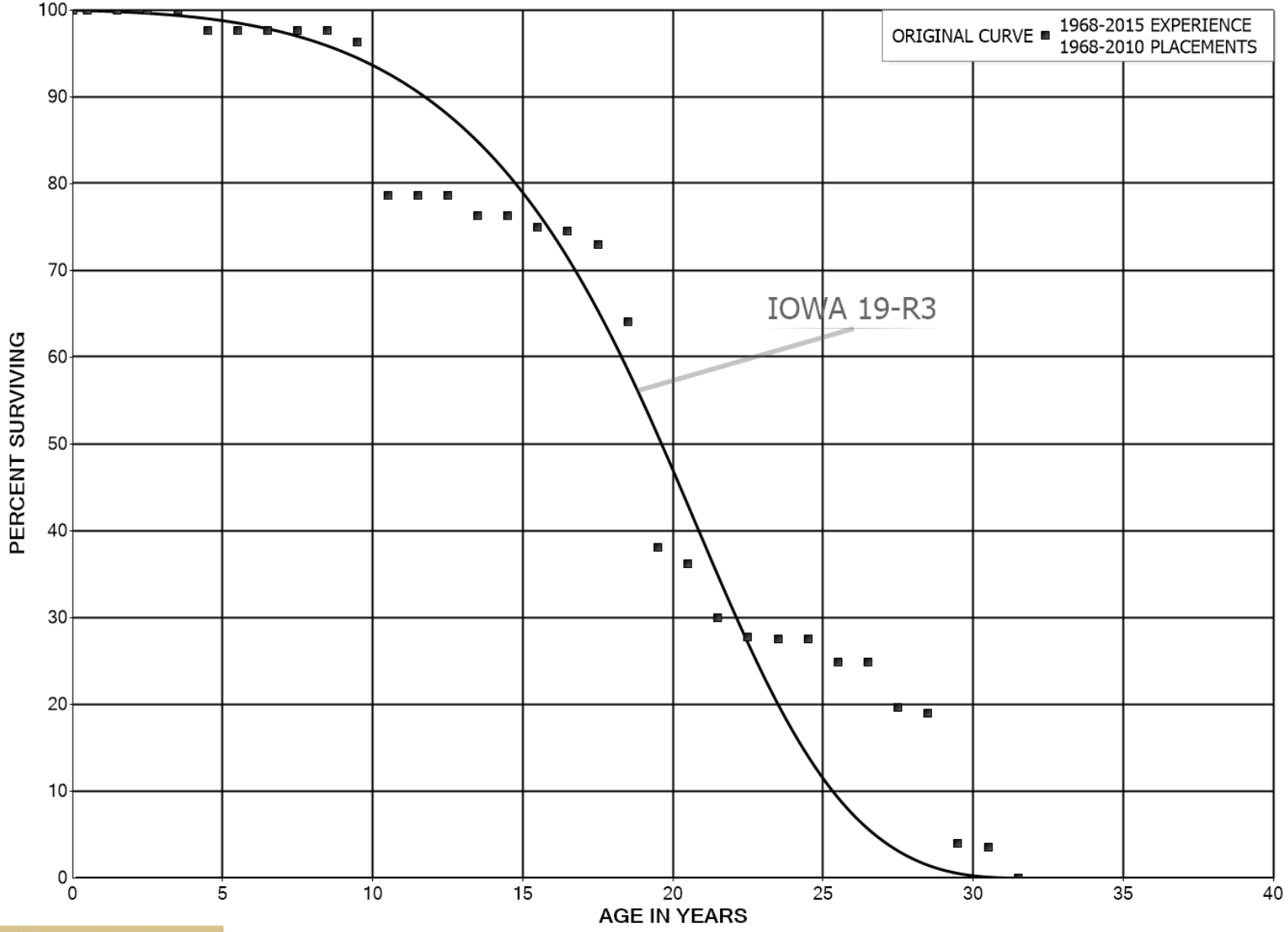
ACCOUNT R03 - RADIOS - FIXED UHF EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1976-2015 EXPERIENCE BAND 1976-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	794,415		0.0000	1.0000	100.00
0.5	791,030		0.0000	1.0000	100.00
1.5	791,030		0.0000	1.0000	100.00
2.5	791,030		0.0000	1.0000	100.00
3.5	782,054	64,764	0.0828	0.9172	100.00
4.5	717,290	2,571	0.0036	0.9964	91.72
5.5	714,718		0.0000	1.0000	91.39
6.5	664,939	120,949	0.1819	0.8181	91.39
7.5	504,468	40,640	0.0806	0.9194	74.77
8.5	463,828	40,546	0.0874	0.9126	68.74
9.5	423,282	24,923	0.0589	0.9411	62.73
10.5	398,359	56,185	0.1410	0.8590	59.04
11.5	342,174		0.0000	1.0000	50.71
12.5	342,174	30,009	0.0877	0.9123	50.71
13.5	312,165		0.0000	1.0000	46.27
14.5	312,165	10,053	0.0322	0.9678	46.27
15.5	302,112		0.0000	1.0000	44.78
16.5	302,112		0.0000	1.0000	44.78
17.5	302,112	14,969	0.0495	0.9505	44.78
18.5	287,143		0.0000	1.0000	42.56
19.5	287,143		0.0000	1.0000	42.56
20.5	287,143	107,012	0.3727	0.6273	42.56
21.5	180,132		0.0000	1.0000	26.70
22.5	180,132		0.0000	1.0000	26.70
23.5	180,132	157,782	0.8759	0.1241	26.70
24.5	22,350		0.0000	1.0000	3.31
25.5	22,350		0.0000	1.0000	3.31
26.5	22,350		0.0000	1.0000	3.31
27.5	22,350	22,350	1.0000		3.31
28.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R04 - RADIOS - FIXED VHF EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

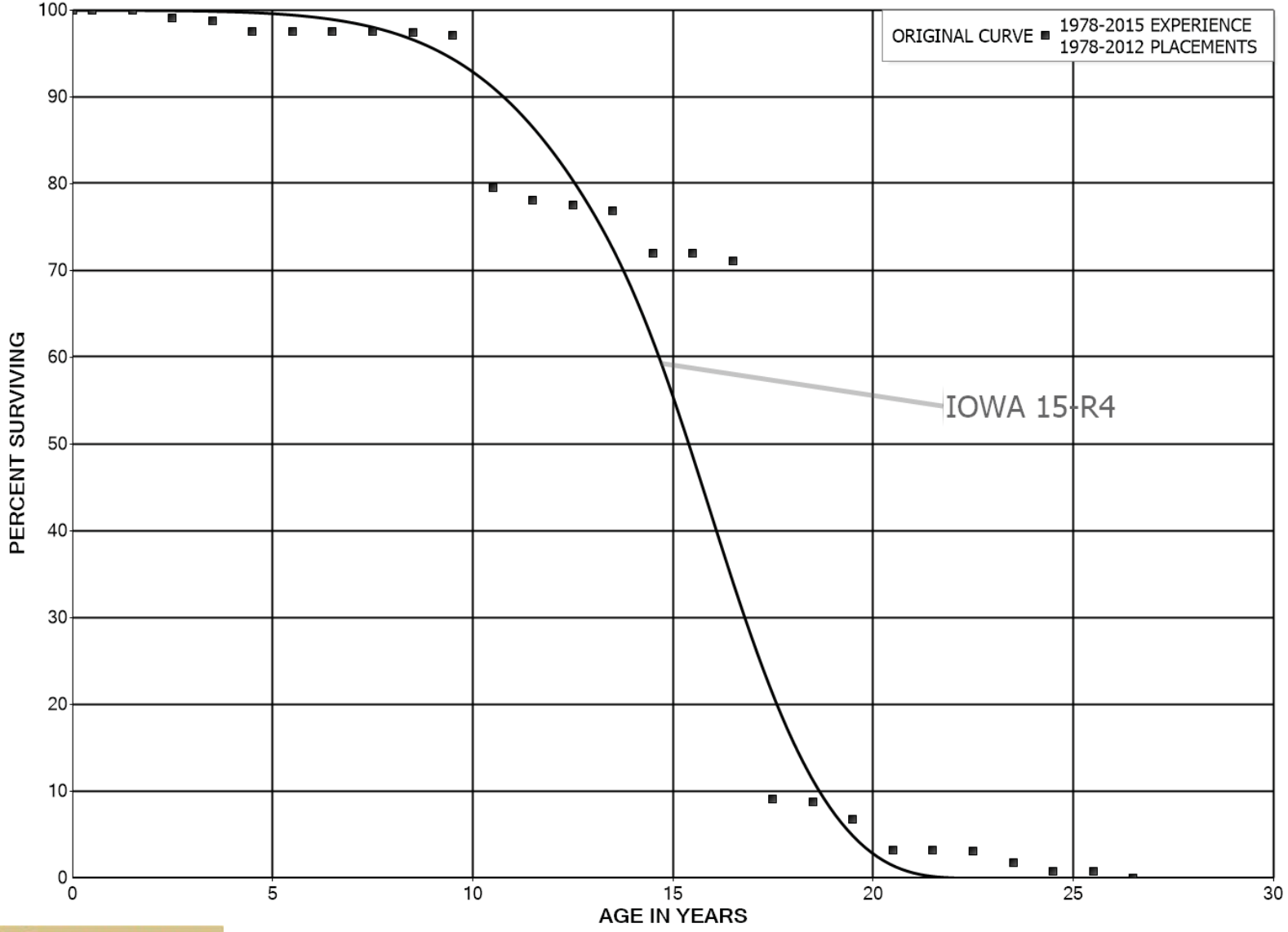
ACCOUNT R04 - RADIOS - FIXED VHF EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2010 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,446,342		0.0000	1.0000	100.00
0.5	4,446,342		0.0000	1.0000	100.00
1.5	4,446,342		0.0000	1.0000	100.00
2.5	4,446,342	2,815	0.0006	0.9994	100.00
3.5	4,443,527	100,821	0.0227	0.9773	99.94
4.5	4,342,706		0.0000	1.0000	97.67
5.5	4,274,065		0.0000	1.0000	97.67
6.5	4,274,065		0.0000	1.0000	97.67
7.5	4,274,065		0.0000	1.0000	97.67
8.5	4,274,065	58,697	0.0137	0.9863	97.67
9.5	4,004,327	734,453	0.1834	0.8166	96.33
10.5	3,269,873	4,032	0.0012	0.9988	78.66
11.5	3,265,282		0.0000	1.0000	78.56
12.5	3,147,036	91,387	0.0290	0.9710	78.56
13.5	3,055,649		0.0000	1.0000	76.28
14.5	3,055,649	55,707	0.0182	0.9818	76.28
15.5	2,999,943	13,726	0.0046	0.9954	74.89
16.5	2,986,216	65,444	0.0219	0.9781	74.55
17.5	2,920,772	356,547	0.1221	0.8779	72.91
18.5	2,564,225	1,039,595	0.4054	0.5946	64.01
19.5	1,524,630	74,301	0.0487	0.9513	38.06
20.5	1,450,329	249,527	0.1720	0.8280	36.21
21.5	1,200,802	90,709	0.0755	0.9245	29.98
22.5	1,110,094	6,486	0.0058	0.9942	27.71
23.5	941,929	2,316	0.0025	0.9975	27.55
24.5	939,613	90,645	0.0965	0.9035	27.48
25.5	848,968		0.0000	1.0000	24.83
26.5	848,968	179,152	0.2110	0.7890	24.83
27.5	669,816	21,779	0.0325	0.9675	19.59
28.5	648,037	513,070	0.7917	0.2083	18.95
29.5	134,966	14,179	0.1051	0.8949	3.95
30.5	120,787	120,787	1.0000		3.53
31.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R05 - RADIOS - MOBILE VHF BASE STATION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

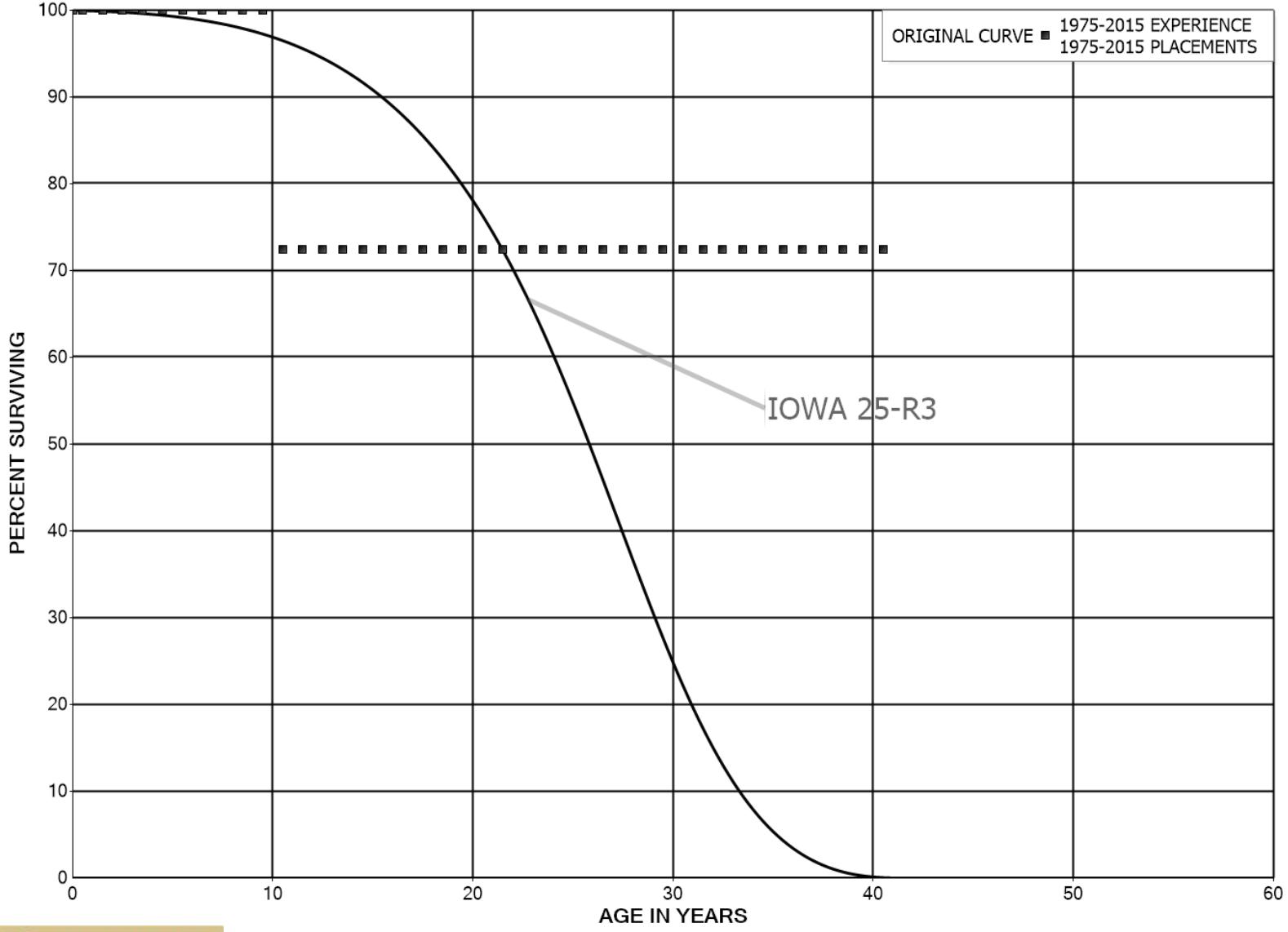
ACCOUNT R05 - RADIOS - MOBILE VHF BASE STATION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1978-2012 EXPERIENCE BAND 1978-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,104,030		0.0000	1.0000	100.00
0.5	9,104,030		0.0000	1.0000	100.00
1.5	9,104,030	82,942	0.0091	0.9909	100.00
2.5	9,021,088	37,902	0.0042	0.9958	99.09
3.5	8,268,047	93,309	0.0113	0.9887	98.67
4.5	8,172,088		0.0000	1.0000	97.56
5.5	7,818,683	6,366	0.0008	0.9992	97.56
6.5	7,812,317		0.0000	1.0000	97.48
7.5	7,812,317	10,505	0.0013	0.9987	97.48
8.5	7,352,576	20,805	0.0028	0.9972	97.35
9.5	1,761,018	319,279	0.1813	0.8187	97.07
10.5	1,441,739	25,352	0.0176	0.9824	79.47
11.5	1,413,587	10,295	0.0073	0.9927	78.08
12.5	1,261,094	11,659	0.0092	0.9908	77.51
13.5	1,249,436	78,884	0.0631	0.9369	76.79
14.5	1,170,552	733	0.0006	0.9994	71.94
15.5	1,156,464	13,556	0.0117	0.9883	71.90
16.5	1,116,944	973,911	0.8719	0.1281	71.05
17.5	143,032	5,250	0.0367	0.9633	9.10
18.5	137,783	31,710	0.2301	0.7699	8.77
19.5	106,073	56,883	0.5363	0.4637	6.75
20.5	49,190		0.0000	1.0000	3.13
21.5	49,190	1,871	0.0380	0.9620	3.13
22.5	47,319	19,561	0.4134	0.5866	3.01
23.5	27,758	16,061	0.5786	0.4214	1.77
24.5	11,698		0.0000	1.0000	0.74
25.5	8,536	8,536	1.0000		0.74
26.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R06 - RAMPS - YARD STORAGE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

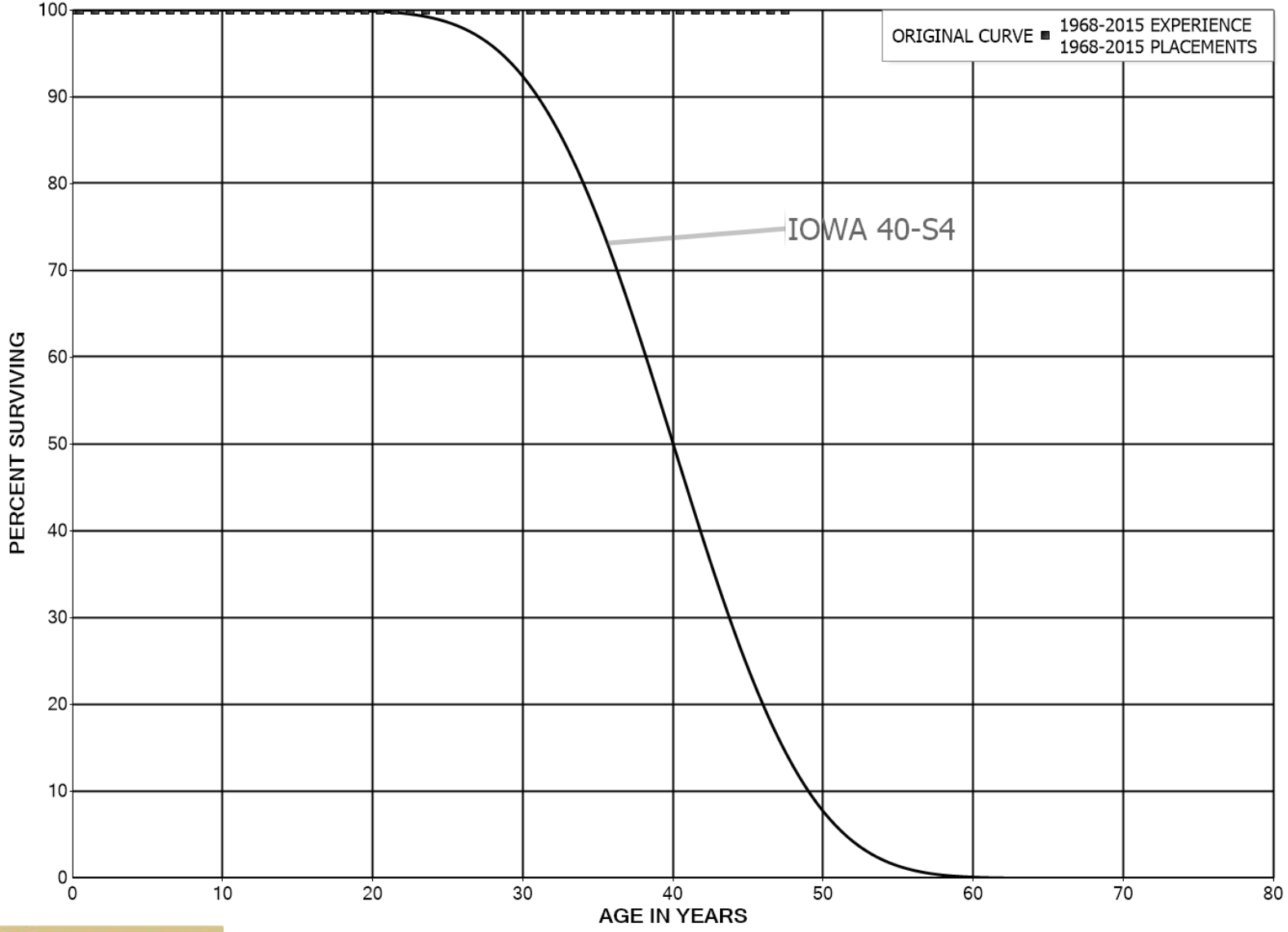
ACCOUNT R06 - RAMPS - YARD STORAGE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1975-2015 EXPERIENCE BAND 1975-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,827,330		0.0000	1.0000	100.00
0.5	1,695,776		0.0000	1.0000	100.00
1.5	1,664,996		0.0000	1.0000	100.00
2.5	1,664,996		0.0000	1.0000	100.00
3.5	1,664,996		0.0000	1.0000	100.00
4.5	1,664,996		0.0000	1.0000	100.00
5.5	1,470,416		0.0000	1.0000	100.00
6.5	1,195,179		0.0000	1.0000	100.00
7.5	1,066,911		0.0000	1.0000	100.00
8.5	1,004,386		0.0000	1.0000	100.00
9.5	847,069	233,772	0.2760	0.7240	100.00
10.5	575,925		0.0000	1.0000	72.40
11.5	575,925		0.0000	1.0000	72.40
12.5	575,925		0.0000	1.0000	72.40
13.5	575,925		0.0000	1.0000	72.40
14.5	521,151		0.0000	1.0000	72.40
15.5	521,151		0.0000	1.0000	72.40
16.5	429,890		0.0000	1.0000	72.40
17.5	429,890		0.0000	1.0000	72.40
18.5	429,890		0.0000	1.0000	72.40
19.5	379,924		0.0000	1.0000	72.40
20.5	379,924		0.0000	1.0000	72.40
21.5	379,924		0.0000	1.0000	72.40
22.5	330,462		0.0000	1.0000	72.40
23.5	318,978		0.0000	1.0000	72.40
24.5	300,868		0.0000	1.0000	72.40
25.5	220,787		0.0000	1.0000	72.40
26.5	114,938		0.0000	1.0000	72.40
27.5	114,938		0.0000	1.0000	72.40
28.5	82,374		0.0000	1.0000	72.40
29.5	82,374		0.0000	1.0000	72.40
30.5	82,374		0.0000	1.0000	72.40
31.5	82,374		0.0000	1.0000	72.40
32.5	82,374		0.0000	1.0000	72.40
33.5	65,163		0.0000	1.0000	72.40
34.5	65,163		0.0000	1.0000	72.40
35.5	65,163		0.0000	1.0000	72.40
36.5	23,740		0.0000	1.0000	72.40
37.5	23,740		0.0000	1.0000	72.40
38.5	23,740		0.0000	1.0000	72.40
39.5	23,740		0.0000	1.0000	72.40
40.5					72.40

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R07 - REACTORS AND RESISTORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R07 - REACTORS AND RESISTORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,225,065		0.0000	1.0000	100.00
0.5	1,150,230		0.0000	1.0000	100.00
1.5	1,044,650		0.0000	1.0000	100.00
2.5	1,044,650		0.0000	1.0000	100.00
3.5	1,024,903		0.0000	1.0000	100.00
4.5	1,024,903		0.0000	1.0000	100.00
5.5	1,024,903		0.0000	1.0000	100.00
6.5	1,024,903		0.0000	1.0000	100.00
7.5	1,024,903		0.0000	1.0000	100.00
8.5	1,024,903		0.0000	1.0000	100.00
9.5	1,009,016		0.0000	1.0000	100.00
10.5	1,009,016		0.0000	1.0000	100.00
11.5	1,009,016		0.0000	1.0000	100.00
12.5	1,009,016		0.0000	1.0000	100.00
13.5	1,009,016		0.0000	1.0000	100.00
14.5	1,009,016		0.0000	1.0000	100.00
15.5	807,059		0.0000	1.0000	100.00
16.5	807,059		0.0000	1.0000	100.00
17.5	807,059		0.0000	1.0000	100.00
18.5	807,059		0.0000	1.0000	100.00
19.5	776,038		0.0000	1.0000	100.00
20.5	69,855		0.0000	1.0000	100.00
21.5	69,855		0.0000	1.0000	100.00
22.5	69,855		0.0000	1.0000	100.00
23.5	69,855		0.0000	1.0000	100.00
24.5	69,855		0.0000	1.0000	100.00
25.5	69,855		0.0000	1.0000	100.00
26.5	69,855		0.0000	1.0000	100.00
27.5	69,855		0.0000	1.0000	100.00
28.5	69,855		0.0000	1.0000	100.00
29.5	69,855		0.0000	1.0000	100.00
30.5	69,855		0.0000	1.0000	100.00
31.5	69,855		0.0000	1.0000	100.00
32.5	69,855		0.0000	1.0000	100.00
33.5	69,855		0.0000	1.0000	100.00
34.5	58,523		0.0000	1.0000	100.00
35.5	58,523		0.0000	1.0000	100.00
36.5	58,523		0.0000	1.0000	100.00
37.5	50,523		0.0000	1.0000	100.00
38.5	20,083		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

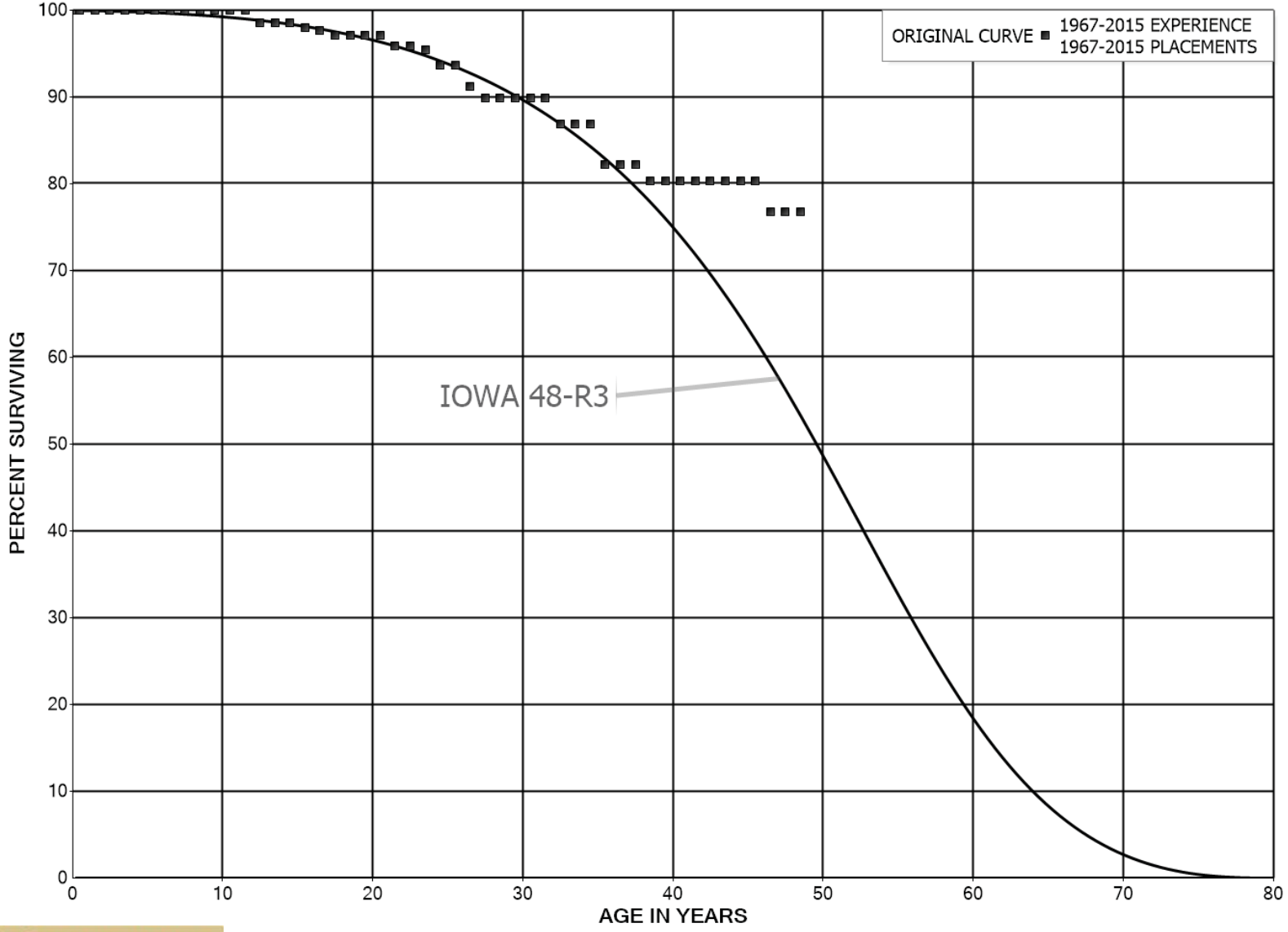
ACCOUNT R07 - REACTORS AND RESISTORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,083		0.0000	1.0000	100.00
40.5	20,083		0.0000	1.0000	100.00
41.5	20,083		0.0000	1.0000	100.00
42.5	20,083		0.0000	1.0000	100.00
43.5	20,083		0.0000	1.0000	100.00
44.5	20,083		0.0000	1.0000	100.00
45.5	20,083		0.0000	1.0000	100.00
46.5	20,083		0.0000	1.0000	100.00
47.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R08 - RECLOSERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R08 - RECLOSERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,507,617		0.0000	1.0000	100.00
0.5	6,949,014		0.0000	1.0000	100.00
1.5	6,662,682		0.0000	1.0000	100.00
2.5	5,895,099		0.0000	1.0000	100.00
3.5	5,108,664		0.0000	1.0000	100.00
4.5	4,814,440		0.0000	1.0000	100.00
5.5	4,354,278		0.0000	1.0000	100.00
6.5	4,163,117		0.0000	1.0000	100.00
7.5	4,006,122		0.0000	1.0000	100.00
8.5	4,006,122		0.0000	1.0000	100.00
9.5	3,961,448	0	0.0000	1.0000	100.00
10.5	3,776,745		0.0000	1.0000	100.00
11.5	3,769,335	54,532	0.0145	0.9855	100.00
12.5	3,471,248		0.0000	1.0000	98.55
13.5	3,435,200		0.0000	1.0000	98.55
14.5	3,360,707	21,116	0.0063	0.9937	98.55
15.5	3,214,479	11,904	0.0037	0.9963	97.93
16.5	3,174,022	16,452	0.0052	0.9948	97.57
17.5	2,931,930		0.0000	1.0000	97.07
18.5	2,779,686		0.0000	1.0000	97.07
19.5	2,732,873		0.0000	1.0000	97.07
20.5	2,654,108	34,715	0.0131	0.9869	97.07
21.5	2,311,277		0.0000	1.0000	95.80
22.5	2,268,542	10,513	0.0046	0.9954	95.80
23.5	2,189,545	40,426	0.0185	0.9815	95.35
24.5	2,095,649		0.0000	1.0000	93.59
25.5	1,926,765	50,160	0.0260	0.9740	93.59
26.5	1,795,981	26,171	0.0146	0.9854	91.16
27.5	1,577,364		0.0000	1.0000	89.83
28.5	1,457,161		0.0000	1.0000	89.83
29.5	1,446,674		0.0000	1.0000	89.83
30.5	1,298,556		0.0000	1.0000	89.83
31.5	1,102,647	37,181	0.0337	0.9663	89.83
32.5	1,051,786		0.0000	1.0000	86.80
33.5	841,501		0.0000	1.0000	86.80
34.5	593,657	31,275	0.0527	0.9473	86.80
35.5	562,383		0.0000	1.0000	82.23
36.5	548,383		0.0000	1.0000	82.23
37.5	496,996	11,624	0.0234	0.9766	82.23
38.5	485,373		0.0000	1.0000	80.30

NEWFOUNDLAND AND LABRADOR HYDRO

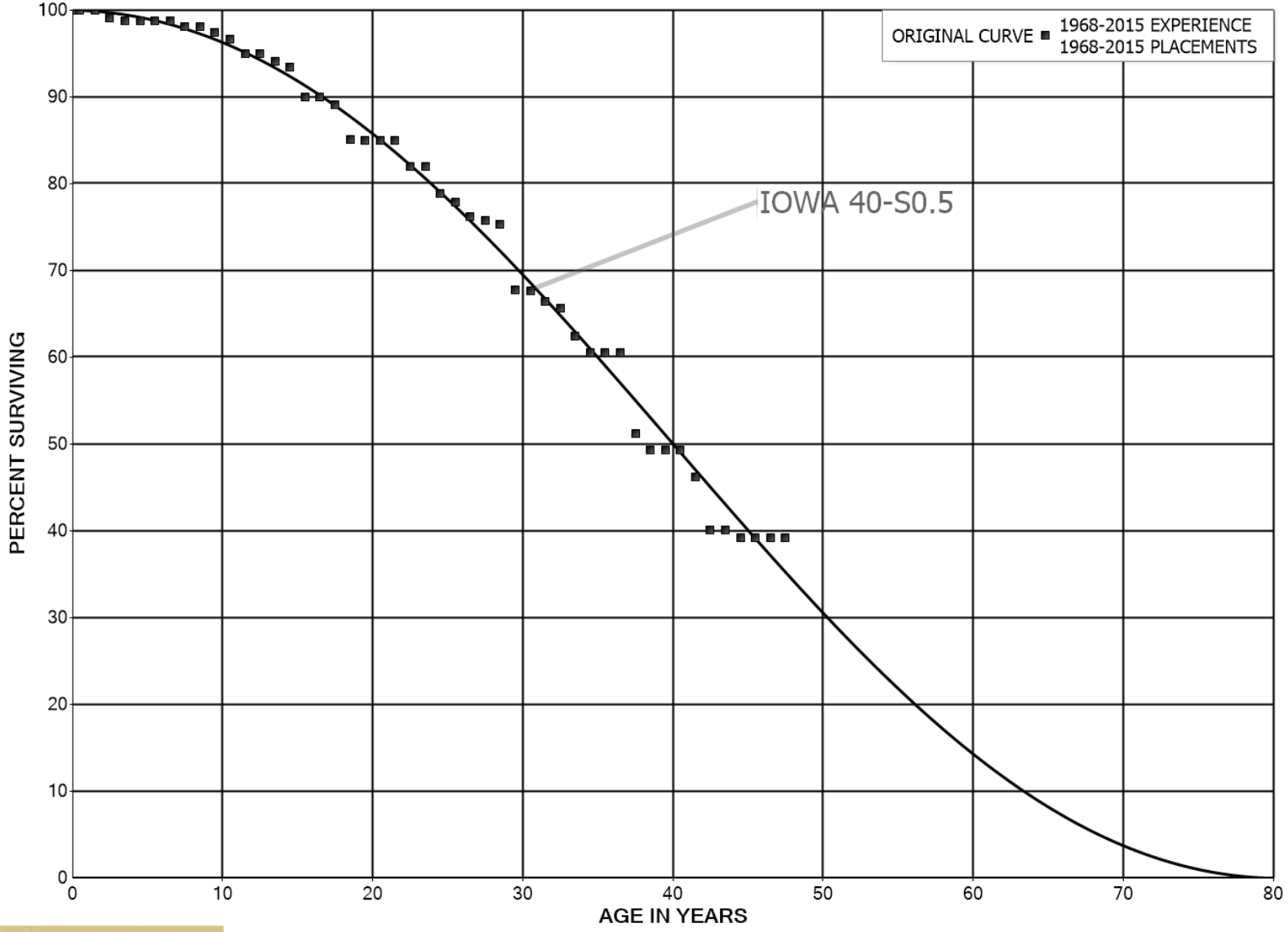
ACCOUNT R08 - RECLOSERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	472,069		0.0000	1.0000	80.30
40.5	217,567		0.0000	1.0000	80.30
41.5	217,567		0.0000	1.0000	80.30
42.5	217,567		0.0000	1.0000	80.30
43.5	217,567		0.0000	1.0000	80.30
44.5	194,087		0.0000	1.0000	80.30
45.5	66,147	2,943	0.0445	0.9555	80.30
46.5	63,204		0.0000	1.0000	76.73
47.5	6,652		0.0000	1.0000	76.73
48.5					76.73

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R09 - REGULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R09 - REGULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,317,428		0.0000	1.0000	100.00
0.5	7,195,261		0.0000	1.0000	100.00
1.5	7,036,686	62,379	0.0089	0.9911	100.00
2.5	6,437,137	23,079	0.0036	0.9964	99.11
3.5	5,797,385		0.0000	1.0000	98.76
4.5	5,454,934		0.0000	1.0000	98.76
5.5	5,137,229		0.0000	1.0000	98.76
6.5	4,734,361	31,826	0.0067	0.9933	98.76
7.5	4,459,382		0.0000	1.0000	98.09
8.5	4,387,654	33,037	0.0075	0.9925	98.09
9.5	4,264,904	32,602	0.0076	0.9924	97.36
10.5	4,195,732	74,216	0.0177	0.9823	96.61
11.5	3,999,184		0.0000	1.0000	94.90
12.5	3,848,301	35,132	0.0091	0.9909	94.90
13.5	3,786,478	26,996	0.0071	0.9929	94.04
14.5	3,754,164	135,900	0.0362	0.9638	93.37
15.5	3,599,347		0.0000	1.0000	89.99
16.5	3,599,347	36,932	0.0103	0.9897	89.99
17.5	3,562,415	159,232	0.0447	0.9553	89.06
18.5	3,299,274	6,206	0.0019	0.9981	85.08
19.5	3,293,068		0.0000	1.0000	84.92
20.5	3,227,427		0.0000	1.0000	84.92
21.5	3,203,096	110,541	0.0345	0.9655	84.92
22.5	2,994,693		0.0000	1.0000	81.99
23.5	2,994,693	114,403	0.0382	0.9618	81.99
24.5	2,880,290	37,794	0.0131	0.9869	78.86
25.5	2,721,560	59,487	0.0219	0.9781	77.82
26.5	2,659,228	13,342	0.0050	0.9950	76.12
27.5	2,544,001	16,301	0.0064	0.9936	75.74
28.5	2,431,494	241,814	0.0995	0.9005	75.26
29.5	2,189,679	6,206	0.0028	0.9972	67.77
30.5	1,955,130	35,576	0.0182	0.9818	67.58
31.5	1,853,715	19,163	0.0103	0.9897	66.35
32.5	1,798,115	88,684	0.0493	0.9507	65.66
33.5	1,614,517	48,276	0.0299	0.9701	62.43
34.5	1,451,262		0.0000	1.0000	60.56
35.5	727,891		0.0000	1.0000	60.56
36.5	727,891	112,698	0.1548	0.8452	60.56
37.5	615,193	22,659	0.0368	0.9632	51.18
38.5	555,281		0.0000	1.0000	49.30

NEWFOUNDLAND AND LABRADOR HYDRO

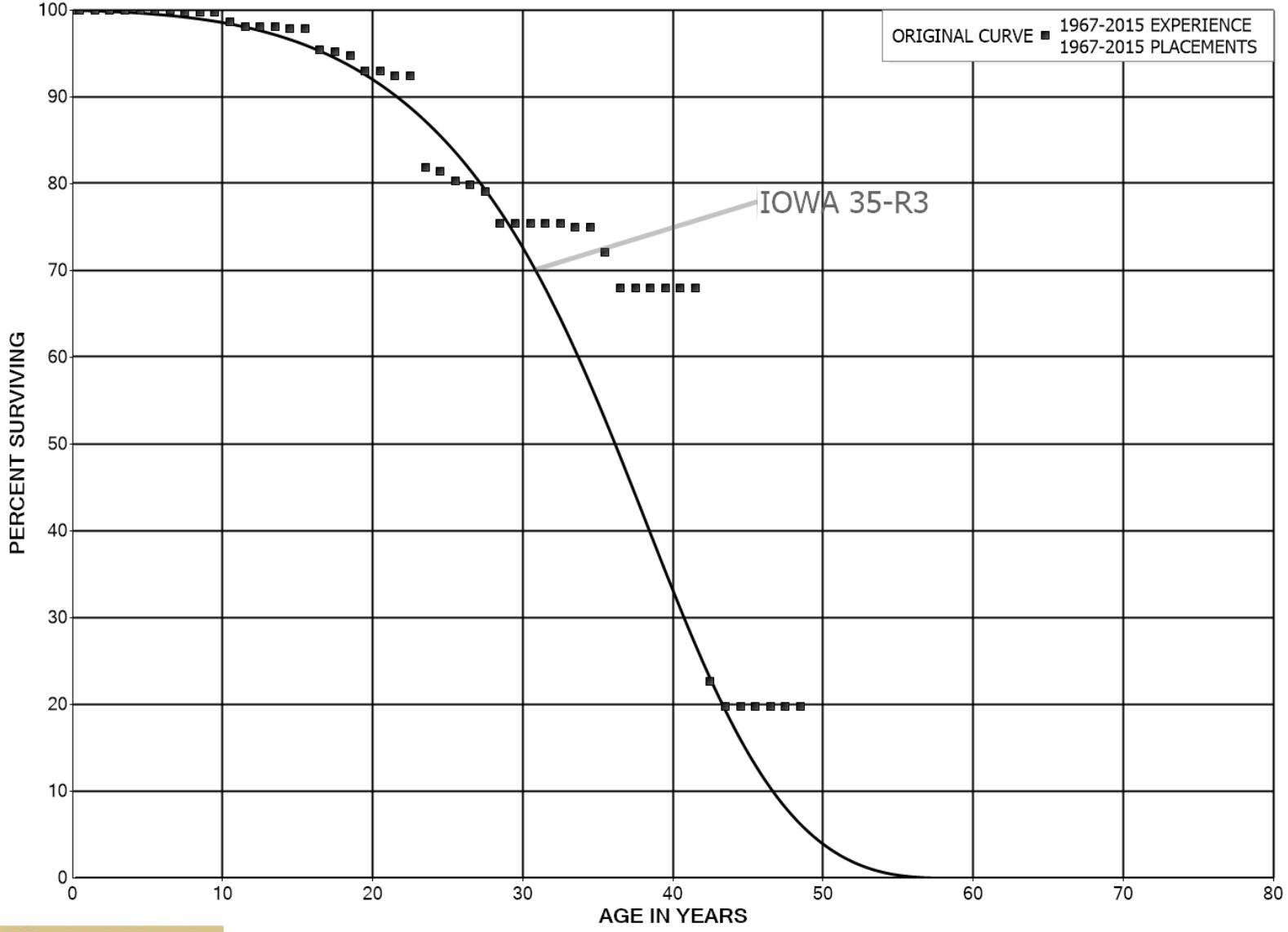
ACCOUNT R09 - REGULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	555,281		0.0000	1.0000	49.30
40.5	319,070	19,871	0.0623	0.9377	49.30
41.5	299,199	40,203	0.1344	0.8656	46.23
42.5	258,996		0.0000	1.0000	40.02
43.5	258,996	5,232	0.0202	0.9798	40.02
44.5	73,033		0.0000	1.0000	39.21
45.5	18,866		0.0000	1.0000	39.21
46.5	18,866		0.0000	1.0000	39.21
47.5					39.21

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R11 - REVENUE METERING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R11 - REVENUE METERING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,508,564		0.0000	1.0000	100.00
0.5	1,225,032		0.0000	1.0000	100.00
1.5	1,137,869		0.0000	1.0000	100.00
2.5	1,137,869		0.0000	1.0000	100.00
3.5	1,110,539		0.0000	1.0000	100.00
4.5	1,110,539		0.0000	1.0000	100.00
5.5	1,110,539		0.0000	1.0000	100.00
6.5	1,020,842	2,849	0.0028	0.9972	100.00
7.5	1,017,993		0.0000	1.0000	99.72
8.5	1,017,993		0.0000	1.0000	99.72
9.5	1,017,993	11,675	0.0115	0.9885	99.72
10.5	1,006,318	5,741	0.0057	0.9943	98.58
11.5	1,000,577		0.0000	1.0000	98.01
12.5	961,003		0.0000	1.0000	98.01
13.5	874,366	1,423	0.0016	0.9984	98.01
14.5	751,458		0.0000	1.0000	97.86
15.5	751,458	18,546	0.0247	0.9753	97.86
16.5	732,912	2,216	0.0030	0.9970	95.44
17.5	730,695	3,414	0.0047	0.9953	95.15
18.5	717,902	12,997	0.0181	0.9819	94.71
19.5	675,441		0.0000	1.0000	92.99
20.5	667,906	4,262	0.0064	0.9936	92.99
21.5	658,159		0.0000	1.0000	92.40
22.5	658,159	75,135	0.1142	0.8858	92.40
23.5	548,693	3,113	0.0057	0.9943	81.85
24.5	529,063	7,155	0.0135	0.9865	81.39
25.5	506,277	3,057	0.0060	0.9940	80.29
26.5	479,375	4,300	0.0090	0.9910	79.80
27.5	443,227	20,791	0.0469	0.9531	79.09
28.5	388,109		0.0000	1.0000	75.38
29.5	344,832		0.0000	1.0000	75.38
30.5	330,328		0.0000	1.0000	75.38
31.5	300,515		0.0000	1.0000	75.38
32.5	267,391	1,500	0.0056	0.9944	75.38
33.5	263,370	81	0.0003	0.9997	74.95
34.5	230,673	8,900	0.0386	0.9614	74.93
35.5	184,070	10,380	0.0564	0.9436	72.04
36.5	165,782		0.0000	1.0000	67.98
37.5	127,806		0.0000	1.0000	67.98
38.5	119,068		0.0000	1.0000	67.98

NEWFOUNDLAND AND LABRADOR HYDRO

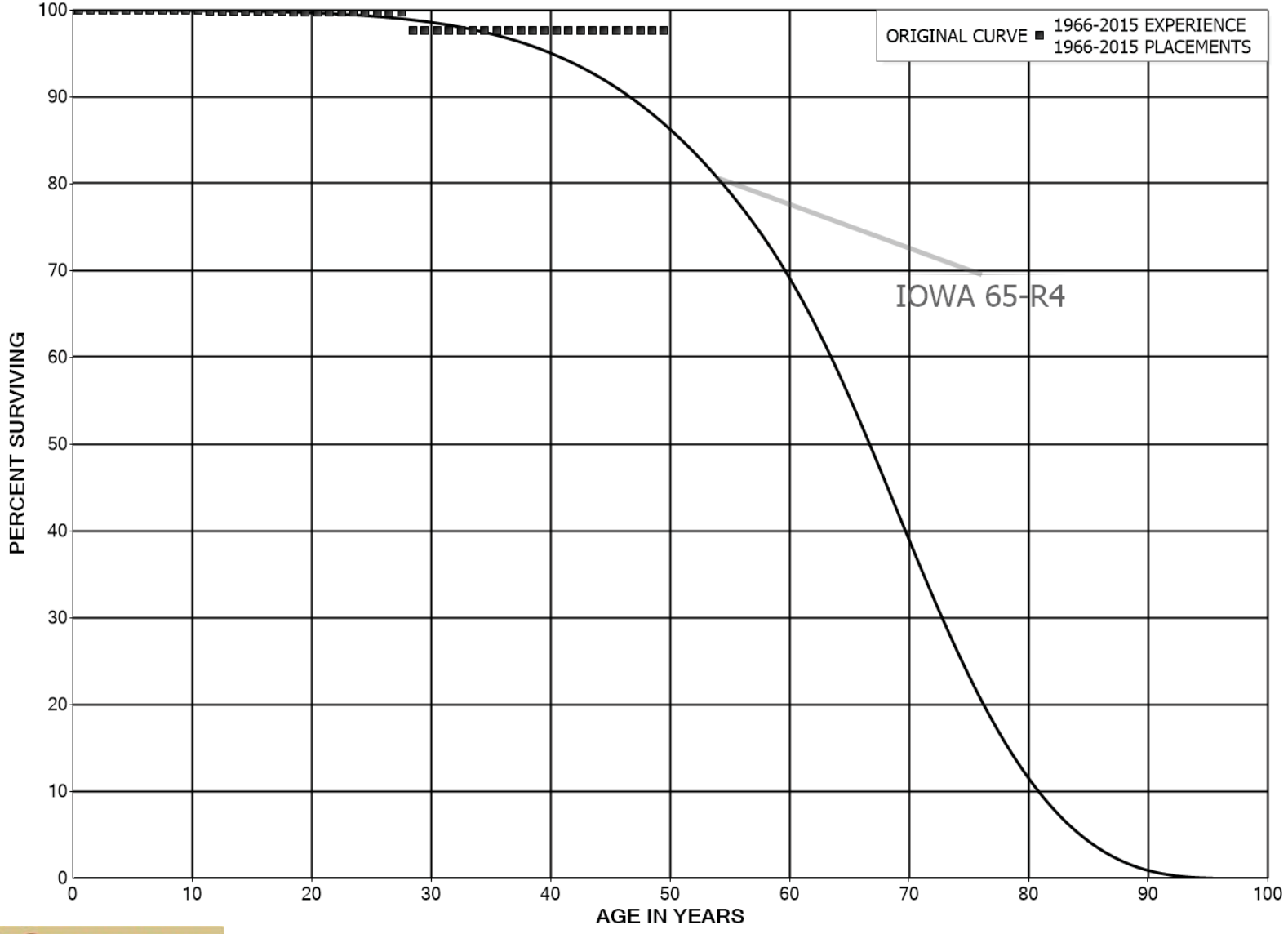
ACCOUNT R11 - REVENUE METERING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	109,085		0.0000	1.0000	67.98
40.5	109,085		0.0000	1.0000	67.98
41.5	95,985	64,116	0.6680	0.3320	67.98
42.5	31,869	3,996	0.1254	0.8746	22.57
43.5	27,873		0.0000	1.0000	19.74
44.5	27,873		0.0000	1.0000	19.74
45.5	19,571		0.0000	1.0000	19.74
46.5	19,571		0.0000	1.0000	19.74
47.5	12,751		0.0000	1.0000	19.74
48.5					19.74

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R12 - RIGHT-OF-WAYS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R12 - RIGHT-OF-WAYS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,059,531	1,600	0.0001	0.9999	100.00
0.5	21,605,210		0.0000	1.0000	99.99
1.5	21,293,543		0.0000	1.0000	99.99
2.5	20,849,493		0.0000	1.0000	99.99
3.5	20,504,169		0.0000	1.0000	99.99
4.5	20,490,290		0.0000	1.0000	99.99
5.5	20,392,646		0.0000	1.0000	99.99
6.5	20,226,290	11,091	0.0005	0.9995	99.99
7.5	20,065,833		0.0000	1.0000	99.94
8.5	19,966,375		0.0000	1.0000	99.94
9.5	18,837,838		0.0000	1.0000	99.94
10.5	18,709,150	15,824	0.0008	0.9992	99.94
11.5	18,614,027		0.0000	1.0000	99.85
12.5	18,581,320		0.0000	1.0000	99.85
13.5	17,152,270		0.0000	1.0000	99.85
14.5	17,141,738		0.0000	1.0000	99.85
15.5	17,126,720		0.0000	1.0000	99.85
16.5	17,022,978		0.0000	1.0000	99.85
17.5	16,432,628	14,319	0.0009	0.9991	99.85
18.5	16,235,393		0.0000	1.0000	99.77
19.5	15,703,747	1,048	0.0001	0.9999	99.77
20.5	15,377,901		0.0000	1.0000	99.76
21.5	15,341,710		0.0000	1.0000	99.76
22.5	15,253,473		0.0000	1.0000	99.76
23.5	15,229,499		0.0000	1.0000	99.76
24.5	15,060,740		0.0000	1.0000	99.76
25.5	14,274,519		0.0000	1.0000	99.76
26.5	13,724,745		0.0000	1.0000	99.76
27.5	13,549,048	286,000	0.0211	0.9789	99.76
28.5	12,699,887		0.0000	1.0000	97.65
29.5	12,659,912		0.0000	1.0000	97.65
30.5	10,945,808		0.0000	1.0000	97.65
31.5	10,878,870		0.0000	1.0000	97.65
32.5	9,092,770		0.0000	1.0000	97.65
33.5	8,299,505		0.0000	1.0000	97.65
34.5	7,183,257		0.0000	1.0000	97.65
35.5	7,061,068		0.0000	1.0000	97.65
36.5	7,061,068		0.0000	1.0000	97.65
37.5	4,170,908		0.0000	1.0000	97.65
38.5	4,145,244		0.0000	1.0000	97.65

NEWFOUNDLAND AND LABRADOR HYDRO

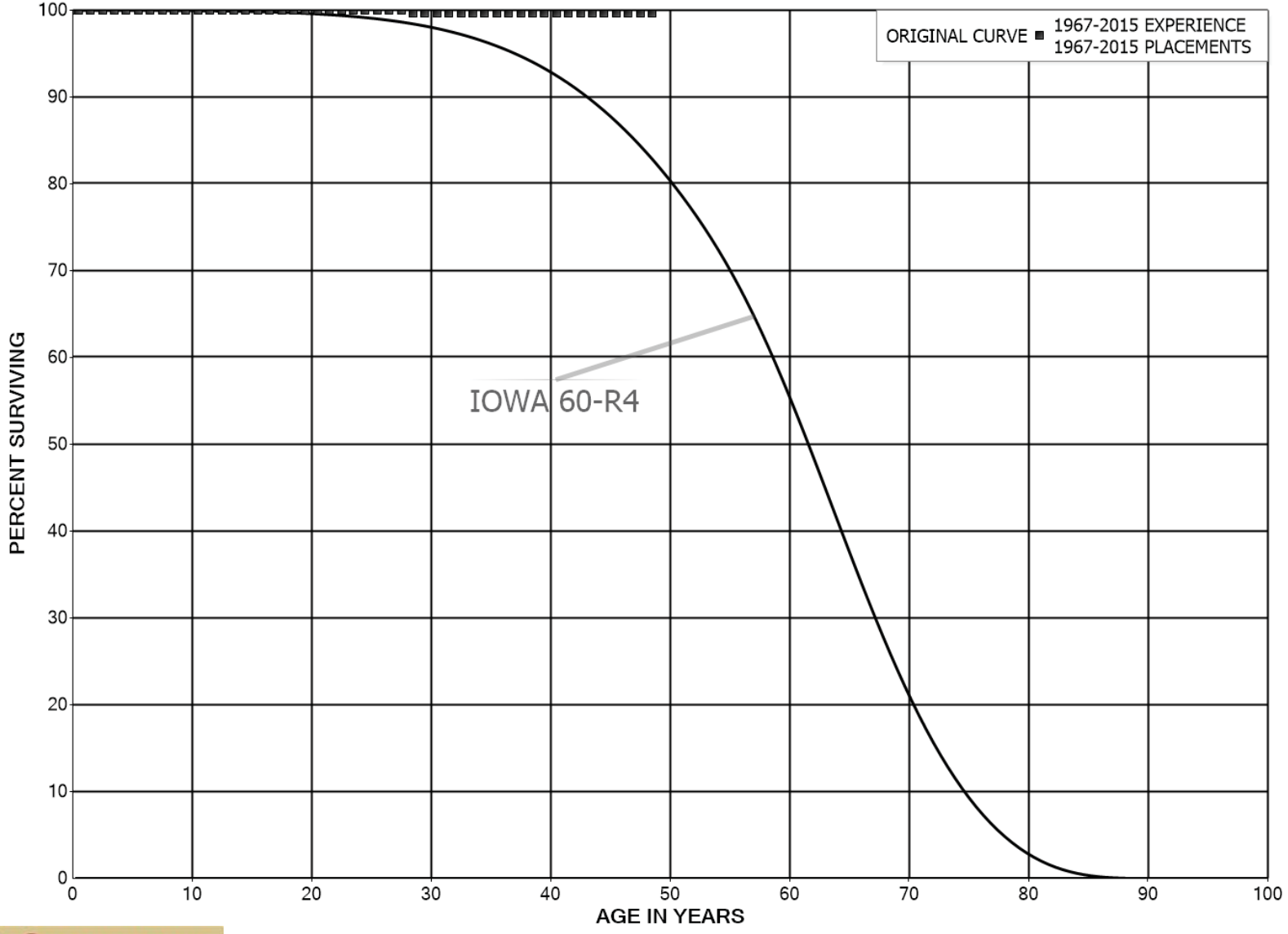
ACCOUNT R12 - RIGHT-OF-WAYS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,010,899		0.0000	1.0000	97.65
40.5	4,010,899		0.0000	1.0000	97.65
41.5	3,436,307		0.0000	1.0000	97.65
42.5	3,430,573		0.0000	1.0000	97.65
43.5	3,430,573		0.0000	1.0000	97.65
44.5	3,430,573		0.0000	1.0000	97.65
45.5	3,131,034		0.0000	1.0000	97.65
46.5	3,045,745		0.0000	1.0000	97.65
47.5	2,771,429		0.0000	1.0000	97.65
48.5	1,057,755		0.0000	1.0000	97.65
49.5					97.65

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R13 - ROADS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R13 - ROADS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	84,743,338		0.0000	1.0000	100.00
0.5	83,803,528		0.0000	1.0000	100.00
1.5	83,297,928	47	0.0000	1.0000	100.00
2.5	83,246,209		0.0000	1.0000	100.00
3.5	83,000,618		0.0000	1.0000	100.00
4.5	81,947,247	2,866	0.0000	1.0000	100.00
5.5	80,961,124		0.0000	1.0000	100.00
6.5	80,636,806		0.0000	1.0000	100.00
7.5	80,231,941		0.0000	1.0000	100.00
8.5	79,296,607		0.0000	1.0000	100.00
9.5	79,296,607		0.0000	1.0000	100.00
10.5	77,938,263		0.0000	1.0000	100.00
11.5	77,938,263		0.0000	1.0000	100.00
12.5	77,170,348		0.0000	1.0000	100.00
13.5	77,126,335		0.0000	1.0000	100.00
14.5	76,693,992		0.0000	1.0000	100.00
15.5	76,538,121		0.0000	1.0000	100.00
16.5	76,538,121		0.0000	1.0000	100.00
17.5	76,538,121		0.0000	1.0000	100.00
18.5	76,522,472		0.0000	1.0000	100.00
19.5	76,518,513		0.0000	1.0000	100.00
20.5	76,508,506		0.0000	1.0000	100.00
21.5	76,483,366		0.0000	1.0000	100.00
22.5	76,477,954		0.0000	1.0000	100.00
23.5	76,477,954		0.0000	1.0000	100.00
24.5	76,423,390		0.0000	1.0000	100.00
25.5	76,371,146		0.0000	1.0000	100.00
26.5	76,007,793		0.0000	1.0000	100.00
27.5	74,701,137	294,807	0.0039	0.9961	100.00
28.5	74,406,330		0.0000	1.0000	99.60
29.5	74,393,088		0.0000	1.0000	99.60
30.5	74,076,302	3,012	0.0000	1.0000	99.60
31.5	13,533,189		0.0000	1.0000	99.60
32.5	3,934,256		0.0000	1.0000	99.60
33.5	3,931,345		0.0000	1.0000	99.60
34.5	3,915,579		0.0000	1.0000	99.60
35.5	748,219		0.0000	1.0000	99.60
36.5	743,158		0.0000	1.0000	99.60
37.5	732,109		0.0000	1.0000	99.60
38.5	720,351		0.0000	1.0000	99.60

NEWFOUNDLAND AND LABRADOR HYDRO

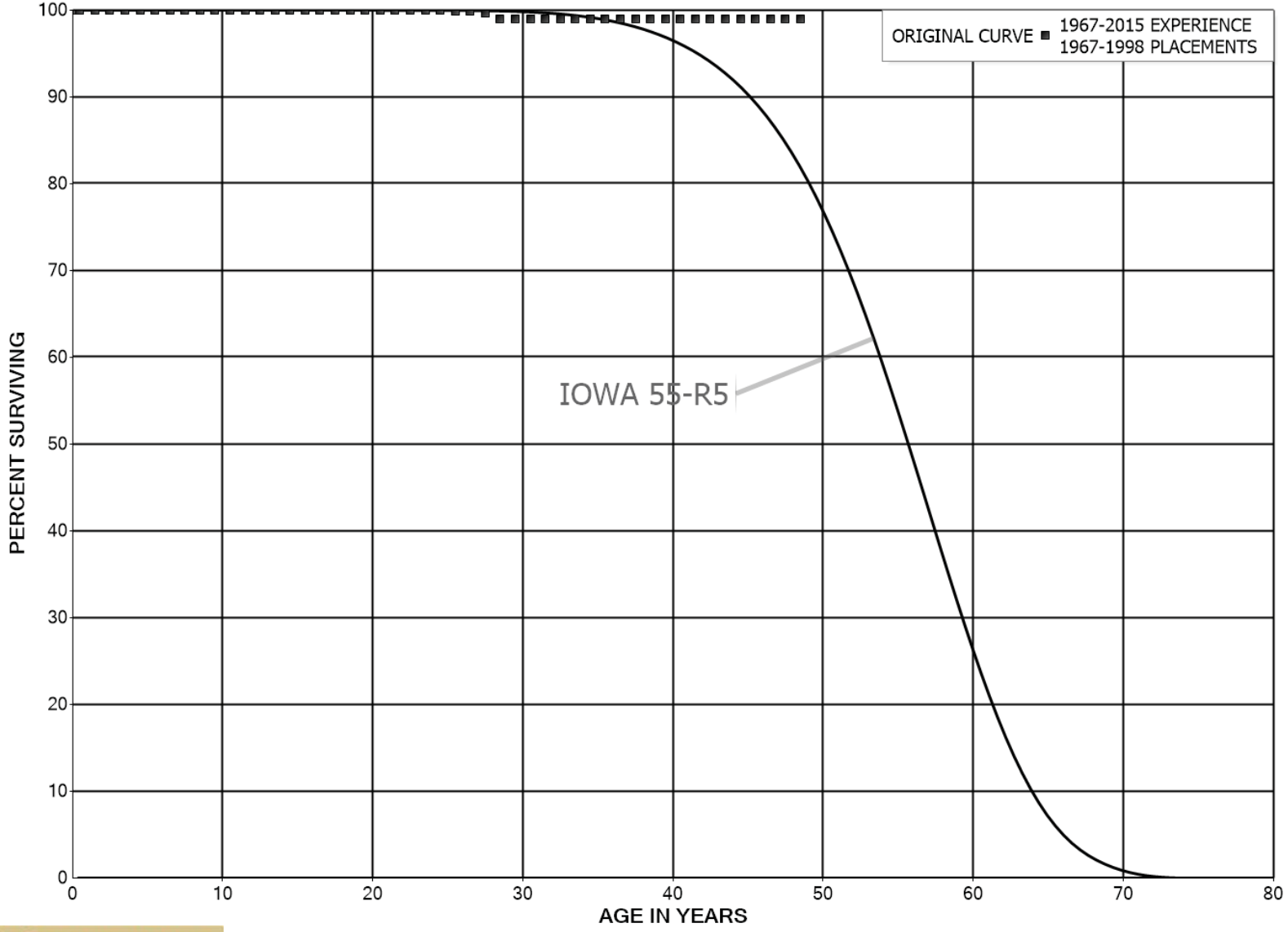
ACCOUNT R13 - ROADS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	720,351		0.0000	1.0000	99.60
40.5	720,351		0.0000	1.0000	99.60
41.5	720,351		0.0000	1.0000	99.60
42.5	709,139		0.0000	1.0000	99.60
43.5	709,139		0.0000	1.0000	99.60
44.5	682,139		0.0000	1.0000	99.60
45.5	553,964		0.0000	1.0000	99.60
46.5	63,486		0.0000	1.0000	99.60
47.5	40,993		0.0000	1.0000	99.60
48.5					99.60

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT R15 - RUNNER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R15 - RUNNER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-1998 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	11,783,932		0.0000	1.0000	100.00
0.5	11,783,932		0.0000	1.0000	100.00
1.5	11,783,932		0.0000	1.0000	100.00
2.5	11,783,932		0.0000	1.0000	100.00
3.5	11,783,932		0.0000	1.0000	100.00
4.5	11,783,932		0.0000	1.0000	100.00
5.5	11,783,932		0.0000	1.0000	100.00
6.5	11,783,932		0.0000	1.0000	100.00
7.5	11,783,932		0.0000	1.0000	100.00
8.5	11,783,932		0.0000	1.0000	100.00
9.5	11,783,932		0.0000	1.0000	100.00
10.5	11,783,932		0.0000	1.0000	100.00
11.5	11,783,932		0.0000	1.0000	100.00
12.5	11,783,932		0.0000	1.0000	100.00
13.5	11,783,932		0.0000	1.0000	100.00
14.5	11,783,932		0.0000	1.0000	100.00
15.5	11,783,932		0.0000	1.0000	100.00
16.5	11,783,932		0.0000	1.0000	100.00
17.5	11,737,244		0.0000	1.0000	100.00
18.5	11,737,244		0.0000	1.0000	100.00
19.5	11,677,403		0.0000	1.0000	100.00
20.5	11,677,403		0.0000	1.0000	100.00
21.5	11,661,244		0.0000	1.0000	100.00
22.5	11,661,244		0.0000	1.0000	100.00
23.5	11,661,244		0.0000	1.0000	100.00
24.5	11,661,244	14,003	0.0012	0.9988	100.00
25.5	11,647,242	58	0.0000	1.0000	99.88
26.5	11,063,796	28,005	0.0025	0.9975	99.88
27.5	11,035,791	72,023	0.0065	0.9935	99.63
28.5	10,963,769		0.0000	1.0000	98.98
29.5	10,963,769		0.0000	1.0000	98.98
30.5	8,318,863		0.0000	1.0000	98.98
31.5	8,318,863		0.0000	1.0000	98.98
32.5	8,318,863		0.0000	1.0000	98.98
33.5	8,318,863		0.0000	1.0000	98.98
34.5	8,318,863		0.0000	1.0000	98.98
35.5	8,268,519		0.0000	1.0000	98.98
36.5	8,268,519		0.0000	1.0000	98.98
37.5	8,268,519		0.0000	1.0000	98.98
38.5	8,138,207		0.0000	1.0000	98.98

NEWFOUNDLAND AND LABRADOR HYDRO

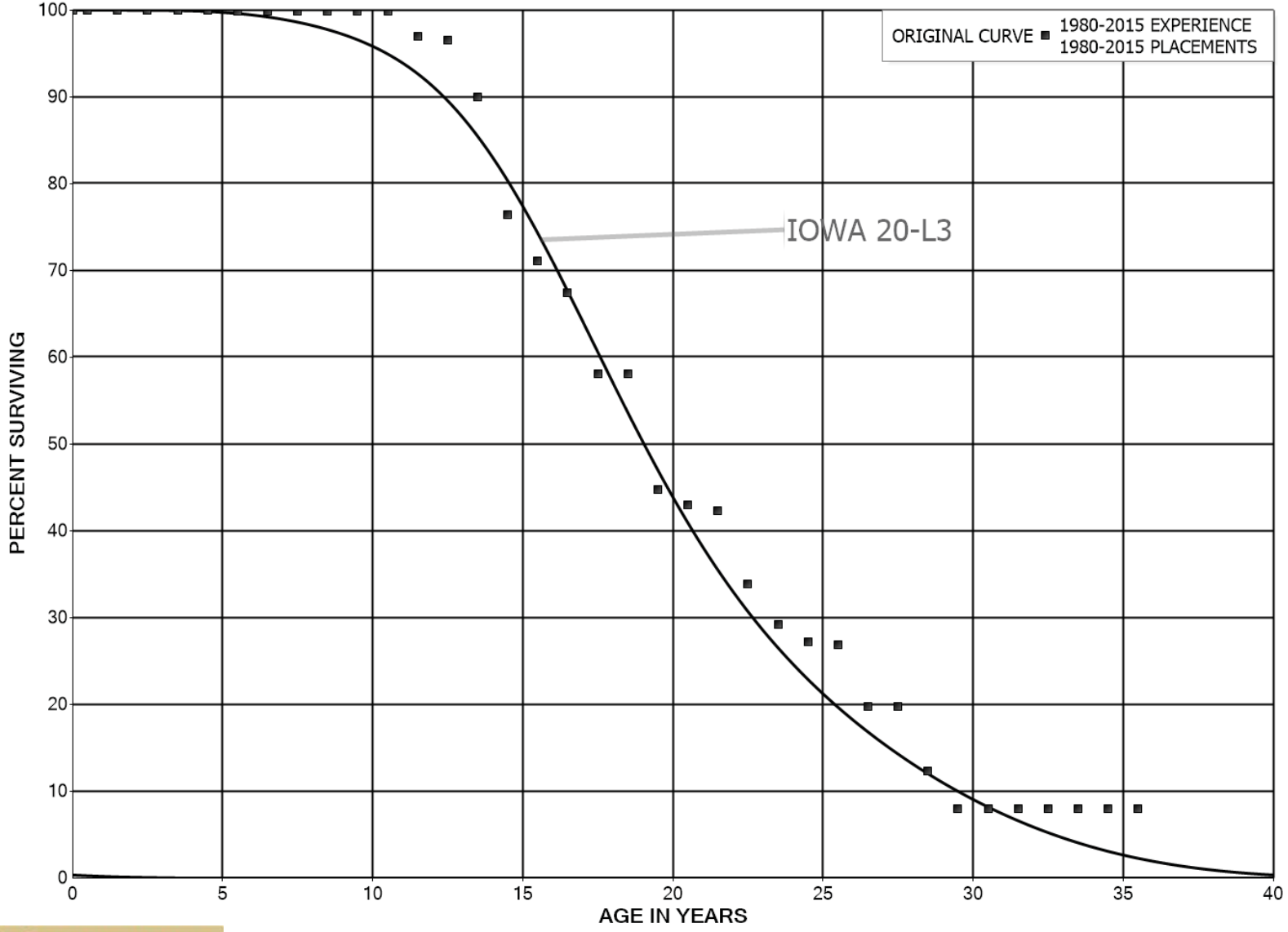
ACCOUNT R15 - RUNNER

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-1998 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,138,207		0.0000	1.0000	98.98
40.5	8,138,207		0.0000	1.0000	98.98
41.5	8,138,207		0.0000	1.0000	98.98
42.5	8,138,207		0.0000	1.0000	98.98
43.5	8,138,207		0.0000	1.0000	98.98
44.5	8,138,207		0.0000	1.0000	98.98
45.5	6,679,642		0.0000	1.0000	98.98
46.5	6,679,642		0.0000	1.0000	98.98
47.5	5,230,693		0.0000	1.0000	98.98
48.5					98.98

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S01 - SCADA EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

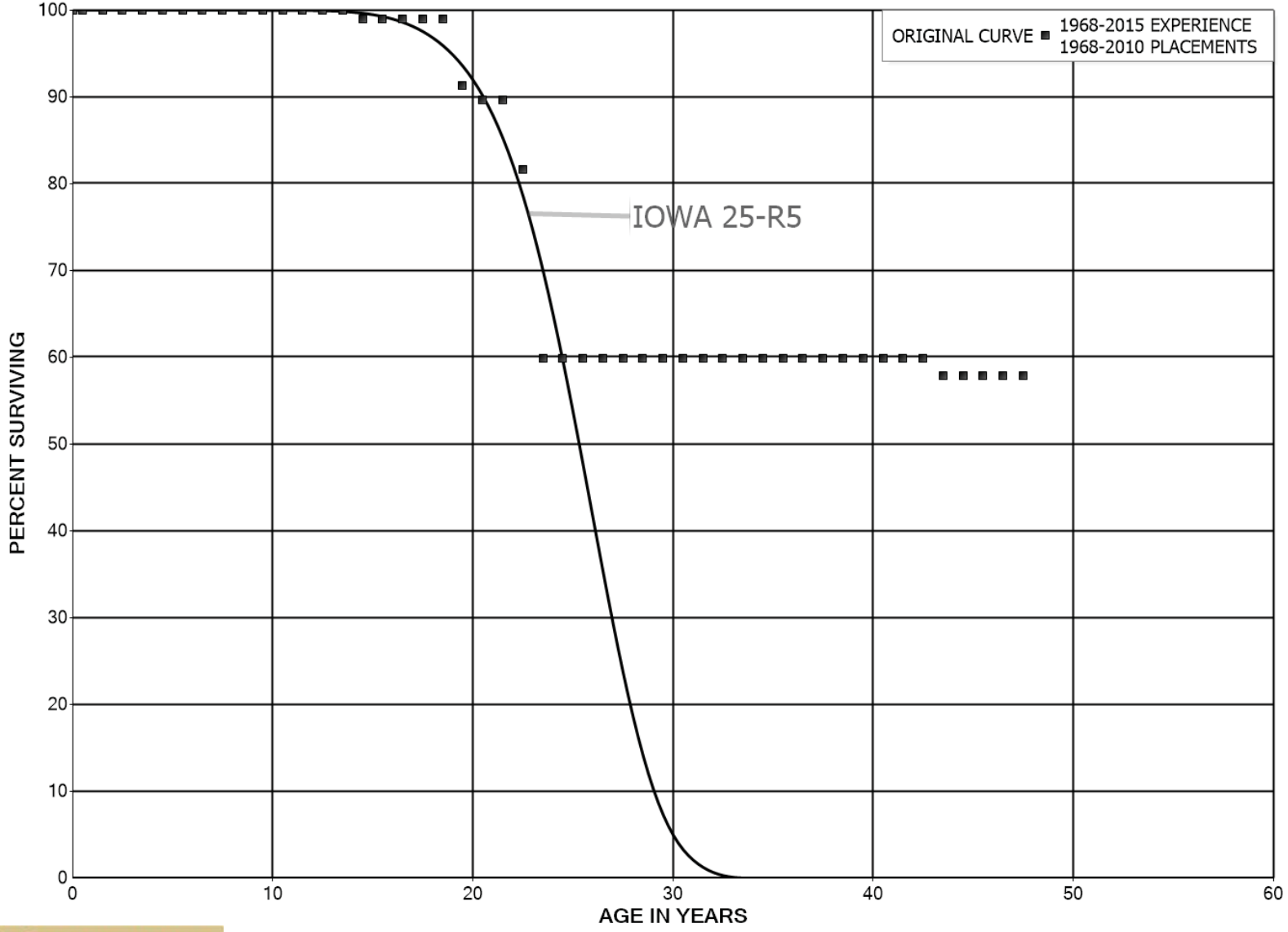
ACCOUNT S01 - SCADA EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2015 EXPERIENCE BAND 1980-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,659,317		0.0000	1.0000	100.00
0.5	6,863,926		0.0000	1.0000	100.00
1.5	6,836,602		0.0000	1.0000	100.00
2.5	6,626,915		0.0000	1.0000	100.00
3.5	6,553,388		0.0000	1.0000	100.00
4.5	6,467,080	9,152	0.0014	0.9986	100.00
5.5	6,091,299		0.0000	1.0000	99.86
6.5	5,839,306		0.0000	1.0000	99.86
7.5	5,558,497		0.0000	1.0000	99.86
8.5	5,282,731		0.0000	1.0000	99.86
9.5	5,056,843		0.0000	1.0000	99.86
10.5	4,853,295	141,749	0.0292	0.9708	99.86
11.5	4,368,191	21,620	0.0049	0.9951	96.94
12.5	3,783,706	255,345	0.0675	0.9325	96.46
13.5	3,129,541	470,373	0.1503	0.8497	89.95
14.5	2,329,086	163,210	0.0701	0.9299	76.43
15.5	2,165,876	112,977	0.0522	0.9478	71.08
16.5	1,872,257	257,060	0.1373	0.8627	67.37
17.5	1,596,218		0.0000	1.0000	58.12
18.5	1,596,218	368,961	0.2311	0.7689	58.12
19.5	1,227,257	48,564	0.0396	0.9604	44.69
20.5	1,164,407	17,781	0.0153	0.9847	42.92
21.5	1,146,625	228,460	0.1992	0.8008	42.26
22.5	918,165	127,565	0.1389	0.8611	33.84
23.5	790,600	54,709	0.0692	0.9308	29.14
24.5	735,891	7,398	0.0101	0.9899	27.12
25.5	655,116	174,629	0.2666	0.7334	26.85
26.5	452,574	188	0.0004	0.9996	19.69
27.5	452,385	171,129	0.3783	0.6217	19.68
28.5	281,256	98,514	0.3503	0.6497	12.24
29.5	127,278		0.0000	1.0000	7.95
30.5	127,278		0.0000	1.0000	7.95
31.5	127,278		0.0000	1.0000	7.95
32.5	127,278		0.0000	1.0000	7.95
33.5	127,278		0.0000	1.0000	7.95
34.5	127,278		0.0000	1.0000	7.95
35.5					7.95

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S02 - SECTIONALIZERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S02 - SECTIONALIZERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2010 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	241,094		0.0000	1.0000	100.00
0.5	241,094		0.0000	1.0000	100.00
1.5	241,094		0.0000	1.0000	100.00
2.5	241,094		0.0000	1.0000	100.00
3.5	241,094		0.0000	1.0000	100.00
4.5	241,094		0.0000	1.0000	100.00
5.5	235,651		0.0000	1.0000	100.00
6.5	235,651		0.0000	1.0000	100.00
7.5	235,651		0.0000	1.0000	100.00
8.5	235,651		0.0000	1.0000	100.00
9.5	235,651		0.0000	1.0000	100.00
10.5	235,651		0.0000	1.0000	100.00
11.5	235,651		0.0000	1.0000	100.00
12.5	235,651		0.0000	1.0000	100.00
13.5	235,651	2,387	0.0101	0.9899	100.00
14.5	233,264		0.0000	1.0000	98.99
15.5	229,158		0.0000	1.0000	98.99
16.5	229,158		0.0000	1.0000	98.99
17.5	229,158		0.0000	1.0000	98.99
18.5	229,158	17,768	0.0775	0.9225	98.99
19.5	189,387	3,493	0.0184	0.9816	91.31
20.5	185,893		0.0000	1.0000	89.63
21.5	185,893	16,621	0.0894	0.9106	89.63
22.5	169,272	45,060	0.2662	0.7338	81.61
23.5	124,212		0.0000	1.0000	59.89
24.5	77,660		0.0000	1.0000	59.89
25.5	77,660		0.0000	1.0000	59.89
26.5	75,933		0.0000	1.0000	59.89
27.5	75,933		0.0000	1.0000	59.89
28.5	75,933		0.0000	1.0000	59.89
29.5	73,992		0.0000	1.0000	59.89
30.5	73,992		0.0000	1.0000	59.89
31.5	73,992		0.0000	1.0000	59.89
32.5	73,992		0.0000	1.0000	59.89
33.5	73,992		0.0000	1.0000	59.89
34.5	73,992		0.0000	1.0000	59.89
35.5	73,992		0.0000	1.0000	59.89
36.5	73,992		0.0000	1.0000	59.89
37.5	73,992		0.0000	1.0000	59.89
38.5	73,992		0.0000	1.0000	59.89

NEWFOUNDLAND AND LABRADOR HYDRO

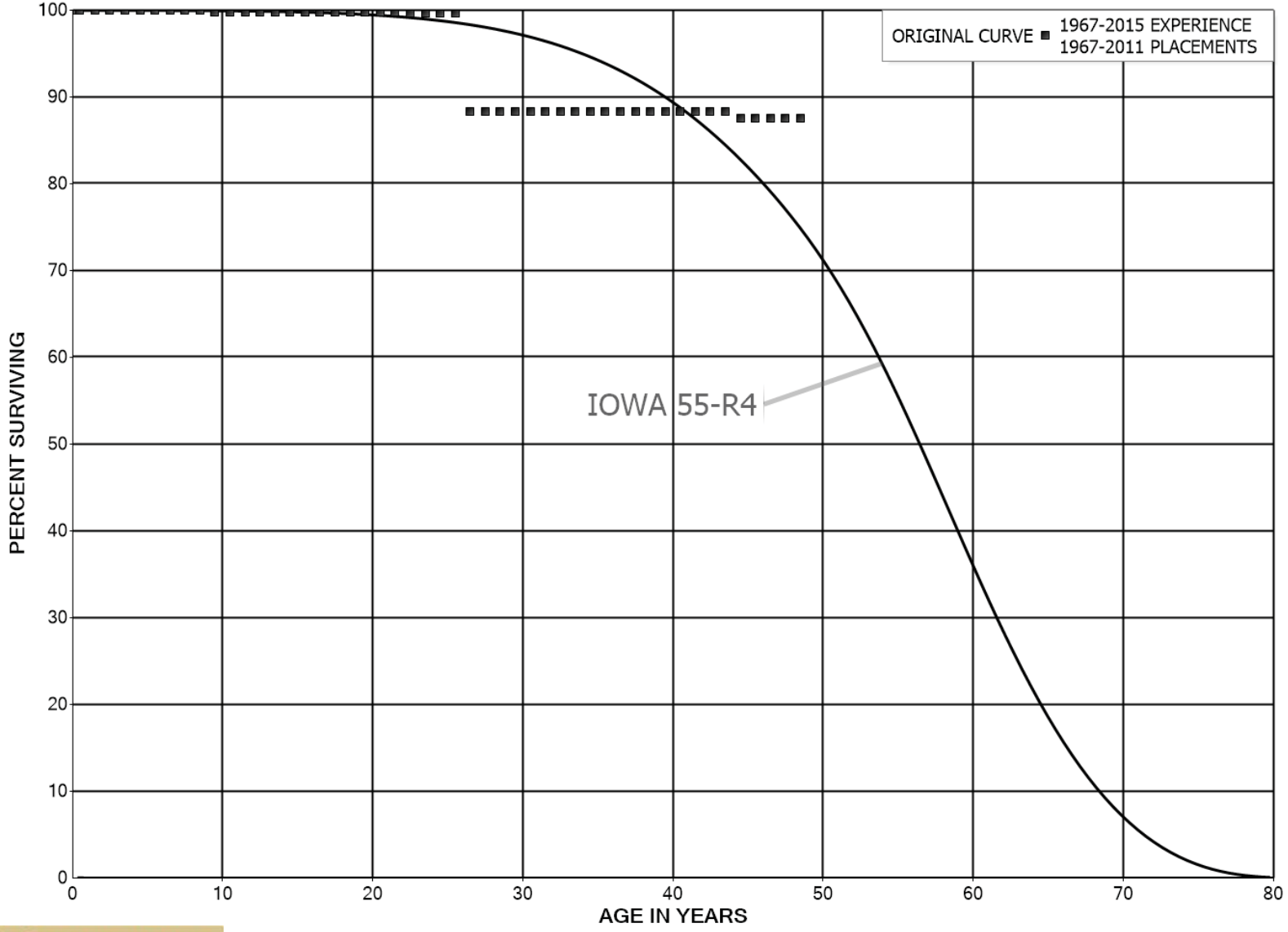
ACCOUNT S02 - SECTIONALIZERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2010 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	73,992		0.0000	1.0000	59.89
40.5	50,223		0.0000	1.0000	59.89
41.5	50,223		0.0000	1.0000	59.89
42.5	50,223	1,756	0.0350	0.9650	59.89
43.5	48,467		0.0000	1.0000	57.79
44.5	48,467		0.0000	1.0000	57.79
45.5	48,467		0.0000	1.0000	57.79
46.5	48,467		0.0000	1.0000	57.79
47.5					57.79

