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2. Cost of Capital: Dr. James Vander Weide
3. Depreciation Study: Gannett Fleming Inc.

OPINION
ON
CAPITAL STRUCTURE
AND
RETURN ON EQUITY
FOR
Newfoundland Power Inc.

Prepared by

KATHLEEN C. MCSHANE

FOSTER ASSOCIATES, INC.



September 2012

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I. INTRODUCTION AND SUMMARY OF CONCLUSIONS

A. INTRODUCTION

My name is Kathleen C. McShane and my business address is One Church Street, Suite 101, Rockville, Maryland 20850. I am President of Foster Associates, Inc., an economic consulting firm. I hold a Masters in Business Administration with a concentration in Finance from the University of Florida (1980) and am a Chartered Financial Analyst (1989). I have testified on issues related to cost of capital and various ratemaking issues on behalf of electric utilities, local gas distribution utilities, pipelines and telephone companies in more than 200 proceedings in Canada and the U.S., including the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB" or "Board"). My professional experience is provided in Appendix G.

I have been requested by Newfoundland Power Inc. ("Newfoundland Power" or "the Company") to provide an expert opinion on the reasonableness of its capital structure and to recommend a fair return on equity ("ROE") for the Company.

B. SUMMARY OF CONCLUSIONS

My principal conclusions are as follows:

1. The allowed return for Newfoundland Power must meet all three requirements of the fair return standard: comparable returns, financial integrity and capital attraction. The fair return extends to all components of the return, including the allowed capital structure and ROE, that is, the overall return allowed must satisfy the fair return standard.
2. The economic principle guiding the fair return is the opportunity cost principle. The opportunity cost of capital represents the expected return foregone when the decision is made to commit capital to an alternative investment of comparable risk. It represents the return that investors require to commit capital to a specific

investment and the cost to the firm of attracting and retaining capital. Satisfying the fair return standard means allowing a return commensurate with the opportunity cost of capital.

3. Satisfying the comparable return requirement of the fair return standard requires consideration of returns available to comparable utilities in the U.S., given the similarity of operating and regulatory environments, the integration of the two capital markets, and the small number of Canadian utilities with equity market data.
4. Newfoundland Power's forecast capital structure includes a common equity ratio of 45%. The Company's capital structure is reasonable in light of its business risks, the importance of maintaining the existing credit ratings, the upward trend in the common equity ratios of Newfoundland Power's Canadian peers, the necessity of ensuring financial strength in uncertain capital markets and the need to be positioned to compete for capital on reasonable terms and conditions.
5. With respect to broad cost of capital trends since late October 2009, the end of the oral portion of the 2010 General Rate Application ("2010 GRA") which bear on the fair return:
 - a. Risks to the global financial system, as assessed by the Bank of Canada, are as high in mid-2012 as they were at the end of 2009.
 - b. There has been a material reduction in long-term Government of Canada bond yields. This decline largely reflects a confluence of factors, including deterioration in the global economic outlook, the Bank of Canada's decisions to maintain its overnight rate at historically low levels, investor flight to quality, i.e., away from riskier assets including equities, and a decreasing global pool of safe haven assets. The reduction in long-term Government of Canada bond yields since the end of the oral portion

of the 2010 GRA has little, if any, correlation with trends in the market cost of equity.

c. Although the absolute level of yields on long-term A-rated Canadian utility bonds has declined, the spread between those yields and the yield on long-term Government of Canada bonds is slightly higher than it was at the end of the oral portion of the 2010 GRA. The somewhat higher recent spreads indicate that investors view the risk associated with A-rated utility bonds to be no less than at the end of the oral portion of the 2010 GRA.

d. As of mid-2012, the level of the equity markets is little changed from the end of the oral portion of the 2010 GRA, equity market volatility is similar and investor confidence levels are lower. Equity market indicators point to a higher current market cost of equity than at the end of the oral portion of the 2010 GRA Application. In combination with the decline in long-term Government of Canada bond yields, the equity market risk premium is even higher.

e. The persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields make it difficult to construct an ROE automatic adjustment mechanism that would successfully capture changes in the utility cost of equity.

f. My estimate of a fair ROE for Newfoundland Power is based on the premise that the allowed ROE will remain unchanged for the proposed test period. As a result, my equity risk premium tests are based on forecasts of long-term Government of Canada bond yields for 2013-2014.

6. The fair return on equity for Newfoundland Power was estimated at 10.5%, and reflects the following:

- a. The recommended return on equity is based on the results of equity risk premium and discounted cash flow tests.
- b. A forecast 30-year Government of Canada bond yield for 2013-2014 of 3.50%.
- c. Three separate equity risk premium tests with the following costs of equity before adjustment for financing flexibility:

Risk Premium Test	Cost of Equity
Risk-Adjusted Equity Market	8.9%
Discounted Cash Flow-Based	9.5%
Historic Utility	10.25%
Average	9.6%

- d. The discounted cash flow test, applied to a sample of U.S electric and gas utilities selected to serve as a proxy for Newfoundland Power, as well as to a sample of Canadian utilities, supports a cost of equity of 9.4%.
- e. The addition of an allowance for financing flexibility equal to the midpoint of the indicated range of 50 to 160 basis points (mid-point of approximately 100 basis points) to the “bare-bones” return on equity estimate of 9.5%, derived from the equity risk premium and DCF tests, is required to fully recognize the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures. The resulting estimate of the fair return on equity for Newfoundland Power is approximately 10.5%.
- f. An alternative approach is to give weight to the comparable earnings test and to limit the financing flexibility to the market-based tests to the minimum level of 50 basis points. The comparable earnings test, which measures returns in relation to book value, was applied to a sample of 21 Canadian low risk unregulated companies of reasonably comparable risk

to an average risk Canadian utility, e.g., Newfoundland Power. Based on the comparable earnings test, a fair return on equity for an average risk Canadian utility is in the range of 11.0% to 12.0%.

- g. This alternative approach, with preponderant weight given to the results of the equity risk premium and discounted cash flow tests, provides additional support for a fair return on equity for Newfoundland Power of 10.5%.

II. BACKGROUND FOR REVIEW OF NEWFOUNDLAND POWER'S COST OF CAPITAL

In Reasons for Decision: Order No. P.U. 43(2009), issued on December 24, 2009, the Board determined the allowed return on rate base for Newfoundland Power for 2010, incorporating a regulated return on common equity of 9.0%. The 9.0% regulated return on common equity was based predominantly on the application of the Capital Asset Pricing Model, premised on a forecast long-term Government of Canada bond yield of 4.5%. In the Decision, the Board also concluded that discontinuing the use of the automatic adjustment formula would be an excessive response to financial market conditions, which, while severe in the fall of 2008 and the spring of 2009, appeared to be settling. In Order No. P.U. 12(2010), the Board approved the continuation of the automatic adjustment formula that it had initially approved in 1998, with a modification: the substitution of actual long-term Government of Canada bond yields with forecast yields. The application of the formula for 2011 produced a regulated return on equity for Newfoundland Power of 8.38%; if it had been applied for 2012, the formula would have produced a regulated return on equity of only 7.85%, based on a forecast long-term Canada bond yield of 3.06%.¹

In November 2011, Newfoundland Power applied to the Board for a suspension of the formula to establish a return on rate base for 2012, approval of the continued use, on an interim basis, of the

¹ Based on the August 2012 *Consensus Forecasts* and July 2012 30-year/10-year Government of Canada bond yield spreads, the indicated ROE for 2013 would only be 7.53% based on a forecast 30-year Government of Canada bond yield of 2.66%.

existing 2011 range of rate of return on rate base and the establishment of a process to determine a fair and reasonable return on rate base for 2012. The Board approved the suspension of the automatic adjustment formula in Order No. P.U. 25(2011), followed by a process to set the return on rate base for 2012. A negotiated settlement was subsequently reached and approved by the PUB in Order No. P.U. 17(2012) on June 15, 2012, which established a rate of return on common equity of 8.8% to be used in determining a just and reasonable return on rate base for 2012. In May 2012, the PUB directed Newfoundland Power to file a General Rate Application ("GRA") for 2013.

This Opinion represents my analysis of and recommendations for the capital structure and fair return on equity for the purpose of the determination of a fair return on rate base for Newfoundland Power for its proposed 2013 and 2014 test years.

III. FAIR RETURN STANDARD

The standards for a fair return arise from legal precedents² which are echoed in numerous regulatory decisions across North America, including the Board's Order No. P.U. 43(2009). A fair return gives a regulated utility the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;
2. maintain its financial integrity; and,
3. attract capital on reasonable terms.

The legal precedents make it clear that the three requirements are separate and distinct. The fair return standard is met only if all three requirements are satisfied. In other words, the fair return standard is only satisfied if the utility can attract capital on reasonable terms and conditions, its

² The principal seminal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, (262 U.S. 679, 692 (1923)); and, *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)).

financial integrity can be maintained and the return allowed is comparable to the returns of enterprises of similar risk.³

Further, as the Federal Court of Appeal held in *TransCanada PipeLines Ltd. v. National Energy Board et al.*, [2004] F.C.A. 149, the required rate of return must be based on the cost of equity. The impact on customers of any rate increases cannot be a factor in the determination of the cost of equity capital.⁴

A fair return on the capital provided by investors not only compensates the investors who have put up, and continue to commit, the funds necessary to deliver service, but benefits all stakeholders, including ratepayers. Fair compensation on the capital committed to the utility provides the financial means to pursue technological innovations and build the infrastructure required to support long-term growth in the underlying economy. An inadequate return, on the other hand, undermines the ability of a utility to compete for investment capital. Moreover, inadequate returns act as a disincentive to necessary expansion and innovation, potentially degrading the quality of service or depriving existing customers from the benefit of lower unit

³ The British Columbia Utilities Commission (“BCUC”) has recognized that the comparable return requirement is distinct from the capital attraction standard, specifically:

The Commission Panel accepts the relevance of two separate standards namely the capital attraction standard and the comparable returns standard in establishing a fair return on equity for a benchmark low-risk utility. One standard does not trump the other, neither is one subsumed by the other. (BCUC, *In the Matter of Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., Application to Determine the Appropriate Return on Equity and Capital Structure and to Review and Revise the Automatic Adjustment Mechanism, Decision*, March 2, 2006, page 48)

The Alberta Utilities Commission (“AUC”) recognized that the requirements of the fair return standard are separate and distinct:

The Commission notes with approval the following description by the ATCO Utilities of how the three factors or criteria of the fairness standard are assessed:

In the ATCO Utilities' view, the assertion that the three-part test is "simply three ways of looking at the same thing" fails to recognize the critical fact that there are differing tests which help to "triangulate" a Fair Return. Each may have greater or lesser relevance depending upon the economic landscape upon which the tests are conducted. The frailty of reliance on only a single leg of the three legged stool for stability and reliability of the result over changing economic conditions should be obvious. (Alberta Utilities Commission, *2009 Generic Cost of Capital, Decision 2009-216*, November 12, 2009, page 28)

⁴ In its *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc.*, RH-1-2008, March 2009 (page 6), the NEB stated: “In the Board’s view, the Federal Court of Appeal was clear that the overall return on equity must be determined solely on the basis of a company’s cost of equity capital, and that the impact of any resulting toll increase is an irrelevant consideration in that determination.”

costs that might be achieved from growth. In short, if a utility is not provided the opportunity to earn a fair return, it may be prevented from making the requisite level of investments in the existing infrastructure in order to reliably provide utility services to its customers.