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S04 - SEWAGE DISPOSAL SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S04 - SEWAGE DISPOSAL SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2011 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,028,054		0.0000	1.0000	100.00
0.5	3,028,054		0.0000	1.0000	100.00
1.5	3,028,054		0.0000	1.0000	100.00
2.5	3,028,054		0.0000	1.0000	100.00
3.5	3,028,054		0.0000	1.0000	100.00
4.5	2,884,687		0.0000	1.0000	100.00
5.5	2,758,930		0.0000	1.0000	100.00
6.5	2,714,051		0.0000	1.0000	100.00
7.5	2,669,446		0.0000	1.0000	100.00
8.5	2,611,317	8,327	0.0032	0.9968	100.00
9.5	2,567,675		0.0000	1.0000	99.68
10.5	2,567,675		0.0000	1.0000	99.68
11.5	2,567,675		0.0000	1.0000	99.68
12.5	2,469,764		0.0000	1.0000	99.68
13.5	2,113,937		0.0000	1.0000	99.68
14.5	2,113,937		0.0000	1.0000	99.68
15.5	2,113,937		0.0000	1.0000	99.68
16.5	1,137,751		0.0000	1.0000	99.68
17.5	1,082,153		0.0000	1.0000	99.68
18.5	1,077,919		0.0000	1.0000	99.68
19.5	1,064,436		0.0000	1.0000	99.68
20.5	933,197		0.0000	1.0000	99.68
21.5	933,197	899	0.0010	0.9990	99.68
22.5	932,298		0.0000	1.0000	99.59
23.5	916,457		0.0000	1.0000	99.59
24.5	916,457		0.0000	1.0000	99.59
25.5	866,450	97,985	0.1131	0.8869	99.59
26.5	460,447		0.0000	1.0000	88.32
27.5	457,750		0.0000	1.0000	88.32
28.5	457,750		0.0000	1.0000	88.32
29.5	457,750		0.0000	1.0000	88.32
30.5	457,750		0.0000	1.0000	88.32
31.5	457,750		0.0000	1.0000	88.32
32.5	362,744		0.0000	1.0000	88.32
33.5	359,744		0.0000	1.0000	88.32
34.5	357,077		0.0000	1.0000	88.32
35.5	213,958		0.0000	1.0000	88.32
36.5	213,958		0.0000	1.0000	88.32
37.5	179,942		0.0000	1.0000	88.32
38.5	172,081		0.0000	1.0000	88.32

NEWFOUNDLAND AND LABRADOR HYDRO

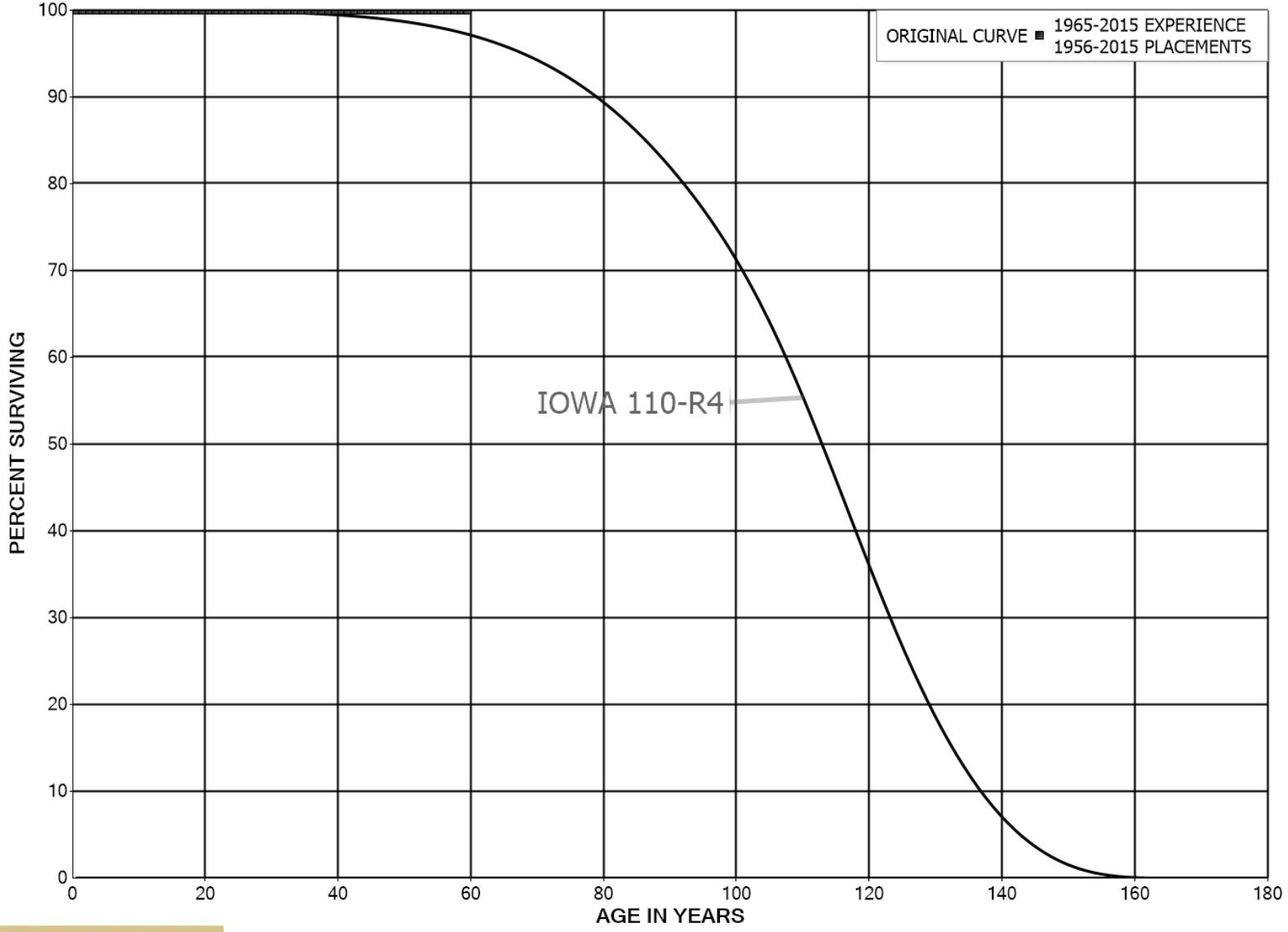
ACCOUNT S04 - SEWAGE DISPOSAL SYSTEM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2011 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	172,081		0.0000	1.0000	88.32
40.5	172,081		0.0000	1.0000	88.32
41.5	172,081		0.0000	1.0000	88.32
42.5	172,081		0.0000	1.0000	88.32
43.5	167,427	1,523	0.0091	0.9909	88.32
44.5	164,517		0.0000	1.0000	87.52
45.5	150,432		0.0000	1.0000	87.52
46.5	17,904		0.0000	1.0000	87.52
47.5	10,112		0.0000	1.0000	87.52
48.5					87.52

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S06 - SPILLWAY STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S06 - SPILLWAY STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	28,083,039		0.0000	1.0000	100.00
0.5	28,033,039		0.0000	1.0000	100.00
1.5	28,033,039		0.0000	1.0000	100.00
2.5	28,033,039		0.0000	1.0000	100.00
3.5	28,033,039		0.0000	1.0000	100.00
4.5	28,033,039		0.0000	1.0000	100.00
5.5	28,033,039		0.0000	1.0000	100.00
6.5	28,033,039		0.0000	1.0000	100.00
7.5	28,033,039		0.0000	1.0000	100.00
8.5	28,070,270		0.0000	1.0000	100.00
9.5	28,070,270		0.0000	1.0000	100.00
10.5	28,070,270		0.0000	1.0000	100.00
11.5	28,070,270		0.0000	1.0000	100.00
12.5	26,332,464		0.0000	1.0000	100.00
13.5	26,332,464		0.0000	1.0000	100.00
14.5	26,332,464		0.0000	1.0000	100.00
15.5	26,332,464		0.0000	1.0000	100.00
16.5	26,332,464		0.0000	1.0000	100.00
17.5	26,332,464		0.0000	1.0000	100.00
18.5	26,332,464		0.0000	1.0000	100.00
19.5	26,332,464		0.0000	1.0000	100.00
20.5	26,332,464		0.0000	1.0000	100.00
21.5	26,332,464		0.0000	1.0000	100.00
22.5	26,332,464		0.0000	1.0000	100.00
23.5	26,325,756		0.0000	1.0000	100.00
24.5	26,290,175		0.0000	1.0000	100.00
25.5	26,290,175		0.0000	1.0000	100.00
26.5	26,290,175		0.0000	1.0000	100.00
27.5	26,261,403		0.0000	1.0000	100.00
28.5	26,261,403		0.0000	1.0000	100.00
29.5	26,261,403		0.0000	1.0000	100.00
30.5	26,261,403		0.0000	1.0000	100.00
31.5	19,750,348		0.0000	1.0000	100.00
32.5	19,747,399		0.0000	1.0000	100.00
33.5	7,917,388		0.0000	1.0000	100.00
34.5	7,917,388		0.0000	1.0000	100.00
35.5	7,917,388		0.0000	1.0000	100.00
36.5	4,434,743		0.0000	1.0000	100.00
37.5	4,434,743		0.0000	1.0000	100.00
38.5	4,434,743		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

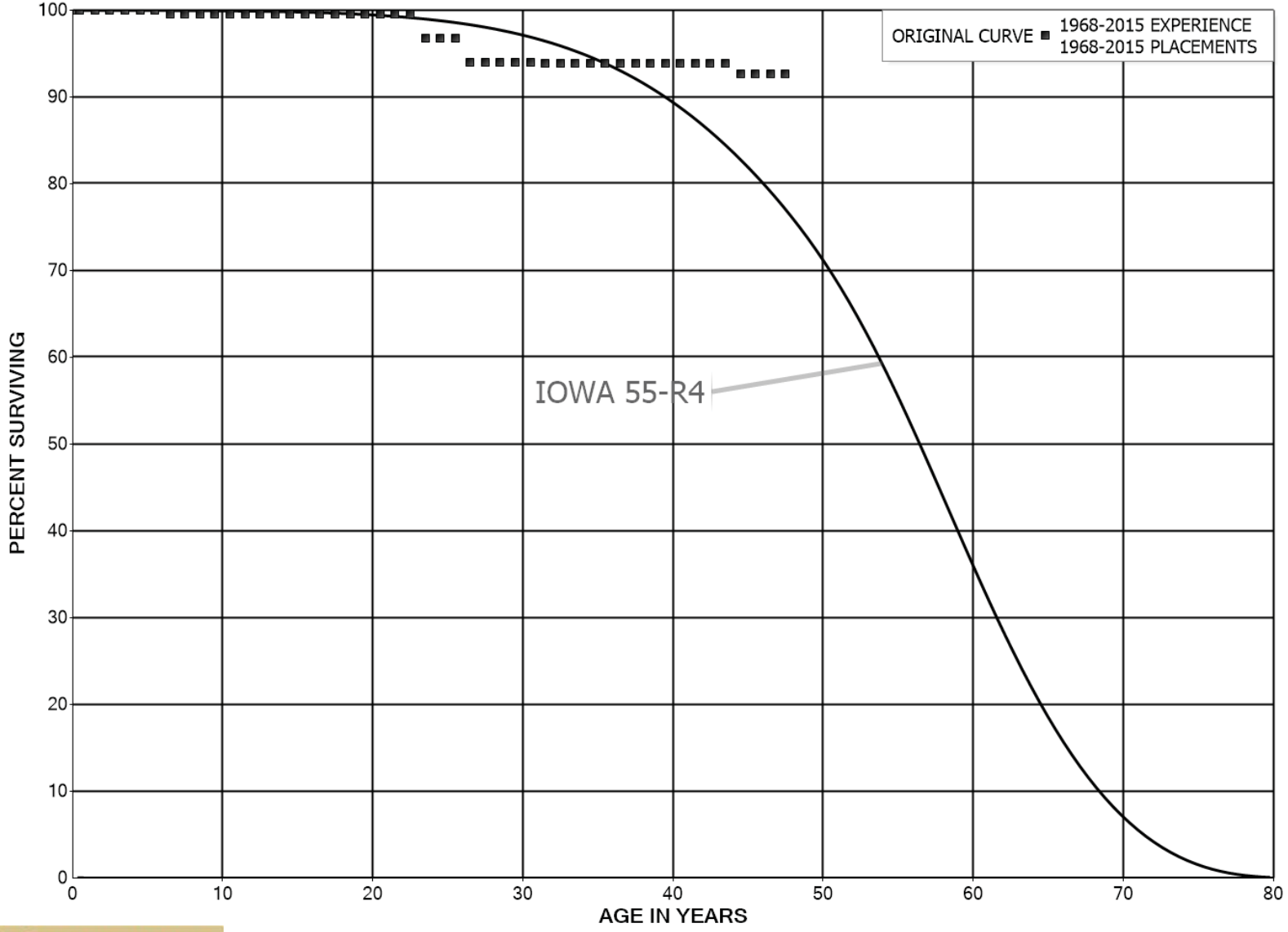
ACCOUNT S06 - SPILLWAY STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,434,743		0.0000	1.0000	100.00
40.5	4,434,743		0.0000	1.0000	100.00
41.5	4,434,743		0.0000	1.0000	100.00
42.5	4,434,743		0.0000	1.0000	100.00
43.5	4,434,743		0.0000	1.0000	100.00
44.5	4,434,743		0.0000	1.0000	100.00
45.5	4,434,743		0.0000	1.0000	100.00
46.5	4,434,743		0.0000	1.0000	100.00
47.5	4,434,743		0.0000	1.0000	100.00
48.5	2,173,611		0.0000	1.0000	100.00
49.5	37,231		0.0000	1.0000	100.00
50.5	37,231		0.0000	1.0000	100.00
51.5	37,231		0.0000	1.0000	100.00
52.5	37,231		0.0000	1.0000	100.00
53.5	37,231		0.0000	1.0000	100.00
54.5	37,231		0.0000	1.0000	100.00
55.5	37,231		0.0000	1.0000	100.00
56.5	37,231		0.0000	1.0000	100.00
57.5	37,231		0.0000	1.0000	100.00
58.5	37,231		0.0000	1.0000	100.00
59.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S07 - STACKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S07 - STACKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,603,104		0.0000	1.0000	100.00
0.5	13,821,283		0.0000	1.0000	100.00
1.5	13,801,764	9,927	0.0007	0.9993	100.00
2.5	13,791,837		0.0000	1.0000	99.93
3.5	11,609,146		0.0000	1.0000	99.93
4.5	10,819,314		0.0000	1.0000	99.93
5.5	10,819,314	50,280	0.0046	0.9954	99.93
6.5	10,769,034		0.0000	1.0000	99.46
7.5	10,479,141		0.0000	1.0000	99.46
8.5	10,370,962		0.0000	1.0000	99.46
9.5	10,370,962		0.0000	1.0000	99.46
10.5	8,301,831		0.0000	1.0000	99.46
11.5	8,301,831		0.0000	1.0000	99.46
12.5	8,301,831		0.0000	1.0000	99.46
13.5	8,301,831		0.0000	1.0000	99.46
14.5	8,207,809		0.0000	1.0000	99.46
15.5	8,207,809		0.0000	1.0000	99.46
16.5	8,207,809		0.0000	1.0000	99.46
17.5	8,207,809		0.0000	1.0000	99.46
18.5	8,207,809		0.0000	1.0000	99.46
19.5	8,086,784		0.0000	1.0000	99.46
20.5	8,049,829		0.0000	1.0000	99.46
21.5	8,049,829		0.0000	1.0000	99.46
22.5	8,049,829	225,731	0.0280	0.9720	99.46
23.5	6,975,642		0.0000	1.0000	96.67
24.5	6,975,642		0.0000	1.0000	96.67
25.5	6,975,642	195,010	0.0280	0.9720	96.67
26.5	6,780,633		0.0000	1.0000	93.97
27.5	6,774,500		0.0000	1.0000	93.97
28.5	6,774,500		0.0000	1.0000	93.97
29.5	6,746,581		0.0000	1.0000	93.97
30.5	6,746,581	12,760	0.0019	0.9981	93.97
31.5	6,733,821		0.0000	1.0000	93.79
32.5	6,733,821		0.0000	1.0000	93.79
33.5	6,733,821		0.0000	1.0000	93.79
34.5	6,733,821		0.0000	1.0000	93.79
35.5	5,035,613		0.0000	1.0000	93.79
36.5	5,035,613		0.0000	1.0000	93.79
37.5	5,035,613		0.0000	1.0000	93.79
38.5	5,035,613		0.0000	1.0000	93.79

NEWFOUNDLAND AND LABRADOR HYDRO

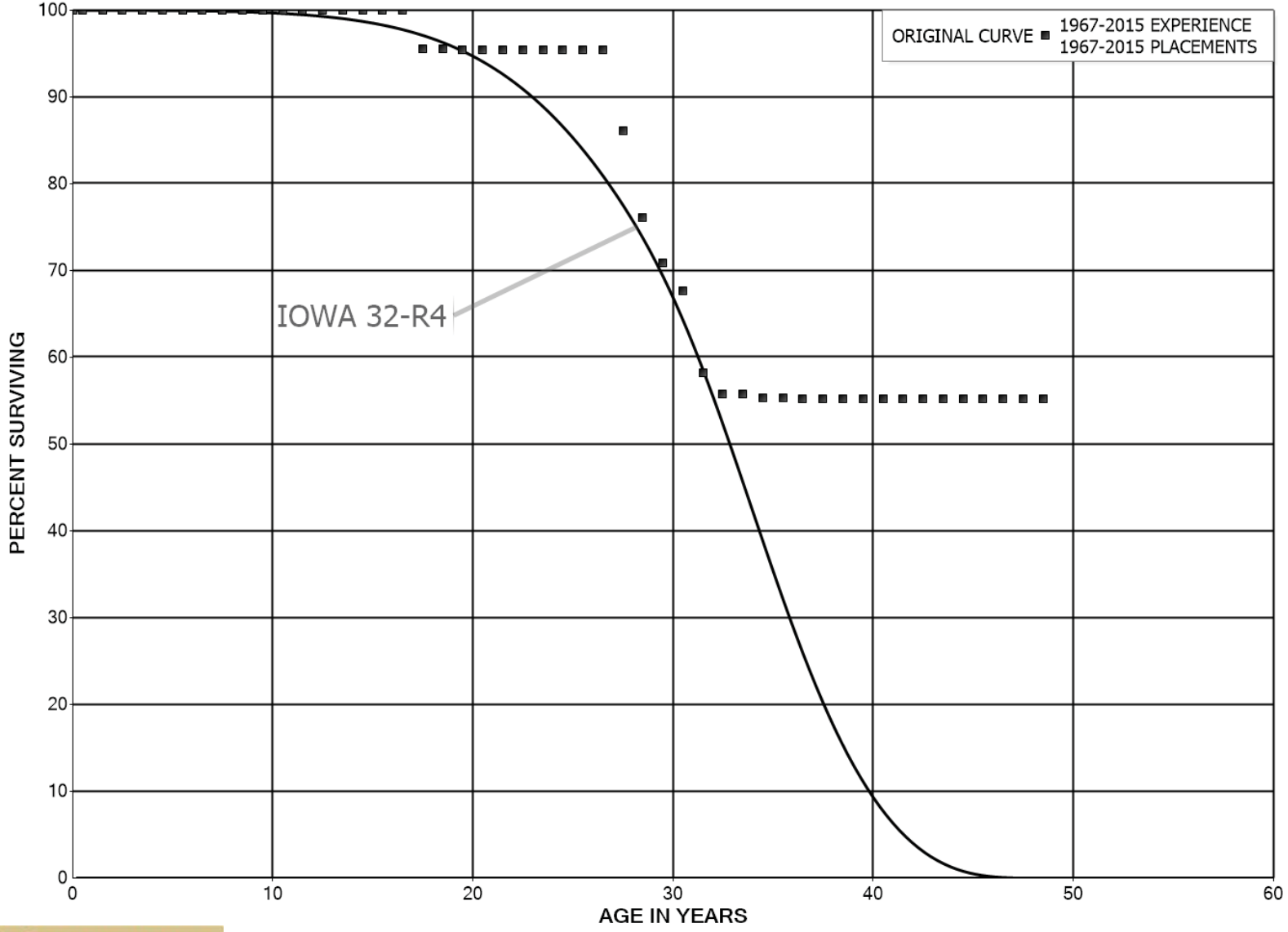
ACCOUNT S07 - STACKS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,027,012		0.0000	1.0000	93.79
40.5	4,365,649		0.0000	1.0000	93.79
41.5	4,296,040		0.0000	1.0000	93.79
42.5	4,296,040		0.0000	1.0000	93.79
43.5	4,296,040	56,428	0.0131	0.9869	93.79
44.5	3,809,218		0.0000	1.0000	92.56
45.5	3,809,218		0.0000	1.0000	92.56
46.5	3,809,218		0.0000	1.0000	92.56
47.5					92.56

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S08 - STATIC EXCITATION SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S08 - STATIC EXCITATION SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,697,385		0.0000	1.0000	100.00
0.5	13,016,565		0.0000	1.0000	100.00
1.5	13,016,565		0.0000	1.0000	100.00
2.5	11,796,837		0.0000	1.0000	100.00
3.5	11,233,766		0.0000	1.0000	100.00
4.5	11,233,766		0.0000	1.0000	100.00
5.5	11,233,766		0.0000	1.0000	100.00
6.5	11,233,766		0.0000	1.0000	100.00
7.5	11,233,766		0.0000	1.0000	100.00
8.5	11,233,766		0.0000	1.0000	100.00
9.5	11,233,766		0.0000	1.0000	100.00
10.5	11,233,766		0.0000	1.0000	100.00
11.5	10,585,051		0.0000	1.0000	100.00
12.5	9,994,625		0.0000	1.0000	100.00
13.5	9,405,190		0.0000	1.0000	100.00
14.5	9,388,601		0.0000	1.0000	100.00
15.5	9,059,543		0.0000	1.0000	100.00
16.5	9,059,543	405,819	0.0448	0.9552	100.00
17.5	8,633,626		0.0000	1.0000	95.52
18.5	8,633,626	6,733	0.0008	0.9992	95.52
19.5	8,626,892		0.0000	1.0000	95.45
20.5	8,626,892		0.0000	1.0000	95.45
21.5	8,626,892		0.0000	1.0000	95.45
22.5	8,626,892		0.0000	1.0000	95.45
23.5	8,498,957		0.0000	1.0000	95.45
24.5	8,498,957		0.0000	1.0000	95.45
25.5	8,498,957	2,227	0.0003	0.9997	95.45
26.5	8,277,464	811,162	0.0980	0.9020	95.42
27.5	7,464,167	864,084	0.1158	0.8842	86.07
28.5	6,600,084	461,167	0.0699	0.9301	76.11
29.5	6,138,917	272,384	0.0444	0.9556	70.79
30.5	5,866,532	822,012	0.1401	0.8599	67.65
31.5	5,044,521	214,141	0.0425	0.9575	58.17
32.5	4,830,380		0.0000	1.0000	55.70
33.5	4,805,335	32,738	0.0068	0.9932	55.70
34.5	4,772,597	5,000	0.0010	0.9990	55.32
35.5	3,277,853	5,419	0.0017	0.9983	55.26
36.5	3,272,434		0.0000	1.0000	55.17
37.5	3,272,434		0.0000	1.0000	55.17
38.5	3,264,434		0.0000	1.0000	55.17

NEWFOUNDLAND AND LABRADOR HYDRO

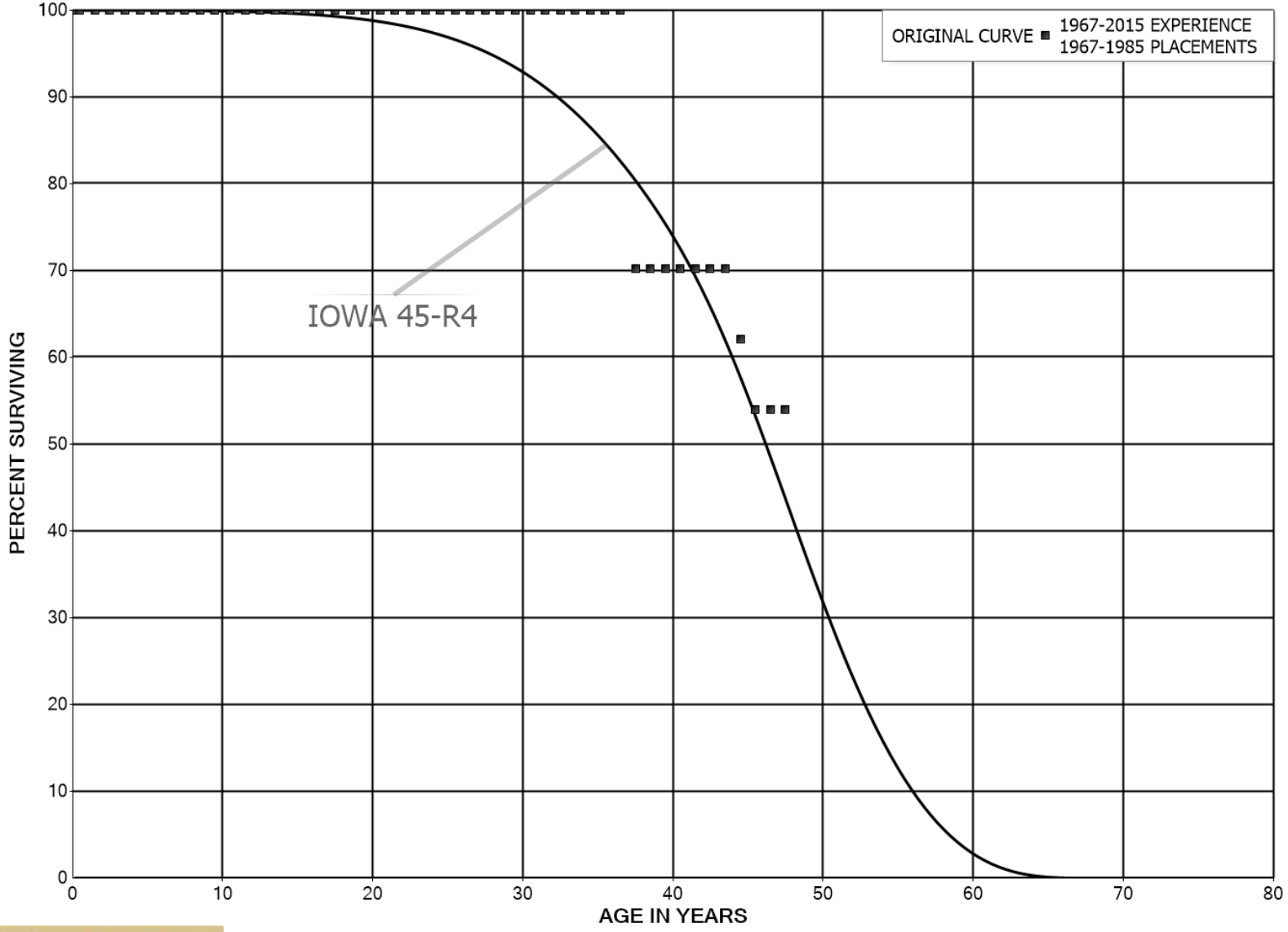
ACCOUNT S08 - STATIC EXCITATION SYSTEM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,256,434		0.0000	1.0000	55.17
40.5	3,223,516		0.0000	1.0000	55.17
41.5	3,186,792		0.0000	1.0000	55.17
42.5	3,186,792		0.0000	1.0000	55.17
43.5	3,186,792		0.0000	1.0000	55.17
44.5	3,186,792		0.0000	1.0000	55.17
45.5	2,498,060		0.0000	1.0000	55.17
46.5	2,498,060		0.0000	1.0000	55.17
47.5	951,236		0.0000	1.0000	55.17
48.5					55.17

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S09 - STATIC EXCITATION - TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S09 - STATIC EXCITATION - TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-1985 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	884,861		0.0000	1.0000	100.00
0.5	884,861		0.0000	1.0000	100.00
1.5	884,861		0.0000	1.0000	100.00
2.5	884,861		0.0000	1.0000	100.00
3.5	884,861		0.0000	1.0000	100.00
4.5	884,861		0.0000	1.0000	100.00
5.5	884,861		0.0000	1.0000	100.00
6.5	884,861		0.0000	1.0000	100.00
7.5	884,861		0.0000	1.0000	100.00
8.5	884,861		0.0000	1.0000	100.00
9.5	884,861		0.0000	1.0000	100.00
10.5	884,861		0.0000	1.0000	100.00
11.5	884,861		0.0000	1.0000	100.00
12.5	884,861		0.0000	1.0000	100.00
13.5	884,861		0.0000	1.0000	100.00
14.5	884,861		0.0000	1.0000	100.00
15.5	884,861		0.0000	1.0000	100.00
16.5	884,861		0.0000	1.0000	100.00
17.5	884,861		0.0000	1.0000	100.00
18.5	884,861		0.0000	1.0000	100.00
19.5	884,861		0.0000	1.0000	100.00
20.5	884,861		0.0000	1.0000	100.00
21.5	884,861		0.0000	1.0000	100.00
22.5	884,861		0.0000	1.0000	100.00
23.5	884,861		0.0000	1.0000	100.00
24.5	884,861		0.0000	1.0000	100.00
25.5	884,861		0.0000	1.0000	100.00
26.5	884,861		0.0000	1.0000	100.00
27.5	884,861		0.0000	1.0000	100.00
28.5	884,861		0.0000	1.0000	100.00
29.5	884,861		0.0000	1.0000	100.00
30.5	559,732		0.0000	1.0000	100.00
31.5	559,732		0.0000	1.0000	100.00
32.5	559,732		0.0000	1.0000	100.00
33.5	514,767		0.0000	1.0000	100.00
34.5	514,767		0.0000	1.0000	100.00
35.5	249,534		0.0000	1.0000	100.00
36.5	249,534	74,379	0.2981	0.7019	100.00
37.5	168,390		0.0000	1.0000	70.19
38.5	168,390		0.0000	1.0000	70.19

NEWFOUNDLAND AND LABRADOR HYDRO

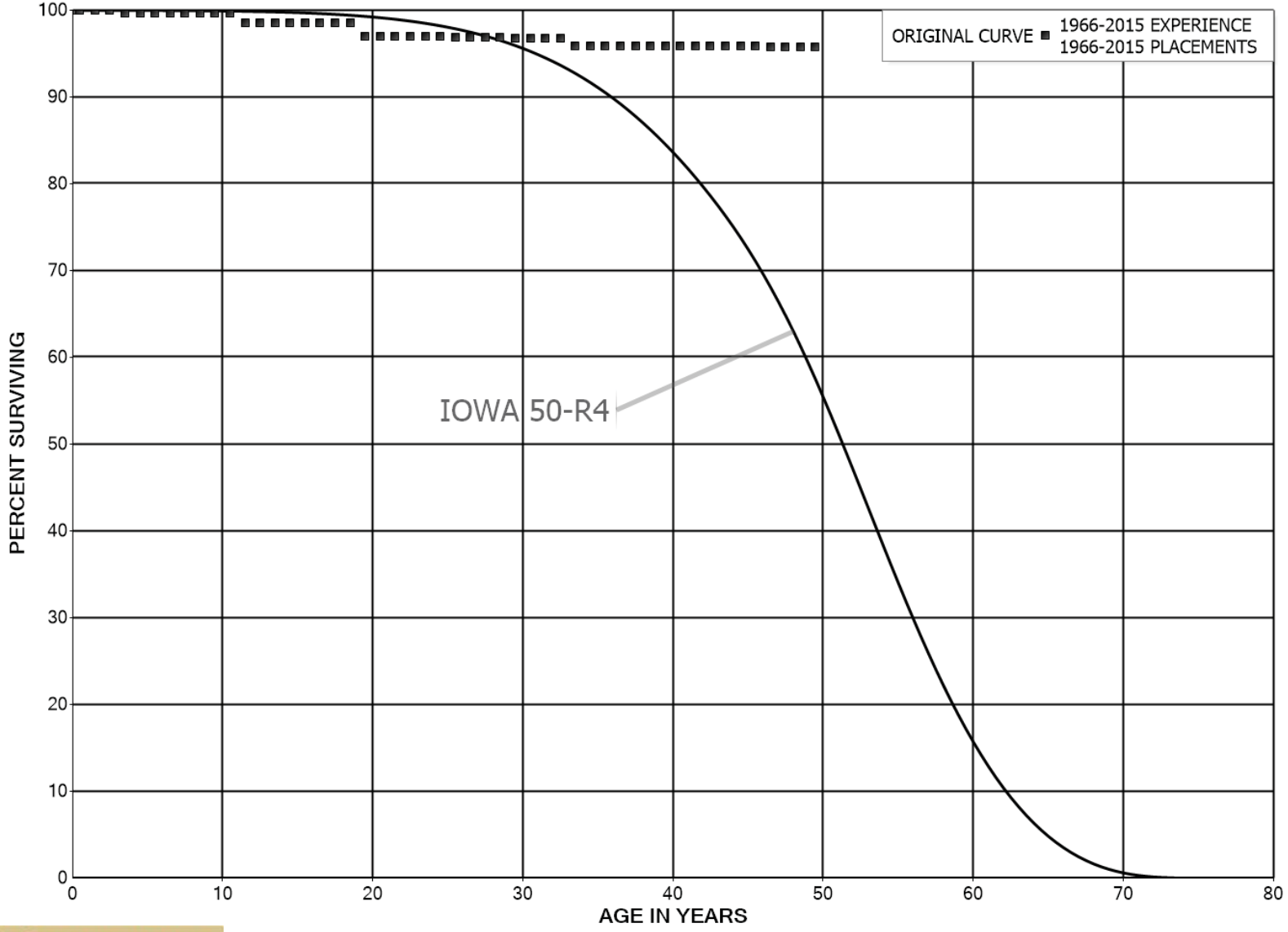
ACCOUNT S09 - STATIC EXCITATION - TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-1985 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	168,390		0.0000	1.0000	70.19
40.5	168,390		0.0000	1.0000	70.19
41.5	168,390		0.0000	1.0000	70.19
42.5	168,390		0.0000	1.0000	70.19
43.5	168,390	19,468	0.1156	0.8844	70.19
44.5	148,923	19,468	0.1307	0.8693	62.08
45.5	129,455		0.0000	1.0000	53.96
46.5	129,455		0.0000	1.0000	53.96
47.5	37,221	37,221	1.0000		53.96
48.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S10 - STATION SERVICE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S10 - STATION SERVICE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,341,141		0.0000	1.0000	100.00
0.5	3,777,641		0.0000	1.0000	100.00
1.5	3,749,113		0.0000	1.0000	100.00
2.5	3,721,185	13,370	0.0036	0.9964	100.00
3.5	3,613,933		0.0000	1.0000	99.64
4.5	3,587,621		0.0000	1.0000	99.64
5.5	3,569,367		0.0000	1.0000	99.64
6.5	3,229,864		0.0000	1.0000	99.64
7.5	2,854,538		0.0000	1.0000	99.64
8.5	2,854,538		0.0000	1.0000	99.64
9.5	2,854,538		0.0000	1.0000	99.64
10.5	2,854,538	32,567	0.0114	0.9886	99.64
11.5	2,821,972		0.0000	1.0000	98.50
12.5	2,821,972		0.0000	1.0000	98.50
13.5	2,820,609		0.0000	1.0000	98.50
14.5	2,820,609		0.0000	1.0000	98.50
15.5	2,820,609		0.0000	1.0000	98.50
16.5	2,820,609		0.0000	1.0000	98.50
17.5	2,820,609		0.0000	1.0000	98.50
18.5	2,820,609	45,266	0.0160	0.9840	98.50
19.5	2,692,387		0.0000	1.0000	96.92
20.5	2,671,359		0.0000	1.0000	96.92
21.5	2,629,236		0.0000	1.0000	96.92
22.5	2,626,792		0.0000	1.0000	96.92
23.5	2,625,906	484	0.0002	0.9998	96.92
24.5	2,622,647	2,892	0.0011	0.9989	96.91
25.5	2,594,718		0.0000	1.0000	96.80
26.5	2,496,612		0.0000	1.0000	96.80
27.5	2,427,377		0.0000	1.0000	96.80
28.5	2,424,708	2,402	0.0010	0.9990	96.80
29.5	2,419,450		0.0000	1.0000	96.70
30.5	1,907,004		0.0000	1.0000	96.70
31.5	1,907,004		0.0000	1.0000	96.70
32.5	1,131,562	9,576	0.0085	0.9915	96.70
33.5	1,114,260	695	0.0006	0.9994	95.88
34.5	1,104,479		0.0000	1.0000	95.82
35.5	901,880		0.0000	1.0000	95.82
36.5	719,873		0.0000	1.0000	95.82
37.5	710,886		0.0000	1.0000	95.82
38.5	673,980		0.0000	1.0000	95.82

NEWFOUNDLAND AND LABRADOR HYDRO

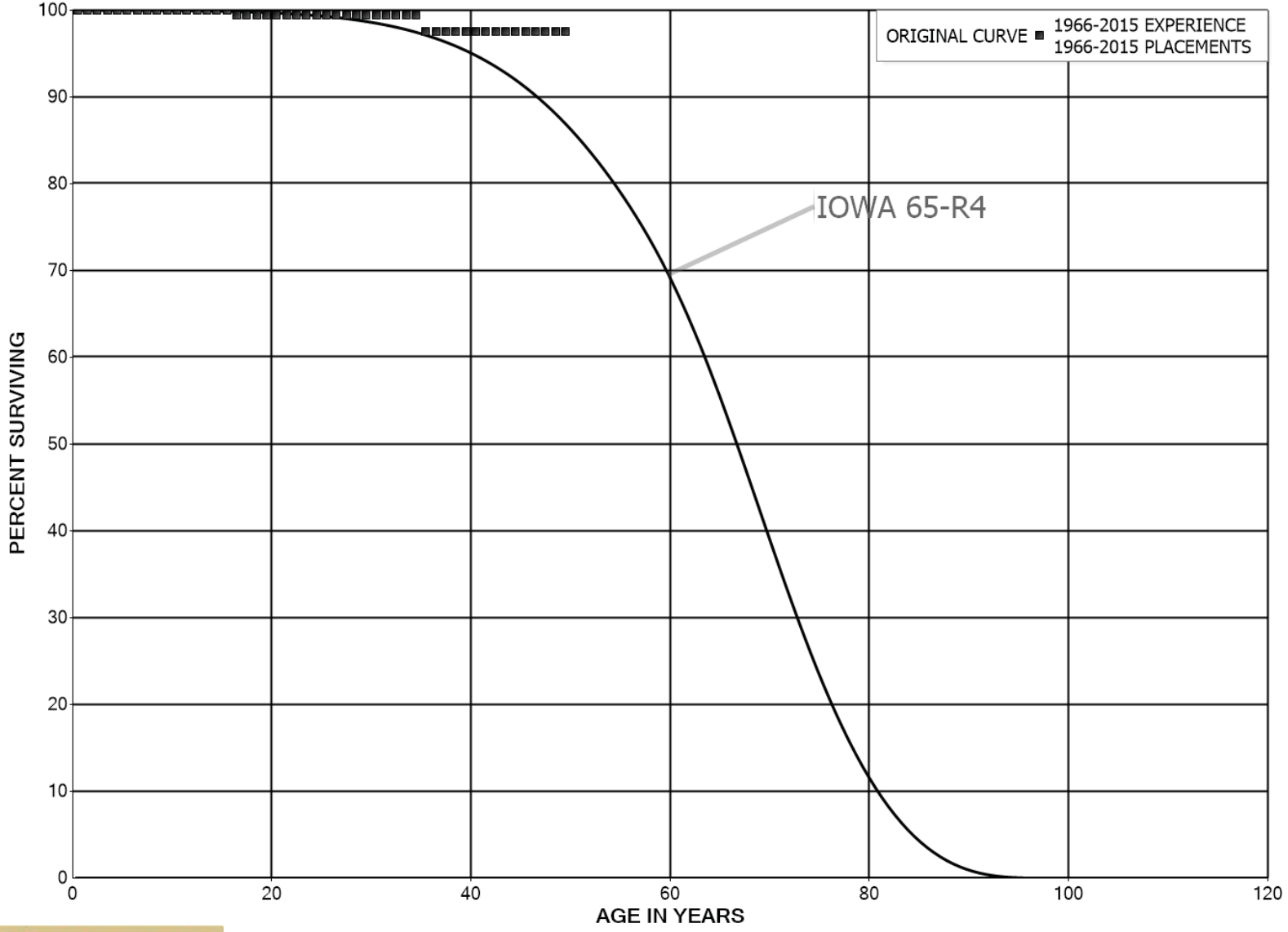
ACCOUNT S10 - STATION SERVICE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	673,980		0.0000	1.0000	95.82
40.5	672,480		0.0000	1.0000	95.82
41.5	672,030	237	0.0004	0.9996	95.82
42.5	671,793		0.0000	1.0000	95.79
43.5	671,793		0.0000	1.0000	95.79
44.5	519,921		0.0000	1.0000	95.79
45.5	518,898	316	0.0006	0.9994	95.79
46.5	518,582		0.0000	1.0000	95.73
47.5	511,196		0.0000	1.0000	95.73
48.5	491,605		0.0000	1.0000	95.73
49.5					95.73

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S11 - STOP LOGS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S11 - STOP LOGS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	3,146,969		0.0000	1.0000	100.00
0.5	2,853,106		0.0000	1.0000	100.00
1.5	2,853,106		0.0000	1.0000	100.00
2.5	2,853,106		0.0000	1.0000	100.00
3.5	2,853,106		0.0000	1.0000	100.00
4.5	2,853,106		0.0000	1.0000	100.00
5.5	2,853,106		0.0000	1.0000	100.00
6.5	2,853,106		0.0000	1.0000	100.00
7.5	2,645,784		0.0000	1.0000	100.00
8.5	2,645,784		0.0000	1.0000	100.00
9.5	2,645,784		0.0000	1.0000	100.00
10.5	2,645,784		0.0000	1.0000	100.00
11.5	2,645,784		0.0000	1.0000	100.00
12.5	2,510,772		0.0000	1.0000	100.00
13.5	2,510,772		0.0000	1.0000	100.00
14.5	2,510,772		0.0000	1.0000	100.00
15.5	2,510,772	16,397	0.0065	0.9935	100.00
16.5	2,471,527		0.0000	1.0000	99.35
17.5	2,448,776		0.0000	1.0000	99.35
18.5	2,448,776		0.0000	1.0000	99.35
19.5	2,448,776		0.0000	1.0000	99.35
20.5	2,448,776		0.0000	1.0000	99.35
21.5	2,448,776		0.0000	1.0000	99.35
22.5	2,448,776		0.0000	1.0000	99.35
23.5	2,448,776		0.0000	1.0000	99.35
24.5	2,448,776		0.0000	1.0000	99.35
25.5	2,448,776		0.0000	1.0000	99.35
26.5	2,448,776		0.0000	1.0000	99.35
27.5	2,383,388		0.0000	1.0000	99.35
28.5	2,383,388		0.0000	1.0000	99.35
29.5	2,383,388		0.0000	1.0000	99.35
30.5	2,383,388		0.0000	1.0000	99.35
31.5	2,187,620		0.0000	1.0000	99.35
32.5	2,175,246		0.0000	1.0000	99.35
33.5	884,391		0.0000	1.0000	99.35
34.5	884,391	16,475	0.0186	0.9814	99.35
35.5	867,916		0.0000	1.0000	97.50
36.5	305,958		0.0000	1.0000	97.50
37.5	305,958		0.0000	1.0000	97.50
38.5	305,958		0.0000	1.0000	97.50

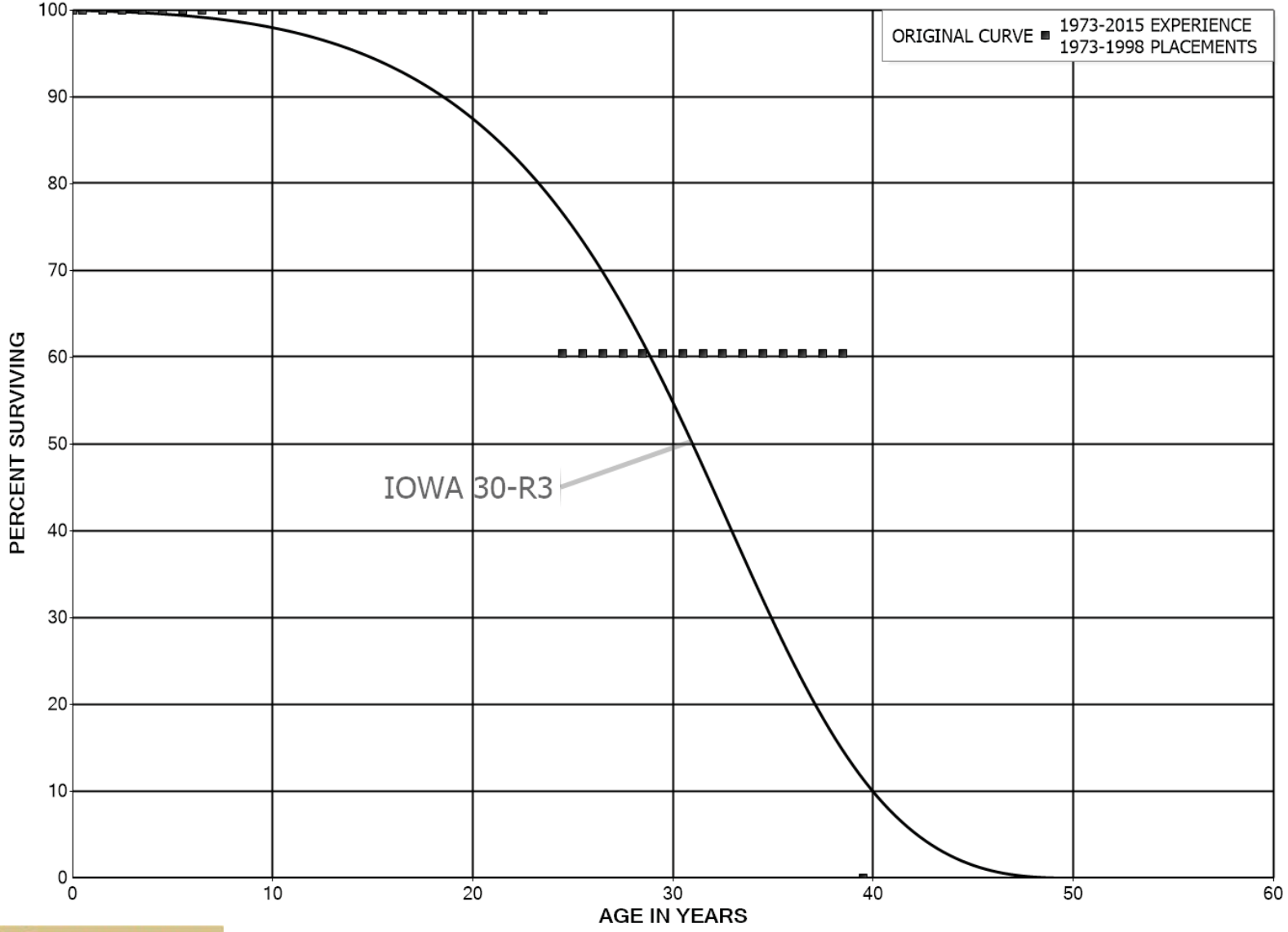
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S11 - STOP LOGS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015			EXPERIENCE BAND 1966-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	305,958		0.0000	1.0000	97.50
40.5	305,958		0.0000	1.0000	97.50
41.5	305,958		0.0000	1.0000	97.50
42.5	305,958		0.0000	1.0000	97.50
43.5	305,958		0.0000	1.0000	97.50
44.5	305,958		0.0000	1.0000	97.50
45.5	285,958		0.0000	1.0000	97.50
46.5	285,958		0.0000	1.0000	97.50
47.5	285,958		0.0000	1.0000	97.50
48.5	137,480		0.0000	1.0000	97.50
49.5					97.50

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S12 - STORAGE PALLETS AND RACKINGS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

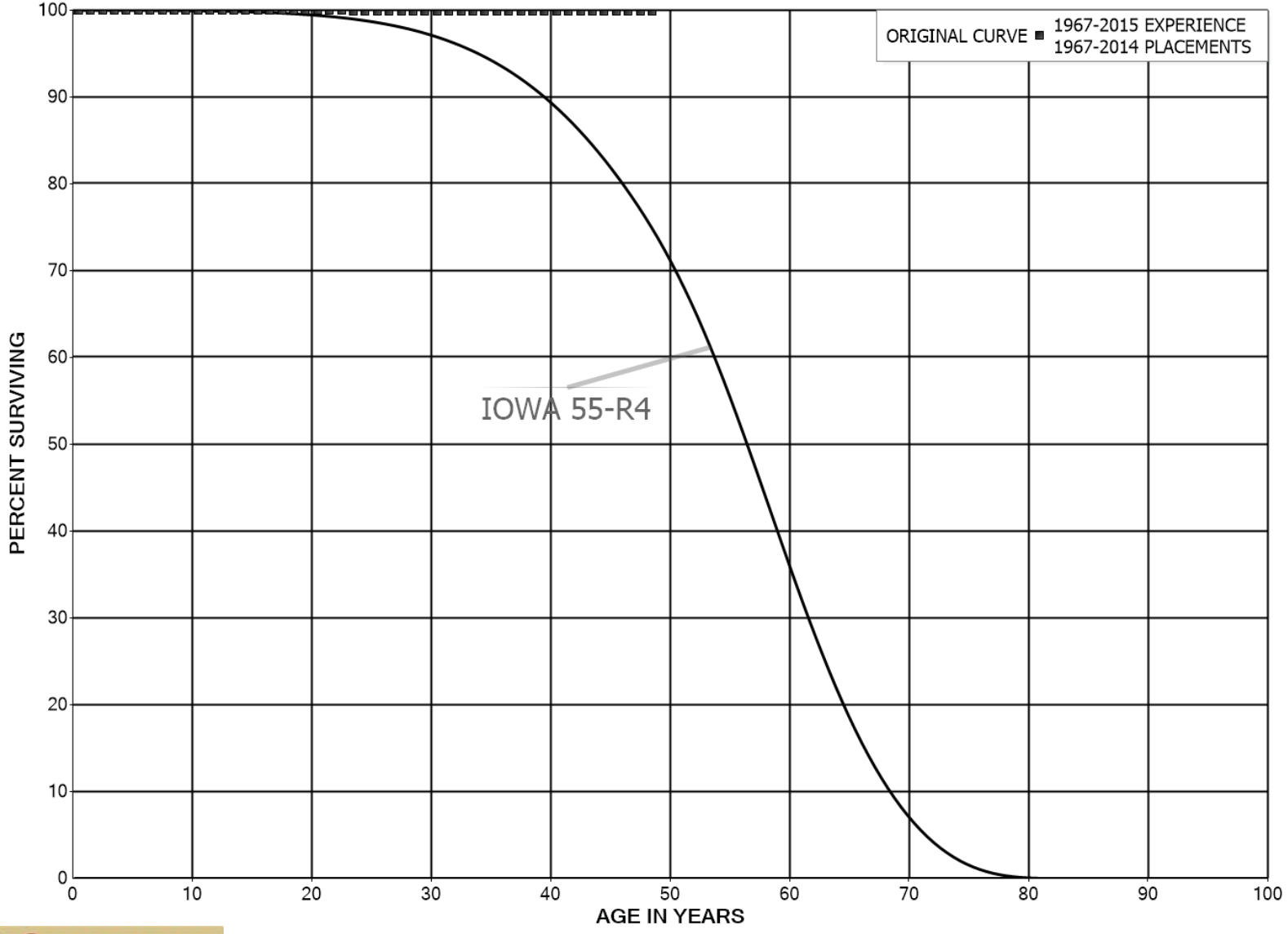
ACCOUNT S12 - STORAGE PALLETS AND RACKINGS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1973-1998 EXPERIENCE BAND 1973-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	33,439		0.0000	1.0000	100.00
0.5	33,439		0.0000	1.0000	100.00
1.5	33,439		0.0000	1.0000	100.00
2.5	33,439		0.0000	1.0000	100.00
3.5	33,439		0.0000	1.0000	100.00
4.5	33,439		0.0000	1.0000	100.00
5.5	33,439		0.0000	1.0000	100.00
6.5	33,439		0.0000	1.0000	100.00
7.5	33,439		0.0000	1.0000	100.00
8.5	33,439		0.0000	1.0000	100.00
9.5	33,439		0.0000	1.0000	100.00
10.5	33,439		0.0000	1.0000	100.00
11.5	33,439		0.0000	1.0000	100.00
12.5	33,439		0.0000	1.0000	100.00
13.5	33,439		0.0000	1.0000	100.00
14.5	33,439		0.0000	1.0000	100.00
15.5	33,439		0.0000	1.0000	100.00
16.5	33,439		0.0000	1.0000	100.00
17.5	29,742		0.0000	1.0000	100.00
18.5	29,742		0.0000	1.0000	100.00
19.5	29,742		0.0000	1.0000	100.00
20.5	29,742		0.0000	1.0000	100.00
21.5	29,742		0.0000	1.0000	100.00
22.5	29,742		0.0000	1.0000	100.00
23.5	29,742	11,790	0.3964	0.6036	100.00
24.5	17,952		0.0000	1.0000	60.36
25.5	17,952		0.0000	1.0000	60.36
26.5	17,952		0.0000	1.0000	60.36
27.5	17,952		0.0000	1.0000	60.36
28.5	17,952		0.0000	1.0000	60.36
29.5	17,952		0.0000	1.0000	60.36
30.5	17,952		0.0000	1.0000	60.36
31.5	7,245		0.0000	1.0000	60.36
32.5	7,245		0.0000	1.0000	60.36
33.5	7,245		0.0000	1.0000	60.36
34.5	7,245		0.0000	1.0000	60.36
35.5	7,245		0.0000	1.0000	60.36
36.5	7,245		0.0000	1.0000	60.36
37.5	7,245		0.0000	1.0000	60.36
38.5	7,245	7,245	1.0000		60.36
39.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S13 - STORM AND YARD DRAINAGE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S13 - STORM AND YARD DRAINAGE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2014 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,311,021		0.0000	1.0000	100.00
0.5	1,311,021		0.0000	1.0000	100.00
1.5	1,274,643		0.0000	1.0000	100.00
2.5	1,199,628		0.0000	1.0000	100.00
3.5	1,199,628		0.0000	1.0000	100.00
4.5	1,199,628		0.0000	1.0000	100.00
5.5	1,199,628		0.0000	1.0000	100.00
6.5	1,132,337		0.0000	1.0000	100.00
7.5	1,132,337		0.0000	1.0000	100.00
8.5	1,132,337		0.0000	1.0000	100.00
9.5	1,132,337		0.0000	1.0000	100.00
10.5	1,132,337		0.0000	1.0000	100.00
11.5	1,132,337		0.0000	1.0000	100.00
12.5	1,132,337		0.0000	1.0000	100.00
13.5	1,132,337		0.0000	1.0000	100.00
14.5	1,132,337		0.0000	1.0000	100.00
15.5	1,132,337		0.0000	1.0000	100.00
16.5	1,132,337		0.0000	1.0000	100.00
17.5	1,132,337		0.0000	1.0000	100.00
18.5	1,132,337		0.0000	1.0000	100.00
19.5	1,132,337		0.0000	1.0000	100.00
20.5	1,100,589		0.0000	1.0000	100.00
21.5	1,100,589		0.0000	1.0000	100.00
22.5	1,100,589	2,307	0.0021	0.9979	100.00
23.5	1,058,425		0.0000	1.0000	99.79
24.5	1,028,005		0.0000	1.0000	99.79
25.5	991,410		0.0000	1.0000	99.79
26.5	988,122		0.0000	1.0000	99.79
27.5	987,158		0.0000	1.0000	99.79
28.5	981,498		0.0000	1.0000	99.79
29.5	981,498		0.0000	1.0000	99.79
30.5	607,268		0.0000	1.0000	99.79
31.5	607,268		0.0000	1.0000	99.79
32.5	369,288		0.0000	1.0000	99.79
33.5	369,288		0.0000	1.0000	99.79
34.5	369,288		0.0000	1.0000	99.79
35.5	108,814		0.0000	1.0000	99.79
36.5	108,814		0.0000	1.0000	99.79
37.5	108,814		0.0000	1.0000	99.79
38.5	108,814		0.0000	1.0000	99.79

NEWFOUNDLAND AND LABRADOR HYDRO

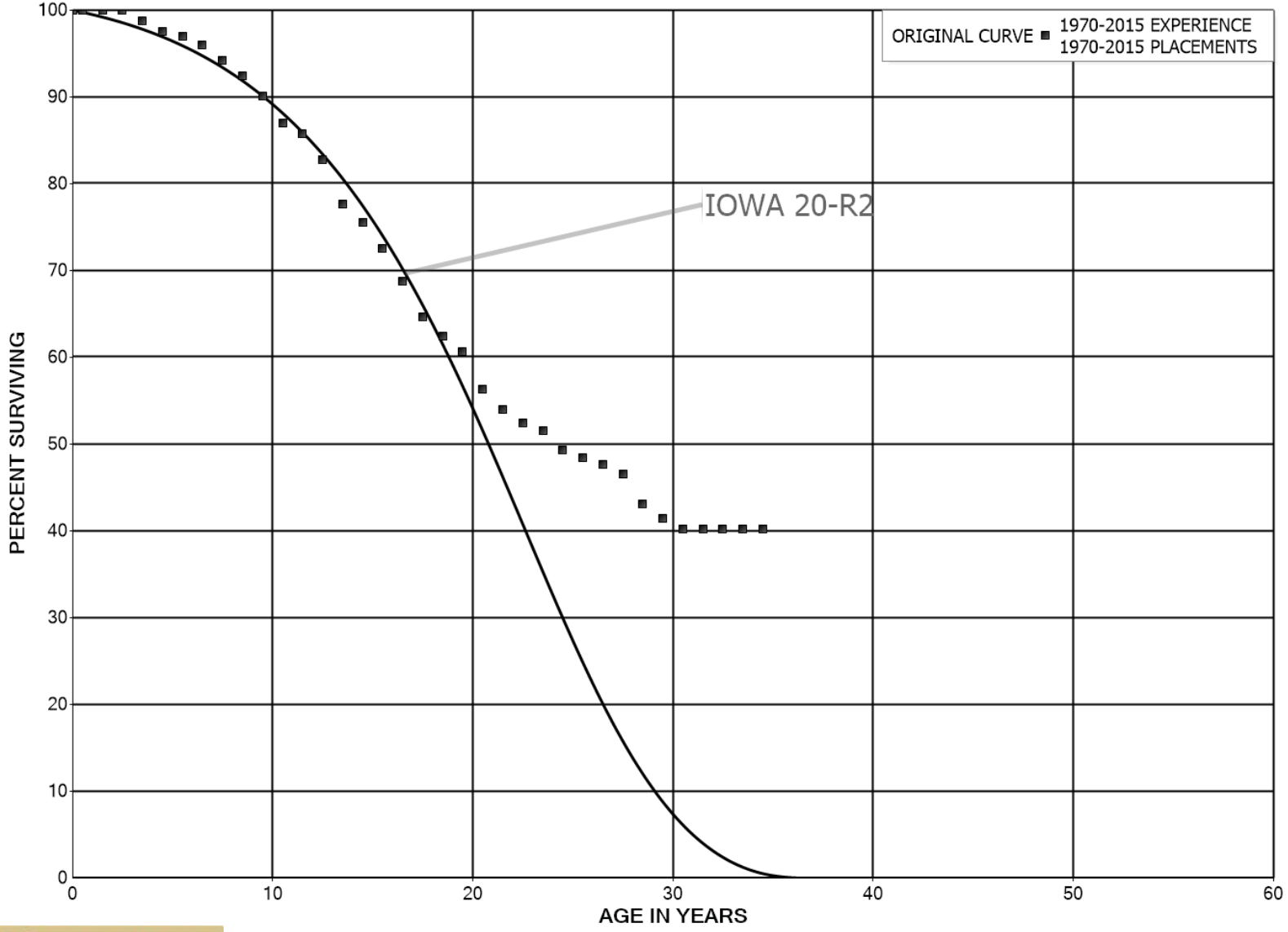
ACCOUNT S13 - STORM AND YARD DRAINAGE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2014 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	108,814		0.0000	1.0000	99.79
40.5	108,814		0.0000	1.0000	99.79
41.5	108,814		0.0000	1.0000	99.79
42.5	108,814		0.0000	1.0000	99.79
43.5	108,814		0.0000	1.0000	99.79
44.5	108,814		0.0000	1.0000	99.79
45.5	108,814		0.0000	1.0000	99.79
46.5	3,047		0.0000	1.0000	99.79
47.5	3,047		0.0000	1.0000	99.79
48.5					99.79

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S14 - STREET LIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

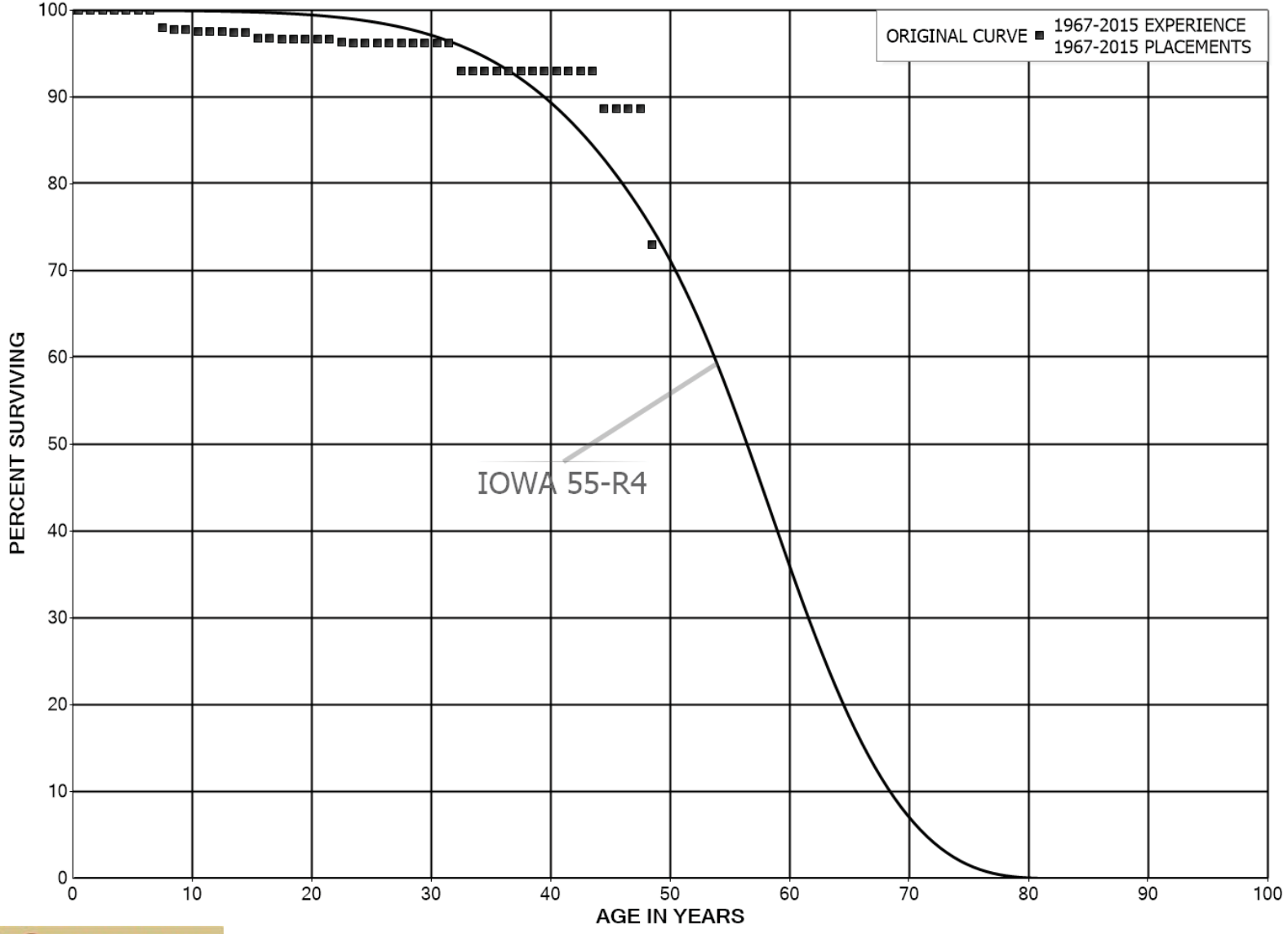
ACCOUNT S14 - STREET LIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1970-2015 EXPERIENCE BAND 1970-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	4,790,929		0.0000	1.0000	100.00
0.5	4,505,158	911	0.0002	0.9998	100.00
1.5	4,310,573	3,122	0.0007	0.9993	99.98
2.5	4,017,528	48,174	0.0120	0.9880	99.91
3.5	3,781,275	44,305	0.0117	0.9883	98.71
4.5	3,463,905	21,013	0.0061	0.9939	97.55
5.5	3,252,992	34,922	0.0107	0.9893	96.96
6.5	2,986,806	55,916	0.0187	0.9813	95.92
7.5	2,712,883	50,181	0.0185	0.9815	94.12
8.5	2,493,576	61,414	0.0246	0.9754	92.38
9.5	2,236,371	78,382	0.0350	0.9650	90.11
10.5	1,985,921	27,513	0.0139	0.9861	86.95
11.5	1,761,238	62,823	0.0357	0.9643	85.75
12.5	1,515,266	92,607	0.0611	0.9389	82.69
13.5	1,309,392	36,720	0.0280	0.9720	77.63
14.5	1,143,152	44,150	0.0386	0.9614	75.46
15.5	996,794	51,929	0.0521	0.9479	72.54
16.5	865,991	52,125	0.0602	0.9398	68.76
17.5	734,874	25,057	0.0341	0.9659	64.62
18.5	549,678	15,726	0.0286	0.9714	62.42
19.5	490,774	34,789	0.0709	0.9291	60.63
20.5	435,479	18,446	0.0424	0.9576	56.34
21.5	381,184	10,866	0.0285	0.9715	53.95
22.5	333,063	6,064	0.0182	0.9818	52.41
23.5	293,605	12,659	0.0431	0.9569	51.46
24.5	265,247	4,394	0.0166	0.9834	49.24
25.5	196,675	3,062	0.0156	0.9844	48.42
26.5	153,525	3,757	0.0245	0.9755	47.67
27.5	120,007	8,967	0.0747	0.9253	46.50
28.5	95,102	3,573	0.0376	0.9624	43.03
29.5	81,271	2,376	0.0292	0.9708	41.41
30.5	78,895		0.0000	1.0000	40.20
31.5	64,024		0.0000	1.0000	40.20
32.5	62,054		0.0000	1.0000	40.20
33.5	54,256		0.0000	1.0000	40.20
34.5					40.20

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S15 - STRUCTURAL SUPPORTS (WOOD OR STEEL)
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S15 - STRUCTURAL SUPPORTS (WOOD OR STEEL)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	12,277,223		0.0000	1.0000	100.00
0.5	12,179,460		0.0000	1.0000	100.00
1.5	11,871,197		0.0000	1.0000	100.00
2.5	11,871,197		0.0000	1.0000	100.00
3.5	10,317,542		0.0000	1.0000	100.00
4.5	10,288,677		0.0000	1.0000	100.00
5.5	10,062,423		0.0000	1.0000	100.00
6.5	9,992,435	207,829	0.0208	0.9792	100.00
7.5	9,751,260	21,304	0.0022	0.9978	97.92
8.5	9,297,859		0.0000	1.0000	97.71
9.5	9,278,982	24,028	0.0026	0.9974	97.71
10.5	9,236,985		0.0000	1.0000	97.45
11.5	9,222,195		0.0000	1.0000	97.45
12.5	9,036,221	1,793	0.0002	0.9998	97.45
13.5	8,939,304	5,431	0.0006	0.9994	97.43
14.5	8,882,032	63,993	0.0072	0.9928	97.37
15.5	8,513,296		0.0000	1.0000	96.67
16.5	8,493,894	502	0.0001	0.9999	96.67
17.5	8,296,190		0.0000	1.0000	96.67
18.5	8,240,559		0.0000	1.0000	96.67
19.5	7,961,861	500	0.0001	0.9999	96.67
20.5	7,350,657		0.0000	1.0000	96.66
21.5	7,182,086	26,788	0.0037	0.9963	96.66
22.5	7,100,924	5,780	0.0008	0.9992	96.30
23.5	6,483,604	3,186	0.0005	0.9995	96.22
24.5	6,059,754		0.0000	1.0000	96.18
25.5	5,163,851		0.0000	1.0000	96.18
26.5	4,771,442		0.0000	1.0000	96.18
27.5	4,692,431		0.0000	1.0000	96.18
28.5	4,383,596		0.0000	1.0000	96.18
29.5	4,307,874		0.0000	1.0000	96.18
30.5	4,296,130		0.0000	1.0000	96.18
31.5	4,281,964	140,974	0.0329	0.9671	96.18
32.5	3,825,207	2,126	0.0006	0.9994	93.01
33.5	3,148,194	274	0.0001	0.9999	92.96
34.5	2,886,049		0.0000	1.0000	92.95
35.5	2,632,494		0.0000	1.0000	92.95
36.5	2,266,710		0.0000	1.0000	92.95
37.5	1,426,301		0.0000	1.0000	92.95
38.5	1,272,759		0.0000	1.0000	92.95

NEWFOUNDLAND AND LABRADOR HYDRO

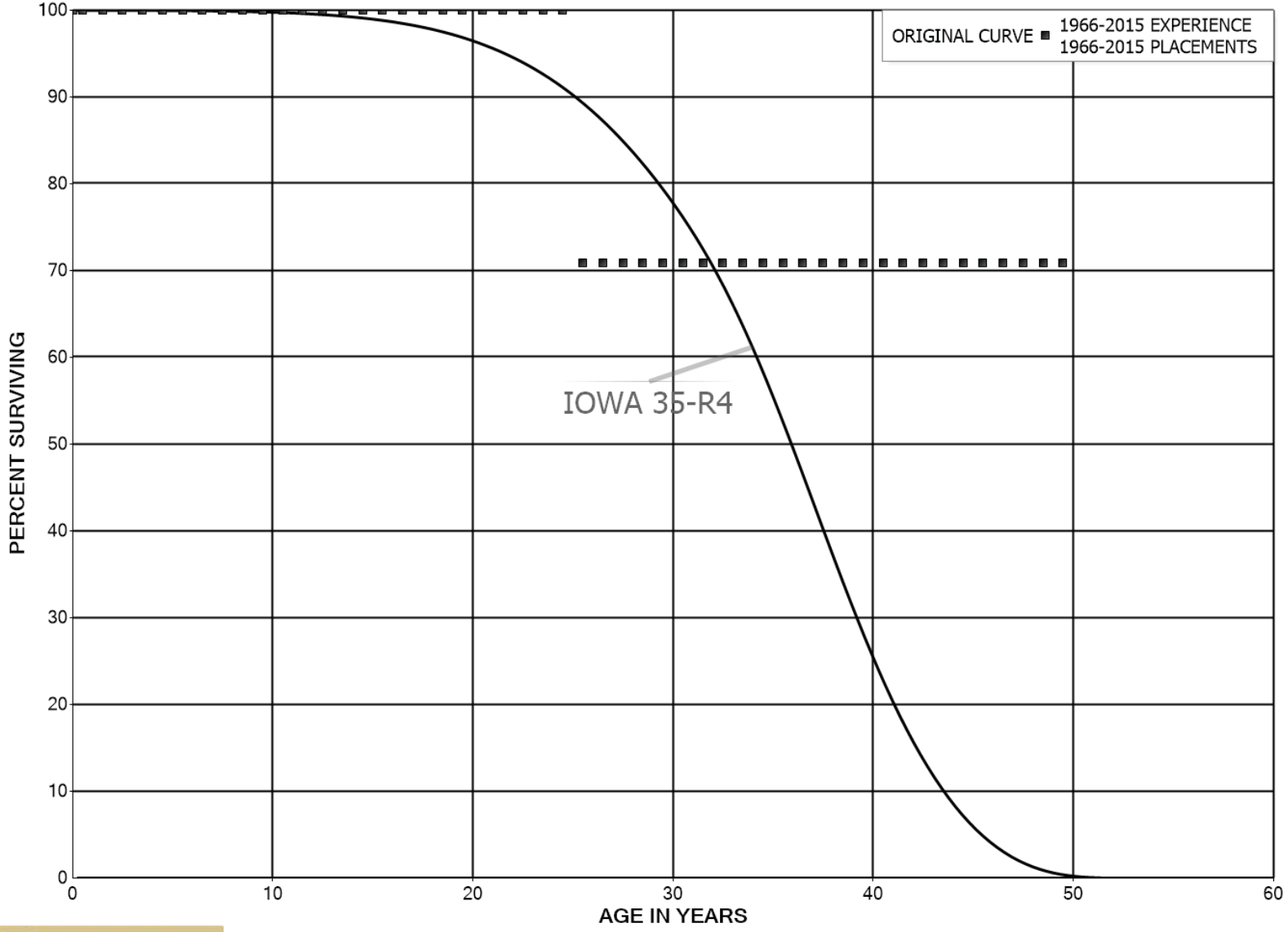
ACCOUNT S15 - STRUCTURAL SUPPORTS (WOOD OR STEEL)

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,186,025		0.0000	1.0000	92.95
40.5	1,096,654		0.0000	1.0000	92.95
41.5	1,055,841		0.0000	1.0000	92.95
42.5	1,055,841		0.0000	1.0000	92.95
43.5	1,055,841	49,499	0.0469	0.9531	92.95
44.5	1,002,463		0.0000	1.0000	88.59
45.5	377,439		0.0000	1.0000	88.59
46.5	377,439		0.0000	1.0000	88.59
47.5	259,173	45,607	0.1760	0.8240	88.59
48.5					73.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S17 - SUMP SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S17 - SUMP SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	725,064		0.0000	1.0000	100.00
0.5	296,458		0.0000	1.0000	100.00
1.5	296,458		0.0000	1.0000	100.00
2.5	296,458		0.0000	1.0000	100.00
3.5	296,458		0.0000	1.0000	100.00
4.5	296,458		0.0000	1.0000	100.00
5.5	296,458		0.0000	1.0000	100.00
6.5	220,838		0.0000	1.0000	100.00
7.5	220,838		0.0000	1.0000	100.00
8.5	220,838		0.0000	1.0000	100.00
9.5	220,838		0.0000	1.0000	100.00
10.5	220,838		0.0000	1.0000	100.00
11.5	220,838		0.0000	1.0000	100.00
12.5	220,838		0.0000	1.0000	100.00
13.5	220,838		0.0000	1.0000	100.00
14.5	220,838		0.0000	1.0000	100.00
15.5	220,838		0.0000	1.0000	100.00
16.5	197,983		0.0000	1.0000	100.00
17.5	197,983		0.0000	1.0000	100.00
18.5	197,983		0.0000	1.0000	100.00
19.5	197,983		0.0000	1.0000	100.00
20.5	197,983		0.0000	1.0000	100.00
21.5	197,983		0.0000	1.0000	100.00
22.5	197,983		0.0000	1.0000	100.00
23.5	197,983		0.0000	1.0000	100.00
24.5	197,983	57,819	0.2920	0.7080	100.00
25.5	140,164		0.0000	1.0000	70.80
26.5	140,164		0.0000	1.0000	70.80
27.5	118,404		0.0000	1.0000	70.80
28.5	118,404		0.0000	1.0000	70.80
29.5	118,404		0.0000	1.0000	70.80
30.5	116,978		0.0000	1.0000	70.80
31.5	116,978		0.0000	1.0000	70.80
32.5	116,978		0.0000	1.0000	70.80
33.5	116,978		0.0000	1.0000	70.80
34.5	116,978		0.0000	1.0000	70.80
35.5	116,978		0.0000	1.0000	70.80
36.5	62,921		0.0000	1.0000	70.80
37.5	62,921		0.0000	1.0000	70.80
38.5	62,921		0.0000	1.0000	70.80

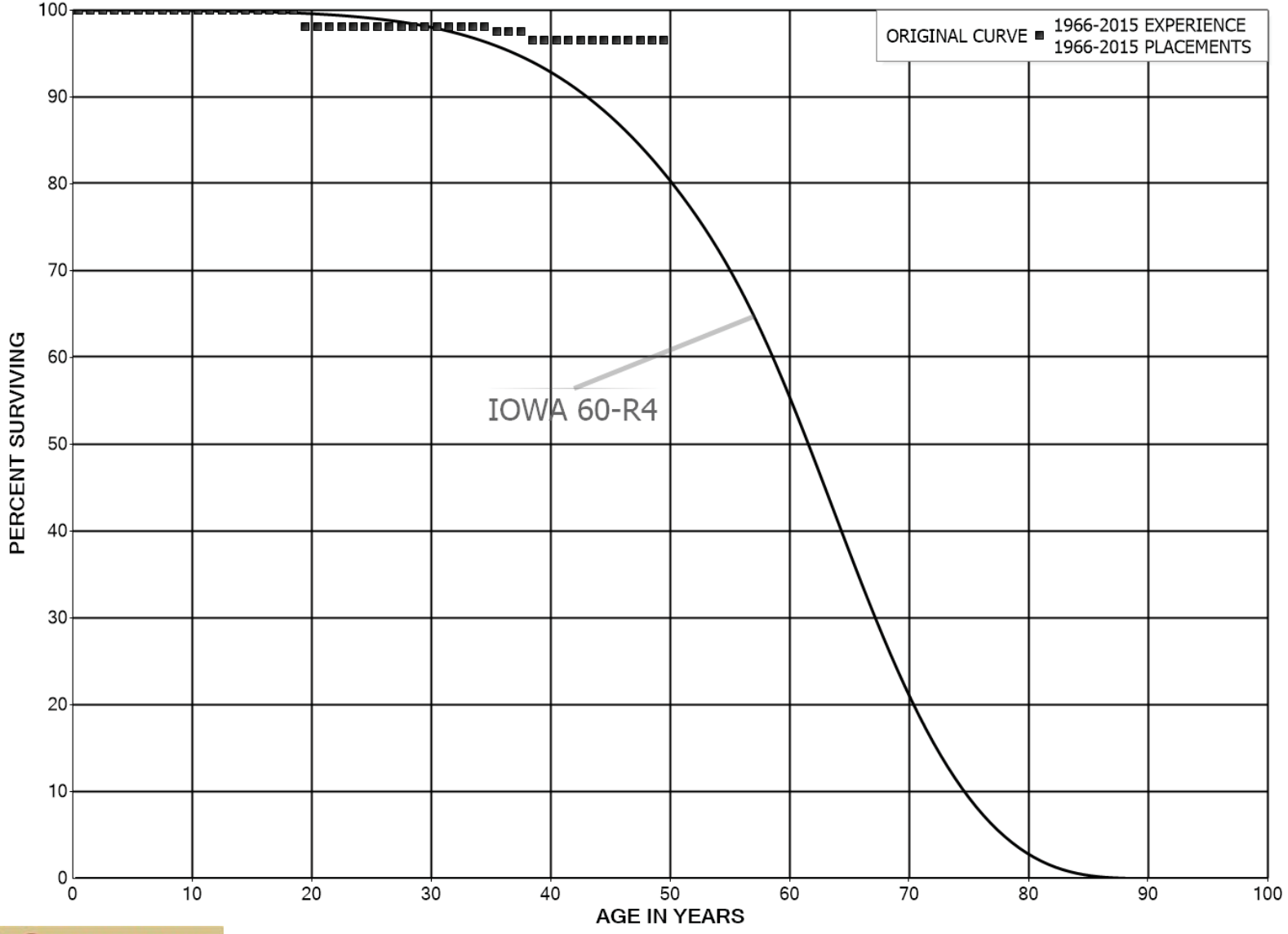
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S17 - SUMP SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015			EXPERIENCE BAND 1966-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	62,921		0.0000	1.0000	70.80
40.5	62,921		0.0000	1.0000	70.80
41.5	62,921		0.0000	1.0000	70.80
42.5	62,921		0.0000	1.0000	70.80
43.5	62,921		0.0000	1.0000	70.80
44.5	62,921		0.0000	1.0000	70.80
45.5	62,921		0.0000	1.0000	70.80
46.5	62,921		0.0000	1.0000	70.80
47.5	62,921		0.0000	1.0000	70.80
48.5	62,921		0.0000	1.0000	70.80
49.5					70.80

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S18 - SURGE SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S18 - SURGE SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,113,998		0.0000	1.0000	100.00
0.5	5,851,323		0.0000	1.0000	100.00
1.5	4,354,373		0.0000	1.0000	100.00
2.5	4,354,373		0.0000	1.0000	100.00
3.5	4,354,373		0.0000	1.0000	100.00
4.5	4,354,373		0.0000	1.0000	100.00
5.5	4,354,373		0.0000	1.0000	100.00
6.5	4,354,373		0.0000	1.0000	100.00
7.5	4,354,373		0.0000	1.0000	100.00
8.5	4,354,373		0.0000	1.0000	100.00
9.5	4,354,373		0.0000	1.0000	100.00
10.5	4,354,373		0.0000	1.0000	100.00
11.5	4,354,373		0.0000	1.0000	100.00
12.5	4,354,373		0.0000	1.0000	100.00
13.5	4,054,722		0.0000	1.0000	100.00
14.5	4,054,722		0.0000	1.0000	100.00
15.5	4,054,722		0.0000	1.0000	100.00
16.5	4,054,722		0.0000	1.0000	100.00
17.5	4,054,722		0.0000	1.0000	100.00
18.5	4,054,722	79,504	0.0196	0.9804	100.00
19.5	3,975,218		0.0000	1.0000	98.04
20.5	3,975,218		0.0000	1.0000	98.04
21.5	3,975,218		0.0000	1.0000	98.04
22.5	3,975,218		0.0000	1.0000	98.04
23.5	3,975,218		0.0000	1.0000	98.04
24.5	3,975,218		0.0000	1.0000	98.04
25.5	3,975,218		0.0000	1.0000	98.04
26.5	3,975,218		0.0000	1.0000	98.04
27.5	3,975,218		0.0000	1.0000	98.04
28.5	3,975,218		0.0000	1.0000	98.04
29.5	3,975,218		0.0000	1.0000	98.04
30.5	3,975,218		0.0000	1.0000	98.04
31.5	3,975,218		0.0000	1.0000	98.04
32.5	3,975,218		0.0000	1.0000	98.04
33.5	3,975,218		0.0000	1.0000	98.04
34.5	3,975,218	20,116	0.0051	0.9949	98.04
35.5	3,955,102		0.0000	1.0000	97.54
36.5	3,955,102		0.0000	1.0000	97.54
37.5	3,955,102	40,232	0.0102	0.9898	97.54
38.5	3,914,870		0.0000	1.0000	96.55

NEWFOUNDLAND AND LABRADOR HYDRO

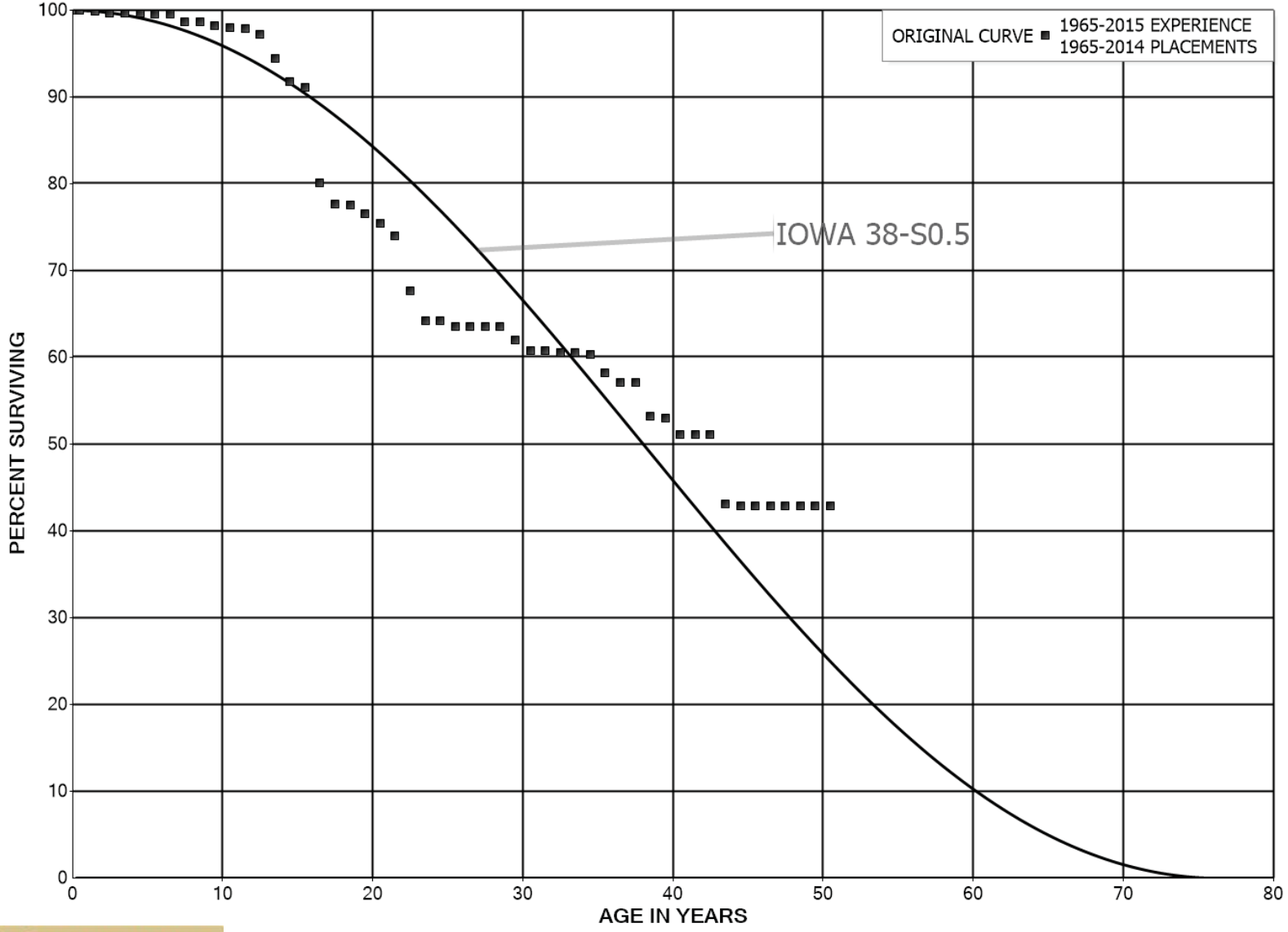
ACCOUNT S18 - SURGE SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,914,870		0.0000	1.0000	96.55
40.5	3,914,870		0.0000	1.0000	96.55
41.5	3,914,870		0.0000	1.0000	96.55
42.5	3,914,870		0.0000	1.0000	96.55
43.5	3,914,870		0.0000	1.0000	96.55
44.5	3,914,870		0.0000	1.0000	96.55
45.5	3,914,870		0.0000	1.0000	96.55
46.5	3,914,870		0.0000	1.0000	96.55
47.5	3,914,870	193	0.0000	1.0000	96.55
48.5	1,579,908	1,063	0.0007	0.9993	96.55
49.5					96.48

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S19 - STATION SWITCHING
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S19 - STATION SWITCHING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2014 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	14,987,536		0.0000	1.0000	100.00
0.5	14,987,536	30,076	0.0020	0.9980	100.00
1.5	13,544,458	30,286	0.0022	0.9978	99.80
2.5	13,389,022		0.0000	1.0000	99.58
3.5	13,328,869		0.0000	1.0000	99.58
4.5	12,879,443	11,835	0.0009	0.9991	99.58
5.5	12,867,607	3,666	0.0003	0.9997	99.48
6.5	12,863,942	112,047	0.0087	0.9913	99.46
7.5	11,847,988		0.0000	1.0000	98.59
8.5	11,460,837	45,998	0.0040	0.9960	98.59
9.5	11,271,119	28,935	0.0026	0.9974	98.19
10.5	10,988,593	10,235	0.0009	0.9991	97.94
11.5	10,969,670	73,083	0.0067	0.9933	97.85
12.5	10,295,143	296,280	0.0288	0.9712	97.20
13.5	9,183,387	260,263	0.0283	0.9717	94.40
14.5	8,056,983	58,587	0.0073	0.9927	91.73
15.5	7,587,324	915,270	0.1206	0.8794	91.06
16.5	6,641,282	203,143	0.0306	0.9694	80.07
17.5	6,213,224	13,631	0.0022	0.9978	77.63
18.5	5,699,538	71,055	0.0125	0.9875	77.46
19.5	5,482,134	75,203	0.0137	0.9863	76.49
20.5	5,372,925	108,818	0.0203	0.9797	75.44
21.5	4,954,681	421,338	0.0850	0.9150	73.91
22.5	4,533,343	232,664	0.0513	0.9487	67.63
23.5	4,054,060		0.0000	1.0000	64.16
24.5	3,987,759	43,462	0.0109	0.9891	64.16
25.5	3,879,906		0.0000	1.0000	63.46
26.5	3,754,538		0.0000	1.0000	63.46
27.5	3,730,230		0.0000	1.0000	63.46
28.5	3,679,692	85,425	0.0232	0.9768	63.46
29.5	3,559,218	70,855	0.0199	0.9801	61.98
30.5	1,027,242		0.0000	1.0000	60.75
31.5	918,837	4,141	0.0045	0.9955	60.75
32.5	914,696		0.0000	1.0000	60.48
33.5	791,491	1,920	0.0024	0.9976	60.48
34.5	724,263	25,334	0.0350	0.9650	60.33
35.5	442,403	9,003	0.0204	0.9796	58.22
36.5	433,400		0.0000	1.0000	57.03
37.5	433,400	29,596	0.0683	0.9317	57.03
38.5	403,804	1,054	0.0026	0.9974	53.14

NEWFOUNDLAND AND LABRADOR HYDRO

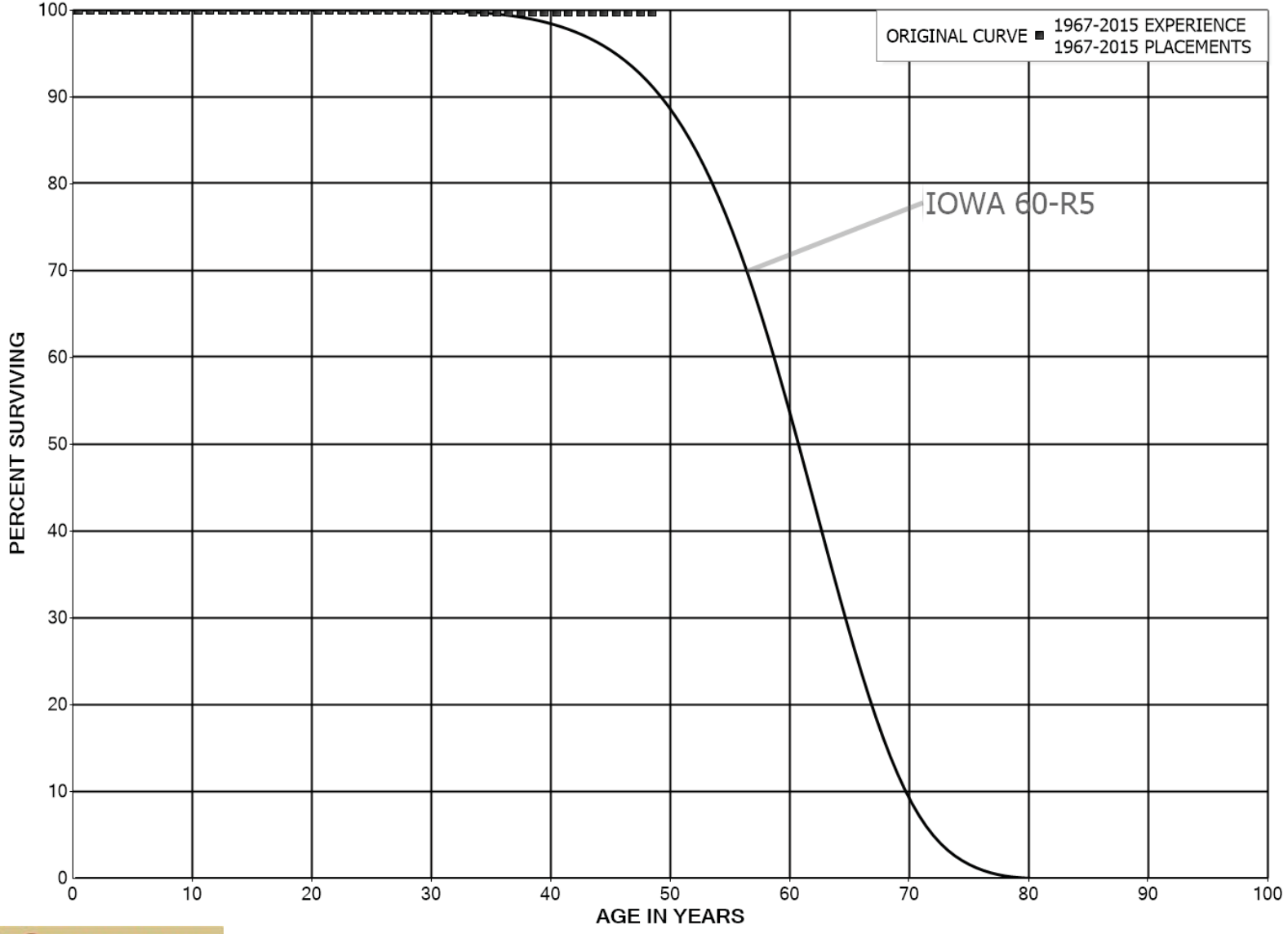
ACCOUNT S19 - STATION SWITCHING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2014 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	402,750	14,301	0.0355	0.9645	53.00
40.5	388,449		0.0000	1.0000	51.12
41.5	388,449		0.0000	1.0000	51.12
42.5	308,438	48,663	0.1578	0.8422	51.12
43.5	259,776	1,335	0.0051	0.9949	43.05
44.5	258,441		0.0000	1.0000	42.83
45.5	257,441		0.0000	1.0000	42.83
46.5	257,441		0.0000	1.0000	42.83
47.5	95,999		0.0000	1.0000	42.83
48.5	95,999		0.0000	1.0000	42.83
49.5	95,999		0.0000	1.0000	42.83
50.5					42.83

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT S20 - SWITCHING SYSTEMS - L.V.
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S20 - SWITCHING SYSTEMS - L.V.

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,306,330		0.0000	1.0000	100.00
0.5	1,960,879		0.0000	1.0000	100.00
1.5	1,811,180		0.0000	1.0000	100.00
2.5	1,811,180		0.0000	1.0000	100.00
3.5	1,809,042		0.0000	1.0000	100.00
4.5	1,809,042		0.0000	1.0000	100.00
5.5	1,809,042		0.0000	1.0000	100.00
6.5	1,809,042		0.0000	1.0000	100.00
7.5	1,809,042		0.0000	1.0000	100.00
8.5	1,809,042		0.0000	1.0000	100.00
9.5	1,809,042		0.0000	1.0000	100.00
10.5	1,809,042		0.0000	1.0000	100.00
11.5	1,809,042		0.0000	1.0000	100.00
12.5	1,809,042		0.0000	1.0000	100.00
13.5	1,809,042		0.0000	1.0000	100.00
14.5	1,809,042		0.0000	1.0000	100.00
15.5	1,809,042		0.0000	1.0000	100.00
16.5	1,809,042		0.0000	1.0000	100.00
17.5	1,809,042		0.0000	1.0000	100.00
18.5	1,809,042		0.0000	1.0000	100.00
19.5	1,809,042		0.0000	1.0000	100.00
20.5	1,809,042		0.0000	1.0000	100.00
21.5	1,809,042		0.0000	1.0000	100.00
22.5	1,809,042		0.0000	1.0000	100.00
23.5	1,809,042		0.0000	1.0000	100.00
24.5	1,809,042		0.0000	1.0000	100.00
25.5	1,809,042		0.0000	1.0000	100.00
26.5	1,795,661		0.0000	1.0000	100.00
27.5	1,795,661		0.0000	1.0000	100.00
28.5	1,795,661		0.0000	1.0000	100.00
29.5	1,795,661		0.0000	1.0000	100.00
30.5	765,324		0.0000	1.0000	100.00
31.5	765,324		0.0000	1.0000	100.00
32.5	707,369	1,722	0.0024	0.9976	100.00
33.5	364,335		0.0000	1.0000	99.76
34.5	364,335		0.0000	1.0000	99.76
35.5	71,442		0.0000	1.0000	99.76
36.5	71,442		0.0000	1.0000	99.76
37.5	28,493		0.0000	1.0000	99.76
38.5	28,493		0.0000	1.0000	99.76

NEWFOUNDLAND AND LABRADOR HYDRO

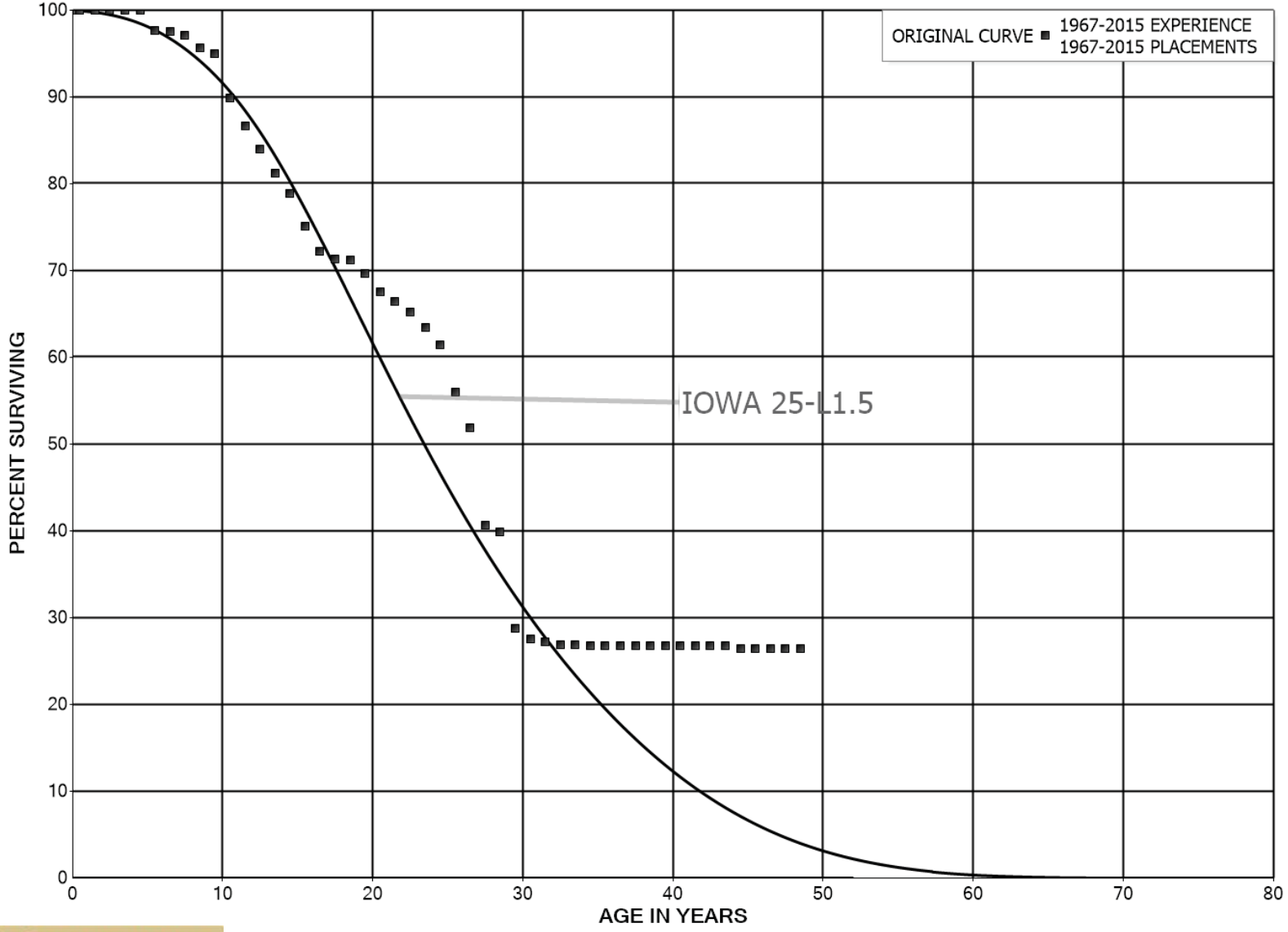
ACCOUNT S20 - SWITCHING SYSTEMS - L.V.

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	28,493		0.0000	1.0000	99.76
40.5	28,493		0.0000	1.0000	99.76
41.5	28,493		0.0000	1.0000	99.76
42.5	28,493		0.0000	1.0000	99.76
43.5	28,493		0.0000	1.0000	99.76
44.5	28,493		0.0000	1.0000	99.76
45.5	23,423		0.0000	1.0000	99.76
46.5	11,423		0.0000	1.0000	99.76
47.5	11,423		0.0000	1.0000	99.76
48.5					99.76

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT T01 - TELECONTROL SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T01 - TELECONTROL SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,199,483		0.0000	1.0000	100.00
0.5	18,510,064		0.0000	1.0000	100.00
1.5	18,310,634	1,631	0.0001	0.9999	100.00
2.5	18,000,446	11,656	0.0006	0.9994	99.99
3.5	17,202,985		0.0000	1.0000	99.93
4.5	15,075,735	352,364	0.0234	0.9766	99.93
5.5	13,947,912	4,840	0.0003	0.9997	97.59
6.5	13,789,637	66,036	0.0048	0.9952	97.56
7.5	13,042,480	194,359	0.0149	0.9851	97.09
8.5	12,692,265	88,720	0.0070	0.9930	95.64
9.5	12,486,781	673,815	0.0540	0.9460	94.97
10.5	11,743,989	420,613	0.0358	0.9642	89.85
11.5	11,138,133	348,807	0.0313	0.9687	86.63
12.5	9,517,145	315,280	0.0331	0.9669	83.92
13.5	8,914,288	249,255	0.0280	0.9720	81.14
14.5	8,035,109	391,488	0.0487	0.9513	78.87
15.5	7,410,979	287,039	0.0387	0.9613	75.03
16.5	6,465,242	70,023	0.0108	0.9892	72.12
17.5	6,274,301	10,860	0.0017	0.9983	71.34
18.5	6,033,283	136,290	0.0226	0.9774	71.22
19.5	5,746,169	174,088	0.0303	0.9697	69.61
20.5	5,232,026	86,805	0.0166	0.9834	67.50
21.5	5,145,221	91,571	0.0178	0.9822	66.38
22.5	5,044,135	135,495	0.0269	0.9731	65.20
23.5	4,698,390	152,797	0.0325	0.9675	63.45
24.5	4,536,500	401,226	0.0884	0.9116	61.38
25.5	4,067,439	297,921	0.0732	0.9268	55.95
26.5	3,744,346	815,621	0.2178	0.7822	51.86
27.5	2,916,250	52,918	0.0181	0.9819	40.56
28.5	2,830,872	790,317	0.2792	0.7208	39.82
29.5	2,040,555	85,767	0.0420	0.9580	28.71
30.5	1,829,540	18,823	0.0103	0.9897	27.50
31.5	1,797,594	22,110	0.0123	0.9877	27.22
32.5	1,775,483	4,829	0.0027	0.9973	26.88
33.5	1,745,127	8,730	0.0050	0.9950	26.81
34.5	1,736,397		0.0000	1.0000	26.67
35.5	1,057,081		0.0000	1.0000	26.67
36.5	1,057,081		0.0000	1.0000	26.67
37.5	1,028,979		0.0000	1.0000	26.67
38.5	985,184		0.0000	1.0000	26.67

NEWFOUNDLAND AND LABRADOR HYDRO

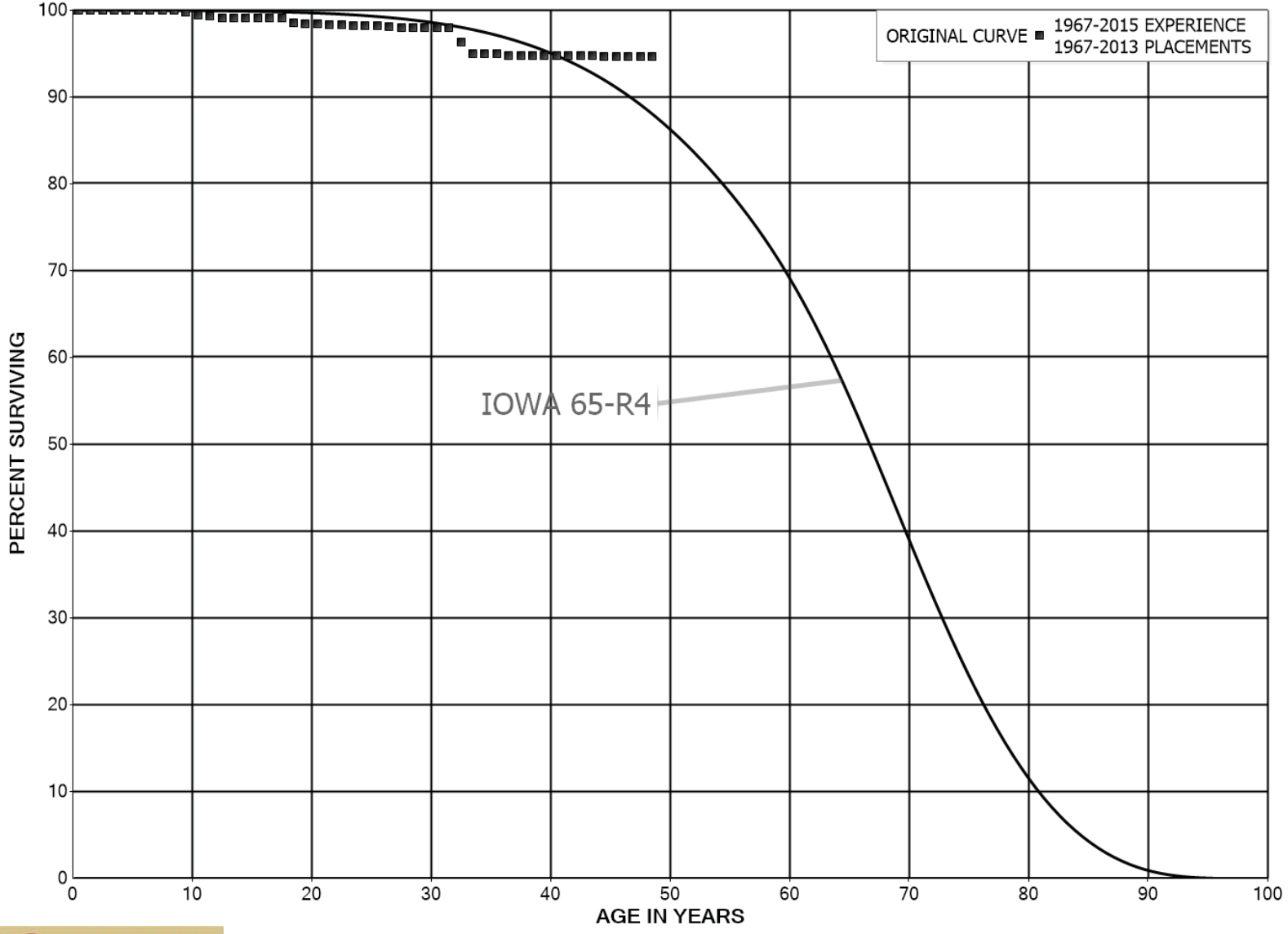
ACCOUNT T01 - TELECONTROL SYSTEM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	977,989		0.0000	1.0000	26.67
40.5	939,761		0.0000	1.0000	26.67
41.5	800,037		0.0000	1.0000	26.67
42.5	800,037		0.0000	1.0000	26.67
43.5	800,037	8,113	0.0101	0.9899	26.67
44.5	791,925		0.0000	1.0000	26.40
45.5	305,809		0.0000	1.0000	26.40
46.5	305,809		0.0000	1.0000	26.40
47.5	155,517		0.0000	1.0000	26.40
48.5					26.40

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT T04 - TOWERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T04 - TOWERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2013 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	79,600,586		0.0000	1.0000	100.00
0.5	79,600,586		0.0000	1.0000	100.00
1.5	79,600,586	7,600	0.0001	0.9999	100.00
2.5	79,567,365		0.0000	1.0000	99.99
3.5	74,039,634		0.0000	1.0000	99.99
4.5	73,866,151		0.0000	1.0000	99.99
5.5	73,763,472		0.0000	1.0000	99.99
6.5	73,763,472	2,280	0.0000	1.0000	99.99
7.5	73,761,192		0.0000	1.0000	99.99
8.5	72,263,060	170,680	0.0024	0.9976	99.99
9.5	72,092,380	232,649	0.0032	0.9968	99.75
10.5	71,859,731	121,423	0.0017	0.9983	99.43
11.5	69,685,171	164,133	0.0024	0.9976	99.26
12.5	65,326,035		0.0000	1.0000	99.03
13.5	57,728,762		0.0000	1.0000	99.03
14.5	53,667,989		0.0000	1.0000	99.03
15.5	46,005,128		0.0000	1.0000	99.03
16.5	45,193,882		0.0000	1.0000	99.03
17.5	45,193,882	236,129	0.0052	0.9948	99.03
18.5	44,957,753	44,232	0.0010	0.9990	98.51
19.5	44,884,788		0.0000	1.0000	98.41
20.5	44,884,788	81,674	0.0018	0.9982	98.41
21.5	44,803,115	959	0.0000	1.0000	98.23
22.5	44,670,344	3,412	0.0001	0.9999	98.23
23.5	44,666,932	30,006	0.0007	0.9993	98.22
24.5	43,190,983	6,005	0.0001	0.9999	98.16
25.5	39,217,234	17,827	0.0005	0.9995	98.14
26.5	38,506,736	38,423	0.0010	0.9990	98.10
27.5	37,963,098		0.0000	1.0000	98.00
28.5	37,963,098		0.0000	1.0000	98.00
29.5	37,963,098	43,091	0.0011	0.9989	98.00
30.5	23,010,552		0.0000	1.0000	97.89
31.5	22,684,833	375,208	0.0165	0.9835	97.89
32.5	17,081,479	227,210	0.0133	0.9867	96.27
33.5	16,826,528		0.0000	1.0000	94.99
34.5	16,693,350	7,750	0.0005	0.9995	94.99
35.5	16,685,600	34,169	0.0020	0.9980	94.95
36.5	16,651,431		0.0000	1.0000	94.75
37.5	16,651,431		0.0000	1.0000	94.75
38.5	12,505,973		0.0000	1.0000	94.75

NEWFOUNDLAND AND LABRADOR HYDRO

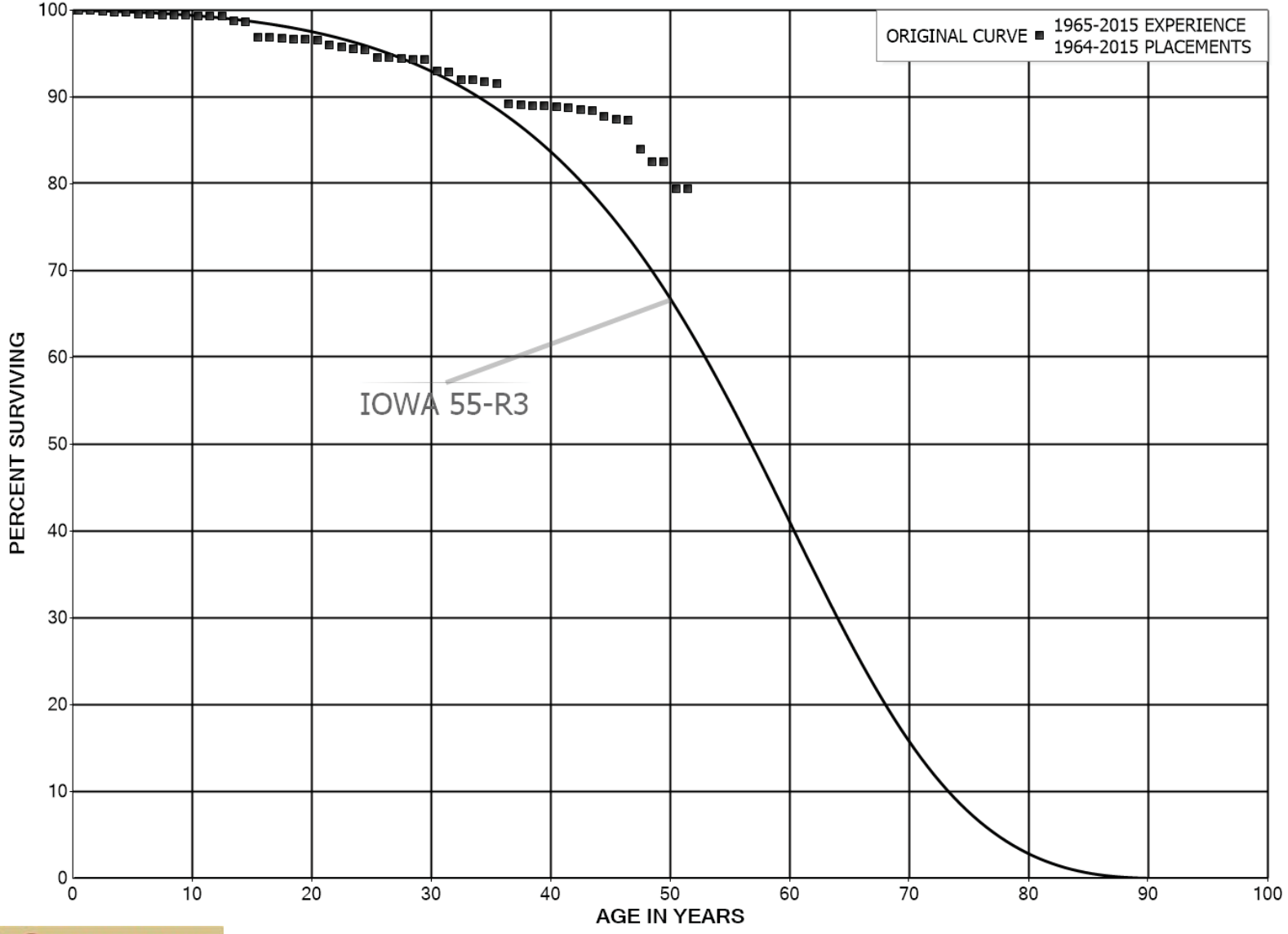
ACCOUNT T04 - TOWERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2013 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,438,050		0.0000	1.0000	94.75
40.5	12,438,050		0.0000	1.0000	94.75
41.5	12,110,026		0.0000	1.0000	94.75
42.5	12,110,026		0.0000	1.0000	94.75
43.5	12,110,026	16,304	0.0013	0.9987	94.75
44.5	12,093,722		0.0000	1.0000	94.63
45.5	11,446,353		0.0000	1.0000	94.63
46.5	11,446,353		0.0000	1.0000	94.63
47.5	7,774,613		0.0000	1.0000	94.63
48.5					94.63

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT T05 - TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T05 - TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1964-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	95,857,145		0.0000	1.0000	100.00
0.5	88,122,308	44,665	0.0005	0.9995	100.00
1.5	87,306,677	85,098	0.0010	0.9990	99.95
2.5	83,964,424	86,565	0.0010	0.9990	99.85
3.5	79,640,935	2,646	0.0000	1.0000	99.75
4.5	78,308,268	151,515	0.0019	0.9981	99.75
5.5	77,048,931	63,822	0.0008	0.9992	99.55
6.5	73,335,629	76,919	0.0010	0.9990	99.47
7.5	73,162,681	2,100	0.0000	1.0000	99.37
8.5	71,487,233		0.0000	1.0000	99.36
9.5	71,305,019	32,828	0.0005	0.9995	99.36
10.5	70,725,698	7,335	0.0001	0.9999	99.32
11.5	69,555,115	17,569	0.0003	0.9997	99.31
12.5	68,284,510	399,150	0.0058	0.9942	99.28
13.5	65,467,625	68,388	0.0010	0.9990	98.70
14.5	65,302,912	1,159,208	0.0178	0.9822	98.60
15.5	63,964,689	22,254	0.0003	0.9997	96.85
16.5	63,746,431	45,664	0.0007	0.9993	96.81
17.5	61,628,637	68,254	0.0011	0.9989	96.75
18.5	61,455,645	28,619	0.0005	0.9995	96.64
19.5	59,296,221	74,827	0.0013	0.9987	96.59
20.5	56,400,128	274,922	0.0049	0.9951	96.47
21.5	55,900,930	134,546	0.0024	0.9976	96.00
22.5	55,128,410	169,465	0.0031	0.9969	95.77
23.5	54,501,695	58,870	0.0011	0.9989	95.48
24.5	53,955,513	462,135	0.0086	0.9914	95.37
25.5	50,310,923	38,486	0.0008	0.9992	94.56
26.5	45,550,027	59,609	0.0013	0.9987	94.48
27.5	43,779,727	52,574	0.0012	0.9988	94.36
28.5	43,335,243	6,946	0.0002	0.9998	94.25
29.5	41,977,199	558,539	0.0133	0.9867	94.23
30.5	38,116,191	76,284	0.0020	0.9980	92.98
31.5	37,977,943	332,661	0.0088	0.9912	92.79
32.5	37,344,865	34,653	0.0009	0.9991	91.98
33.5	36,287,993	77,705	0.0021	0.9979	91.89
34.5	35,054,159	80,185	0.0023	0.9977	91.70
35.5	31,704,163	794,690	0.0251	0.9749	91.49
36.5	30,739,599	44,523	0.0014	0.9986	89.19
37.5	25,293,691	17,718	0.0007	0.9993	89.06
38.5	21,654,288	19,455	0.0009	0.9991	89.00

NEWFOUNDLAND AND LABRADOR HYDRO

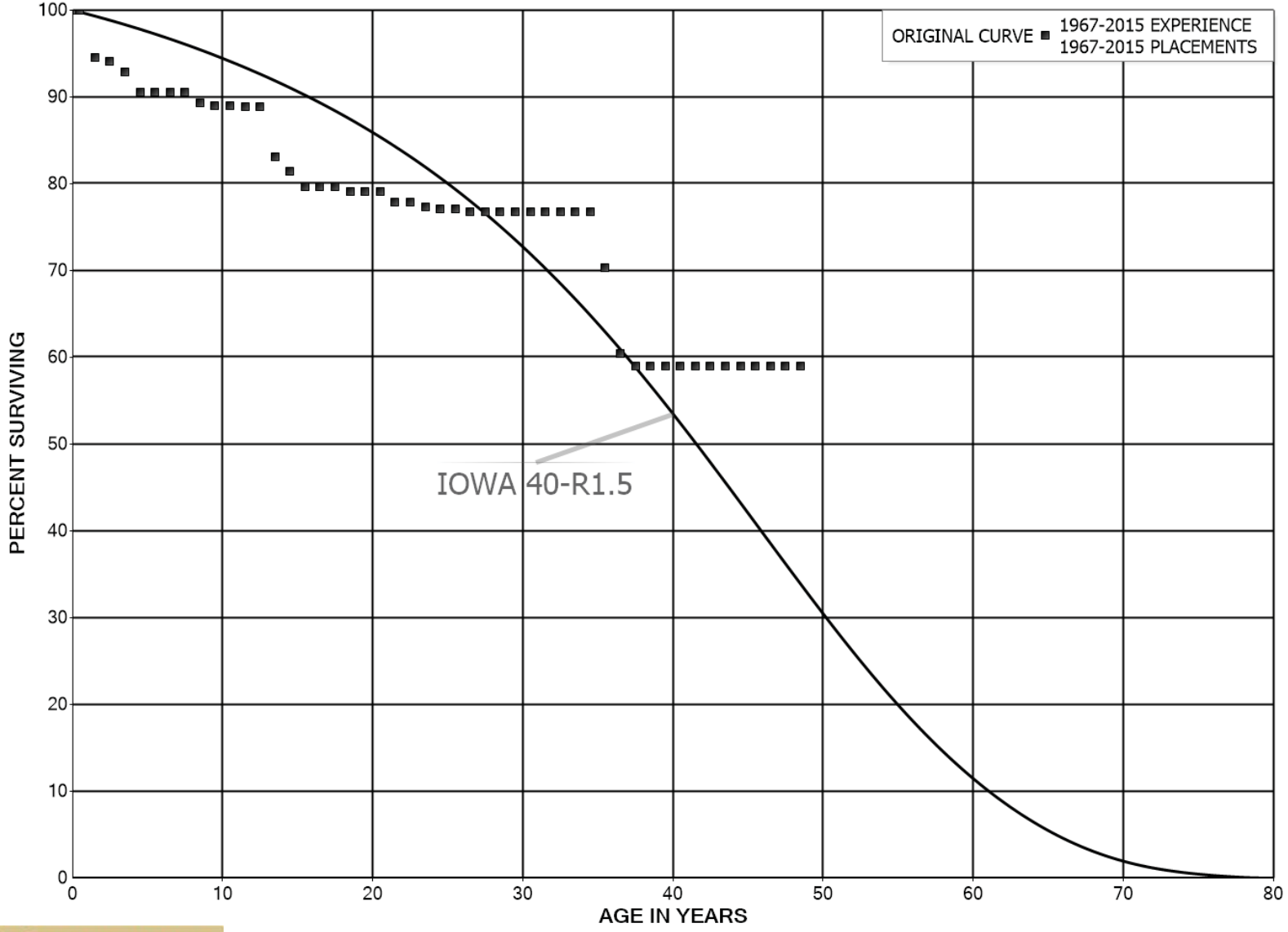
ACCOUNT T05 - TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1964-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	21,367,880	25,149	0.0012	0.9988	88.92
40.5	21,012,271	20,930	0.0010	0.9990	88.82
41.5	19,792,714	38,836	0.0020	0.9980	88.73
42.5	19,723,384	26,747	0.0014	0.9986	88.55
43.5	18,859,494	141,679	0.0075	0.9925	88.43
44.5	16,378,658	62,522	0.0038	0.9962	87.77
45.5	8,134,007	10,840	0.0013	0.9987	87.44
46.5	6,541,534	255,505	0.0391	0.9609	87.32
47.5	5,198,559	88,284	0.0170	0.9830	83.91
48.5	2,559,705		0.0000	1.0000	82.48
49.5	2,264,269	83,535	0.0369	0.9631	82.48
50.5	10,236		0.0000	1.0000	79.44
51.5					79.44

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT T06 - TRANSFORMERS - PAD MOUNT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T06 - TRANSFORMERS - PAD MOUNT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,339,323		0.0000	1.0000	100.00
0.5	19,025,934	1,037,385	0.0545	0.9455	100.00
1.5	5,438,744	30,758	0.0057	0.9943	94.55
2.5	5,236,512	67,945	0.0130	0.9870	94.01
3.5	3,461,719	85,606	0.0247	0.9753	92.79
4.5	3,222,545		0.0000	1.0000	90.50
5.5	3,042,969		0.0000	1.0000	90.50
6.5	2,910,912		0.0000	1.0000	90.50
7.5	2,600,334	35,827	0.0138	0.9862	90.50
8.5	2,466,035	8,554	0.0035	0.9965	89.25
9.5	2,358,118		0.0000	1.0000	88.94
10.5	2,291,822	1,547	0.0007	0.9993	88.94
11.5	2,220,050		0.0000	1.0000	88.88
12.5	2,189,344	143,918	0.0657	0.9343	88.88
13.5	1,952,037	38,858	0.0199	0.9801	83.04
14.5	1,557,037	34,478	0.0221	0.9779	81.39
15.5	1,480,587		0.0000	1.0000	79.58
16.5	1,434,899		0.0000	1.0000	79.58
17.5	1,434,157	8,724	0.0061	0.9939	79.58
18.5	1,353,006		0.0000	1.0000	79.10
19.5	1,196,585		0.0000	1.0000	79.10
20.5	1,186,320	18,186	0.0153	0.9847	79.10
21.5	1,028,887		0.0000	1.0000	77.89
22.5	995,883	7,468	0.0075	0.9925	77.89
23.5	895,282	2,527	0.0028	0.9972	77.30
24.5	810,675		0.0000	1.0000	77.08
25.5	810,675	4,037	0.0050	0.9950	77.08
26.5	742,670		0.0000	1.0000	76.70
27.5	742,670		0.0000	1.0000	76.70
28.5	694,732		0.0000	1.0000	76.70
29.5	694,732		0.0000	1.0000	76.70
30.5	667,713		0.0000	1.0000	76.70
31.5	653,479		0.0000	1.0000	76.70
32.5	582,832		0.0000	1.0000	76.70
33.5	455,538		0.0000	1.0000	76.70
34.5	387,862	32,374	0.0835	0.9165	76.70
35.5	355,488	50,169	0.1411	0.8589	70.30
36.5	305,319	7,311	0.0239	0.9761	60.38
37.5	298,008		0.0000	1.0000	58.93
38.5	298,008		0.0000	1.0000	58.93

NEWFOUNDLAND AND LABRADOR HYDRO

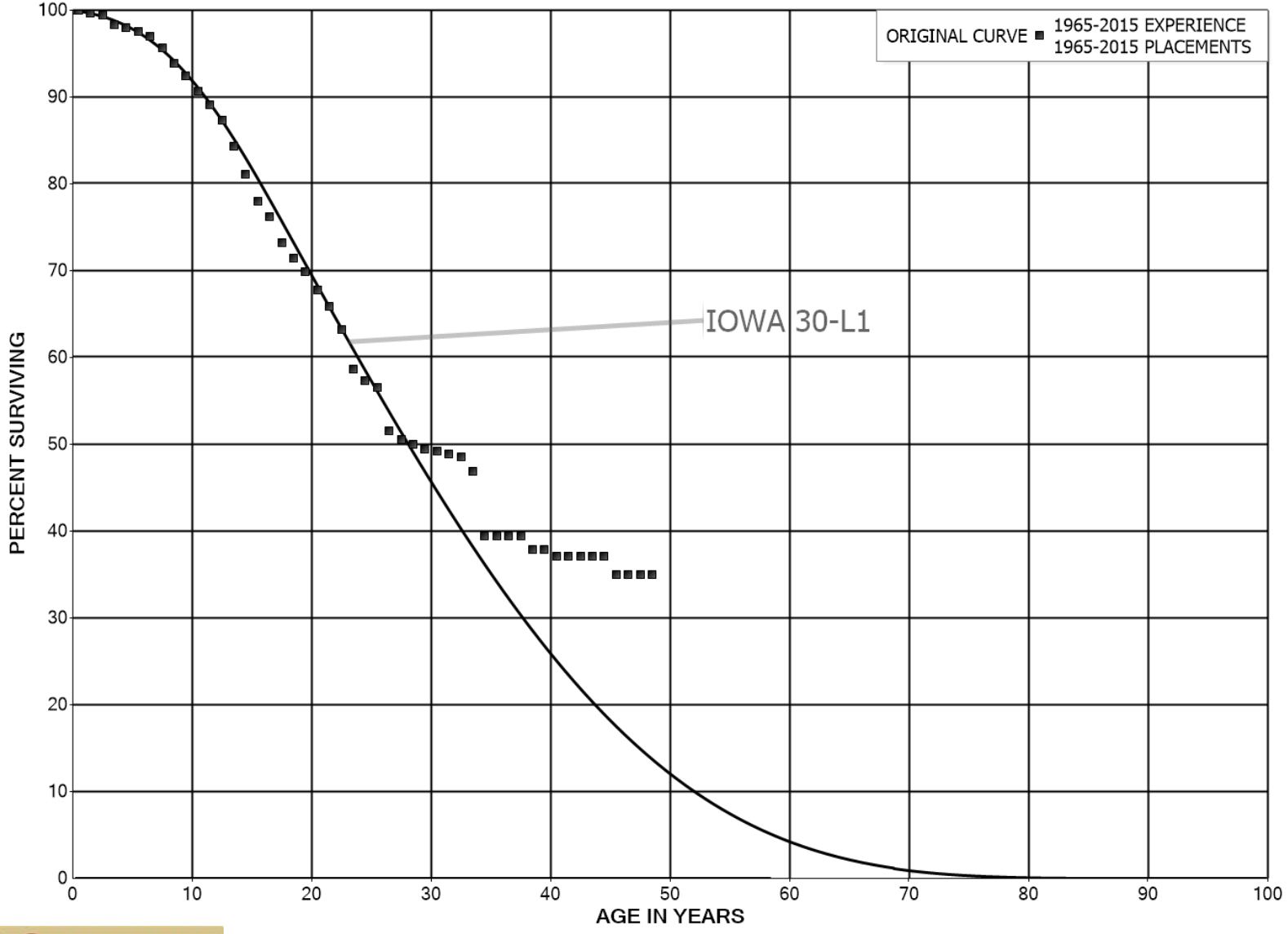
ACCOUNT T06 - TRANSFORMERS - PAD MOUNT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	298,008		0.0000	1.0000	58.93
40.5	298,008		0.0000	1.0000	58.93
41.5	274,029		0.0000	1.0000	58.93
42.5	274,029		0.0000	1.0000	58.93
43.5	274,029		0.0000	1.0000	58.93
44.5	274,029		0.0000	1.0000	58.93
45.5	195,242		0.0000	1.0000	58.93
46.5	195,242		0.0000	1.0000	58.93
47.5	85,000		0.0000	1.0000	58.93
48.5					58.93

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT T07 - TRANSFORMERS - POLE MOUNTED
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T07 - TRANSFORMERS - POLE MOUNTED

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	43,804,624		0.0000	1.0000	100.00
0.5	41,387,708	154,817	0.0037	0.9963	100.00
1.5	37,951,239	97,742	0.0026	0.9974	99.63
2.5	34,300,336	388,576	0.0113	0.9887	99.37
3.5	30,404,497	103,376	0.0034	0.9966	98.24
4.5	26,498,939	101,334	0.0038	0.9962	97.91
5.5	24,036,269	138,131	0.0057	0.9943	97.54
6.5	22,186,028	312,976	0.0141	0.9859	96.97
7.5	20,807,119	375,541	0.0180	0.9820	95.61
8.5	19,123,371	300,274	0.0157	0.9843	93.88
9.5	17,823,982	336,369	0.0189	0.9811	92.41
10.5	16,466,088	299,150	0.0182	0.9818	90.66
11.5	15,366,282	291,170	0.0189	0.9811	89.02
12.5	14,092,016	483,117	0.0343	0.9657	87.33
13.5	12,790,215	491,814	0.0385	0.9615	84.34
14.5	11,670,634	445,063	0.0381	0.9619	81.09
15.5	10,538,290	252,623	0.0240	0.9760	78.00
16.5	9,600,508	374,858	0.0390	0.9610	76.13
17.5	8,621,213	201,789	0.0234	0.9766	73.16
18.5	7,288,480	166,518	0.0228	0.9772	71.45
19.5	6,226,539	181,504	0.0292	0.9708	69.81
20.5	5,461,653	154,378	0.0283	0.9717	67.78
21.5	5,024,915	204,742	0.0407	0.9593	65.86
22.5	4,519,138	329,705	0.0730	0.9270	63.18
23.5	3,321,858	70,736	0.0213	0.9787	58.57
24.5	2,979,311	39,725	0.0133	0.9867	57.32
25.5	2,668,644	236,710	0.0887	0.9113	56.56
26.5	2,183,299	44,916	0.0206	0.9794	51.54
27.5	1,975,636	19,057	0.0096	0.9904	50.48
28.5	1,497,522	17,463	0.0117	0.9883	49.99
29.5	1,304,970	5,411	0.0041	0.9959	49.41
30.5	1,147,953	8,622	0.0075	0.9925	49.21
31.5	983,742	6,192	0.0063	0.9937	48.84
32.5	759,544	26,243	0.0346	0.9654	48.53
33.5	602,543	96,039	0.1594	0.8406	46.85
34.5	78,504		0.0000	1.0000	39.38
35.5	78,504		0.0000	1.0000	39.38
36.5	78,181		0.0000	1.0000	39.38
37.5	67,297	2,708	0.0402	0.9598	39.38
38.5	64,589		0.0000	1.0000	37.80

NEWFOUNDLAND AND LABRADOR HYDRO

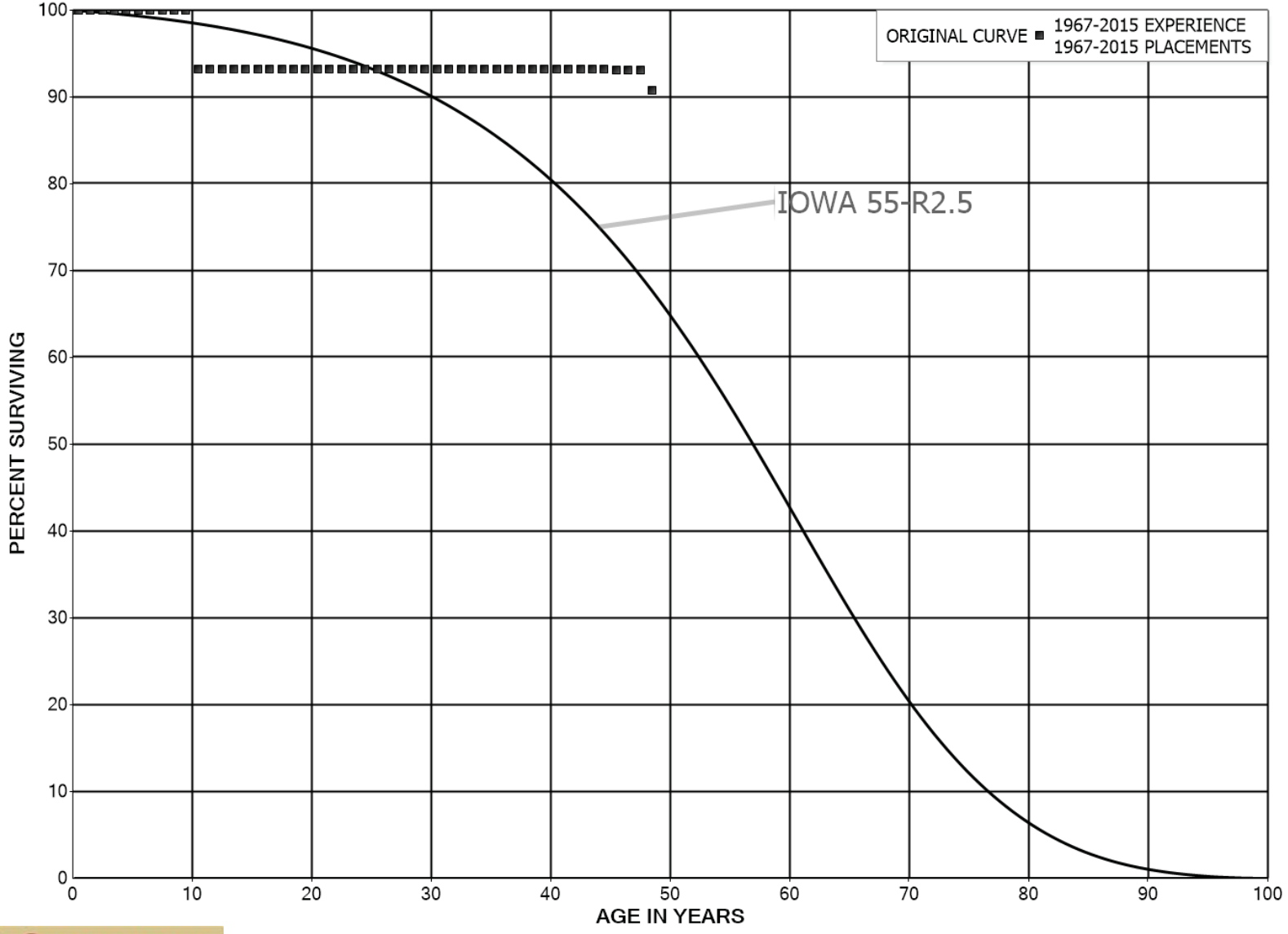
ACCOUNT T07 - TRANSFORMERS - POLE MOUNTED

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2015 EXPERIENCE BAND 1965-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	64,589	1,253	0.0194	0.9806	37.80
40.5	63,335		0.0000	1.0000	37.07
41.5	63,335		0.0000	1.0000	37.07
42.5	63,335		0.0000	1.0000	37.07
43.5	63,335		0.0000	1.0000	37.07
44.5	63,024	3,526	0.0559	0.9441	37.07
45.5	16,201		0.0000	1.0000	34.99
46.5	16,201		0.0000	1.0000	34.99
47.5	12,695		0.0000	1.0000	34.99
48.5					34.99

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT T09 - TURBINES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T09 - TURBINES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	104,485,714		0.0000	1.0000	100.00
0.5	92,867,454		0.0000	1.0000	100.00
1.5	87,453,107		0.0000	1.0000	100.00
2.5	74,877,766		0.0000	1.0000	100.00
3.5	73,185,902		0.0000	1.0000	100.00
4.5	73,185,902		0.0000	1.0000	100.00
5.5	72,755,889		0.0000	1.0000	100.00
6.5	71,700,417		0.0000	1.0000	100.00
7.5	71,700,417		0.0000	1.0000	100.00
8.5	69,995,413		0.0000	1.0000	100.00
9.5	69,078,643	4,678,499	0.0677	0.9323	100.00
10.5	64,400,143		0.0000	1.0000	93.23
11.5	64,400,143		0.0000	1.0000	93.23
12.5	52,470,546		0.0000	1.0000	93.23
13.5	52,470,546		0.0000	1.0000	93.23
14.5	52,470,546		0.0000	1.0000	93.23
15.5	52,470,546		0.0000	1.0000	93.23
16.5	52,470,546		0.0000	1.0000	93.23
17.5	52,470,546		0.0000	1.0000	93.23
18.5	52,470,546		0.0000	1.0000	93.23
19.5	52,470,546		0.0000	1.0000	93.23
20.5	52,468,967		0.0000	1.0000	93.23
21.5	52,468,967		0.0000	1.0000	93.23
22.5	52,468,967		0.0000	1.0000	93.23
23.5	52,468,967		0.0000	1.0000	93.23
24.5	52,468,967		0.0000	1.0000	93.23
25.5	52,468,967		0.0000	1.0000	93.23
26.5	50,881,792		0.0000	1.0000	93.23
27.5	43,971,956		0.0000	1.0000	93.23
28.5	43,963,063		0.0000	1.0000	93.23
29.5	43,963,063		0.0000	1.0000	93.23
30.5	33,036,048		0.0000	1.0000	93.23
31.5	33,036,048		0.0000	1.0000	93.23
32.5	32,989,272		0.0000	1.0000	93.23
33.5	25,897,915		0.0000	1.0000	93.23
34.5	25,897,915		0.0000	1.0000	93.23
35.5	16,711,577		0.0000	1.0000	93.23
36.5	16,711,577		0.0000	1.0000	93.23
37.5	12,468,906	2,201	0.0002	0.9998	93.23
38.5	12,248,799		0.0000	1.0000	93.21

NEWFOUNDLAND AND LABRADOR HYDRO

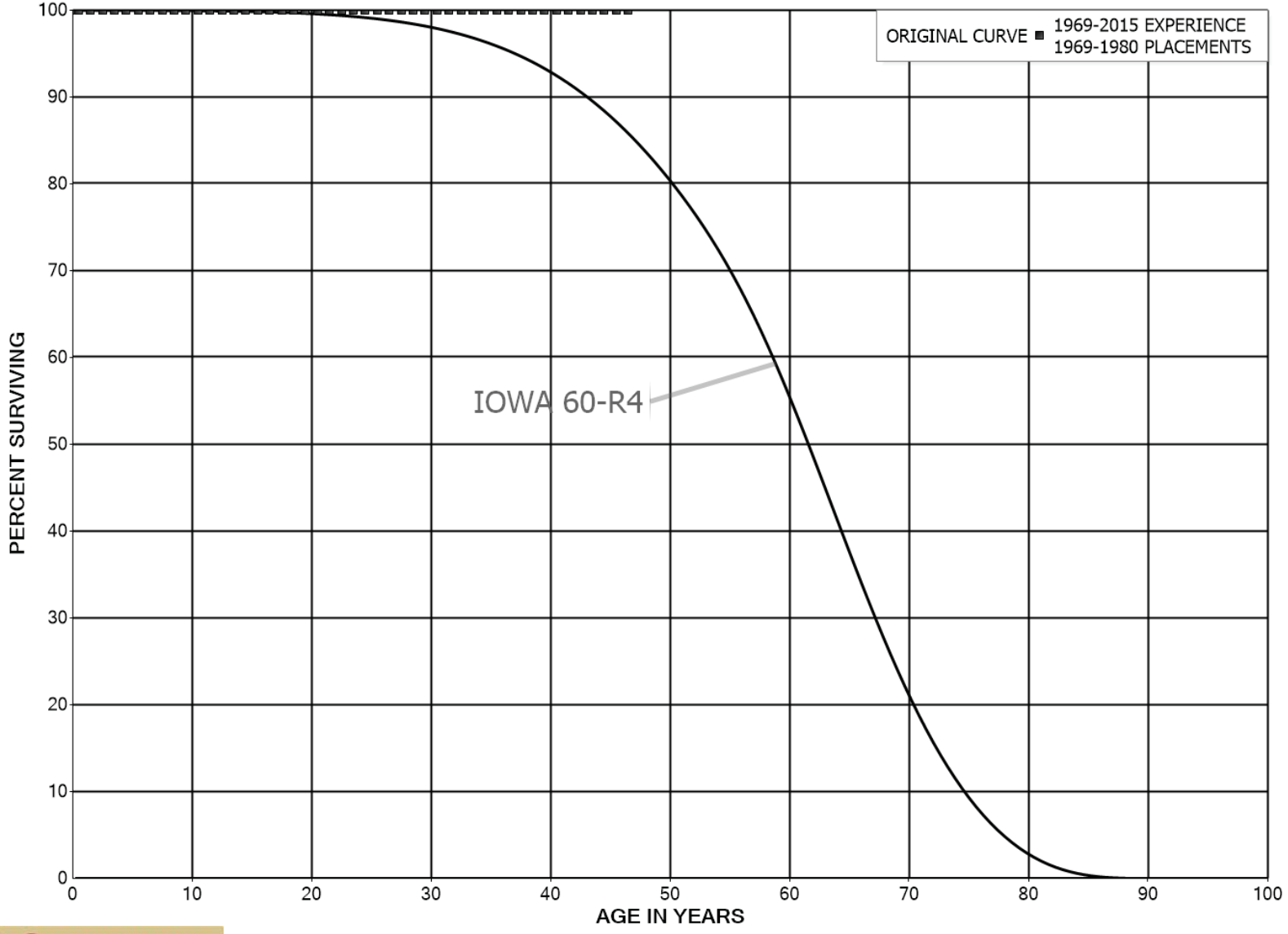
ACCOUNT T09 - TURBINES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	12,248,799		0.0000	1.0000	93.21
40.5	12,146,926		0.0000	1.0000	93.21
41.5	12,146,926		0.0000	1.0000	93.21
42.5	12,146,926	5,339	0.0004	0.9996	93.21
43.5	12,141,587	5,339	0.0004	0.9996	93.17
44.5	12,110,248	8,333	0.0007	0.9993	93.13
45.5	10,418,575		0.0000	1.0000	93.06
46.5	10,418,575	4,593	0.0004	0.9996	93.06
47.5	1,806,578	43,789	0.0242	0.9758	93.02
48.5					90.77

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V01 - VACUUM CLEANING SYSTEM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V01 - VACUUM CLEANING SYSTEM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1969-1980 EXPERIENCE BAND 1969-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	72,451		0.0000	1.0000	100.00
0.5	72,451		0.0000	1.0000	100.00
1.5	72,451		0.0000	1.0000	100.00
2.5	72,451		0.0000	1.0000	100.00
3.5	72,451		0.0000	1.0000	100.00
4.5	72,451		0.0000	1.0000	100.00
5.5	72,451		0.0000	1.0000	100.00
6.5	72,451		0.0000	1.0000	100.00
7.5	72,451		0.0000	1.0000	100.00
8.5	72,451		0.0000	1.0000	100.00
9.5	72,451		0.0000	1.0000	100.00
10.5	72,451		0.0000	1.0000	100.00
11.5	72,451		0.0000	1.0000	100.00
12.5	72,451		0.0000	1.0000	100.00
13.5	72,451		0.0000	1.0000	100.00
14.5	72,451		0.0000	1.0000	100.00
15.5	72,451		0.0000	1.0000	100.00
16.5	72,451		0.0000	1.0000	100.00
17.5	72,451		0.0000	1.0000	100.00
18.5	72,451		0.0000	1.0000	100.00
19.5	72,451		0.0000	1.0000	100.00
20.5	72,451		0.0000	1.0000	100.00
21.5	72,451		0.0000	1.0000	100.00
22.5	72,451		0.0000	1.0000	100.00
23.5	72,451		0.0000	1.0000	100.00
24.5	72,451		0.0000	1.0000	100.00
25.5	72,451		0.0000	1.0000	100.00
26.5	72,451		0.0000	1.0000	100.00
27.5	72,451		0.0000	1.0000	100.00
28.5	72,451		0.0000	1.0000	100.00
29.5	72,451		0.0000	1.0000	100.00
30.5	72,451		0.0000	1.0000	100.00
31.5	72,451		0.0000	1.0000	100.00
32.5	72,451		0.0000	1.0000	100.00
33.5	72,451		0.0000	1.0000	100.00
34.5	72,451		0.0000	1.0000	100.00
35.5	23,574		0.0000	1.0000	100.00
36.5	23,574		0.0000	1.0000	100.00
37.5	23,574		0.0000	1.0000	100.00
38.5	23,574		0.0000	1.0000	100.00

NEWFOUNDLAND AND LABRADOR HYDRO

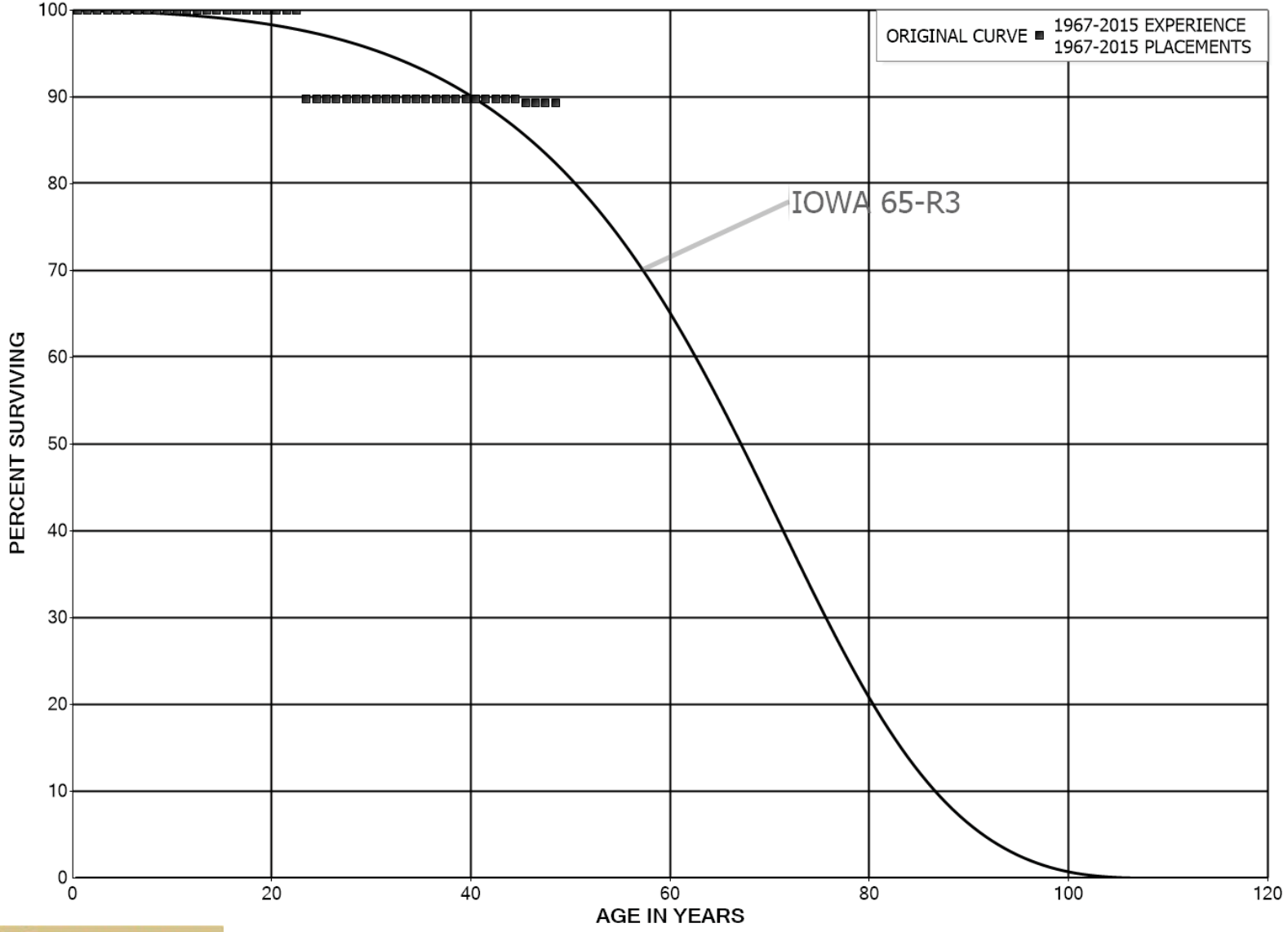
ACCOUNT V01 - VACUUM CLEANING SYSTEM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1969-1980 EXPERIENCE BAND 1969-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	23,574		0.0000	1.0000	100.00
40.5	23,574		0.0000	1.0000	100.00
41.5	23,574		0.0000	1.0000	100.00
42.5	23,574		0.0000	1.0000	100.00
43.5	23,574		0.0000	1.0000	100.00
44.5	23,574		0.0000	1.0000	100.00
45.5	23,574		0.0000	1.0000	100.00
46.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V02 - VALVES - PENSTOCK
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V02 - VALVES - PENSTOCK

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	8,073,931		0.0000	1.0000	100.00
0.5	7,853,424		0.0000	1.0000	100.00
1.5	7,853,424		0.0000	1.0000	100.00
2.5	7,853,424		0.0000	1.0000	100.00
3.5	7,853,424		0.0000	1.0000	100.00
4.5	7,853,424		0.0000	1.0000	100.00
5.5	7,853,424		0.0000	1.0000	100.00
6.5	7,853,424		0.0000	1.0000	100.00
7.5	5,978,246		0.0000	1.0000	100.00
8.5	5,848,451		0.0000	1.0000	100.00
9.5	5,671,553		0.0000	1.0000	100.00
10.5	5,459,235		0.0000	1.0000	100.00
11.5	5,247,883		0.0000	1.0000	100.00
12.5	5,011,386		0.0000	1.0000	100.00
13.5	5,011,386		0.0000	1.0000	100.00
14.5	4,816,450		0.0000	1.0000	100.00
15.5	4,816,450		0.0000	1.0000	100.00
16.5	4,816,450		0.0000	1.0000	100.00
17.5	4,816,450		0.0000	1.0000	100.00
18.5	4,816,450		0.0000	1.0000	100.00
19.5	4,816,450		0.0000	1.0000	100.00
20.5	4,816,450		0.0000	1.0000	100.00
21.5	4,816,450		0.0000	1.0000	100.00
22.5	4,816,450	497,499	0.1033	0.8967	100.00
23.5	4,318,951		0.0000	1.0000	89.67
24.5	4,318,951		0.0000	1.0000	89.67
25.5	4,318,951		0.0000	1.0000	89.67
26.5	4,318,951		0.0000	1.0000	89.67
27.5	4,316,519		0.0000	1.0000	89.67
28.5	4,316,519		0.0000	1.0000	89.67
29.5	4,316,519		0.0000	1.0000	89.67
30.5	2,111,625		0.0000	1.0000	89.67
31.5	2,111,625		0.0000	1.0000	89.67
32.5	2,111,625		0.0000	1.0000	89.67
33.5	2,089,406		0.0000	1.0000	89.67
34.5	2,089,406		0.0000	1.0000	89.67
35.5	2,089,406		0.0000	1.0000	89.67
36.5	2,089,406		0.0000	1.0000	89.67
37.5	2,089,406		0.0000	1.0000	89.67
38.5	1,985,406		0.0000	1.0000	89.67

NEWFOUNDLAND AND LABRADOR HYDRO

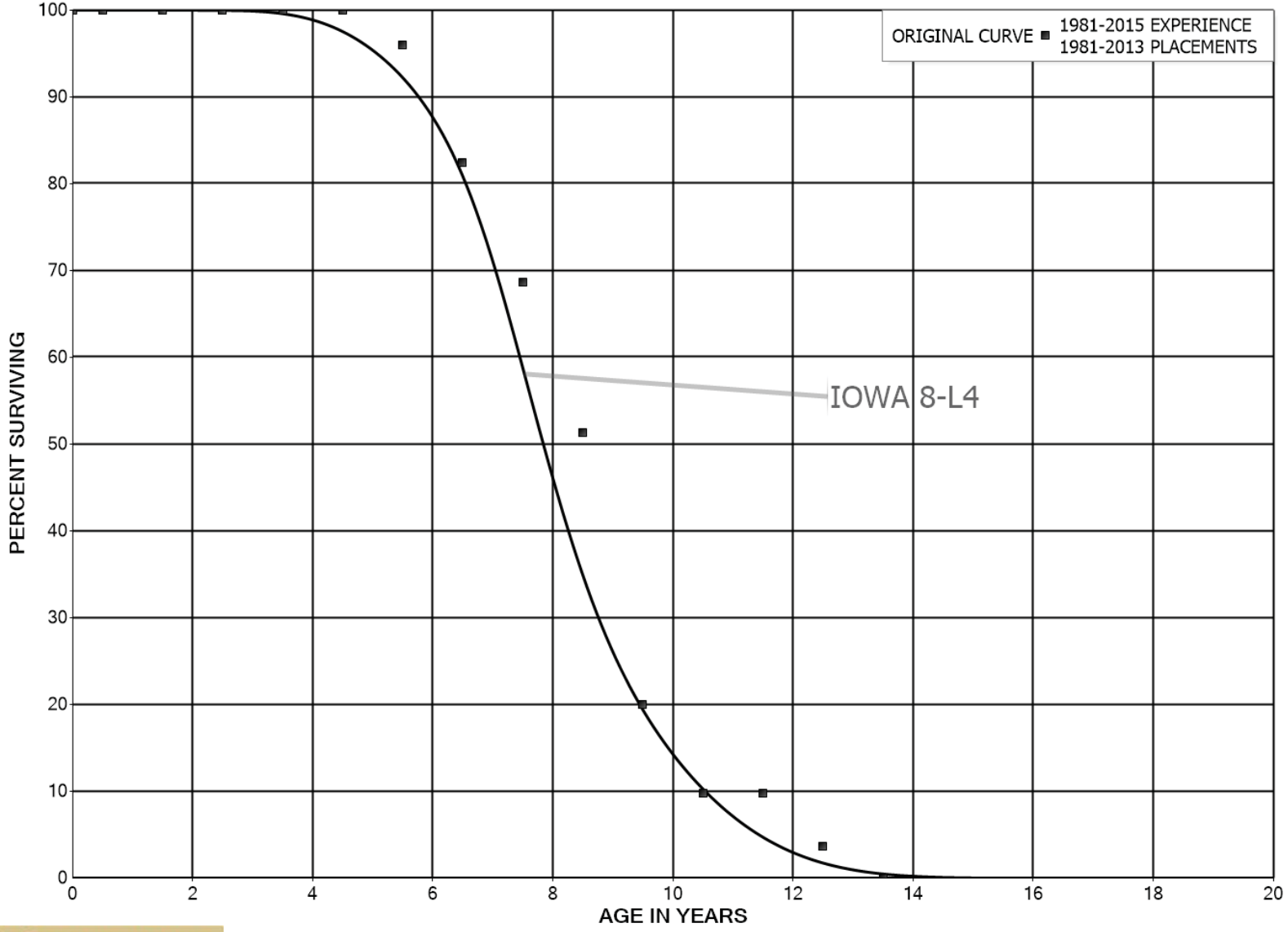
ACCOUNT V02 - VALVES - PENSTOCK

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2015 EXPERIENCE BAND 1967-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,985,406		0.0000	1.0000	89.67
40.5	1,971,105		0.0000	1.0000	89.67
41.5	1,971,105		0.0000	1.0000	89.67
42.5	1,971,105		0.0000	1.0000	89.67
43.5	1,971,105		0.0000	1.0000	89.67
44.5	1,971,105	8,672	0.0044	0.9956	89.67
45.5	1,415,205		0.0000	1.0000	89.28
46.5	1,415,205		0.0000	1.0000	89.28
47.5	1,415,205		0.0000	1.0000	89.28
48.5					89.28

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V03 - VEHICLES - 1 TON
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

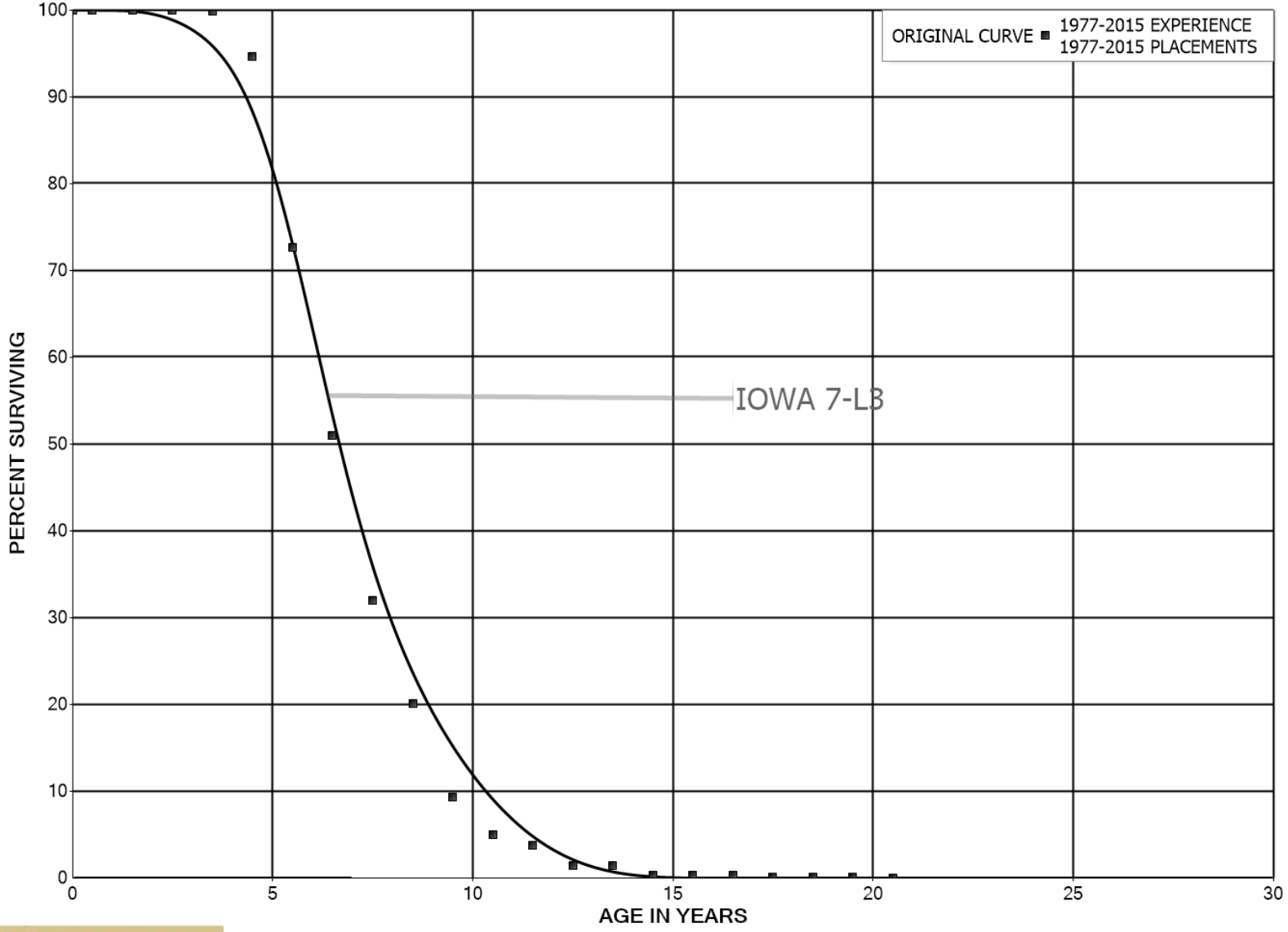
ACCOUNT V03 - VEHICLES - 1 TON

ORIGINAL LIFE TABLE

PLACEMENT BAND 1981-2013 EXPERIENCE BAND 1981-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	379,343		0.0000	1.0000	100.00
0.5	379,343		0.0000	1.0000	100.00
1.5	379,343		0.0000	1.0000	100.00
2.5	327,695		0.0000	1.0000	100.00
3.5	327,695		0.0000	1.0000	100.00
4.5	327,695	13,283	0.0405	0.9595	100.00
5.5	314,412	44,240	0.1407	0.8593	95.95
6.5	270,173	45,393	0.1680	0.8320	82.45
7.5	224,780	56,766	0.2525	0.7475	68.59
8.5	168,014	102,809	0.6119	0.3881	51.27
9.5	65,206	33,491	0.5136	0.4864	19.90
10.5	31,715		0.0000	1.0000	9.68
11.5	31,715	19,876	0.6267	0.3733	9.68
12.5	11,838	11,838	1.0000		3.61
13.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V04 - VEHICLES - 3/4 TON AND UNDER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