IV. CAPITAL STRUCTURE

A. NEWFOUNDLAND POWER'S PROPOSED CAPITAL STRUCTURE

Newfoundland Power is requesting that the Board approve its forecast actual capital structure which includes a common equity ratio of 45% for both 2013 and 2014.

B. ANALYTICAL FRAMEWORK

The economic principle guiding the fair return is the opportunity cost principle. The opportunity cost of capital represents the expected return foregone when a decision is made to commit capital to an alternative investment of comparable risk. It represents the return investors require to commit capital to a specific investment and the cost to the firm of attracting and retaining capital. Satisfying the fair return standard means allowing a return commensurate with the opportunity cost of capital.

A utility's overall cost of capital represents the weighted average cost of the various sources of capital that it uses to finance its rate base assets. The weights represent the proportion of each source of funds used to finance the rate base assets and the cost of each source of funds represents what the company must pay for each type of capital it uses, including debt and common equity.

For utilities that are regulated on an original cost rate base, as is typical in Canada, including Newfoundland and Labrador, and the U.S., in most cases, the cost of debt is an embedded cost, or weighted average of the costs that were determined at the time the debt was issued.

The utility cost of equity is a forward-looking cost, which, in accordance with the opportunity cost principle articulated above, represents the return that an equity shareholder expects to earn on an equity investment. It also represents the return that an equity investor requires in order to commit equity funds to or retain equity funds in an equity investment. From the perspective of the firm, it represents the cost that must be paid in order to attract and retain equity funding.

The overall cost of capital to a firm depends, in the first instance, on business risk. Business risk comprises the fundamental characteristics of the business and the political/regulatory operating environment that together determine the probability that future returns (including the return on and of the capital invested) to investors will fall short of their expected and required returns. Business risk thus relates largely to the assets of the firm.

The cost of capital is also a function of financial risk. The use of debt in a firm's capital structure creates a class of investors whose claims on the cash flows of the firm take precedence over those of the equity holder. Financial risk refers to the additional risk that is borne by the common equity shareholder because the firm is using debt to finance a portion of its assets. The capital structure, comprised of debt and equity, can be viewed as a summary measure of the financial risk of the firm. Since the issuance of debt carries unavoidable servicing costs which must be paid before the equity shareholder receives any return, the potential variability of the equity shareholder's return rises as more debt is added to the capital structure. Thus, as the debt ratio rises, the cost of equity rises.

There are effectively three approaches that can be used to determine the fair return. The first two approaches entail separate determinations of capital structure and return on equity. The third approach establishes an overall allowed rate of return without separately specifying the capital structure and return on equity.

The first approach either accepts the utility's actual capital structure for regulatory purposes or deems a capital structure that does not necessarily equate the total (fundamental business, regulatory and financial) risk of the "subject" regulated company to those of the proxy companies used to estimate the cost of equity. If, at the subject utility's actual or deemed capital

structure, its total (business and financial) risk is higher or lower than that of the proxy companies, the proxies' estimated cost of equity needs to be adjusted upward or downward to arrive at the cost of equity of the specific utility.

The second approach assesses the utility's fundamental business and regulatory risks, and then establishes a capital structure that will equate its total risk with that of the proxy companies. This approach permits the application of the proxy companies' cost of equity without adjustment for differential total risk.

The third approach establishes the overall return (combining capital structure, cost of debt and cost of equity) for proxy companies and applies that overall return to the subject company, adjusted as warranted for differences in total risk between the subject utility and the proxy companies.

All three approaches have been taken by regulators in Canada. The first approach has been used by the BCUC, the Ontario Energy Board (OEB),⁵ and the Régie de l'énergie du Québec (Régie).⁶ The second approach has been used by the AUC (and its predecessor)⁷ and the National Energy Board (NEB).⁸ The third approach has also been utilized by the NEB in setting the allowed return on rate base for Trans Québec and Maritimes Pipelines Inc.⁹

The three approaches are equally valid as long as the overall return, i.e., the combination of capital structure and return on equity in the first two approaches, satisfies all three fair return requirements.

⁵ The Ontario Energy Board historically awarded different returns on equity and capital structures for Enbridge Gas Distribution, Natural Resource Gas and Union Gas.

⁶ The Régie has awarded different capital structures and returns on equity for Gazifère, Gaz Métro and Hydro Québec Distribution and Transmission.

⁷ Alberta Energy and Utilities Board, *Generic Cost of Capital, Decision 2004-052*, July 2, 2004, Alberta Utilities Commission (AUC), *2009 Generic Cost of Capital, Decision 2009-216*, November 12, 2009 and AUC, *2011 Generic Cost of Capital, Decision 2011-474*, December 8, 2011.

⁸ National Energy Board, *Reasons for Decision, Cost of Capital, RH-2-94*, March 1995

⁹ National Energy Board, *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008*, March 2009.

In summary, the various components of the cost of capital are inextricably linked; it is impossible to determine if the return on equity is fair without reference to the capital structure of the utility. Thus, the determination of a fair return must take into account all of the elements of the cost of capital, including the capital structure and the cost rates for each of the types of financing. It is the overall return on capital which must meet the requirements of the fair return standard.

For Newfoundland Power, I have relied on the first approach. Specifically, I analyzed Newfoundland Power's requested forecast capital structure, based on the principles set out in Section IV.C below. I then determined whether, with the proposed capital structure, Newfoundland Power would face a similar level of investment risk to an average risk Canadian utility.

C. PRINCIPLES FOR CAPITAL STRUCTURE DETERMINATION

The following principles should be respected when establishing both the cost of capital generally and a reasonable capital structure for Newfoundland Power:

1. Stand-Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity
4. Ability to Attract Capital on Reasonable Terms and Conditions
5. Comparability of Returns

Each of these five principles is defined below. The five principles which apply to the determination of a reasonable capital structure include the three standards (Principles 3 to 5) which govern a fair return identified in Section III above, reflecting the interdependence between capital structure and ROE.

308 **1. Stand-Alone Principle**

309
310 Under the stand-alone principle:

311
312 a utility is regulated as if the provision of the regulated service were the only activity in
313 which the company was engaged. The cost of providing utility service and rates for
314 provision of that service are to reflect only the expenses, capital costs, risks and required
315 returns associated with the provision of regulated service (National Energy Board,
316 *Reasons for Decision, TransCanada PipeLines Limited, RH-R-1-2002, Review of RH-4-*
317 *2001 Cost of Capital Decision*, February 2003, page 25).

318
319 The stand-alone principle encompasses the notion that the cost of capital incurred by a utility
320 should be equivalent to that which would be faced if it was raising capital in the public markets
321 on the strength of its own business and financial parameters; in other words, as if it were
322 operating as an independent entity. The cost of capital for the company should reflect neither
323 subsidies given to, nor taken from, other activities of the firm. Respect for the stand-alone
324 principle is intended to promote efficient allocation of capital resources among the various
325 activities of the firm. Adherence to the stand-alone principle ensures that the focus of the
326 determination of a fair return is on the use of capital, i.e., their opportunity cost, not the source of
327 the capital. The opportunity cost of capital reflects the return that could be earned if that capital
328 were invested in an alternative venture of similar risk.

329
330 The stand-alone principle, a cornerstone of Canadian utility regulation with a history dating to at
331 least 1978,¹⁰ has been respected by virtually every Canadian regulator in setting both regulated
332 capital structures and allowed rates of returns on equity.

333
334 As Newfoundland Power is a stand-alone regulated entity which raises its own debt on the
335 strength of its own business and financial risk profile, the application of the stand-alone principle
336 is not an issue.

¹⁰ Public Utilities Board of Alberta, *In the Matter of The Alberta Gas Trunk Line Company Act*, Decision C78221, December 21, 1978, pages 19-27.

2. Compatibility of Capital Structure with Business Risks

The capital structure of a utility should be consistent with the business and regulatory risks of the specific entity for which the capital structure is being set. The business risk of a utility is the risk of not earning a compensatory return on the invested capital and of a failure to recover the capital that has been invested. At a high level, because debt financing magnifies business risk, all other things equal, the higher the business risk of the utility, the higher a reasonable common equity ratio would be. The fundamental business risks of a utility include demand, competitive, supply, operating, technology-related and political risks. Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between the utility's customers and its investors.

3. Maintenance of Creditworthiness and Financial Integrity

A reasonable capital structure for Newfoundland Power, in conjunction with the returns allowed on the various sources of capital, should provide the basis for stand-alone investment grade debt ratings in the A category. Debt ratings in the A category ensure that the utility would be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. In contrast to unregulated companies, utilities do not have the same flexibility to defer financing new assets. Utilities are required to provide service on demand, and must access the capital markets when service requirements demand it.

The importance of credit ratings in the A category arises from two factors: market access and cost. Even a utility with split-ratings (that is, one debt rating in the A category and one rating in the BBB/Baa¹¹ category) faces a higher cost of debt and lesser market access relative to a utility with all debt ratings in the A category. Regulated issuers with BBB/Baa ratings can be closed out of the market at times, particularly at the longer end (20-30 year term) of the debt market.¹² Newfoundland Power is principally financing long-term assets. Thus, the Company needs to

¹¹ BBB is the DBRS and Standard Poor's medium grade ratings designation; Baa is the corresponding Moody's designation.

¹² During the period June 11, 2008 to January 29, 2009 inclusive there was not a single issuer without at least one "A" credit rating who was able to issue long-term debt on any terms in the public Canadian debt market.

maintain the financing flexibility required to be able to access debt with long-term maturities in both strong and weak capital market conditions.

Insufficient equity for the level of business risk and/or inadequate credit metrics (which largely reflect the debt/equity structure and cash flows from returns on and of capital) are factors that could result in a downgrade of a utility's debt rating. If a utility experiences a downgrade, the downgrade would not only result in an increase in the cost of the additional debt that the company needs to raise, but it will affect all of the outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing debt holders are the most likely purchasers of future issues, a debt rating downgrade, with the resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.

4. Ability to Attract Capital on Reasonable Terms and Conditions

A higher cost of debt to the utility translates into a higher cost of debt to ratepayers. The relative cost of A rated debt versus BBB rated debt varies with market conditions, but ratings in the BBB category can be materially more costly to ratepayers than ratings in the A category.¹³ As the global financial market crisis demonstrated, capital markets can deteriorate rapidly, and spreads can widen dramatically.

Although the market for lower rated credits in Canada has been growing, it is still relatively small.¹⁴ Institutional investors continue to face limits on the proportion of BBB rated debt they are allowed to hold in their portfolios or are precluded from investing in BBB rated debt. The relatively small size of the Canadian market for BBB rated debt and the limitations on the ability of BBB issuers to raise debt in the long-term end of the debt market underscore the importance of A credit ratings.

¹³ Over the past 15 years, the average spread between yields on long-term BBB-rated and A-rated corporate debt in Canada has been 75 basis points. During the same period, the spread has been as high as 200 basis points.