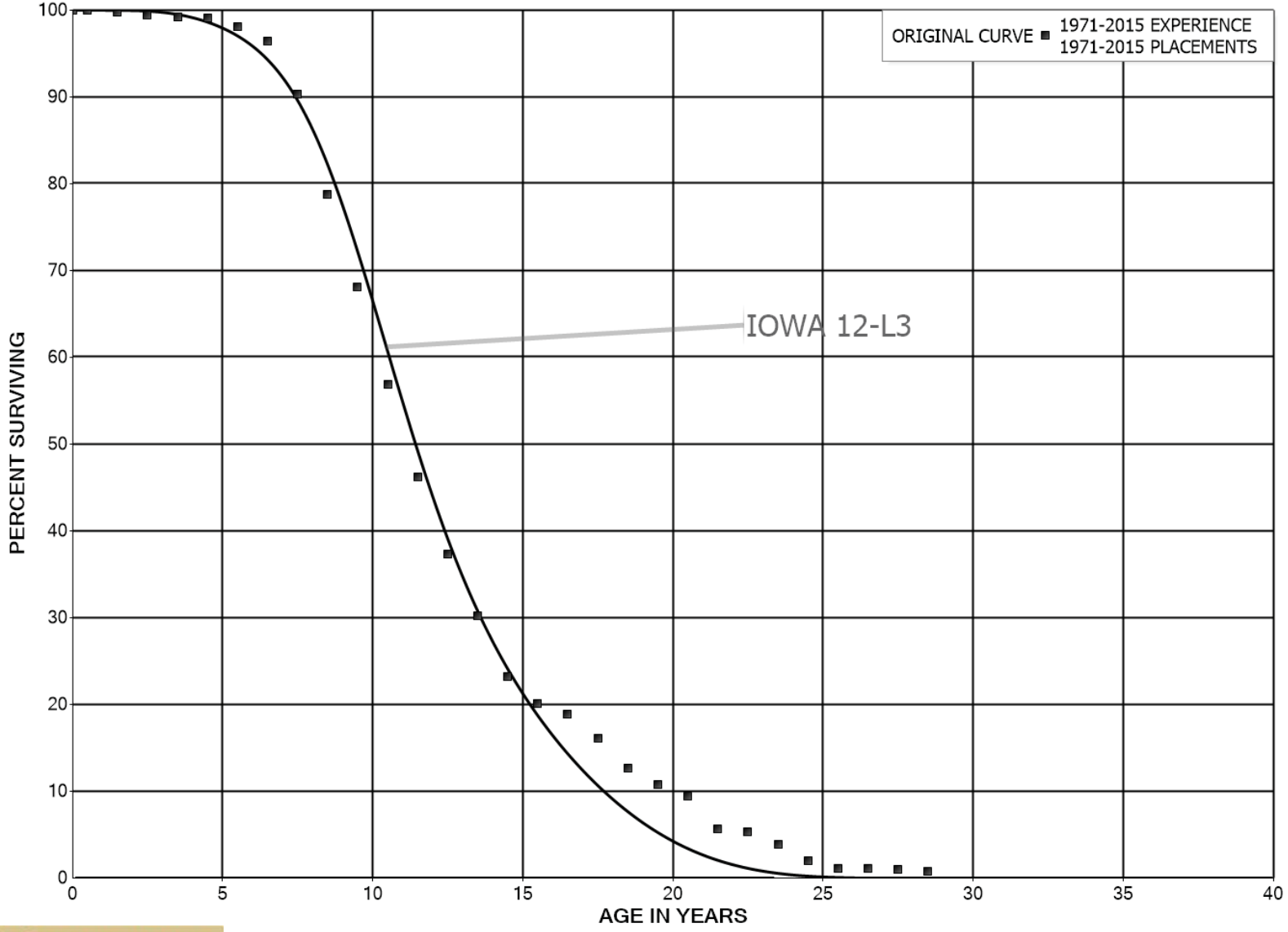
ACCOUNT V04 - VEHICLES - 3/4 TON AND UNDER

ORIGINAL LIFE TABLE

PLACEMENT BAND 1977-2015 EXPERIENCE BAND 1977-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,593,915		0.0000	1.0000	100.00
0.5	12,522,318		0.0000	1.0000	100.00
1.5	11,803,485		0.0000	1.0000	100.00
2.5	11,521,445	14,631	0.0013	0.9987	100.00
3.5	10,756,433	568,573	0.0529	0.9471	99.87
4.5	9,466,923	2,199,136	0.2323	0.7677	94.59
5.5	6,450,055	1,927,343	0.2988	0.7012	72.62
6.5	4,070,137	1,512,403	0.3716	0.6284	50.92
7.5	2,481,830	923,593	0.3721	0.6279	32.00
8.5	1,302,139	698,230	0.5362	0.4638	20.09
9.5	603,909	286,197	0.4739	0.5261	9.32
10.5	317,713	79,109	0.2490	0.7510	4.90
11.5	217,530	133,534	0.6139	0.3861	3.68
12.5	83,997	3,550	0.0423	0.9577	1.42
13.5	80,446	62,639	0.7786	0.2214	1.36
14.5	17,807		0.0000	1.0000	0.30
15.5	17,807	2,532	0.1422	0.8578	0.30
16.5	15,275	8,795	0.5758	0.4242	0.26
17.5	6,480		0.0000	1.0000	0.11
18.5	6,480	4,537	0.7001	0.2999	0.11
19.5	1,943	1,943	1.0000		0.03
20.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V05 - VEHICLES - BOOMS/BODIES/CRANES/CAB/CHASSIS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

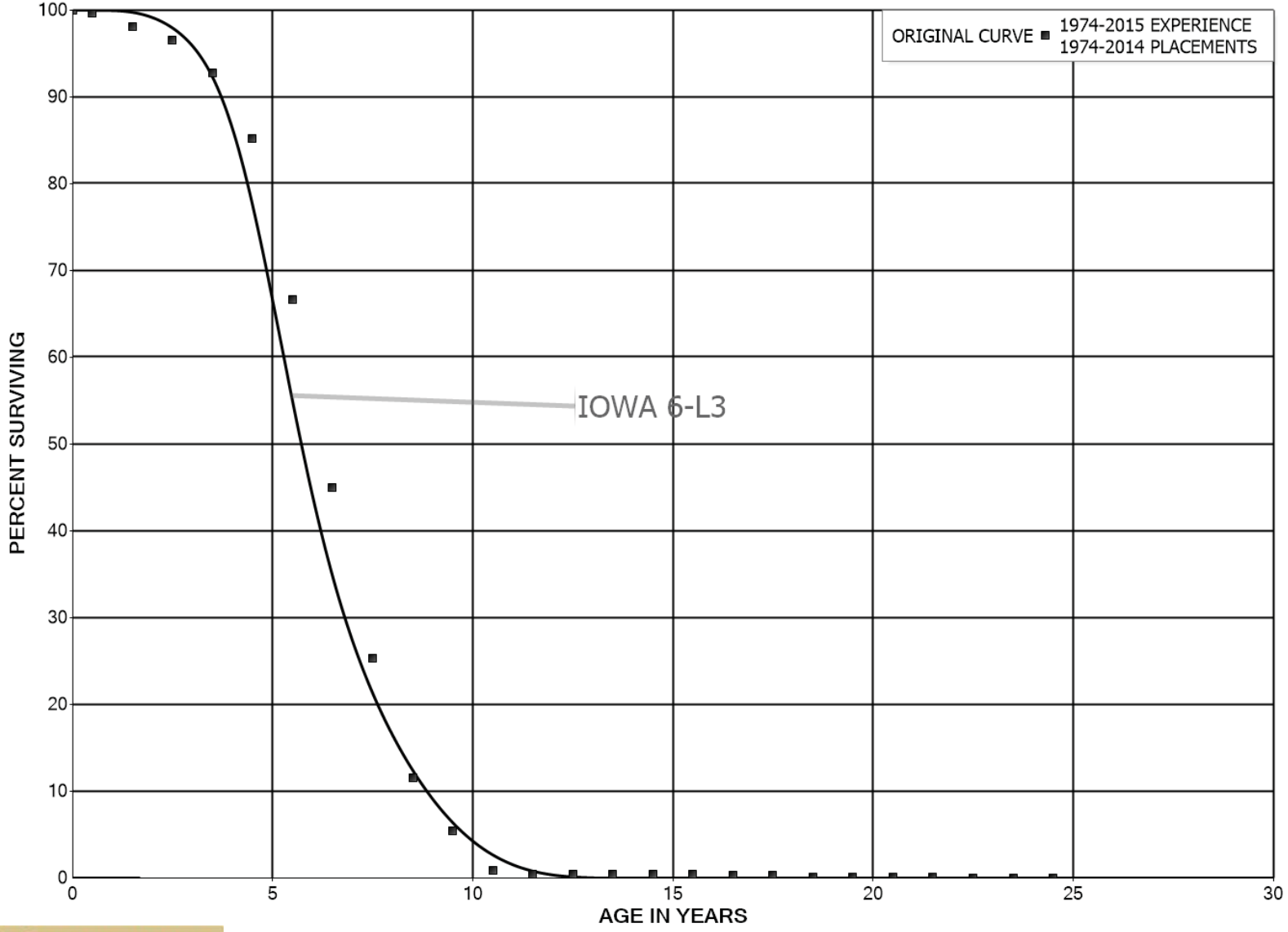
ACCOUNT V05 - VEHICLES - BOOMS/BODIES/CRANES/CAB/CHASSIS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2015 EXPERIENCE BAND 1971-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	27,223,902		0.0000	1.0000	100.00
0.5	24,655,661	68,025	0.0028	0.9972	100.00
1.5	23,611,135	84,894	0.0036	0.9964	99.72
2.5	22,203,256	40,397	0.0018	0.9982	99.37
3.5	20,170,991	15,155	0.0008	0.9992	99.18
4.5	18,491,838	202,273	0.0109	0.9891	99.11
5.5	17,542,955	301,536	0.0172	0.9828	98.03
6.5	15,403,032	973,183	0.0632	0.9368	96.34
7.5	13,818,921	1,768,914	0.1280	0.8720	90.25
8.5	10,585,012	1,423,991	0.1345	0.8655	78.70
9.5	8,847,582	1,460,983	0.1651	0.8349	68.11
10.5	6,751,902	1,263,554	0.1871	0.8129	56.87
11.5	5,022,061	975,560	0.1943	0.8057	46.22
12.5	3,843,935	727,581	0.1893	0.8107	37.24
13.5	2,986,309	696,520	0.2332	0.7668	30.20
14.5	2,289,789	301,191	0.1315	0.8685	23.15
15.5	1,965,599	124,552	0.0634	0.9366	20.11
16.5	1,841,046	273,432	0.1485	0.8515	18.83
17.5	1,567,615	332,219	0.2119	0.7881	16.04
18.5	1,235,396	185,014	0.1498	0.8502	12.64
19.5	1,050,382	129,020	0.1228	0.8772	10.74
20.5	921,362	369,877	0.4014	0.5986	9.43
21.5	551,486	31,815	0.0577	0.9423	5.64
22.5	519,671	149,068	0.2869	0.7131	5.32
23.5	370,603	183,466	0.4950	0.5050	3.79
24.5	187,137	80,847	0.4320	0.5680	1.91
25.5	106,290	6,157	0.0579	0.9421	1.09
26.5	100,133	11,503	0.1149	0.8851	1.02
27.5	88,629	16,230	0.1831	0.8169	0.91
28.5	72,399		0.0000	1.0000	0.74
29.5	72,399	44,189	0.6104	0.3896	0.74
30.5	28,210	28,210	1.0000		0.29
31.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V06 - VEHICLES - CARS, STATION WAGONS AND VANS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

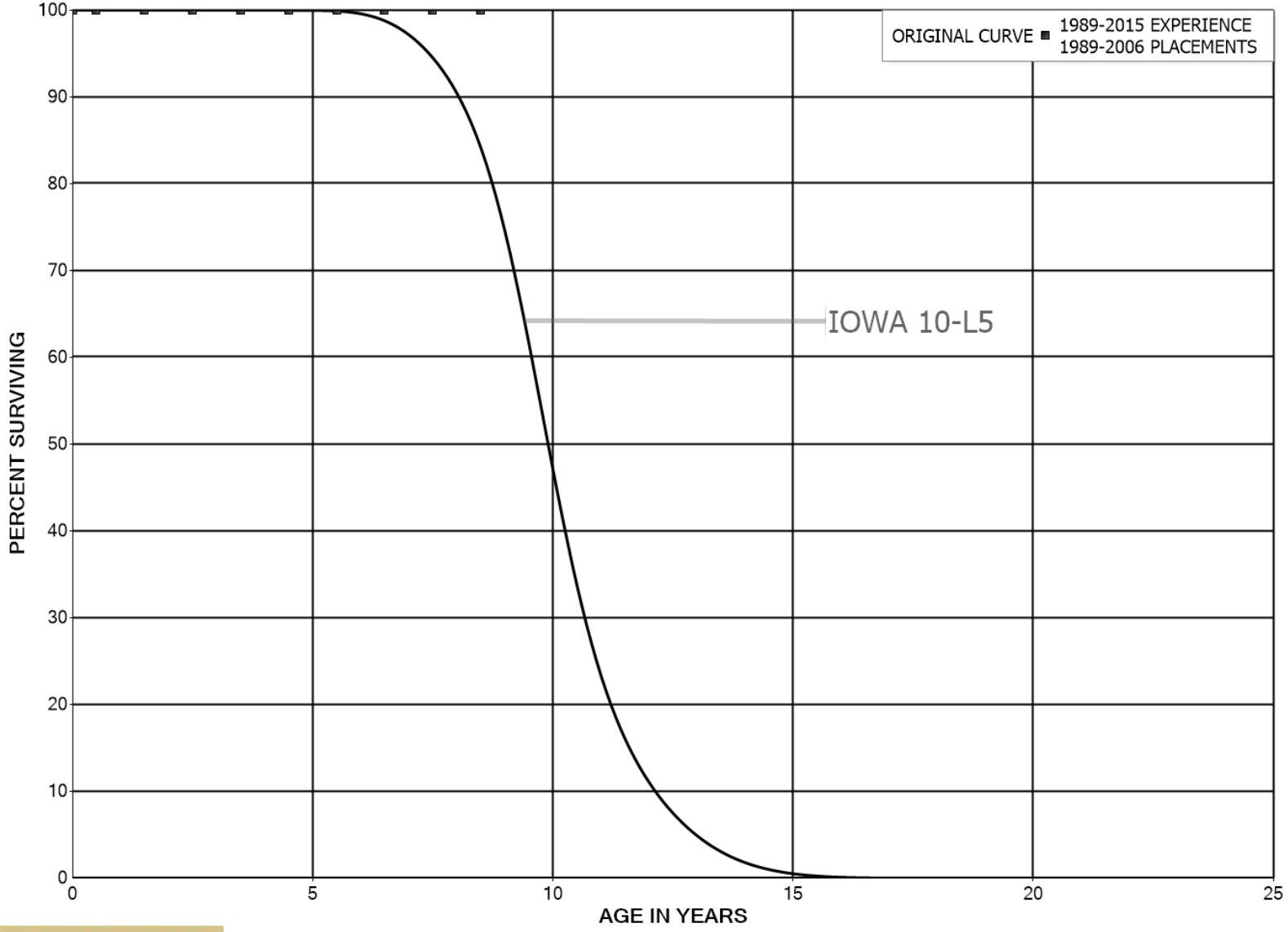
ACCOUNT V06 - VEHICLES - CARS, STATION WAGONS AND VANS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1974-2014 EXPERIENCE BAND 1974-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,814,453	34,490	0.0035	0.9965	100.00
0.5	9,779,963	150,355	0.0154	0.9846	99.65
1.5	9,409,596	159,717	0.0170	0.9830	98.12
2.5	8,973,608	343,570	0.0383	0.9617	96.45
3.5	8,426,528	684,758	0.0813	0.9187	92.76
4.5	7,460,987	1,632,087	0.2187	0.7813	85.22
5.5	5,542,176	1,804,839	0.3257	0.6743	66.58
6.5	3,500,464	1,528,182	0.4366	0.5634	44.90
7.5	1,733,996	941,698	0.5431	0.4569	25.30
8.5	760,437	402,658	0.5295	0.4705	11.56
9.5	336,728	286,895	0.8520	0.1480	5.44
10.5	49,833	28,612	0.5742	0.4258	0.80
11.5	21,221		0.0000	1.0000	0.34
12.5	21,221		0.0000	1.0000	0.34
13.5	21,221		0.0000	1.0000	0.34
14.5	21,221		0.0000	1.0000	0.34
15.5	21,221	2,230	0.1051	0.8949	0.34
16.5	18,991		0.0000	1.0000	0.31
17.5	18,991	12,282	0.6467	0.3533	0.31
18.5	6,709		0.0000	1.0000	0.11
19.5	6,709		0.0000	1.0000	0.11
20.5	6,709		0.0000	1.0000	0.11
21.5	6,709	6,208	0.9252	0.0748	0.11
22.5	502		0.0000	1.0000	0.01
23.5	502	502	1.0000		0.01
24.5					

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT V07 - VEHICLES - DUMP TRUCKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

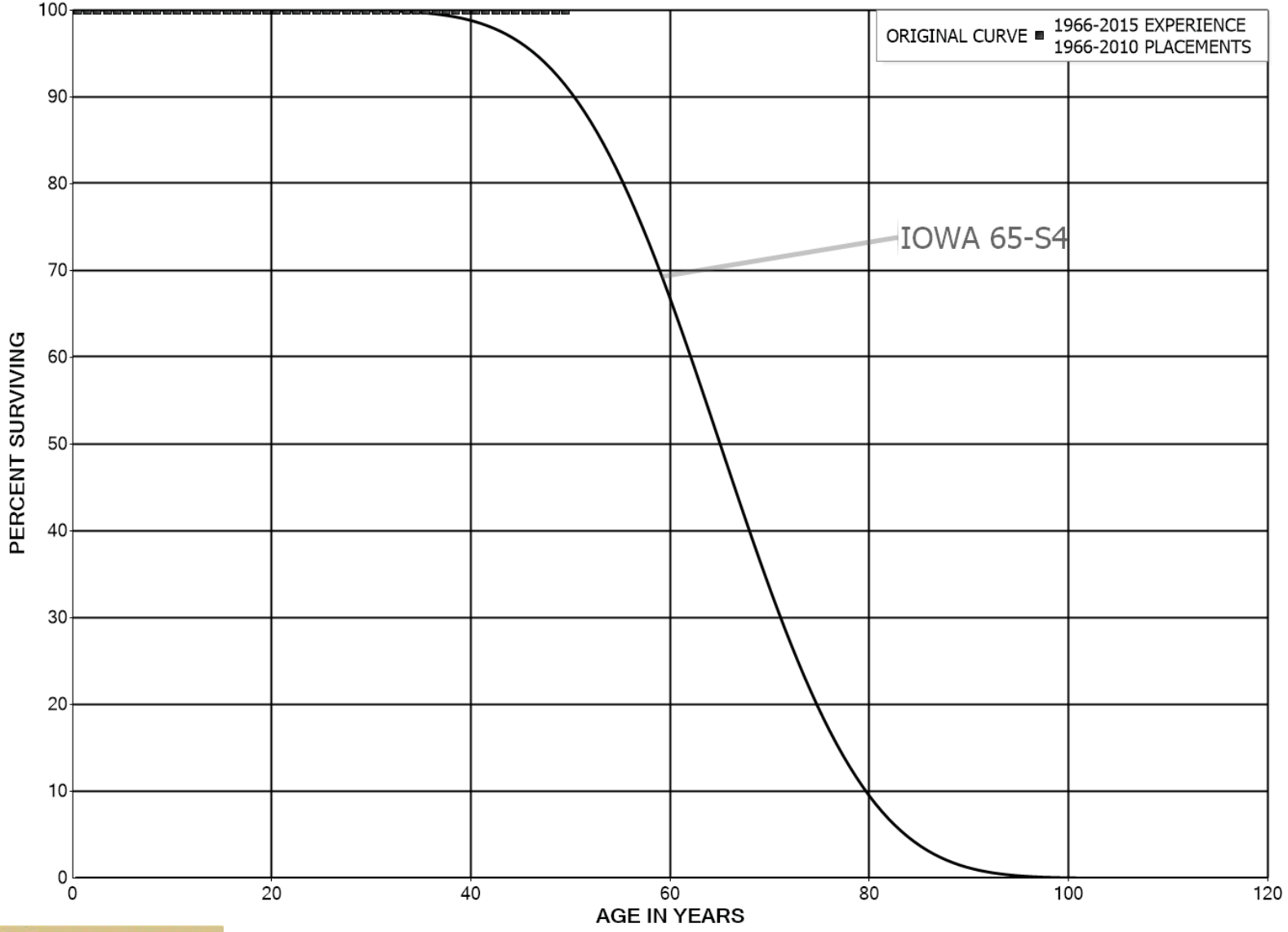
ACCOUNT V07 - VEHICLES - DUMP TRUCKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1989-2006 EXPERIENCE BAND 1989-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	36,457		0.0000	1.0000	100.00
0.5	36,457		0.0000	1.0000	100.00
1.5	36,457		0.0000	1.0000	100.00
2.5	36,457		0.0000	1.0000	100.00
3.5	36,457		0.0000	1.0000	100.00
4.5	36,457		0.0000	1.0000	100.00
5.5	36,457		0.0000	1.0000	100.00
6.5	36,457		0.0000	1.0000	100.00
7.5	36,457		0.0000	1.0000	100.00
8.5	36,457	24,922	0.6836	0.3164	100.00
9.5	11,535		0.0000	1.0000	31.64
10.5	11,535		0.0000	1.0000	31.64
11.5	11,535		0.0000	1.0000	31.64
12.5					31.64

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT W01 - WATER REGULATING STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W01 - WATER REGULATING STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2010 EXPERIENCE BAND 1966-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	22,451,738		0.0000	1.0000	100.00
0.5	22,451,738		0.0000	1.0000	100.00
1.5	22,451,738		0.0000	1.0000	100.00
2.5	22,451,738		0.0000	1.0000	100.00
3.5	22,451,738		0.0000	1.0000	100.00
4.5	22,451,738		0.0000	1.0000	100.00
5.5	22,156,264		0.0000	1.0000	100.00
6.5	22,156,264		0.0000	1.0000	100.00
7.5	22,156,264		0.0000	1.0000	100.00
8.5	22,156,264		0.0000	1.0000	100.00
9.5	22,156,264		0.0000	1.0000	100.00
10.5	22,156,264		0.0000	1.0000	100.00
11.5	22,156,264		0.0000	1.0000	100.00
12.5	6,815,749		0.0000	1.0000	100.00
13.5	6,815,749		0.0000	1.0000	100.00
14.5	6,815,749		0.0000	1.0000	100.00
15.5	6,815,749		0.0000	1.0000	100.00
16.5	6,764,780		0.0000	1.0000	100.00
17.5	6,764,780		0.0000	1.0000	100.00
18.5	6,764,780		0.0000	1.0000	100.00
19.5	6,764,780		0.0000	1.0000	100.00
20.5	6,764,780		0.0000	1.0000	100.00
21.5	6,764,780		0.0000	1.0000	100.00
22.5	6,764,780		0.0000	1.0000	100.00
23.5	6,764,780		0.0000	1.0000	100.00
24.5	6,764,780		0.0000	1.0000	100.00
25.5	6,764,780		0.0000	1.0000	100.00
26.5	6,764,780		0.0000	1.0000	100.00
27.5	6,764,780		0.0000	1.0000	100.00
28.5	6,764,780		0.0000	1.0000	100.00
29.5	6,764,780		0.0000	1.0000	100.00
30.5	6,759,713		0.0000	1.0000	100.00
31.5	6,759,713		0.0000	1.0000	100.00
32.5	4,998,878		0.0000	1.0000	100.00
33.5	4,998,878		0.0000	1.0000	100.00
34.5	4,998,878		0.0000	1.0000	100.00
35.5	4,976,785		0.0000	1.0000	100.00
36.5	3,053,361		0.0000	1.0000	100.00
37.5	3,053,361		0.0000	1.0000	100.00
38.5	3,053,361		0.0000	1.0000	100.00

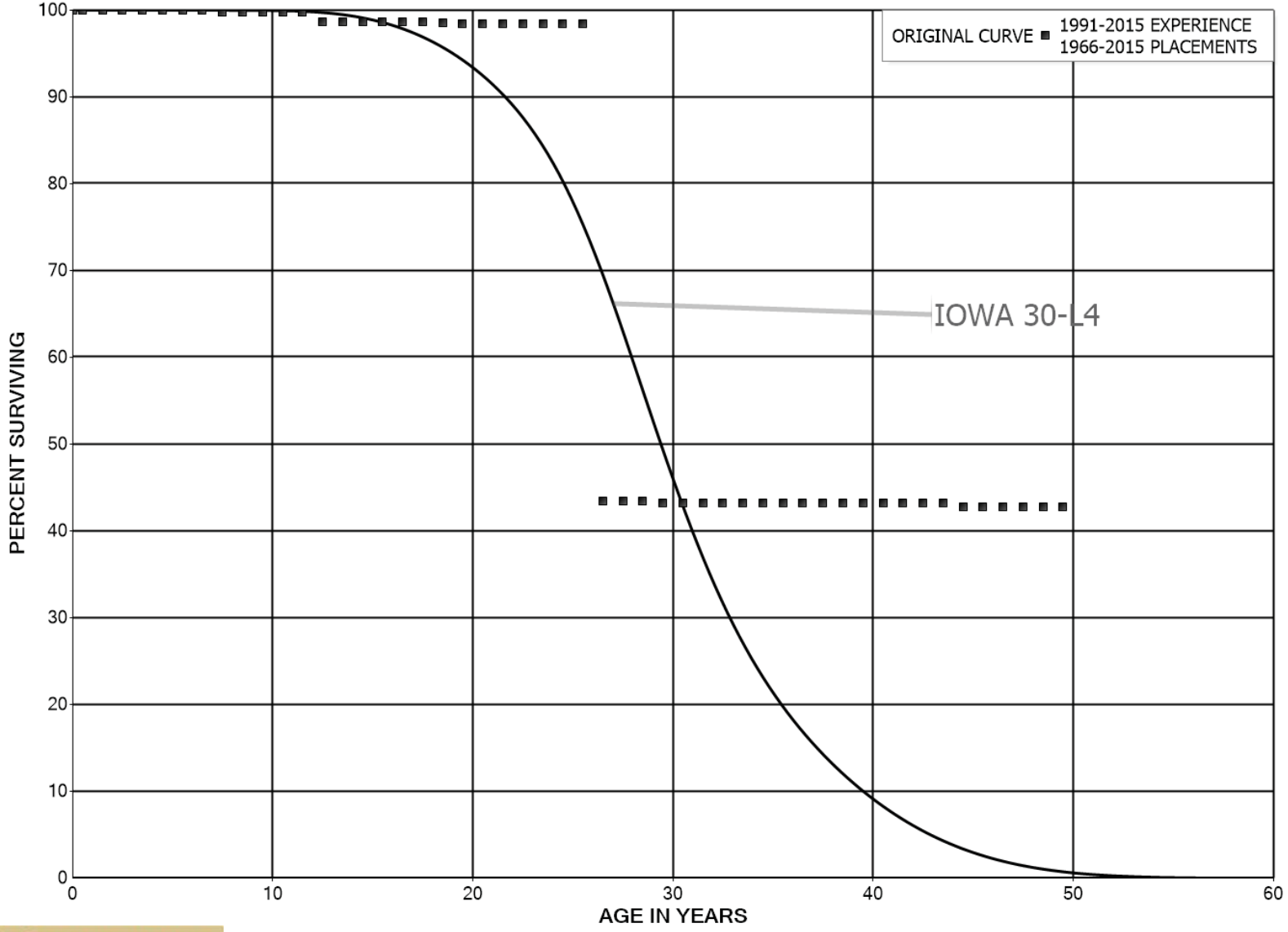
NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W01 - WATER REGULATING STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2010			EXPERIENCE BAND 1966-2015		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,053,361		0.0000	1.0000	100.00
40.5	3,053,361		0.0000	1.0000	100.00
41.5	3,053,361		0.0000	1.0000	100.00
42.5	3,053,361		0.0000	1.0000	100.00
43.5	3,053,361		0.0000	1.0000	100.00
44.5	3,053,361		0.0000	1.0000	100.00
45.5	3,053,361		0.0000	1.0000	100.00
46.5	3,053,361		0.0000	1.0000	100.00
47.5	3,053,361		0.0000	1.0000	100.00
48.5	781,461		0.0000	1.0000	100.00
49.5					100.00

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT W02 - WATER SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W02 - WATER SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1991-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	2,324,846		0.0000	1.0000	100.00
0.5	2,124,283		0.0000	1.0000	100.00
1.5	2,259,981		0.0000	1.0000	100.00
2.5	2,084,208		0.0000	1.0000	100.00
3.5	2,124,231		0.0000	1.0000	100.00
4.5	2,125,340		0.0000	1.0000	100.00
5.5	2,454,829		0.0000	1.0000	100.00
6.5	2,457,165	7,626	0.0031	0.9969	100.00
7.5	2,395,303		0.0000	1.0000	99.69
8.5	3,784,905		0.0000	1.0000	99.69
9.5	3,776,339		0.0000	1.0000	99.69
10.5	3,752,978		0.0000	1.0000	99.69
11.5	3,919,163	40,451	0.0103	0.9897	99.69
12.5	2,688,795		0.0000	1.0000	98.66
13.5	2,721,048		0.0000	1.0000	98.66
14.5	2,734,055		0.0000	1.0000	98.66
15.5	2,734,055		0.0000	1.0000	98.66
16.5	2,715,938		0.0000	1.0000	98.66
17.5	2,715,938	5,586	0.0021	0.9979	98.66
18.5	2,710,352	2,336	0.0009	0.9991	98.46
19.5	2,678,403		0.0000	1.0000	98.37
20.5	2,544,238		0.0000	1.0000	98.37
21.5	2,575,860		0.0000	1.0000	98.37
22.5	2,565,367		0.0000	1.0000	98.37
23.5	2,484,432		0.0000	1.0000	98.37
24.5	2,492,740		0.0000	1.0000	98.37
25.5	2,447,836	1,367,535	0.5587	0.4413	98.37
26.5	944,603		0.0000	1.0000	43.41
27.5	851,259		0.0000	1.0000	43.41
28.5	811,236	3,483	0.0043	0.9957	43.41
29.5	797,394		0.0000	1.0000	43.23
30.5	470,655		0.0000	1.0000	43.23
31.5	470,655		0.0000	1.0000	43.23
32.5	470,655		0.0000	1.0000	43.23
33.5	398,413		0.0000	1.0000	43.23
34.5	381,761		0.0000	1.0000	43.23
35.5	366,294		0.0000	1.0000	43.23
36.5	200,109		0.0000	1.0000	43.23
37.5	147,452		0.0000	1.0000	43.23
38.5	115,200		0.0000	1.0000	43.23

NEWFOUNDLAND AND LABRADOR HYDRO

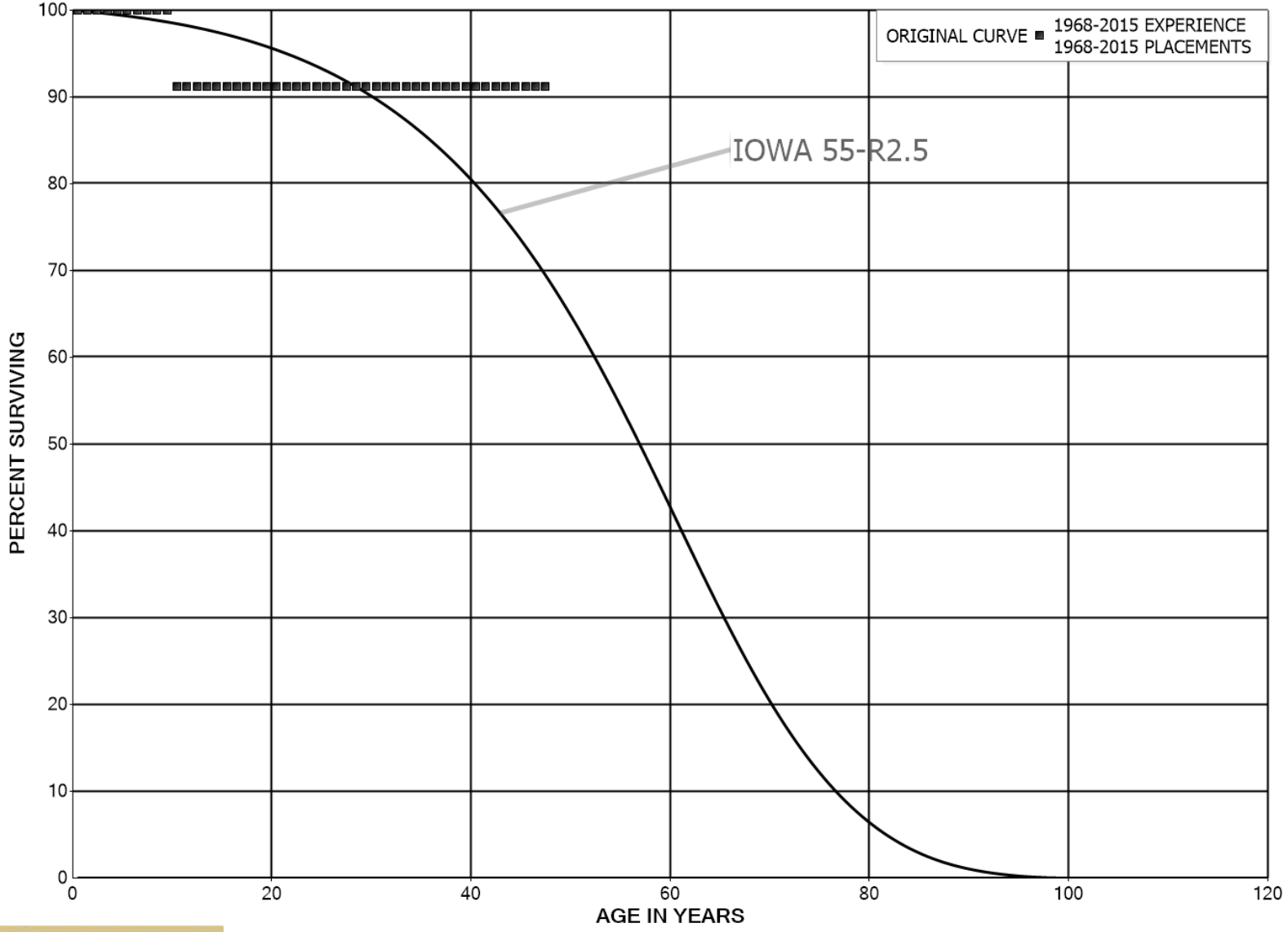
ACCOUNT W02 - WATER SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1966-2015 EXPERIENCE BAND 1991-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	102,192		0.0000	1.0000	43.23
40.5	102,192		0.0000	1.0000	43.23
41.5	102,192		0.0000	1.0000	43.23
42.5	102,192		0.0000	1.0000	43.23
43.5	102,192	1,101	0.0108	0.9892	43.23
44.5	91,345		0.0000	1.0000	42.76
45.5	85,567		0.0000	1.0000	42.76
46.5	53,945		0.0000	1.0000	42.76
47.5	46,655		0.0000	1.0000	42.76
48.5	36,616		0.0000	1.0000	42.76
49.5					42.76

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT W03 - WATER SYSTEMS - FEED
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W03 - WATER SYSTEMS - FEED

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,917,971		0.0000	1.0000	100.00
0.5	6,675,751		0.0000	1.0000	100.00
1.5	6,580,151		0.0000	1.0000	100.00
2.5	6,409,265		0.0000	1.0000	100.00
3.5	6,409,265		0.0000	1.0000	100.00
4.5	6,409,265		0.0000	1.0000	100.00
5.5	6,409,265		0.0000	1.0000	100.00
6.5	6,409,265		0.0000	1.0000	100.00
7.5	6,409,265		0.0000	1.0000	100.00
8.5	6,409,265		0.0000	1.0000	100.00
9.5	6,409,265	564,259	0.0880	0.9120	100.00
10.5	5,845,006		0.0000	1.0000	91.20
11.5	5,845,006		0.0000	1.0000	91.20
12.5	5,845,006		0.0000	1.0000	91.20
13.5	5,845,006		0.0000	1.0000	91.20
14.5	5,845,006		0.0000	1.0000	91.20
15.5	5,845,006		0.0000	1.0000	91.20
16.5	5,845,006	3,817	0.0007	0.9993	91.20
17.5	5,841,189		0.0000	1.0000	91.14
18.5	5,841,189		0.0000	1.0000	91.14
19.5	5,841,189		0.0000	1.0000	91.14
20.5	5,841,189		0.0000	1.0000	91.14
21.5	5,841,189		0.0000	1.0000	91.14
22.5	5,841,189		0.0000	1.0000	91.14
23.5	5,841,189		0.0000	1.0000	91.14
24.5	5,841,189		0.0000	1.0000	91.14
25.5	5,841,189		0.0000	1.0000	91.14
26.5	5,841,189		0.0000	1.0000	91.14
27.5	5,841,189		0.0000	1.0000	91.14
28.5	5,841,189		0.0000	1.0000	91.14
29.5	5,841,189		0.0000	1.0000	91.14
30.5	5,841,189		0.0000	1.0000	91.14
31.5	5,841,189		0.0000	1.0000	91.14
32.5	5,841,189		0.0000	1.0000	91.14
33.5	5,841,189		0.0000	1.0000	91.14
34.5	5,841,189		0.0000	1.0000	91.14
35.5	3,169,983		0.0000	1.0000	91.14
36.5	2,062,600		0.0000	1.0000	91.14
37.5	2,062,600		0.0000	1.0000	91.14
38.5	2,062,600		0.0000	1.0000	91.14

NEWFOUNDLAND AND LABRADOR HYDRO

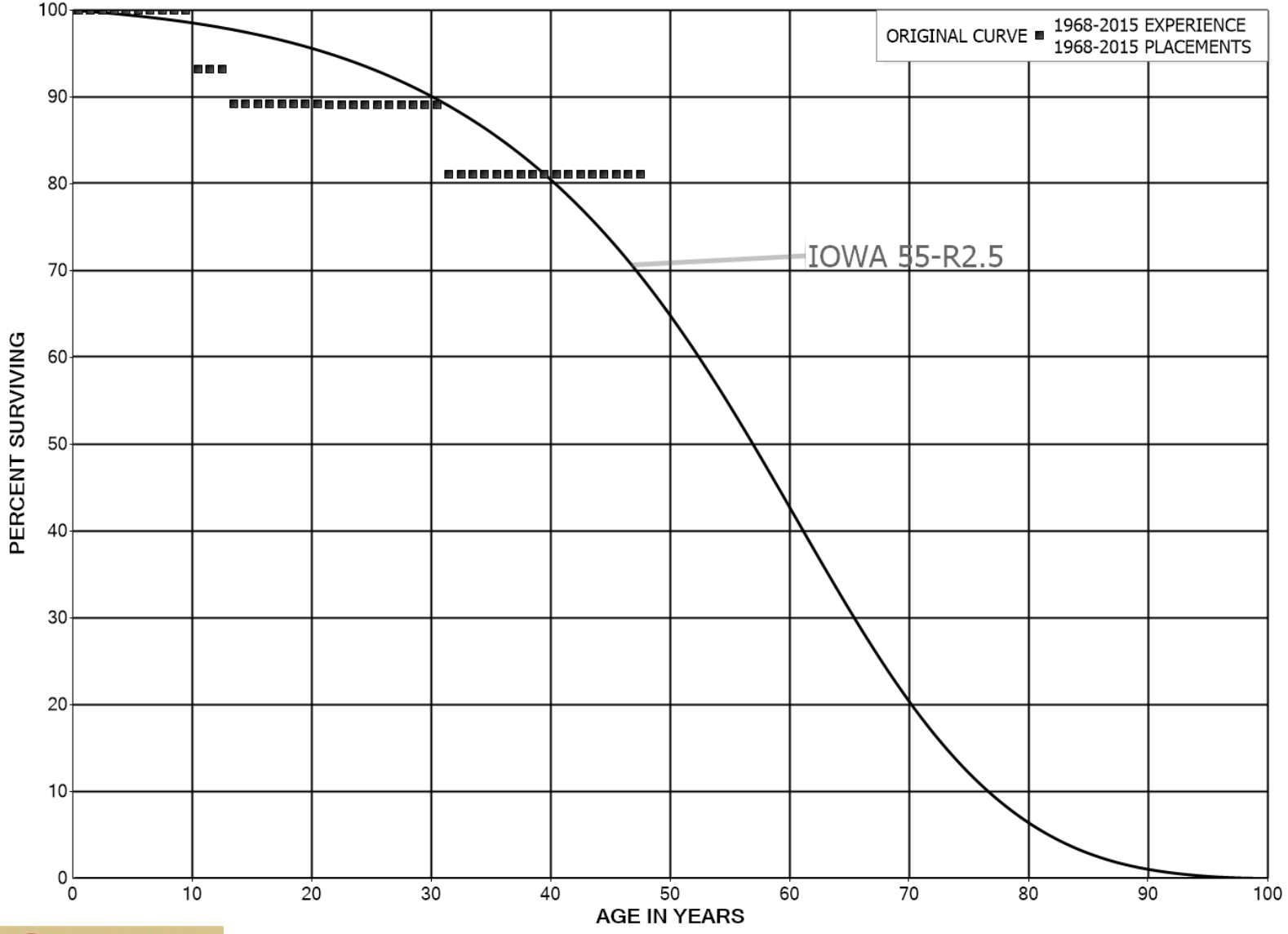
ACCOUNT W03 - WATER SYSTEMS - FEED

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,062,600		0.0000	1.0000	91.14
40.5	2,062,600		0.0000	1.0000	91.14
41.5	2,062,600		0.0000	1.0000	91.14
42.5	2,062,600		0.0000	1.0000	91.14
43.5	2,062,600		0.0000	1.0000	91.14
44.5	329,755		0.0000	1.0000	91.14
45.5	329,755		0.0000	1.0000	91.14
46.5	329,755		0.0000	1.0000	91.14
47.5					91.14

NEWFOUNDLAND AND LABRADOR HYDRO
ACCOUNT W04 - WATER TREATMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W04 - WATER TREATMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	16,019,602		0.0000	1.0000	100.00
0.5	11,859,599		0.0000	1.0000	100.00
1.5	11,859,599		0.0000	1.0000	100.00
2.5	11,542,239		0.0000	1.0000	100.00
3.5	10,882,444		0.0000	1.0000	100.00
4.5	9,464,291		0.0000	1.0000	100.00
5.5	9,464,291		0.0000	1.0000	100.00
6.5	9,464,291		0.0000	1.0000	100.00
7.5	9,464,291		0.0000	1.0000	100.00
8.5	9,464,291		0.0000	1.0000	100.00
9.5	9,464,291	642,386	0.0679	0.9321	100.00
10.5	8,821,905		0.0000	1.0000	93.21
11.5	8,821,905		0.0000	1.0000	93.21
12.5	8,821,905	380,586	0.0431	0.9569	93.21
13.5	8,441,318		0.0000	1.0000	89.19
14.5	8,441,318		0.0000	1.0000	89.19
15.5	8,441,318		0.0000	1.0000	89.19
16.5	8,441,318		0.0000	1.0000	89.19
17.5	8,441,318		0.0000	1.0000	89.19
18.5	6,032,194		0.0000	1.0000	89.19
19.5	5,807,399		0.0000	1.0000	89.19
20.5	5,792,685	8,799	0.0015	0.9985	89.19
21.5	5,783,887	563	0.0001	0.9999	89.06
22.5	5,783,324		0.0000	1.0000	89.05
23.5	5,783,324		0.0000	1.0000	89.05
24.5	3,102,160		0.0000	1.0000	89.05
25.5	3,087,023		0.0000	1.0000	89.05
26.5	3,087,023		0.0000	1.0000	89.05
27.5	3,029,481		0.0000	1.0000	89.05
28.5	3,029,481		0.0000	1.0000	89.05
29.5	3,029,481		0.0000	1.0000	89.05
30.5	3,029,481	272,733	0.0900	0.9100	89.05
31.5	2,756,748		0.0000	1.0000	81.03
32.5	2,737,925		0.0000	1.0000	81.03
33.5	2,737,925		0.0000	1.0000	81.03
34.5	2,737,925		0.0000	1.0000	81.03
35.5	2,115,562		0.0000	1.0000	81.03
36.5	2,110,464		0.0000	1.0000	81.03
37.5	2,110,464		0.0000	1.0000	81.03
38.5	2,110,464		0.0000	1.0000	81.03

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W04 - WATER TREATMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2015 EXPERIENCE BAND 1968-2015

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,110,464		0.0000	1.0000	81.03
40.5	2,110,464		0.0000	1.0000	81.03
41.5	2,110,464		0.0000	1.0000	81.03
42.5	2,110,464		0.0000	1.0000	81.03
43.5	2,110,464		0.0000	1.0000	81.03
44.5	1,905,927		0.0000	1.0000	81.03
45.5	1,905,927		0.0000	1.0000	81.03
46.5	65,708		0.0000	1.0000	81.03
47.5					81.03

PART VI. DEPRECIATION CALCULATIONS

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT A01 - AIRCRAFT LANDING STRIP

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-R2						
NET SALVAGE PERCENT.. -6						
1974	7,976.40	6,995	8,455			
1993	192,208.10	110,576	202,845	896	15.09	59
1994	194,620.58	107,774	197,704	8,594	15.76	545
2006	78,390.03	20,723	38,015	45,078	24.77	1,820
2015	2,302.95	54	99	2,342	22.02	106
	475,498.06	246,122	447,118	56,910		2,530

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.5 0.53

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT A04 - AUXILIARY POWER SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -3						
1956	85,469.97	88,034	88,034			
1966	283,631.50	292,140	292,140			
1970	12,000.00	12,327	12,360			
1974	5,049.52	5,045	5,201			
1978	2,000.00	1,930	2,060			
1979	99,773.88	95,368	102,767			
1980	135,560.00	128,271	139,092	535	2.44	219
1982	413,537.76	382,783	415,075	10,869	3.04	3,575
1983	43,498.13	39,755	43,109	1,694	3.38	501
1984	221,073.63	199,243	216,051	11,655	3.75	3,108
1988	165,905.06	138,300	149,967	20,915	5.72	3,656
1989	680,140.87	552,499	599,108	101,437	6.34	16,000
1992	63,724.33	47,280	51,269	14,367	8.39	1,712
1999	16,056.11	8,815	9,559	6,979	14.01	498
2000	164,084.55	85,011	92,183	76,824	14.91	5,153
2001	368,268.81	179,292	194,417	184,900	15.82	11,688
2003	448,397.32	189,511	205,498	256,351	17.69	14,491
2005	97,542.86	34,830	37,768	62,701	19.60	3,199
2010	336,595.37	63,330	68,673	278,020	24.52	11,338
2011	59,826.71	9,223	10,001	51,621	25.51	2,024
2012	213,015.53	25,523	27,676	191,730	26.51	7,232
2013	802,476.86	68,877	74,688	751,863	27.50	27,340
2015	1,337,310.13	24,518	26,586	1,350,843	27.67	48,820
	6,054,938.90	2,671,905	2,863,282	3,373,305		160,554

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.0 2.65

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B01 - BATTERY AND POWER SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 26-L1.5						
NET SALVAGE PERCENT.. -3						
1956	1,465.79	1,289	1,510			
1968	46,703.90	37,096	48,105			
1970	3,635.52	2,827	3,745			
1971	61,437.84	47,266	63,281			
1972	17,191.24	13,076	17,707			
1973	351.12	264	362			
1975	6,046.84	4,439	6,228			
1978	39,546.11	27,902	40,732			
1979	8,963.00	6,235	9,232			
1980	309,979.19	212,566	319,279			
1982	78,356.38	52,149	80,707			
1985	112,621.82	71,519	116,000			
1987	2,173.59	1,335	2,239			
1988	6,546.56	3,952	6,743			
1989	13,813.16	8,192	14,228			
1990	281,180.21	163,743	289,616			
1992	165,114.78	92,556	165,623	4,445	11.85	375
1994	25,099.57	13,493	24,145	1,708	12.43	137
1995	71,903.31	37,771	67,589	6,471	12.74	508
1996	182,381.97	93,493	167,300	20,553	13.06	1,574
1997	11,760.26	5,870	10,504	1,609	13.40	120
1998	189,198.12	91,665	164,029	30,845	13.77	2,240
1999	20,241.49	9,494	16,989	3,860	14.16	273
2000	184,734.09	83,503	149,423	40,853	14.59	2,800
2001	849,065.18	368,652	659,680	214,857	15.04	14,286
2002	6,611.36	2,742	4,907	1,903	15.53	123
2003	1,372,752.91	540,010	966,315	447,620	16.07	27,854
2004	425,839.87	157,735	282,257	156,358	16.65	9,391
2005	436,123.50	150,655	269,588	179,619	17.28	10,395
2006	400,764.27	127,807	228,703	184,084	17.95	10,255
2007	482,048.57	140,170	250,826	245,684	18.66	13,166
2008	358,693.69	93,786	167,824	201,631	19.40	10,393
2009	766,844.06	176,808	316,387	473,462	20.18	23,462
2010	559,022.38	110,950	198,538	377,255	20.99	17,973
2011	707,836.53	116,929	209,237	519,835	21.83	23,813
2012	1,212,344.62	158,012	282,753	965,962	22.71	42,535
2013	761,528.57	71,802	128,485	655,889	23.62	27,768
2014	380,909.69	21,728	38,881	353,456	24.56	14,392
2015	839,165.25	23,596	42,224	822,117	17.82	46,135
	11,399,996.31	3,343,077	5,831,921	5,910,076		299,968

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.7 2.63

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B02 - BOILER SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. -8						
1968	14,985,641.26	14,088,601	16,184,493			
1971	795,588.25	726,269	859,235			
1979	2,040.12	1,660	2,082	121	9.86	12
1981	314,253.38	245,976	308,543	30,851	11.01	2,802
1982	68,031.30	52,130	65,390	8,084	11.62	696
1986	142,517.51	99,085	124,288	29,631	14.25	2,079
1987	29,961.22	20,264	25,418	6,940	14.95	464
1988	480,335.28	315,537	395,798	122,964	15.67	7,847
1989	4,309,160.53	2,745,797	3,444,223	1,209,670	16.40	73,760
1993	184,491.61	102,216	128,216	71,035	19.48	3,647
1996	19,423.10	9,476	11,886	9,091	21.93	415
1997	53,585.52	24,914	31,251	26,621	22.78	1,169
1999	92,545.14	38,755	48,613	51,336	24.49	2,096
2007	1,855,849.81	412,388	517,284	1,487,034	31.77	46,806
2014	542,621.76	21,537	27,015	559,016	38.53	14,509
	23,876,045.79	18,904,605	22,173,735	3,612,394		156,302

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.1 0.65

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B03 - BOOMS - TIMBER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R2						
NET SALVAGE PERCENT.. 0						
1966	38,209.00	38,209	38,209			
1970	1,982.00	1,962	1,275	707	0.25	707
1979	46,793.75	41,646	27,067	19,727	2.75	7,173
2014	37,008.66	1,998	1,299	35,710	23.65	1,510
2015	51,562.11	1,485	965	50,597	16.89	2,996
	175,555.52	85,300	68,815	106,740		12,386

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.6 7.06

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B04 - BRIDGES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -11						
1966	564,791.18	441,739	626,918			
1980	221,425.80	130,152	220,742	25,041	30.58	819
1983	26,746.98	14,488	24,572	5,117	33.28	154
1984	1,988,230.31	1,045,756	1,773,639	433,297	34.20	12,670
1992	629,308.12	249,858	423,768	274,764	41.75	6,581
1994	55,564.63	20,221	34,295	27,382	43.69	627
1996	36,386.80	12,030	20,403	19,986	45.64	438
1997	63,600.25	19,963	33,858	36,738	46.62	788
2003	312,030.06	66,392	112,603	233,750	52.54	4,449
2007	337,011.43	48,803	82,772	291,311	56.52	5,154
2011	19,193.98	1,472	2,497	18,809	60.51	311
	4,254,289.54	2,050,874	3,356,067	1,366,195		31,991

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.7 0.75

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B05 - BUILDINGS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R0.5						
NET SALVAGE PERCENT.. -3						
1967	321,303.14	183,276	330,942			
1968	1,704,287.55	954,946	1,755,416			
1969	102,525.34	56,412	105,601			
1970	122,471.07	66,125	126,145			
1971	49,280.73	26,090	50,759			
1972	63,651.61	33,043	65,561			
1973	277,231.53	140,947	285,548			
1974	25,512.63	12,703	26,278			
1975	904,839.77	440,829	915,239	16,746	26.35	636
1977	436,824.10	203,278	422,041	27,888	27.41	1,017
1978	16,205.52	7,364	15,289	1,403	27.94	50
1979	132,860.64	58,899	122,285	14,561	28.48	511
1980	607,564.93	262,582	545,167	80,625	29.02	2,778
1981	187,623.82	78,963	163,941	29,312	29.57	991
1982	894,510.05	366,327	760,560	160,785	30.12	5,338
1983	117,158.22	46,628	96,808	23,865	30.68	778
1984	251,476.43	97,185	201,773	57,248	31.24	1,833
1985	222,466.52	83,407	173,168	55,973	31.80	1,760
1986	500,259.66	181,786	377,420	137,847	32.36	4,260
1987	1,246,537.52	438,335	910,061	373,873	32.93	11,354
1988	254,576.87	86,478	179,544	82,670	33.51	2,467
1989	21,449,089.59	7,034,272	14,604,392	7,488,170	34.08	219,723
1990	1,708,283.45	539,824	1,120,770	638,762	34.66	18,429
1991	136,545.27	41,517	86,197	54,445	35.24	1,545
1992	223,784.38	65,369	135,718	94,780	35.82	2,646
1993	144,816.43	40,542	84,172	64,989	36.41	1,785
1994	493,681.26	132,208	274,487	234,005	37.00	6,324
1995	562,879.15	143,898	298,758	281,008	37.59	7,476
1996	1,063,005.55	258,833	537,383	557,513	38.18	14,602
1997	946,089.64	218,866	454,404	520,068	38.77	13,414
1998	60,623.02	13,288	27,588	34,854	39.36	886
1999	363,208.48	75,120	155,962	218,143	39.96	5,459
2000	536,570.67	104,344	216,637	336,031	40.56	8,285
2001	2,025,328.99	368,821	765,738	1,320,351	41.16	32,078
2002	39,901.19	6,773	14,062	27,036	41.76	647
2003	3,414,776.99	537,431	1,115,802	2,401,418	42.36	56,691
2004	667,419.28	96,792	200,957	486,485	42.96	11,324
2005	1,137,562.52	150,914	313,324	858,365	43.56	19,705
2006	4,506,177.04	541,183	1,123,592	3,517,770	44.17	79,642
2007	967,374.99	104,024	215,972	780,424	44.78	17,428
2008	839,316.47	79,879	165,843	698,653	45.38	15,396
2009	873,943.37	72,193	149,885	750,277	45.99	16,314
2010	6,581,913.04	459,641	954,296	5,825,074	46.61	124,975

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B05 - BUILDINGS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R0.5						
NET SALVAGE PERCENT.. -3						
2011	3,558,651.72	203,797	423,119	3,242,292	47.22	68,664
2012	2,120,456.52	94,789	196,799	1,987,271	47.83	41,549
2013	1,748,268.28	55,822	115,896	1,684,820	48.45	34,774
2014	2,301,553.82	44,093	91,545	2,279,055	49.07	46,445
2015	2,266,372.60	56,492	117,287	2,217,077	20.12	110,193
	69,176,761.36	15,366,328	31,590,131	39,661,933		1,010,172

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 39.3 1.46

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B06 - BUILDINGS - METAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -3						
1965	496,680.62	387,037	511,581			
1966	284,920.26	219,088	293,468			
1967	796,275.99	603,789	820,164			
1968	1,348,322.58	1,007,485	1,388,772			
1969	1,344,302.45	989,125	1,384,632			
1970	147,186.08	106,617	151,602			
1971	700,196.43	498,812	721,202			
1975	551,697.72	365,435	544,365	23,884	19.63	1,217
1976	311,245.64	202,083	301,030	19,553	20.33	962
1977	113,072.12	71,911	107,121	9,343	21.04	444
1978	684,309.29	425,849	634,360	70,479	21.77	3,237
1979	247,825.70	150,836	224,691	30,569	22.50	1,359
1980	3,138,866.66	1,866,333	2,780,157	452,876	23.25	19,479
1981	584,160.14	339,019	505,015	96,670	24.01	4,026
1982	1,925,035.45	1,089,819	1,623,433	359,354	24.77	14,508
1983	1,399,100.34	771,623	1,149,437	291,636	25.55	11,414
1984	408,162.84	219,070	326,335	94,073	26.34	3,571
1985	87,197.01	45,495	67,771	22,042	27.14	812
1986	16,689.87	8,458	12,599	4,592	27.94	164
1987	284,222.63	139,668	208,054	84,695	28.76	2,945
1988	435,449.77	207,213	308,672	139,841	29.59	4,726
1989	146,934.65	67,637	100,755	50,588	30.42	1,663
1990	1,575,617.29	700,502	1,043,493	579,393	31.26	18,535
1991	1,490,557.45	638,950	951,803	583,471	32.11	18,171
1992	932,441.26	384,694	573,054	387,360	32.97	11,749
1993	491,155.09	194,631	289,929	215,961	33.84	6,382
1994	11,845.40	4,499	6,702	5,499	34.72	158
1995	103,615.40	37,645	56,077	50,647	35.60	1,423
1996	510,264.42	176,881	263,488	262,084	36.49	7,182
1998	176,530.51	55,210	82,243	99,583	38.30	2,600
2001	110,073.41	28,735	42,805	70,571	41.06	1,719
2002	780,974.95	190,282	283,451	520,953	41.99	12,407
2003	166,852.30	37,714	56,180	115,678	42.93	2,695
2004	50,241.99	10,472	15,599	36,150	43.87	824
2005	284,953.12	54,377	81,002	212,500	44.81	4,742
2007	49,389.10	7,659	11,409	39,462	46.72	845
2008	17,818.02	2,439	3,633	14,720	47.69	309
2009	75,434.91	8,970	13,362	64,336	48.65	1,322

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B06 - BUILDINGS - METAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -3						
2011	31,646.84	2,614	3,894	28,702	50.59	567
2014	889,193.02	24,646	36,714	879,155	53.52	16,427
2015	10,828,614.63	120,458	179,439	10,974,035	46.01	238,514
	34,029,073.35	12,463,780	18,159,493	16,890,453		417,098

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.5 1.23

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B07 - BUS DUCT GENERATOR

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R4						
NET SALVAGE PERCENT.. -3						
1968	27,238.00	25,804	28,055			
1980	311,717.00	254,045	285,957	35,112	8.35	4,205
1988	120,878.46	80,710	90,848	33,657	14.07	2,392
2003	365,970.58	116,854	131,533	245,417	27.60	8,892
2015	630,303.53	8,635	9,720	639,493	37.09	17,242
	1,456,107.57	486,048	546,113	953,678		32,731

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.1 2.25

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B08 - BUSWORK AND HARDWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -8						
1967	268,547.91	243,337	290,032			
1968	104,589.03	93,573	112,956			
1969	18,000.00	15,886	19,231	209	9.14	23
1970	521,630.42	453,618	549,137	14,224	9.74	1,460
1974	8,694.70	7,071	8,560	830	12.35	67
1975	68,040.25	54,319	65,757	7,726	13.04	592
1976	2,298.22	1,800	2,179	303	13.74	22
1977	238,137.96	182,810	221,304	35,885	14.46	2,482
1978	322,711.68	242,576	293,655	54,874	15.20	3,610
1979	155,744.87	114,547	138,667	29,537	15.95	1,852
1980	132,765.41	95,467	115,570	27,817	16.71	1,665
1981	212,209.10	149,017	180,396	48,790	17.49	2,790
1982	238,384.77	163,278	197,660	59,796	18.29	3,269
1983	166,412.59	111,070	134,458	45,268	19.10	2,370
1985	23,798.53	15,031	18,196	7,506	20.76	362
1986	84,174.63	51,618	62,487	28,422	21.61	1,315
1987	110,667.31	65,784	79,636	39,885	22.48	1,774
1988	22,543.64	12,972	15,704	8,643	23.36	370
1989	400,025.39	222,494	269,345	162,682	24.25	6,709
1990	150,841.82	80,966	98,015	64,894	25.15	2,580
1991	707,463.50	365,832	442,865	321,196	26.06	12,325
1992	555,332.55	276,129	334,274	265,485	26.98	9,840
1993	33,128.06	15,807	19,135	16,643	27.91	596
1994	149,377.90	68,242	82,612	78,716	28.85	2,728
1995	465,654.41	203,275	246,079	256,828	29.79	8,621
1996	98,866.85	41,109	49,765	57,011	30.75	1,854
1997	55,916.37	22,091	26,743	33,647	31.71	1,061
1998	326,389.45	122,177	147,904	204,597	32.67	6,263
2000	299,484.25	99,491	120,441	203,002	34.62	5,864
2002	48,570.45	14,079	17,044	35,412	36.58	968
2003	37,106.47	9,971	12,071	28,004	37.56	746
2004	112,224.95	27,755	33,599	87,604	38.55	2,272
2005	6,333.49	1,431	1,732	5,108	39.54	129
2009	33,674.74	4,721	5,715	30,654	43.51	705
2012	1,035,536.04	78,287	94,771	1,023,608	46.50	22,013
2014	46,222.92	1,498	1,814	48,107	48.50	992
2015	46,405.63	531	643	49,476	46.45	1,065
	7,307,906.26	3,729,660	4,510,152	3,382,387		111,354

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.4 1.52

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C01 - CABLES - TELECONTROL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. -3						
1982	12,612.10	11,674	12,990			
1993	112,541.10	80,678	115,917			
1999	176,607.97	96,956	181,906			
2000	22,031.28	11,414	22,692			
2001	129,578.38	63,085	133,466			
2002	260,377.55	118,451	268,189			
2003	892,247.63	377,099	919,015			
2010	99,451.25	18,712	90,721	11,714	24.52	478
2012	923,499.09	110,654	536,484	414,720	26.51	15,644
2013	11,851.59	1,017	4,931	7,276	27.50	265
2015	2,541.47	47	228	2,390	27.67	86
	2,643,339.41	889,787	2,286,539	436,101		16,473

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.5 0.62

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C02 - CABLE - SUBMARINE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R4						
NET SALVAGE PERCENT.. -14						
1975	475,796.93	433,444	501,133	41,276	9.04	4,566
1980	169,115.97	139,624	161,428	31,364	12.41	2,527
1982	123,400.69	97,348	112,550	28,127	13.86	2,029
1988	1,550,390.96	1,035,334	1,197,018	570,428	18.64	30,602
1989	2,453,451.52	1,585,554	1,833,163	963,772	19.49	49,450
1990	2,979,349.00	1,859,764	2,150,196	1,246,262	20.36	61,211
1999	922,348.37	381,339	440,891	610,586	28.68	21,290
2007	104,280.98	22,376	25,870	93,010	36.53	2,546
2008	42,294.63	8,014	9,266	38,950	37.52	1,038
2009	80,687.42	13,266	15,337	76,646	38.51	1,990
	8,901,116.47	5,576,063	6,446,852	3,700,420		177,249

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.9 1.99

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C03- CABLES - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-S4						
NET SALVAGE PERCENT.. -14						
1967	67,835.10	59,069	68,848	8,484	14.17	599
1968	67,096.88	57,584	67,117	9,373	14.83	632
1970	135,075.57	112,307	130,899	23,087	16.24	1,422
1971	28,808.00	23,547	27,445	5,396	16.98	318
1972	12,861.35	10,324	12,033	2,629	17.75	148
1975	15,303.23	11,569	13,484	3,962	20.21	196
1976	3,697.85	2,735	3,188	1,028	21.07	49
1977	6,782.66	4,902	5,714	2,018	21.96	92
1978	85,112.12	60,060	70,003	27,025	22.86	1,182
1979	84,286.46	58,005	67,607	28,480	23.78	1,198
1980	62,069.93	41,619	48,509	22,251	24.71	900
1981	47,782.87	31,176	36,337	18,135	25.66	707
1982	99,352.11	63,011	73,442	39,819	26.62	1,496
1983	33,221.24	20,457	23,844	14,028	27.59	508
1987	44,595.82	24,132	28,127	22,712	31.52	721
1989	77,293.50	38,903	45,343	42,772	33.51	1,276
1990	80,930.60	39,211	45,702	46,559	34.50	1,350
1991	94,095.94	43,801	51,052	56,217	35.50	1,584
1992	52,174.86	23,296	27,153	32,326	36.50	886
1993	6,622.24	2,831	3,300	4,249	37.50	113
1995	166,037.71	64,672	75,378	113,905	39.50	2,884
1996	9,885.30	3,663	4,269	7,000	40.50	173
1998	22,326.20	7,424	8,653	16,799	42.50	395
2000	68,281.30	20,109	23,438	54,403	44.50	1,223
2001	17,652.00	4,863	5,668	14,455	45.50	318
2012	323,501.29	21,512	25,073	343,718	56.50	6,084
2013	109,168.13	5,186	6,045	118,407	57.50	2,059
2014	464,890.58	13,249	15,442	514,533	58.50	8,795
2015	550,805.10	5,400	6,294	621,623	57.64	10,785
	2,837,545.94	874,617	1,019,407	2,215,395		48,093

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.1 1.69

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C04 - CABLES - ABOVE GROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. -14						
1967	176,785.73	148,733	187,166	14,370	15.72	914
1968	631,767.69	523,114	658,290	61,925	16.42	3,771
1970	331,759.42	265,565	334,189	44,017	17.87	2,463
1971	193,228.00	151,956	191,222	29,058	18.61	1,561
1973	1,019.00	772	971	191	20.13	9
1974	55,053.53	40,889	51,455	11,306	20.91	541
1975	13,512.29	9,830	12,370	3,034	21.71	140
1976	18,193.77	12,960	16,309	4,432	22.51	197
1977	117,653.40	81,973	103,155	30,970	23.33	1,327
1978	526,233.47	358,342	450,940	148,966	24.16	6,166
1979	144,962.66	96,400	121,310	43,947	25.00	1,758
1980	1,157,039.66	750,750	944,748	374,277	25.85	14,479
1981	65,447.70	41,396	52,093	22,517	26.71	843
1982	272,572.07	167,848	211,221	99,511	27.59	3,607
1983	564,279.89	338,043	425,395	217,884	28.47	7,653
1984	26,779.68	15,590	19,619	10,910	29.36	372
1985	914,217.74	516,414	649,858	392,350	30.27	12,962
1986	84,189.34	46,100	58,013	37,963	31.18	1,218
1987	152,983.16	81,096	102,052	72,349	32.10	2,254
1988	117,705.66	60,316	75,902	58,282	33.03	1,765
1989	406,872.20	201,304	253,322	210,512	33.96	6,199
1990	289,793.00	138,201	173,913	156,451	34.90	4,483
1991	469,171.72	215,279	270,908	263,948	35.85	7,363
1992	382,068.34	168,417	211,937	223,621	36.80	6,077
1993	54,650.56	23,093	29,060	33,242	37.76	880
1994	671,843.79	271,642	341,836	424,066	38.72	10,952
1995	227,348.10	87,731	110,401	148,776	39.69	3,748
1996	93,595.81	34,392	43,279	63,420	40.66	1,560
1997	20,857.26	7,276	9,156	14,621	41.64	351
1998	290,277.41	95,857	120,627	210,289	42.62	4,934
1999	87,492.36	27,262	34,307	65,434	43.60	1,501
2000	117,716.09	34,488	43,400	90,796	44.58	2,037
2001	115,541.04	31,678	39,864	91,853	45.57	2,016
2002	34,593.27	8,834	11,117	28,319	46.56	608
2003	91,821.83	21,720	27,333	77,344	47.55	1,627
2005	114,623.60	22,802	28,694	101,977	49.53	2,059
2006	42,472.94	7,650	9,627	38,792	50.52	768
2010	60,549.31	6,316	7,948	61,078	54.51	1,120
2011	299,364.07	25,538	32,137	309,138	55.51	5,569

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C04 - CABLES - ABOVE GROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. -14						
2012	851,025.79	56,590	71,213	898,956	56.50	15,911
2013	162,111.78	7,701	9,691	175,116	57.50	3,045
2015	101,754.69	1,021	1,285	114,715	56.00	2,048
	10,550,928.82	5,202,879	6,547,333	5,480,726		148,856

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.8 1.41

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C06 - CAPACITORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. -3						
1966	44,470.98	42,704	28,601	17,204	2.37	7,259
1970	2,823.50	2,625	1,758	1,150	3.41	337
1971	260,900.32	240,473	161,054	107,673	3.68	29,259
1976	24,435.00	21,422	14,347	10,821	5.21	2,077
1980	73,112.99	60,611	40,594	34,712	6.83	5,082
1982	23,267.18	18,624	12,473	11,492	7.80	1,473
1987	83,725.72	59,923	40,133	46,104	10.68	4,317
1995	9,531.39	5,217	3,494	6,323	16.40	386
1996	315,830.49	165,441	110,802	214,503	17.20	12,471
2000	156,646.75	66,797	44,737	116,609	20.51	5,685
	994,744.32	683,837	457,993	566,594		68,346

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.3 6.87

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C07 - CHEMICAL FEED SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R4						
NET SALVAGE PERCENT.. -6						
1968	50,551.82	47,000	53,585			
1969	244,559.50	225,071	259,233			
1971	72,184.00	64,918	76,358	157	6.82	23
1979	50,551.82	39,653	46,641	6,944	11.70	594
1980	49,318.00	37,860	44,532	7,745	12.41	624
1997	28,676.00	12,314	14,484	15,913	26.77	594
2014	13,291.22	470	553	13,536	43.50	311
	509,132.36	427,286	495,386	44,295		2,146

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.6 0.42

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C09 - CIRCUIT BREAKERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -8						
1965	425,666.49	311,538	349,668	110,052	19.34	5,690
1966	367,145.54	264,806	297,217	99,300	19.93	4,982
1967	1,042,097.33	740,185	830,779	294,686	20.54	14,347
1968	796,597.78	556,915	625,078	235,248	21.16	11,118
1969	111,883.17	76,951	86,369	34,465	21.79	1,582
1970	1,667,950.56	1,127,668	1,265,687	535,700	22.44	23,873
1971	447,005.29	296,983	333,332	149,434	23.09	6,472
1972	570,106.07	371,892	417,409	198,306	23.76	8,346
1974	143,276.68	89,981	100,994	53,745	25.11	2,140
1975	284,265.78	174,942	196,354	110,653	25.81	4,287
1976	46,322.66	27,924	31,342	18,686	26.51	705
1977	591,124.91	348,683	391,360	247,055	27.23	9,073
1978	368,036.29	212,321	238,308	159,171	27.95	5,695
1979	77,376.00	43,621	48,960	34,606	28.68	1,207
1980	752,547.60	414,235	464,935	347,816	29.42	11,822
1981	201,796.88	108,354	121,616	96,325	30.17	3,193
1982	1,010,144.64	528,754	593,470	497,486	30.92	16,089
1983	312,136.55	159,057	178,524	158,583	31.69	5,004
1985	39,560.00	19,055	21,387	21,338	33.24	642
1986	37,090.93	17,338	19,460	20,598	34.03	605
1987	74,384.82	33,714	37,840	42,496	34.82	1,220
1988	144,831.66	63,532	71,308	85,110	35.63	2,389
1989	584,900.94	248,047	278,406	353,287	36.44	9,695
1990	377,794.87	154,708	173,643	234,375	37.25	6,292
1991	105,091.04	41,464	46,539	66,959	38.08	1,758
1992	1,090,316.93	413,906	464,566	712,976	38.91	18,324
1993	272,449.19	99,358	111,519	182,726	39.74	4,598
1994	25,447.73	8,891	9,979	17,505	40.59	431
1995	829,497.24	277,115	311,032	584,825	41.44	14,113
1996	429,268.08	136,765	153,504	310,106	42.30	7,331
1997	193,557.82	58,672	65,853	143,189	43.16	3,318
1998	154,366.88	44,375	49,806	116,910	44.03	2,655
2000	264,854.19	67,792	76,089	209,954	45.78	4,586
2001	18,558.77	4,453	4,998	15,045	46.67	322
2002	421,478.53	94,376	105,927	349,270	47.56	7,344
2003	349,437.85	72,648	81,540	295,853	48.45	6,106
2004	80,483.15	15,429	17,317	69,605	49.35	1,410
2005	50,011.92	8,768	9,841	44,172	50.26	879
2006	186,607.14	29,660	33,290	168,246	51.17	3,288
2007	289,169.14	41,224	46,270	266,033	52.08	5,108
2008	295,465.76	37,230	41,787	277,316	53.00	5,232
2009	608,353.56	66,576	74,725	582,297	53.92	10,799
2010	473,265.53	43,870	49,239	461,888	54.85	8,421

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C09 - CIRCUIT BREAKERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2.5						
NET SALVAGE PERCENT.. -8						
2011	952,197.82	72,500	81,374	947,000	55.77	16,980
2012	3,317,849.11	196,471	220,518	3,362,759	56.71	59,297
2013	3,601,188.71	152,966	171,688	3,717,596	57.64	64,497
2014	1,864,738.64	47,669	53,503	1,960,415	58.58	33,466
2015	13,308,974.30	162,423	182,303	14,191,390	43.75	324,375
	39,656,672.47	8,585,805	9,636,653	33,192,554		761,106

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.6 1.92

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C10 - COMPRESSED AIR SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 41-R1.5						
NET SALVAGE PERCENT.. 0						
1966	36,402.01	27,843	36,402			
1967	134,088.28	101,351	134,088			
1968	20,339.00	15,185	20,339			
1969	41,026.75	30,230	41,027			
1970	6,003.88	4,364	6,004			
1971	115,324.40	82,668	115,324			
1974	96,150.08	65,781	95,714	436	12.95	34
1975	10,000.00	6,727	9,788	212	13.42	16
1976	41,950.85	27,729	40,347	1,604	13.90	115
1977	138,474.81	89,873	130,768	7,707	14.39	536
1978	62,390.47	39,717	57,790	4,600	14.90	309
1979	42,011.01	26,211	38,138	3,873	15.42	251
1980	227,569.20	138,983	202,225	25,344	15.96	1,588
1982	153,558.59	89,663	130,463	23,096	17.06	1,354
1983	56,543.78	32,230	46,896	9,648	17.63	547
1984	166,456.15	92,525	134,627	31,829	18.21	1,748
1987	36,205.07	18,526	26,956	9,249	20.02	462
1988	114,736.03	56,948	82,861	31,875	20.65	1,544
1989	75,207.79	36,155	52,607	22,601	21.29	1,062
1990	41,543.60	19,323	28,116	13,428	21.93	612
1991	35,627.98	15,998	23,278	12,350	22.59	547
1992	515,633.45	223,104	324,623	191,010	23.26	8,212
1993	44,089.54	18,356	26,709	17,381	23.93	726
1994	234,644.19	93,743	136,399	98,245	24.62	3,990
1995	129,037.60	49,380	71,849	57,189	25.31	2,260
1996	10,656.00	3,896	5,669	4,987	26.01	192
1997	28,531.93	9,937	14,459	14,073	26.72	527
1998	83,020.75	27,457	39,951	43,070	27.44	1,570
1999	164,358.52	51,472	74,893	89,466	28.16	3,177
2000	194,860.89	57,556	83,746	111,115	28.89	3,846
2001	147,959.05	41,032	59,703	88,256	29.63	2,979
2002	41,272.02	10,690	15,554	25,718	30.38	847
2003	199,999.97	48,146	70,054	129,946	31.13	4,174
2006	30,617.63	5,668	8,247	22,371	33.41	670
2007	245,404.91	40,762	59,310	186,095	34.19	5,443
2008	437,893.16	64,401	93,705	344,188	34.97	9,842
2009	168,689.23	21,601	31,430	137,259	35.75	3,839
2010	140,437.37	15,243	22,179	118,258	36.55	3,236
2011	594,575.25	53,078	77,230	517,345	37.34	13,855

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C10 - COMPRESSED AIR SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 41-R1.5						
NET SALVAGE PERCENT.. 0						
2013	1,517,053.33	75,853	110,368	1,406,685	38.95	36,115
2014	1,947,748.40	58,432	85,020	1,862,728	39.77	46,838
2015	8,138,617.43	172,539	251,050	7,887,568	23.03	342,491
	16,666,710.35	2,160,376	3,115,906	13,550,805		505,554
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					26.8	3.03

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C11 - COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	833,717.71	750,346	833,718			
2012	486,015.94	340,211	474,522	11,494	1.50	7,663
2013	507,503.04	253,752	353,930	153,573	2.50	61,429
2014	906,905.69	272,072	379,483	527,423	3.50	150,692
2015	2,165,632.80	216,563	302,060	1,863,573	4.50	414,127
	4,899,775.18	1,832,944	2,343,713	2,556,063		633,911

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.0 12.94

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C12 - CONDENSERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -3						
1968	125,930.00	94,097	125,930	3,778	15.10	250
	125,930.00	94,097	125,930	3,778		250

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.1 0.20

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C13 - CONDUCTOR - TRANSMISSION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R3						
NET SALVAGE PERCENT.. -20						
1967	4,914,310.79	4,075,949	3,201,552	2,695,621	18.53	145,473
1968	2,408,871.94	1,966,593	1,544,708	1,345,938	19.18	70,174
1969	252,646.14	202,924	159,392	143,783	19.84	7,247
1970	773,190.55	610,669	479,665	448,164	20.51	21,851
1974	1,719,831.21	1,261,661	991,002	1,072,795	23.32	46,003
1976	115,943.00	81,647	64,132	75,000	24.79	3,025
1977	3,045,179.01	2,099,346	1,648,982	2,005,233	25.53	78,544
1978	4,925,086.90	3,320,474	2,608,146	3,301,958	26.29	125,597
1980	181,069.54	116,464	91,479	125,804	27.84	4,519
1981	4,162,701.19	2,611,662	2,051,393	2,943,848	28.63	102,824
1982	3,398,474.63	2,078,521	1,632,624	2,445,546	29.42	83,125
1983	5,998,197.19	3,571,351	2,805,204	4,392,633	30.23	145,307
1984	47,247.22	27,366	21,495	35,202	31.04	1,134
1985	5,404,348.91	3,041,568	2,389,073	4,096,146	31.86	128,567
1987	2,718,221.55	1,439,037	1,130,326	2,131,540	33.53	63,571
1988	1,473,940.83	755,247	593,227	1,175,502	34.38	34,191
1990	10,521,540.36	5,031,401	3,952,035	8,673,813	36.09	240,338
1991	86,132.87	39,690	31,175	72,184	36.96	1,953
1993	41,589.61	17,701	13,904	36,004	38.72	930
1994	60,822.38	24,803	19,482	53,505	39.61	1,351
1995	1,422,398.39	554,445	435,502	1,271,376	40.51	31,384
1996	1,224,020.27	455,086	357,458	1,111,366	41.41	26,838
1997	1,145,752.44	405,143	318,229	1,056,674	42.32	24,969
1998	1,573,598.67	527,464	414,309	1,474,009	43.24	34,089
1999	21,688.99	6,871	5,397	20,630	44.16	467
2000	3,007,366.22	897,410	704,893	2,903,946	45.08	64,418
2001	2,311,965.35	646,426	507,751	2,266,607	46.02	49,253
2002	2,594,819.36	676,719	531,545	2,582,238	46.96	54,988
2003	221,106.87	53,509	42,030	223,298	47.90	4,662
2004	434,397.16	96,869	76,088	445,189	48.85	9,113
2006	705,521.48	130,524	102,523	744,103	50.75	14,662
2009	111,767.05	14,217	11,167	122,953	53.64	2,292
2012	299,025.72	20,572	16,159	342,672	56.56	6,059
	67,322,773.79	36,859,329	28,952,047	51,835,281		1,628,918

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.8 2.42

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C14 - CONDUCTOR - DISTRIBUTION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -14						
1971	3,753.07	3,392	4,073	205	9.32	22
1977	656.03	539	647	101	12.57	8
1980	680,075.68	526,164	631,829	143,457	14.46	9,921
1981	3,794,248.37	2,871,143	3,447,731	877,712	15.13	58,011
1982	324,313.18	239,824	287,986	81,731	15.81	5,170
1983	365,982.33	264,146	317,192	100,028	16.51	6,059
1984	869,595.49	611,983	734,883	256,456	17.22	14,893
1985	1,131,140.14	775,415	931,135	358,365	17.94	19,976
1986	665,165.55	443,515	532,583	225,706	18.68	12,083
1987	929,287.13	601,732	722,573	336,814	19.44	17,326
1988	912,838.30	573,505	688,677	351,959	20.20	17,424
1989	1,267,583.55	771,336	926,237	518,808	20.98	24,729
1990	810,770.90	477,131	572,949	351,330	21.77	16,138
1991	674,376.06	383,195	460,149	308,640	22.57	13,675
1992	209,024.16	114,483	137,474	100,814	23.38	4,312
1993	718,909.28	378,635	454,673	364,884	24.21	15,072
1994	531,275.33	268,644	322,594	283,060	25.04	11,304
1995	767,449.08	371,540	446,153	428,739	25.89	16,560
1996	736,198.70	340,558	408,950	430,317	26.74	16,093
1997	1,387,592.71	611,292	734,053	847,803	27.61	30,706
1998	529,319.58	221,390	265,850	337,574	28.49	11,849
1999	506,039.28	200,369	240,607	336,278	29.37	11,450
2000	690,169.14	257,541	309,261	477,532	30.27	15,776
2001	579,576.91	203,058	243,836	416,882	31.17	13,374
2002	3,846,551.26	1,258,997	1,511,831	2,873,237	32.08	89,565
2003	456,361.12	138,736	166,597	353,655	33.00	10,717
2004	302,078.96	84,715	101,728	242,642	33.93	7,151
2005	211,959.87	54,447	65,381	176,253	34.86	5,056
2006	836,237.51	194,685	233,782	719,529	35.81	20,093
2007	503,436.12	105,216	126,346	447,571	36.75	12,179
2008	513,342.62	94,804	113,843	471,368	37.71	12,500
2009	700,782.34	112,380	134,948	663,944	38.67	17,169
2010	257,354.34	35,010	42,041	251,343	39.63	6,342
2011	679,683.14	75,764	90,979	683,860	40.60	16,844
2012	1,516,047.71	131,731	158,186	1,570,108	41.57	37,770
2013	2,528,214.39	156,905	188,415	2,693,749	42.55	63,308
2014	1,708,712.98	63,639	76,419	1,871,514	43.53	42,994
2015	1,173,947.41	17,532	21,052	1,317,248	37.67	34,968
	34,320,049.72	14,035,091	16,853,643	22,271,213		738,587

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.2 2.15

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C15 - CONTROL, METER, RELAYING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. 0						
1966	36,520.98	32,339	36,521			
1967	2,199,495.92	1,931,707	2,199,496			
1968	187,202.31	162,960	187,202			
1969	15,677.96	13,522	15,678			
1970	533,801.11	456,000	533,801			
1974	120,963.38	98,615	115,780	5,183	7.39	701
1975	601,106.89	483,290	567,412	33,695	7.84	4,298
1976	15,568.70	12,334	14,481	1,088	8.31	131
1977	246,762.49	192,475	225,978	20,784	8.80	2,362
1978	373,655.09	286,593	336,478	37,177	9.32	3,989
1979	375,981.62	283,302	332,614	43,368	9.86	4,398
1980	455,216.20	336,632	395,227	59,989	10.42	5,757
1981	170,456.85	123,539	145,042	25,415	11.01	2,308
1982	658,589.68	467,269	548,603	109,987	11.62	9,465
1983	388,062.45	269,218	316,078	71,984	12.25	5,876
1984	100,532.36	68,136	79,996	20,536	12.89	1,593
1985	252,442.18	166,864	195,909	56,533	13.56	4,169
1986	359,520.68	231,441	271,726	87,795	14.25	6,161
1987	368,451.36	230,743	270,906	97,545	14.95	6,525
1988	280,161.31	170,408	200,069	80,092	15.67	5,111
1989	472,543.72	278,801	327,330	145,214	16.40	8,855
1990	855,124.00	488,490	573,517	281,607	17.15	16,420
1991	317,765.84	175,486	206,031	111,735	17.91	6,239
1992	1,264,624.68	673,729	790,999	473,626	18.69	25,341
1993	186,436.87	95,642	112,290	74,147	19.48	3,806
1994	598,119.58	294,723	346,023	252,097	20.29	12,425
1995	1,065,976.45	503,674	591,344	474,632	21.10	22,494
1996	404,758.31	182,850	214,677	190,081	21.93	8,668
1997	565,586.88	243,485	285,866	279,721	22.78	12,279
1998	730,947.18	299,140	351,209	379,738	23.63	16,070
1999	530,389.44	205,659	241,456	288,933	24.49	11,798
2000	822,908.39	300,979	353,368	469,540	25.37	18,508
2001	950,459.04	326,483	383,311	567,148	26.26	21,597
2002	239,056.24	76,797	90,165	148,891	27.15	5,484
2003	446,753.60	133,356	156,568	290,186	28.06	10,342
2004	445,632.59	122,772	144,142	301,491	28.98	10,403
2005	427,141.09	107,853	126,626	300,515	29.90	10,051
2006	409,537.22	93,886	110,228	299,309	30.83	9,708
2007	82,358.78	16,945	19,895	62,464	31.77	1,966
2008	223,078.36	40,600	47,667	175,411	32.72	5,361
2009	894,285.65	141,297	165,891	728,395	33.68	21,627
2010	539,700.35	72,320	84,908	454,792	34.64	13,129
2011	412,886.73	45,418	53,324	359,563	35.60	10,100

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C15 - CONTROL, METER, RELAYING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R3						
NET SALVAGE PERCENT.. 0						
2012	1,129,269.89	96,835	113,690	1,015,580	36.57	27,771
2013	601,208.05	36,824	43,234	557,974	37.55	14,859
2014	700,071.44	25,728	30,206	669,865	38.53	17,386
2015	6,588,417.68	97,509	114,482	6,473,936	33.40	193,830
	29,645,207.57	11,194,668	13,067,444	16,577,763		599,361
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					27.7	2.02

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C16 - COOLING SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R1.5						
NET SALVAGE PERCENT.. -3						
1965	49,714.69	40,171	51,206			
1966	135,606.99	108,353	139,675			
1968	3,234.56	2,524	3,332			
1969	49,140.60	37,860	50,615			
1971	36,015.66	27,006	37,096			
1973	19,339.13	14,078	19,919			
1977	283,921.00	193,156	292,439			
1979	137,803.24	90,201	139,351	2,586	14.58	177
1980	26,475.28	16,975	26,225	1,045	15.10	69
1981	25,088.47	15,737	24,312	1,529	15.64	98
1982	166,753.32	102,238	157,947	13,809	16.19	853
1983	8,937.20	5,351	8,267	938	16.75	56
1984	249,308.82	145,599	224,935	31,853	17.32	1,839
1988	32,571.66	17,009	26,277	7,272	19.72	369
1989	129,470.58	65,510	101,206	32,149	20.35	1,580
1992	37,915.23	17,271	26,682	12,371	22.31	555
1993	9,304.03	4,078	6,300	3,283	22.98	143
1994	352,789.80	148,438	229,321	134,052	23.66	5,666
1995	161,864.75	65,229	100,772	65,949	24.35	2,708
1998	313,562.88	109,325	168,895	154,075	26.46	5,823
1999	106,668.44	35,213	54,400	55,468	27.18	2,041
2000	152,434.02	47,455	73,313	83,694	27.91	2,999
2002	39,354.90	10,752	16,611	23,925	29.39	814
2003	86,319.27	21,916	33,858	55,051	30.14	1,827
2005	28,881.00	6,210	9,594	20,153	31.65	637
2006	135,121.63	26,374	40,745	98,430	32.42	3,036
2007	79,243.07	13,896	21,468	60,152	33.19	1,812
2008	340,925.64	52,936	81,780	269,373	33.97	7,930
2009	480,251.41	64,800	100,109	394,550	34.76	11,351
2010	348,761.61	39,964	61,740	297,484	35.55	8,368
2011	446,006.93	42,034	64,938	394,449	36.34	10,854
2012	16,052.49	1,178	1,820	14,714	37.15	396
2013	1,708,834.64	90,205	139,357	1,620,743	37.95	42,707
2014	557,250.79	17,650	27,268	546,700	38.77	14,101
2015	3,252,113.98	73,023	112,813	3,236,865	22.49	143,925
	10,007,037.71	1,769,715	2,674,586	7,632,663		272,734

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.0 2.73

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C17 - COUNTERPOISE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -6						
1967	431,098.26	320,208	314,987	141,977	16.46	8,626
1968	247,792.88	181,380	178,423	84,237	17.02	4,949
1970	546.00	387	381	198	18.20	11
1974	15,552.35	10,281	10,113	6,372	20.70	308
1978	123,318.62	75,104	73,879	56,839	23.40	2,429
1981	9,506.07	5,399	5,311	4,765	25.53	187
1982	27,542.40	15,256	15,007	14,188	26.26	540
1983	15,526.13	8,378	8,241	8,217	27.00	304
1985	214,651.00	109,629	107,842	119,688	28.50	4,200
1986	106,804.26	52,963	52,100	61,113	29.27	2,088
1987	11,117.41	5,346	5,259	6,525	30.05	217
1988	215,117.18	100,205	98,571	129,453	30.83	4,199
1989	147,661.97	66,536	65,451	91,071	31.62	2,880
1990	34,172.01	14,871	14,629	21,593	32.42	666
1991	558.98	235	231	362	33.23	11
1992	161,824.60	65,339	64,274	107,260	34.05	3,150
1993	365,268.31	141,709	139,398	247,786	34.87	7,106
1994	331,398.89	123,269	121,259	230,024	35.70	6,443
1995	19,011.26	6,764	6,654	13,498	36.54	369
1996	17,886.51	6,074	5,975	12,985	37.38	347
1997	48,442.27	15,657	15,402	35,947	38.23	940
1999	3,158.47	916	901	2,447	39.96	61
2000	280,787.97	76,683	75,433	222,202	40.83	5,442
2001	216,852.36	55,544	54,638	175,226	41.71	4,201
2002	181,203.61	43,340	42,633	149,443	42.59	3,509
2003	352,909.92	78,352	77,075	297,010	43.48	6,831
2012	43,379.13	2,751	2,706	43,276	51.71	837
	3,623,088.82	1,582,576	1,556,773	2,283,701		70,851

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.2 1.96

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C18 - CRANES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R3						
NET SALVAGE PERCENT.. -3						
1966	658,978.00	422,473	206,343	472,404	26.43	17,874
1967	189,000.00	119,194	58,216	136,454	27.14	5,028
1969	234,007.00	142,517	69,608	171,419	28.61	5,992
1979	597,576.53	295,263	144,211	471,293	36.42	12,940
1980	136,287.00	65,696	32,087	108,289	37.24	2,908
1982	1,501,411.45	686,842	335,465	1,210,989	38.91	31,123
1984	993,957.00	429,986	210,012	813,764	40.60	20,043
1985	123,618.00	51,912	25,355	101,972	41.46	2,460
1988	304,605.66	116,220	56,764	256,980	44.07	5,831
1989	23,800.39	8,773	4,285	20,229	44.95	450
1993	15,442.12	4,876	2,382	13,523	48.54	279
1995	3,781.63	1,093	534	3,361	50.36	67
1996	6,207.08	1,709	835	5,558	51.29	108
2002	8,414.90	1,621	792	7,875	56.91	138
2003	1,560,150.29	278,694	136,117	1,470,838	57.86	25,421
2006	93,901.29	12,808	6,256	90,462	60.73	1,490
2008	15,189.34	1,638	800	14,845	62.67	237
2011	143,366.54	9,303	4,544	143,124	65.59	2,182
2013	215,839.27	7,812	3,815	218,499	67.54	3,235
2014	63,166.18	1,375	672	64,389	68.52	940
2015	13,442.50	118	57	13,788	58.32	236
	6,902,142.17	2,659,923	1,299,150	5,810,056		138,982

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.8 2.01

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D01 - DAMS, DYKES, CANALS AND TUNNELS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 110-R4						
NET SALVAGE PERCENT.. -8						
1956	615,305.93	348,759	103,011	561,519	52.27	10,743
1966	42,867,104.87	20,454,708	6,041,606	40,254,867	61.40	655,617
1967	27,131,965.00	12,695,904	3,749,926	25,552,596	62.34	409,891
1969	146,223.72	65,724	19,413	138,509	64.22	2,157
1970	4,899,824.94	2,156,678	637,007	4,654,804	65.17	71,426
1978	3,644,386.00	1,329,284	392,624	3,543,313	72.85	48,638
1979	26,954,544.28	9,574,869	2,828,082	26,282,826	73.82	356,039
1980	8,733,611.13	3,019,185	891,762	8,540,538	74.79	114,194
1982	54,770,206.67	17,885,145	5,282,647	53,869,176	76.74	701,970
1983	21,684,267.05	6,872,308	2,029,839	21,389,169	77.72	275,208
1984	113,124,637.53	34,764,785	10,268,302	111,906,307	78.70	1,421,935
1985	10,995,558.61	3,273,281	966,813	10,908,390	79.68	136,902
1986	48,803.37	14,054	4,151	48,557	80.67	602
1988	12,002,331.79	3,224,167	952,306	12,010,212	82.64	145,332
1989	503,088.54	130,303	38,487	504,849	83.62	6,037
1992	38,009.96	8,736	2,580	38,471	86.59	444
1993	4,711.97	1,037	306	4,783	87.58	55
2003	28,219,035.47	3,457,566	1,021,245	29,455,313	97.52	302,044
2005	2,863,283.51	294,608	87,017	3,005,329	99.52	30,198
2009	704,177.11	44,870	13,253	747,258	103.51	7,219
2010	496,885.77	26,784	7,911	528,726	104.51	5,059
2012	1,302,985.46	44,778	13,226	1,393,998	106.50	13,089
2014	158,306.95	2,332	689	170,283	108.50	1,569
	361,909,255.63	119,689,865	35,352,203	355,509,793		4,716,368

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 75.4 1.30

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D02 - DIESEL SYSTEMS AND ENGINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0.5						
NET SALVAGE PERCENT.. -11						
1965	644,462.40	507,901	715,353			
1968	10,325.00	7,908	11,461			
1973	394,804.06	285,903	438,233			
1980	1,137,849.89	746,694	1,202,375	60,638	10.22	5,933
1981	453,076.02	292,495	470,994	31,920	10.46	3,052
1982	933,452.28	592,668	954,353	81,779	10.70	7,643
1983	1,238,000.00	772,289	1,243,590	130,590	10.95	11,926
1984	337,094.61	206,395	332,351	41,824	11.21	3,731
1986	154,494.96	90,958	146,466	25,023	11.74	2,131
1987	41,924.03	24,180	38,936	7,600	12.01	633
1988	83,806.15	47,294	76,156	16,869	12.29	1,373
1989	64,057.60	35,324	56,881	14,223	12.58	1,131
1990	472,403.24	254,423	409,688	114,680	12.87	8,911
1991	383,928.98	201,659	324,724	101,437	13.17	7,702
1992	28,368.16	14,510	23,365	8,124	13.48	603
1993	108,978.30	54,241	87,342	33,624	13.79	2,438
1994	1,528,540.74	739,074	1,190,105	506,575	14.11	35,902
1995	630,494.80	295,616	476,020	223,829	14.44	15,501
1996	530,077.55	240,768	387,700	200,686	14.77	13,587
1997	1,429,293.16	627,625	1,010,643	575,872	15.11	38,112
1998	1,109,693.01	470,039	756,888	474,871	15.46	30,716
1999	232,763.17	94,872	152,769	105,598	15.82	6,675
2000	1,480,070.67	578,950	932,263	710,615	16.19	43,892
2001	1,962,927.92	735,580	1,184,479	994,371	16.56	60,047
2002	1,639,155.44	585,867	943,401	876,062	16.95	51,685
2003	242,831.69	82,480	132,815	136,728	17.35	7,881
2005	1,106,121.95	333,469	536,974	690,821	18.21	37,936
2006	357,925.58	100,278	161,474	235,823	18.69	12,618
2007	916,657.89	236,465	380,771	636,719	19.19	33,180
2008	109,011.51	25,507	41,073	79,930	19.73	4,051
2009	2,637,507.76	550,395	886,282	2,041,352	20.30	100,559
2010	2,771,772.15	503,343	810,516	2,266,151	20.91	108,376
2011	3,742,552.77	571,623	920,465	3,233,769	21.56	149,989
2012	2,407,096.08	294,975	474,988	2,196,889	22.24	98,781
2013	1,510,549.68	136,820	220,316	1,456,394	22.96	63,432
2014	6,633,910.89	374,073	602,357	6,761,284	23.73	284,926
2015	2,431,370.59	98,777	159,057	2,539,764	13.16	192,991
	41,897,350.68	11,811,438	18,893,624	27,612,435		1,448,044

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 19.1 3.46

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D03 - DISCONNECT SWITCHES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -3						
1965	242,270.77	179,805	229,620	19,919	15.37	1,296
1966	177,667.19	130,095	166,138	16,859	15.90	1,060
1967	714,863.43	515,954	658,899	77,410	16.46	4,703
1968	482,439.40	343,143	438,211	58,702	17.02	3,449
1969	207,719.11	145,486	185,793	28,158	17.60	1,600
1970	1,273,238.73	877,469	1,120,571	190,865	18.20	10,487
1971	232,031.02	157,300	200,880	38,112	18.80	2,027
1972	280,022.05	186,584	238,277	50,146	19.42	2,582
1974	160,146.36	102,870	131,370	33,581	20.70	1,622
1975	172,354.33	108,581	138,663	38,862	21.36	1,819
1976	21,825.02	13,475	17,208	5,272	22.03	239
1977	395,853.89	239,374	305,693	102,037	22.71	4,493
1978	242,505.95	143,512	183,272	66,509	23.40	2,842
1979	42,312.17	24,485	31,269	12,313	24.10	511
1980	274,055.46	154,945	197,872	84,405	24.81	3,402
1981	134,922.49	74,463	95,093	43,877	25.53	1,719
1982	281,577.30	151,552	193,539	96,486	26.26	3,674
1983	44,083.42	23,116	29,520	15,886	27.00	588
1984	44,313.73	22,614	28,879	16,764	27.75	604
1985	15,913.15	7,897	10,085	6,306	28.50	221
1986	31,745.19	15,297	19,535	13,163	29.27	450
1987	151,700.26	70,882	90,520	65,731	30.05	2,187
1988	132,691.61	60,061	76,701	59,971	30.83	1,945
1989	502,766.48	220,133	281,121	236,728	31.62	7,487
1990	481,796.61	203,736	260,181	236,070	32.42	7,282
1991	36,330.90	14,812	18,916	18,505	33.23	557
1992	231,030.02	90,642	115,754	122,207	34.05	3,589
1993	104,983.77	39,577	50,542	57,591	34.87	1,652
1994	35,727.81	12,913	16,491	20,309	35.70	569
1995	422,371.06	146,018	186,472	248,570	36.54	6,803
1996	301,380.12	99,447	126,999	183,423	37.38	4,907
1997	30,529.45	9,588	12,244	19,201	38.23	502
1998	166,141.53	49,502	63,217	107,909	39.09	2,761
2000	170,065.45	45,130	57,633	117,534	40.83	2,879
2001	96,520.44	24,023	30,679	68,737	41.71	1,648
2002	187,571.33	43,593	55,670	137,528	42.59	3,229
2003	129,652.34	27,970	35,719	97,823	43.48	2,250
2004	157,797.58	31,383	40,078	122,454	44.38	2,759
2005	187,574.40	34,145	43,605	149,597	45.28	3,304
2006	35,094.81	5,797	7,403	28,745	46.18	622
2009	532,335.09	60,511	77,275	471,030	48.93	9,627
2010	57,070.54	5,504	7,029	51,754	49.85	1,038
2011	1,097,601.33	86,746	110,779	1,019,750	50.78	20,082

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D03 - DISCONNECT SWITCHES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -3						
2012	1,533,843.65	94,507	120,690	1,459,169	51.71	28,218
2013	1,081,960.39	47,619	60,812	1,053,607	52.65	20,012
2014	2,921,484.67	77,696	99,222	2,909,907	53.58	54,310
2015	4,625,646.05	58,126	74,229	4,690,186	40.32	116,324
	20,883,527.85	5,278,078	6,740,368	14,769,665		355,931

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.5 1.70

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT D04 - DYKES AND LINERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-L1.5						
NET SALVAGE PERCENT.. -8						
1968	26,479.96	17,309	28,598			
1974	142,100.00	87,075	150,013	3,455	18.17	190
1975	213,342.87	129,249	222,670	7,740	18.44	420
1980	53,900.59	30,700	52,890	5,323	19.85	268
1981	213,183.92	119,779	206,355	23,884	20.15	1,185
1982	89,895.87	49,816	85,823	11,265	20.45	551
1983	68,476.83	37,383	64,403	9,552	20.77	460
1985	211,511.23	111,822	192,647	35,785	21.44	1,669
1987	181,989.53	92,846	159,955	36,594	22.16	1,651
1990	264,232.48	126,651	218,195	67,176	23.36	2,876
1992	217,059.26	99,016	170,585	63,839	24.26	2,631
1998	39,596.79	14,693	25,313	17,452	27.57	633
1999	134,484.01	47,654	82,098	63,145	28.22	2,238
2002	75,888.45	22,812	39,301	42,659	30.31	1,407
2005	16,513.92	3,996	6,884	10,951	32.59	336
2011	478,782.72	52,572	90,571	426,514	37.73	11,304
2014	49,894.57	1,860	3,204	50,682	40.55	1,250
	2,477,333.00	1,045,233	1,799,505	876,014		29,069

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.1 1.17

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT E01 - ELEVATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S5						
NET SALVAGE PERCENT.. -3						
1971	89,800.00	83,327	89,800	2,694	4.46	604
	89,800.00	83,327	89,800	2,694		604
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					4.5	0.67

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT E02 - EMS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R2.5						
NET SALVAGE PERCENT.. 0						
1980	16,461.46	12,633	16,461			
1990	11,759,258.77	7,132,814	11,759,259			
1992	12,860.27	7,297	12,860			
1993	48,931.95	26,773	48,932			
1994	229,340.02	120,699	229,340			
1998	99,085.18	43,541	99,085			
1999	45,962.90	19,160	45,427	536	20.41	26
2000	117,114.88	46,109	109,322	7,793	21.22	367
2001	299,861.84	111,036	263,260	36,602	22.04	1,661
2004	8,032.68	2,396	5,681	2,352	24.56	96
2005	236,118.93	64,562	153,073	83,046	25.43	3,266
2009	22,360.02	3,846	9,119	13,241	28.98	457
2011	12,028.86	1,443	3,421	8,608	30.80	279
2012	9,801.36	918	2,177	7,625	31.72	240
	12,917,219.12	7,593,227	12,757,417	159,802		6,392

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.0 0.05

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT E03 - ENVIRONMENTAL EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R2.5						
NET SALVAGE PERCENT.. 0						
1968	584,529.60	458,920	543,919	40,611	9.67	4,200
1994	100,098.42	42,220	50,040	50,058	26.02	1,924
1995	29,947.59	12,099	14,340	15,608	26.82	582
1997	129,242.84	47,533	56,337	72,906	28.45	2,563
2008	71,891.96	11,135	13,197	58,695	38.03	1,543
2015	20,165.58	298	354	19,812	33.17	597
	935,875.99	572,205	678,187	257,689		11,409

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 22.6 1.22

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F01 - FALL ARREST EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R4						
NET SALVAGE PERCENT.. 0						
2005	198,105.16	130,353	179,958	18,147	5.13	3,537
2006	217,857.72	131,586	181,660	36,198	5.94	6,094
2007	195,813.28	107,174	147,958	47,855	6.79	7,048
2008	199,279.40	97,248	134,255	65,024	7.68	8,467
2009	501,083.68	213,462	294,692	206,392	8.61	23,971
2010	43,100.70	15,631	21,579	21,522	9.56	2,251
2011	205,129.64	61,129	84,391	120,739	10.53	11,466
2012	184,242.00	42,744	59,010	125,232	11.52	10,871
2013	246,771.47	40,964	56,552	190,219	12.51	15,205
2014	336,964.29	33,696	46,519	290,445	13.50	21,514
2015	180,672.63	6,396	8,830	171,843	13.61	12,626
	2,509,019.97	880,383	1,215,404	1,293,616		123,050

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.5 4.90

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F02 - FENCING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 52-R3						
NET SALVAGE PERCENT.. -3						
1967	95,307.91	75,041	98,167			
1968	58,848.45	45,705	60,614			
1969	66,173.02	50,660	68,158			
1970	117,281.68	88,440	120,800			
1971	13,312.00	9,883	13,711			
1972	65,739.16	48,010	67,711			
1973	24,667.06	17,707	25,407			
1974	51,949.96	36,633	53,508			
1975	11,288.90	7,813	11,628			
1976	59,296.08	40,251	61,075			
1977	19,241.61	12,802	19,819			
1978	145,749.97	94,952	150,122			
1979	18,281.62	11,653	18,637	193	19.82	10
1980	279,753.22	174,273	278,725	9,421	20.55	458
1981	85,268.34	51,885	82,983	4,843	21.28	228
1982	189,624.32	112,569	180,038	15,275	22.03	693
1983	282,397.46	163,390	261,319	29,550	22.79	1,297
1984	85,097.82	47,938	76,670	10,981	23.56	466
1985	245,056.33	134,261	214,731	37,677	24.34	1,548
1986	25,867.46	13,767	22,018	4,625	25.13	184
1987	213,373.01	110,184	176,224	43,550	25.93	1,680
1988	75,843.42	37,948	60,692	17,427	26.74	652
1989	182,675.48	88,433	141,436	46,720	27.56	1,695
1990	112,235.72	52,488	83,947	31,656	28.39	1,115
1991	137,599.47	62,060	99,256	42,471	29.23	1,453
1992	122,833.27	53,333	85,299	41,219	30.08	1,370
1993	43,943.39	18,340	29,332	15,930	30.93	515
1994	83,857.05	33,552	53,662	32,711	31.80	1,029
1995	82,864.42	31,727	50,743	34,607	32.67	1,059
1996	45,009.81	16,440	26,293	20,067	33.56	598
1997	57,176.21	19,876	31,789	27,102	34.45	787
1998	133,014.01	43,867	70,159	66,845	35.35	1,891
1999	43,860.85	13,683	21,884	23,293	36.25	643
2000	52,825.13	15,527	24,833	29,577	37.16	796
2001	163,588.29	45,105	72,139	96,357	38.08	2,530
2002	50,286.59	12,939	20,694	31,101	39.01	797
2003	1,015,869.57	242,668	388,113	658,233	39.94	16,481
2004	32,448.49	7,147	11,431	21,991	40.88	538
2005	116,002.80	23,368	37,374	82,109	41.83	1,963
2006	5,454.01	996	1,593	4,025	42.78	94
2008	58,461.93	8,465	13,539	46,677	44.69	1,044
2009	255,773.00	32,172	51,454	211,992	45.65	4,644
2011	813,892.56	71,097	113,709	724,600	47.59	15,226

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F02 - FENCING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 52-R3						
NET SALVAGE PERCENT.. -3						
2012	296,669.35	20,155	32,235	273,334	48.57	5,628
2013	110,462.43	5,383	8,609	105,167	49.54	2,123
2014	370,645.31	10,865	17,377	364,388	50.52	7,213
2015	938,720.95	11,022	17,629	949,254	43.55	21,797
	7,555,588.89	2,326,473	3,627,286	4,154,971		100,245
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					41.4	1.33

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F03 - FIRE FIGHTING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. 0						
1967	597,273.05	501,112	597,273			
1968	39,688.85	32,878	39,689			
1969	101,232.00	82,727	101,232			
1970	9,203.91	7,411	9,204			
1971	281,955.00	223,534	281,955			
1973	21,689.45	16,627	21,689			
1975	10,000.43	7,392	10,000			
1976	58,348.31	42,314	58,348			
1977	28,858.00	20,512	28,858			
1978	192,136.50	133,727	192,136			
1979	115,181.72	78,439	115,182			
1980	214,201.74	142,616	214,202			
1981	9,401.89	6,113	9,402			
1982	406,897.98	258,055	401,975	4,923	18.29	269
1983	94,674.89	58,509	91,140	3,535	19.10	185
1984	583,752.17	351,185	547,045	36,707	19.92	1,843
1985	185,991.75	108,768	169,429	16,563	20.76	798
1986	152,946.68	86,843	135,276	17,671	21.61	818
1987	96,794.16	53,276	82,989	13,805	22.48	614
1988	217,479.69	115,873	180,497	36,983	23.36	1,583
1989	762,666.44	392,773	611,828	150,838	24.25	6,220
1990	64,327.11	31,971	49,802	14,525	25.15	578
1992	149,080.69	68,637	106,917	42,164	26.98	1,563
1995	24,518.16	9,910	15,437	9,081	29.79	305
1997	180,253.80	65,937	102,711	77,543	31.71	2,445
1998	68,518.74	23,749	36,994	31,525	32.67	965
1999	94,038.17	30,769	47,929	46,109	33.64	1,371
2001	216,064.47	62,227	96,932	119,132	35.60	3,346
2002	629,240.42	168,888	263,079	366,161	36.58	10,010
2003	657,749.39	163,648	254,916	402,833	37.56	10,725
2005	55,241.78	11,557	18,002	37,240	39.54	942
2008	238,692.84	35,708	55,623	183,070	42.52	4,306
2009	1,916,574.45	248,771	387,514	1,529,060	43.51	35,143
2010	4,415.61	485	755	3,661	44.51	82
2011	210,565.13	18,909	29,455	181,110	45.51	3,980
2012	586,212.13	41,035	63,921	522,291	46.50	11,232
2013	558,076.76	27,904	43,466	514,611	47.50	10,834
2014	951,159.22	28,535	44,450	906,709	48.50	18,695
2015	3,121,815.69	33,091	51,546	3,070,269	46.45	66,098
	13,906,919.17	3,792,415	5,568,798	8,338,121		194,950

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.8 1.40

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F04 - FOOTINGS AND FOUNDATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -8						
1965	167,301.40	121,171	141,041	39,645	21.41	1,852
1967	1,723,662.79	1,209,732	1,408,104	453,452	22.76	19,923
1968	891,091.56	615,181	716,059	246,320	23.45	10,504
1970	490,202.40	326,852	380,449	148,970	24.87	5,990
1973	14,582.27	9,190	10,697	5,052	27.07	187
1974	68,284.09	42,183	49,100	24,647	27.82	886
1975	108,441.06	65,621	76,382	40,734	28.58	1,425
1976	113,065.81	66,973	77,955	44,156	29.35	1,504
1977	1,266,265.77	733,645	853,949	513,618	30.13	17,047
1978	1,106,583.24	626,787	729,568	465,542	30.91	15,061
1979	334,143.65	184,822	215,129	145,746	31.71	4,596
1980	540,108.76	291,571	339,383	243,934	32.51	7,503
1981	299,457.16	157,625	183,472	139,942	33.32	4,200
1982	471,876.97	241,956	281,632	227,995	34.14	6,678
1983	766,192.98	382,424	445,134	382,354	34.96	10,937
1984	7,817.94	3,793	4,415	4,028	35.80	113
1985	25,845.64	12,179	14,176	13,737	36.64	375
1986	47,648.73	21,780	25,352	26,109	37.49	696
1987	307,062.57	136,017	158,321	173,307	38.34	4,520
1988	115,812.71	49,627	57,765	67,313	39.21	1,717
1989	340,873.18	141,139	164,283	203,860	40.08	5,086
1990	1,312,152.51	524,336	610,317	806,808	40.95	19,702
1991	1,012,711.49	389,870	453,801	639,927	41.83	15,298
1992	626,613.85	231,967	270,005	406,738	42.72	9,521
1993	84,738.76	30,102	35,038	56,480	43.62	1,295
1994	5,426.96	1,847	2,150	3,711	44.52	83
1995	467,057.62	151,871	176,775	327,647	45.43	7,212
1996	148,954.64	46,183	53,756	107,115	46.34	2,312
1998	114,131.79	31,897	37,127	86,135	48.18	1,788
1999	65,572.18	17,312	20,151	50,667	49.11	1,032
2000	30,492.18	7,574	8,816	24,116	50.05	482
2001	33,856.28	7,881	9,173	27,392	50.99	537
2002	2,625,474.99	570,165	663,662	2,171,851	51.93	41,823
2003	1,044,934.04	210,425	244,930	883,599	52.88	16,710
2004	9,714.31	1,803	2,099	8,392	53.83	156
2008	29,323.54	3,571	4,157	27,512	57.67	477
2011	40,587.70	2,974	3,462	40,373	60.59	666

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F04 - FOOTINGS AND FOUNDATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -8						
2012	22,681.06	1,296	1,509	22,987	61.56	373
2014	680,260.20	16,729	19,472	715,209	63.52	11,260
2015	2,852,234.26	28,032	32,628	3,047,785	54.45	55,974
	20,413,239.04	7,716,103	8,981,394	13,064,904		307,501
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.5						1.51

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F05 - FREQUENCY CONVERSION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S4						
NET SALVAGE PERCENT.. 0						
1977	1,607,215.00	1,273,991	1,590,594	16,621	9.33	1,781
1982	12,043.92	8,661	10,813	1,231	12.64	97
2005	47,702.22	11,130	13,896	33,806	34.50	980
2007	28,008.98	5,291	6,606	21,403	36.50	586
2009	758,606.76	109,573	136,804	621,803	38.50	16,151
	2,453,576.88	1,408,646	1,758,713	694,864		19,595

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.5 0.80

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F06 - FUEL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -11						
1956	11,785.53	9,924	13,082			
1966	73,482.51	54,959	81,566			
1968	828,616.98	601,894	919,765			
1969	757,540.47	541,857	840,870			
1970	800.00	563	888			
1971	87,288.00	60,440	96,890			
1973	3,244.42	2,169	3,601			
1974	290,612.82	190,709	322,580			
1975	44,415.90	28,595	49,302			
1976	212,487.00	134,063	235,861			
1977	16,590.50	10,254	18,415			
1978	128,269.57	77,597	142,379			
1980	179,972.65	104,040	191,675	8,095	23.96	338
1981	495,612.65	279,686	515,271	34,859	24.58	1,418
1982	104,546.72	57,536	106,000	10,047	25.21	399
1983	17,194.91	9,223	16,992	2,094	25.84	81
1985	205,026.03	104,049	191,691	35,888	27.14	1,322
1986	24,674.35	12,161	22,404	4,985	27.80	179
1987	460,163.55	219,943	405,205	105,577	28.47	3,708
1988	13,928.85	6,450	11,883	3,578	29.14	123
1989	282,980.18	126,711	233,442	80,666	29.83	2,704
1990	773,369.43	334,448	616,160	242,280	30.52	7,938
1991	370,174.16	154,332	284,329	126,564	31.22	4,054
1992	661,127.69	265,361	488,879	244,973	31.92	7,675
1993	338,825.34	130,656	240,710	135,386	32.63	4,149
1994	371,177.35	137,198	252,762	159,245	33.35	4,775
1995	223,856.04	79,166	145,849	102,631	34.07	3,012
1996	403,902.53	136,293	251,095	197,237	34.80	5,668
1997	89,694.14	28,813	53,083	46,477	35.53	1,308
1998	83,733.99	25,523	47,021	45,924	36.27	1,266
1999	410,246.57	118,215	217,790	237,584	37.02	6,418
2000	244,674.28	66,431	122,387	149,201	37.77	3,950
2001	731,207.43	186,353	343,322	468,318	38.52	12,158
2002	436,496.97	103,879	191,378	293,134	39.28	7,463
2003	270,163.44	59,676	109,942	189,939	40.05	4,743
2005	780,471.63	145,716	268,455	597,869	41.59	14,375
2006	545,970.78	92,480	170,378	435,650	42.37	10,282
2007	758,499.28	115,345	212,502	629,432	43.15	14,587
2008	348,333.75	46,862	86,335	300,315	43.94	6,835
2009	2,308,883.16	270,125	497,656	2,065,204	44.73	46,170
2010	535,159.47	53,106	97,838	496,189	45.53	10,898
2011	1,724,597.41	140,510	258,864	1,655,439	46.33	35,731
2012	588,452.12	37,362	68,833	584,349	47.14	12,396

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F06 - FUEL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R1.5						
NET SALVAGE PERCENT.. -11						
2013	786,406.17	35,789	65,935	806,976	47.95	16,830
2014	1,591,994.48	43,471	80,087	1,687,027	48.77	34,591
2015	8,897,247.05	175,792	323,865	9,552,079	27.59	346,215
	28,513,898.25	5,615,725	9,915,217	21,735,210		633,759
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					34.3	2.22

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G01 - GAS TURBINE SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -2						
1968	995,759.29	835,788	1,015,674			
1974	4,704,054.47	3,641,257	4,798,136			
1975	6,031,773.20	4,592,404	6,152,409			
1977	384,018.97	282,286	391,699			
1981	210,609.85	142,595	214,822			
1989	83,605.00	45,519	76,732	8,545	20.98	407
1992	13,070,767.89	6,405,314	10,797,482	2,534,701	23.38	108,413
1997	548,240.40	216,099	364,280	194,925	27.61	7,060
1999	9,087.69	3,220	5,428	3,841	29.37	131
2001	61,837.92	19,385	32,677	30,398	31.17	975
2007	31,100.00	5,816	9,804	21,918	36.75	596
2009	129,634.16	18,600	31,354	100,873	38.67	2,609
2010	1,268,695.89	154,421	260,309	1,033,761	39.63	26,085
2011	222,865.40	22,228	37,470	189,853	40.60	4,676
2012	376,344.00	29,259	49,322	334,549	41.57	8,048
2013	7,810,787.00	433,724	731,131	7,235,872	42.55	170,056
2014	2,091,471.80	69,695	117,485	2,015,816	43.53	46,309
2015	31,295,107.96	418,165	704,904	31,216,106	37.67	828,673
	69,325,760.89	17,335,775	25,791,118	44,921,158		1,204,038

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.3 1.74

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G02 - GATES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 80-R4						
NET SALVAGE PERCENT.. -8						
1966	1,986,152.97	1,270,124	581,347	1,563,698	32.63	47,922
1967	1,051,672.86	660,608	302,366	833,441	33.47	24,901
1970	396,402.00	235,197	107,652	320,462	36.05	8,889
1978	267,693.00	132,773	60,771	228,337	43.26	5,278
1979	1,419,329.57	686,146	314,055	1,218,821	44.19	27,581
1980	1,051,492.17	495,127	226,624	908,988	45.12	20,146
1982	4,123,249.27	1,836,373	840,525	3,612,584	47.01	76,847
1983	1,976,506.08	854,918	391,304	1,743,323	47.96	36,350
1984	1,120,133.00	470,131	215,184	994,560	48.91	20,334
1985	185,213.00	75,335	34,482	165,548	49.87	3,320
1986	139,462.75	54,919	25,137	125,483	50.83	2,469
1988	1,014,882.86	373,213	170,823	925,250	52.76	17,537
1989	180,329.65	63,954	29,272	165,484	53.73	3,080
2004	439,111.41	67,997	31,123	443,117	68.53	6,466
2012	32,000.00	1,512	692	33,868	76.50	443
2013	1,925,734.06	64,994	29,748	2,050,045	77.50	26,452
2014	321,648.04	6,513	2,981	344,399	78.50	4,387
2015	1,417,520.75	10,104	4,625	1,526,298	74.69	20,435
	19,048,533.44	7,359,938	3,368,711	17,203,705		352,837

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.8 1.85

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G03 - GENERATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S3						
NET SALVAGE PERCENT.. -8						
1966	18,139.94	13,449	12,962	6,629	20.38	325
1967	1,704,660.61	1,246,232	1,201,125	639,908	21.00	30,472
1968	5,528,661.06	3,984,000	3,839,801	2,131,153	21.63	98,528
1970	3,447,277.74	2,409,118	2,321,921	1,401,139	22.94	61,078
1971	1,587,930.00	1,091,506	1,051,999	662,965	23.63	28,056
1977	3,185,771.51	1,953,213	1,882,517	1,558,116	28.10	55,449
1978	271,000.00	162,505	156,623	136,057	28.91	4,706
1979	786,015.97	460,629	443,957	404,940	29.73	13,621
1980	12,037,307.04	6,886,124	6,636,884	6,363,408	30.57	208,159
1982	5,671,758.61	3,082,535	2,970,964	3,154,535	32.29	97,694
1983	177,355.00	93,797	90,402	101,141	33.17	3,049
1985	9,224,267.93	4,601,046	4,434,513	5,527,696	34.98	158,024
1988	76,992.57	34,847	33,586	49,566	37.76	1,313
1989	1,201,412.25	524,797	505,802	791,723	38.71	20,453
1990	173,110.77	72,856	70,219	116,741	39.67	2,943
1992	5,093,864.21	1,980,494	1,908,811	3,592,562	41.60	86,360
1999	165,900.34	45,454	43,809	135,363	48.51	2,790
2001	97,014.30	23,373	22,527	82,248	50.50	1,629
2002	36,867.35	8,270	7,971	31,846	51.50	618
2003	9,985,526.61	2,073,942	1,998,876	8,785,493	52.50	167,343
2007	28,008.68	3,956	3,813	26,436	56.50	468
2008	2,209,404.51	275,315	265,350	2,120,807	57.50	36,884
2009	234,765.50	25,355	24,437	229,110	58.50	3,916
2010	1,951,761.81	178,371	171,915	1,935,988	59.50	32,538
2011	450,761.35	33,703	32,483	454,339	60.50	7,510
2012	1,757,101.50	102,190	98,491	1,799,179	61.50	29,255
2013	2,362,076.23	98,113	94,562	2,456,480	62.50	39,304
2014	3,252,441.14	81,072	78,138	3,434,498	63.50	54,087
2015	32,415,720.45	287,074	276,683	34,732,295	60.11	577,812
	105,132,874.98	31,833,336	30,681,141	82,862,364		1,824,384

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.4 1.74

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G04 - GENERATOR - WINDINGS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S3						
NET SALVAGE PERCENT.. -8						
1967	6,417,497.74	5,479,568	6,930,898			
2010	4,435,555.02	526,944	1,065,837	3,724,562	44.50	83,698
2012	3,882,451.10	293,513	593,682	3,599,365	46.50	77,406
2013	7,746,727.46	418,323	846,132	7,520,334	47.50	158,323
2014	2,132,526.63	69,094	139,755	2,163,373	48.50	44,606
	24,614,757.95	6,787,442	9,576,304	17,007,634		364,033

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.7 1.48

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G05 - GLYCOL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S3						
NET SALVAGE PERCENT.. -8						
1974	83,699.00	73,785	90,395			
1989	9,270.24	6,217	8,119	1,893	15.16	125
1992	437,684.30	266,484	347,993	124,706	17.45	7,146
	530,653.54	346,486	446,507	126,599		7,271

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.4 1.37

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G06 - GOVENORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S4						
NET SALVAGE PERCENT.. -14						
1967	62,233.00	62,873	30,355	40,591	5.12	7,928
1968	77,729.00	77,918	37,619	50,992	5.43	9,391
1970	63,822.00	62,878	30,358	42,399	6.11	6,939
1971	77,729.00	75,851	36,621	51,990	6.48	8,023
1977	143,225.00	129,424	62,487	100,790	9.33	10,803
1980	251,003.31	214,862	103,736	182,408	11.21	16,272
1982	2,305,849.08	1,890,301	912,647	1,716,021	12.64	135,761
1985	1,422,117.29	1,079,015	520,954	1,100,260	15.05	73,107
1996	11,438.67	5,651	2,728	10,312	25.50	404
2002	594,634.45	203,365	98,186	579,697	31.50	18,403
2003	623,150.91	197,333	95,273	615,119	32.50	18,927
2006	912,512.80	219,610	106,029	934,236	35.50	26,317
2009	1,295,214.64	213,272	102,969	1,373,576	38.50	35,677
	7,840,659.15	4,432,353	2,139,962	6,798,390		367,952

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.5 4.69

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G07 - GROUND WIRE SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -6						
1966	2,823.94	2,392	2,369	624	11.05	56
1967	181,215.81	151,297	149,826	42,263	11.68	3,618
1968	94,918.28	78,040	77,281	23,332	12.34	1,891
1970	172,220.16	137,147	135,814	46,739	13.68	3,417
1971	53,073.00	41,549	41,145	15,112	14.38	1,051
1974	221,600.40	164,298	162,701	72,195	16.53	4,368
1975	47,892.56	34,816	34,478	16,288	17.28	943
1976	4,623.64	3,294	3,262	1,639	18.04	91
1977	44,065.95	30,735	30,436	16,274	18.81	865
1978	237,477.65	162,021	160,446	91,280	19.60	4,657
1979	76,455.67	50,983	50,487	30,556	20.40	1,498
1980	369,454.09	240,596	238,257	153,364	21.21	7,231
1981	72,125.46	45,816	45,371	31,082	22.04	1,410
1982	346,989.02	214,800	212,712	155,096	22.88	6,779
1983	352,232.23	212,277	210,213	163,153	23.73	6,875
1985	455,703.00	259,352	256,831	226,214	25.47	8,882
1986	29,607.81	16,343	16,184	15,200	26.36	577
1987	144,022.64	77,027	76,278	76,386	27.25	2,803
1988	44,015.48	22,768	22,547	24,109	28.16	856
1989	283,026.53	141,385	140,010	159,998	29.08	5,502
1990	468,797.25	225,877	223,681	273,244	30.00	9,108
1991	520,887.35	241,639	239,290	312,851	30.93	10,115
1992	215,011.55	95,848	94,916	132,996	31.87	4,173
1993	11,320.04	4,839	4,792	7,207	32.82	220
1994	5,612.73	2,297	2,275	3,674	33.77	109
1995	415,398.75	162,281	160,703	279,620	34.73	8,051
1996	142,553.83	53,025	52,509	98,598	35.70	2,762
1997	27,653.81	9,769	9,674	19,639	36.67	536
1998	27,958.88	9,354	9,263	20,373	37.64	541
2000	109,199.72	32,410	32,095	83,657	39.60	2,113
2001	353,363.79	98,204	97,249	277,317	40.58	6,834
2002	63,869.83	16,544	16,383	51,319	41.56	1,235
2003	408,552.10	98,029	97,076	335,989	42.55	7,896
2004	9,440.40	2,085	2,065	7,942	43.54	182
2005	19,932.54	4,022	3,983	17,145	44.53	385
2006	70,228.07	12,817	12,692	61,750	45.53	1,356
2008	1,052,859.55	151,780	150,305	965,726	47.52	20,323
2009	174,838.48	21,869	21,656	163,673	48.51	3,374
2010	267,722.45	28,327	28,052	255,734	49.51	5,165
2011	277,276.56	23,995	23,762	270,151	50.51	5,348
2012	741,955.69	50,051	49,564	736,909	51.50	14,309

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G07 - GROUND WIRE SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -6						
2013	642,861.66	30,971	30,670	650,763	52.50	12,395
2014	541,315.19	15,647	15,495	558,299	53.50	10,435
2015	568,198.08	5,842	5,785	596,505	51.05	11,685
	10,370,351.62	3,484,458	3,450,583	7,541,990		202,020
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					37.3	1.95

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I02 - INSTRUMENTATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-L0.5						
NET SALVAGE PERCENT.. 0						
1968	1,270,122.22	798,056	1,270,122			
1969	533,320.62	331,192	533,321			
1971	1,562,828.30	947,074	1,562,828			
1979	25,332.75	13,688	25,333			
1987	19,531.16	9,062	19,531			
1988	172,549.37	78,280	172,549			
1989	19,048.01	8,438	19,048			
1990	518,407.16	224,123	518,407			
1992	19,933.21	8,179	19,309	624	17.69	35
1994	104,218.77	40,367	95,298	8,921	18.38	485
1999	356,341.34	116,167	274,244	82,097	20.22	4,060
2002	18,448.05	5,258	12,413	6,035	21.45	281
2005	47,283.46	11,222	26,493	20,790	22.88	909
2006	497,358.78	109,419	258,314	239,045	23.40	10,216
2009	418,330.78	67,489	159,326	259,005	25.16	10,294
2012	45,371.19	4,250	10,033	35,338	27.19	1,300
2014	338,972.40	14,464	34,147	304,826	28.72	10,614
	5,967,397.57	2,786,728	5,010,716	956,682		38,194

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.0 0.64

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I03 - INSULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-L3						
NET SALVAGE PERCENT.. 0						
1967	88,700.61	69,440	82,281	6,420	7.60	845
1968	114,208.17	88,560	104,936	9,272	7.86	1,180
1969	50,398.83	38,706	45,863	4,536	8.12	559
1970	96,375.98	73,301	86,855	9,521	8.38	1,136
1974	12,479.49	9,156	10,849	1,630	9.32	175
1975	514.00	374	443	71	9.53	7
1976	12,341.27	8,910	10,558	1,783	9.73	183
1977	50,283.33	36,032	42,695	7,588	9.92	765
1978	35,427.46	25,214	29,876	5,551	10.09	550
1979	14,781.95	10,449	12,381	2,401	10.26	234
1980	11,311.61	7,941	9,409	1,903	10.43	182
1981	69,020.58	48,137	57,038	11,983	10.59	1,132
1982	426,433.41	295,216	349,806	76,627	10.77	7,115
1983	630,479.97	433,051	513,129	117,351	10.96	10,707
1984	70,036.88	47,705	56,526	13,511	11.16	1,211
1985	999,174.39	673,733	798,317	200,857	11.40	17,619
1986	7,562.44	5,043	5,976	1,586	11.66	136
1987	533,947.06	351,492	416,488	117,459	11.96	9,821
1988	575,583.15	373,145	442,145	133,438	12.31	10,840
1989	600,838.56	382,818	453,607	147,232	12.70	11,593
1990	3,212,707.83	2,006,561	2,377,605	835,103	13.14	63,554
1991	1,700,167.83	1,038,071	1,230,027	470,141	13.63	34,493
1992	767,820.50	456,961	541,460	226,360	14.17	15,975
1993	1,189,492.76	687,527	814,661	374,832	14.77	25,378
1994	969,319.30	542,538	642,862	326,457	15.41	21,185
1995	1,758,689.02	949,692	1,125,305	633,384	16.10	39,341
1996	1,786,367.83	926,875	1,098,269	688,099	16.84	40,861
1997	889,877.07	442,144	523,903	365,974	17.61	20,782
1998	720,448.60	341,284	404,393	316,056	18.42	17,158
1999	1,020,689.48	459,310	544,244	476,445	19.25	24,750
2000	3,892,028.71	1,655,786	1,961,967	1,930,062	20.11	95,975
2001	681,643.97	273,046	323,536	358,108	20.98	17,069
2002	1,987,065.50	744,871	882,609	1,104,456	21.88	50,478
2003	1,841,341.62	642,370	761,154	1,080,188	22.79	47,397
2004	2,775,970.27	895,445	1,061,027	1,714,943	23.71	72,330
2005	333,171.22	98,522	116,740	216,431	24.65	8,780
2006	1,324,258.63	355,656	421,422	902,837	25.60	35,267
2007	3,136,964.12	756,448	896,327	2,240,637	26.56	84,361
2008	808,745.61	172,611	204,530	604,216	27.53	21,948
2009	2,123,592.33	393,162	465,864	1,657,728	28.52	58,125
2010	323,890.26	50,805	60,200	263,690	29.51	8,936
2011	490,774.50	63,099	74,767	416,008	30.50	13,640
2012	994,068.55	99,407	117,789	876,280	31.50	27,818

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I03 - INSULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-L3						
NET SALVAGE PERCENT.. 0						
2013	105,635.07	7,546	8,941	96,694	32.50	2,975
2014	2,685,733.84	115,111	136,397	2,549,337	33.50	76,100
2015	67,958.16	1,101	1,304	66,654	30.46	2,188
	41,988,321.72	17,154,372	20,326,481	21,661,840		1,002,854
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					21.6	2.39

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I04 - INTAKE STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 110-R4						
NET SALVAGE PERCENT.. -8						
1966	3,784,392.00	1,805,782	562,054	3,525,089	61.40	57,412
1967	1,784,000.00	834,790	259,831	1,666,889	62.34	26,739
1979	1,454,249.47	516,583	160,788	1,409,801	73.82	19,098
1982	5,039,574.77	1,645,667	512,218	4,930,523	76.74	64,250
1983	16,004.48	5,072	1,579	15,706	77.72	202
1984	3,401,783.55	1,045,416	325,388	3,348,538	78.70	42,548
1989	6,768.76	1,753	546	6,764	83.62	81
1994	5,240.80	1,103	343	5,317	88.57	60
1997	10,571.59	1,915	596	10,821	91.55	118
2002	24,045.32	3,180	990	24,979	96.53	259
2003	3,909,814.02	479,054	149,107	4,073,492	97.52	41,771
	19,436,444.76	6,340,315	1,973,440	19,017,921		252,538

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 75.3 1.30

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I05 - INVERTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-S1.5						
NET SALVAGE PERCENT.. -8						
1968	182,290.86	191,677	183,692	13,182	0.66	13,182
1979	114,154.89	106,126	101,704	21,583	3.48	6,202
1996	17,604.84	11,667	11,181	7,832	9.66	811
2000	11,968.11	6,763	6,481	6,445	11.92	541
2001	110,955.28	59,676	57,190	62,642	12.55	4,991
2005	2,340.00	970	930	1,597	15.40	104
2006	16,272.78	6,186	5,928	11,647	16.20	719
2008	5,505.60	1,696	1,625	4,321	17.87	242
2012	4,964.72	740	709	4,653	21.55	216
2014	5,643.32	366	351	5,744	23.50	244
2015	49,804.41	1,296	1,242	52,546	20.25	2,595
	521,504.81	387,163	371,033	192,192		29,847

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.4 5.72

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L03 - LAND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
1965	5,754.24	3,441	5,754			
1967	174,343.48	100,793	174,343			
1968	82,098.79	46,643	82,099			
1970	313,594.10	171,765	313,594			
1971	996,777.00	535,598	979,075	17,702	34.70	510
1972	286,219.42	150,780	275,626	10,593	35.49	298
1974	262,393.06	132,666	242,514	19,879	37.08	536
1975	59,952.49	29,672	54,241	5,711	37.88	151
1976	61,289.90	29,664	54,226	7,064	38.70	183
1977	391,514.65	185,214	338,572	52,943	39.52	1,340
1978	777,770.02	359,431	657,041	120,729	40.34	2,993
1979	37,126.06	16,741	30,603	6,523	41.18	158
1980	1,053,203.62	463,125	846,594	206,610	42.02	4,917
1981	271,954.44	116,541	213,037	58,917	42.86	1,375
1982	516,244.80	215,310	393,588	122,657	43.72	2,806
1983	260,255.97	105,594	193,026	67,230	44.57	1,508
1984	96,772.74	38,141	69,722	27,051	45.44	595
1985	252,388.80	96,546	176,486	75,903	46.31	1,639
1986	85,530.68	31,726	57,995	27,536	47.18	584
1987	569,158.86	204,368	373,586	195,573	48.07	4,069
1988	188,757.84	65,561	119,846	68,912	48.95	1,408
1989	2,213,223.50	742,160	1,356,671	856,552	49.85	17,183
1990	765,815.64	247,718	452,829	312,987	50.74	6,168
1991	440,749.89	137,219	250,837	189,913	51.65	3,677
1992	569,666.82	170,444	311,572	258,095	52.56	4,910
1993	226,860.93	65,125	119,049	107,812	53.47	2,016
1994	187,262.38	51,460	94,069	93,193	54.39	1,713
1995	344,790.90	90,518	165,467	179,324	55.31	3,242
1996	255,875.08	64,002	116,996	138,879	56.24	2,469
1997	24,438.72	5,810	10,621	13,818	57.17	242
1998	321,505.42	72,403	132,353	189,152	58.11	3,255
1999	117,692.64	25,030	45,755	71,938	59.05	1,218
2000	73,029.87	14,615	26,716	46,314	59.99	772
2002	172,683.92	30,185	55,178	117,506	61.89	1,899
2003	228,663.43	37,073	67,770	160,893	62.84	2,560
2004	102,617.32	15,324	28,012	74,605	63.80	1,169
2005	87,428.65	11,937	21,821	65,608	64.76	1,013
2006	110,490.47	13,657	24,965	85,525	65.73	1,301
2008	64,541.12	6,317	11,548	52,993	67.66	783
2009	268,364.85	22,792	41,664	226,701	68.63	3,303
2010	13,384.00	962	1,759	11,625	69.61	167
2011	64,779.67	3,817	6,977	57,803	70.58	819

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L03 - LAND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. 0						
2012	49,683.60	2,279	4,166	45,518	71.56	636
2014	369,783.31	7,296	13,337	356,446	73.52	4,848
2015	380,361.34	3,005	5,493	374,868	62.79	5,970
	14,196,794.43	4,940,468	9,017,193	5,179,601		96,403

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 53.7 0.68

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L04 - LIGHTING SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. 0						
1967	45,238.49	37,955	45,238			
1968	2,726.81	2,259	2,727			
1970	42,486.22	34,210	42,486			
1971	28,226.00	22,378	28,226			
1974	16,618.25	12,514	16,618			
1975	39,752.16	29,385	39,752			
1976	4,407.08	3,196	4,407			
1977	29,959.51	21,295	29,960			
1978	67,894.94	47,255	67,035	860	15.20	57
1979	83,571.46	56,912	80,735	2,836	15.95	178
1980	25,900.92	17,245	24,464	1,437	16.71	86
1981	9,888.87	6,430	9,122	767	17.49	44
1982	33,845.59	21,465	30,450	3,396	18.29	186
1983	10,991.30	6,793	9,636	1,355	19.10	71
1985	3,562.54	2,083	2,955	608	20.76	29
1986	5,857.33	3,326	4,718	1,139	21.61	53
1987	39,322.35	21,643	30,702	8,620	22.48	383
1988	9,837.24	5,241	7,435	2,402	23.36	103
1989	18,023.88	9,282	13,167	4,857	24.25	200
1990	35,606.52	17,696	25,104	10,503	25.15	418
1991	18,831.10	9,016	12,790	6,041	26.06	232
1992	2,735.87	1,260	1,787	949	26.98	35
2012	93,027.28	6,512	9,238	83,789	46.50	1,802
2013	257,991.58	12,900	18,300	239,692	47.50	5,046
	926,303.29	408,251	557,052	369,251		8,923

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.4 0.96

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L05 - LIGHTNING ARRESTORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 58-R3						
NET SALVAGE PERCENT.. 0						
1967	44,408.00	31,476	44,408			
1968	50,362.17	35,149	50,362			
1970	61,016.99	41,229	61,017			
1977	65.00	38	62	3	23.72	
1978	19,225.18	11,114	18,190	1,035	24.47	42
1980	290.19	160	262	28	25.99	1
1981	2,066.49	1,113	1,822	244	26.77	9
1982	25,686.00	13,485	22,070	3,616	27.55	131
1986	5,702.63	2,675	4,378	1,325	30.79	43
1987	293.76	134	219	75	31.62	2
1988	811.34	357	584	227	32.45	7
1989	339.63	145	237	103	33.30	3
1992	0.01					
1994	2,591.45	909	1,488	1,103	37.65	29
1995	0.03					
1996	2,464.63	789	1,291	1,174	39.44	30
2000	5,055,707.52	1,298,811	2,125,676	2,930,032	43.10	67,982
2004	11,440.48	2,199	3,599	7,841	46.85	167
2005	79,719.06	14,019	22,944	56,775	47.80	1,188
2006	90,109.92	14,355	23,494	66,616	48.76	1,366
2007	13,132.00	1,875	3,069	10,063	49.72	202
2008	52,590.01	6,637	10,862	41,728	50.68	823
2009	80,001.12	8,759	14,335	65,666	51.65	1,271
2010	22,899.74	2,124	3,476	19,424	52.62	369
2011	57,338.86	4,359	7,134	50,205	53.59	937
2012	86,164.40	5,096	8,340	77,824	54.57	1,426
2013	17,692.67	750	1,228	16,465	55.54	296
2014	90,140.65	2,300	3,764	86,377	56.52	1,528
2015	321,349.88	3,278	5,365	315,985	48.52	6,512
	6,193,609.81	1,503,335	2,439,676	3,753,934		84,364

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 44.5 1.36

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L06 - LINE COUPLING EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 24-R5						
NET SALVAGE PERCENT.. 0						
1984	11,225.56	11,071	11,226			
	11,225.56	11,071	11,226			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M01 - MAIN BREAKERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-R0.5						
NET SALVAGE PERCENT.. -8						
1968	87,097.27	59,172	94,065			
1970	6,264.96	4,110	6,766			
1980	14,200.00	7,533	12,753	2,583	21.37	121
1983	14,000.00	6,862	11,617	3,503	22.94	153
1986	14,774.50	6,626	11,217	4,739	24.56	193
1991	4,678.14	1,762	2,983	2,069	27.35	76
1996	96,202.47	29,117	49,292	54,607	30.23	1,806
1997	4,516.36	1,298	2,197	2,681	30.82	87
1998	23,610.58	6,429	10,884	14,615	31.41	465
2001	47,957.90	10,864	18,391	33,404	33.19	1,006
2003	92,548.49	18,134	30,699	69,253	34.38	2,014
2004	27,895.94	5,036	8,525	21,603	34.98	618
2006	119,193.09	17,838	30,198	98,531	36.18	2,723
	552,939.70	174,781	289,587	307,588		9,262

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.2 1.68

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M02 - MARINE TERMINAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -6						
1969	2,596,299.63	1,843,479	2,752,078			
1971	69,000.00	47,237	73,140			
1980	12,849.36	7,213	13,620			
1983	11,371.66	5,882	12,054			
1984	286,814.46	144,061	304,023			
2013	857,536.19	34,960	74,628	834,360	62.50	13,350
	3,833,871.30	2,082,832	3,229,543	834,360		13,350

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 62.5 0.35

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M03 - METALCLAD SWITCHGEAR CUB/EQU 4kv/600

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R4						
NET SALVAGE PERCENT.. -6						
1968	431,573.00	401,249	457,467			
1980	780,388.00	599,083	814,153	13,058	12.41	1,052
1987	56,409.27	36,129	49,099	10,695	17.81	601
1994	567,211.45	281,118	382,040	219,204	23.96	9,149
1995	14,288.77	6,769	9,199	5,947	24.89	239
2015	383,774.09	4,800	6,523	400,277	41.70	9,599
	2,233,644.58	1,329,148	1,718,481	649,182		20,640

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.5 0.92

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M04 - METER TEST SWITCHES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R5						
NET SALVAGE PERCENT.. 0						
1981	9,277.57	8,294	9,278			
1982	1,993.00	1,753	1,978	15	4.21	4
1984	897.55	760	858	40	5.36	7
1987	11,856.77	9,326	10,525	1,332	7.47	178
1988	3,304.10	2,525	2,850	454	8.25	55
1991	12,722.44	8,789	9,918	2,804	10.82	259
1993	1,215.96	776	876	340	12.65	27
1994	11,342.69	6,935	7,826	3,517	13.60	259
1997	5,690.51	3,005	3,391	2,299	16.52	139
	58,300.59	42,163	47,500	10,800		928

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.6 1.59

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M05 - METERING TANKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-R3						
NET SALVAGE PERCENT.. 0						
1966	2,500.00	2,281	2,500			
1968	7,113.61	6,391	7,114			
1970	3,981.00	3,516	3,981			
1972	7,362.00	6,381	7,362			
1978	5,434.41	4,372	5,390	44	7.23	6
1979	8,161.00	6,463	7,968	193	7.70	25
1981	131,092.38	100,197	123,537	7,555	8.72	866
1983	5,347.32	3,925	4,839	508	9.84	52
1984	11,116.01	7,983	9,843	1,273	10.43	122
1988	13,825.07	8,956	11,042	2,783	13.03	214
1989	11,884.85	7,475	9,216	2,669	13.73	194
1992	17,501.52	9,966	12,288	5,214	15.93	327
1993	36,142.64	19,839	24,460	11,683	16.69	700
1994	21,417.03	11,299	13,931	7,486	17.48	428
1996	14,331.25	6,941	8,558	5,773	19.08	303
1997	1,246.12	576	710	536	19.90	27
2011	66,568.46	7,898	9,738	56,830	32.61	1,743
2012	59,915.40	5,554	6,848	53,067	33.57	1,581
2013	95,443.06	6,320	7,792	87,651	34.55	2,537
2014	140,033.36	5,564	6,860	133,174	35.53	3,748
	660,416.49	231,897	283,977	376,440		12,873

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.2 1.95

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M06 - METERS - DIGITAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L3						
NET SALVAGE PERCENT.. 0						
1990	22,825.78	17,222	17,997	4,829	4.91	984
1991	374,351.59	277,956	290,461	83,891	5.15	16,290
1992	134,335.27	98,266	102,687	31,648	5.37	5,893
1993	3,358.12	2,423	2,532	826	5.57	148
1994	86,708.38	61,780	64,559	22,149	5.75	3,852
1995	19,048.53	13,410	14,013	5,036	5.92	851
1996	51,918.38	36,109	37,734	14,184	6.09	2,329
1997	116,144.02	79,733	83,320	32,824	6.27	5,235
1998	149,674.43	101,105	105,654	44,020	6.49	6,783
1999	89,708.70	59,342	62,012	27,697	6.77	4,091
2000	22,935.00	14,782	15,447	7,488	7.11	1,053
2001	149,440.00	93,101	97,290	52,150	7.54	6,916
2002	193,794.17	115,695	120,900	72,894	8.06	9,044
2003	64,795.71	36,707	38,358	26,438	8.67	3,049
2004	202,181.96	107,561	112,400	89,782	9.36	9,592
2005	100,278.86	49,538	51,767	48,512	10.12	4,794
2006	59,047.43	26,748	27,951	31,096	10.94	2,842
2007	88,321.99	36,212	37,841	50,481	11.80	4,278
2008	72,758.52	26,593	27,789	44,970	12.69	3,544
2009	1,436,699.35	459,025	479,677	957,022	13.61	70,318
2010	394,115.26	107,199	112,022	282,093	14.56	19,375
2011	308,158.46	69,027	72,133	236,025	15.52	15,208
2012	521,108.69	90,933	95,024	426,085	16.51	25,808
2013	711,833.66	88,979	92,982	618,852	17.50	35,363
2014	89,571.49	6,718	7,020	82,551	18.50	4,462
2015	411,554.67	11,647	12,171	399,384	17.17	23,261
	5,874,668.42	2,087,811	2,181,741	3,692,927		285,363

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.9 4.86

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M07 - METERS - ANALOGUE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L2						
NET SALVAGE PERCENT.. 0						
1981	138,968.27	97,889	138,968			
1983	11,142.31	7,626	11,097	45	7.89	6
1984	56,507.73	38,109	55,455	1,053	8.14	129
1987	145,955.65	94,054	136,866	9,090	8.89	1,022
1988	197,071.51	125,101	182,045	15,027	9.13	1,646
1989	148,738.52	92,991	135,318	13,420	9.37	1,432
	698,383.99	455,770	659,749	38,635		4,235

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.1 0.61

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M08 - METERS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-L4						
NET SALVAGE PERCENT.. 0						
1987	450.00	385	411	39	3.18	12
1988	11,760.00	9,942	10,612	1,148	3.40	338
1993	8,812.52	7,110	7,589	1,224	4.25	288
1994	13,132.41	10,494	11,201	1,931	4.42	437
1995	22,190.79	17,501	18,680	3,511	4.65	755
1996	16,112.88	12,466	13,306	2,807	4.98	564
1997	39,570.21	29,822	31,831	7,739	5.42	1,428
1998	833.04	607	648	185	5.97	31
2000	1,765.00	1,175	1,254	511	7.36	69
2003	15,820.86	8,773	9,364	6,457	9.80	659
2004	3,754.50	1,932	2,062	1,692	10.68	158
2005	27,658.30	13,075	13,956	13,702	11.60	1,181
2006	21,750.00	9,343	9,972	11,778	12.55	938
2012	79,242.94	12,607	13,456	65,787	18.50	3,556
	262,853.45	135,232	144,342	118,512		10,414

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.4 3.96

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M10 - MISCELLANEOUS UNITS OF PROPERTY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 22-R1.5						
NET SALVAGE PERCENT.. 0						
1970	6,185.00	6,185	6,185			
1985	315,254.84	259,943	315,255			
1989	795,281.80	607,667	795,282			
1990	825,974.72	616,854	825,975			
1991	50,436.68	36,750	50,437			
2004	15,584.21	6,212	11,257	4,327	13.23	327
2007	17,122.85	5,160	9,351	7,772	15.37	506
2010	20,438,077.12	4,069,017	7,373,837	13,064,240	17.62	741,444
2011	1,339,679.15	219,828	398,370	941,309	18.39	51,186
2013	1,581,834.50	145,956	264,501	1,317,334	19.97	65,966
2014	110,378.30	6,171	11,183	99,195	20.77	4,776
2015	320,146.61	11,909	21,581	298,566	12.96	23,038
	25,815,955.78	5,991,652	10,083,214	15,732,742		887,243

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.7 3.44

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M11 - MOBILE - A.T.V.'S AND SNOWMOBILES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 6-L3						
NET SALVAGE PERCENT.. +20						
2007	46,853.00	29,611	37,482			
2008	72,292.00	43,279	57,834			
2009	156,935.00	89,557	125,548			
2010	91,663.35	50,232	73,331			
2011	156,948.00	79,730	123,955	1,603	2.19	732
2012	83,583.00	35,996	55,962	10,904	2.77	3,936
2013	803,692.66	259,323	403,166	239,788	3.58	66,980
2014	279,015.41	55,430	86,176	137,036	4.51	30,385
2015	215,756.83	16,328	25,385	147,220	4.78	30,799
	1,906,739.25	659,486	988,839	536,552		132,832

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.0 6.97

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M12 - MOBILE - AIR COMPRESSOR ATTACHMENT AND BOAT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L0						
NET SALVAGE PERCENT.. +20						
1979	87,567.04	44,064	70,054			
1980	0.01					
1981	3,430.57	1,669	2,744			
1986	15,409.87	6,799	12,328			
1988	32,750.14	13,821	26,200			
1989	25,669.08	10,576	20,535			
1993	13,484.38	4,978	10,788			
1994	4,062.24	1,454	3,250			
1996	11,982.66	4,007	9,586			
1997	12,900.00	4,159	10,320			
1998	2,375.00	736	1,900			
1999	31,217.74	9,278	24,974			
2000	17,995.00	5,118	14,396			
2006	12,599.00	2,500	10,079			
2009	77,874.00	11,650	59,636	2,663	16.26	164
2010	22,689.00	2,986	15,285	2,866	16.71	172
2011	24,400.00	2,743	14,041	5,479	17.19	319
2012	35,640.00	3,265	16,713	11,799	17.71	666
	432,045.73	129,803	322,829	22,807		1,321

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.3 0.31

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M13 - MOBILE - ARGO'S

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 9-R5						
NET SALVAGE PERCENT.. +20						
2010	117,000.00	56,992	93,600			
2011	22,239.69	8,896	17,792			
2012	59,494.00	18,509	47,595			
2013	88,553.28	19,679	111,081	40,239-		
	287,286.97	104,076	270,068	40,239-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M14 - MOBILE - FLEX/FORK/LOAD/GRADE/MUSK/TRAILER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-L3						
NET SALVAGE PERCENT.. +20						
1981	42,744.83	31,042	34,196			
1982	10,643.83	7,630	8,515			
1984	13,077.69	9,120	10,462			
1988	134,706.88	88,307	107,766			
1989	86,197.29	55,511	68,958			
1990	43,680.00	27,625	34,944			
1992	145,304.06	88,603	116,243			
1993	36,994.60	22,147	29,596			
1995	30,432.96	17,624	24,346			
1998	371,250.63	206,415	297,001			
1999	283,809.60	155,401	227,048			
2000	222,125.00	119,356	177,700			
2001	282,760.01	148,293	225,349	859	6.20	139
2002	179,687.00	91,200	138,590	5,160	6.58	784
2003	15,997.87	7,779	11,821	977	7.06	138
2004	136,636.50	62,914	95,606	13,703	7.64	1,794
2005	328,255.24	141,368	214,826	47,778	8.31	5,749
2006	622,272.69	246,973	375,306	122,512	9.07	13,507
2007	396,251.24	142,828	217,045	99,956	9.89	10,107
2008	1,164,855.27	375,344	570,381	361,503	10.75	33,628
2009	851,566.55	240,333	365,216	316,037	11.65	27,128
2010	352,166.32	84,833	128,914	152,819	12.58	12,148
2011	1,777,190.38	353,064	536,524	885,228	13.53	65,427
2012	819,248.40	127,075	193,106	462,293	14.51	31,860
2013	363,231.41	40,359	61,330	229,255	15.50	14,791
2014	1,486,091.26	99,069	150,548	1,038,325	16.50	62,929
2015	384,134.71	9,649	14,663	292,645	15.40	19,003
	10,581,312.22	2,999,862	4,436,000	4,029,050		299,132

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5 2.83

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M16 - MULTIPLEX EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 18-S1.5						
NET SALVAGE PERCENT.. 0						
1980	72,014.91	71,455	72,015			
1999	37,192.70	25,229	37,193			
2000	108,463.34	70,862	108,463			
2001	736,804.61	461,733	718,722	18,083	6.72	2,691
2002	353,971.09	211,597	329,367	24,604	7.24	3,398
2003	609,578.15	345,765	538,209	71,369	7.79	9,162
2004	4,819.61	2,578	4,013	807	8.37	96
2005	62,819.85	31,410	48,892	13,928	9.00	1,548
2008	138,997.61	52,973	82,456	56,542	11.14	5,076
2010	495,304.03	143,638	223,584	271,720	12.78	21,261
2011	12,028.86	2,900	4,514	7,515	13.66	550
2012	180,222.11	34,242	53,300	126,922	14.58	8,705
	2,812,216.87	1,454,382	2,220,728	591,489		52,487

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.3 1.87

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT O01 - OFFICE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	16,183.45	15,779	16,183			
1997	66,014.61	61,064	66,015			
1998	3,480.00	3,045	3,480			
1999	54,164.38	44,686	54,164			
2000	48,627.79	37,687	48,628			
2001	24,963.81	18,099	24,964			
2002	21,822.24	14,730	21,790	32	6.50	5
2003	37,899.07	23,687	35,040	2,859	7.50	381
2004	32,921.94	18,930	28,003	4,919	8.50	579
2005	9,608.92	5,045	7,463	2,146	9.50	226
2006	77,147.66	36,645	54,209	22,939	10.50	2,185
2007	23,654.54	10,053	14,872	8,783	11.50	764
2008	134,350.49	50,381	74,529	59,821	12.50	4,786
2009	48,737.86	15,840	23,432	25,306	13.50	1,875
2010	280,792.29	77,218	114,229	166,563	14.50	11,487
2011	117,705.69	26,484	39,178	78,528	15.50	5,066
2012	65,898.39	11,532	17,060	48,838	16.50	2,960
2013	47,195.96	5,899	8,726	38,470	17.50	2,198
2014	169,148.66	12,686	18,767	150,382	18.50	8,129
2015	6,121.97	153	226	5,896	19.50	302
	1,286,439.72	489,643	670,958	615,481		40,943

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.0 3.18

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT 002 - OFFICE FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	29,219.24	28,489	29,219			
1997	36,590.65	33,846	36,591			
1998	79,197.16	69,298	79,197			
1999	80,433.08	66,357	80,433			
2000	211,310.15	163,765	204,954	6,356	4.50	1,412
2001	22,901.71	16,604	20,780	2,122	5.50	386
2002	29,959.88	20,223	25,309	4,651	6.50	716
2003	16,175.45	10,110	12,653	3,522	7.50	470
2004	7,439.05	4,277	5,353	2,086	8.50	245
2005	85,208.45	44,734	55,985	29,223	9.50	3,076
2006	119,900.15	56,953	71,278	48,622	10.50	4,631
2007	59,862.92	25,442	31,841	28,022	11.50	2,437
2008	85,940.49	32,228	40,334	45,606	12.50	3,648
2009	130,101.60	42,283	52,918	77,184	13.50	5,717
2010	194,647.39	53,528	66,991	127,656	14.50	8,804
2011	84,517.24	19,016	23,799	60,718	15.50	3,917
2012	90,136.68	15,774	19,741	70,396	16.50	4,266
2013	24,491.46	3,061	3,831	20,660	17.50	1,181
2014	36,046.62	2,703	3,383	32,664	18.50	1,766
2015	53,910.54	1,348	1,687	52,224	19.50	2,678
	1,477,989.91	710,039	866,277	611,713		45,350

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.5 3.07

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P01 - P.C.B. STORAGE CONTAINER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R4						
NET SALVAGE PERCENT.. 0						
1991	42,479.84	31,605	41,427	1,052	7.68	137
	42,479.84	31,605	41,427	1,052		137
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					7.7	0.32

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P02 - PABX - PRIVATE AUTO BRANCH EXCHANGE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R4						
NET SALVAGE PERCENT.. 0						
1998	37,491.90	29,356	37,492			
2000	258,657.30	184,811	258,657			
2003	84,331.38	50,388	78,648	5,683	8.05	706
2006	800,527.97	372,246	581,020	219,508	10.70	20,515
	1,181,008.55	636,801	955,817	225,191		21,221
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.6						1.80

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P03 - PENSTOCK

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
NET SALVAGE PERCENT.. -8						
1966	13,597,173.00	9,744,490	5,227,231	9,457,716	23.55	401,602
1967	6,972,000.00	4,912,641	2,635,285	4,894,475	24.33	201,170
1970	351,355.39	234,509	125,798	253,666	26.74	9,486
1979	11,030,667.78	6,045,075	3,242,756	8,670,365	34.48	251,461
1982	12,972,402.67	6,560,834	3,519,425	10,490,770	37.22	281,858
1985	4,690,571.00	2,170,348	1,164,239	3,901,578	40.01	97,515
1989	414,557.06	167,511	89,858	357,864	43.81	8,169
2003	6,732,225.16	1,294,203	694,248	6,576,555	57.54	114,295
2006	2,147,468.60	314,098	168,492	2,150,774	60.52	35,538
	58,908,420.66	31,443,709	16,867,332	46,753,763		1,401,094

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 33.4 2.38

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P04 - POLE CRIBS AND POLE HARDWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S2.5						
NET SALVAGE PERCENT.. -20						
1968	1,845.17	1,943	1,842	372	4.29	87
1970	77,086.69	79,950	75,808	16,696	4.75	3,515
1978	11,761.12	11,291	10,706	3,407	7.00	487
1979	1,413.56	1,341	1,272	424	7.34	58
1981	3,061,318.96	2,824,471	2,678,127	995,456	8.09	123,048
1982	1,428,282.57	1,298,669	1,231,381	482,558	8.48	56,905
1983	727,698.47	651,182	617,442	255,796	8.90	28,741
1984	896,385.01	788,611	747,751	327,911	9.34	35,108
1985	736,521.61	636,098	603,140	280,686	9.81	28,612
1986	1,193,610.51	1,010,811	958,438	473,895	10.30	46,009
1987	2,151,281.92	1,784,204	1,691,759	889,779	10.81	82,311
1988	1,154,830.63	936,397	887,880	497,917	11.35	43,869
1989	1,696,041.19	1,342,105	1,272,567	762,682	11.92	63,983
1990	1,761,660.55	1,358,388	1,288,006	825,987	12.51	66,026
1991	1,767,156.41	1,325,070	1,256,414	864,174	13.13	65,817
1992	1,095,693.13	797,169	755,865	558,967	13.78	40,564
1993	1,292,032.25	909,890	862,746	687,693	14.46	47,558
1994	1,579,697.47	1,074,011	1,018,363	877,274	15.17	57,830
1995	1,861,510.71	1,218,389	1,155,261	1,078,552	15.91	67,791
1996	2,633,416.42	1,654,976	1,569,227	1,590,873	16.67	95,433
1997	4,885,285.29	2,937,854	2,785,635	3,076,707	17.46	176,215
1998	1,878,680.76	1,076,958	1,021,158	1,233,259	18.28	67,465
1999	1,372,514.80	747,268	708,550	938,468	19.12	49,083
2000	2,050,387.44	1,055,195	1,000,522	1,459,943	19.99	73,034
2001	2,399,127.49	1,161,456	1,101,278	1,777,675	20.88	85,138
2002	4,734,632.00	2,145,981	2,034,792	3,646,766	21.78	167,436
2003	3,265,505.84	1,375,980	1,304,687	2,613,920	22.71	115,100
2004	3,602,858.68	1,402,045	1,329,401	2,994,029	23.65	126,597
2005	3,462,816.60	1,234,730	1,170,755	2,984,625	24.60	121,326
2006	4,537,133.14	1,466,928	1,390,922	4,053,638	25.57	158,531
2007	3,973,884.13	1,152,633	1,092,912	3,675,749	26.54	138,498
2008	5,702,540.68	1,460,512	1,384,839	5,458,210	27.53	198,264
2009	5,642,349.74	1,255,513	1,190,461	5,580,359	28.51	195,733
2010	5,042,753.64	949,208	900,027	5,151,277	29.51	174,560
2011	7,085,136.89	1,093,123	1,036,485	7,465,679	30.50	244,776
2012	7,655,567.91	918,668	871,069	8,315,612	31.50	263,988
2013	15,939,566.56	1,366,276	1,295,485	17,831,995	32.50	548,677
2014	1,880,919.80	96,739	91,727	2,165,377	33.50	64,638
2015	8,130,250.53	154,150	146,163	9,610,137	31.24	307,623
	118,371,156.27	42,756,183	40,540,863	101,504,524		4,230,434

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 24.0 3.57

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P05 - POLE STRUCTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 57-R3						
NET SALVAGE PERCENT.. -20						
1967	1,368,472.29	1,178,616	1,053,667	588,500	16.09	36,576
1968	686,797.97	582,696	520,922	303,236	16.70	18,158
1969	420,665.37	351,320	314,075	190,723	17.33	11,005
1970	2,780,493.34	2,284,698	2,042,489	1,294,103	17.97	72,015
1971	20,688.28	16,712	14,940	9,886	18.63	531
1974	2,809,521.88	2,148,846	1,921,039	1,450,387	20.67	70,169
1975	4,543.00	3,407	3,046	2,406	21.38	113
1976	111,728.97	82,091	73,388	60,687	22.10	2,746
1977	289,602.19	208,329	186,243	161,280	22.83	7,064
1978	5,599,369.39	3,940,769	3,522,994	3,196,249	23.57	135,607
1979	3,913.00	2,693	2,408	2,288	24.31	94
1980	867,615.85	583,225	521,395	519,744	25.07	20,732
1981	6,018,792.76	3,948,352	3,529,773	3,692,778	25.84	142,909
1982	6,850,067.63	4,381,139	3,916,679	4,303,402	26.62	161,660
1983	5,788,514.54	3,605,920	3,223,644	3,722,573	27.41	135,811
1984	443,026.83	268,522	240,055	291,577	28.21	10,336
1985	2,041,402.54	1,202,500	1,075,019	1,374,664	29.02	47,370
1986	169,584.93	96,967	86,687	116,815	29.84	3,915
1987	4,807,814.12	2,666,087	2,383,446	3,385,931	30.66	110,435
1988	2,640,192.35	1,417,371	1,267,111	1,901,120	31.50	60,353
1989	585,499.62	303,966	271,742	430,858	32.34	13,323
1990	23,934,682.00	11,997,594	10,725,687	17,995,931	33.19	542,209
1991	223,252.59	107,866	96,431	171,472	34.05	5,036
1992	143,107.01	66,522	59,470	112,258	34.92	3,215
1993	127,323.81	56,854	50,827	101,962	35.79	2,849
1994	115,719.28	49,528	44,277	94,586	36.67	2,579
1995	3,027,560.94	1,239,060	1,107,703	2,525,370	37.56	67,236
1996	6,014,190.95	2,347,411	2,098,554	5,118,475	38.46	133,086
1997	284,490.40	105,649	94,449	246,939	39.36	6,274
1998	3,247,147.94	1,143,684	1,022,438	2,874,140	40.27	71,372
1999	81,830.77	27,237	24,350	73,847	41.19	1,793
2000	6,781,138.74	2,125,724	1,900,368	6,236,998	42.11	148,112
2001	4,203,315.22	1,235,321	1,104,360	3,939,618	43.04	91,534
2002	1,106,847.87	303,631	271,442	1,056,775	43.97	24,034
2003	4,285,684.52	1,090,844	975,200	4,167,621	44.91	92,799
2004	455,122.20	106,739	95,423	450,724	45.86	9,828
2005	2,515,578.70	539,652	482,442	2,536,252	46.81	54,182
2006	4,551,912.00	885,493	791,619	4,670,675	47.76	97,795
2007	487,546.53	84,985	75,975	509,081	48.72	10,449
2008	2,858,815.26	440,555	393,850	3,036,728	49.68	61,126
2009	3,045,510.63	407,124	363,963	3,290,650	50.65	64,968
2010	591,671.63	67,017	59,912	650,094	51.62	12,594
2011	3,723,983.33	345,750	309,096	4,159,684	52.59	79,096