¹⁴ For the period January 2010 – June 2012, of the \$140 billion of new corporate debt in Canada reported by RBC Capital Markets (*Credit Weekly*, various issues), only 20% was for issues rated in the BBB rating category or lower. Of the 108 issues that were rated in the BBB rating category or lower, only eight were for a term longer than 10 years.

Newfoundland Power is competing for capital in a global market in which there may be unprecedented requirements for energy infrastructure capital, particularly in the power sector. In its 2011 *World Energy Outlook*, the International Energy Agency estimated that between 2011 and 2035 close to \$38 trillion in global cumulative energy infrastructure investment is required, \$17 trillion of which is required by the electricity industry (over \$7 trillion for transmission and distribution assets).¹⁵ The Conference Board of Canada estimates that investment in electricity infrastructure in Canada over the period 2011 to 2030 will be close to \$348 billion.¹⁶ To compete successfully for the required capital, that is, to continue to be able to attract capital on flexible terms and conditions, Newfoundland Power requires financial metrics (which reflect the combination of capital structure and ROE) that are competitive with those of its peers.

Debt ratings in the A category, which depends partly on an appropriate capital structure, and partly on adequate cash flows from earnings and return of capital, would allow Newfoundland Power to attract debt capital on reasonable terms and conditions.

5. Comparability of Returns

As it is the overall return which must meet the comparable returns requirement of the fair return standard, it is the composite of a regulated utility's financial parameters, including the adopted capital structure and allowed returns on capital, that need to be comparable to the returns of similar risk companies.

Comparability of the regulated utility's overall return to its peers, including capital structure, is not only a legal requirement, it is necessary in order to be competitive in the capital markets. Newfoundland Power competes for capital not only with other Canadian regulated companies, but with regulated companies globally, as well as with unregulated companies, both within Canada and globally. The achievement of comparable returns requires recognition of the

¹⁵ International Energy Agency, *2011 World Energy Outlook*, October 2011, Figure 2.20.

¹⁶ Conference Board of Canada, *Shedding Light on the Economic Impact of Investing in Electricity Infrastructure*, February 2012.

financial parameters, including capital structure, of Newfoundland Power's comparable risk peers, including regulated companies throughout North America.

D. BUSINESS RISK PROFILE OF NEWFOUNDLAND POWER

1. Overview

As noted above, business risk comprises the fundamental characteristics of the business (e.g., demand, supply and operating factors) that together determine the probability that future returns to investors will fall short of their expected and required returns. While different business risk categories can be identified, they are inter-related. The regulatory framework, for example, is frequently designed around the inherent demand/competitive risks.

Business risks have both short-term and longer-term aspects. Short-term business risks relate primarily to year-to-year variability in earnings due to the combination of fundamental underlying economic factors and the existing regulatory framework. Long-term business risks are important because utility assets are long-lived. Long-term business risks comprise factors that may negatively impact the long-run viability of the utility and impair the ability of the shareholders to fully recover their invested capital and a compensatory return thereon. As utilities represent capital-intensive investments with very limited alternative uses, whose committed capital is recovered over an extended period of time, it is the long-term business risks that are of primary concern to the investor.

Regulatory risk relates to the framework that determines how the fundamental business risks are allocated between ratepayers and shareholders. The regulatory framework is dynamic: it is subject to change as a result of shifts in underlying fundamental risk factors including the competitive environment, energy policy, and regulatory philosophy.

Because utilities are generally regulated on the basis of annual revenue requirements, the longer-term risks are sometimes downplayed, essentially on the grounds that the regulatory framework will allow the regulator to provide compensation to investors as the risks materialize, through

higher ROEs and/or assurance of return of capital. This premise may not hold. If the utility is losing customers and load, competitive limits on regulated prices may constrain a utility's ability to earn higher returns or recover the invested capital when the risk materializes. Second, utility assets are long-lived. No regulatory panel can bind its successors and thus guarantee that investors will be compensated in the future for risks as they materialize.

2. Demographics and Economic Outlook

Newfoundland Power is a relatively small integrated electric utility serving most of the larger communities on the island portion of Newfoundland and Labrador. The utility serves approximately 247,000 mostly residential and commercial customers, delivers 5,550 GWh of power annually and forecasts an approximately \$950 million rate base in 2014. Newfoundland Power's long-term business risk profile largely relates to the demographics and economic outlook of its service area.

During the past 15 years, the province of Newfoundland and Labrador has benefited greatly from the development and expansion of the oil and gas industry. The oil and gas industry has accounted for approximately 50% of provincial growth since 1997, and was approximately 30% of GDP in 2010. During the 10-year period ending 2011, real GDP growth in Newfoundland and Labrador outpaced Canada as a whole (3.6% versus 1.9%) as well as any of the individual provinces. While the Province's real economic growth was the most rapid of all the provinces, the annual rates of real growth were also by far the most volatile, primarily due to volatility in exports generally and oil and gas production specifically.¹⁷

¹⁷ In 2009, for example, real GDP in Newfoundland and Labrador declined by 10%. The decline in real GDP was significantly less dramatic when adjusted for income earned by non-resident owners of provincial resource-related mega-projects.

Table 1 below compares historic economic indicators that are more closely related to Newfoundland Power's growth to the corresponding data for Canada as a whole.

Table 1

10 Year Compound Growth Rate 2001-2011		
	Newfoundland and Labrador	Canada
Personal Disposable Income ^{1/}	4.5%	4.5%
Retail Sales	4.1%	4.2%
Housing Starts	7.7%	1.4%
Population	-0.2%	1.1%
Employment	1.0%	1.5%
Service Industries (GDP, real)	2.6%	2.6%

^{1/} Data for 2001-2011.

Source: Conference Board of Canada.

As the table shows, the rates of growth in personal disposable income and real GDP of the service producing industries in Newfoundland and Labrador were in line with those for Canada as a whole, employment growth lagged the rest of the country, and, as a result of outmigration, the Province's population declined. Growth in housing starts significantly surpassed the rest of the country, albeit from a relatively small base, predominantly reflecting migration from rural to urban areas. Over this same period (2001-2011), Newfoundland Power experienced annual customer growth of approximately 1.3% and electricity sales growth of approximately 1.8%. Newfoundland Power's growth over this period reflects in part new household formation and in part a high capture rate in new housing.

Over the longer-term, the Conference Board of Canada anticipates that real growth in Newfoundland and Labrador will be relatively modest, at approximately 0.6% per year from 2011 to 2035, compared to 2.1% for Canada as a whole.¹⁸ The relatively low growth forecasts for Newfoundland and Labrador are primarily attributable to a declining labour force resulting from persistent outmigration¹⁹ and a low and falling natural rate of population growth (i.e., an

¹⁸ Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2012*, May 2012.

¹⁹ Since 1982, there have been only two years (2009 and 2010) in which Newfoundland and Labrador experienced positive net migration.

aging population). The Conference Board notes that its forecast rate of real GDP growth is significantly impacted by the expected decline in offshore production, absent which GDP growth would average 1.0% per year from 2011 to 2035. Nevertheless, forecasts for the remaining economic indicators highlighted in Table 1 above also point to limited longer-term growth prospects for the province and for Newfoundland Power. As shown in Table 2 below, Newfoundland and Labrador is expected to lag Canada as a whole in each of the economic indicators.²⁰

Table 2

Newfoundland and Labrador			
	<u>2011-2021</u>	<u>2021-2035</u>	<u>2011-2035</u>
Personal Disposable Income	2.7%	1.7%	2.2%
Retail Sales	2.9%	1.6%	2.1%
Housing Starts	-8.1%	-8.1%	-8.1%
Population	0.0%	-0.5%	-0.3%
Employment	-0.1%	-1.0%	-0.6%
Service Industries (GDP, real)	1.4%	0.9%	1.1%

Canada			
	<u>2011-2021</u>	<u>2021-2035</u>	<u>2011-2035</u>
Personal Disposable Income	3.7%	3.4%	3.6%
Retail Sales	3.9%	3.0%	3.4%
Housing Starts	0.9%	-0.9%	-0.2%
Population	1.2%	1.0%	1.0%
Employment	1.1%	0.7%	0.9%
Service Industries (GDP, real)	2.3%	2.0%	2.2%

Source: Conference Board of Canada, *Provincial Outlook Long-Term Economic Forecast 2012*, May 2012

As detailed in the Company's evidence, Newfoundland Power's service territory has been, in recent years, characterized by migration from rural areas to urban areas. This trend is expected to continue. As a result, the percentage of Newfoundland Power's net distribution investment attributable to small, rural communities is disproportionately high, as summarized in the table below.

²⁰ Newfoundland and Labrador is one of only two provinces, the other being New Brunswick, forecast to experience an absolute decline in population between 2011 and 2035.

515
516

Table 3

	Population		
	Under 1,000	Between 1,000 and 10,000	Over 10,000
Number of Municipalities	133	48	7
Percent of Municipalities	71%	25%	4%
Percent of Customers	14%	43%	43%
Percent of Sales	11%	29%	60%
Percent of Distribution Investment	40%	37%	23%

517 Source: Company data.
518

519 New investment must be made to serve customers who have moved to urban areas, as well as to
520 maintain service in communities with declining populations. As a consequence, the total
521 investment that must be recovered is increasing, but, over the longer term, it must be recovered
522 from an ageing and declining total customer base, potentially putting pressure on the ability to
523 recover the invested capital.

524

525 There has been no material change in the long-term outlook for Newfoundland Power's service
526 area since its last two general rate applications in 2007 and 2009.²¹

527

528 **3. Operating Environment**

529

530 As regards operating risks, the principal risk relates to weather-related service disruption. As
531 indicated in the Company's testimony, Newfoundland Power's service area is characterized by
532 the most severe wind and ice conditions in populated regions of Canada. The need to address
533 supply disruptions due to severe weather conditions entails unanticipated and potentially volatile
534 capital and operating costs. Operating risks have not changed materially since Newfoundland
535 Power's last two general rate applications in 2009 and 2007.

536

537

²¹ The business risk analysis that I conducted in my *Opinion on Capital Structure and Fair Return on Equity* for Newfoundland Power filed in May 2009 similarly concluded that the long-term outlook for the service area had not changed materially since its previous general rate application in 2007.

4. Supply

With respect to supply risks, Newfoundland Power relies on Newfoundland and Labrador Hydro (NLH) for over 90% of its power supply. DBRS views Newfoundland Power's reliance on NLH for most of its supply as a challenge (*Rating Report, Newfoundland Power Inc.*, July 18, 2012), as it has consistently since 1994. Power costs, over which the Company has little control, but which can influence customers' consumption behaviour (e.g., conservation), make up almost two-thirds of Newfoundland Power's costs. As Newfoundland Power has no plans to build additional generating facilities, its dependence on NLH will gradually increase.

5. Regulatory Framework

Newfoundland Power's regulatory framework remains constructive. Newfoundland Power has a weather normalization mechanism²² and a rate stabilization mechanism. The latter allows for pass-through of variations between forecast and actual fuel costs and contains components to account for both energy and demand variances, limiting Newfoundland Power's exposure to both fluctuations in costs of fuel oil and customer demand. The Company also has a variation account for employee future benefits costs.

Newfoundland Power's allowed rate of return on rate base is set within a range of +/- 18 basis points. The corresponding range of return on equity is approximately +/- 40 basis points. Earnings above the upper end of the allowed rate of return on rate base range are credited to an excess earnings account for the benefit of ratepayers. If Newfoundland Power earns below the lower end of the allowed return on rate base range, the under-earnings are to the account of the shareholder. As constructed, the allowed return on rate base range creates an element of asymmetric risk.

²² Weather normalization clauses or deferral accounts are common for utilities, particularly gas distribution utilities, which have significant heating load. In the absence of the weather normalization mechanism, Newfoundland Power's annual revenues would vary widely from year to year, due to its relatively high heating load.

As discussed in further detail below, in August 2009, Moody's adopted a new ratings framework for electric and gas utilities.²³ The new ratings framework gives 50% weight to two factors that reflect regulatory risk, regulatory framework (25% weight) and ability to recover costs and earn returns (25% weight). Moody's assigns letter grades to these factors, using the same rating scale that it uses to assign debt ratings. Moody's first applied its new framework to Newfoundland Power in its March 2010 *Credit Opinion*. On both regulatory framework and ability to recover costs and earn returns, Moody's assigned Newfoundland Power a letter grade of "A". These grades were confirmed in its July 2011 *Credit Opinion*. The grades assigned Newfoundland Power on these two categories are the same as the average grade assigned to all other Canadian utilities that have been rated by Moody's.²⁴ Based on Moody's assessment, Newfoundland Power would be considered of approximately average regulatory risk relative to its Canadian peers.

6. Overall Assessment

In summary, the business risk profile of Newfoundland Power has not changed materially since its last two GRAs in 2007 and 2009.

E. BOND RATINGS AND CREDIT METRICS

Bond ratings or credit ratings are the credit rating agencies' opinion of the credit quality of individual debt obligations or of a debt issuer's general creditworthiness. Credit quality refers to the ability of the issuer to pay the interest and repay the principal on the loan when they are due. Bond ratings are an important determinant of the relative price (credit spread) an issuer will have to pay to obtain new debt.

Bond ratings are partly a function of credit metrics or credit ratios. Credit metrics are objective measurements of a firm's cash flows, earnings, debt leverage and interest coverage used to assess financial strength and credit risk.

²³ Moody's Global Infrastructure Finance, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009.

²⁴ Includes utilities in Alberta, British Columbia, Nova Scotia and Ontario.

For regulated utilities, the debt ratio (and its converse, the equity ratio) is, on its own, a key credit metric, and is a contributing factor to the magnitude of other critical credit ratios, as well as to the bond rating itself. An examination of debt ratings and credit metrics provides valuable insight into a utility's financial strength relative to its peers and into trends over time, and thus into the reasonableness of its capital structure.

Newfoundland Power is rated by two major debt rating agencies, Moody's and DBRS. In August 2009, during Newfoundland Power's 2010 GRA, Moody's upgraded Newfoundland Power's first mortgage bonds from Baa1 to A2 with a Stable outlook.²⁵ The upgrade was made in the context of an industry-wide change, under which the debt rating agency widened the notching between the secured and unsecured debt ratings of investment-grade utilities to two notches.²⁶ The upgrade to Newfoundland Power's First Mortgage Bonds reflected two factors. First, it represented Moody's conclusion that there should be a wider differential between the secured and unsecured ratings of regulated utilities, given the lower default rates of utilities compared to other non-financial corporate issuers. Second, it reflected a one-notch upgrade for Newfoundland Power largely in recognition of its improved and likely sustainable credit metrics

²⁵ The Moody's ratings scale is as follows:

Rating	Rating Definition
Aaa	Highest quality with minimal credit risk
Aa	High quality with very low credit risk
A	Upper medium credit with low credit risk
Baa	Medium grade with moderate credit risk; may possess certain speculative elements
Ba	Have speculative elements and are subject to substantial credit risk
B	Speculative and subject to high credit risk
Caa	Of poor standing and subject to very high credit risk

To ratings within each major category, a modifier of 1 to 3 is appended, with 1 meaning that the obligation ranks in the upper end of its generic rating category and 3 means that the obligation ranks at the lower end of its generic rating category. Ratings of Baa3 or higher are considered investment grade.

²⁶ Over \$90 billion of securities in North America were upgraded. For most utilities with senior secured securities the upgrades were a single notch. Since there was previously no notching differential between Newfoundland Power's senior secured securities' (First Mortgage Bonds) rating and its issuer rating, the upgrade for its First Mortgage Bonds represented a two-notch change.

in 2008.²⁷ At the same time, Moody's assigned an issuer rating to Newfoundland Power of Baa1.²⁸

In August 2009, as noted above, Moody's also adopted a new ratings framework for electric and gas utilities.²⁹ In addition to the two business/regulatory risk factors, to which it gives 50% weight, Moody's methodology for rating gas distribution and electric utilities worldwide also considers diversification (10% weight)³⁰ and financial strength and liquidity (40% weight). The financial strength and liquidity factors are divided into sub-categories with individual weights assigned to the sub-categories. The sub-categories and weights are: Liquidity (10%),³¹ Cash from Operations (CFO) plus Interest/Interest, or CFO Interest Coverage (7.5%), CFO to Debt (7.5%), CFO less Dividends to Debt (7.5%) and Debt to Total Capital (7.5%). Each utility is assigned a rating in each of the eight categories based on the criteria applicable to the factor. The actual rating assigned to the utility is based on the weighted average of the ratings assigned to each of the factors.

For the four credit metrics discussed above, Moody's indicative ranges for A, Baa and Ba ratings based on those factors are set out in the table below:

Table 4

Metric	A	Baa	Ba
CFO Interest Coverage	4.5-6.0X	2.7-4.5X	1.5-2.7X
CFO/Debt	22-30%	13-22%	5-13%
CFO less Dividends to Debt	17-25%	9-17%	0-9%
Debt/Total Capital	35-45%	45-55%	55-65%

Source: Moody's, *Rating Methodology: Regulated Gas and Electric Utilities*, August 2009.

²⁷ In its *Rating Action* (May 2009), Moody's did note that Newfoundland Power's credit metrics remained "somewhat weaker than those of other Baa1-rated low risk regulated utilities."

²⁸ An issuer rating represents Moody's opinion of the ability of entities to honor senior unsecured financial obligations and contracts. At present, all of Newfoundland Power's long-term debt is secured, in contrast to the majority of Canadian utilities, whose long-term debt is mostly unsecured.

²⁹ As noted in Section IV.D, Moody's first applied its new framework to Newfoundland Power in its March 2010 *Credit Opinion*. In assigning the upgrade to Newfoundland Power in August 2009, Moody's principally followed its March 2005 Global Regulated Electric Utilities ratings methodology.

³⁰ Diversification for electric utilities is comprised of market position (5%), which reflects the make-up of the customer base (e.g., dependence on industrial load) and growth potential, and generation and fuel diversity (5%).

³¹ Liquidity encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources.

Although the new Moody's rating methodology released in August 2009 gives weight to a different set of credit metrics than the 2006 methodology,³² there are two metrics common to both, debt/capital and CFO-Dividends to Debt.³³ As the table below shows, Moody's has strengthened its guidelines for the debt ratio across all rating categories and for the CFO-Dividends to Debt ratio in the higher rating categories (A and above).

Table 5

Metric	Rating Category							
	Aa		A		Baa		Ba	
	2006	2009	2006	2009	2006	2009	2006	2009
Debt/ Capitalization	30-40%	25-35%	40-50%	35-45%	50-65%	45-55%	65-85%	55-65%
CFO - Dividends/ Debt	21-26%	25-35%	15-21%	17-25%	10-15%	9-17%	5-10%	0-9%

Newfoundland Power's Moody's ratings and outlook have not changed since the upgrade in August 2009. In its most recent *Credit Opinion* for Newfoundland Power (July 2011), Moody's assigned the following ratings to each of the eight key factors:

Table 6

Factor	Weighting	Rating
Regulatory Framework	25%	A
Ability to Recover Costs and Earn Returns	25%	A
Market Position	5%	Baa
Generation and Fuel Diversity	5%	A
Liquidity	10%	A
CFO Interest Coverage	7.5%	Baa3
CFO to Debt	7.5%	Baa3
CFO-Dividends to Debt	7.5%	Baa2
Debt/Capital	7.5%	Baa2
Indicated Rating from Methodology Grid		A3
Actual Rating		Baa1

Source: Moody's, *Credit Opinion: Newfoundland Power Inc.*, July 19, 2011.

³² The new methodology focuses on cash flow rather than earnings based ratios to reduce the impact from non-cash items such as pension expense.

³³ Referred to as Retained Cash Flow to Debt in the 2006 methodology.

Moody's noted that, while the assigned rating of Baa1 is one notch lower than the rating implied by the grid, the difference in part reflects its belief that Newfoundland Power's future financial metrics will be modestly weaker than those in 2010 due primarily to the reduction in the allowed ROE to 8.38% in 2011 from 9.0% in 2010. Moody's considers, as it had previously, e.g. in the May 2009 *Rating Action* noted above and in previous *Credit Opinions*, that Newfoundland Power's financial metrics are somewhat weaker than those of its Baa1 rated peers in North America, including its sister company, FortisAlberta Inc. The Baa1 rating is one notch lower than the median rating accorded by Moody's to the regulated Canadian companies it rates (Schedule 4).

With respect to its assessment of Newfoundland Power's business and regulatory risk, Moody's continues to conclude that Newfoundland Power operates in a supportive business and regulatory environment. A review of the *Credit Opinions* for Newfoundland Power since March 2009 (most recent available at the time of the Company's last GRA) does not indicate Moody's has materially changed its assessment of Newfoundland Power's business and regulatory environment over the past three years.

According to Moody's, it is unlikely that there will be a downward revision to Newfoundland Power's rating in the near-term. However, Newfoundland Power's rating would likely be downgraded if there were a perceived meaningful reduction in the level of regulatory support combined with weaker liquidity and a sustained deterioration in Newfoundland Power's financial metrics such as CFO interest coverage of less than 2.6 times (compared to Moody's 12-18 months forward view of 3.0 to 3.3 times), CFO to debt in the low teens (versus 15-17% anticipated) and CFO less dividends to debt below 9% (compared to a forward range of 7-13%).

With respect to DBRS, it recently confirmed the rating of Newfoundland Power's senior secured debt of A with a Stable trend.³⁴ Newfoundland Power's DBRS rating has remained unchanged since the beginning of 1996. Newfoundland Power's A debt rating by DBRS is equal to the

³⁴ DBRS, *Rating Report: Newfoundland Power Inc.*, September 10, 2012.

Canadian utility industry average (Schedule 4). Similar to its May 2008 Rating Report,³⁵ DBRS views Newfoundland Power's principal business strengths to be its supportive regulatory framework and stable customer base. The key challenges are related to its reliance on Newfoundland and Labrador Hydro for the preponderance of its power supply, managing forecast risk and limited growth potential.³⁶

With respect to the financial profile, DBRS considers Newfoundland Power to have a strong balance sheet, a reasonable financial profile and reasonable debt leverage. In the January 2012 Rating Report, DBRS noted that Newfoundland Power's coverage ratios had shown gradual improvement (which is consistent with their expectations in the May 2008 Rating Report), with an expectation that credit metrics would remain flat, and within the Company's current credit rating, but recognized that the Company's credit profile was dependent on its future rate applications to the PUB.