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P05 - POLE STRUCTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 57-R3						
NET SALVAGE PERCENT.. -20						
2012	2,562,848.59	185,079	165,458	2,909,960	53.57	54,321
2013	2,491,211.49	129,025	115,347	2,874,107	54.54	52,697
2014	4,784,879.85	149,059	133,257	5,608,599	55.52	101,019
2015	3,836,606.31	47,881	42,805	4,561,123	47.58	95,862
	129,790,285.41	54,559,510	48,775,465	106,972,878		2,946,987
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					36.3	2.27

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P06 - POLES - CONCRETE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R4						
NET SALVAGE PERCENT.. -20						
1981	23,208.03	26,992	25,031	2,819	0.77	2,819
1982	72,462.60	83,442	77,380	9,575	1.01	9,480
1984	58,940.77	66,457	61,629	9,100	1.51	6,026
1986	69,138.28	76,130	70,599	12,367	2.06	6,003
1987	10,316.62	11,216	10,401	1,979	2.35	842
1990	23,134.24	23,952	22,212	5,549	3.43	1,618
1994	34,476.00	31,988	29,665	11,706	5.67	2,065
1997	1,639.61	1,354	1,256	712	7.79	91
1999	571.34	429	398	288	9.35	31
2005	15,775.50	7,830	7,261	11,670	14.66	796
2014	24,097.27	1,735	1,608	27,308	23.50	1,162
	333,760.26	331,525	307,440	93,072		30,933

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.0 9.27

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P07 - POLES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 43-R1						
NET SALVAGE PERCENT.. -20						
1968	1,429.92	1,170	1,716			
1970	17,408.79	13,798	20,891			
1978	2,920.56	1,989	3,438	67	18.59	4
1979	287.20	191	330	15	19.12	1
1981	1,553,445.95	987,992	1,707,915	156,220	20.21	7,730
1982	486,800.75	302,000	522,059	62,102	20.77	2,990
1983	348,061.32	210,391	363,697	53,977	21.34	2,529
1984	430,502.34	253,378	438,008	78,595	21.91	3,587
1985	131,555.88	75,262	130,103	27,764	22.50	1,234
1986	901,692.63	501,002	866,069	215,962	23.09	9,353
1987	1,101,007.77	593,619	1,026,173	295,036	23.68	12,459
1988	943,974.25	492,890	852,046	280,723	24.29	11,557
1989	1,606,604.49	811,522	1,402,857	525,068	24.90	21,087
1990	1,001,598.39	488,592	844,616	357,302	25.52	14,001
1991	829,595.79	390,102	674,359	321,156	26.15	12,281
1992	757,385.96	342,832	592,645	316,218	26.78	11,808
1993	952,488.78	414,138	715,909	427,078	27.42	15,575
1994	1,338,365.33	557,633	963,965	642,073	28.07	22,874
1995	951,666.66	379,247	655,594	486,406	28.72	16,936
1996	1,577,293.90	599,965	1,037,144	855,609	29.37	29,132
1997	1,948,899.80	705,416	1,219,434	1,119,246	30.03	37,271
1998	1,152,928.92	395,754	684,129	699,386	30.70	22,781
1999	951,172.04	308,716	533,669	607,737	31.37	19,373
2000	1,146,005.31	350,513	605,923	769,283	32.04	24,010
2001	1,271,276.81	364,709	630,463	895,069	32.72	27,355
2002	6,273,454.43	1,680,734	2,905,440	4,622,705	33.40	138,404
2003	1,513,912.45	376,437	650,737	1,165,958	34.09	34,202
2004	1,430,524.60	328,151	567,266	1,149,364	34.78	33,047
2005	1,946,928.17	409,135	707,261	1,629,053	35.47	45,928
2006	4,237,066.54	808,788	1,398,130	3,686,350	36.16	101,946
2007	2,043,174.40	350,094	605,198	1,846,611	36.86	50,098
2008	1,910,171.40	289,460	500,382	1,791,824	37.57	47,693
2009	1,439,822.76	189,659	327,858	1,399,929	38.28	36,571
2010	6,400,391.33	716,281	1,238,216	6,442,254	38.99	165,228
2011	2,459,336.59	225,797	390,329	2,560,875	39.71	64,489
2012	3,783,242.36	271,349	469,074	4,070,817	40.43	100,688
2013	4,806,162.69	246,787	426,614	5,340,781	41.16	129,757
2014	4,724,196.35	146,318	252,936	5,416,100	41.89	129,293
2015	8,231,876.13	231,151	399,585	9,478,667	20.87	454,177
	72,604,629.74	15,812,962	27,332,178	59,793,378		1,857,449

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.2 2.56

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P08 - POWER LINE CARRIER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. -6						
1978	50,794.89	51,366	53,843			
1980	901,642.38	892,280	955,741			
1982	10,151.14	9,826	10,760			
1990	1,997.13	1,710	2,117			
1995	319,668.37	236,787	338,848			
1996	115,824.11	82,602	122,774			
1999	532,472.13	331,879	525,099	39,321	10.30	3,818
2000	1,168,541.93	691,169	1,093,568	145,086	11.05	13,130
2002	594,654.98	311,889	493,471	136,863	12.63	10,836
2003	258,180.09	126,436	200,047	73,624	13.45	5,474
2004	287,074.34	130,362	206,259	98,040	14.29	6,861
2008	368,553.14	112,199	177,521	213,145	17.82	11,961
2009	351,267.78	93,086	147,281	225,063	18.75	12,003
2012	10,750.00	1,554	2,459	8,936	21.59	414
	4,971,572.41	3,073,145	4,329,788	940,079		64,497

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.6 1.30

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P09 - POWER SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L3						
NET SALVAGE PERCENT.. -6						
1980	3,939.62	3,664	3,591	585	2.45	239
1990	3,702.71	2,961	2,902	1,023	4.91	208
1992	2,349.84	1,822	1,786	705	5.37	131
1997	29,300.16	21,321	20,895	10,163	6.27	1,621
1998	2,672.81	1,914	1,876	957	6.49	147
1999	4,402.88	3,087	3,025	1,642	6.77	243
2000	7,428.22	5,075	4,974	2,900	7.11	408
2003	374,436.07	224,845	220,349	176,553	8.67	20,364
2004	29,433.83	16,598	16,266	14,934	9.36	1,596
2006	96,294.52	46,239	45,314	56,758	10.94	5,188
2007	1,087.65	473	464	689	11.80	58
2008	24,903.99	9,649	9,456	16,942	12.69	1,335
2012	23,109.92	4,275	4,189	20,308	16.51	1,230
2013	47,739.50	6,325	6,199	44,405	17.50	2,537
2014	13,790.40	1,096	1,074	13,544	18.50	732
	664,592.12	349,344	342,360	362,108		36,037

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.0 5.42

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P10 - POWERHOUSE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
NET SALVAGE PERCENT.. -8						
1966	6,311,169.11	4,008,731	2,148,243	4,667,820	30.89	151,111
1967	4,570,325.24	2,853,622	1,529,230	3,406,721	31.64	107,671
1969	2,852,512.87	1,719,038	921,217	2,159,497	33.15	65,143
1970	2,813,125.00	1,664,100	891,776	2,146,399	33.92	63,278
1971	3,591,077.62	2,083,961	1,116,776	2,761,588	34.70	79,585
1976	5,000.00	2,614	1,401	3,999	38.70	103
1978	1,083,475.00	540,763	289,790	880,363	40.34	21,824
1979	6,557,377.81	3,193,472	1,711,353	5,370,615	41.18	130,418
1980	2,154,843.14	1,023,353	548,406	1,778,825	42.02	42,333
1981	242,625.77	112,290	60,175	201,861	42.86	4,710
1982	12,555,601.74	5,655,490	3,030,726	10,529,324	43.72	240,835
1983	4,570,723.64	2,002,838	1,073,303	3,863,079	44.57	86,674
1984	11,985,754.79	5,101,861	2,734,042	10,210,573	45.44	224,705
1985	6,005,216.38	2,480,949	1,329,518	5,156,116	46.31	111,339
1986	10,005.17	4,008	2,148	8,658	47.18	184
1987	219,450.45	85,102	45,605	191,401	48.07	3,982
1988	1,492,250.75	559,768	299,975	1,311,656	48.95	26,796
1989	1,071,438.20	388,028	207,941	949,212	49.85	19,041
1990	38,861.82	13,576	7,275	34,696	50.74	684
1991	10,918.56	3,671	1,967	9,825	51.65	190
1993	2,707,655.42	839,470	449,864	2,474,404	53.47	46,276
1994	44,880.61	13,320	7,138	41,333	54.39	760
1995	148,263.24	42,037	22,527	137,597	55.31	2,488
1997	7,274.98	1,868	1,001	6,856	57.17	120
1998	9,563.03	2,326	1,246	9,082	58.11	156
2000	107,638.74	23,265	12,468	103,782	59.99	1,730
2003	20,849,611.08	3,650,775	1,956,419	20,561,161	62.84	327,199
2006	83,289.00	11,118	5,958	83,994	65.73	1,278
2008	110,785.58	11,710	6,275	113,373	67.66	1,676
2013	136,303.49	4,828	2,587	144,621	72.54	1,994
2014	405,707.09	8,645	4,633	433,531	73.52	5,897
2015	966,020.00	8,242	4,417	1,038,885	62.79	16,545
	93,718,745.32	38,114,839	20,425,400	80,790,845		1,786,725

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.2 1.91

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P11 - PRINTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 6-SQUARE						
NET SALVAGE PERCENT.. 0						
2010	33,674.17	30,868	33,674			
2011	109,892.75	82,420	109,893			
2012	442,736.53	258,262	440,915	1,822	2.50	729
2013	234,151.87	97,564	166,565	67,587	3.50	19,311
2014	127,631.90	31,908	54,475	73,157	4.50	16,257
2015	89,913.38	7,492	12,791	77,123	5.50	14,022
	1,038,000.60	508,514	818,313	219,688		50,319

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.4 4.85

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P12 - PROTECTIVE CONTROL AND RELAY PANELS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
1967	284,441.83	263,069	284,442			
1968	57,082.00	52,369	57,082			
1980	274,001.64	220,533	274,002			
1984	65,632.30	48,999	65,632			
1987	97,943.45	68,057	97,943			
1988	11,036.18	7,467	11,036			
1995	81,935.56	43,543	69,049	12,887	16.40	786
1996	422,516.97	214,879	340,748	81,769	17.20	4,754
1999	123,789.76	54,256	86,037	37,753	19.66	1,920
2003	1,715,668.03	581,371	921,918	793,750	23.14	34,302
2004	267,884.42	83,885	133,022	134,862	24.04	5,610
2005	136,944.76	39,322	62,355	74,590	24.95	2,990
2006	84,139.78	21,949	34,806	49,334	25.87	1,907
2007	417,771.63	97,880	155,215	262,557	26.80	9,797
2008	67,175.89	13,934	22,096	45,080	27.74	1,625
2009	143,451.35	25,863	41,013	102,438	28.69	3,571
2010	77,951.21	11,916	18,896	59,055	29.65	1,992
2011	272,015.61	34,119	54,105	217,911	30.61	7,119
2012	1,802,811.24	176,153	279,337	1,523,474	31.58	48,242
2013	1,875,300.36	131,271	208,164	1,667,136	32.55	51,218
2014	424,664.40	17,836	28,284	396,380	33.53	11,822
2015	802,970.72	13,490	21,392	781,579	29.26	26,712
	9,507,129.09	2,222,161	3,266,574	6,240,555		214,367

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.1 2.25

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R01 - RADIO TOWERS (WOOD OR STEEL)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-R3						
NET SALVAGE PERCENT.. -14						
1980	1,129,316.10	830,927	1,287,420			
1982	163,082.69	114,492	185,914			
1984	345,750.61	230,747	394,156			
1990	60,871.98	33,844	69,394			
1993	20,347.95	10,110	23,197			
2001	2,219,146.63	731,019	1,700,743	829,084	34.13	24,292
2003	4,407,288.75	1,259,192	2,929,557	2,094,752	35.97	58,236
2005	231,191.05	55,732	129,663	133,895	37.85	3,538
2007	365,470.35	71,695	166,801	249,835	39.74	6,287
2009	181,643.40	27,350	63,631	143,442	41.66	3,443
2010	214,646.98	27,377	63,694	181,004	42.63	4,246
2012	157,380.61	12,821	29,828	149,586	44.57	3,356
2013	262,969.06	15,301	35,598	264,186	45.55	5,800
	9,759,106.16	3,420,607	7,079,596	4,045,785		109,198

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.0 1.12

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R02 - RADIOS - FIXED MICROWAVE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 19-R5						
NET SALVAGE PERCENT.. 0						
1980	133,758.69	133,759	133,759			
2001	2,927,352.03	2,183,190	2,716,833	210,519	4.83	43,586
2003	1,936,460.85	1,263,792	1,572,704	363,757	6.60	55,115
2007	184,426.72	82,507	102,674	81,753	10.50	7,786
2010	52,446.64	15,182	18,893	33,554	13.50	2,485
2012	42,443.68	7,819	9,730	32,714	15.50	2,111
2014	935,875.16	73,887	91,948	843,927	17.50	48,224
	6,212,763.77	3,760,136	4,646,541	1,566,223		159,307

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.8 2.56

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R03 - RADIOS - FIXED UHF EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-L0.5						
NET SALVAGE PERCENT.. 0						
2008	39,521.58	12,094	16,134	23,388	10.41	2,247
2009	49,779.53	13,805	18,417	31,363	10.84	2,893
2012	8,976.21	1,544	2,060	6,916	12.42	557
2015	3,385.14	198	264	3,121	8.04	388
	101,662.46	27,641	36,875	64,787		6,085

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.6 5.99

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R04 - RADIOS - FIXED VHF EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 19-R3						
NET SALVAGE PERCENT.. 0						
1992	161,678.78	143,128	161,679			
2003	118,245.16	69,330	106,929	11,316	7.86	1,440
2004	560.00	306	472	88	8.61	10
2006	211,040.32	97,524	150,413	60,627	10.22	5,932
2010	68,641.70	19,039	29,364	39,278	13.73	2,861
	560,165.96	329,327	448,857	111,309		10,243

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 10.9 1.83

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R05 - RADIOS - MOBILE VHF BASE STATION

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-R4						
NET SALVAGE PERCENT.. 0						
1990	3,162.00	3,162	3,162			
1999	25,964.56	23,195	25,965			
2000	13,354.38	11,592	13,354			
2003	142,198.39	107,407	132,744	9,454	3.67	2,576
2004	2,800.00	1,982	2,450	350	4.38	80
2006	5,570,753.44	3,364,735	4,158,470	1,412,283	5.94	237,758
2007	449,236.51	245,881	303,884	145,353	6.79	21,407
2010	353,405.39	128,170	158,405	195,000	9.56	20,397
2011	2,650.00	790	976	1,674	10.53	159
2012	715,139.17	165,912	205,051	510,089	11.52	44,279
	7,278,663.84	4,052,826	5,004,461	2,274,203		326,656

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.0 4.49

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R06 - RAMPS - YARD STORAGE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R3						
NET SALVAGE PERCENT.. 0						
1975	23,739.53	23,331	23,740			
1979	41,423.85	39,104	41,424			
1982	17,210.71	15,717	17,211			
1987	32,563.96	27,849	32,564			
1989	105,848.63	87,304	102,299	3,550	4.38	811
1990	80,081.66	64,674	75,782	4,300	4.81	894
1991	18,109.67	14,285	16,739	1,371	5.28	260
1992	11,484.17	8,824	10,340	1,144	5.79	198
1993	49,461.82	36,918	43,259	6,203	6.34	978
1996	49,965.87	33,617	39,391	10,575	8.18	1,293
1999	91,261.53	53,662	62,879	28,383	10.30	2,756
2001	54,773.84	28,855	33,811	20,963	11.83	1,772
2005	37,371.68	14,724	17,253	20,119	15.15	1,328
2006	157,317.16	56,508	66,213	91,104	16.02	5,687
2007	62,524.29	20,233	23,708	38,816	16.91	2,295
2008	128,268.49	36,839	43,166	85,102	17.82	4,776
2009	275,236.83	68,809	80,627	194,610	18.75	10,379
2010	194,580.30	41,407	48,519	146,061	19.68	7,422
2014	30,779.66	1,810	2,121	28,659	23.53	1,218
2015	131,553.97	3,078	3,607	127,947	20.87	6,131
	1,593,557.62	677,548	784,653	808,905		48,198

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.8 3.02

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R07 - REACTORS AND RESISTORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S4						
NET SALVAGE PERCENT.. 0						
1968	20,083.02	18,366	14,534	5,549	3.42	1,623
1977	30,440.00	25,729	20,361	10,079	6.19	1,628
1978	8,000.00	6,674	5,282	2,718	6.63	410
1981	11,332.11	9,026	7,143	4,189	8.14	515
1995	706,182.60	361,389	285,991	420,192	19.53	21,515
1996	31,021.13	15,107	11,955	19,066	20.52	929
2000	201,957.01	78,258	61,931	140,026	24.50	5,715
2006	15,887.39	3,773	2,986	12,901	30.50	423
2012	19,747.12	1,728	1,368	18,379	36.50	504
2014	105,579.69	3,959	3,133	102,447	38.50	2,661
2015	74,835.30	965	763	74,072	38.26	1,936
	1,225,065.37	524,974	415,447	809,618		37,859

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.4 3.09

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R08- RECLOSERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-R3						
NET SALVAGE PERCENT.. -8						
1967	6,652.00	5,770	7,184			
1968	56,551.87	48,453	61,076			
1970	127,939.91	106,740	138,175			
1971	23,480.43	19,310	25,359			
1975	254,501.39	196,067	274,862			
1976	13,304.00	10,064	14,113	255	14.38	18
1978	51,386.25	37,380	52,420	3,077	15.67	196
1979	14,000.00	9,973	13,986	1,134	16.34	69
1981	247,844.16	168,855	236,796	30,876	17.72	1,742
1982	210,284.73	139,860	196,134	30,974	18.44	1,680
1983	13,679.99	8,877	12,449	2,325	19.16	121
1984	195,909.41	123,864	173,702	37,880	19.90	1,904
1985	148,118.05	91,148	127,822	32,145	20.65	1,557
1986	10,486.97	6,272	8,796	2,530	21.42	118
1987	120,202.29	69,805	97,892	31,926	22.19	1,439
1988	192,446.10	108,338	151,929	55,913	22.98	2,433
1989	80,623.21	43,935	61,613	25,460	23.78	1,071
1990	168,883.99	88,956	124,748	57,647	24.59	2,344
1991	53,470.41	27,177	38,112	19,636	25.41	773
1992	68,483.94	33,529	47,020	26,943	26.24	1,027
1993	42,735.36	20,115	28,209	17,945	27.08	663
1994	308,115.99	139,136	195,119	137,646	27.93	4,928
1995	78,765.23	34,044	47,742	37,324	28.79	1,296
1996	46,812.70	19,328	27,105	23,453	29.65	791
1997	152,244.41	59,844	83,923	80,501	30.53	2,637
1998	225,640.57	84,176	118,045	125,647	31.42	3,999
1999	28,552.97	10,080	14,136	16,701	32.31	517
2000	125,112.26	41,607	58,348	76,773	33.22	2,311
2001	74,492.85	23,247	32,601	47,851	34.13	1,402
2002	36,048.05	10,503	14,729	24,203	35.05	691
2003	243,555.38	65,923	92,448	170,592	35.97	4,743
2004	7,409.35	1,849	2,593	5,409	36.91	147
2005	184,703.55	42,182	59,154	140,326	37.85	3,707
2006	44,673.53	9,258	12,983	35,264	38.79	909
2008	156,994.85	25,786	36,161	133,393	40.70	3,277
2009	191,161.39	27,268	38,240	168,214	41.66	4,038
2010	460,161.79	55,602	77,974	419,001	42.63	9,829
2011	294,224.11	29,129	40,849	276,913	43.60	6,351
2012	786,434.97	60,695	85,116	764,234	44.57	17,147

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R08- RECLOSERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 48-R3						
NET SALVAGE PERCENT.. -8						
2013	767,583.00	42,312	59,337	769,653	45.55	16,897
2014	286,332.34	9,469	13,279	295,960	46.53	6,361
2015	558,602.79	7,420	10,405	592,886	40.15	14,767
	7,158,606.54	2,163,346	3,012,684	4,718,611		123,900
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.1	1.73

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R09 - REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-S0.5						
NET SALVAGE PERCENT.. -8						
1968	18,866.12	14,594	18,554	1,821	11.35	160
1970	54,167.14	40,760	51,819	6,682	12.13	551
1971	180,731.24	134,095	170,477	24,713	12.52	1,974
1975	236,210.70	164,799	209,512	45,596	14.16	3,220
1977	37,253.00	25,126	31,943	8,290	15.02	552
1980	723,370.55	461,908	587,231	194,009	16.35	11,866
1981	114,979.59	72,023	91,564	32,614	16.80	1,941
1982	94,913.39	58,249	74,053	28,453	17.27	1,648
1983	36,438.00	21,900	27,842	11,511	17.74	649
1984	65,838.76	38,717	49,221	21,885	18.22	1,201
1985	228,343.71	131,259	166,872	79,739	18.71	4,262
1987	96,206.56	52,679	66,972	36,931	19.72	1,873
1988	101,884.72	54,358	69,106	40,929	20.24	2,022
1989	2,844.72	1,477	1,878	1,194	20.77	57
1990	120,936.14	61,061	77,628	52,983	21.30	2,487
1993	97,861.56	44,971	57,172	48,518	22.98	2,111
1994	24,330.81	10,793	13,721	12,556	23.57	533
1995	65,641.15	28,073	35,690	35,202	24.16	1,457
1997	103,909.72	40,989	52,110	60,112	25.39	2,368
2000	18,916.42	6,466	8,220	12,210	27.34	447
2001	5,317.92	1,719	2,185	3,558	28.03	127
2002	26,690.60	8,129	10,335	18,491	28.72	644
2003	150,883.10	43,020	54,692	108,262	29.44	3,677
2004	122,332.16	32,468	41,277	90,842	30.17	3,011
2005	36,569.64	8,975	11,410	28,085	30.91	909
2006	89,712.14	20,153	25,621	71,268	31.68	2,250
2007	71,728.09	14,583	18,540	58,926	32.47	1,815
2008	243,153.44	44,183	56,170	206,436	33.27	6,205
2009	402,868.52	64,177	81,589	353,509	34.10	10,367
2010	317,705.00	43,405	55,181	287,940	34.94	8,241
2011	342,450.78	38,741	49,252	320,595	35.81	8,953
2012	616,673.74	54,946	69,854	596,154	36.70	16,244
2013	537,169.67	34,664	44,068	536,075	37.61	14,254
2014	158,574.53	6,251	7,947	163,313	38.54	4,237
2015	122,166.67	2,375	3,020	128,920	27.20	4,740
	5,667,640.00	1,882,086	2,392,726	3,728,325		127,053

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.3 2.24

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R11- REVENUE METERING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R3						
NET SALVAGE PERCENT.. 0						
1967	12,751.00	11,793	12,045	706	2.63	268
1968	6,820.00	6,257	6,391	429	2.89	148
1970	8,301.90	7,493	7,653	649	3.41	190
1974	13,100.00	11,397	11,640	1,460	4.55	321
1976	9,983.00	8,497	8,678	1,305	5.21	250
1977	8,738.30	7,345	7,502	1,236	5.58	222
1978	37,976.15	31,499	32,171	5,805	5.97	972
1979	7,907.86	6,464	6,602	1,306	6.39	204
1980	37,702.15	30,345	30,993	6,709	6.83	982
1981	32,616.27	25,813	26,364	6,252	7.30	856
1982	2,521.70	1,960	2,002	520	7.80	67
1983	33,124.09	25,250	25,789	7,335	8.32	882
1984	29,812.28	22,257	22,732	7,080	8.87	798
1985	14,504.27	10,588	10,814	3,690	9.45	390
1986	43,276.88	30,850	31,509	11,768	10.05	1,171
1987	34,327.14	23,853	24,362	9,965	10.68	933
1988	31,848.65	21,548	22,008	9,841	11.32	869
1989	23,844.81	15,676	16,011	7,834	11.99	653
1990	15,631.27	9,968	10,181	5,450	12.68	430
1991	16,516.52	10,198	10,416	6,101	13.39	456
1992	34,331.48	20,481	20,918	13,413	14.12	950
1994	5,484.96	3,036	3,101	2,384	15.63	153
1995	7,534.74	4,004	4,089	3,446	16.40	210
1996	29,464.09	14,985	15,305	14,159	17.20	823
1997	9,378.65	4,555	4,652	4,727	18.00	263
2001	121,485.76	47,275	48,284	73,202	21.38	3,424
2002	86,636.39	31,561	32,234	54,402	22.25	2,445
2003	39,573.82	13,410	13,696	25,878	23.14	1,118
2009	89,696.48	16,171	16,516	73,180	28.69	2,551
2012	27,330.13	2,670	2,727	24,603	31.58	779
2014	87,162.67	3,661	3,739	83,424	33.53	2,488
2015	283,532.20	4,763	4,865	278,667	29.26	9,524
	1,242,915.61	485,623	495,989	746,926		35,790

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.9 2.88

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R12 - RIGHT-OF-WAYS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
1966	1,057,755.13	745,315	833,259	224,496	19.20	11,692
1967	1,713,673.55	1,187,970	1,328,145	385,529	19.94	19,334
1968	274,316.09	186,999	209,064	65,252	20.69	3,154
1969	85,289.66	57,131	63,872	21,418	21.46	998
1970	299,538.55	197,096	220,352	79,187	22.23	3,562
1973	5,734.27	3,562	3,982	1,752	24.62	71
1974	574,591.95	349,708	390,972	183,620	25.44	7,218
1976	134,344.85	78,292	87,530	46,815	27.12	1,726
1977	25,664.00	14,621	16,346	9,318	27.97	333
1978	2,890,160.13	1,608,259	1,798,026	1,092,134	28.83	37,882
1980	122,188.63	64,704	72,339	49,850	30.58	1,630
1981	1,116,248.39	575,817	643,761	472,487	31.47	15,014
1982	793,264.95	398,219	445,207	348,058	32.37	10,752
1983	1,786,100.11	871,617	974,464	811,636	33.28	24,388
1984	66,937.79	31,718	35,461	31,477	34.20	920
1985	1,714,103.64	787,956	880,931	833,173	35.12	23,724
1986	39,975.47	17,804	19,905	20,070	36.05	557
1987	563,160.38	242,677	271,312	291,848	36.99	7,890
1988	175,696.96	73,171	81,805	93,892	37.93	2,475
1989	549,774.56	220,927	246,995	302,780	38.88	7,788
1990	786,220.76	304,448	340,371	445,850	39.83	11,194
1991	168,758.87	62,856	70,273	98,486	40.79	2,414
1992	23,974.15	8,575	9,587	14,387	41.75	345
1993	88,237.17	30,245	33,814	54,423	42.72	1,274
1994	36,190.83	11,865	13,265	22,926	43.69	525
1995	324,798.29	101,636	113,629	211,169	44.66	4,728
1996	531,645.83	158,351	177,036	354,610	45.64	7,770
1997	182,916.05	51,723	57,826	125,090	46.62	2,683
1998	590,349.41	158,031	176,678	413,671	47.60	8,691
1999	103,742.35	26,207	29,299	74,443	48.58	1,532
2000	15,017.65	3,565	3,986	11,032	49.57	223
2001	10,532.16	2,340	2,616	7,916	50.56	157
2002	1,429,050.07	295,699	330,590	1,098,460	51.55	21,309
2003	32,707.00	6,270	7,010	25,697	52.54	489
2004	79,298.85	13,993	15,644	63,655	53.53	1,189
2005	128,687.90	20,729	23,175	105,513	54.53	1,935
2006	1,128,537.74	164,597	184,018	944,520	55.52	17,012
2007	99,457.18	12,975	14,506	84,951	56.52	1,503
2008	149,366.07	17,211	19,242	130,124	57.51	2,263
2009	166,356.00	16,611	18,571	147,785	58.51	2,526
2010	97,644.83	8,247	9,220	88,425	59.51	1,486
2011	13,878.97	959	1,072	12,807	60.51	212
2012	345,323.60	18,596	20,790	324,534	61.50	5,277

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R12 - RIGHT-OF-WAYS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
2013	444,049.95	17,078	19,093	424,957	62.50	6,799
2014	311,667.47	7,193	8,042	303,625	63.50	4,781
2015	452,720.59	3,712	4,150	448,570	60.48	7,417
	21,729,648.80	9,237,275	10,327,231	11,402,418		296,842
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					38.4	1.37

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R13 - ROADS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. -8						
1967	40,992.69	32,673	12,330	31,942	15.72	2,032
1968	22,493.01	17,644	6,658	17,634	16.42	1,074
1969	490,478.00	378,392	142,796	386,920	17.14	22,574
1970	128,175.47	97,201	36,681	101,749	17.87	5,694
1971	27,000.00	20,115	7,591	21,569	18.61	1,159
1973	11,211.47	8,046	3,036	9,072	20.13	451
1977	11,758.50	7,761	2,929	9,770	23.33	419
1978	11,048.80	7,128	2,690	9,243	24.16	383
1979	5,061.00	3,188	1,203	4,263	25.00	171
1980	3,165,500.82	1,945,845	734,317	2,684,424	25.85	103,846
1981	15,766.30	9,447	3,565	13,463	26.71	504
1982	2,911.13	1,698	641	2,503	27.59	91
1983	9,598,932.99	5,447,778	2,055,866	8,310,982	28.47	291,921
1984	60,540,101.27	33,389,295	12,600,352	52,782,957	29.36	1,797,785
1985	316,785.74	169,525	63,975	278,154	30.27	9,189
1986	13,242.22	6,869	2,592	11,710	31.18	376
1988	1,306,655.61	634,329	239,381	1,171,807	33.03	35,477
1989	363,353.41	170,311	64,271	328,151	33.96	9,663
1990	52,244.27	23,604	8,908	47,516	34.90	1,361
1991	54,563.98	23,719	8,951	49,978	35.85	1,394
1993	5,411.45	2,166	817	5,027	37.76	133
1994	25,140.01	9,630	3,634	23,517	38.72	607
1995	10,006.93	3,658	1,380	9,427	39.69	238
1996	3,959.23	1,378	520	3,756	40.66	92
1997	15,649.07	5,172	1,952	14,949	41.64	359
2000	155,870.51	43,263	16,326	152,014	44.58	3,410
2001	432,343.06	112,297	42,378	424,553	45.57	9,317
2002	44,013.10	10,648	4,018	43,516	46.56	935
2003	767,915.72	172,090	64,943	764,406	47.55	16,076
2005	1,358,343.31	255,993	96,606	1,370,405	49.53	27,668
2007	935,334.53	142,766	53,877	956,284	51.52	18,561
2008	404,864.35	54,582	20,598	416,655	52.51	7,935
2009	324,318.06	37,888	14,298	335,966	53.51	6,279
2010	983,257.78	97,166	36,669	1,025,249	54.51	18,808
2011	1,053,370.50	85,130	32,126	1,105,514	55.51	19,916
2012	245,591.86	15,471	5,839	259,400	56.50	4,591
2013	51,671.03	2,325	877	54,928	57.50	955
2014	505,599.92	13,651	5,152	540,896	58.50	9,246
2015	939,809.96	8,932	3,371	1,011,624	56.00	18,065
	84,440,747.06	43,468,774	16,404,114	74,791,893		2,448,755

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.5 2.90

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R14 - ROUTERS AND LAN

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	651,646.86	586,482	651,647			
2012	673,410.48	471,387	673,410			
2013	268,747.57	134,374	223,667	45,081	2.50	18,032
2014	286,810.01	86,043	143,219	143,591	3.50	41,026
2015	850,362.78	85,036	141,544	708,819	4.50	157,515
	2,730,977.70	1,363,322	1,833,487	897,491		216,573

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.1 7.93

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R15 - RUNNER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R5						
NET SALVAGE PERCENT.. 0						
1967	5,230,693.06	4,368,099	3,187,705	2,042,988	9.07	225,247
1968	1,448,949.16	1,192,355	870,144	578,805	9.74	59,426
1970	1,458,564.95	1,161,820	847,861	610,704	11.19	54,576
1977	130,312.00	90,034	65,704	64,608	17.00	3,800
1980	50,343.45	32,266	23,547	26,796	19.75	1,357
1985	2,644,906.00	1,464,326	1,068,620	1,576,286	24.55	64,207
1989	583,387.23	280,983	205,053	378,334	28.51	13,270
1994	16,158.41	6,316	4,609	11,549	33.50	345
1996	59,841.42	21,217	15,483	44,358	35.50	1,250
1998	46,687.84	14,855	10,841	35,847	37.50	956
	11,669,843.52	8,632,271	6,299,567	5,370,277		424,434

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.7 3.64

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S01 - SCADA EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-L3						
NET SALVAGE PERCENT.. 0						
1980	127,277.80	111,686	127,278			
1986	55,464.80	44,705	55,465			
1989	27,913.07	21,409	27,913			
1990	73,377.15	55,363	73,377			
1995	14,286.26	10,058	14,286			
1998	18,979.59	12,821	18,443	537	6.49	83
1999	180,642.42	119,495	171,893	8,749	6.77	1,292
2001	330,081.74	205,641	295,813	34,269	7.54	4,545
2002	398,819.76	238,095	342,498	56,322	8.06	6,988
2003	562,865.09	318,863	458,682	104,183	8.67	12,016
2004	343,355.76	182,665	262,763	80,593	9.36	8,610
2005	203,547.66	100,553	144,645	58,903	10.12	5,820
2006	225,887.94	102,327	147,197	78,691	10.94	7,193
2007	275,766.06	113,064	162,642	113,124	11.80	9,587
2008	280,808.49	102,636	147,641	133,167	12.69	10,494
2009	251,993.65	80,512	115,816	136,178	13.61	10,006
2010	366,628.59	99,723	143,451	223,178	14.56	15,328
2011	86,307.46	19,333	27,810	58,497	15.52	3,769
2012	73,526.84	12,830	18,456	55,071	16.51	3,336
2013	209,687.85	26,211	37,704	171,984	17.50	9,828
2014	27,323.88	2,049	2,947	24,377	18.50	1,318
2015	795,391.14	22,510	32,381	763,010	17.17	44,439
	4,929,933.00	2,002,549	2,829,101	2,100,832		154,652

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.6 3.14

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S02 - SECTIONALIZERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-R5						
NET SALVAGE PERCENT.. 0						
1968	48,466.85	48,467	48,467			
1975	23,769.58	23,770	23,770			
1986	1,941.08	1,855	1,531	410	1.11	369
1989	1,726.87	1,596	1,318	409	1.89	216
1991	46,552.06	41,487	34,249	12,303	2.72	4,523
1996	22,003.75	16,714	13,798	8,206	6.01	1,365
2000	4,105.58	2,532	2,091	2,015	9.58	210
2010	5,443.11	1,197	988	4,455	19.50	228
	154,008.88	137,618	126,212	27,797		6,911

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.0 4.49

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S03 - SERVERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 7-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	52,745.62	48,978	52,746			
2010	1,661,109.97	1,305,151	1,661,110			
2011	358,846.88	230,688	358,847			
2012	183,377.26	91,689	183,377			
2013	257,792.01	92,068	240,975	16,817	4.50	3,737
2014	440,602.61	94,417	247,122	193,481	5.50	35,178
2015	64,729.57	4,624	12,103	52,627	6.50	8,096
	3,019,203.92	1,867,615	2,756,280	262,924		47,011

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.6 1.56

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S04 - SEWAGE DISPOSAL SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -6						
1967	10,112.35	8,443	10,719			
1968	7,791.63	6,406	8,259			
1969	132,528.13	107,276	140,480			
1970	14,085.17	11,217	14,930			
1971	1,387.00	1,086	1,470			
1972	4,653.28	3,580	4,932			
1977	7,861.00	5,483	8,333			
1978	34,016.40	23,208	36,057			
1980	143,118.72	93,202	151,706			
1981	2,667.48	1,694	2,828			
1982	3,000.00	1,857	3,180			
1983	95,005.41	57,256	100,706			
1988	2,697.73	1,395	2,659	201	28.16	7
1989	308,017.92	153,869	293,334	33,165	29.08	1,140
1990	50,007.03	24,095	45,934	7,073	30.00	236
1992	15,841.00	7,062	13,463	3,328	31.87	104
1995	131,238.24	51,270	97,741	41,372	34.73	1,191
1996	13,483.21	5,015	9,561	4,731	35.70	133
1997	4,233.64	1,496	2,852	1,636	36.67	45
1998	55,598.68	18,602	35,463	23,472	37.64	624
1999	976,185.68	308,171	587,493	447,264	38.62	11,581
2002	355,826.77	92,167	175,706	201,470	41.56	4,848
2003	97,910.98	23,493	44,787	58,999	42.55	1,387
2006	35,314.99	6,445	12,287	25,147	45.53	552
2007	58,129.37	9,500	18,111	43,506	46.52	935
2008	44,604.54	6,430	12,258	35,023	47.52	737
2009	44,878.73	5,613	10,700	36,871	48.51	760
2010	125,757.70	13,306	25,366	107,937	49.51	2,180
2011	143,366.51	12,407	23,653	128,315	50.51	2,540
	2,919,319.29	1,061,044	1,894,968	1,199,510		29,000

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.4 0.99

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S05 - SOFTWARE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 7-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	1,013,220.31	940,846	762,788	250,432	0.50	250,432
2010	1,384,293.79	1,087,653	881,811	502,483	1.50	334,989
2011	1,302,502.98	837,327	678,860	623,643	2.50	249,457
2012	1,018,232.31	509,116	412,764	605,468	3.50	172,991
2013	2,774,542.51	990,900	803,369	1,971,174	4.50	438,039
2014	1,012,715.03	217,015	175,944	836,771	5.50	152,140
2015	1,576,292.03	112,595	91,286	1,485,006	6.50	228,462
	10,081,798.96	4,695,452	3,806,822	6,274,977		1,826,510
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					3.4	18.12

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S06 - SPILLWAY STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 110-R4						
NET SALVAGE PERCENT.. -8						
1956	37,231.12	21,103	7,168	33,042	52.27	632
1966	2,136,380.00	1,019,407	346,252	1,961,038	61.40	31,939
1967	2,261,132.00	1,058,055	359,379	2,082,644	62.34	33,408
1979	3,482,644.79	1,237,115	420,199	3,341,057	73.82	45,260
1982	11,830,011.26	3,863,076	1,312,133	11,464,279	76.74	149,391
1983	2,949.09	935	318	2,867	77.72	37
1984	6,511,055.23	2,000,938	679,639	6,352,301	78.70	80,715
1988	28,771.28	7,729	2,625	28,448	82.64	344
1991	35,581.53	8,524	2,895	35,533	85.60	415
1992	6,707.73	1,542	524	6,720	86.59	78
2003	1,737,806.17	212,926	72,323	1,804,508	97.52	18,504
2015	50,000.00	259	88	53,912	102.60	525
	28,120,270.20	9,431,609	3,203,543	27,166,349		361,248

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 75.2 1.28

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S07 - STACKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -8						
1968	1,297,967.37	1,087,296	1,401,805			
1971	430,393.00	343,296	464,535	289	14.38	20
1974	69,609.69	52,584	71,155	4,023	16.53	243
1975	661,362.47	489,862	662,862	51,409	17.28	2,975
1976	8,601.34	6,243	8,448	841	18.04	47
1986	27,918.81	15,701	21,246	8,906	26.36	338
1988	6,132.90	3,232	4,373	2,251	28.16	80
1992	336,677.64	152,917	206,921	156,691	31.87	4,917
1995	36,955.81	14,710	19,905	20,007	34.73	576
1996	121,024.55	45,866	62,064	68,643	35.70	1,923
2001	94,022.28	26,623	36,025	65,519	40.58	1,615
2005	52,308.82	10,754	14,552	41,942	44.53	942
2007	108,179.45	18,013	24,374	92,460	46.52	1,988
2008	289,892.88	42,579	57,616	255,468	47.52	5,376
2011	527,981.53	46,553	62,994	507,226	50.51	10,042
2015	3,781,821.18	39,618	53,610	4,030,757	51.05	78,957
	7,850,849.72	2,395,847	3,172,485	5,306,433		110,039

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 48.2 1.40

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S08 - STATIC EXCITATION SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 32-R4						
NET SALVAGE PERCENT.. -6						
1967	951,235.75	1,005,477	816,518	191,792	0.09	191,792
1968	431,036.26	452,901	367,787	89,111	0.28	89,111
1970	688,732.45	714,316	580,075	149,981	0.69	149,981
1974	36,724.00	36,944	30,001	8,926	1.63	5,476
1975	32,918.00	32,832	26,662	8,231	1.89	4,355
1976	8,000.00	7,910	6,423	2,057	2.15	957
1977	8,000.00	7,836	6,363	2,117	2.43	871
1980	1,489,744.00	1,415,294	1,149,318	429,811	3.32	129,461
1982	25,045.38	23,196	18,837	7,711	4.04	1,909
1988	2,134.84	1,749	1,420	843	7.27	116
1989	219,265.38	174,753	141,912	90,509	7.94	11,399
1992	127,935.69	92,810	75,368	60,244	10.10	5,965
1998	20,098.07	11,291	9,169	12,135	15.04	807
2002	589,435.62	259,486	210,721	414,081	18.71	22,132
2003	590,425.47	241,341	195,986	429,865	19.66	21,865
2004	648,715.35	244,538	198,582	489,056	20.62	23,718
2012	563,071.00	65,093	52,860	543,995	28.51	19,081
2013	1,219,727.63	101,002	82,020	1,210,891	29.50	41,047
2015	680,819.64	11,980	9,729	711,940	29.53	24,109
	8,333,064.53	4,900,749	3,979,751	4,853,298		744,152

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.5 8.93

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S09 - STATIC EXCITATION - TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R4						
NET SALVAGE PERCENT.. -6						
1968	92,234.00	85,753	97,768			
1978	6,765.39	5,417	7,171			
1980	265,233.03	203,612	277,137	4,010	12.41	323
1982	44,965.17	32,983	44,893	2,770	13.86	200
1985	325,129.00	220,719	300,422	44,215	16.18	2,733
	734,326.59	548,484	727,391	50,995		3,256

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.7 0.44

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S10 - STATION SERVICE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-R4						
NET SALVAGE PERCENT.. -6						
1966	491,604.69	442,415	374,999	146,102	7.55	19,351
1967	19,591.00	17,423	14,768	5,998	8.05	745
1968	7,386.55	6,486	5,498	2,332	8.58	272
1970	1,022.42	873	740	344	9.74	35
1971	151,872.00	127,628	108,180	52,804	10.36	5,097
1974	450.00	359	304	173	12.35	14
1975	1,500.00	1,175	996	594	13.04	46
1977	36,906.00	27,807	23,570	15,550	14.46	1,075
1978	8,987.26	6,630	5,620	3,906	15.20	257
1979	182,007.25	131,384	111,364	81,564	15.95	5,114
1980	202,598.85	142,984	121,196	93,559	16.71	5,599
1981	9,086.29	6,262	5,308	4,323	17.49	247
1982	7,725.34	5,193	4,402	3,787	18.29	207
1983	775,442.31	507,977	430,570	391,399	19.10	20,492
1985	512,446.00	317,659	269,254	273,939	20.76	13,196
1986	2,856.46	1,719	1,457	1,571	21.61	73
1987	2,668.56	1,557	1,320	1,509	22.48	67
1988	69,235.33	39,102	33,144	40,245	23.36	1,723
1989	98,106.21	53,556	45,395	58,598	24.25	2,416
1990	25,037.31	13,190	11,180	15,360	25.15	611
1991	2,774.58	1,408	1,193	1,748	26.06	67
1992	886.43	433	367	573	26.98	21
1993	2,443.94	1,145	971	1,620	27.91	58
1994	42,122.46	18,887	16,009	28,641	28.85	993
1995	21,028.01	9,009	7,636	14,654	29.79	492
1996	82,955.52	33,854	28,695	59,238	30.75	1,926
2002	1,362.83	388	329	1,116	36.58	31
2008	375,325.90	59,518	50,448	347,397	42.52	8,170
2009	339,502.31	46,711	39,593	320,279	43.51	7,361
2010	18,254.70	2,125	1,801	17,549	44.51	394
2011	26,312.12	2,505	2,123	25,768	45.51	566
2012	93,881.41	6,966	5,905	93,609	46.50	2,013
2013	27,928.40	1,480	1,254	28,350	47.50	597
2014	28,527.93	907	769	29,471	48.50	608
2015	1,563,499.52	17,567	14,891	1,642,419	46.45	35,359
	5,233,335.89	2,054,282	1,741,249	3,806,087		135,293

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.1 2.59

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S11 - STOP LOGS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. 0						
1966	137,480.00	96,871	45,941	91,539	19.20	4,768
1967	148,478.00	102,929	48,814	99,664	19.94	4,998
1970	20,000.00	13,160	6,241	13,759	22.23	619
1979	561,958.08	305,188	144,736	417,222	29.70	14,048
1982	1,290,854.99	648,009	307,320	983,535	32.37	30,384
1983	12,373.49	6,038	2,864	9,509	33.28	286
1984	195,768.00	92,765	43,994	151,774	34.20	4,438
1988	65,388.47	27,232	12,915	52,473	37.93	1,383
1998	22,751.29	6,090	2,888	19,863	47.60	417
1999	22,847.30	5,772	2,737	20,110	48.58	414
2003	135,012.07	25,880	12,273	122,739	52.54	2,336
2008	207,322.36	23,890	11,330	195,992	57.51	3,408
2015	293,863.07	2,410	1,143	292,720	60.48	4,840
	3,114,097.12	1,356,234	643,196	2,470,901		72,339

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.2 2.32

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S12 - STORAGE PALLETS AND RACKINGS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R3						
NET SALVAGE PERCENT.. 0						
1984	10,706.05	8,786	10,706			
1998	3,696.62	1,957	3,697			
	14,402.67	10,743	14,403			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S13 - STORM AND YARD DRAINAGE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. 0						
1967	3,047.17	2,400	3,047			
1969	105,766.52	80,768	105,767			
1980	260,474.54	160,025	260,475			
1983	237,980.07	135,304	225,246	12,734	23.73	537
1985	374,229.91	200,928	334,492	39,738	25.47	1,560
1987	5,660.27	2,856	4,755	905	27.25	33
1988	963.97	470	782	182	28.16	6
1989	3,287.74	1,549	2,579	709	29.08	24
1990	36,594.92	16,634	27,691	8,904	30.00	297
1991	30,419.95	13,313	22,163	8,257	30.93	267
1992	39,856.38	16,762	27,904	11,952	31.87	375
1995	31,748.63	11,701	19,479	12,270	34.73	353
2009	67,290.58	7,940	13,218	54,073	48.51	1,115
2013	75,014.75	3,409	5,675	69,340	52.50	1,321
2014	36,378.00	992	1,652	34,726	53.50	649
	1,308,713.40	655,051	1,054,925	253,788		6,537

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.8 0.50

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S14 - STREET LIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-R2						
NET SALVAGE PERCENT.. -6						
1981	54,255.98	55,527	57,511			
1982	7,797.99	7,869	8,266			
1983	1,970.32	1,958	2,073	16	1.25	13
1984	14,870.88	14,557	15,414	349	1.53	228
1986	10,258.60	9,727	10,299	575	2.11	273
1987	15,938.15	14,859	15,734	1,160	2.41	481
1988	29,761.78	27,273	28,878	2,669	2.71	985
1989	40,088.51	36,099	38,224	4,270	3.01	1,419
1990	64,177.85	56,668	60,003	8,026	3.34	2,403
1991	15,698.78	13,579	14,378	2,263	3.68	615
1992	33,394.44	28,230	29,892	5,506	4.05	1,360
1993	37,254.73	30,723	32,531	6,959	4.44	1,567
1994	35,848.17	28,784	30,478	7,521	4.85	1,551
1995	20,507.08	15,977	16,917	4,821	5.30	910
1996	43,177.00	32,564	34,481	11,287	5.77	1,956
1997	160,139.81	116,447	123,301	46,447	6.28	7,396
1998	78,991.65	55,221	58,471	25,260	6.81	3,709
1999	78,875.09	52,756	55,861	27,747	7.38	3,760
2000	102,207.84	65,167	69,003	39,337	7.97	4,936
2001	129,520.08	78,325	82,935	54,356	8.59	6,328
2002	113,267.13	64,594	68,396	51,667	9.24	5,592
2003	183,149.00	97,943	103,708	90,430	9.91	9,125
2004	197,169.97	98,230	104,011	104,989	10.60	9,905
2005	172,067.42	79,158	83,817	98,574	11.32	8,708
2006	195,791.12	82,393	87,242	120,297	12.06	9,975
2007	169,126.18	64,359	68,147	111,127	12.82	8,668
2008	218,006.97	73,948	78,300	152,787	13.60	11,234
2009	231,264.08	68,639	72,679	172,461	14.40	11,976
2010	189,899.06	48,109	50,941	150,352	15.22	9,879
2011	273,065.16	57,021	60,377	229,072	16.06	14,264
2012	188,079.80	30,802	32,615	166,750	16.91	9,861
2013	289,923.32	34,266	36,282	271,037	17.77	15,253
2014	193,673.80	13,857	14,673	190,621	18.65	10,221
2015	285,771.56	10,723	11,354	291,564	13.61	21,423
	3,874,989.30	1,566,352	1,657,192	2,450,297		195,974

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.5 5.06

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S15 - STRUCTURAL SUPPORTS (WOOD OR STEEL)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -6						
1967	213,565.83	178,306	219,728	6,652	11.68	570
1968	118,266.43	97,236	119,825	5,537	12.34	449
1970	625,023.62	497,735	613,364	49,161	13.68	3,594
1971	3,879.00	3,037	3,743	369	14.38	26
1974	40,813.35	30,260	37,290	5,972	16.53	361
1975	89,370.64	64,970	80,063	14,670	17.28	849
1976	86,734.84	61,783	76,136	15,803	18.04	876
1977	153,542.15	107,093	131,972	30,783	18.81	1,637
1978	840,408.57	573,376	706,577	184,256	19.60	9,401
1979	365,784.41	243,918	300,583	87,148	20.40	4,272
1980	253,554.46	165,120	203,479	65,289	21.21	3,078
1981	261,871.02	166,347	204,991	72,592	22.04	3,294
1982	674,886.46	417,782	514,837	200,543	22.88	8,765
1983	315,782.64	190,311	234,522	100,208	23.73	4,223
1984	14,166.81	8,300	10,228	4,789	24.60	195
1985	11,743.67	6,684	8,237	4,211	25.47	165
1986	75,722.14	41,797	51,507	28,758	26.36	1,091
1987	308,834.94	165,172	203,543	123,822	27.25	4,544
1988	79,011.14	40,871	50,366	33,386	28.16	1,186
1989	392,408.53	196,026	241,565	174,388	29.08	5,997
1990	895,903.74	431,667	531,948	417,710	30.00	13,924
1991	420,663.60	195,145	240,479	205,424	30.93	6,642
1992	611,539.56	272,614	335,945	312,287	31.87	9,799
1993	54,374.77	23,243	28,643	28,994	32.82	883
1994	168,570.90	68,972	84,995	93,690	33.77	2,774
1995	610,704.02	238,579	294,004	353,342	34.73	10,174
1996	278,697.88	103,666	127,749	167,671	35.70	4,697
1997	55,631.15	19,653	24,219	34,750	36.67	948
1998	197,201.80	65,979	81,307	127,727	37.64	3,393
1999	19,402.49	6,125	7,548	13,019	38.62	337
2000	304,743.10	90,448	111,460	211,568	39.60	5,343
2001	51,839.87	14,407	17,754	37,196	40.58	917
2002	95,124.17	24,639	30,363	70,469	41.56	1,696
2003	185,974.29	44,623	54,989	142,144	42.55	3,341
2004	14,790.11	3,267	4,026	11,652	43.54	268
2005	17,969.12	3,626	4,468	14,579	44.53	327
2006	18,876.25	3,445	4,245	15,764	45.53	346
2007	432,097.80	70,618	87,023	371,001	46.52	7,975
2008	33,346.06	4,807	5,924	29,423	47.52	619
2009	69,987.69	8,754	10,788	63,399	48.51	1,307
2010	226,254.53	23,940	29,502	210,328	49.51	4,248
2011	28,864.22	2,498	3,078	27,518	50.51	545

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S15 - STRUCTURAL SUPPORTS (WOOD OR STEEL)

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R4						
NET SALVAGE PERCENT.. -6						
2012	1,553,655.32	104,807	129,155	1,517,720	51.50	29,470
2014	308,262.78	8,911	10,981	315,778	53.50	5,902
2015	97,763.28	1,005	1,238	102,391	51.05	2,006
	11,677,609.15	5,091,562	6,274,387	6,103,879		172,454
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					35.4	1.48

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S17 - SUMP SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R4						
NET SALVAGE PERCENT.. 0						
1966	62,921.44	61,465	53,103	9,818	0.81	9,818
1979	54,056.59	47,153	40,739	13,318	4.47	2,979
1985	1,426.00	1,114	962	464	7.67	60
1988	21,760.44	15,711	13,574	8,186	9.73	841
1999	22,854.33	10,552	9,116	13,738	18.84	729
2009	75,619.94	14,000	12,096	63,524	28.52	2,227
2015	428,606.40	6,515	5,628	422,978	32.39	13,059
	667,245.14	156,510	135,218	532,027		29,713

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 17.9 4.45

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S18 - SURGE SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. 0						
1966	1,578,845.51	1,183,613	1,313,100	265,746	15.02	17,693
1967	2,334,768.00	1,723,059	1,911,562	423,206	15.72	26,922
2002	299,651.03	67,122	74,465	225,186	46.56	4,836
2014	1,496,950.24	37,424	41,518	1,455,432	58.50	24,879
2015	1,262,674.34	11,112	12,328	1,250,347	56.00	22,328
	6,972,889.12	3,022,330	3,352,973	3,619,917		96,658

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.5 1.39

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S19 - STATION SWITCHING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 38-S0.5						
NET SALVAGE PERCENT.. 0						
1965	95,998.62	73,818	87,581	8,418	8.78	959
1968	161,442.28	119,467	141,740	19,702	9.88	1,994
1970	1,000.00	720	854	146	10.64	14
1973	80,010.49	55,144	65,425	14,585	11.81	1,235
1980	256,525.40	157,088	186,375	70,150	14.73	4,762
1981	65,308.50	39,220	46,532	18,776	15.18	1,237
1982	123,205.18	72,528	86,050	37,155	15.63	2,377
1984	108,404.79	61,163	72,566	35,839	16.56	2,164
1985	2,461,120.55	1,358,145	1,611,358	849,763	17.03	49,898
1986	35,050.06	18,890	22,412	12,638	17.52	721
1987	50,537.58	26,585	31,542	18,996	18.01	1,055
1988	24,307.96	12,461	14,784	9,524	18.52	514
1989	125,368.04	62,585	74,253	51,115	19.03	2,686
1990	64,390.22	31,263	37,092	27,298	19.55	1,396
1991	66,301.23	31,249	37,075	29,226	20.09	1,455
1992	246,618.65	112,732	133,750	112,869	20.63	5,471
1994	309,425.68	132,239	156,894	152,532	21.76	7,010
1995	34,006.02	14,014	16,627	17,379	22.34	778
1996	146,348.10	58,001	68,815	77,533	22.94	3,380
1997	500,055.41	190,151	225,603	274,452	23.55	11,654
1998	224,915.13	81,858	97,120	127,795	24.17	5,287
1999	30,772.14	10,681	12,672	18,100	24.81	730
2000	411,071.49	135,654	160,945	250,126	25.46	9,824
2001	866,140.97	270,556	320,998	545,143	26.13	20,863
2002	815,476.44	240,133	284,903	530,573	26.81	19,790
2003	601,443.56	165,872	196,797	404,647	27.52	14,704
2004	8,687.61	2,231	2,647	6,041	28.24	214
2005	253,591.03	60,261	71,496	182,095	28.97	6,286
2006	143,720.54	31,278	37,109	106,612	29.73	3,586
2007	387,150.67	76,311	90,539	296,612	30.51	9,722
2008	903,906.47	159,377	189,091	714,815	31.30	22,838
2011	449,426.34	49,437	58,654	390,772	33.82	11,554
2012	60,152.93	5,224	6,198	53,955	34.70	1,555
2013	125,150.30	7,871	9,339	115,811	35.61	3,252
2014	1,413,001.86	53,920	63,973	1,349,029	36.55	36,909
	11,650,032.24	3,978,127	4,719,809	6,930,224		267,874

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.9 2.30

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S20 - SWITCHING SYSTEMS - L.V.

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R5						
NET SALVAGE PERCENT.. 0						
1967	11,423.00	8,935	3,623	7,800	13.07	597
1969	12,000.00	9,064	3,676	8,324	14.68	567
1970	5,070.00	3,759	1,524	3,546	15.51	229
1978	42,949.00	26,700	10,827	32,122	22.70	1,415
1980	292,893.12	172,710	70,037	222,856	24.62	9,052
1982	341,312.01	190,223	77,139	264,173	26.56	9,946
1983	57,955.20	31,354	12,715	45,240	27.54	1,643
1985	1,030,337.00	523,411	212,253	818,084	29.52	27,713
1989	13,381.22	5,910	2,397	10,984	33.50	328
2012	2,137.86	125	51	2,087	56.50	37
2014	149,698.41	3,742	1,517	148,181	58.50	2,533
2015	345,451.74	2,936	1,191	344,261	58.32	5,903
	2,304,608.56	978,869	396,950	1,907,659		59,963

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.8 2.60

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T01 - TELECONTROL SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L1.5						
NET SALVAGE PERCENT.. 0						
1967	155,517.13	123,356	155,517			
1968	150,292.25	118,070	150,292			
1970	486,115.14	374,114	486,115			
1974	139,723.79	102,781	139,724			
1975	38,228.01	27,784	38,228			
1976	7,194.87	5,163	7,195			
1977	43,794.87	31,024	43,795			
1978	28,102.56	19,638	28,103			
1980	679,315.49	461,663	679,315			
1982	25,527.39	16,838	25,527			
1984	13,123.52	8,383	13,124			
1985	125,247.66	78,706	125,248			
1987	32,460.35	19,723	32,460			
1988	12,474.58	7,450	12,269	206	10.07	20
1989	25,171.86	14,771	24,326	846	10.33	82
1990	67,835.32	39,073	64,348	3,487	10.60	329
1991	9,093.53	5,140	8,465	629	10.87	58
1992	210,249.91	116,563	191,964	18,286	11.14	1,641
1993	9,515.51	5,169	8,513	1,003	11.42	88
1995	340,055.68	176,829	291,215	48,841	12.00	4,070
1996	150,823.71	76,558	126,081	24,743	12.31	2,010
1997	230,157.88	113,790	187,397	42,761	12.64	3,383
1998	120,918.27	58,089	95,665	25,253	12.99	1,944
1999	658,698.64	306,427	504,646	154,053	13.37	11,522
2000	232,641.59	104,503	172,103	60,539	13.77	4,396
2001	629,924.69	272,127	448,158	181,767	14.20	12,800
2002	287,577.81	118,712	195,503	92,075	14.68	6,272
2003	1,272,180.85	499,204	822,125	450,056	15.19	29,628
2004	185,243.03	68,540	112,877	72,366	15.75	4,595
2005	68,977.27	23,839	39,260	29,717	16.36	1,816
2006	116,763.42	37,318	61,458	55,305	17.01	3,251
2007	155,855.93	45,510	74,949	80,907	17.70	4,571
2008	681,121.71	178,726	294,339	386,783	18.44	20,975
2009	153,434.75	35,597	58,624	94,811	19.20	4,938
2010	775,458.93	154,782	254,906	520,553	20.01	26,015
2011	2,127,249.56	353,123	581,548	1,545,702	20.85	74,134
2012	785,805.63	103,098	169,789	616,017	21.72	28,362

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T01 - TELECONTROL SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L1.5						
NET SALVAGE PERCENT.. 0						
2013	308,556.04	29,375	48,377	260,179	22.62	11,502
2014	199,430.31	11,487	18,917	180,513	23.56	7,662
2015	689,419.53	19,580	32,246	657,174	17.14	38,342
	12,429,278.97	4,362,623	6,824,711	5,604,568		304,406
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					18.4	2.45

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T02 - TEST EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	171,525.07	167,237	171,525			
1997	44,520.05	41,181	44,520			
1998	62,092.77	54,331	62,093			
1999	66,647.04	54,984	66,647			
2000	21,555.00	16,705	21,555			
2001	129,850.59	94,142	129,851			
2003	35,528.41	22,205	32,293	3,235	7.50	431
2004	56,187.58	32,308	46,985	9,203	8.50	1,083
2005	104,172.87	54,691	79,537	24,636	9.50	2,593
2006	125,767.44	59,740	86,880	38,887	10.50	3,704
2007	111,117.86	47,225	68,679	42,439	11.50	3,690
2008	118,554.56	44,458	64,655	53,900	12.50	4,312
2009	245,322.20	79,730	115,952	129,370	13.50	9,583
2010	143,454.99	39,450	57,372	86,083	14.50	5,937
2011	82,921.77	18,657	27,133	55,789	15.50	3,599
2012	51,402.18	8,995	13,081	38,321	16.50	2,322
2013	40,726.65	5,091	7,404	33,323	17.50	1,904
2014	279,396.00	20,955	30,475	248,921	18.50	13,455
2015	64,570.87	1,614	2,347	62,224	19.50	3,191
	1,955,313.90	863,699	1,128,984	826,330		55,804

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.8 2.85

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T03 - TOOLS AND EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
1996	200,248.76	195,243	200,249			
1997	488,362.83	451,736	488,363			
1998	244,471.89	213,913	244,472			
1999	673,202.49	555,392	673,202			
2000	323,762.71	250,916	323,763			
2001	211,193.15	153,115	204,742	6,451	5.50	1,173
2002	183,918.34	124,145	166,004	17,914	6.50	2,756
2003	326,809.44	204,256	273,126	53,683	7.50	7,158
2004	172,231.32	99,033	132,425	39,806	8.50	4,683
2005	452,386.88	237,503	317,583	134,804	9.50	14,190
2006	1,130,061.14	536,779	717,768	412,293	10.50	39,266
2007	613,104.06	260,569	348,427	264,677	11.50	23,015
2008	619,700.32	232,388	310,744	308,956	12.50	24,716
2009	1,999,143.86	649,722	868,793	1,130,351	13.50	83,730
2010	479,417.85	131,840	176,293	303,125	14.50	20,905
2011	790,951.91	177,964	237,969	552,983	15.50	35,676
2012	479,101.79	83,843	112,113	366,989	16.50	22,242
2013	817,875.96	102,234	136,705	681,171	17.50	38,924
2014	667,366.06	50,052	66,929	600,437	18.50	32,456
2015	561,016.93	14,025	18,754	542,263	19.50	27,808
	11,434,327.69	4,724,668	6,018,424	5,415,904		378,698

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.3 3.31

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T04 - TOWERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
NET SALVAGE PERCENT.. -20						
1967	7,774,613.38	6,467,514	5,053,292	4,276,244	19.94	214,456
1968	3,671,739.67	3,003,586	2,346,805	2,059,283	20.69	99,530
1970	647,368.87	511,162	399,389	377,454	22.23	16,979
1974	328,024.10	239,570	187,184	206,445	25.44	8,115
1976	67,922.93	47,500	37,113	44,395	27.12	1,637
1977	4,145,457.94	2,833,951	2,214,264	2,760,286	27.97	98,687
1981	133,177.73	82,440	64,413	95,400	31.47	3,031
1982	27,740.73	16,711	13,057	20,232	32.37	625
1983	5,228,146.18	3,061,602	2,392,135	3,881,640	33.28	116,636
1984	325,719.13	185,210	144,711	246,152	34.20	7,197
1985	14,909,454.99	8,224,473	6,426,065	11,465,281	35.12	326,460
1988	505,215.54	252,482	197,273	408,986	37.93	10,783
1989	692,670.62	334,020	260,981	570,224	38.88	14,666
1990	3,967,744.87	1,843,716	1,440,559	3,320,735	39.83	83,373
1991	1,445,942.58	646,267	504,951	1,230,180	40.79	30,159
1993	131,812.19	54,218	42,362	115,813	42.72	2,711
1996	28,732.47	10,270	8,024	26,455	45.64	580
1999	811,245.78	245,924	192,149	781,346	48.58	16,084
2000	7,662,860.96	2,182,812	1,705,506	7,489,927	49.57	151,098
2001	4,060,773.88	1,082,521	845,811	4,027,118	50.56	79,650
2002	7,597,273.00	1,886,433	1,473,935	7,642,793	51.55	148,260
2003	4,195,002.97	964,968	753,963	4,280,041	52.54	81,463
2004	2,053,137.11	434,756	339,690	2,124,075	53.53	39,680
2007	1,498,132.33	234,536	183,251	1,614,508	56.52	28,565
2010	102,678.68	10,407	8,131	115,083	59.51	1,934
2011	173,482.90	14,381	11,236	196,943	60.51	3,255
2012	5,527,731.64	357,202	279,095	6,354,183	61.50	103,320
2013	25,620.47	1,182	924	29,821	62.50	477
	77,739,423.64	35,229,814	27,526,269	65,761,040		1,689,411

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.9 2.17

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T05 - TRANSFORMERS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

SURVIVOR CURVE.. IOWA 55-R3
NET SALVAGE PERCENT.. -6

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1964	10,236.25	8,315	8,068	2,782	12.85	216
1965	2,170,497.40	1,740,615	1,689,003	611,724	13.39	45,685
1966	295,436.32	233,791	226,859	86,303	13.94	6,191
1967	2,550,570.08	1,990,339	1,931,322	772,282	14.51	53,224
1968	1,087,469.18	836,239	811,443	341,274	15.10	22,601
1969	1,581,634.14	1,197,648	1,162,136	514,396	15.71	32,743
1970	8,182,128.19	6,099,500	5,918,638	2,754,418	16.32	168,776
1971	2,339,157.03	1,714,926	1,664,075	815,431	16.96	48,080
1972	837,143.10	603,253	585,365	302,007	17.61	17,150
1973	30,493.88	21,586	20,946	11,378	18.27	623
1974	1,198,626.20	833,019	808,318	462,226	18.94	24,405
1975	330,460.22	225,267	218,587	131,701	19.63	6,709
1976	266,952.78	178,373	173,084	109,886	20.33	5,405
1977	3,621,685.19	2,370,382	2,300,096	1,538,890	21.04	73,141
1978	5,401,385.00	3,459,213	3,356,641	2,368,827	21.77	108,812
1979	169,874.23	106,403	103,248	76,819	22.50	3,414
1980	3,269,811.65	2,000,818	1,941,490	1,524,510	23.25	65,570
1981	1,156,129.07	690,506	670,031	555,466	24.01	23,135
1982	1,022,219.43	595,564	577,904	505,649	24.77	20,414
1983	300,416.84	170,510	165,454	152,988	25.55	5,988
1984	61,963.44	34,226	33,211	32,470	26.34	1,233
1985	3,302,469.71	1,773,238	1,720,658	1,779,960	27.14	65,584
1986	1,351,098.86	704,625	683,732	748,433	27.94	26,787
1987	391,909.57	198,195	192,318	223,106	28.76	7,758
1988	1,710,691.01	837,760	812,919	1,000,413	29.59	33,809
1989	4,722,409.22	2,237,121	2,170,787	2,834,967	30.42	93,194
1990	3,182,456.02	1,456,096	1,412,920	1,960,483	31.26	62,715
1991	487,312.18	214,978	208,604	307,947	32.11	9,590
1992	457,250.18	194,141	188,384	296,301	32.97	8,987
1993	637,973.44	260,174	252,459	423,793	33.84	12,523
1994	224,276.70	87,659	85,060	152,673	34.72	4,397
1995	2,821,265.16	1,054,854	1,023,576	1,966,965	35.60	55,252
1996	2,130,805.18	760,150	737,610	1,521,043	36.49	41,684
1997	104,738.09	35,547	34,493	76,529	37.39	2,047
1998	2,072,130.48	666,933	647,157	1,549,301	38.30	40,452
1999	196,003.17	59,647	57,878	149,885	39.21	3,823
2000	179,015.54	51,303	49,782	139,974	40.13	3,488
2001	96,325.48	25,879	25,112	76,993	41.06	1,875
2002	2,417,735.37	606,230	588,254	1,974,545	41.99	47,024
2003	1,253,034.95	291,477	282,834	1,045,383	42.93	24,351
2004	1,163,248.70	249,519	242,120	990,924	43.87	22,588
2005	546,492.29	107,324	104,142	475,140	44.81	10,603
2006	182,214.29	32,414	31,453	161,694	45.77	3,533

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T05 - TRANSFORMERS - OTHER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
NET SALVAGE PERCENT.. -6						
2007	1,673,348.41	267,038	259,120	1,514,629	46.72	32,419
2008	96,028.90	13,529	13,128	88,663	47.69	1,859
2009	3,649,480.13	446,612	433,369	3,435,080	48.65	70,608
2010	1,107,821.46	114,869	111,463	1,062,828	49.62	21,419
2011	1,330,021.46	113,040	109,688	1,300,135	50.59	25,699
2012	4,236,924.35	280,067	271,763	4,219,377	51.57	81,818
2013	3,130,464.89	148,427	144,026	3,174,267	52.54	60,416
2014	770,965.88	21,991	21,339	795,885	53.52	14,871
2015	7,745,073.72	88,666	86,037	8,123,741	46.01	176,565
	89,255,274.41	38,509,996	37,368,104	57,242,487		1,801,253

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.8 2.02

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T06 - TRANSFORMERS - PAD MOUNT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R1.5						
NET SALVAGE PERCENT.. -8						
1967	85,000.00	70,388	91,800			
1968	110,241.68	90,189	118,150	911	9.70	94
1970	78,787.71	62,818	82,293	2,798	10.47	267
1974	23,978.75	18,018	23,604	2,293	12.17	188
1981	67,676.80	44,512	58,312	14,779	15.64	945
1982	127,293.37	81,833	107,204	30,273	16.19	1,870
1983	70,647.20	44,349	58,099	18,200	16.75	1,087
1984	14,234.01	8,716	11,418	3,955	17.32	228
1985	27,018.49	16,122	21,120	8,060	17.90	450
1987	47,938.17	27,039	35,422	16,351	19.11	856
1989	63,969.03	33,939	44,461	24,626	20.35	1,210
1991	82,079.46	40,666	53,274	35,372	21.65	1,634
1992	93,133.80	44,483	58,274	42,311	22.31	1,897
1993	33,003.74	15,167	19,869	15,775	22.98	686
1994	139,248.04	61,433	80,479	69,909	23.66	2,955
1995	10,265.00	4,337	5,682	5,404	24.35	222
1996	156,420.31	63,181	82,769	86,165	25.04	3,441
1997	72,427.27	27,866	36,505	41,716	25.75	1,620
1998	742.00	271	355	446	26.46	17
1999	45,687.77	15,814	20,717	28,626	27.18	1,053
2000	41,970.99	13,701	17,949	27,380	27.91	981
2001	356,142.61	109,140	142,977	241,657	28.65	8,435
2002	93,388.29	26,753	35,047	65,812	29.39	2,239
2003	30,705.67	8,174	10,708	22,454	30.14	745
2004	70,225.32	17,273	22,628	53,215	30.89	1,723
2005	66,295.63	14,946	19,580	52,019	31.65	1,644
2006	99,363.64	20,336	26,641	80,672	32.42	2,488
2007	98,472.00	18,106	23,719	82,631	33.19	2,490
2008	310,577.85	50,565	66,242	269,182	33.97	7,924
2009	132,056.82	18,683	24,475	118,146	34.76	3,399
2010	179,576.76	21,576	28,265	165,678	35.55	4,660
2011	153,567.38	15,176	19,881	145,972	36.34	4,017
2012	1,706,848.53	131,342	172,062	1,671,334	37.15	44,989
2013	171,473.68	9,491	12,433	172,759	37.95	4,552
2014	12,549,805.40	416,779	545,993	13,007,797	38.77	335,512
2015	313,388.75	7,378	9,666	328,794	22.49	14,620
	17,723,651.92	1,670,560	2,188,073	16,953,472		461,138

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.8 2.60

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T07 - TRANSFORMERS - POLE MOUNTED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-L1						
NET SALVAGE PERCENT.. -8						
1967	12,694.59	9,602	11,784	1,926	8.99	214
1968	3,506.89	2,622	3,218	569	9.23	62
1970	43,296.14	31,610	38,792	7,968	9.72	820
1971	311.65	225	276	61	9.97	6
1978	10,884.00	7,123	8,741	3,014	11.82	255
1979	323.10	208	255	94	12.11	8
1981	428,000.05	266,865	327,501	134,739	12.68	10,626
1982	130,758.66	80,118	98,322	42,897	12.98	3,305
1983	218,005.26	131,221	161,036	74,410	13.28	5,603
1984	155,589.64	91,972	112,869	55,168	13.58	4,062
1985	151,605.75	87,925	107,903	55,831	13.89	4,020
1986	175,088.19	99,527	122,141	66,954	14.21	4,712
1987	459,057.33	255,660	313,750	182,032	14.53	12,528
1988	162,746.89	88,762	108,930	66,837	14.85	4,501
1989	248,635.14	132,563	162,683	105,843	15.19	6,968
1990	270,942.21	141,238	173,329	119,289	15.52	7,686
1991	271,811.17	138,265	169,681	123,875	15.87	7,806
1992	867,575.72	430,384	528,174	408,808	16.22	25,204
1993	301,034.54	145,545	178,615	146,502	16.57	8,841
1994	282,360.08	132,753	162,917	142,032	16.94	8,384
1995	583,381.91	266,720	327,323	302,729	17.30	17,499
1996	895,423.58	397,141	487,378	479,679	17.68	27,131
1997	1,130,944.07	486,125	596,580	624,840	18.06	34,598
1998	604,436.78	251,325	308,430	344,362	18.45	18,665
1999	685,159.47	274,774	337,207	402,765	18.86	21,356
2000	687,281.02	265,485	325,807	416,457	19.27	21,612
2001	627,766.65	232,550	285,389	392,599	19.71	19,919
2002	818,683.48	289,418	355,178	529,000	20.18	26,214
2003	983,095.61	329,852	404,800	656,943	20.68	31,767
2004	800,656.38	253,360	310,927	553,782	21.21	26,109
2005	1,021,524.86	302,290	370,975	732,272	21.78	33,621
2006	999,114.89	274,077	336,352	742,692	22.38	33,186
2007	1,308,207.61	328,251	402,835	1,010,029	23.03	43,857
2008	1,065,933.24	241,374	296,218	854,990	23.71	36,060
2009	1,712,109.10	342,690	420,555	1,428,523	24.44	58,450
2010	2,361,337.29	408,039	500,752	2,049,492	25.20	81,329
2011	3,802,181.60	547,500	671,900	3,434,456	26.00	132,094
2012	3,507,262.82	398,974	489,627	3,298,217	26.84	122,884

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T07 - TRANSFORMERS - POLE MOUNTED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-L1						
NET SALVAGE PERCENT.. -8						
2013	3,553,161.54	292,910	359,464	3,477,950	27.71	125,512
2014	3,281,651.61	164,202	201,511	3,342,673	28.61	116,836
2015	2,416,916.21	68,911	84,569	2,525,700	18.44	136,969
	37,040,456.72	8,690,156	10,664,694	29,338,999		1,281,279
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					22.9	3.46

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T09 - TURBINES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -14						
1967	1,762,788.78	1,408,172	1,210,723	798,856	16.46	48,533
1968	8,607,404.86	6,775,982	5,825,876	3,986,566	17.02	234,228
1970	1,683,339.64	1,283,989	1,103,952	815,055	18.20	44,783
1971	26,000.00	19,508	16,773	12,867	18.80	684
1975	101,873.10	71,033	61,073	55,062	21.36	2,578
1977	217,905.93	145,841	125,392	123,021	22.71	5,417
1978	4,242,670.89	2,778,894	2,389,246	2,447,399	23.40	104,590
1980	2,788,239.51	1,744,762	1,500,117	1,678,476	24.81	67,653
1982	7,091,357.09	4,224,371	3,632,043	4,452,104	26.26	169,539
1983	46,776.00	27,147	23,341	29,984	27.00	1,111
1985	10,927,015.21	6,001,934	5,160,362	7,296,435	28.50	256,015
1987	8,893.22	4,599	3,954	6,184	30.05	206
1988	6,909,835.55	3,461,641	2,976,261	4,900,952	30.83	158,967
1989	1,587,174.93	769,149	661,302	1,148,077	31.62	36,309
2003	11,929,596.94	2,848,466	2,449,063	11,150,678	43.48	256,455
2006	305,590.00	55,865	48,032	300,341	46.18	6,504
2009	67,170.20	8,451	7,266	69,308	48.93	1,416
2013	2,448,806.00	119,287	102,561	2,689,078	52.65	51,075
2014	289,550.40	8,523	7,328	322,759	53.58	6,024
2015	4,117,648.02	57,268	49,238	4,644,881	40.32	115,200
	65,159,636.27	31,814,882	27,353,903	46,928,082		1,567,287

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 29.9 2.41

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T10.00 - HOLYROOD GAS TURBINE - COMBUSTOR OVERHAUL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 3-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	2,206,062.36	367,684	40,444	2,165,618	2.50	866,247
	2,206,062.36	367,684	40,444	2,165,618		866,247

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5 39.27

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T11.00 - HOLYROOD GAS TURBINE - TURBINE OVERHAUL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 6-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	2,206,062.35	183,831	40,444	2,165,618	5.50	393,749
	2,206,062.35	183,831	40,444	2,165,618		393,749

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 17.85

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T12.00 - HOLYROOD GAS TURBINE - COMPRESSOR OVERHAUL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 12-SQUARE						
NET SALVAGE PERCENT.. 0						
2015	3,088,487.29	128,697	56,622	3,031,865	11.50	263,640
	3,088,487.29	128,697	56,622	3,031,865		263,640

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.5 8.54

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V01 - VACUUM CLEANING SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
NET SALVAGE PERCENT.. 0						
1969	23,574.00	16,840	23,574			
1980	48,877.00	27,819	43,406	5,471	25.85	212
	72,451.00	44,659	66,980	5,471		212

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.8 0.29

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V02 - VALVES - PENSTOCK

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
NET SALVAGE PERCENT.. -8						
1967	1,415,205.48	993,245	804,476	723,946	22.76	31,808
1970	547,228.00	364,875	295,530	295,476	24.87	11,881
1975	14,300.75	8,654	7,009	8,436	28.58	295
1977	104,000.00	60,255	48,803	63,517	30.13	2,108
1982	22,218.67	11,393	9,228	14,768	34.14	433
1985	2,204,894.06	1,038,979	841,518	1,539,768	36.64	42,024
1988	2,432.20	1,042	844	1,783	39.21	45
2001	194,935.91	45,378	36,754	173,777	50.99	3,408
2003	236,497.01	47,625	38,574	216,843	52.88	4,101
2004	211,351.90	39,226	31,771	196,489	53.83	3,650
2005	212,317.84	36,053	29,201	200,102	54.78	3,653
2006	176,897.79	27,217	22,044	169,006	55.74	3,032
2007	129,795.39	17,878	14,480	125,699	56.71	2,217
2008	1,875,177.71	228,381	184,977	1,840,215	57.67	31,909
2015	220,507.28	2,167	1,755	236,393	54.45	4,341
	7,567,759.99	2,922,368	2,366,964	5,806,217		144,905

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.1 1.91

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V03 - VEHICLES - 1 TON

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 8-L4						
NET SALVAGE PERCENT.. +15						
2013	51,647.92	13,719	16,140	27,761	5.50	5,047
	51,647.92	13,719	16,140	27,761		5,047

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.5 9.77

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V04 - VEHICLES - 3/4 TON AND UNDER

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 7-L3						
NET SALVAGE PERCENT.. +15						
2004	21,073.00	15,174	17,912			
2007	256,097.59	161,085	217,683			
2008	75,904.47	45,901	64,519			
2009	452,574.79	264,335	384,689			
2010	817,731.47	450,803	695,072			
2011	720,937.71	354,546	612,797			
2012	750,380.31	302,513	637,823			
2013	282,039.93	83,564	183,264	56,470	4.56	12,384
2014	718,833.74	130,059	285,232	325,777	5.51	59,125
2015	1,071,596.79	73,779	161,805	749,052	5.67	132,108
	5,167,169.80	1,881,759	3,260,796	1,131,298		203,617