F. CHANGES IN ALLOWED CAPITAL STRUCTURE RATIOS FOR CANADIAN UTILITIES

As discussed above, the overall return, which includes both capital structure and ROE, needs to meet the three requirements of the fair return standard. Changes in the capital structure ratios of Newfoundland Power's peers are also a relevant consideration to the assessment of a reasonable capital structure for Newfoundland Power.

Since the settlement on capital structure in the 2010 GRA (September 2009), there have been a number of increases in the deemed common equity ratios adopted for other Canadian utilities with which Newfoundland Power competes for capital.³⁷ The deemed common equity ratios of

³⁵ DBRS, *Rating Report: Newfoundland Power Inc.*, May 5, 2008. At the time of Newfoundland Power's last GRA, this was the most recent report available from DBRS.

³⁶ In its January 2012 Rating Report, DBRS also included as a Challenge the sensitivity of Newfoundland Power's earnings to interest rates. This Challenge has been deleted since the suspension of the automatic adjustment mechanism for return on rate base.

³⁷ Both Enbridge Gas and Union Gas have applied for increases to their deemed common equity ratios, from the 36% that was in place prior to the commencement of their five-year incentive regulation plans (due to expire at the end of 2012) to 40% for Union and 42% for Enbridge, compared to the 40% equity ratio that the OEB has adopted for the Ontario electricity distributors. The two proceedings are on-going.

all but one of the Alberta utilities have increased.³⁸ In its *Generic Cost of Capital Decision 2009-216* (November 2009), the AUC implemented a base two percentage point across-the-board increase in common equity ratios, with some company-specific adjustments to the base increase. The increases that were approved in that decision were confirmed in *Generic Cost of Capital Decision 2011-474* (December 2011).

The base increase in 2009 reflected the following four considerations: (1) the credit crisis warranted an increase in the equity ratios for all utilities to reflect increased risk and the re-pricing of risk; (2) lower ROEs and tax rates required an increase to maintain credit metrics at the same level as in 2004 (the previous generic cost of capital proceeding); (3) the analysis of equity ratios and credit ratings of relatively pure-play Canadian utilities did not indicate any equity ratio increase was required; and (4) the business risk analysis did not indicate major changes in the relative risks of the various utility segments; any increase in equity ratios should be relatively uniform across the utility sectors and individual utilities unless utility-specific factors require otherwise.

With respect to the first consideration, the AUC stated:

“events that drove the original [financial] crisis will be factored into investors’ perceptions. Companies will therefore protect their balance sheets and investors will adjust risk perceptions whether unexpected events present themselves again or not. In order to protect investors’ and ratepayers’ interests, the Commission must award equity ratios that recognize the need for the ongoing viability of the utility even in adverse conditions.” (AUC, *Generic Cost of Capital Decision 2009-216*, page 90)

In addition, since the 2009 settlement on Newfoundland Power’s capital structure, the allowed common equity ratios for several of the BC utilities have increased (FortisBC Energy Inc. and the three Pacific Northern Gas utilities), as have those of a number of the NEB-regulated pipelines. FortisBC Energy Inc.’s common equity ratio was increased by five percentage points, from 35% to 40%, Pacific Northern Gas-West’s equity ratio was also increased by five percentage points (from 40% to 45%) and those of the two divisions of Pacific Northern Gas (N.E.) were increased by four percentage points to 40% as the result of negotiated settlements.

³⁸ For ATCO Pipelines in *Decision 2011-474*, due to the AUC’s conclusion that, due to its integration with NGTL, its business risk had declined significantly.

Foothills, NGTL, and Westcoast have negotiated common equity ratios of 40%, or four (Foothills and Westcoast) to five (NGTL) percentage points higher than at the time of Newfoundland Power's settlement on capital structure in 2009.³⁹

In isolation, the upward trend in the allowed equity ratios of Newfoundland Power's Canadian peers since the settlement on capital structure in 2009 provides support for maintaining Newfoundland Power's regulated common equity ratio at the 45% forecast for the test period.

G. REASONABLENESS OF PROPOSED CAPITAL STRUCTURE

Within a reasonable range, the capital structure for a particular utility is appropriately a decision for management, because management is in the best position to assess its business risks, financing requirements and access to debt and equity capital. Newfoundland Power's actual and approved (for rate setting purposes) common equity ratios have been close to 45% for at least 15 years. In my opinion, Newfoundland Power's proposed capital structure, which contains approximately 45% common equity, remains reasonable, for the reasons summarized below.

1. There has been no material change in the level of business risk to which Newfoundland Power is exposed since which would warrant a change in the common equity ratio from the level agreed to by parties to the negotiated settlement in Newfoundland Power's 2010 GRA and accepted by the Board.
2. Maintenance of debt ratings in the A category is a reasonable objective. With a common equity ratio of approximately 45%, Newfoundland Power's credit metrics have been sufficient to achieve and maintain debt ratings in the A category by both Moody's and DBRS for its senior secured debentures, but only a Baa1 issuer rating (i.e., the rating that would be applicable to unsecured debt) by

³⁹ BCUC, *In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision*, December 16, 2009 ("2009 ROE Decision"); BCUC, Order G-84-10, May 2010, (Pacific Northern Gas Ltd. (PNG-West Division) and Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek and Tumbler Ridge Divisions); National Energy Board, Order TG-03-2010, June 2010, (Foothills Pipe Line Ltd., for 2010-2012); Order TG-05-2010, September 2010, (Nova Gas Transmission Ltd., for 2010-2012); and Order TG-01-2011, January 2011, (Westcoast Energy Inc., for 2011-2013).

Moody's. If the approved common equity ratio were to be lowered, not only would the credit metrics weaken, but also a decision to lower the equity ratio would likely be viewed by the credit rating agencies as a reduction in the level of regulatory support afforded the Company, particularly given Moody's strengthening of the capital structure guidelines in its revised August 2009 ratings methodology.

3. Over the past several years, while Newfoundland Power's common equity ratio has remained relatively constant, the allowed common equity ratios of a number of its Canadian peers have been raised, particularly in Alberta and British Columbia, as well as at the National Energy Board. As noted above the AUC increases were in part to recognize the repricing of risk. As discussed in Section V below, capital market conditions remain unsettled. Persistent risks to the global financial system support, at a minimum, maintenance of Newfoundland Power's equity ratio at previously approved levels.

4. Future investment requirements for power sector infrastructure globally are potentially massive, and may entail significant competition for capital. Newfoundland Power should be positioned so that it can continue to compete successfully for capital, that is, continue to obtain capital as required on reasonable terms and conditions. As noted above, Newfoundland Power's credit metrics have been considered weaker than those of its similarly rated peers.

At the forecast capital structure and its current debt ratings, in my opinion, Newfoundland Power would be viewed by investors as an approximately average risk Canadian utility. The ROE developed below is intended to apply to an average risk Canadian utility, e.g., to Newfoundland Power.

V. TRENDS IN ECONOMIC AND CAPITAL MARKET CONDITIONS

This section addresses broad trends in cost of capital since the oral portion of the 2010 GRA ended in late October 2009. In simple terms, the purpose of this section is to compare the current state of, and risks in, the markets where the costs of the various forms of capital are determined compared to the end of the oral portion of the 2010 GRA. It is also intended to provide an appreciation of the protracted nature of the recovery from the global financial crisis and economic recession and of the recurrent bouts of capital market turbulence in the intervening 2¾ years.

In brief, as of the end of July 2012:

1. The systemic risks to the global financial system, as assessed by the Bank of Canada, are no lower than they were at the end of 2009.
2. Long-term Government of Canada bond yields are much lower than they were at the end of the oral portion of the 2010 GRA. The reduction reflects a confluence of factors, including weak global economic conditions, central bank decisions to keep short-term interest rates low, investor risk aversion/flight to safety and a shrinking pool of risk-free assets. The trend in long-term Government of Canada bond yields is not indicative of the trend in the market cost of equity.
3. Yields on high grade Canadian corporate bonds have also fallen, largely tracking the decline in long-term Government of Canada bond yields. Spreads on high grade corporate bonds, including utility bonds, are slightly higher than they were at the end of the oral portion of the proceeding, indicating that the credit risk is not perceived to have declined.

- 817 4. Investor confidence is lower, equity market volatility is similar and the indicated
818 market cost of equity is higher than it was at the end of the oral portion of the
819 2010 GRA.
820

821 When the 2010 GRA commenced in May 2009, recovery from the global financial crisis was
822 underway. Governments world-wide had already begun to take extraordinary steps, using both
823 monetary and fiscal policy tools, to stabilize the capital markets and real economies. By the
824 close of the oral portion of the 2010 GRA:
825

- 826 1. The 10-year and 30-year Government of Canada bond yields, which had fallen to
827 lows of approximately 2.6% and 3.3% respectively during the crisis, hovered
828 around 3.4% and 3.9% at the end of October 2009. The October 2009 Consensus
829 Economics, *Consensus Forecasts* anticipated that the 10-year Canada bond yield
830 would increase to 3.9% over the next year, suggesting a forecast 30-year Canada
831 bond yield of approximately 4.4%.
832

- 833 2. Spreads on investment grade long-term corporate debt (measured by the DEX
834 Long Corporate Index) had sky-rocketed from close to 100 basis points in early
835 2007 to almost 400 basis points in December 2008. By the end of October 2009,
836 the spreads had retreated to just under 200 basis points.
837

- 838 3. Spreads on the Bloomberg 30-year Canadian A-rated utility bond index, which
839 had averaged approximately 95 basis points between 2003 and 2007, jumped to a
840 peak of over 300 basis points in December 2008, recovering to around 145 basis
841 points at the end of October 2009, corresponding to a yield of 5.35%.
842

- 843 4. The S&P/TSX Index had plummeted by 50% from late May 2008 to early March
844 2009. By the end of October 2009, the equity market had recovered significantly,
845 moving up almost 50% from the market trough. While the market was still over

846 25% below its 2008 peak, investor confidence generally had been on an upward
847 trajectory since the market trough.⁴⁰

848
849 5. In early June 2009, Finance Minister Jim Flaherty announced that there were
850 cautious signs that the Canadian economy, which had been in recession since
851 2008Q4, had stabilized. The October 2009 Consensus Economics, *Consensus*
852 *Forecasts* anticipated positive real GDP growth in 2009Q4, and 2.6% growth in
853 2010.

854
855 Order No. P.U. 43(2009), issued in December 2009, which established an ROE of 9.0% for
856 Newfoundland Power for 2010 at a forecast 30-year Government of Canada bond yield of 4.5%,
857 was premised upon a relatively optimistic outlook for economic recovery following the recession
858 of 2008-2009 and rapid stabilization of capital market conditions from the financial crisis.

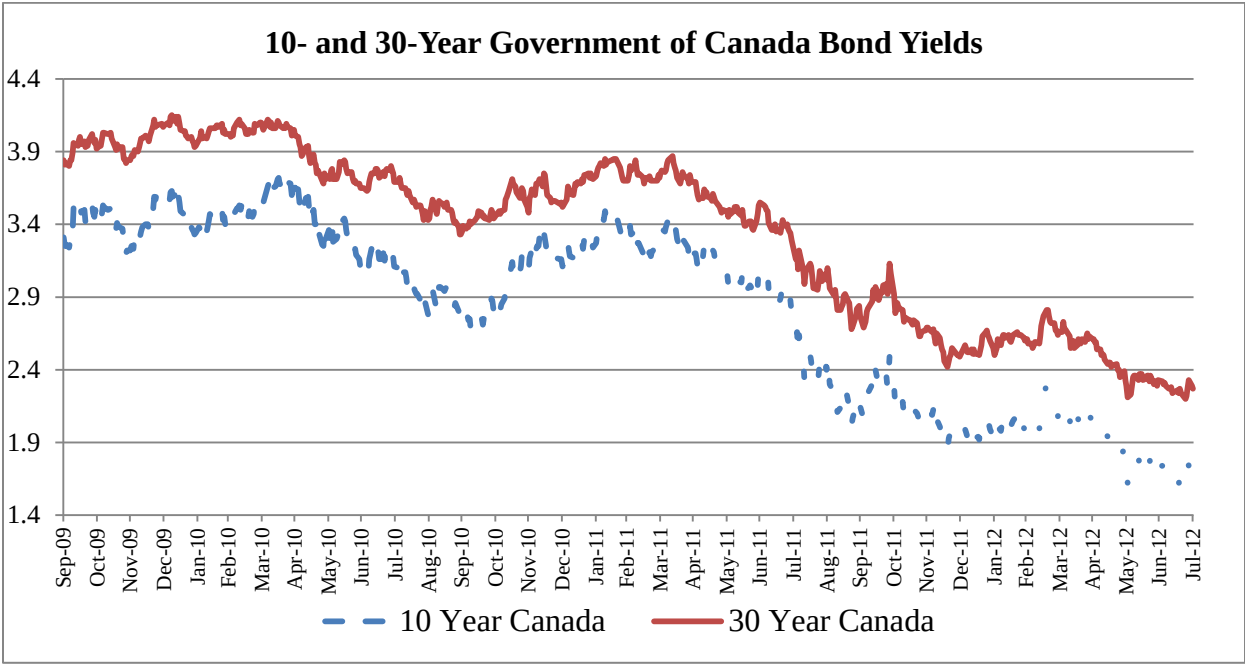
859
860 From the close of the oral portion of the 2010 GRA to April 2010, economic and financial
861 market conditions in Canada continued to improve. Real GDP growth rates in Canada in
862 2009Q4 and 2010Q1 were 4.9% and 5.5% respectively. Between December 2009 and April
863 2010, long-term Canada bond yields hovered within a fairly narrow range of 3.9% to 4.2%.
864 Chart 1 below shows the trends in 10-year and 30-year Government of Canada bond yields from
865 the end of 2009Q3 to the end of July 2012.

866

⁴⁰ As measured by the State Street Investor Confidence Global and North American Indices, which represent a quantitative assessment of investors' risk appetite, by measuring the actual and changing levels of risk contained in investment portfolios. The indices use "the aggregated portfolios of the world's most sophisticated investors, representing approximately 15 percent of the world's investable securities." The higher the index value is, the higher is investor confidence. A level of 100 is considered neutral, that is, it represents the level at which investors are neither increasing nor decreasing their allocations to risky assets. At the end of October 2009, the Global and North American index levels were 108 and 101 respectively, compared to 95 and 86 at the March 2009 equity market trough.

867

Chart 1



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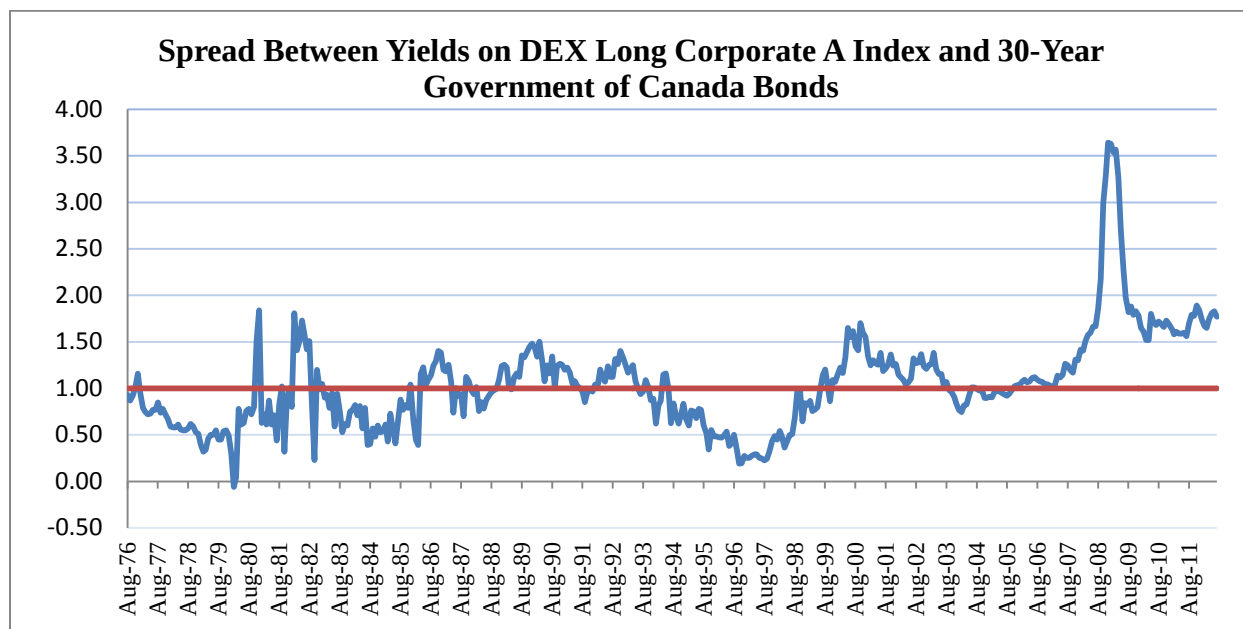
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875

The spread between A-rated corporate and long-term Canada bond yields, having narrowed from the March 2009 peak of 360 to 180 basis points at the end of October 2009, contracted further. The spread reached 150 basis points at the end of April 2010, still well above the pre-crisis long-term average of less than 100 basis points. Chart 2 below sets out the spreads since 1976, the first year that 30-year Government of Canada bond yields were reported.

876

Chart 2



877

878

879 The corresponding spread between the Bloomberg 30-year A-rated utility bond index and the 30-
 880 year Canada bond had also contracted to approximately 130 basis points at the end of April 2010
 881 (yield of 5.3%).

882

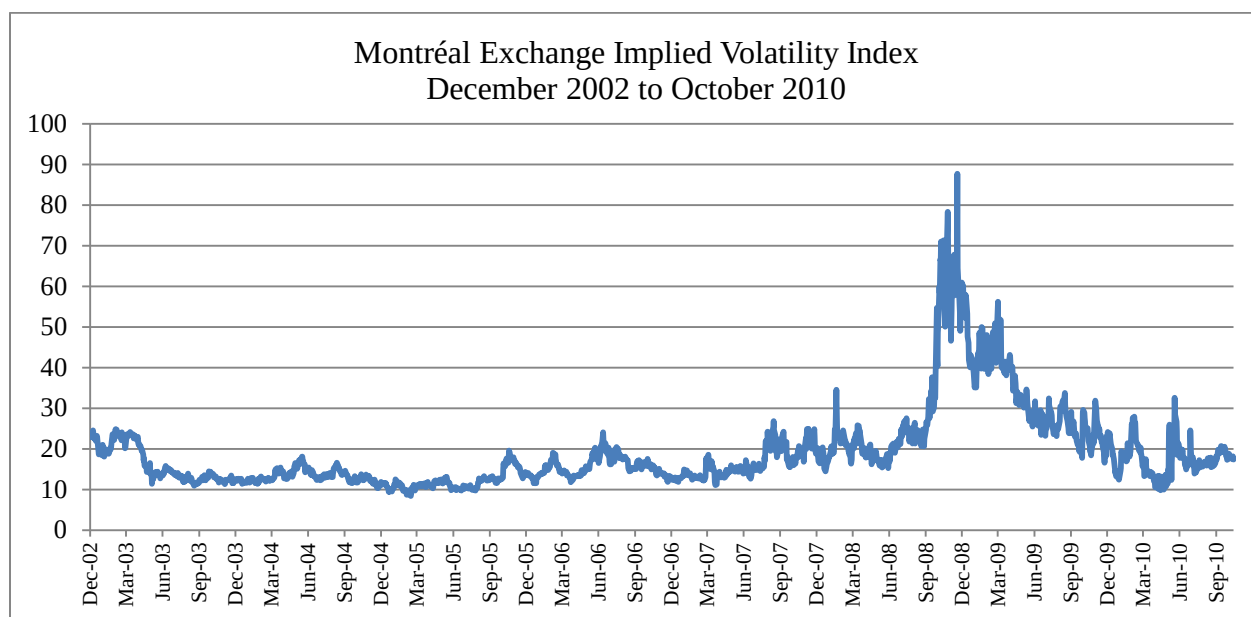
883 The equity market's recovery from its March 2009 trough had continued; the S&P/TSX
 884 Composite Index ended April 2010 approximately 20% below its 2008 peak. Expected equity
 885 market volatility, as measured by the Implied Volatility Index ("MVX"), had fallen to below pre-
 886 crisis average levels. Chart 3 below tracks the MVX from its inception in December 2002 until
 887 mid-October 2010.⁴¹

888

⁴¹ The MVX, introduced by the Montréal Stock Exchange in 2002, measured the market expectation of stock market volatility over the next month. It has been described as a good proxy of investor sentiment for the Canadian equity market: the higher the index, the greater the risk of market turmoil. A rising index reflects the heightened fears of investors for the coming month. The MVX was replaced by a somewhat different measure of implied volatility, called the S&P/TSX 60 VIX Index (VIXC), in October 2010, with historical data available from October 1, 2009. Similar to the MVX, the VIXC measures the market's expectation of stock market volatility over the next month.

889

Chart 3



890

891

892 In May 2010, the sovereign debt crisis in Europe erupted. As the Bank of Canada noted in its
 893 June 2010 *Financial System Review*, “mounting concerns over fiscal sustainability in some euro-
 894 area member states and the exposure of global banks to sovereign risk erupted into a period of
 895 severe stress in international financial markets....”. With Government of Canada bonds
 896 increasingly viewed as a safe haven alternative to U.S. Treasuries, a flight to quality exerted
 897 downward pressure on Canada bond yields. Foreign investors acquired over \$11 billion of
 898 Government of Canada bonds in May 2010,⁴² helping to push long-term Canada bond yields to
 899 their lowest level since April 2009. At the end of May 2010, the yield on long-term Government
 900 of Canada bonds had fallen to 3.73%. The corresponding yields on the Bloomberg 30-year A-
 901 rated utility index had not changed materially (yield of 5.36%), pushing the A-rated
 902 utility/government bond yield spread to close to 165 basis points.