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.6 3.94

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V05 - VEHICLES - BOOMS/BODIES/CRANES/CAB/CHASSIS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 12-L3						
NET SALVAGE PERCENT.. +15						
2000	23,000.00	14,825	19,137	413	2.90	142
2002	130,045.00	79,772	102,972	7,566	3.34	2,265
2003	202,565.49	121,675	157,062	15,119	3.52	4,295
2004	466,287.00	274,468	354,293	42,051	3.69	11,396
2005	634,697.00	364,157	470,066	69,426	3.90	17,802
2006	313,439.36	173,396	223,825	42,598	4.19	10,167
2007	1,464,993.85	765,826	988,554	256,691	4.62	55,561
2008	610,927.99	294,265	379,847	139,442	5.20	26,816
2009	1,838,387.86	793,035	1,023,677	538,953	5.91	91,193
2010	746,610.15	278,705	359,762	274,857	6.73	40,841
2011	1,663,998.12	516,255	666,399	747,999	7.62	98,163
2012	1,991,867.42	488,168	630,144	1,062,943	8.54	124,466
2013	1,322,985.14	233,342	301,206	823,331	9.51	86,575
2014	976,501.08	103,753	133,928	696,098	10.50	66,295
2015	2,568,240.80	103,038	133,005	2,050,000	10.09	203,171
	14,954,546.26	4,604,680	5,943,877	6,767,488		839,148

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.1 5.61

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V06 - VEHICLES - CARS, STATION WAGONS AND VANS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 6-L3						
NET SALVAGE PERCENT.. +15						
2006	21,051.00	14,911	17,893			
2007	31,861.28	21,395	27,082			
2008	238,285.56	151,569	202,543			
2009	236,872.66	143,623	201,342			
2010	286,725.00	166,946	243,716			
2011	280,782.15	151,552	238,665			
2012	203,510.02	93,122	172,984			
2013	276,271.38	94,714	234,831			
2014	220,013.03	46,440	177,625	9,386	4.51	2,081
	1,795,372.08	884,272	1,516,681	9,385		2,081

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.5 0.12

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT V07 - VEHICLES - DUMP TRUCKS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-L5						
NET SALVAGE PERCENT.. +15						
2003	11,535.00	8,814	11,535	1,730-		
	11,535.00	8,814	11,535	1,730-		
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W01 - WATER REGULATING STRUCTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-S4						
NET SALVAGE PERCENT.. -8						
1966	781,460.65	617,530	407,033	436,945	17.44	25,054
1967	2,271,900.00	1,767,390	1,164,940	1,288,712	18.18	70,886
1979	1,923,424.16	1,161,999	765,909	1,311,389	28.64	45,789
1980	22,093.09	12,995	8,565	15,296	29.60	517
1983	1,760,835.28	949,672	625,957	1,275,745	32.54	39,205
1985	5,067.02	2,566	1,691	3,781	34.52	110
1999	50,969.18	13,974	9,211	45,836	48.50	945
2003	15,340,515.10	3,186,145	2,100,085	14,467,671	52.50	275,575
2010	295,473.83	27,003	17,798	301,314	59.50	5,064
	22,451,738.31	7,739,274	5,101,189	19,146,688		463,145

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.3 2.06

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W02 - WATER SUPPLY SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-L4						
NET SALVAGE PERCENT.. -8						
1966	36,616.00	36,461	34,844	4,701	2.34	2,009
1967	10,039.39	9,939	9,498	1,345	2.50	538
1968	7,289.13	7,174	6,856	1,016	2.66	382
1969	31,622.36	30,931	29,560	4,592	2.83	1,623
1970	5,778.10	5,616	5,367	873	3.00	291
1971	9,746.00	9,410	8,993	1,533	3.18	482
1976	13,007.24	12,086	11,550	2,498	4.19	596
1977	32,252.39	29,701	28,384	6,449	4.42	1,459
1978	52,656.72	48,073	45,942	10,927	4.64	2,355
1979	166,185.56	150,464	143,793	35,687	4.85	7,358
1980	15,467.03	13,887	13,271	3,433	5.06	678
1981	16,651.69	14,843	14,185	3,799	5.24	725
1982	72,242.09	63,978	61,141	16,880	5.40	3,126
1985	326,739.18	284,303	271,698	81,180	5.83	13,925
1986	10,359.04	8,954	8,557	2,631	5.99	439
1987	40,022.75	34,291	32,771	10,454	6.20	1,686
1988	93,343.70	79,069	75,563	25,248	6.47	3,902
1989	135,698.19	113,238	108,217	38,337	6.82	5,621
1990	44,904.42	36,777	35,146	13,351	7.25	1,842
1991	28,308.25	22,655	21,651	8,922	7.77	1,148
1992	90,973.91	70,840	67,699	30,553	8.37	3,650
1993	18,883.67	14,249	13,617	6,777	9.04	750
1995	139,943.07	98,139	93,788	57,351	10.52	5,452
1996	39,359.32	26,483	25,309	17,199	11.31	1,521
1999	18,116.97	10,540	10,073	9,493	13.84	686
2003	1,242,574.09	556,922	532,230	809,750	17.55	46,140
2005	38,828.51	14,663	14,013	27,922	19.51	1,431
2006	25,217.49	8,624	8,242	18,993	20.50	926
2007	53,657.88	16,419	15,691	42,260	21.50	1,966
2008	54,235.70	14,644	13,995	44,580	22.50	1,981
2011	9,250.00	1,498	1,432	8,558	25.50	336
2013	269,116.45	24,220	23,146	267,500	27.50	9,727
2015	245,467.25	4,666	4,459	260,646	27.83	9,366
	3,394,553.54	1,873,757	1,790,681	1,875,437		134,117

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.0 3.95

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W03 - WATER SYSTEMS - FEED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -8						
1968	329,755.00	245,929	354,161	1,974	17.02	116
1971	1,732,845.00	1,231,766	1,773,858	97,615	18.80	5,192
1980	1,646,391.76	976,019	1,405,559	372,544	24.81	15,016
2013	170,885.85	7,886	11,357	173,200	52.65	3,290
2015	2,651,382.05	34,935	50,310	2,813,183	40.32	69,771
	6,531,259.66	2,496,535	3,595,245	3,458,516		93,385

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.0 1.43

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W04 - WATER TREATMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R2.5						
NET SALVAGE PERCENT.. -6						
1968	65,708.12	48,097	69,651			
1969	1,663,202.51	1,198,836	1,762,995			
1971	204,537.00	142,699	216,809			
1988	57,541.66	26,804	57,967	3,027	30.83	98
1990	15,137.27	6,587	14,245	1,801	32.42	56
1991	2,681,164.08	1,124,934	2,432,817	409,217	33.23	12,315
1995	5,359.72	1,907	4,124	1,557	36.54	43
1997	2,409,124.70	778,640	1,683,911	869,761	38.23	22,751
2012	659,794.84	41,837	90,478	608,905	51.71	11,775
2015	4,160,003.20	53,797	116,343	4,293,261	40.32	106,480
	11,921,573.10	3,424,138	6,449,340	6,187,528		153,518

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.3 1.29

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT A04.1 - AUXILIARY POWER SYSTEMS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 30-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -3						
2010	620,866.42	327,484	313,020	326,472	5.24	62,304
	620,866.42	327,484	313,020	326,472		62,304

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 10.04

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B01.1 - BATTERY AND POWER SYSTEMS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 26-L1.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -3						
1968	62,070.09	54,810	35,509	28,423	3.69	7,703
2013	44,556.86	14,837	9,612	36,282	5.17	7,018
	106,626.95	69,647	45,121	64,705		14,721

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.4 13.81

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B02.1 - BOILER SYSTEM - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 40-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1976	6,373.00	6,092	5,908	975	4.34	225
1979	20,390.00	19,269	18,687	3,334	4.56	731
1980	17,650,550.81	16,614,958	16,113,472	2,949,123	4.62	638,338
1983	2,205,577.30	2,048,993	1,987,149	394,874	4.79	82,437
1984	88,778.32	82,106	79,628	16,253	4.83	3,365
1985	36,723.56	33,799	32,779	6,882	4.87	1,413
1986	2,072.08	1,897	1,840	398	4.91	81
1987	138,230.21	125,891	122,091	27,198	4.94	5,506
1989	42,488.95	38,240	37,086	8,802	5.00	1,760
1992	164,446.23	144,982	140,606	36,996	5.06	7,311
1996	9,711.53	8,252	8,003	2,485	5.13	484
1997	955,842.08	803,209	778,966	253,343	5.14	49,289
1999	181,052.03	148,189	143,716	51,820	5.16	10,043
2001	408,654.76	323,746	313,974	127,373	5.18	24,589
2007	3,620,559.38	2,414,864	2,341,977	1,568,227	5.22	300,427
2008	4,217,954.40	2,678,570	2,597,723	1,957,668	5.22	375,032
2009	1,322,059.11	789,030	765,215	662,609	5.23	126,694
2010	1,357,501.38	749,486	726,864	739,237	5.23	141,346
2011	714,762.78	356,159	345,409	426,535	5.23	81,555
2012	1,376,773.06	593,398	575,488	911,427	5.24	173,936
2013	82,687.17	28,766	27,898	61,404	5.24	11,718
2014	376,808.77	90,567	87,833	319,120	5.24	60,901
2015	93,433.07	8,819	8,553	92,355	5.22	17,693
	35,073,429.98	28,109,282	27,260,865	10,618,440		2,114,874

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.0 6.03

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B05.1 - BUILDINGS - OTHER - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-R0.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -3						
2004	119,618.36	82,847	82,613	40,594	5.12	7,929
2006	594,079.01	385,908	384,816	227,085	5.13	44,266
2008	113,363.32	67,301	67,111	49,653	5.13	9,679
2010	176,461.62	91,230	90,972	90,783	5.13	17,696
2011	296,727.90	138,154	137,762	167,867	5.14	32,659
	1,300,250.21	765,440	763,274	575,983		112,229

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1 8.63

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT B06.1 - BUILDINGS - METAL - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -3						
2009	72,011.04	40,981	39,551	34,620	5.24	6,607
	72,011.04	40,981	39,551	34,620		6,607

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 9.17

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C01.1 - CABLES - TELECONTROL - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 30-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -3						
2004	89,749.79	63,572	63,121	29,321	5.20	5,639
	89,749.79	63,572	63,121	29,321		5,639

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 6.28

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C03.1 - CABLES - UNDERGROUND - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-S4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -14						
1980	544,049.00	540,859	481,561	138,655	5.20	26,664
	544,049.00	540,859	481,561	138,655		26,664

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 4.90

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C04.1 - CABLES - ABOVE GROUND - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -14						
1980	629,827.19	625,747	560,583	157,420	5.16	30,508
	629,827.19	625,747	560,583	157,420		30,508

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 4.84

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C07.1 - CHEMICAL FEED SYSTEMS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -6						
1987	8,841.21	7,929	8,054	1,318	5.08	259
1995	68,322.84	57,694	58,602	13,820	5.20	2,658
	77,164.05	65,623	66,656	15,138		2,917

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 3.78

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C12.1 - CONDENSERS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -3						
1980	2,042,518.00	1,828,512	1,896,994	206,800	5.09	40,629
1997	51,553.63	41,313	42,860	10,240	5.21	1,965
2008	235,595.08	142,620	147,962	94,701	5.24	18,073
	2,329,666.71	2,012,445	2,087,816	311,741		60,667

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1 2.60

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT C15.1 - CONTROL, METER, RELAYING - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 40-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
2012	119,879.96	47,842	48,437	71,443	5.24	13,634
	119,879.96	47,842	48,437	71,443		13,634

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 11.37

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT E03.1 - ENVIRONMENTAL EQUIPMENT - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-R2.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
2000	263,583.82	196,222	199,368	64,216	5.17	12,421
2001	2,680.00	1,960	1,991	689	5.18	133
2003	815,776.03	572,593	581,775	234,001	5.19	45,087
2008	150,049.97	88,006	89,418	60,632	5.21	11,638
2014	48,171.15	10,681	10,852	37,319	5.23	7,136
	1,280,260.97	869,462	883,404	396,857		76,415

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 5.97

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F03.1 - FIRE FIGHTING EQUIPMENT - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
1968	76,937.47	69,733	60,373	16,564	4.43	3,739
1980	506,992.00	442,315	382,942	124,050	5.03	24,662
2009	213,220.13	117,951	102,118	111,102	5.25	21,162
	797,149.60	629,999	545,433	251,716		49,563

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1 6.22

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F04.1 - FOOTINGS AND FOUNDATIONS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 65-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1987	56,612.79	51,569	46,927	14,214	5.19	2,739
	56,612.79	51,569	46,927	14,214		2,739

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 4.84

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT F06.1 - FUEL SYSTEMS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 50-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -11						
1980	4,294,944.43	4,097,952	3,707,897	1,059,491	5.02	211,054
1991	76,747.60	69,343	62,743	22,447	5.11	4,393
1992	37,066.15	33,239	30,075	11,068	5.12	2,162
1995	37,257.20	32,563	29,464	11,891	5.13	2,318
2001	712,705.67	574,776	520,067	271,036	5.16	52,526
2008	775,913.22	501,764	454,005	407,259	5.18	78,621
2010	2,366,125.59	1,330,665	1,204,008	1,422,391	5.19	274,064
2012	3,379,559.02	1,487,432	1,345,853	2,405,458	5.19	463,479
2013	1,628,833.20	578,182	523,149	1,284,856	5.19	247,564
	13,309,152.08	8,705,916	7,877,261	6,895,898		1,336,181

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 10.04

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G01.1 - GAS TURBINE SYSTEMS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -2						
1987	24,645.16	21,192	23,906	1,232	5.05	244
	24,645.16	21,192	23,906	1,232		244
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.0	0.99

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G03.1 - GENERATORS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 65-S3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1987	846.63	772	687	227	5.22	43
2008	78,948.91	50,156	44,661	40,604	5.25	7,734
2012	210,136.55	90,779	80,832	146,115	5.25	27,831
2013	777,505.62	270,872	241,193	598,513	5.25	114,002
	1,067,437.71	412,579	367,373	785,459		149,610

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.3 14.02

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT G06.1 - GOVENORS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 45-S4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -14						
1980	218,343.00	218,755	198,381	50,530	4.76	10,616
1999	922,781.05	798,046	723,721	328,249	5.25	62,524
2003	1,003,258.64	805,438	730,424	413,291	5.25	78,722
	2,144,382.69	1,822,239	1,652,526	792,071		151,862

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 7.08

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I02.1 - INSTUMENTATION - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 30-L0.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
1980	2,307,659.57	1,912,819	1,881,919	425,741	4.57	93,160
1987	470,718.02	380,957	374,803	95,915	4.67	20,539
1988	112,204.97	90,369	88,909	23,296	4.69	4,967
1989	32,021.39	25,668	25,253	6,768	4.70	1,440
1994	655,548.30	509,086	500,862	154,686	4.77	32,429
2004	1,639,203.46	1,104,413	1,086,572	552,631	4.91	112,552
2005	1,156,534.93	757,808	745,567	410,968	4.93	83,361
2008	344,737.06	200,178	196,944	147,793	4.99	29,618
2014	8,698.00	1,930	1,899	6,799	5.12	1,328
	6,727,325.70	4,983,228	4,902,728	1,824,598		379,394

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.8 5.64

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT I05.1 - INVERTERS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 25-S1.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
2000	18,910.94	15,304	14,372	6,052	4.74	1,277
2008	5,505.60	3,512	3,298	2,648	5.10	519
	24,416.54	18,816	17,670	8,700		1,796

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.8 7.36

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT L03.1 - LAND IMPROVEMENTS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 75-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
1989	5,765.52	4,807	4,965	801	5.22	153
	5,765.52	4,807	4,965	801		153

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 2.65

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M02.1 - MARINE TERMINAL - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 65-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -6						
1996	346,931.75	289,763	288,055	79,693	5.24	15,209
2009	121,591.12	71,299	70,879	58,008	5.25	11,049
	468,522.87	361,062	358,934	137,700		26,258

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 5.60

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT M10.1 - MISCELLANEOUS UNITS OF PROPERTY - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 22-R1.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
2011	174,380.59	78,989	81,721	92,660	5.06	18,312
2014	1,437,566.30	314,813	325,701	1,111,866	5.10	218,013
	1,611,946.89	393,802	407,422	1,204,525		236,325
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.1	14.66

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT O02.1 - OFFICE FURNITURE - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
1998	58,975.29	51,603	48,674	10,302	2.50	4,121
	58,975.29	51,603	48,674	10,302		4,121

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 2.5 6.99

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P10.1 - POWERHOUSE - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 75-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1980	8,874,021.38	8,338,606	7,826,979	1,756,964	5.19	338,529
1987	29,410.44	26,797	25,153	6,610	5.21	1,269
	8,903,431.82	8,365,403	7,852,132	1,763,575		339,798

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 3.82

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT P12.1 - PROTECTIVE CONTROL AND RELAY PANELS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 35-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
2008	106,685.08	62,746	65,531	41,154	5.21	7,899
	106,685.08	62,746	65,531	41,154		7,899

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 7.40

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT R13.1 - ROADS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 60-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1980	1,859.00	1,750	1,635	373	5.16	72
	1,859.00	1,750	1,635	373		72

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 3.87

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S07.1 - STACKS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1968	2,511,250.83	2,447,065	2,153,213	558,938	4.81	116,203
1980	1,698,208.00	1,599,121	1,407,093	426,972	5.11	83,556
1992	511,777.49	451,876	397,613	155,107	5.22	29,714
2005	2,016,821.65	1,451,640	1,277,322	900,845	5.25	171,590
2011	261,850.00	130,523	114,849	167,949	5.25	31,990
2012	2,182,691.48	942,923	829,695	1,527,612	5.25	290,974
2014	19,519.33	4,685	4,122	16,959	5.25	3,230
	9,202,118.78	7,027,833	6,183,907	3,754,381		727,257
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.2	7.90

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT S08.1 - STATIC EXCITATION SYSTEM - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 32-R4						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -6						
1968	1,115,787.92	1,172,386	813,916	368,819	0.28	368,819
2000	329,058.01	261,217	181,347	167,454	5.15	32,515
2001	16,588.65	12,936	8,981	8,603	5.17	1,664
	1,461,434.58	1,446,539	1,004,244	544,877		402,998

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.4 27.58

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T03.1 - TOOLS AND EQUIPMENT - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. 0						
2001	30,649.10	22,502	22,162	8,487	5.25	1,617
2010	320,612.40	164,035	161,554	159,059	5.25	30,297
	351,261.50	186,537	183,716	167,546		31,914

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 9.09

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T05.1 - TRANSFORMERS - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R3						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -6						
2013	126,690.40	43,376	38,007	96,285	5.24	18,375
	126,690.40	43,376	38,007	96,285		18,375

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 14.50

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT T09.1 - TURBINES - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R2.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -14						
1980	6,398,098.00	6,322,366	5,612,011	1,681,821	5.08	331,067
1995	1,579.76	1,429	1,268	533	5.18	103
2006	611,180.01	447,464	397,189	299,556	5.22	57,386
2007	1,705,004.00	1,198,760	1,064,072	879,633	5.22	168,512
2009	988,302.25	622,279	552,362	574,303	5.22	110,020
2010	430,013.25	249,931	221,850	268,365	5.23	51,313
2012	1,691,863.26	769,272	682,840	1,245,884	5.23	238,219
2013	10,126,535.70	3,713,324	3,296,111	8,248,140	5.23	1,577,082
2014	5,124,796.25	1,295,406	1,149,860	4,692,408	5.23	897,210
	27,077,372.48	14,620,231	12,977,563	17,890,642		3,430,912
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					5.2	12.67

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W03.1 - WATER SYSTEMS - FEED - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R2.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -8						
1979	1,107,382.84	1,040,222	887,011	308,962	5.07	60,939
1980	1,024,814.00	959,385	818,080	288,719	5.08	56,834
2014	95,600.00	22,893	19,521	83,727	5.23	16,009
2015	590,837.65	56,153	47,882	590,222	5.18	113,942
	2,818,634.49	2,078,653	1,772,494	1,271,631		247,724

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.1 8.79

NEWFOUNDLAND AND LABRADOR HYDRO

ACCOUNT W04.1 - WATER TREATMENT - HOLYROOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2015

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
INTERIM SURVIVOR CURVE.. IOWA 55-R2.5						
PROBABLE RETIREMENT YEAR.. 3-2021						
NET SALVAGE PERCENT.. -6						
1969	177,015.88	167,637	157,358	30,279	4.90	6,179
1979	5,098.00	4,700	4,412	992	5.07	196
1980	622,363.00	571,839	536,775	122,930	5.08	24,199
1983	18,823.46	17,097	16,049	3,904	5.11	764
1995	9,354.00	7,867	7,385	2,530	5.18	488
1996	224,794.62	187,073	175,602	62,680	5.19	12,077
2011	1,418,153.65	691,898	649,473	853,770	5.23	163,245
2013	317,359.44	108,207	101,572	234,829	5.23	44,900
	2,792,962.05	1,756,318	1,648,626	1,311,914		252,048

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 9.02

APPENDIX I

ADDITIONAL EVIDENCE OF LARRY KENNEDY

NEWFOUNDLAND AND LABRADOR HYDRO

IN THE MATTER OF

AN APPLICATION BY NEWFOUNDLAND AND LABRADOR HYDRO BEFORE THE NEWFOUNDLAND AND LABRADOR BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

EVIDENCE

OF

LARRY E. KENNEDY RELATED TO

THE CONVERSION TO GROUP ACCOUNTING METHODS

JULY, 2017

CONCENTRIC ADVISORS

DEPRECIATION EVIDENCE OF
LARRY KENNEDY

Introduction and Overview

Q1. Please state your name and business address.

A1. My name is Larry Kennedy and my business address is Suite 277, 200 Rivercrest Drive S.E., Calgary, Alberta, T2C 2X5.

Q2. Please state your occupation.

A2. I am Vice President of Concentric Advisors ULC.

Q3. Have you previously testified before this or any other regulatory boards?

A3. Yes, I have testified on numerous occasions before regulatory boards throughout Canada as summarized in my Curriculum Vitae, attached to this evidence. Also, as summarized in my Curriculum Vitae, I have prepared a number of additional depreciation reviews that have resulted in negotiated settlements or where appearances were not required.

Of specific note, I have presented expert reports and testimony on depreciation-related matters on behalf of Newfoundland and Labrador Hydro ("NL Hydro") to the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") on three (3) prior occasions.

Q4. Please state the purpose of this evidence.

A4. Concentric Advisors was retained by NL Hydro to complete a full and complete depreciation study for inclusion as part of a regulatory application to the PUB. Additionally, Concentric Advisors was asked to provide a response to a PUB directive resulting from the last depreciation study and negotiated settlement application relating to the historical NL Hydro departure from the use of typical regulated group depreciation accounting. This evidence discusses the issues and

concepts related to Group Depreciation and provides a recommendation to convert to group depreciation accounting. This recommendation was used in the development of the depreciation rates that are determined in the Concentric Advisors Depreciation Study.

Q5. Please summarize the PUB Directive.

A5. In PUB Order No P.U. 40(2012), the Board directed as follows:

> *"In accordance with the terms of the Settlement Agreement Hydro has agreed to provide, at the time of its next depreciation study, a report, on a limited number of groups of property, comparing the agreed methodology to the application of depreciation on a pure group basis. The Board notes that the findings of this report would not be applied retroactively but rather would provide information for future rate making purposes. In the Board's view this is a reasonable approach to resolve what appears to have been a difference in expert opinion on this specific issue. The Board will accept this recommendation."*[1]

Q6. Please describe the current NLHydro accounting practices.

A6. At present, the current NL Hydro practice would be described as a "Hybrid Unit Depreciation" practice. Within the current accounting system (JD Edwards), each asset is ascribed with a life estimate. The accounting system then prepares the depreciation expense entries utilizing a remaining life calculation on each asset, with the associated depreciation expense tracked against each specific asset. At the time of retirement of the asset, the original cost of the asset is removed from the gross plant in service ledger. Additionally the accumulated depreciation expense associated with the specific asset is removed from the accumulated depreciation account. The difference between the original cost and the accumulated depreciation expense is booked as a loss to the income statement on the period of the retirement transactions. As the current system will not allow for the over depreciation of an asset, the entry to the income statement is virtually always a loss, absent any net salvage considerations.

[1] Order No. P.U. 40(2012), page 3, lines 28-35.

Currently, the annual charges to the income statement (as described above) are large enough to warrant inclusion in the revenue requirement. As such, the retirement entries need to be forecast for all test periods, and the associated gain and loss for each forecast retirement transaction requires estimation and inclusion in the each test year's revenue requirement. To the extent that the current practice of estimating the forecast losses, there exists for the potential of material over or under statement of the company's net income.

While the above discussion describes a unit depreciation process, there are some aspects of a more traditional grouping process in the current NL Hydro practices. Average service life estimates and retirement dispersion curves are developed on the basis of combining all of the average age and retirement characteristics of the overall UOP grouping rather than on each individual asset. The same depreciation rate is then applied to all assets within the UOP grouping. In this manner the depreciation rate does recognize a weighted probability of retirement dispersion providing for potential retirement of the asset either prior to or later than the average service life estimate.

Q7. Please outline the concept of Group Depreciation Accounting

A7. Group depreciation refers to the widely accepted procedure for rate regulated utilities where, rather than depreciating each item by itself (unit depreciation), a group containing homogenous units of plant which are alike in character, used in the same manner throughout the utilities service territory, and operated under the same general conditions is formed. Group depreciation recognizes that there will be differing lives for individual units within the group. For example, poles are often combined into a single group. Some poles will be retired due to storms or third party damage (for example automobile accidents, for strikes by farm equipment, etc.). Others will decay, while some will be displaced due to road relocations, and some will be replaced due to the need to provide underground service. However they are combined into the same group because they are homogenous units. With group depreciation, the entire group is considered as the asset being depreciated,

therefore, one depreciation rate is applied to the entire group and only one accumulated depreciation account is tracked for the entire group.

Under group depreciation no gain or loss is recognized for retirement of individual assets, as only one depreciation calculation is made on the entire group. Upon retirement of an asset from the group, the total original cost of the asset is debited to the accumulated depreciation account and credited to the asset account. Any gross salvage received (if applicable) for the retired asset is credited to the accumulated depreciation account and any cost of removal is debited to the accumulated depreciation account and any cost of removal is debited to the accumulated depreciation account. Under group depreciation, since the accumulated depreciation relates to the entire group rather than to specific assets within the group, no gain or loss is recognized. This assumes that the group depreciation rate is accurate for the group as a whole and that the cost of the retired asset, net of gross salvage and cost of removal, is being fully provided for in the accumulated depreciation account.

Details of the Review

Q8. Please describe the review that was undertaken to comply with negotiated settlement agreement.

A8. The negotiated settlement determined that the following Units of Plant (accounts) be studied for review:

- C11 - Computers
- R14 - Routers and LAN
- S03 - Servers
- S05 - Software
- V04 - Vehicles - ¾ ton and under
- V06 - Vehicles - Cars, Stations Wagons and Vans

In addition to the above accounts, two additional accounts were reviewed, in order

to analyze the impacts when applied to longer life accounts with a retirement dispersion considered in the depreciation rates, and with a significantly larger level of investment as compared to the accounts as agreed to in negotiated settlement process. The two additional accounts were:

- C13 - Conductor
- P07 – Poles-Wood

Q9. Please further explain why it was necessary to include the two additional accounts in the analysis.

A9. The accounts that were selected during the negotiated settlement process were all short life accounts and most were subjected to a Square Iowa curve. The use of Square Iowa curves results in an analysis where the benefits of group accounting are eliminated due to the underlying assumption that the assets would be amortized in a method which removes any retirement dispersion. Secondly, short life accounts such as vehicles also have a limited amount of retirement dispersion, and therefore the benefits of group accounting would be reduced.

Given the above, Concentric Advisors suggested that the analysis to be completed by NLHydro should include at least two accounts that have long average service life estimates and would retire due to diverse forces of retirement.

Q10. Please summarize the results of the review.

A10. The analysis indicated that the benefits of group accounting increase as the life estimates and amount of retirement dispersion of the account increases. Consistent with this finding, the accounts that are amortized through the use of a square Iowa indicated more benefit of continued use of the Hybrid approach, whereas the long life accounts such as Wood poles and Conductor were virtually neutral as to the use of the current Hybrid approach versus traditional grouping accounting approaches.

A summary of the results of the testing is presented in the following table:

Estimate of Increase in Depreciation in Moving to the Group Accounting Method					
UOP	Description		2013	2014	2015
C11	Computers	5-Square	(41,924.12)	507,678.91	616,991.42
R14	Routers and LAN	5-Square	9,948.78	422,351.76	571,690.71
S03	Servers	7-Square	(5,387.18)	784,970.35	842,901.91
S05	Software	7-Square	23,162.87	85,730.82	94,654.46
V04	Vehicles - 3/4 ton and Under	7-L3	9,003.03	20,784.87	165,763.57
V06	Vehicles - Cars, Station Wagons and Vans	6-L3	13,030.53	31,135.78	229,956.17
C13	Conductor	60-R3	(6,254.89)	(5,485.91)	(0.71)
P07	Poles - Wood	43-R1	(50,827.16)	(9,775.94)	20,049.82
			(49,248.14)	1,837,390.62	2,542,007.34

As noted above, the two long lived accounts indicate virtually no impact of a conversion to group accounting. I also note that as of December 31, 2015, accounts subjected to amortization accounting represent $79 million of the approximately of the $2.5 Billion (3.2%) of depreciable investment.

While the above analysis indicates that approximately $79 million of investment could be subjected to higher depreciation expense with a discontinuation of the current Hybrid approach, Concentric Advisors views that changes to the approach for the amortized accounts can be made that would eliminate this issue. As discussed in the Concentric Advisors depreciation study report, it is recommended that when each vintage for each applicable amortized account reaches the complete amortization period, that vintage be fully retired irrespective of whether the associated equipment is still in service. In this manner, these accounts would be depreciated in a manner consistent with the current Hybrid approach, and the impacts noted in the table above would be virtually eliminated.

Q11. What is your Recommendation with regard to the Board Directive Based on this Review?

A11. Based on the review as described herein, I recommend the following:

- That NL Hydro convert to a more traditional Group Accounting and Depreciation Practice for all accounts other than Amortized accounts as discussed below;

- That amortized accounts (as noted with a Square or SQ Iowa curve) be subjected to a pure amortization procedure wherein the investment in these accounts is retired when it reaches its full amortization period. All retirements in these accounts should be made only at the expiration of the amortization period.

Q12. Does this conclude your Evidence?

A12. Yes.

LARRY E. KENNEDY, CDP
VICE PRESIDENT

Larry E. Kennedy, CDP
Vice President

TECHNICAL SPECIALTIES

- Public Utility Plant Depreciation
- Public Utility Plant Accounting

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Mr. Kennedy joined Gannett Fleming, Inc. in January 1999 and was Vice President of Gannett Fleming Canada ULC. Mr. Kennedy is now Vice President of Concentric Advisors UCL. His responsibilities include the assembly of data, the preparation and review of depreciation studies, advice to clients regarding asset retirement obligation accounting, plant accounting issues, and provision of general regulatory litigation support.
Representative assignments include:

REPRESENTATIVE PROJECT EXPERIENCE

- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board. Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.

- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004 additional depreciation studies were filed in 2005, 2010 and 2012, and 2014. The 2010, 2012, and 2014 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards.

LARRY E. KENNEDY, CPA
VICE PRESIDENT

- ATCO: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta Assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities (NWT) Inc. and the distribution assets of Northland Utilities (Yellowknife) Inc. ATCO Electric studies were submitted to the AUC for review, while the Northland Utilities Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to Yukon Public Utilities Board. ATCO Gas studies were prepared in 2010 and were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements.

- BC Hydro: This assignment included the development of an average service life study for all of the BC Hydro's electric generation, transmission, distribution and general plant assets. The study, which was prepared for submission to the British Columbia Utilities Commission ("BCUC), included development of depreciation policy for the company, development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, and the compilation of a detailed report. The assignment included the support of the study through the regulatory process. Mr. Kennedy has also completed a review of the cost allocation procedures and practices which was filed with the BCUC in 2010.

- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2014. The 2011 and 2014 depreciation studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2015. Mr. Kennedy has also consulted on issues regarding IFRS compliance and required componentization.

- Enbridge Gas Distribution Inc.: Full and Comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.

- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in

service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.

- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Inc.: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the BCUC in 2005, 2010, 2011 and 2015 encompassing both the FortisBC electric and natural gas companies. FortisAlberta studies were completed in 2004 (updated in 2005), 2009 and 2010. Additionally, a Technical Update was prepared for FortisAlberta in 2015 and submitted to the AUC for review. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates.

- International Financial Reporting Standards (IFRS): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association, and to the British Columbia Utilities Commission on this topic.

- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada.

- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a

field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. A similar study was also completed in 2006 2011, and 2014. The 2011 and 2014 depreciation studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2015. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.

- Newfoundland and Labrador Hydro: Mr. Kennedy developed a comprehensive depreciation study that included the development of depreciation policy and rates for Newfoundland and Labrador Hydro. The study provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 study was the subject of Regulatory Review in 2012.

- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives the regulated assets were completed in 2011 and 2013, and were submitted to the Ontario Energy Board for review.

- TransCanada PipeLines Limited – Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012.

- TransCanada PipeLines Limited – Mainline Facilities: The study prepared for submission to the National Energy Board of Canada ("NEB") included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta – Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002, and was supported through an appearance



before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011. The 2011 study was fully supported through an appearance before the NEB in 2012

Mr. Kennedy has successfully completed the series of week-long programs offered by Depreciation Programs, Inc. and is a past president of the Society of Depreciation Professionals.

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation-Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation-Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011

Revision 2 - October 16, 2017
Exhibit 11 - Depreciation Study
Page 609 of 633

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524 Appearance Pending

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Appearance Pending
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	Appearance Pending
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272 Appearance Pending

APPENDIX 2

ESTIMATION OF SURIVOR CURVES

ESTIMATION OF SURVIVOR CURVES

Average Service Life

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages. A discussion of the general concept of survivor curves is presented. Also, the Iowa type survivor curves are reviewed.

SURVIVOR CURVES

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the

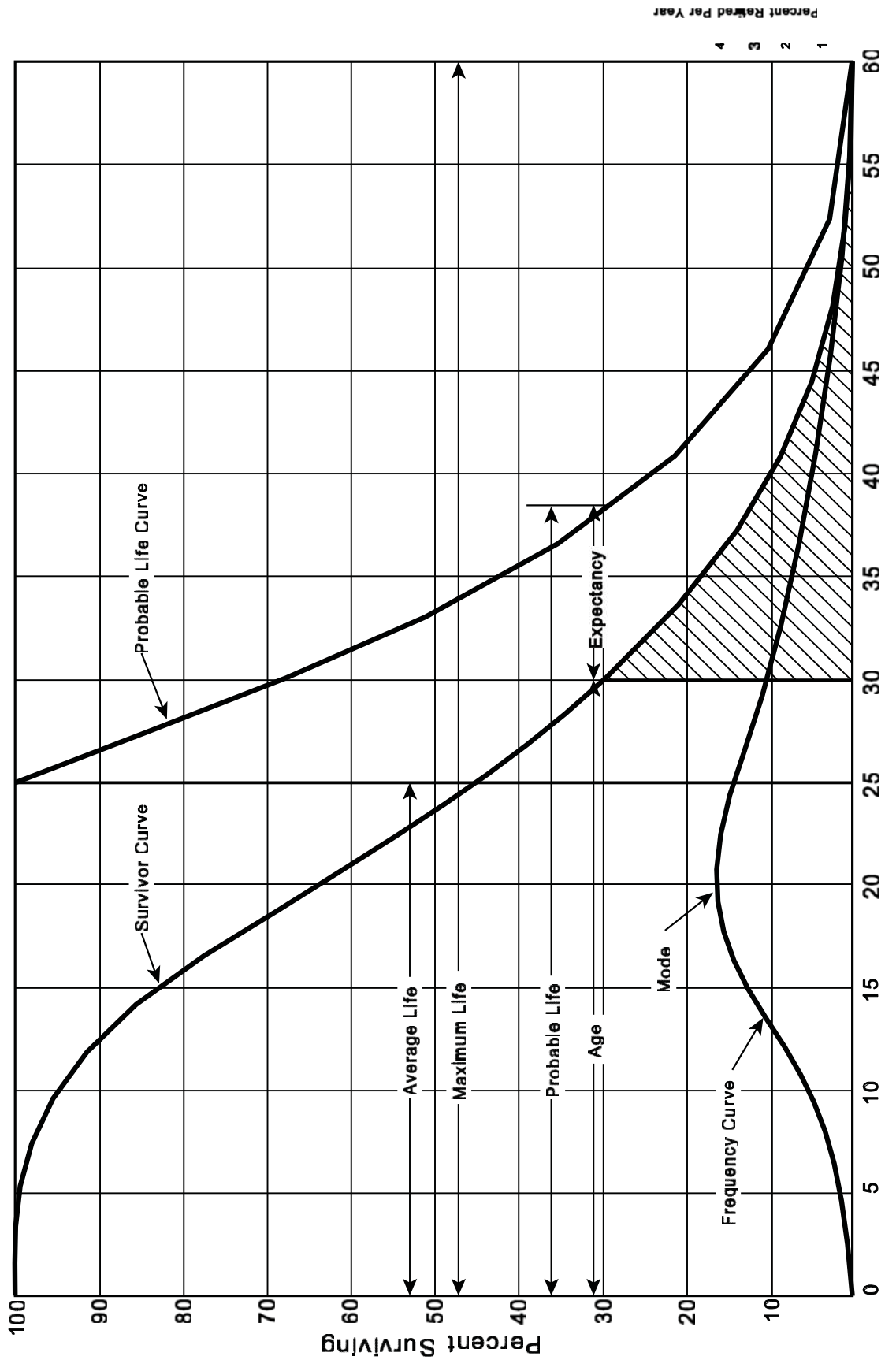


Figure 1. A Typical Survivor Curve and Derived Curves

Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.[1] These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[2] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[3] presenting his development of the fourth family consisting of the four O type survivor curves.

[1] Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

[2]Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[3]Couch, Frank V. B., Jr. "Classification of Type O Retirement Characteristics of Industrial Property." Unpublished M.S. thesis (Engineering Valuation). Library, Iowa State College, Ames, Iowa. 1957.

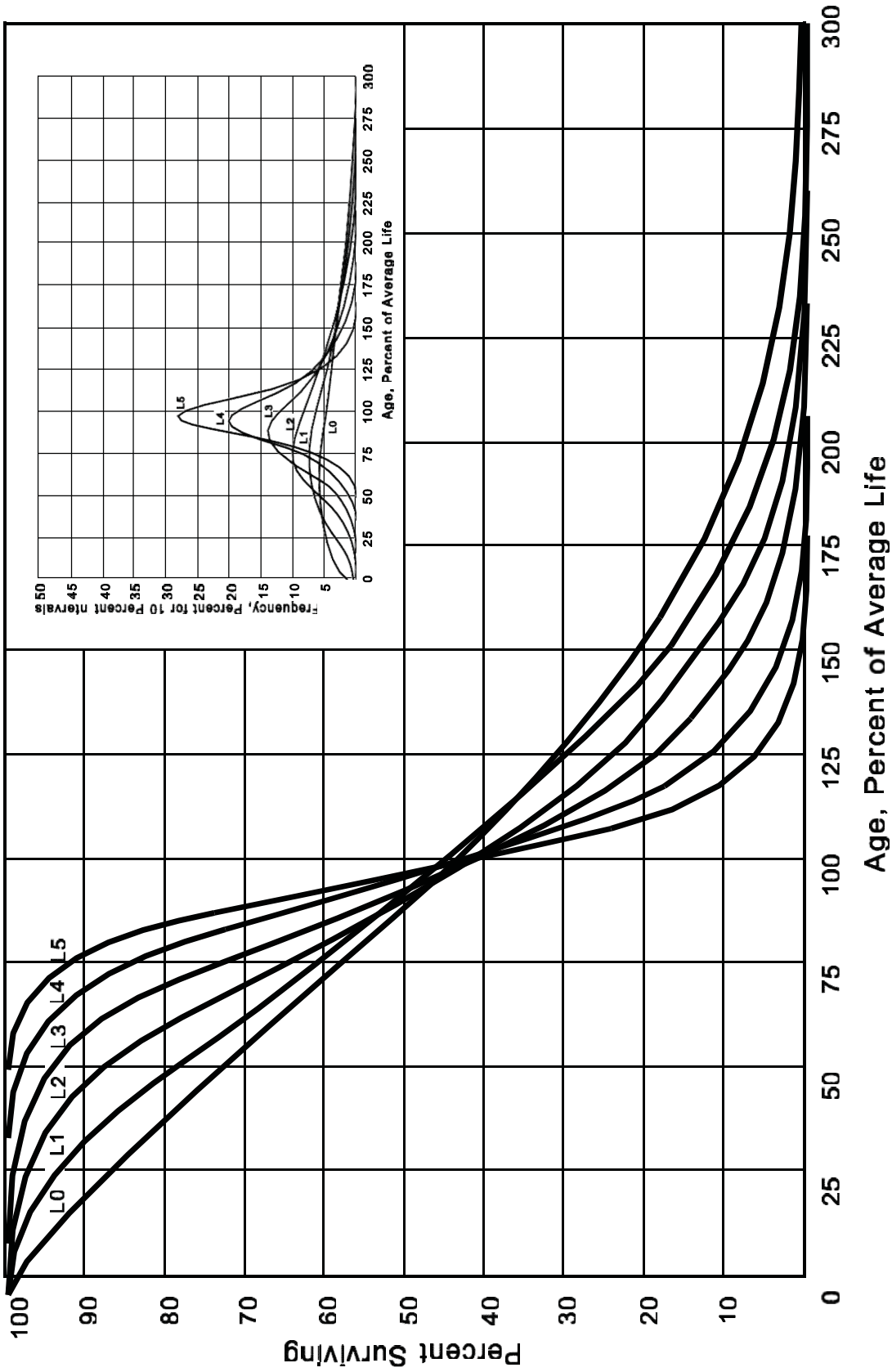


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

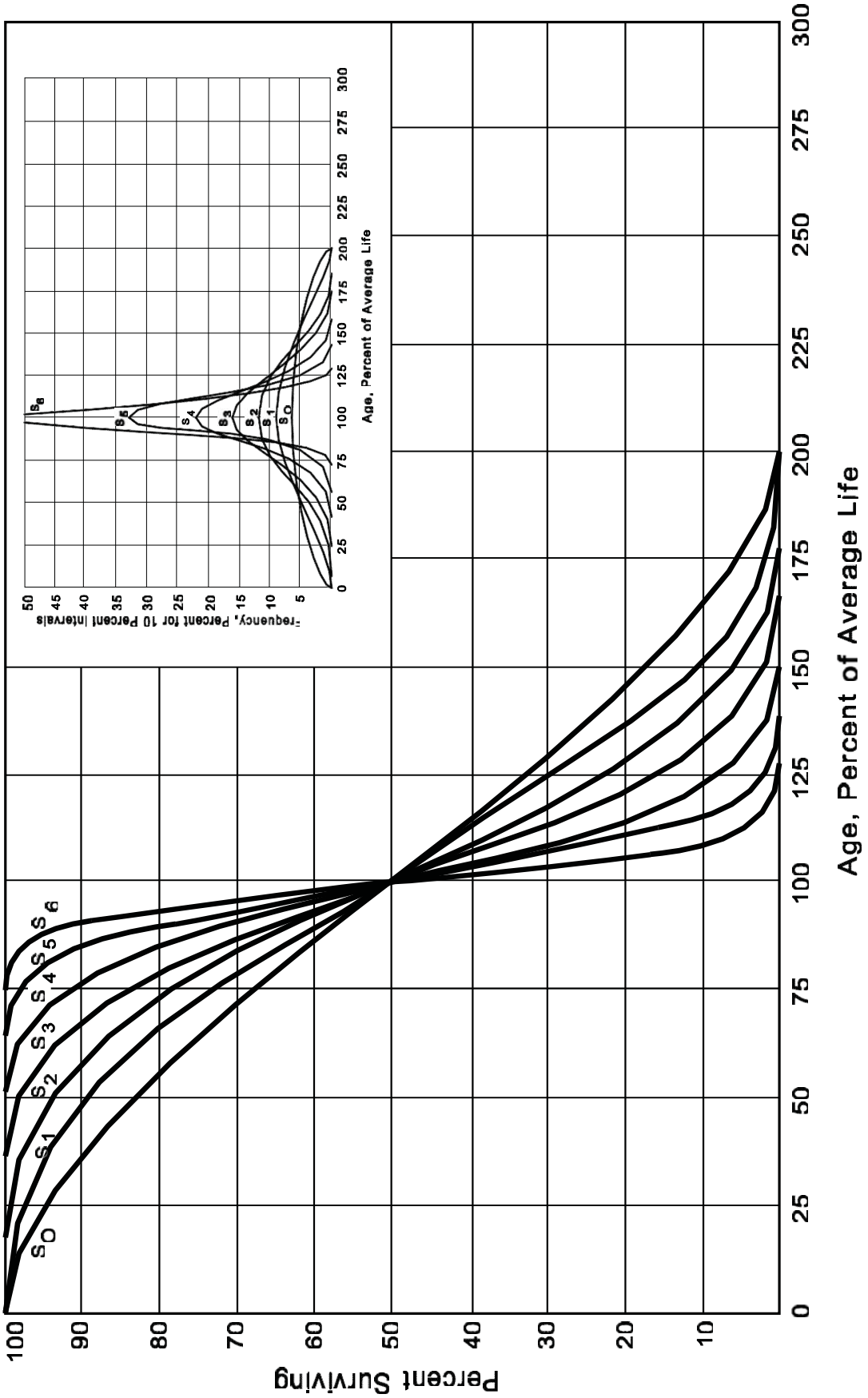


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

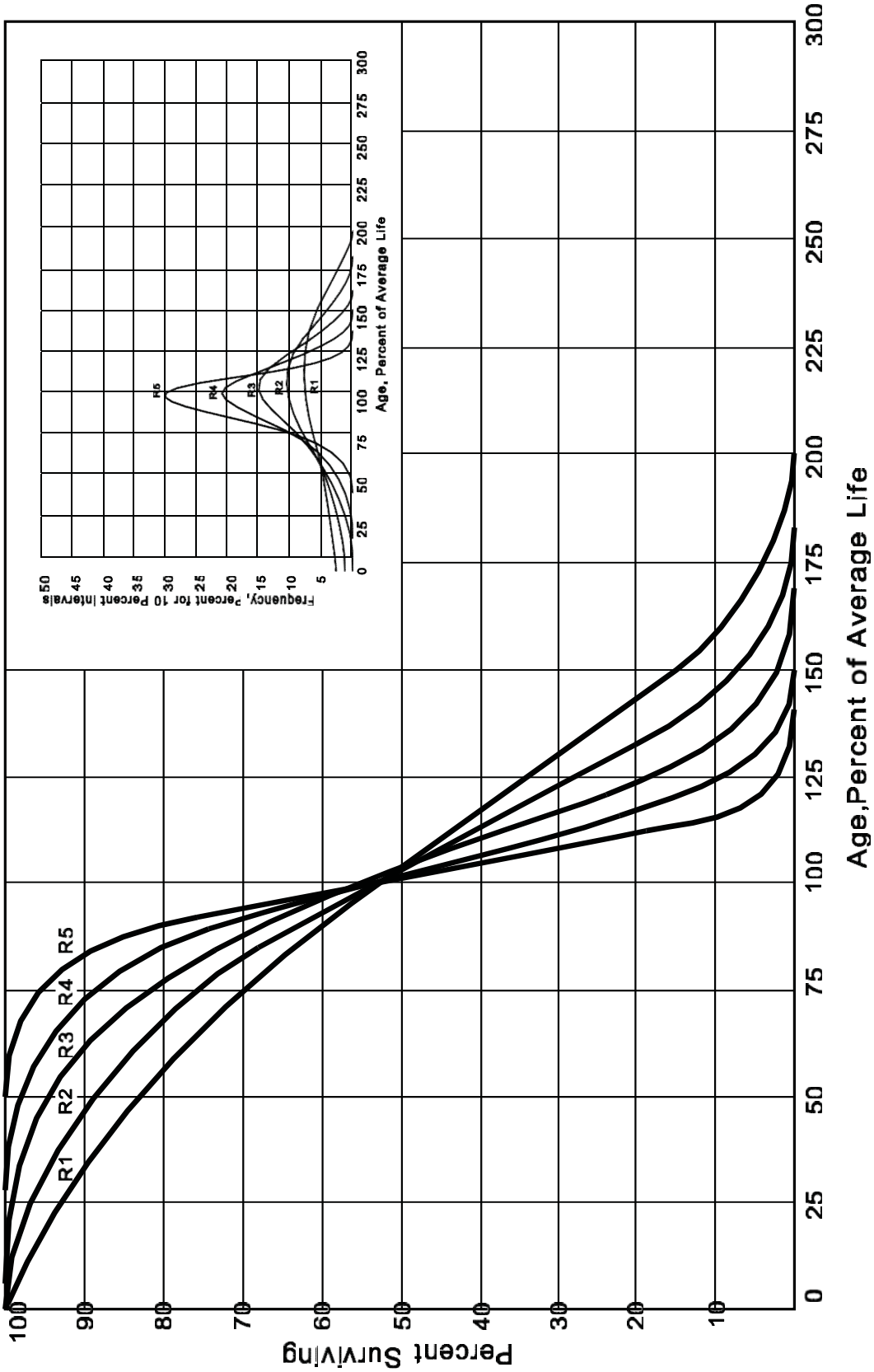


Figure 4. Right Modalor "R" Iowa Type Survivor Curves

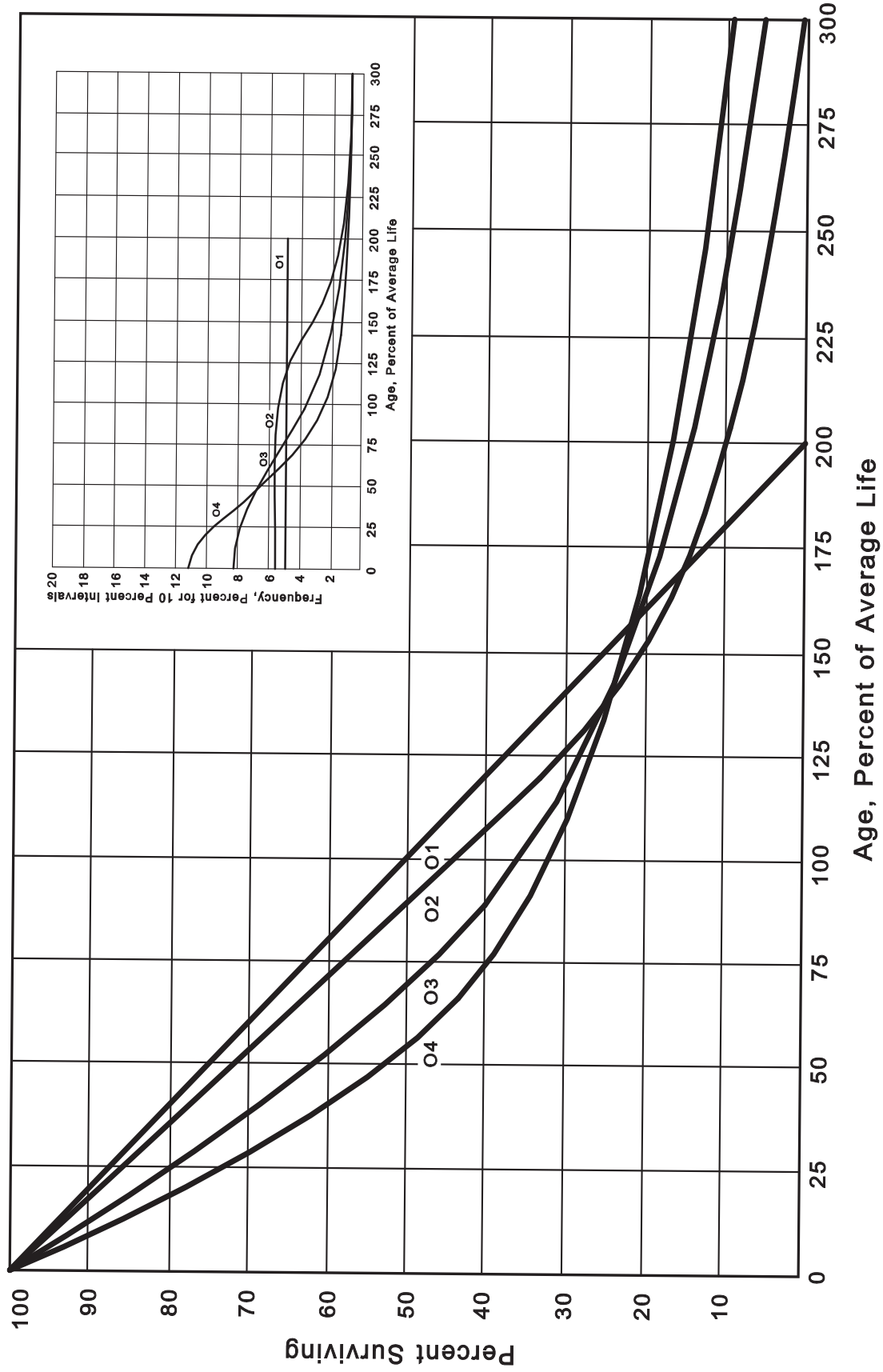


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements,"[4] "Engineering Valuation and Depreciation,"[5] and "Depreciation Systems."[6]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2007-2016 during which there were placements during the years 2007-2016. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on the following pages. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2002 were

[4]Winfrey, Robley, Supra Note 1.
[5]Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.
[6]Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2002-2016

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2003	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2004	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2005	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2006	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2007	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2008		5	11	12	13	14	15	16	18	20	113	7½-8½
2009			6	12	13	15	16	17	19	19	124	6½-7½
2010				6	13	15	16	17	19	19	131	5½-6½
2011					7	14	16	17	19	20	143	4½-5½
2012						8	18	20	22	23	146	3½-4½
2013							9	20	22	25	150	2½-3½
2014								11	23	25	151	1½-2½
2015									11	24	153	½-1½
2016										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2007-2016

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2003	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2004	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2005	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2006	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2007	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2008		-	-	-	-	-	-	-	-	-	-	7½-8½
2009			-	-	-	-	-	-	-	-	-	6½-7½
2010				-	-	-	-	(12)[b]	-	-	-	5½-6½
2011					-	-	-	-	22[a]	-	-	4½-5½
2012						-	-	(19)[b]	-	-	10	3½-4½
2013							-	-	-	-	-	2½-3½
2014								-	-	(102)[c]	(121)	1½-2½
2015									-	-	-	½-1½
2016												0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

retired in 2007. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2007 retirements of 2002 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on the following page. The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT JANUARY 1
OF EACH YEAR 2007-2016
SUMMARIZED BY AGE INTERVAL

Experience Band 2007-2016 Placement Band 2002-2016

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2002	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2003	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2004	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2005	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2006	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2007	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2008		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2009			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2010				580[a]	574	561	546	530	501	482	3,057	5½-6½
2011					660[a]	653	639	623	628	609	3,789	4½-5½
2012						750[a]	742	724	685	663	4,332	3½-4½
2013							850[a]	841	821	799	4,955	2½-3½
2014								960[a]	949	923	5,719	1½-2½
2015									1,080[a]	1,069	6,579	½-1½
2016										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a] Additions during the year.

shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2006 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

For the entire experience band 2006-2015, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on the following page, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent

SCHEDULE 4. ORIGINAL LIFE TABLE

CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2007-2016 Placement Band 2002-2016

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval (1)	Exposures at Beginning of Age Interval (2)	Retirements During Age Interval (3)	Retirement Ratio (4)	Survivor Ratio (5)	Percent Surviving at Beginning of Age Interval (6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 divided by Column 2.
Column 5 = 1.0000 minus Column 4.
Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15				
Exposures at age 4½	=	3,789,000				
Retirements from age 4½ to 5½	=	143,000				
Retirement Ratio	=	143,000	÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000	-	0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15)	x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an

average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

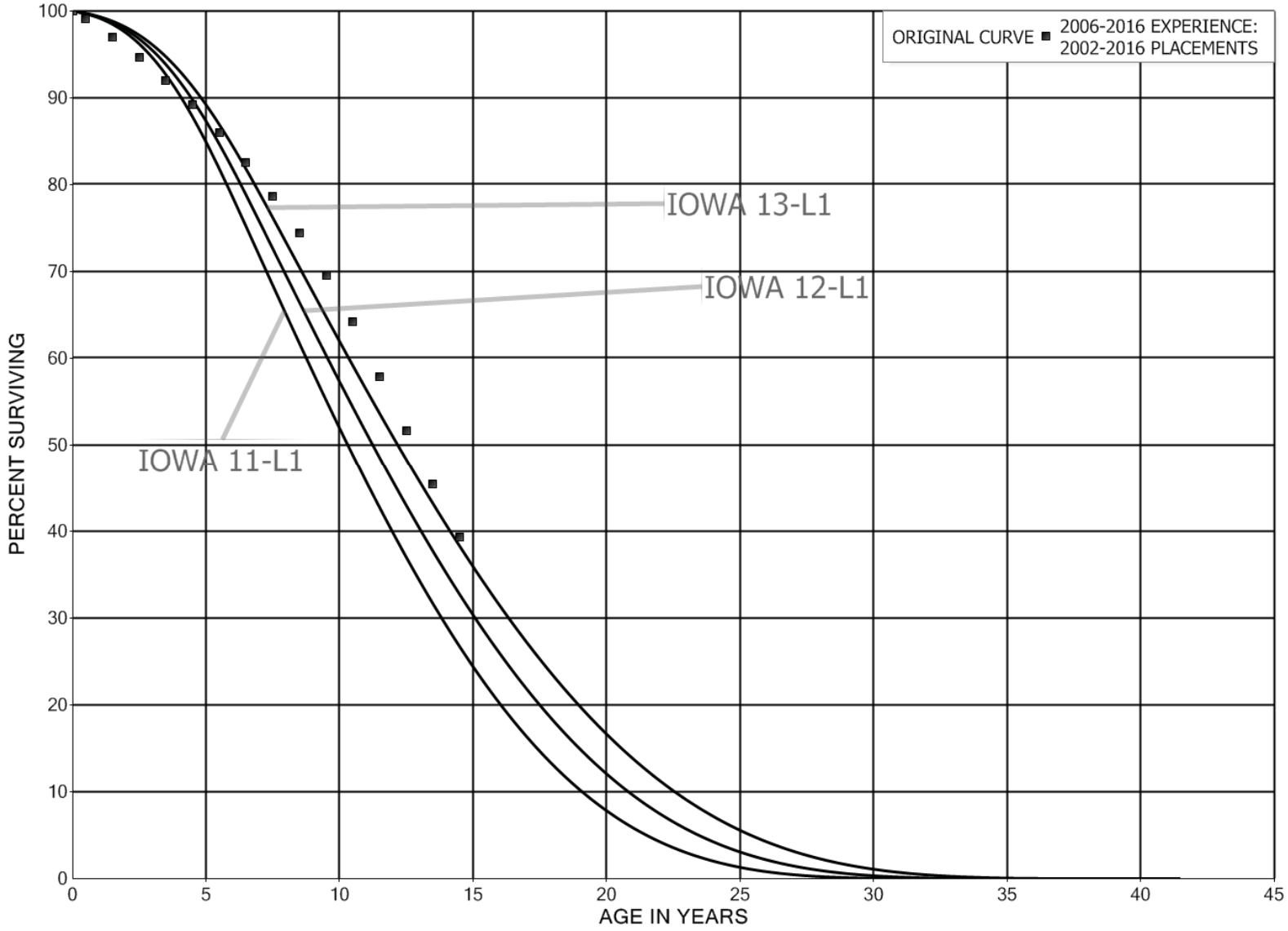


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

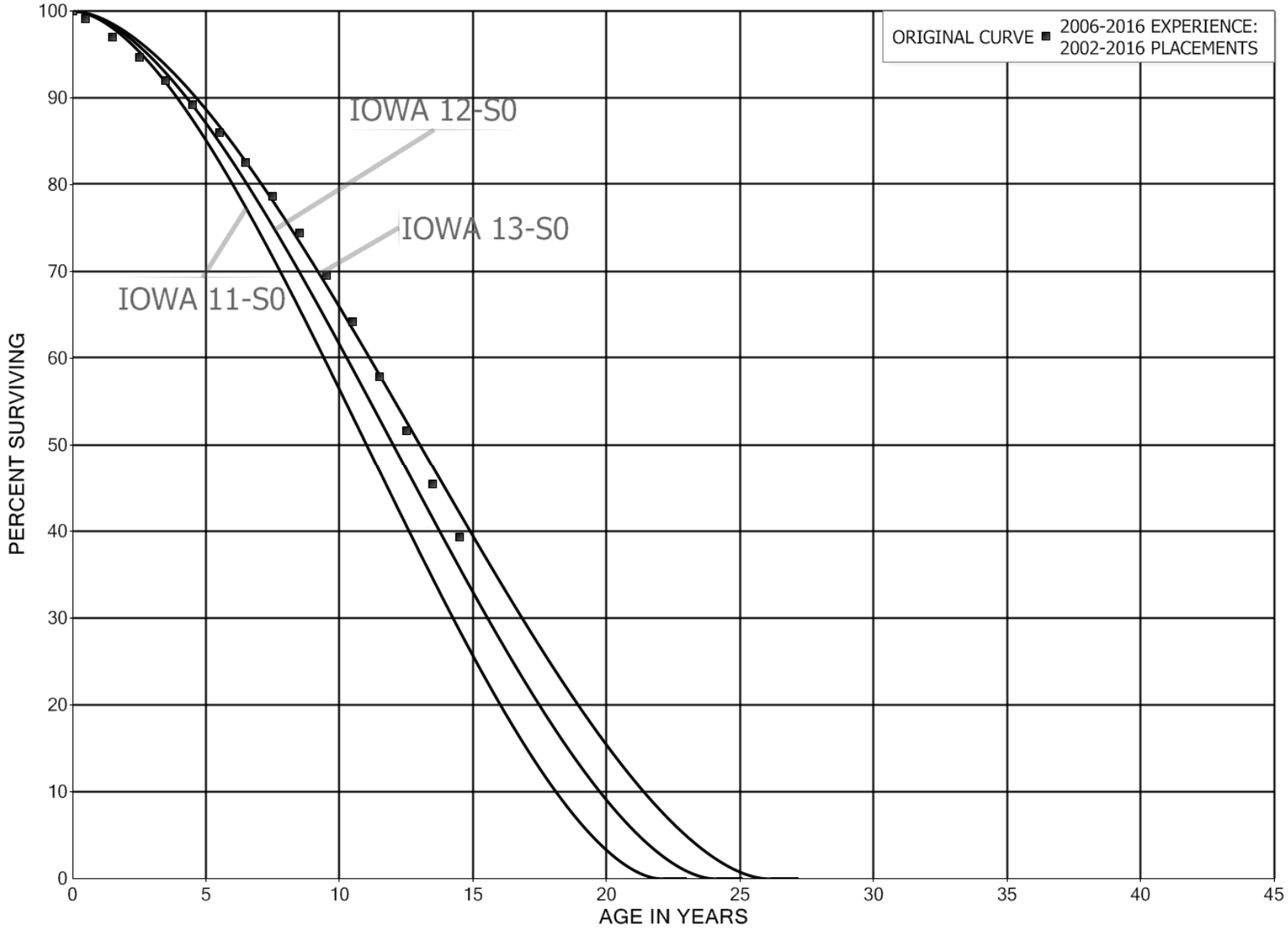


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

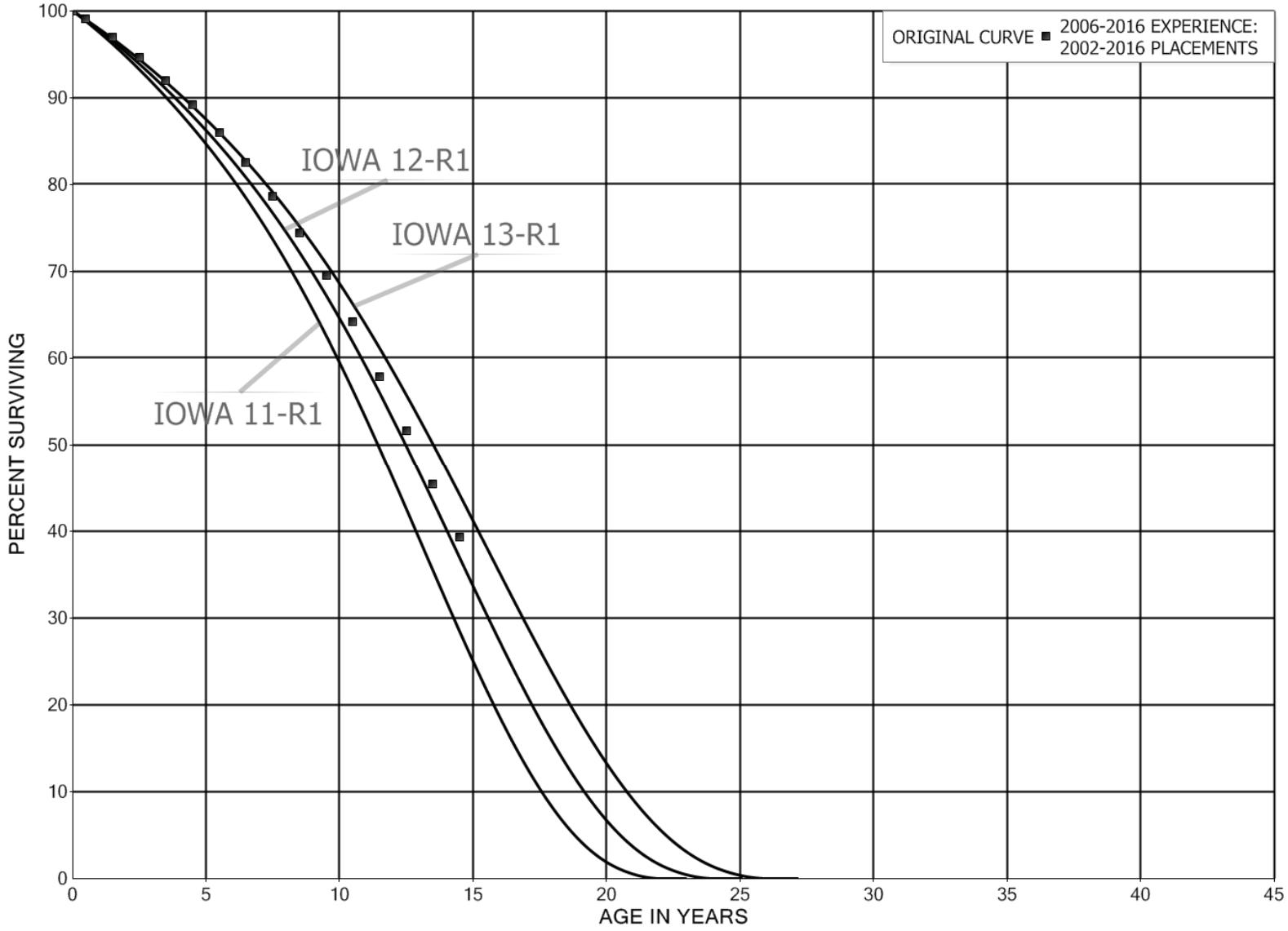
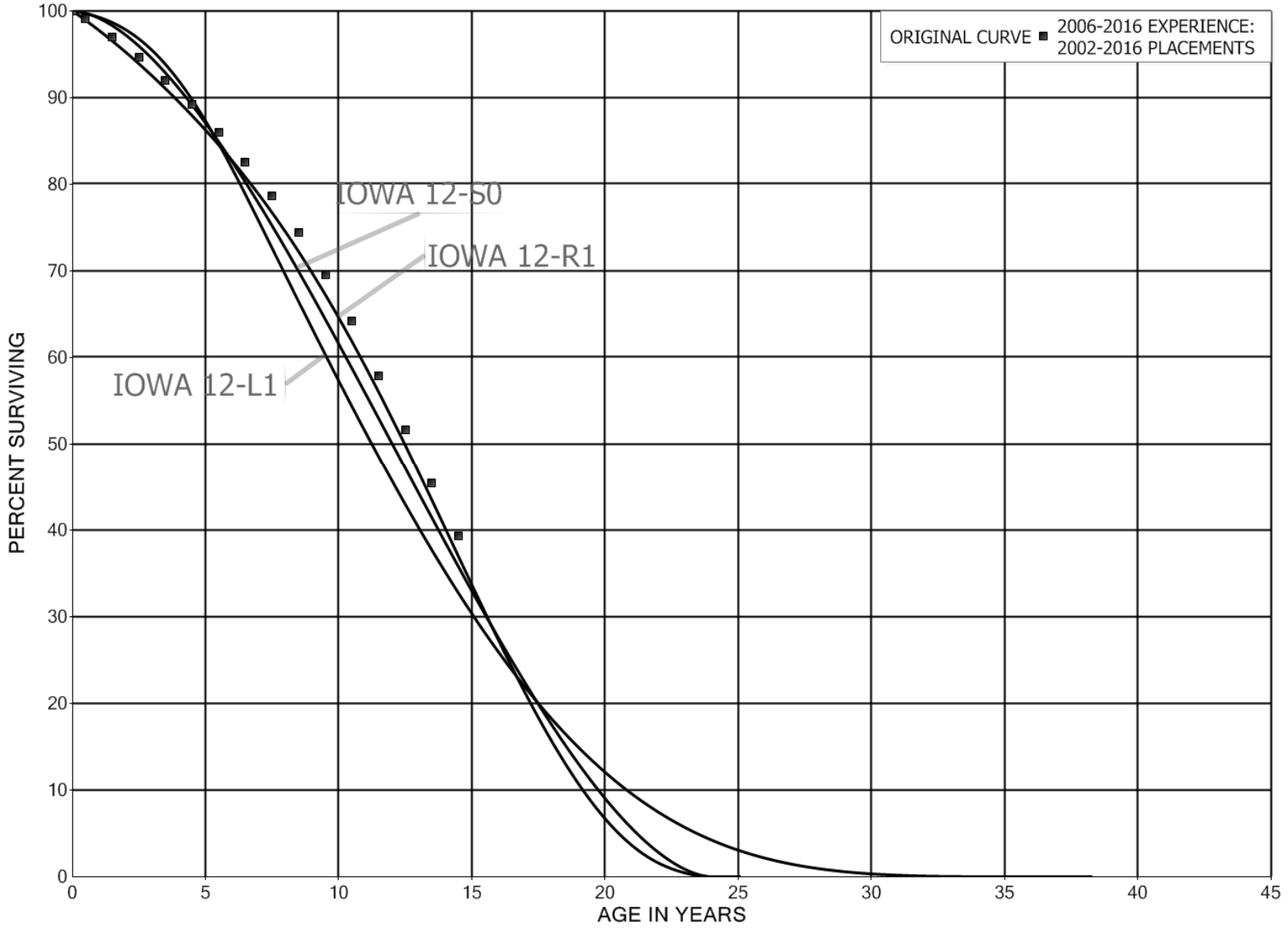


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES





CONCENTRIC ADVISORS ULC

Suite 277 • 200 Rivercrest Drive S.E. • Calgary, AB T2C 2X5 • Canada
t: 403.257.5946 • f: 403.257.5947

Exhibit 12 - Automatic Return on Equity Adjustment Report

Automatic Return on Equity Adjustment

Newfoundland and Labrador Hydro

June 2017

A Report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Table of Contents

1.0 Overview 1

2.0 Flow-through of Adjustment to Return on Equity 1

2.1 Adjustment to Return on Equity and Weighted Average Cost of Capital 1

2.2 Adjustment to Revenue Requirement for Rate Setting 1

3.0 Allocation of Revised Revenue Requirement 2

4.0 Revisions to Customer Rates 3

5.0 Revisions to Excess Earnings Account Definition 4

6.0 Implementation Process 4

7.0 Conclusion 5

1.0 Overview

In Board Order No. P.U. 49(2016), the Board of Commissioners of Public Utilities (the Board) determined that Newfoundland and Labrador Hydro's (Hydro) target return on equity should be subject to an adjustment process in the years between General Rate Applications (GRAs) so that it continues to be the same as Newfoundland Power's return on equity. As such, it directed Hydro to file a proposal in relation to an adjustment mechanism for its target return on equity.

This report provides an overview of the calculation of the adjustment to return on equity, the allocation of the adjustment to various customers, the required adjustment to customer rates to reflect the change in revenue requirement, and any process related matters to implement the rate adjustment.

2.0 Flow-through of Adjustment to Return on Equity

2.1 Adjustment to Return on Equity and Weighted Average Cost of Capital

Upon the delivery of an order to change Newfoundland Power's rate of return on equity, Hydro would be required to update its return on equity to be equal to that of Newfoundland Power. This change would, in turn, cause a change in Hydro's weighted average cost of capital and return on rate base. For illustrative purposes, Hydro's 2015 Test Year weighted average cost of capital (WACC) for rate setting would reduce from 6.61% to 6.56% if the approved Test Year return on equity was revised from 8.50% to 8.25%.

Appendix A to this report provides the calculation showing the impact on WACC and return on rate base of 25 basis point reduction in the Test Year return on equity based on the illustrative change in return on equity noted above.

2.2 Adjustment to Revenue Requirement for Rate Setting

To reflect a revised return on rate base in customer rates and ensure that Hydro's rates reflect the same return on equity as Newfoundland Power would require Hydro to calculate a revised

Test Year revenue requirement for rate setting. Using the illustrative change in return on equity noted in section 2.1, a reduction of 5 basis points in return on rate base would reduce Hydro's revenue requirement to be recovered through customer rates by $964,000, or approximately 0.17% of the approved 2015 Test Year revenue requirement from customer rates.

The calculation of the revised Test Year revenue requirement was derived by updating the Test Year rate of return on rate base (as provided in Appendix A) in the calculation of the revised Test Year return on rate base. Finance schedules showing the derivation of the revised 2015 Test Year revenue requirement for rate setting reflecting the illustrative change from 8.50% return on equity to 8.25% return on equity is provided in Appendix B.

3.0 Allocation of Revised Revenue Requirement

In order to allocate the return on equity adjustment amongst customer groups, Hydro would be required to revise its approved Test Year cost of service for rate setting to reflect the revised Test Year return on rate base. Doing so would provide revised Test Year revenue requirements by class consistent with the approved cost of service methodology for the most recently approved Test Year. As Hydro would be revising the approved Test Year cost of service study, Hydro would submit a revised Test Year cost of service study for Board approval reflecting the revised return on equity approved for Newfoundland Power.

Table 1 provides the impact of 25 basis point return on equity decrease on 2015 Test Year revenue requirement by rate class.

Table 1

Allocation of Revised Revenue Requirement

Customer Group	Approved 2015 Test Year Revenue Requirement ($000)	Revised 2015 Test Year Revenue Requirement ($000)	Change ($000)	Change (%)
Newfoundland Power – Incl. Rural Deficit	443,366	442,515	(851)	(0.19)
Island Industrial	34,829	34,776	(53)	(0.15)
Labrador Industrial	5,218	5,210	(8)	(0.15)
CFB Goose Bay Secondary	932	932	0	0.00
Hydro Rural Labrador Int. – Incl. Rural Deficit	20,169	20,117	(52)	(0.26)
Rural Revenues from Deficit Areas	60,851	60,851	0	0.00
Total	**565,365**	**564,401**	**(964)**	**(0.17)**

Table 1 allocates the reduced Rural Deficit of $203,000 resulting from the reduction in the Test Year return on rate base to Newfoundland Power and the Hydro Rural Labrador Interconnected customers.

4.0 Revisions to Customer Rates

Hydro would follow the Board's most recently approved rate design approach in computing proposed rates to recover the revised Test Year revenue requirement.

For Newfoundland Power, the second block energy rate is currently set based on the Test Year price of Holyrood fuel and the demand charge is negotiated. Therefore, Hydro would propose that changes to the Test Year revenue requirement allocated to Newfoundland Power would be applied through a change in the first block rate.

The Island Industrial Customers' rates for demand, energy, and specifically assigned charges currently are an output from the approved Test Year cost of service study. Hydro proposes to use this same approach, using the Revised Test Year cost of service study, for Island Industrial

Customer rate design. For Hydro Rural Labrador Interconnected and Labrador Industrial Transmissions customers, Hydro proposes to adjust customer rates by applying the percentage change in Test Year revenue requirement for each class of service.

Hydro Rural rates would be required to change when Newfoundland Power's return changes to ensure its customers receive the same rates as Newfoundland Power regardless of whether Hydro changed its return on equity, so there would be no change in existing process for these customers.

With an automatic update to Hydro's Test Year revenue requirement due to a change in the return on equity from Newfoundland Power, the process for implementation of compliance rates reflecting a Newfoundland Power GRA would be required to change. The compliance application for Newfoundland Power would also need to reflect the revised supply cost from Hydro as a result of any required change in the approved return on equity for Hydro. Therefore, Hydro's compliance application in response to the establishment of a revised return on equity would need to be filed prior to Newfoundland Power filing its application to establish customer rates.

5.0 Revisions to Excess Earnings Account Definition

As Hydro's rate of return on rate base would be impacted by a change of return on equity, Hydro would be required to revise its Excess Earnings Account definition to reflect the revised rate of return on rate base.

6.0 Implementation Process

Hydro proposes that it would file an automatic adjustment application with the Board within 10 business days following the publication of a Board Order approving Newfoundland Power's return on equity. Hydro's application would include the following:

- Revised Test Year weighted average cost of capital and rate of return on rate base to reflect return on equity equal to that approved for Newfoundland Power;

- Finance schedules providing revised requirement from customer rates;
- Revised test year cost of service study identifying change in revenue requirement by customer class;
- Derivation of revised customer rates;
- Revised Excess Earnings Account Definition; and
- Proposed revised schedule of rates, toll and charges.

7.0 Conclusion

Board Order No. P.U. 49(2016) directed Hydro to file a proposal in relation to an adjustment mechanism for its target return on equity to reflect any future changes to Newfoundland Power's approved target return on equity for rate setting.[1] Hydro submits that the proposal outlined in this document addresses the Board's order and provides a reasonable approach by which Hydro can ensure its Test Year return on equity reflected in customer rates remains the same as that of Newfoundland Power.

[1] Page 24 of Order No. P.U. 49(2016).

Sample Calculation of Revised Weighted Average Cost of Capital

Regulated Average Capital Structure	**Test Year (%)**
Debt	74.2
Asset retirement obligation	0.6
Employee future benefits	3.9
Equity	21.2
Total	**100.0**

Weighted Average Cost of Capital[1]	**Test Year (%)**	**Revised (%)**
Embedded cost of debt	6.47	6.47
Asset retirement obligation	0.00	0.00
Employee future benefits	0.00	0.00
Equity	8.50	8.25
Weighted Average Cost of Capital	**6.61**	**6.56**

[1] Hydro's rate of return on rate base is equal to its approved weighted average cost of capital.