903

904 In its June 2010 *Financial System Review*, the Bank considered that, despite the momentum
 905 gained in the domestic and global economic recovery, the strengthening of the Canadian
 906 financial system and the fact that “bold policy actions taken by European governments and
 907 central banks, with international support, succeeded in heading off a full-blown crisis of
 908 confidence” the risks to Canadian financial stability had increased during the prior six months.

⁴² Statistics Canada, *Canada's International Transactions in Securities*, May 2010.

The strength in the Canadian economy during the first part of 2010 led the Bank of Canada to raise its target overnight rate three times between June and September (from 0.25% to 1.0%). However, in October 2010, the Bank of Canada announced that the economic outlook for Canada had changed and it expected growth to be more muted and the global recovery more gradual than previously forecasted. The changed economic outlook led the Bank of Canada to leave its target overnight rate unchanged, leaving significant monetary stimulus in place, and to conclude that “any further reduction in monetary policy stimulus would need to be carefully considered.”⁴³ The Bank’s statements led economists to conclude that there would likely be no further reduction in monetary policy stimulus before mid-2011.⁴⁴

The relatively modest expected pace of growth reflected a combination of domestic factors (high household debt, which limits consumer spending) and international factors (e.g., the weak labour and residential real estate markets in the U.S., the strained balance sheets of banks and governments in Europe and related austerity programs in those countries, as well as constraints on export growth arising from a combination of tempered growth abroad, the high Canadian dollar and relatively weak productivity).

In its December 2010 *Financial System Review*, the Bank of Canada again assessed the risks to the Canadian financial system, summing up those risks as follows:

1. Sovereign debt concerns in several countries;
2. Financial fragility associated with the weak global economic recovery;
3. Global imbalances;⁴⁵

⁴³ Bank of Canada, *Monetary Policy Report*, October 2010.

⁴⁴ Consensus Forecasts, *Consensus Economics*, November 2010.

⁴⁵ Global imbalances refer to imbalances between savings and investment in the world economies, as reflected in the significant distortions among current account balances, e.g., the large and persistent current account deficit in the U.S. and surplus in China.

4. The potential for excessive risk-taking behaviour arising from a prolonged period of exceptionally low interest rates in major advanced economies; and

5. High leverage of Canadian households.

In all but one (potential for excessive risk-taking behaviour) of these categories, the Bank of Canada concluded that the risks to the Canadian financial system had risen over the previous six months. The nature of most of these risks, like the financial crisis itself, underscores the extent to which economies and capital markets globally are inter-twined.

With the Bank of Canada and other central banks maintaining their policy rates at historically low levels to stimulate economic growth, expectations that the global recovery would be protracted, along with rising risks from global sovereign debt, particularly in Europe and the U.S., and continued strong inflows into Canadian bonds,⁴⁶ Government of Canada bond yields drifted downward during the latter half of 2010, as did forecast yields.⁴⁷ At the end of 2010, the yield on the 30-year Government of Canada bonds was 3.5%; the corresponding yield on the Bloomberg 30-year A-rated utility index had also declined, to just below 5%.

As 2011 unfolded, despite headwinds from the ongoing sovereign debt vulnerabilities in Europe and the complications of a two-speed global economic recovery (i.e., modest growth in advanced economies versus emerging economies at risk of overheating), the Canadian economy appeared poised to advance at a steady, but modest pace. GDP growth in Canada in both the fourth quarter of 2010 and the first quarter of 2011 had been stronger than anticipated. From their third quarter 2010 low of 3.33%, long-term Canada bond yields gradually shifted upward, peaking in early second quarter 2011 at 3.87%. Similarly, the downward trend in forecast Canada bond yields reversed; the consensus forecast of the twelve-month forward 10-year Canada increased each month between November 2010 and April 2011.

⁴⁶ On average over the period 2009-2011 non-residents acquired government of Canada bonds at a rate of approximately \$6.8 billion a month compared to approximately \$1.0 billion per month in 2004-2006. At the end of 2011, foreign holdings were 26% compared to 13% in 2006.

⁴⁷ In May 2010, Consensus Economics, *Consensus Forecasts*, had anticipated that the 10-year Government of Canada bond would yield 3.8% and 4.2% three and twelve months forward; in November 2010, the corresponding forecasts had dropped to 2.8% and 3.3%.

In its June 2011 *Financial System Review*, the Bank of Canada noted decreased risk aversion in financial markets, evidenced by low yields on and record bond issuance in high yield (non-investment grade) debt, as well as low volatility in the equity markets. Nevertheless, in the Bank's view, risks to the financial system were still higher than in their six month earlier assessment, as the risk associated with global sovereign debt had edged higher and the risk associated with the low interest rate environment in advanced economies had increased with the growing popularity of riskier securities and strategies in both Canadian and global markets.

The decrease in investor risk aversion can be seen in the decline in yields on high yield Canadian bonds. High yield bonds are considered to have characteristics of both debt and equity, the latter due in large part to their higher default risk, higher sensitivity to the business cycle and closer connection to the underlying fundamental risks of the issuers than high grade corporate bonds. The yield on the DEX Overall High Yield Bond Index, designed to be a broad measure of the Canadian non-investment grade fixed income market, had fallen from 8.2% at the beginning of October 2009 to an average of 6.7% during 2011Q2.

By July 2011, market sentiment had started to shift. In the July 2011 *Monetary Policy Report*, the Bank of Canada pointed to several developments weighing on investor sentiment, including:

1. declines in equity market prices in both advanced and emerging economies during the prior three months in reaction to increasing uncertainty over the strength of the global recovery;
2. some deterioration in corporate credit markets;
3. a sharp reduction in bond issuance; and
4. shifting of capital into perceived safe haven assets and currencies, putting downward pressure on government bond yields in major advanced economies.

By the end of August 2011, 10-year and 30-year Canada bond yields had fallen to 2.5% and 3.1% respectively. The Bloomberg 30-year A-rated utility index yield had also declined (to 4.7%), but not as sharply. In contrast, the yield on the DEX Overall High Yield Bond Index, which had been yielding 6.5% in March and April 2011, had risen to 7.8%.

Over the next few months, a number of the risks with which the Bank of Canada had expressed concern in earlier reports were experienced. In its October 2011 *Monetary Policy Report*, the Bank of Canada referenced the acute fiscal and financial strains in Europe and concerns about the strength of global economic activity that had led to increased and significant financial market volatility, reduced business and consumer confidence, and an escalation of risk aversion. The increased volatility was triggered by a reassessment of the prospects for global economic growth, as well as heightened worries over debt sustainability in the euro area and uncertainty over the direction of fiscal policy in the United States. According to the Bank, the already negative tone in financial markets was exacerbated by numerous credit rating downgrades of sovereigns and global financial institutions. As the Bank noted, as a result, investment flows shifted toward safer and more liquid assets. Government bond yields in a number of advanced economies, where markets are most liquid and which are perceived to be better credit risks, had fallen sharply. At the same time, prices of riskier assets had declined significantly.

In its December 2011 *Financial System Review*, the Bank of Canada judged that the risks to the stability of Canada's financial system were high and had increased markedly over the past six months. In the Bank of Canada's assessment, over the prior six months, the risks associated with global sovereign debt and an economic downturn in advanced economies had risen, with the risks associated with global imbalances, Canadian household finances and the low interest rate environment unchanged.

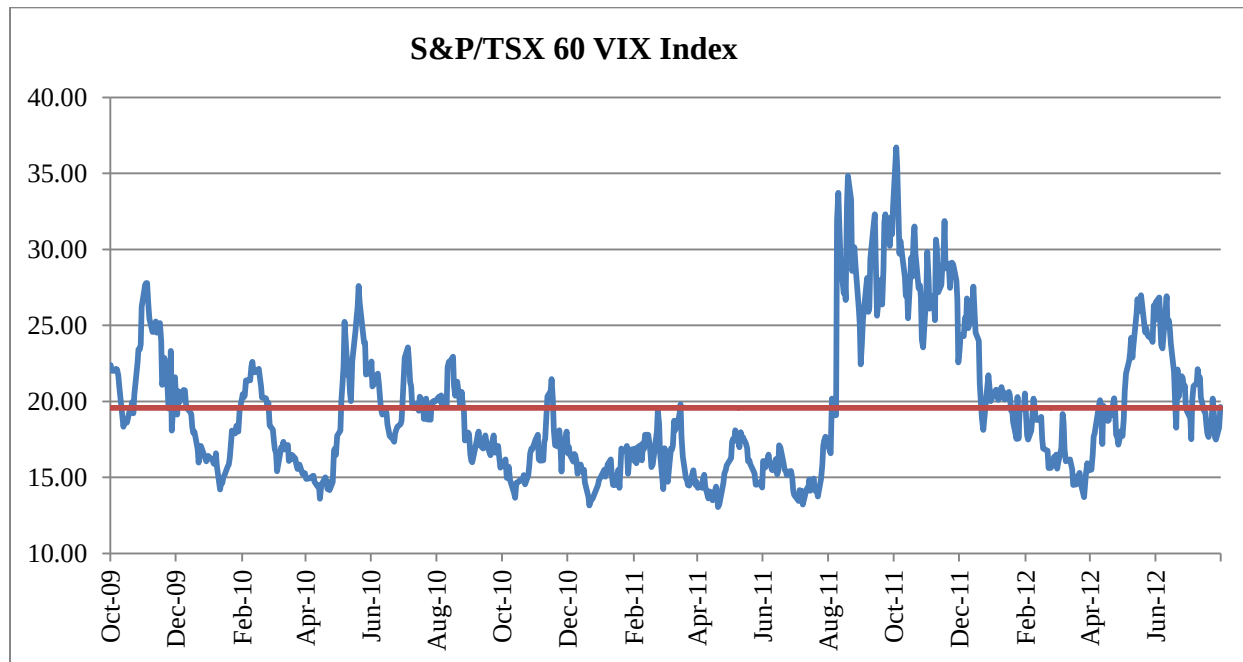
By the end of 2011, 10-year and 30-year Government of Canada bonds were yielding 1.9% and 2.5% respectively.⁴⁸ With the core rate of inflation running at approximately 2.0% during 2011

⁴⁸ Forecasts of long-term Government of Canada bonds had also experienced another significant decline. From November 2010 to April 2011, the monthly 12-month forward consensus forecasts of 10-year Canada bond yields had gradually moved up from 3.3% to 4.0%. They then reversed course; by December 2011, the 12-month forward consensus forecast of 10-year Canada bond yields had declined to 2.7%. Of that 1.3 percentage point decline, 1.1

and expected to average 2.0% over the longer-term,⁴⁹ the real yield on the 10-year Government of Canada bond was negative. Long-term A-rated utility bonds were yielding just over 4%. In contrast, the S&P/TSX Composite ended the year down more than 15% from its early year high. High yield Canadian bonds had continued to climb, reaching 9.5% at the end of September 2011 and ending the year at 9.1%.

As Chart 4 below demonstrates, expected equity market volatility, as measured by the VIXC,⁵⁰ increased markedly in August 2011. On average during November 2011-January 2012, the VIXC was slightly more than 20% higher than during the corresponding period in 2009-2010.