Sample Finance Schedules
Newfoundland and Labrador Hydro
Financial Results and Forecasts
Statement of Income and Retained Earnings
($000s)

		Rate Setting Test Year	Automatic ROE Adjustment (Year)	Revised Rate Setting Test Year
1	**Revenue**			
2	Energy sales	564,002	(964)	563,038
3	Revenue deficiency	-	-	-
4	Other revenue	2,508	-	2,508
5	**Total revenue**	566,510	(964)	565,546
6				
7	**Expenses**			
8	Operating expenses	131,350	-	131,350
9	Other Income and expense	4,074	-	4,074
10	Fuels	187,464	-	187,464
11	Power purchases	62,827	-	62,827
12	Amortization	63,230	-	63,230
13	Accretion of asset retirement obligation	748	-	748
14	Interest	89,453	-	89,453
15	**Total expenses**	539,145	-	539,145
16				
17	**Net income**	27,364	(964)	26,400
18				
19	**Retained earnings**			
20	Balance at beginning of year	259,556	-	259,556
21	Opening adjustment - retained earnings	-	-	-
22	Dividends	-	-	-
23	**Balance at end of year**	286,920	(964)	285,956

Sample Finance Schedules
Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate of Return on Rate Base
($000s)

		Rate Setting Test Year	Automatic ROE Adjustment (Year)	Revised Rate Setting Test Year
1	**Property, plant, and equipment**	1,882,883	-	1,882,883
2	add: accumulated depreciation	204,001	-	204,001
3	add: contributions in aid of construction	17,936	-	17,936
5	less: work in progress	(240,977)	-	(240,977)
6	**Capital assets in service**	1,863,843	-	1,863,843
7	less: asset retirement obligation	(12,169)	-	(12,169)
8	less: contributions in aid of construction	(17,936)	-	(17,936)
9	less: accumulated depreciation	(203,834)	-	(203,834)
10	**Capital assets - current year**	1,629,904	-	1,629,904
11	**Capital assets - previous year**	1,610,437	-	1,610,437
12	Unadjusted capital assets - average	1,620,170	-	1,620,170
13	less: Average net assets not in use	(7,318)	-	(7,318)
14	**Capital assets - average**	1,612,852	-	1,612,852
15				
16	Cash working capital allowance	7,037	-	7,037
17	Fuel	47,398	-	47,398
18	Materials and supplies	27,402	-	27,402
19	Deferred charges	95,132	-	95,132
20	less: Deferred Charges not in use	(4,467)	-	(4,467)
21				-
22	**Average rate base**	1,785,353	-	1,785,353
23				
24	Unadjusted return on regulated equity	27,364	(964)	26,400
25	add: Cost of service exclusions	1,177	-	1,177
26	Interest	89,453	-	89,453
27	**Return on rate base**	117,994	(964)	117,030
28				
29	**Rate of return on rate base**	6.61%	-0.05%	6.56%

Sample Finance Schedules
Newfoundland and Labrador Hydro
Financial Results and Forecasts
Capital Structure
($000s)

		Rate Setting Test Year	Automatic ROE Adjustment (Year)	Revised Rate Setting Test Year
1	**Regulated capital structure**			
2	Long-term debt	1,649,544	-	1,649,544
3	Promissory notes	-	-	-
4	Promissory notes - related party	-	-	-
5	less: sinking funds	(238,850)	-	(238,850)
6	add: mark to market of sinking funds	31,071	-	31,071
7		1,441,765	-	1,441,765
8	Cost of service exclusions	-		-
9	Non-regulated debt pool	(8,187)	-	(8,187)
10	Net regulated debt	1,433,578	-	1,433,578
11	Asset retirement obligation	20,740	-	20,740
12	less: unfunded asset retirement obligation	(8,493)	-	(8,493)
13	Employee future benefits	72,454	-	72,454
14	Contributed capital	100,000	-	100,000
15	Retained earnings cost of service exclusions	2,154	-	2,154
16	Retained earnings	286,920	(964)	285,956
17	**Total**	1,907,353	(964)	1,906,389
18				
19	**Regulated capital structure (%)**			
20	Debt	75.2%	-	75.2%
21	Asset retirement obligation	0.6%	-	0.6%
22	Employee future benefits	3.8%	-	3.8%
23	Equity	20.4%	-	20.4%
24	**Total**	100.0%	-	100.0%
25				
26	**Regulated average capital structure (%)**			
27	Debt	74.2%	-	74.2%
28	Asset retirement obligation	0.6%	-	0.6%
29	Employee future benefits	3.9%	-	3.9%
30	Equity	21.2%	-	21.2%
31	**Total**	100.0%	-	100.0%
32				
33	**Weighted average cost of capital (WACC)**			
34	Embedded cost of debt	6.47%	-	6.47%
35	Asset retirement obligation	0.00%	-	0.00%
36	Employee future benefits	0.00%	-	0.00%
37	Equity	8.50%	-0.25%	8.25%
38	**WACC**	6.61%		6.56%

Exhibit 13 - Cost of Service Expert Evidence

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

Testimony of Bruce R. Chapman

regarding

Cost-of-Service Methodology Issues

to be reviewed in

Newfoundland and Labrador Hydro's
2017 General Rate Application

prepared by

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, WI 53705-2299
Voice 608.231.2266 Fax 608.231.2108

July 5, 2017

Table of Contents

EXECUTIVE SUMMARY I

1. INTRODUCTION 1

2. BACKGROUND OF WITNESS 3

3. ISSUE #1. ALLOCATION OF O&M EXPENSES RELATED TO DEDICATED TRANMISSION ASSETS 4

4. ISSUE #2. CBPP FREQUENCY CONVERTER COST ASSIGNMENT 12

5. ISSUE #3. CBPP PILOT PROJECT 16

6. ISSUE #4. ALLOCATION OF THE RURAL DEFICIT 21

7. ISSUE #5. CLASSIFICATION OF PURCHASES OF WIND GENERATION 26

APPENDIX 1: SUMMARY OF RECOMMENDATIONS 32

EXHIBIT BRC 1. RESUME OF BRUCE R. CHAPMAN 34

EXHIBIT BRC 2. MEMORANDUM RE O&M COSTS FOR SPECIFICALLY ASSIGNED ASSETS 35

Testimony of Bruce R. Chapman

regarding

Cost-of-Service Methodology Issues

to be reviewed in

Newfoundland and Labrador Hydro's
2017 General Rate Application

prepared by

CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC

July 5, 2017

EXECUTIVE SUMMARY

This testimony, prepared by Mr. Bruce Chapman of Christensen Associates Energy Consulting, LLC, of Madison, WI, USA, reviews five costing methodology issues that Newfoundland and Labrador Hydro wish to submit for review in this General Rate Application. These issues are:

- The method to determine the operating and maintenance (O&M) costs related to specifically assigned assets.
- The specific assignment of the frequency converter costs to Corner Brook Pulp and Paper (CBPP).
- The CBPP pilot project that permits flexible operation of site generation through waiver of peak demand limitations.
- The allocation of the Rural Deficit.
- The classification of purchase costs of wind generation.

This review does not address issues related to the transition to interconnection with eastern North America. Such issues will be addressed in a separate proceeding expected to occur in the Fall of 2018.

Issue #1. O&M Costs Related to Dedicated Transmission Assets

Issue. Hydro has reviewed the Industrial customers' concern about O&M costing methods associated with dedicated transmission assets. Original cost appears to have several counterintuitive features. Using a measure based on current cost appears to be computationally feasible, although more challenging than the current method, and to yield superior results.

Recommendations.

- We recommend that Hydro continue to directly assign O&M costs to specifically assigned assets in determining specifically assign charges for Industrial customers.
- To determine the allocation of O&M to specifically assigned assets, we recommend that Hydro determine test-year transmission asset values via Handy-Whitman indexes (the current-year approach) to alleviate the current problem of inadvertently allocating higher O&M costs to newer assets and lower O&M costs to older assets.
- We also recommend that Hydro's previous proposal that A&G expenses be directly assigned in the same proportion as O&M expenses be approved in conjunction with the above recommendations.

Issue #2. CBPP Frequency Converter Cost Assignment

Issue. Hydro and CBPP differ as to the benefits that the frequency converter conveys on the Hydro system. Hydro believes that benefits are almost entirely confined to the customer site and that the costs related to the frequency converter should be assigned directly to the customer.

Recommendation.

- We recommend that the frequency converter unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service to the system that is provided from time to time.

Issue #3. CBPP Pilot Project

Issue. Hydro is proposing to terminate the project, which allows CBPP to avoid having to engage in load following with its own generation to minimize peak demand.

Recommendations.

- We recommend that Hydro not offer to renew the pilot project in the 2017 GRA given the anticipated reduction in the value of energy services that CBPP is likely to be able to provide to the system following completion of the LIL and, subsequently, Muskrat Falls.

- We also recommend that Hydro broach with CBPP the idea of two-part pricing, specifically real-time pricing, as a replacement for its current pilot project and associated Capacity Assistance agreements.

Issue #4. Rural Deficit

Issue. In its 2013 GRA, Hydro proposed a revised rural deficit allocation method based on revenue requirements and the Board approved that method. However, in the 2013 GRA Order, the Board stated it expects that Hydro will address the rural deficit allocation methodology in its cost of service report and all parties will have further opportunity to provide input as part of the review of that report.[1]

Recommendation.

- We recommend that Hydro continue to utilize the rural deficit allocation method based on revenue requirements. The criterion of equalizing revenue-to-cost ratios across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

Issue #5. Classification of Wind Generation

Issue. Hydro views the wind generation that it purchases as lacking capacity value for planning purposes. Hydro proposed, in its Amended 2013 GRA submission, to classify all wind purchases costs as 100% energy-related. Industry practice often confers some capacity value on wind in cost allocation. A combination of wind capacity factors and utility generation classification methods leads to demand classification of about 9 to 20%.

[1] See Order No. P.U. 49(2016), page 105, lines 20-22.

Recommendation.

- We recommend that Hydro's planning perspective for classification of purchases of wind generation be accepted by the Board. An energy-only classification approach is plausible and defensible based on Hydro's planning perspective regarding wind generation. If Hydro's planners had concluded that wind had a capacity role for planning purposes, then classification methods and results in other jurisdictions would have had weight in considering classification shares.

1. INTRODUCTION

The Order of the Newfoundland and Labrador Board of Public Utilities (Board or PUB) closing Newfoundland and Labrador Hydro's (Hydro's) General Rate Application (GRA) for test years 2014 and 2015 states that Hydro committed to review with interested parties several outstanding cost-of-service (COS) methodology issues. While most of these will be discussed in a proceeding for this purpose before completion of the Muskrat Falls (MF) Project (consisting of the generation project and its related transmission projects) some topics have been deemed worthy of review in this GRA. The Board's 2013 GRA Order specifically mentions "the generation credit agreement between Hydro and Corner Brook Pulp and Paper (CBPP), the methodology for assignment of specifically assigned assets and the allocation of associated costs to those assets, and the approach to CDM cost allocation and recovery."[2] (Hydro is currently proposing to defer the CDM issue to a later proceeding. As a result, this testimony offers no arguments regarding the allocation of CDM costs.) In addition to the remaining issues, Hydro wishes to submit for PUB and intervenor consideration its views on three more issues: 1) assignment of the CBPP frequency converter's costs to the customer; 2) the cost allocation of the rural deficit; and 3) the classification of wind generation costs.

In 2015 Hydro requested that Christensen Associates Energy Consulting (CA Energy Consulting) conduct the aforementioned review of the utility's cost-of-service (COS)

[2] PUB Order No. P.U. 49(2016), P. 95.

methodology, focusing on the system that is likely to emerge following its transition to integration with the electricity grid of eastern North America. CA Energy Consulting submitted a report to Hydro dated March 31, 2016, covering the utility's anticipated methodology issues following the transition. The COS review process is expected to occur in the Fall of 2018. Hence the PUB's and Hydro's interest in review of pressing COS methodology issues not likely to be materially affected by the transition in this GRA. (In cases in which the transition might affect the issues currently under discussion, we provide mention of this consideration.)

Accordingly, this testimony draws upon our report and information prepared since its release to review and provide recommendations on five issues before the PUB for this GRA. These issues are:

- The method to determine the O&M costs related to specifically assigned assets.
- The specific assignment of the frequency converter costs to CBPP.
- The CBPP pilot project that permits flexible operation of site generation through waiver of peak demand limitations.
- The allocation of the Rural Deficit.
- The classification of purchase costs from wind generation.

The testimony reviews these issues after a brief description of witness Chapman's background. The testimony closes with a summary of the recommendations. Exhibits follow the testimony. Exhibit BRC 1 offers witness Chapman's resume. Exhibit BRC 2 provides a memorandum to Hydro prepared by CA Energy Consulting that documents North American

practices with respect to O&M cost allocation in cases of direct assignment of transmission assets.

2. BACKGROUND OF WITNESS

This testimony has been prepared by Mr. Bruce R. Chapman, a Vice President at Christensen Associates Energy Consulting, LLC. He has been employed by the firm in positions of increasing responsibility since 1986. Mr. Chapman focuses on utility costing and pricing assignments, including cost-of-service (COS) methodology reviews and COS studies, and rate design, both traditional and innovative. Related costing work includes reviews of distribution cost classification methods, loss factor development, load research analysis, among others. He has undertaken rate reviews of entire utility portfolios as well as designs of specific rates. Innovative rate design assignments include real-time pricing, critical-peak pricing, interruptible/curtailable rate design, fixed bill analysis, reviews of standby and distributed energy resource pricing structures, among others. Mr. Chapman regularly conducts training sessions in utility costing and pricing and has published articles in Electricity Journal and Natural Gas & Electricity. Mr. Chapman holds a Master's degree in Economics from the University of Wisconsin-Madison.

3. ISSUE #1. ALLOCATION OF O&M EXPENSES RELATED TO DEDICATED TRANMISSION ASSETS

Issue. Four Island Industrial Customers are assigned a number of specific charges because each of the customers is served by assets that are deemed to serve them alone.[3] The central issue, identified in the most recent GRA, pertains to the allocation of O&M costs. Currently O&M costs are allocated to these customers based on asset share, with asset value defined in terms of original cost. Periodic investment in new or upgraded facilities results in variation in shares over time across customers due to variations in age of plant.

In the 2013 GRA Order, the Board stated: "Hydro should address this issue more fully in its upcoming general rate application to be filed in 2017, providing supporting documentation on available alternatives and the impacts of each, and information on practices in other jurisdictions if applicable."[4]

Background. The issues surrounding specific cost assignment have grown as the size of the charges has increased. Specifically Assigned Charges to Island Industrial Customers for the 2007 Test Year were $0.7 million while those approved for the 2015 Test Year were $1.7 million, spread across four customers: CBPP, North Atlantic Refining, Ltd. (NARL), Teck Resources (Teck), and Vale Newfoundland and Labrador Limited (Vale).[5] O&M, depreciation

[3] Costs are also specifically assigned to Newfoundland Power for lines and terminal stations that connect them to the Hydro grid. Hydro's definition of specifically assigned plant is "that equipment and those facilities which are owned by Hydro and used to serve the customer only." NLH *2013 Amended General Rate Application*, Schedule A, Article 1.01(ee).

[4] Source: Order No. P.U. 49(2016), page 98, lines 30-33.

[5] Vale was connected in 2012 and does not currently pay a specifically assigned charge.

expense, and return on debt and equity are the bulk of the charges, in declining order, with O&M constituting somewhat more than half in aggregate. Customers who paid for their assigned assets through contributions in aid of construction (CIAC) pay for Test Year allocated O&M costs only.

The assets that generate the charges are solely transmission-related, consisting mostly of lines and terminal stations that connect the customers to the grid. The CBPP facility is different from the others in that the customer has some facilities that operate at 50 Hz instead of the 60 Hz common to the rest of the grid. Additionally, the customer has a small hydro plant that provides generation services to its site. Issues related to the frequency converter that transforms 50 Hz power into 60 Hz are discussed in the section covering issue #3.

Assignment of a share of O&M expenses to the Island Industrial class and to its customers requires use of a sharing mechanism applied to total O&M. The basis for identifying O&M costs assigned to the customer group is the group's share of transmission plant in service, with plant valued at original cost. Similarly, allocation of O&M assigned to these four customers is based on their shares of transmission assets, again valued at original cost.[6]

Analysis. Some United States (U.S.) jurisdictions deem virtually all transmission assets, including connections to large customers, as common property, to be allocated by the utility's transmission cost allocation rule. These utilities tend to be large, with the result that

[6] Hydro also specifically assigns some costs to Newfoundland Power, but these costs are not separately identified in a specifically assigned charge. These costs are not a subject of discussion in this proceeding.

no single customer is a significant share of total sales and no assets that might be directly assigned are a significant share of the total. For example, Georgia Power Company has many large customers, but the utility does not engage in direct assignment of transmission costs because the system as a whole has a capacity of over 17,000 MW. Smaller utilities that serve one or more customers whose loads are an appreciable share of total sales are more likely than other utilities to engage in direct assignment of transmission costs in cases in which the transmission assets serve the individual customer only.

This perspective is borne out by research that CA Energy Consulting conducted early this year. The resulting memorandum appears as Exhibit BRC 2 to this testimony. That memorandum reviewed Canadian and U.S. treatment of O&M related to dedicated transmission assets. The investigation found that direct assignment is relatively more common in Canada than in the U.S. We found five Canadian utilities that directly assign transmission assets serving individual customers to those customers. We found four U.S. investor-owned utilities, one federally-owned utility (Bonneville Power) and three municipal/public power district utilities who engage in direct assignment. While the inquiry was not systematic, it was clear from telephone interviews that the practice is not widespread in the U.S.

The utilities engaging in direct assignment do not appear to have a single dominant approach to the treatment of O&M related to these dedicated transmission facilities. Large Canadian and U.S. utilities often bundle these costs with other transmission costs and allocate such common costs using the utility's transmission cost allocator. For example, Xcel

Energy in Minnesota simply allocates all its transmission-related O&M costs on the basis of the CP allocator that it uses for transmission expenses generally. This approach is arguably less precise in allocating O&M costs to direct assignment customers but likely avoids swings in O&M charges to those customers in response to equipment upgrades.

Other large utilities develop a means of sharing directly assigned costs across direct assignment customers, with sharing usually based on original asset cost. Smaller U.S. firms directly assigned either actual or estimated costs of each facility to the customer that the facility serves.

Hydro may fit the pattern of utilities that directly assign assets by having significant assignable transmission assets, although it is clearly not similar to the small U.S. public power districts. The Industrial customers with directly assigned transmission assets consume about 9% of Island sales at present and were assigned about 11% of transmission assets in 2015.[7]

During Hydro's 2013 GRA, one customer, (Vale) responsible for roughly $500,000 of directly assigned costs for the 2015 Test Year, proposed an improvement to the determination of O&M charges for specifically assigned assets. Their expert, Mr. Melvin Dean, advocated and set out the steps for development of allocation based on current cost.[8] This technique

[7] Based on 2013 Amended GRA COS Study. Sales share: Schedule 1.3.2, column 3, page 1 of 3, (Exhibit 13, p. 17 of 109) Asset share: Schedule 2.2A, line 22 (Exhibit 13, p. 26 of 109.)

[8] Melvin Dean, *Expert's Report on Newfoundland and Labrador Hydro's Amended General Rate Application*, June 4, 2015, p. 3*ff*.

makes use of Handy-Whitman indexes, which are available for sufficiently detailed segments of the electric utility industry to produce reliable cost indexation over many years.

Hydro investigated Vale's proposed approach and found it to be feasible.[9] The utility also found that the outcome of its calculations confirmed Mr. Dean's belief: the relatively newer transmission assets directly assigned to customers, when compared with other transmission assets, produced a reduced O&M cost allocation for the direct assignment customers.[10]

This approach has a parallel in distribution cost classification. Minimum system studies classify the minimum system needed by a utility as customer-related and the remainder as demand-related. Such computations resort to conversion of assets to test-year (*i.e.* current-year) value to avoid biased outcomes.[11] Thus, it seems reasonable to consider test year dollar valuation in transmission as a reasonable approach.

Critics might object that even test-year dollar valuation may not capture the full impact of age. Two identical transmission lines, one built in 2015 and another built in 2005 might have the same 2015-dollar value, but the ten-year-old line would likely be associated with higher O&M costs. Attaining this degree of accuracy in an index would require knowledge of the relationship of O&M cost to vintage, which would be very challenging.

[9] See V-NLH-083, rev. 1, for a description of the method.

[10] NLH, *2013 General Rate Application, Closing Submissions*, Dec. 23, 2015, p. 76.

[11] The bias can arise if old assets purchased at low prices are combined with newer assets purchased at prices that have risen due to inflation.

An alternative might be to track actual expenses associated with each customer's dedicated transmission assets and bill the customer directly, while in addition charging them for their share of remaining transmission-related expenses on the basis of the standard transmission allocator. Under this system, a customer who is directly assigned high asset costs for new or upgraded transmission assets would also have the lower expenses associated with new equipment. Directly assigned O&M costs under this system would be removed from the COS, although customers would continue to be allocated their share of common transmission-related O&M costs. The outcome of this approach is fairly allocated cost for the share of the transmission system common to all customers plus charges for actual repair costs. Since this system is applied, at least by a few small U.S. utilities, it has a regulatory precedent. In Canada, BC Hydro uses actual cost assignment to a limited degree, but only for costs that exceed its definition of normal expenditures.

Hydro has reviewed this approach. Unfortunately, the review concluded that it is not currently feasible, since current and past accounting processes do not supply sufficient detail to identify each individual O&M expense with a specific customer. Without this information, Hydro cannot develop forecasts for each customer of the amount of O&M to be deducted from transmission O&M costs in its COS study. This raises the possibility of double-counting of expenses, or at least some degree of error between actual and forecasted cost. Thus, the utility would need to change its accounting processes and accumulate customer-specific information for some time to implement this otherwise attractive approach.

Treating these O&M costs as common offers a fallback approach found acceptable in some jurisdictions. This approach would shield individual customers against large, unexpected repair costs by "socializing" the costs across the utility. However, this approach, while administratively practicable, is not preferred due to its failure to recognize differences in asset vintage among customers, and between direct assignment customers and other customer groups.

Direct assignment also affects the treatment of administrative and general expenses at Hydro in that the allocation of the various categories of A&G expenses is typically prorated based on shares of underlying assets. Specifically assigned transmission-related A&G thus depends on gross transmission plant assets. Hydro proposed in their 2013 GRA submission to modify A&G allocation to match proportionally the modification in direct assignment of O&M expenses. This methodology is applied to all categories of A&G expenses, with a proposed saving to direct assignment customers outside the direct impact of the change in O&M methodology. This appears to be a consistent extension of that methodology.

If Hydro were to charge for actual O&M expenses, there is a question as to the treatment of A&G expenses. The customers with specifically assigned assets would still be allocated a share of A&G costs based on the allocation of common transmission costs. The issue would then be whether additional charges should be due based on actual O&M expenses which are separately billed. If 5% of all transmission O&M costs were related to specifically assigned facilities, for example, one would expect the charge to reflect not merely direct labor and materials costs but additional elements to cover A&G. Hydro would then use

company accounting data to develop such a rate so that the share of A&G in total transmission maintenance cost would carry over into charges for specifically assigned asset maintenance costs.

Recommendations. We recommend that Hydro continue to directly assign O&M costs to specifically assigned assets in determining specifically assign charges for Industrial customers.

The current method of allocation of O&M expenses is correctly viewed by customers and Hydro as problematic, since direct assignment on the basis of original cost appears to be poorly correlated with actual expense patterns over time. There appears to be a feasible improvement, based on determination of test-year transmission asset value via Handy-Whitman indexes.[12]

We recommend that Hydro determine test-year transmission asset values via Handy-Whitman indexes (the current-year approach) to alleviate the current problem of inadvertently allocating higher O&M costs to newer assets and lower O&M costs to older assets.

We also recommend that Hydro's previous proposal that A&G expenses be directly assigned in the same proportion as O&M expenses be approved in conjunction with the above recommendations.

[12] Hydro understands that both the IC Group and Vale support this move to the current dollar approach. Reference letter of March 24, 2017 to Ms. Tracey Pennel of Hydro from Mr. Dean Porter of Poole Althouse.

4. ISSUE #2. CBPP FREQUENCY CONVERTER COST ASSIGNMENT

Issue. CBPP's paper mill load is served partly through a frequency converter through the conversion of some of its 50 Hz generation to 60 Hz. The customer faces a number of cost allocation and pricing issues arising from the presence of the converter. As a specifically assigned asset, capital expenditure on the frequency converter induces increases in O&M and other costs allocated to the customer through a specifically assigned charge which is updated each GRA. Underlying the issue of the cost allocation mechanism for specifically assigned charges is a question raised by the customer as to whether the unit should in fact be treated as common rather than directly assigned.

Background. The CBPP Mill is the last remaining facility on the Island with load served at the 50 Hz frequency. The customer owns and operates hydro plants with a combined installed capacity of approximately 135 MW. The hydro plants generate electricity at both 50 and 60 Hz and the mill site uses energy at both frequencies. Some of the 50 Hz generation produced at the customer's hydro facilities is converted to 60 Hz[13] at the Hydro frequency converter to serve its mill load.

Originally, the frequency converter provided services not just to the host customer but to the system as a whole. However, the expansion of the Island interconnected System reduced its contribution to the provision of voltage control for the local mill system, and for

[13] Approximately 18 MW.

conversion of 50 Hz power to 60 Hz for use on site. This change in function over time was the basis for the conversion to specific assignment of the assets in 2001.[14]

The frequency converter is relatively old, having been placed in service in 1967. It is owned and maintained by Hydro. Hydro has undertaken significant investment since Hydro's 2007 GRA. Direct assignment of these costs to CBPP has significantly increased their specifically assigned charge, which was approved as approximately $871,000 in the 2015 Test Year. The approved 2015 Test Year specifically assigned charge was an increase of $524,000 relative to the approved 2007 Test Year specifically assigned charge of $347,000.

Hydro maintained, in the 2013 GRA, that the "Corner Brook Frequency Converter remains of primary benefit to Corner Brook Pulp and Paper Limited."[15] Capital expenditures at the frequency converter are subject to the standard Public Utility Board Capital Budget Application process, and customers (including CBPP) are given an opportunity to review and question the Capital Budget Application on a project-by-project basis.[16] Thus, there appear to be questions of interpretation about the role of the frequency converter and associated cost responsibility that interact with the overall issue of specifically assigned charges.

Discussion/Analysis. Regarding the issue of how to treat the frequency converter, there are a variety of views in discussion in the 2013 GRA. Some supported the current arrangement. Mr. Patrick Bowman, representing industrial customers, argued for adjusted treatment of

[14] See 2001 General Rate Application, IC-NLH-32 Revised.

[15] See IC-NLH-186.

[16] See IC-NLH-100 Rev 1.

the CBPP frequency converter unit on four grounds.[17] First, he believed that the technical limit of 18 MW ought to result in a reduction in the value of the rate base that should be allocated to the customer. Second, he joined others in arguing about improper O&M cost allocation due to the vintage issue.[18] He indicated that all increases in O&M responsibility since 2007 should be eliminated. Third, he questions the core issue of whether the unit delivers benefits to the Hydro system, claiming that the frequency converter unit permits improvements in system stability and the occasional delivery of energy during emergency situations. Mr. Bowman indicated that if benefits are conferred upon the system, then some costs should be allocated in common. Fourth, he stated that the technical constraint on the frequency converter unit forces peak consumption of CBPP (and thus industrial customers as a class) upward by about 4.5 MW. More generally, Mr. Bowman objected to the imposition of expenses to maintain the frequency converter, arguing that these have not improved its operation as was expected.

For the longer term, Mr. Bowman wanted to explore changes in ownership of the unit, presumably to alleviate its cost burden. By reducing the asset share of the customer and revising the O&M allocation methodology, Mr. Bowman believes that CBPP and industrial customer cost assignment should be significantly reduced.

[17] See Bowman and Najmidinov, op. cit., p. 59*ff*.

[18] In fact, in oral testimony, Mr. Bowman suggests that the direct assignment of O&M charges to specific customers might occur very rarely in the industry, and that a cursory investigation failed to turn up an example. Transcript of Hydro GRA, Sept. 5, 2015, p. 145.

The unique 50 Hz situation and the ongoing requirement to convert 50 Hz generation to 60 Hz to supply mill load, suggests that the unit's purpose is predominantly, if not exclusively, to serve CBPP. This suggests that the unit fulfills the basic criterion of direct assignment: facilities that provide service exclusively to a particular customer (or customers).[19] This view is in line with that formed by the Board in its final ruling in the 2001 GRA, which supported the conversion to direct assignment. CBPP is compensated for its services in providing emergency capacity support to the grid under the Capacity Assistance Arrangements.

Regarding cost control, one can understand CBPP's concern for cost effective repairs to an aging unit. From Hydro's perspective, ownership imposes the obligation to maintain the unit, and decisions on the scale and cost of the expenditures reside first with the utility. Modifications in the method by which O&M costs are allocated to specific assignment customers may offer some degree of relief to CBPP. However, $543 thousand of annual costs associated with depreciation and return are unavoidable without further action.[20]

Two other issues raised by Mr. Bowman, and mentioned above, pertain to the technical limit of 18 MW on the operation of the frequency converter. CBPP views the limit as having been imposed upon it by Hydro. However, a study by General Electric for Bowater

[19] Reference NARUC's *Electric Utility Cost Allocation Manual*, p. 74. "For cost of service purposes, these [radial] facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them."

[20] Newfoundland and Labrador Hydro, *2013 General Rate Application, Order No. P.U. 14(2017) Compliance Application*, Schedule 3.3A, p. 40 of 109.

Newfoundland, Ltd. (CBPP's predecessor) recommended the 18 MW limit.[21] This review offers no opinion on this technical topic. It has COS implications through the 4.5 MW impact on peak demand. Since the customer is the source of this limit, it appears that the customer would need to make a technical argument for its adjustment.

Recommendations. We recommend that the frequency converter unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service that is provided from time to time. We cannot pass an opinion on the technical issues surrounding benefit limitations pertaining to the 18 MW technical limit on capacity or on the question of cost effectiveness of repairs.

5. ISSUE #3. CBPP PILOT PROJECT

Issues. A pilot project initiated in 2009 assists CBPP by providing relief from the need to use its hydro facilities to follow plant load for the purpose of minimizing peak demand at the site. This pilot project has been periodically reviewed for its ability to deliver benefits to the system via delivery of energy to reduce fuel costs at Holyrood. At issue is whether the pilot project should be extended or terminated, with perhaps an alternative contractual arrangement being put in its place. This review is timely because the benefits to all customers arising from the fuel cost savings that were the basis of the original contract are not expected to continue upon completion of the MF project.

[21] See IC-NLH 194, Rev. 1.

Background. Since 2009, CBPP has been operating under a piloted Generation Credit service contract that permits CBPP to optimize the efficiency of its 60 Hz Deer Lake Power generation. The agreement allows Hydro to call on CBPP to maximize its 60 Hz generation (including the frequency converter) prior to increasing generation at Holyrood for system reasons and prior to starting its standby units (*i.e.*, a "capacity request"). However, capacity is only made available to the grid in this manner if mill loads are reduced and CBPP is able to generate in excess of what it requires for its own use. Otherwise, if the mill is using its maximum power requirements, no excess generation is made available to the grid under this provision[22]. Savings are provided to CBPP for providing this additional capacity to the system by permitting CBPP to exceed its firm power requirements and to avoid costs associated with thermal or standby energy rates.[23,24]

Prior to the winter of 2014/2015, Hydro entered into Capacity Assistance and Supplementary Capacity Assistance agreements with CBPP[25]. Under these arrangements and on rare occasions the facility provides emergency capacity to the grid.[26] This is achieved through load interruption of up to 90 MW at the Corner Brook mill when system generation

[S] See RFI IC-NLH-186.

[23] Reference NLH 2015 Amended Exhibit 4, Section 3.3.1 pg.'s 12-13 and Table 8 pg. 21.

[24] See IC-NLH-059 Rev 1.

[25] See IC-NLH-186.

[26] Bowman and Najmidinov, Updated Pre-Filed Testimony, NLH 2013 Amended General Rate Application, June 4, 2015, p. 58.

reserves are low[27]. Hydro compensates CBPP for services under these arrangements through fixed winter credits and usage payments.[28]

Discussion/Analysis. The pilot project and capacity assistance provisions have allowed CBPP to separate the electricity consumption decision from the generation decision, at least in part. However, it now appears that there will be reduced benefits to Hydro from the provision of emergency capacity assistance, relative to past system conditions.[29] If the current pricing system could be replaced with short-notice pricing that reflects Hydro system conditions, then perhaps CBPP would be able to optimize its generation and consumption to yield more benefits than are possible under the current arrangement.

From the perspective of Hydro's costs, the utility must recover from CBPP its generation, common transmission, and specifically assigned transmission costs (along with any other

[27] Net to the system is approximately 80 MW as this level of load interruption at the mill would effectively shut down production from the CBPP cogeneration unit. There are two contractual arrangements for providing capacity: one for Capacity Assistance (up to 60 MW) and another for Supplemental Capacity Assistance (up to an additional 30 MW). There are fixed fees for the Capacity Assistance arrangements only.

[28] While the current application focuses on the Test Year only, in this case, it may be worth considering future years to avoid taking a position on the issue that might need to be changed in the near future. After the commissioning of the Muskrat Falls Project, Hydro may find that the opportunities for the frequency converter to be used for system support such as capacity assistance may be reduced, since the Hydro system will be long in generation with the arrival of Muskrat Falls power. Should an outage occur on the LIL, Hydro feels that under certain circumstances such as temporary unavailability of sufficient 10-minute reserves, the capacity assistance may be a consideration. The amount of extra capacity required would be uncertain. If the Capacity Assistance Arrangements were in place, it would provide a platform for payment to CBPP. Considering that there are only transmission constraint issues, CBPP's value of services provided may drop from its current level, which may be reflected in any future contract payments.

In the interim, before Muskrat Falls completion but upon completion of the LIL, power from Labrador, specifically recall energy from Churchill Falls, may be available, reducing the value of power supplied by CBPP under the Capacity Assistance and Supplementary Capacity Assistance agreements.

[29] However, the Deer Lake hydraulic capacity likely would be optimized if it were run in harmony with the net supply situation in Hydro's Island grid.

costs that the COS process might allocate to Industrial class customers). An alternative approach to the current Industrial rate combined with the pilot project contractual arrangement would be a "two-part pricing" contract. Such contracts are found in deregulated and regulated markets. The utility and customer agree upon a contractual amount of usage and peak demand that serves as the basis for pricing under a standard tariff. The contract quantity (the "customer baseline load" or CBL) is fixed, and the resulting "base bill" is thus a lump sum dollar amount that changes only with changes in the underlying rate.[30] The contract amounts represent the customer's "normal" level of usage and can vary with the time of the year or time of day. Usage levels that depart from the CBL are priced according to hourly, day-ahead prices that reflect marginal energy and marginal reserves costs.[31] This dynamic pricing arrangement, known as real-time pricing (RTP) is a well-established retail pricing product.

For Hydro and CBPP, use of RTP would require agreement on a pattern of hourly (net) consumption of Hydro energy and monthly peak demands that would serve as the basis for embedded cost responsibility under the Industrial rate. CBPP could have a CBL based on its current Power on Order, multiplied by historical load factor (but backing out capacity assistance and interruptible load relief from the load profile). When priced at embedded cost, the base bill will cover revenue requirements. (The CBL would continue to treat peak

[30] Under regulation, such changes include changes in the fuel cost recovery rate.

[31] These marginal costs are simply the cost of providing an extra kWh of generation services and reflect whatever resources are available. Naturally the pattern and level of marginal costs will change as Hydro interconnects with the North American grid and then adds the Muskrat Falls unit to the set of available resources.

demand in the same manner as the pilot agreement by billing on contract rather than actual demand, and eliminating the need for CBPP to use generation to follow load.)

An additional requirement would be the ability of Hydro to generate day-ahead hourly RTP retail prices (which are just marginal cost and a small mark-up in other jurisdictions). CBPP would then receive daily price vectors that it could use to plan its operations of its mill and hydro facility.

This suggestion is preliminary in that it would require review of any technical limitations on Hydro's ability to deliver power independent of and additional to system conditions indicated by the RTP price. (As an illustration, if marginal cost is low, the cost of incremental load above the CBL might be just $0.03/kWh; while at times of system constraint, the price might be $1.00/kWh, reflecting the high marginal cost of reserves.)

This pricing approach offers Hydro and CBPP several advantages. First, the base bill is stable and predictable, and set to collect required revenue at rates approved by the PUB. Second, RTP pricing allows Hydro to communicate system conditions to CBPP at short notice and permits CBPP to minimize its energy costs and optimize its hydro facility usage. Third, the contract is relatively simple, permitting elimination of various contractual forms of energy currently in use that each has its own terms, constraints, and pricing.[32] Fourth, it may help to avoid debate as to the value to Hydro of the CBPP generation, since CBPP would be paid market value for that generation. When RTP price is high, CBPP may decide to reduce mill

[32]This structure could include the sale of secondary energy, hitherto to Newfoundland Power, but perhaps transferred to NLH, with marginal cost-based settlement provisions with Newfoundland Power, if needed.

production and increase hydro generation, providing power to the grid for which Hydro will pay market price.[33]

Additionally, there is no reason why this structure cannot be applied to other Industrial customers. The embedded costs allocated by the COS study will yield unit costs that will support pricing of the CBL, while marginal cost will support pricing of incremental load.

Recommendations. We recommend that Hydro not offer to renew the pilot project in the 2017 GRA given the anticipated reduction in the value of energy services that CBPP is likely to be able to provide to the system following completion of the LIL and, subsequently, Muskrat Falls. We also recommend that Hydro broach with CBPP the idea of two-part pricing, specifically real-time pricing, as a replacement for its current pilot project and associated Capacity Assistance agreements.

6. ISSUE #4. ALLOCATION OF THE RURAL DEFICIT

Issue. Hydro charges its rural customers at rates that either equal to or partially reflective of the rates charged by Newfoundland Power, rates which fail to cover Hydro's cost of service in its rural areas, costs which tend to be particularly high in isolated locations. Hydro makes up the deficit with supplementary volumetric charges on Newfoundland Power and Rural Labrador Interconnected System (RLIS) customers. The methodology of deficit allocation

[33] This approach appears to fit well with the environment that will follow completion of the Muskrat Falls project. Increases in embedded costs will be incorporated in the base bill that applies to normal levels of consumption. Potentially low marginal costs when power is abundant will permit CBPP to contemplate increased mill production (or reduced hydraulic flow) and will facilitate power delivery by CBPP when system resources are limited.

was reviewed in the 2013 GRA and the Board approved the use of the revenue requirement method as proposed by Hydro. Page 102 of Order No. 49 (2016) states: "the Board expects that Hydro will address the rural deficit allocation methodology in its cost of service report and all parties will have a further opportunity to have input as part of the review of that report." This testimony reports on the review undertaken in the cost of service methodology review report.

Background. Subsidizing rural customers has been a feature of service in the Province since the early 1990s, and the practice of subsidizing small numbers of customers in remote locations is common in other provinces of Canada. The customers benefiting from the subsidy are found in four groups: Island rural interconnected (about 23,700 customers) Island isolated (about 800) Labrador isolated (about 2,700) and L'Anse au Loup (about 1,000) totaling about 28,300 customers.[34]

The cost burden of the rural deficit is allocated to Newfoundland Power and to Labrador Interconnected customers, Island industrial customers having been exempted from responsibility in 1999.[35] The Electric Power Control Act mandates that these two customer groups fund the subsidy, but does not prescribe how it is to be allocated.[36] Until the 2013 GRA Order, the allocation was based on an "equal unit cost" allocation mechanism

[34] As recorded in NLH's COS model, 2015.

[35] Order-in-Council 2003-347 also specifies that NP customers and Labrador rural interconnected customers are to fund the rural deficit. See NLH, *2013 General Rate Application, Final Submission*, revision 1, p. 14. The 1999 date regarding the Island industrial customers is referenced on p. 15.

[36] See Dr. J. Feehan, *Report on the Allocation of the Rural Deficit*, prepared for Miller& Hearn, representing the towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River, p. 1, footnote 1.

developed in 1993 by the Board's witness, Mr. George C. Baker.[37] Under this mechanism, Hydro classified the deficit total among demand, energy and customer categories based on the total costs in each classification for the NP and Labrador Interconnected rural customers combined. The classified amounts of the deficit were then applied to the combined groups' unit costs for each classification to determine the deficit share for each of the two groups of customers. Essentially, this approach has been viewed as allocating the deficit using a mini-COS study.

The difficulty with this "equal unit cost" approach is that it allocates materially higher amount per customer from Labrador Interconnected customers (who are significantly higher users of energy than Island customers, chiefly due to relatively colder weather and consequent heavy use of electric heating) than the amount per customer to be recovered from customers of Newfoundland Power. This approach produced much higher revenue/cost (R/C) ratios for RLIS customers than for NP—1.42 vs. 1.12—as revealed by Hydro's 2103 Amended GRA evidence.[38]

Hydro analyzed the impact of this approach in response to customer concerns about the impact of the resulting charge, and concluded that it was reasonable to modify the approach. After considering options, the utility selected a revenue requirements-based allocation whose purpose is to equalize R/C ratios, and whose effect is to increase the

[37] Board of Commissioners of Public Utilities, *Report on … the Proposed Cost of Service Methodology…* February 1993, Appendix 1.

[38] NLH, *2013 Amended General Rate Application*, Section 4.3.1, reference Table 4.2 for the R/C ratios.

allocation of the deficit burden in the direction of NP customers and reduce the deficit burden for the Labrador Interconnected customers.

Discussion/Analysis. At the 2013 GRA, there was general agreement that there is no solid basis for allocating the rural deficit. Since the deficit has no association with any of the costs of the subsidizing customers, there is no clear cost allocation method available to recommend from a perspective of costing theory. Additionally, industry practice does not have much to offer, since smaller subsidies are less noticeable and do not create debate as a result.

In the absence of cost-related guidance, Hydro gravitated to a notion of fairness based on results, a departure from standard costing practice, and hampered by the difficulty in defining what constitutes fairness. That search for improved fairness caused the utility to explore two alternatives to the established method of allocating the rural deficit. They assessed an equal R/C ratio approach based on revenue requirements, as well as an approach that relies on number of customers. Arguably, achieving equal R/C ratios after imposition of the rural deficit charge is a desirable criterion for allocation. However, a case can be made for equal customer bill impact as well.

These methods lead to annual average costs per customer numbers that are very similar between the two groups of subsidizing customers, NP and Labrador Interconnected.[39] In contrast, the previously approved method, based on equalized unit costs, imposes an

[39] NLH, *2013 Amended General Rate Application*, Section 4.3.1, p. 4.10. See Table 4.3 for results.

annual bill increase of $653 on RLIS customers and just $217 on NP customers, due to differences in consumption levels. Even with impact equalization by means of the alternative approaches, subsidizing customers would have $207-$235 added to their annual bills.

The 2013 GRA process resulted in commentary on Hydro's analysis and proposed change. Most intervenors, and the Board's consultant, Mr. John Wilson, supported a change. The exception, Mr. Larry Brockman, representing NP, felt that the change was unwarranted and that the mini-COS methodology was sound.[40] Another intervenor, Dr. James Feehan, participating on behalf of several Labrador towns, suggested four alternative approaches to allocating the rural deficit, including one similar to Hydro's customer-based alternative.[41]

In the absence of a cost-causative criterion for allocation of the rural deficit, or of a single best indicator of fairness, the choice of an allocator may be influenced by criteria such as simplicity and by acceptability of outcome to stakeholders. These criteria place the equal unit cost method at a disadvantage on both counts.

Hydro's revenue requirements method has the virtue of simplicity of computation and comprehensibility of outcome, relative to its predecessor, the equal unit cost method. The revenue requirements method also avoids the apparent problem of significant differences in R/C ratios that arises with the equal unit cost method, and the consequent price

[40] These views are summarized in NLH's *2013 General Rate Application, Final Submission*, revision 1, p. 71*ff*.

[41] Dr. J. Feehan, *op. cit.*, pp. 7-10.

distortions away from unit cost that arise with R/C ratios of 1.42 for rural Labrador interconnected customers and 1.12 for NP customers.

Additionally, the revenue requirements approach may have an advantage over the customer approach. The customer approach is initially appealing: equal charges to all customers. However, customers vary significantly in size and average bill between NP and rural Labrador interconnected groups, and the approach burdens residential customers more than larger general service customers, thereby imposing a small distortion in R/C ratios. A rate designer striving for parity would automatically move rates against the allocation and in the direction of the equal R/C ratios of the revenue requirements method. In that case, it may make sense not to affect R/C ratios in the first place, and undertake the slightly more complicated revenue requirements computation.

Recommendations. We recommend that Hydro continue to utilize the rural deficit allocation method based on revenue requirements. The criterion of equalizing revenue-to-cost ratios across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

7. ISSUE #5. CLASSIFICATION OF PURCHASES OF WIND GENERATION

Issue. Hydro requested CA Energy Consulting to review its classification of the wind generation that it purchases. The utility is aware that there are diverse views on this

classification issue and would like to arrive at a position that fits its own wind purchase circumstances.

Background. Hydro proposed in its Amended 2013 GRA that wind purchases be classified as 100% energy-related, a change from a load factor-based classification scheme supported previously. (The previous approach classified as energy-related the share of generation costs equal to system load factor and the remainder as demand-related.) The basis for this change is that Hydro's system planners "no longer assume wind generation will be available to meet system capacity requirements." [42] Hydro currently uses its wind purchases as substitutes for generation by its Holyrood units, and measures the benefits of wind in terms of fuel savings.[43] Hence their conclusion that wind purchases should be 100% energy-related.

Discussion/Analysis. In evaluating Hydro's proposal, it is worthwhile to review Hydro's argument and available evidence regarding industry practice. The system planning argument relies on the concept that planners' views are logically prior to observed wind generation patterns, either at Hydro or in other jurisdictions. That is, the first question in classifying wind should be to ascertain planners' views as to the role of wind generation in meeting capacity needs. *If* planners see a capacity role for wind, then it makes sense to examine evidence of the role of wind in meeting capacity needs. Even with respect to conventional dispatchable generation, cost classification strives to reflect the views of

[42] Newfoundland and Labrador Hydro, *Amended 2013 General Rate Application*, p. 1.5R

[43] *Ibid*, p. 1.13

system planners. This perspective does not lead to a single classification methodology but instead allows the utility wide discretion in its approach. In the case of wind generation, it is plausible that Hydro's system planners would find no capacity value in a non-dispatchable wind power purchase while planners at other utilities would find some degree of capacity value.

In fact, many utilities do accord capacity value to wind. During the review of Hydro's 2013 GRA, Vale witness Mr. Melvin Dean referenced previous Hydro research indicating that North American industry practice is varied, sometimes resulting in the classification of wind as energy-only, while at other times granting wind generation a capacity role. Referencing NP-NLH-280, he finds that a high proportion of utilities split wind costs between demand and energy. Many use a percentage of nameplate wind generator capacity as a basis for determining shares.

Witness Dean then presents, for six utilities that report classification shares between energy and demand, information on the relationship between capacity factor and demand share. Two utilities (BC Hydro and Austin Energy) classify wind generation as 100% energy-related, while four other utilities accept a demand component. Three of these classify wind as between 9 and 20% demand-related. A fourth utility, MidAmerican Energy of Ohio, has a demand component of (1 – load factor) of the sort formerly used by Hydro, resulting in a value likely higher than any of the other three.[44]

[44] Melvin Dean, *Expert's Report on Newfoundland and Labrador Hydro's Amended 2013 General Rate Application*, June 4, 2015, page 14.

Additionally, witness Dean reports that Hydro's historical experience, as reported in NP-NLH-390, reveals wind generation levels between 48 and 64% of wind capacity during system peak periods. On this basis, and because Hydro's wind generator capacity factors appear to be above average for the industry, he suggests that a stronger than average demand component should be adopted by Hydro. He observes that the St. John's area has higher average wind speeds than Saskatchewan and that SaskPower accords a 20% demand share to wind generation. He suggests that this should be a floor for Hydro, with a proper choice of share needing to be dependent on a future study for this purpose.[45]

Witness Dean also notes that Austin Energy treats wind generation as base load and, under their base-intermediate-peak methodology, determines that wind generation should be 100% energy-related. (He also suggests that the use of this methodology should discount the value of the zero-demand share for purposes of review of Hydro's proposal since Hydro's generation cost classification methodology is different.) In between the SaskPower and Austin Energy estimates, Nova Scotia calculates a demand share of 9%.

The Nova Scotia case raises an additional consideration as to whether the classification of wind generation should be tied to, or at least influenced by, a utility's classification of its other generation costs. Since wind generation is not dispatchable, it is doubtful that wind needs to be accorded similar treatment. A utility might wish to adopt a similar methodology but the case for similarity of classification does not appear to be strong.

[45] *Ibid*, pp. 14-15.

A Canadian utility not considered directly by witness Dean is Prince Edward Island's Maritime Electric, which sources approximately one-quarter of its energy from wind, measured on the basis of cost.[46] The utility purchases wind on a take-or-pay basis and wind is ranked just behind power purchases from Point Lepreau in New Brunswick in its generation order. Based on this methodology, Maritime Electric classifies its wind purchases as 100% energy-related.[47] This example is fairly similar to that of Hydro's practice of treating wind purchases as substitutes for the fuel costs of generation by the Holyrood units. Arguably, these similarities support Hydro's view of its wind purchases as being driven by energy only.

The above analysis takes place in the context of conditions in which system planners have accorded a role *a priori* to wind power in capacity planning. Once this assumption is made, then calculations of a wind component lead reasonably to the results reported in Mr. Dean's testimony. The issue, then, is whether the presence of a demand share at other utilities, whose planners view wind as having a capacity component in system planning, should have weight in contradicting a utility's system planners who believe, as Hydro's do, that wind should be accorded no weight in capacity planning.

Unfortunately, calculations by other utilities are based on their planners' views and practices. If a utility's planners see no capacity value in wind, as Hydro's evidence suggests that they do, then others' calculations are not necessarily of value. Logically, Hydro's

[46] *Application and Evidence of Maritime Electric Company*, Oct. 21, 2015, Schedule 8-3, p. 32

[47] *Ibid*, p. 92, sec. 13, Cost Allocation Study.

planners' views are prior to discussions of any calculations of capacity factor and, ultimately, classification share. From this perspective, Hydro is entitled to claim that its planners' views are paramount. By extension, the utility need not perform a study of capacity factors and performance of wind generation in peak hours or hours of low reserves since the results are not bound to influence the planners' conclusions.

Recommendation. We recommend that Hydro's planning perspective for classification of purchases of wind generation be accepted by the Board. An energy-only classification approach is plausible and defensible, based on Hydro's planning perspective regarding wind generation. If Hydro's planners had concluded that wind had a capacity role for planning purposes, then classification methods and results in other jurisdictions would have had weight in considering classification shares.

APPENDIX 1: SUMMARY OF RECOMMENDATIONS

Issue #1. O&M Costs Related to Dedicated Transmission Assets

- We recommend that Hydro continue to directly assign O&M costs to specifically assigned assets in determining specifically assign charges for Industrial customers.
- To determine the allocation of O&M to specifically assigned assets, we recommend that Hydro determine test-year transmission asset values via Handy-Whitman indexes (the current-year approach) to alleviate the current problem of inadvertently allocating higher O&M costs to newer assets and lower O&M costs to older assets.
- We also recommend that Hydro's previous proposal that A&G expenses be directly assigned in the same proportion as O&M expenses be approved in conjunction with the above recommendations.

Issue #2. CBPP Frequency Converter Cost Assignment

- We recommend that the frequency converter unit continue to be assigned directly to CBPP, due to its apparent use almost solely by the customer and the availability of compensation for service to the system that is provided from time to time.

Issue #3. CBPP Pilot Project

- We recommend that Hydro not offer to renew the pilot project in the 2017 GRA given the problematic anticipated reduction in the value of energy services that CBPP is likely to be able to provide to the system following completion of the LIL and, subsequently, Muskrat Falls.

- We also recommend that Hydro broach with CBPP the idea of two-part pricing, specifically real-time pricing, as a replacement for its current pilot project and associated Capacity Assistance agreements.

Issue #4. Rural Deficit

- We recommend that Hydro continue to utilize the rural deficit allocation method based on revenue requirements. The criterion of equalizing revenue-to-cost ratios across regions and the concomitant avoidance of price distortion appear to be desirable features of this approach. The relative simplicity of the calculation method, when compared with the existing approach, is an additional advantage.

Issue #5. Classification of Wind Generation

- We recommend that Hydro's planning perspective for classification of purchases of wind generation be accepted by the Board. An energy-only classification approach is plausible and defensible, based on Hydro's planning perspective regarding wind generation. If Hydro's planners had concluded that wind had a capacity role for planning purposes, then classification methods and results in other jurisdictions would have had weight in considering classification shares.

EXHIBIT BRC 1. RESUME OF BRUCE R. CHAPMAN

Bruce R. Chapman

RESUME

January 2017

Address:

800 University Bay Drive, Suite 400
Madison, WI 53705–2299
Telephone: 608.216.7147
Fax: 608.231.2108
Email: brchapman@caenergy.com

Academic Background:

All course work necessary for PhD, University of Wisconsin–Madison, 1981, Economics
MA, University of Wisconsin–Madison, 1979, Economics
BA, University of Pittsburgh, 1976, Economics

Positions Held:

Vice President, Christensen Associates Energy Consulting, LLC, 2015-present
Senior Economist, Christensen Associates Energy Consulting, LLC, 2005–2014
Senior Economist, Laurits R. Christensen Associates, Inc., 1992–2005
Economic Analysis Consultant, Laurits R. Christensen Associates, Inc., 1988–1992
Research Economist, Laurits R. Christensen Associates, Inc., 1986–1988
Associate Consultant, Coopers & Lybrand Consulting Group, Economics Practice, Toronto, Canada, 1985–1986
Research Assistant, University of Wisconsin-Madison, 1980–1981
Research Analyst, Woods Gordon (Economics Group), Toronto, Canada, 1979–1980

Professional Experience:

I assist clients in the electricity and natural gas industries to improve their costing and pricing capabilities. I advise clients in such areas of expertise as: cost-of-service analysis and rate design based upon established regulatory and market-based principles; innovative rate design including demand response products, renewables pricing, fixed billing, and other market-based retail pricing products; load forecasting and load research analysis. I supervise and conduct analysis of costing and pricing issues for utilities, regulators, customers and other industry stakeholders. Additionally, I have supervised the development of software required for the implementation and support of innovative retail products. Examples include cost-of service and rate design models to

support rate applications, and models to predict customer tariff choice and price response. I regularly present costing and pricing issues and concepts at industry conferences and workshops.

Major Projects:

Reviewed economic development and load retention rates for a Canadian utility.

Evaluated behavior or fixed billing customers following instances of very high consumption.

Reviewed the retail rate portfolio of a Canadian utility with respect to industry standards.

Reviewed the cost causation underpinnings of a utility's residential rate design.

Collaborated in a review of standby rate structures for a Midwestern utility.

Provided pricing and revenue recovery guidance to a Caribbean utility.

Provided guidance to a Southeast Asian utility in the design of time-of-use rates. Guidance included instruction in simulation of price response.

Directed a cost-of-service study for a large distribution utility.

Assisted a utility to adjust its costing and pricing methods following addition of significant new generation and transmission assets.

Assisted a utility to merge rates of two separate service territories following a corporate merger.

Reviewed a natural gas distribution utility's proposal for a commodity hedging arrangement.

Assisted in developing an electric vehicle tariff for a Midwestern utility.

Assisted in an evaluation of economic development and load retention rates for a Midwestern utility.

Led an evaluation of a Midwest utility's residential time-of-use rate in comparison with other TOU designs and current marginal costs. Evaluated means by which participation could be increased.

Participated in an evaluation of the merits of a special contract for a large customer of an Eastern utility.

Conducted an analysis of the relative cost-of-service implications of creating a separate class for a specialized subset of customers from an existing large customer class.

Assisted a Great Plains utility to develop a renewable tariff for large industrial customers.

Managed a project that assisted a Great Plains public service commission staff to evaluate natural gas utility submissions for safety-related cost recovery via new riders.

Participated in a load research data development project for a Midwestern utility, including sample design and selection, and class interval load profile development.

Conducted an analysis of the cost implications for a Caribbean utility of introducing LED street lighting.

Developed generic cost-of-service and rate design models for use in client rate cases.

Customized company cost-of-service and rate design models for an Asian utility. The project also included support for marginal cost capability development.

Led a rate case preparation process for a Southeastern utility that included load and energy forecasting, development of revenue requirements, and support for cost of service and rate design.

Participated in a Midwest utility's rate case by reviewing current mass market time-of-use and other rate designs and recommending modifications.

Collaborated in a review of a large Canadian utility's cost-of-service methodology, including a public review process with stakeholders. Testified before regulator regarding recommendations.

Conducted an assessment of a Great Plains public power utility's plans for three pricing concepts: green power, economic development rates, and unbundled retail pricing to facilitate customer choice.

Assisted a distribution utility to review aspects of its distribution cost allocation methodologies by conducting a survey of methodologies across a number of electric utilities.

Assisted a state energy office to review ways in which the state could improve its record of energy efficiency program achievements, as recorded by the ACEEE Scorecard.

Collaborated in the development of rate redesign alternatives for a utility's real-time pricing program structure.

Collaborated in the review of the potential for a Canadian utility to introduce a fuel adjustment mechanism.

Conducted an analysis of probable migration of customers to new time-of-use electricity programs offered by a southeastern utility.

Evaluated the accuracy of an electric utility's fixed bill offer algorithm and recommended modifications.

Led a project which conducted a review of an electric utility's avoided cost calculation and the application of those costs in energy efficiency reviews.

Managed and participated in reviews of rate and gas cost adjustment applications for a Great Plains public service commission's gas division.

Conducted a cost-of-service and rate design study for a Caribbean utility in preparation for a rate submission.

Supported review for an industrial customer group of a large filing by a utility, focusing on non-bypassable riders.

Managed a gas cost review process for a Great Plains regulatory agency.

Analysis of smart grid pricing issues for a Great Plains public power utility.

Contributed to load research sample development for an investor-owned utility.

Managed a review of a large electric and gas utility's costing methodologies.

Managed a cost-of-service and rate design study for a Caribbean utility.

Conducted analysis of distribution costing practices at a large Midwestern investor-owned utility.

Development of a time-of-use rider for two electric utilities.

Management of a study of interruptible pricing program improvements for a large Midwestern utility.

Management of a comprehensive cost-of-service and rate design study for a Caribbean utility.

Strategic pricing for a large hydro-dominated utility.

Evaluation of the net economic benefits of alternative power supply strategies: coal vs. renewables and energy efficiency.

Load forecasting project for a medium-sized electric utility with significant industrial load.

Analysis of alternative means of net metering.

Evaluation of alternative demand response programs for a municipal utility.

Analysis of treatment of margins from real-time pricing.

Analysis of a natural gas energy conservation funding mechanism.

Design and pricing of a small customer Time-of-Use program.

Evaluation of cost of capital for a small Caribbean utility.

Risk pricing of a long-term customer choice retail contract.

Evaluation of response by small customers to fixed billing programs.

Evaluation of response by medium-sized customers to a banded fixed billing program.

Cost-of-service project including marginal cost and traditional cost basis.

Preparation of load research survey sample via stratified random sampling.

Design and pricing of a Critical Peak Pricing product

Evaluation of residential customers' propensity to adopt a voluntary Time-of-Use product

Pricing of a fixed bill product for a new service territory based on response elsewhere

Evaluation of peak period response to a fixed billing product

Development of an electric utility fuel forecast

Customization of fixed bill software for use at a utility site

Design and pricing of a Banded Fixed Billing product.

Long-term wholesale power procurement for an electric utility.

Report on Adoption of Variable Pricing contracts in deregulated retail electricity markets.

Development of Fixed Bill software to generate offers and monitor customer behavior.

Quantitative evaluation of net benefits of demand response programs.

Quantitative evaluations of customer response to fixed billing.

Design and pricing of several pilot and permanent fixed-bill programs.

Development of Efficient Tariff Prices via Marginal Costing.

Analysis of Market Data Available to Estimate Marginal Cost of Reliability.

Evaluation of Risk of Fixed Billing Based on Customer Response.

Cost Allocation Analysis for Rate Case Filing.

Analysis of Customer Response to Fixed Billing.

Fixed Bill Scoping for a Natural Gas Provider.

Analysis of Risk Implications of Fixed Billing for an Electric Utility.

Strategic Assessment of an Electric Utility's Retail Tariff Portfolio.

Guaranteed Bill Product Design and Risk Assessment.

White Paper on Interruptible/Curtailable Service.

Marginal Cost-Based Cost of Service Development.

Software Scoping for Self-Designed Products.

Flat Bill Offer Software Development.

Comprehensive Rate Repricing.

RTP Price Hedging Product Development.

Retail Pricing Under Competition Conference.

Rate Optimization Plan.

Fixed Bill Product Development.

Weather Hedge Evaluation.

Real-Time Pricing Product Development.

Workshop: Creating a Diversified Retail Pricing Portfolio.

Product Mix Business Plan.

Prepared material for testimony in Federal District Court on Real-Time Pricing.

Risk-Based Pricing Workshops.

Survey of New Electricity Market Players.

Analysis of Fixed Bill Products.

Strategic Pricing Plan for a Midwestern Utility.

Product Mix Analysis for Small Customers.

Real-Time Pricing Workshop.

Innovative Pricing and Marginal Costing for a Co-op.

Real-Time Pricing with Multiple Options.

Real-Time Pricing for a G&T and its Co-ops.

Product Mix Analysis for Large Customers.

Real-Time Pricing Service Design for Commercial Customers.

Advanced Service Design Workshop.

Real-Time Pricing Program for a Midwestern Utility.

Evaluation of Customer Response to Real-Time Pricing.

Real-Time Pricing Program Development for an Eastern Utility.

Two-Part Pricing Service Design.

Real-Time Pricing Regional Workshops.

Real-Time Billing Program Support and Revision.

Electricity Efficiency Programs.

Real-Time Pricing Program Redesign for an Eastern Utility.

Real-Time Pricing Implementation for a Canadian Utility.

Real-Time Pricing Practitioners' Workshop.

Real-Time Pricing for a Canadian Utility.

Customer Evaluation of Real-Time Pricing.

Review of Competitive Pricing Strategies.

Evaluation of Process of Marketing Real-Time Pricing.

Review of Methods for Distinguishing Customer Response to Rate Change.

Real-Time Pricing Rate for a Southern Utility.

Review of Accounting and Incentives for a Real-Time Pricing Rate.

Analysis of Load Impact of Priority Service Alternatives.

Benefit/Cost Analysis of an Integrated Energy Management System.

Benefit/Cost Analysis of Marginal Cost-Based Rates for DSM Integrated Resource Plan.

Impact Evaluation of Curtailable Electric Service.

Survey of Households Who Were Candidates for Voluntary Time of Use Rates.

Audit of Energy Management Software.

Real-Time Pricing Rate for a Large Northeastern Public Utility.

Software Design for Real-Time Pricing.

Improved Approaches to Estimating Benefits of DSM Programs.

Load Shapes Assessment Program.

Fuel Purchase Contract Study.

Evaluation of the Effects of Canadian Energy Policy.

Evaluation of Energy Conservation Programs.

Professional Papers:

"Pricing Distributed Generation: Challenges and Alternatives," *Natural Gas & Electricity*, March 2017.

"Pricing of Renewable Energy Made Difficult by Policy Challenges," *Natural Gas & Electricity*, January 2016.

"Room for Fixed Billing in the World of Conservation?," *Natural Gas & Electricity*, August 2008.

"Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, June 2001 (with Ahmad Faruqui, Dan Hansen, and Chris Holmes).

"A Survey of Real-Time Pricing Programs," *The Electricity Journal*, August–September 1993 (with Juliet Mak).

"Real-Time Pricing: DSM at Its Best?," *The Electricity Journal*, August 1990 (with Tom Tramutola).

Conference Presentations:

"Net Metering and Solar Energy Pricing," pre-conference workshop at EUCI's Net Energy Metering and Utility Solar Rates Summit, July 2016.

"Pricing the Purchase of Renewable Energy," post-conference workshop at EUCI's 4th Annual Southeast Clean Power Summit, March 2015.

"Pricing Perspectives of Regulated Utilities on Solar Power," EUCI's Net Metering 2.0 and Utility Solar Rates Conference, Anaheim, CA, January 2015.

Cost of Service and Rate Design; Current Utility Costing and Pricing Challenges; Pricing Renewable Energy; Feed-in Tariffs and Demand Response Alternatives to Supply. Presentations to the Wisconsin Public Utility Institute's Energy Utility Basics Course, 2009–2016.

"The Bill Please," university course and public presentation within the "Decoding the Energy Industry" series; Wisconsin Public Utility Institute, 2014.

Electric Rate Design Principles and Designs (with Dr. Stephen Braithwait), and Pricing Renewable Resources; presentations to the Rate Design and Regulation Workshop, Wisconsin Public Utility Institute, Madison, Wisconsin, 2014.

"Customer Response to Dynamic Pricing: Who Responds and How?," EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles; with Dr. Steven Braithwait.

Cost-of-Service, preconference workshop, EUCI's Smart Ratemaking Conference, Oct. 2009, Los Angeles.

Critical Peak Pricing: Valuation and Viability, presented at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Georgia Power's FlatBill Program, Risks and Returns, presented, with Monamee Adhikari, Georgia Power Company, at AESP's Innovations in Retail Pricing Conference, Chicago, IL, May 17, 2006.

Retail Pricing for Competitive Power Markets, six presentations on retail pricing and unbundling; Infocast conference February 28-March 2, 2001.

Retail Products and Pricing Under Competition, presented at the Canadian Electricity Association's seminar: Setting Up for New Energy Regulation, April 19, 1999.

Using Risk as the Maker of Prices: Risk-Based Pricing, presented at Infocast's conference: Power Industry Retail Pricing, June 23–25, 1999.

"Designing a Retail Pricing Product Mix for a Competitive Market: A C-VALU Case Study," presented at EPRI's Innovative Pricing Conference, Washington, DC, June 18, 1998, (with Kathleen King and David Kulha).

"Retail Products & Pricing in the Competitive Era," presented at IBC Conference: Successfully Implementing Retail Access, Washington, DC, April 27, 1998.

"Risk-Based Pricing: Making Money in Competitive Markets," EMACS Conference, Atlanta, Georgia, October 14, 1997, (with A. Faruqui, EPRI).

"Real-Time Pricing: Becoming Competitive Before Competition," presented at IBC Conference: Successfully Implementing Retail Profit Projects, Atlanta, Georgia, February 24, 1997, and Las Vegas, Nevada, July 17, 1997.

"Effective Retail Product Design for a Competitive Market," IBC Conference: Developing, Negotiating and Contracting Retail Electricity Prices, Atlanta, Georgia, February 24, 1997, (with Kathleen King).

"Innovative Pricing and Data Requirements," presented at the AEIC Load Research Conference, Washington, DC, August 4–6, 1995.

"Lessons Learned and the Path Forward," presented at EPRI's National Conference on Achieving Success in Evolving Electricity Markets, Atlanta, Georgia, October 10–12, 1995 (with Kathleen King).

"A Real-Time Pricing Primer: Service Design for a Competitive Market," presented at the Missouri Valley Electric Association Marketing Division Conference, Kansas City, Missouri, October 13, 1994.

"Real-Time Pricing: Service Design for a Competitive Market," presented at the American Public Power Association workshop, Scottsdale, Arizona, September 28, 1994.

"Customer Response to Real-Time Pricing: Results from Current Experiments," presented at the 6th National Demand-Side Management Conference, Miami Beach, Florida, March 25, 1993.

"Electricity Pricing Innovations for Retail Sales," presented at the Energy Utilities and Regulation Course, Wisconsin Public Utilities Institute, September 13, 1990; revised and presented again in 1992.

"Innovative Pricing in DSM: Recent Field Tests of Real-Time Pricing," presented at the Energy Demand-Side Research Seminar Series, University of Wisconsin-Madison, April 4, 1990 (with D. W. Caves).

Testimony:

Panelist in Cost-of-Service Methodology review hearings on behalf of Nova Scotia Power, before the Nova Scotia Utilities and Review Board, proceeding NSUARB-NSPI-P-892, Matter No. M05473, December 2013.

EXHIBIT BRC 2. MEMORANDUM RE O&M COSTS FOR SPECIFICALLY ASSIGNED ASSETS

CHRISTENSEN ASSOCIATES ENERGY CONSULTING

Christensen Associates Energy Consulting, LLC
800 University Bay Drive, Suite 400
Madison, Wisconsin 53705-2299

Voice 608.231.2266 Fax 608.231.2108
www.caenergy.com

MEMORANDUM

TO: Kevin Fagan, Newfoundland & Labrador Hydro

FROM: Bruce Chapman[1]

DATE: February 28, 2017; revised October 6, 2017

SUBJECT: Direct Assignment of Transmission Assets and O&M Costs

Context

In the recently concluded proceeding pertaining to Newfoundland and Labrador Hydro's (Hydro's) 2013 GRA, the Public Utility Board (PUB) rejected Hydro's proposal to modify its method by which operating and maintenance (O&M) charges are calculated for customers with transmission lines and terminal stations dedicated to their use. At present, customers served by such facilities pay Specifically Assigned Charges, a component of which consists of O&M charges meant to pertain to these facilities. The O&M component is based on the share of the customer's transmission assets in total Island transmission assets, valued at original cost.

Hydro's proposal, at the suggestion of an Industrial customer, Vale, was to value these assets at current cost. In making the proposal, Hydro computed the impact of the change in methodology on the Industrial customers as a whole, on individual customers, and on other customer classes. The PUB, in rejecting the proposal, asked Hydro to document industry practice to evaluate how this costing issue is handled elsewhere. This memorandum reports on research for that purpose.

Approach

CA Energy Consulting conducted interviews via telephone and email with a number of Canadian and U.S. utilities, attempting to locate utilities that undertake direct assignment of transmission assets. We inquired about the incidence of direct assignment and, for those who do so, we asked how the initial construction costs of such assets are recovered and what costing practices

[1] Assistance was provided by Michael O'Sheasy, Robert Camfield and Nicholas Crowley.

are with respect to the O&M expenses engendered by development of new radial lines and terminal stations.

We obtained information from five large Canadian utilities and about 22 U.S. utilities of varying sizes. The U.S. number is approximate because we received evidence regarding some utilities via sources who described their experience with more than one utility. As such, some utility experiences may not indicate general practice by the utility but instead management of special circumstances or special contracts.

Summary of Results

We found the practice of direct assignment of transmission assets to be in use at several utilities in Canada and relatively rare in the United States. All five Canadian utilities contacted use direct assignment of transmission assets to some degree. Of these five, two utilities – BC Hydro and Hydro-Quebec – directly assign O&M costs in some manner based on the assets directly assigned.

- BC Hydro charges customers directly for actual O&M costs that exceed a predetermined "normal" level determined by case-specific factors, and based on O&M costs on their system. (Their Transmission Extension Policy is currently under review, so practice regarding O&M charges may change as part of this review.)
- Hydro-Quebec treats O&M costs in the same manner as initial costs, directly assigning them to Large customer categories and allocating to class based on a 1 NCP allocator.

NB Power separately identifies O&M costs associated with dedicated transmission assets, but allocates these to rates by means of a coincident peak allocator.

Two other utilities – SaskPower and Manitoba Hydro – simply include all additional O&M costs within transmission O&M and allocate those costs to rate class via their preferred allocator.

Our investigation yielded eight cases of direct assignment in the U.S., a minority of the 22 that we contacted or for whom we obtained information indirectly. The utilities engaging in direct assignment use a variety of approaches to recover O&M costs. Some simply bundle all transmission O&M costs together and allocate to class without recognition that some costs pertain to directly assigned assets. However, some are of particular interest to Hydro.

- Bonneville Power Administration allocates O&M costs based on asset measures (circuit-miles of line, type of pole, size of substation/transformer) and applies system per-unit O&M costs pertaining to these facilities.
- Emera Maine, whose directly served transmission customers are generation sources only, allocates O&M costs to these sources based on their share of (undepreciated) transmission assets, valued at original cost.
- A small municipal with a few large customers directly assigns transmission costs and the O&M costs that actually occur on each customer's line. The customers are served under special contract.[2]

[2] This example and the two that follow are from Mark Beauchamp, Utility Financial Solutions.

- Three Nebraska public power districts (PPDs) (Butler, Cedar Knox, and Stanton County) that serve large pumping stations owned by TransCanada Pipeline charged the customer for the costs of transmission line extension and also charge on an ongoing basis for the actual costs of O&M.
- A third Nebraska PPD, Alcorn, directly assigned the cost of transmission facilities to a large customer and charges the customer on the basis of estimated O&M costs. The customer pays a flat fee based on O&M cost indicators from the utility's COS study.

We also conducted an interview with a consultant familiar with an extreme case of a small utility serving large customers.[3] Big Rivers Electric Corporation is a cooperative G&T in Kentucky that at one time served two large aluminum smelters. They treated these customers as a separate rate class, apparently, and assigned all costs related to these facilities to the class. Since this arrangement ended with the closure of the plants, the details of how O&M costs assigned to the class were actually allocated to each customer are not known. Other examples of this situation, in which a utility groups customers whose transmission assets are directly assigned into a single class, and then directly assigns O&M costs associated with those assets to the class, may exist.

If we exclude Emera Maine due to its service to generators only, it appears that this short list of U.S. examples is weighted toward small utilities with a few large customers. This pattern corresponds to the expectations stated in our COS Methodology report, based on industry experience.

The table below provides a summary of utilities contacted (column 1) their use of direct assignment of assets (a "1"in column 2) and their practices with respect to O&M (column 3). In the O&M column of the table, "DA" stands for direct assignment. The abbreviations that follow this identifier are:

- Actual: the utility recovers actual O&M costs.
- Estimated: the utility recovers estimated O&M costs.
- Share: the utility allocates O&M costs among customers with directly assigned assets.
- Bundled: the utility bundles O&M costs directly related to the directly assigned assets with all other transmission costs and applies the allocator used for the relevant transmission account.
- Allocated: the utility separately identifies O&M associated with dedicated transmission assets, then allocates these costs to rate class via a conventional transmission allocator.

The abbreviations simplify utility practice. The appendix provides detail for each utility that directly assigns O&M costs on some basis.

[3] John Wolfram, Catalyst Consulting LLC.

Utilities That Directly Assign Radial Transmission Assets and/or Associated Operating & Maintenance Costs

	Assets	O&M
Canada		
BC Hydro	1	DA - actual, excess
SaskPower	1	bundled
Manitoba Hydro	1	bundled
Hydro-Quebec	1	DA-share
NB Power	1	DA-allocated
United States		
Investor-Owned		
Commonwealth Edison	1	bundled
Emera Maine (generators only)	1	DA - share
Georgia Power		
Gulf Power	1	bundled
Duke Power		
Duke Energy Carolinas		
Duke Energy Progress		
Oklahoma G&E		
PNM Resources		
Public Service of Oklahoma		
Xcel Energy - Minnesota	1	bundled
Federal/State-Owned		
Bonneville Power Admin.	1	DA - share
Santee Cooper		
Tennessee Valley Authority		
Municipal/PPD		
Alcorn PPD	1	DA - estimated
Anonymous Municipal	1	DA - actual
Benton, Cedar Knox, Stanton PPD	1	DA - actual
Big Rivers Electric Corporation	*	
Grand Island Electric Department		

*Separate rate class - no longer in use

Implications of Results

The first implication of this research is that there is no uniform method for associating/determining O&M costs with customers served by dedicated transmission lines and terminal stations.

- Some utilities just bundle transmission costs that could be related to these dedicated facilities in with their other transmission O&M costs.
- A second group allocates O&M costs to direct assignment customers using a variety of allocative methods.
- A third group tracks and directly assigns actual O&M costs to dedicated customers.

The second implication relates to cost allocation. Some utilities make use of a gross (transmission) plant allocator, with gross plant valued at original cost, to split transmission assets between common and directly assigned, and among direct assignment customers.[4] However, there are exceptions. Bonneville uses a somewhat different asset computation, charging on the basis of several categories of equipment and the utility costs of O&M pertaining to that equipment.

The third implication is that few utilities track actual costs by line or terminal station and charge specific customers associated with the facility: one Nebraska PPD does so, and BC Hydro charges for excess costs over its "normal" benchmark.

A fourth implication is that there isn't a wealth of industry practice available to give irrefutable guidance to Hydro or to the PUB regarding O&M cost responsibility associated with dedicated plant. Specifically, although the cases of allocation of O&M costs based on asset value utilize original asset cost, allocation is not the dominant approach, and the numbers utilizing this method are few enough to suggest that Hydro's recommended current valuation should not be ruled out as incompatible with industry practice.

[4] Gross plant often figures in O&M cost allocation. For example, NLH uses gross transmission plant to classify transmission O&M, and then uses a different allocator for each functional classification. Other utilities classify all transmission assets as demand-related and use a single allocator, *e.g.* a CP demand allocator, to allocate both transmission assets and transmission-related O&M. Gross plant plays no role in cost allocation in this case.

Appendix: Summaries by Utility

Canadian Utilities

BC Hydro

BC Hydro directly assigns radial transmission lines that are constructed in response to customer requests. Terminal station construction is the responsibility of the customer. The utility encourages customers to build their own radial lines and to own them. The utility will accept transfer of ownership from the customer if undertaken early in the process. In cases in which the customer is unwilling to build the line, BC Hydro will do so upon request. All costs are the responsibility of the customer, and are paid as incurred via a contribution in aid of construction (CIAC).

In cases of line ownership by BC Hydro, the utility assumes responsibility for a normal level of O&M expenditures, as determined by the utility. This level is based on assessment of customer-specific factors such as remoteness of the customer site and roughness of the terrain. Above-normal expenditure is assigned directly to the customer associated with the line.

Note that BC Hydro's Transmission Extension Policy is currently under review. The current policy dates from 1991.

SaskPower

SaskPower directly assigns connection costs associated with radial lines designed to serve a single customer. The customer pays the full cost under a CIAC scheme.

- The utility interviewee mentioned that, under IFRS, CIAC is recognized as "other income" and functionalized to transmission. Rate base accounts are augmented by construction costs. This appears to be a departure from previous North American practice under GAAP, in which rate base account increases were directly offset by matching CIAC expense, resulting in no change in rate base.

Increases in OM&A costs associated with the new connection are included with all Transmission OM&A and allocated together. Initial OM&A expenses associated with the act of connecting are included with the CIAC.

Manitoba Hydro

Manitoba Hydro directly assigns the costs of radial lines to the customers requesting them. Customers are responsible for the construction of their own terminal stations. Construction costs of radial lines are recovered via CIAC. CIAC is netted against the cost of rate base change by account. There is no effect on rate base.

All increases in O&M costs are deemed common and are recovered through standard tariffs.

Hydro-Quebec

Hydro-Quebec directly assigns to customers applying for radial transmission service only the amount that exceeds a maximum dollar allowance, as defined by the utility. Customer must pay any excess in advance, in a CIAC. However, the customer must reach an agreed usage level. Failure to reach this level results in the customer having to pay that maximum allowance as well.

Assuming that the customer does reach the agreed level, the maximum allowance is entered into rate base. These costs are assigned to the Medium and Large Customer rate categories and then allocated to rate based on a 1 NCP allocator developed for the categories.

NB Power

NB Power directly assigns radial transmission line and substation costs to customers. These customers include large industrial accounts and two municipalities. Customers pay in full for these assets either via CIAC or by monthly lump-sum installments over the life of the asset.

Perhaps of interest, this approach is being challenged by customers who self-generate. They argue that, since they are now providing generation to the grid, they are not responsible for the full asset and OM&A costs of the grid.

NB Power incorporates these dedicated transmission asset values into total asset valuation (at original cost) and payments are amortized into revenues.

The utility has recently modified its COS methodology to separately identify O&M costs associated with dedicated transmission. These costs are not assigned directly to associated customers but instead allocated to rate class based on a coincident peak allocator. This allocation takes place separately from the allocation of common transmission-related O&M costs. (NB Power does not charge the customer directly for actual OM&A expenses as incurred. Accounting practice does not permit this.)

United States

Commonwealth Edison

ComEd builds and maintains transmission assets, including those that are considered radial and serving a single customer or defined small number of customers. However, their accounting system is not capable of identifying such assets. The bulk of the utility's transmission costs generally are recovered via revenue recovery calculations submitted to PJM and the FERC. The exception is the costs of facilities developed and built by ComEd in response to specific interconnection requests, for which the company charges the customer and receives CIAC. The CIAC amount generally covers the full cost of the new facility, or the full cost directly attributable to the customer submitting the request.

O&M costs of the new facilities are all treated as common and recovered via revenue recovery submissions.

Emera Maine

The case of Emera Maine may be less applicable to Hydro's interests in that the customers connected to the grid via directly assigned transmission line costs are remote generators, some of which are wind farms. Customers pay all construction costs via CIAC, not in a single lump sum but instead in installments that can stretch past the period of completion of construction. It should be noted that these facilities tend to be relatively short lines, and thus do not represent significant risk to the utility, at least relative to the risk exposure of smaller utilities.

The utility also finds a middle ground regarding O&M between charging actual cost and socializing all costs. Customers pay O&M based on the radial lines' share of total transmission assets valued at original cost, applied to total transmission O&M costs. The charge is imposed on a lump-sum basis, as a customer-specific fee. The charge is updated annually.

Xcel Energy – Minnesota (Northern States Power)

Xcel Energy charges customers for directly assigned assets via CIAC. As with other large utilities, it does not attempt to identify O&M costs associated with these lines. Instead, the additional O&M costs are included with all others and allocated across rate classes in the standard manner.

Bonneville Power Administration

BPA has dedicated transmission lines and substations in a variety of sizes matching customer needs. The costs of these facilities are recovered in advance from customers under PFIA (Projects Funded in Advance) payments. These costs are non-refundable, making PFIA payments equivalent to CIAC. Assets are owned and operated by BPA. Rate base is not affected by the construction of dedicated facilities.

O&M costs for these facilities are covered under about 150 customer contracts, each of three years' duration, renewing in staggered fashion over time (as opposed to all at once). O&M costs are based on seven-year cost averages. Costs are assigned to customers based on circuit-miles of line, steel or wood poles supporting them, and size of substation/transformer, valued at original, undepreciated cost. In short, the asset values of the facilities are customer-specific while the O&M costs are generic to the transmission function at BPA. Customers thus pay assigned customer-specific O&M costs plus generic transmission-related O&M, the latter being based on standard tariff pricing (in turn based on allocation of common costs).

Anonymous Municipal

This example, also reported by Mark Beauchamp[5], involves a municipal utility that serves a small number of large industrial customers via radial transmission lines. In this case, the customer contracts require the customer to pay the full cost of their assessment via CIAC. Additionally, the customers are responsible for all capital replacement costs. Additionally,

[5] Result of telephone interview with Mr. Beauchamp. (His name is pronounced as it would be in French.)

customers pay for all O&M costs as they are incurred. This is an excellent example of the small utility/large customer combination that results in direct assignment.

The utility has structured its special contracts to match costs associated with these customers as closely as possible to revenues, a strategy for minimizing utility risk. An additional feature is a utility requirement of surety bonds that secure payoff to the utility in the event of customer shutdown. (This is an approximate counterpart of Hydro-Quebec's requirement that the minimum allowance be paid in similar circumstances.)

The example is required to be anonymous at the request of the utility.

Public Power Districts in Nebraska

Mr. Beauchamp also provides two examples from his experiences in Nebraska. The first example concerns three utilities that provide electric service to TransCanada Pipelines pumping stations. (The utilities are Butler, Cedar Knox, and Stanton County PPDs.) As with the municipal utility example above, the contracts under which the pumping stations are served are designed to minimize utility risk. The general context involves the utilities providing energy supply services on a pass-through basis and distribution services priced to cover all other expenses.

The utility also covers its risks by charging the customer for the actual costs of O&M as the costs are incurred. As might be imagined, a less direct arrangement would expose other customers of the PPDs to fluctuating and significant costs.

The second example, Alcorn PPD, involves a transmission line that connects an ethanol plant. In this case, the utility partially collected its construction expenses via CIAC but then charged the customer a significant share of construction costs via a facilities charge, a monthly lump sum.

O&M charges are indirectly the responsibility of the customer in that the utility determined a rate for the length of the line based on its transmission O&M costs in its COS study. This cost is recovered via a flat fee whose size changes with each COS study, but does not connect charges directly to actual line costs.