Chart 4



In its January 2012 *Monetary Policy Report*, the Bank anticipated that growth in the Canadian economy throughout 2012 would be weaker than previously forecast, despite the better than anticipated momentum experienced during the second half of 2011. The weaker growth forecast

percentage points occurred between August and October 2011; it represents the largest two month change (positive or negative) observed since the inception of the *Consensus Forecasts* in 1990.

⁴⁹ Consensus Economics, *Consensus Forecasts*, October 2011.

⁵⁰ Chart 4 tracks expected volatility as measured by the S&P/TSX 60 VIX Index (VIXC) from October 1, 2009, the first day for which historical data are available.

was largely due to the continued deterioration in the global economy, resulting in further tightening of international financial markets and continued risk aversion. Economic indicators suggested that the euro area had entered into a recession in the fourth quarter of 2011 and the "deteriorating financial conditions, bank deleveraging, fiscal consolidation and large negative confidence effects" of this recession were expected to last well into 2012. The Bank found that, since the October *Monetary Policy Report*, investors had continued to shift toward safer and more liquid assets, resulting in yields on government bonds in Canada, Germany, the United Kingdom and the United States continuing to decline at the same time that spreads in some of the euro area's largest economies had risen, in some cases to post-euro record highs. Investor anxiety had also continued at high levels, resulting in continued market volatility in global markets.

The International Monetary Fund's *World Economic Outlook Update* released January 24, 2012 echoed the Bank of Canada's concerns, concluding that the global economic recovery is threatened by intensifying strains in the euro area and fragilities elsewhere and that financial conditions have deteriorated, growth prospects have dimmed and downside risks have escalated. The downside risks relate to the potential reduction in credit availability and output in the eurozone arising from sovereign and bank funding pressures, which is transmitted to the rest of the world, excessive fiscal tightening in the U.S. in the near term but failure to arrive at a credible fiscal consolidation strategy in the medium term, a hard landing in emerging economies, and intensified concerns about an Iran-related oil supply shock.

During the first quarter of 2012, there were signs of improvement in the global economy, e.g., an improving labor market in the U.S. and the provision of liquidity by the European Central Bank. Capital markets appeared to calm and risk aversion to moderate, only to be roiled again by a re-intensification of the eurozone sovereign debt crisis, focused on Greece, Spain and Italy.

The Bank of Canada's June 2012 *Financial System Review* noted that:

1. the global recovery remains modest, fragile and uneven, with economic momentum solid in Canada, growth in the U.S. continuing at a modest pace, but

European economic activity expected to remain sluggish and growth in emerging markets having moderated;

2. the principal risk to domestic financial stability continues to stem from sovereign debt strains in the euro area;

3. the risks associated with high levels of household debt in Canada and a potential correction in the housing market are elevated and have not diminished since the Bank's last assessment in December 2011;

4. global current account imbalances continue to represent an important risk to the global financial system, although they have declined slightly and are expected to narrow further over the next several years. The Bank considered that the reason for their narrowing, i.e., deficient demand for imports in advanced economies due to contractionary fiscal policies and household deleveraging, which, in turn, is leading to weak demand for exports from surplus countries and lower global economic growth;

5. the low interest rate environment continues to create incentives for risky behaviour (e.g., drive for yield, particularly by institutions with balance sheets under stress like pension funds and life insurance companies), with the potential for misallocation of credit and the mispricing of risk.

In summary, the Bank of Canada concluded that the systemic risks to the global economy and financial system are high and unchanged since its previous (December 2011) assessment. A review of each of the Bank of Canada's six-month *Financial System Reviews* indicates that the risks to the global economy and financial system rose in each assessment between December 2009 and December 2011, with no change between December 2011 and June 2012.

With increased economic uncertainty, investor risk aversion and global shifting of funds into the safe haven of a smaller pool of highly rated government bonds,⁵¹ long-term Canada bond yields have fallen more than a full percentage point over the past 12 months, hitting a historical low of 2.20% on July 24, 2012. At the end of July 2012, the yield on long-term⁵² Canada bonds stood at 2.27%.

High grade corporate bond yields have also been impacted by the smaller pool of highly rated sovereign bonds, as investors have sought relatively safe fixed income alternatives.⁵³ The end of July 2012 yield on the Bloomberg 30-year A-rated utility index was 3.79%. The corresponding spread with the long-term Government of Canada bond yield, at 150 basis points, was slightly higher than at the close of the oral portion of the 2010 GRA. The higher spread indicates that investors view the risk associated with A-rated utility bonds as no less than at the end of the oral portion of the 2010 GRA.

The current level of Canada bond yields reflects a confluence of factors, including deterioration in the global economic outlook, the Bank of Canada's decisions to maintain its overnight rate at historically low levels, and investor flight to quality, i.e., away from riskier assets including equities. With respect to the last factor, with the numerous ratings downgrades of sovereign bonds that have taken place in the eurozone over the past two years, the supply of safe haven assets has shrunk,⁵⁴ and a scarcity value attributed to high grade sovereign bonds (including

⁵¹ After the United States and the United Kingdom, Canada is the largest non-eurozone economy with AAA sovereign debt ratings. The U.S. was downgraded to AA+ by Standard & Poor's in August 2011, but still has AAA ratings by Moody's, Fitch and DBRS. Despite the S&P downgrade, U.S. Treasury bonds continue to be regarded as a safe haven investment.

⁵² As represented by the yield on the Government of Canada marketable bonds over 10 years Series V39062.

⁵³ The "flight to quality" arising from market conditions is exacerbated by demographic trends, i.e., the aging of the population, and a corresponding shift of investment into fixed income securities. As baby boomers have aged and the ratio of retirees to active workers in the U.S. has increased, there has been a "strong trend in mutual fund flows that suggests investors have begun earnestly diversifying their portfolios toward fixed-income products, in many cases away from equity funds." (Tom Roseen, Lipper Funds, March 1, 2012) Lipper reported that over the past three years mutual fund investors have invested almost \$5 into fixed income funds for every \$1 invested in equity funds. In the three years following the 2001/2002 equity market collapse, almost \$15 was invested in equity markets for every \$1 invested in fixed income markets.

⁵⁴ *Barclays Capital Equity-Gilt Study 2012* concluded that "An important reason for these low yields is the structural decrease in the supply of risk-free assets that is not likely to be corrected in the next few years." In its April 2012 *Global Financial Stability Report*, the International Monetary Fund found that "the number of sovereigns whose debt is considered safe is declining - taking potentially \$9 trillion in safe assets out of the market by 2016 (roughly 16 percent of the projected total). These developments will put upward pricing pressures on the remaining assets considered safe."

those of Canada, the U.S., the U.K. and Germany) that are viewed as least affected by the eurozone debt crisis.

Over the longer-term, 10-year Government of Canada bond yields are forecast to rise to more normal levels, as indicated in Table 7 below.⁵⁵

Table 7

Year	2014	2015	2016	2017	2018-2022
Forecast 10-year Canada	3.6%	4.2%	4.5%	4.6%	4.7%

Source: Consensus Economics, *Consensus Forecasts*, April 2012.

With an average historical spread between 30-year and 10-year Government of Canada bonds of 35 basis points, the corresponding longer term yield on 30-year Canada bonds is approximately 5.0%.

The recent downward trend in long-term Government of Canada bond yields has little, if any, correlation with trends in the market cost of equity. A comparison of equity market indicators points to a higher market cost of equity in mid-2012 versus at the end of the oral portion of the 2010 GRA Application, and, due to the decline in long-term Government of Canada bond yields, an even higher equity market risk premium.

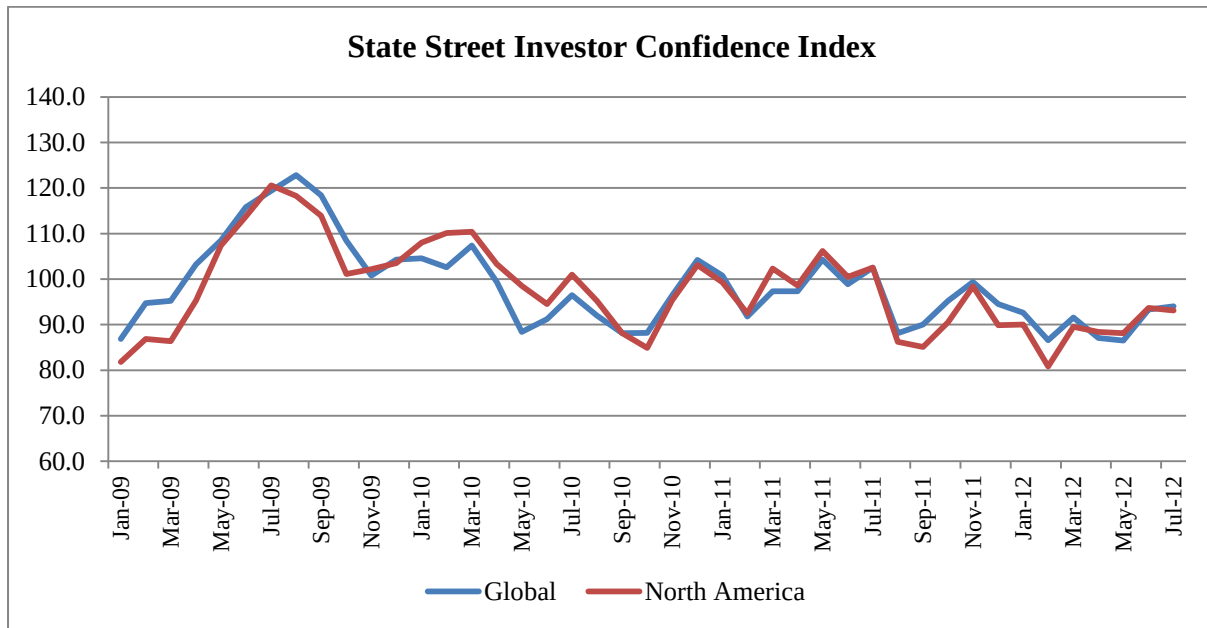
The VIXC averaged close to 19.5 during July 2012, slightly lower than the October 2009⁵⁶ average of 21 (Chart 4 above). High yield bonds, which as noted above, have both debt and equity characteristics, were yielding 8.1% at the end of July 2012, slightly above their 7.8% end of October 2009 level. As referred to above, Global and North American investor confidence levels at the end of July 2012 were well below the October 2009 levels. Chart 5 below shows the Global and North American investor confidence levels from 2009 to July 2012.

⁵⁵ Consensus Economics issues long-term forecasts of key economic indicators, including the 10-year Government of Canada bond yield, twice a year, in April and October.

⁵⁶ The first month for which there are data for the new S&P/TSX 60 VIXC.

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Chart 5



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1146 While both the reported earnings and dividends of the companies that comprise the S&P/TSX
 1147 Composite and the S&P/TSX 60 have increased materially since October 2009, at the end of July
 1148 2012, the two price indices were little changed from their October 2009 levels. As Table 8
 1149 below shows, the resulting index price/earnings (P/E) ratios were lower (and the dividend yields
 1150 were higher) at the end of July 2012 than at the end of October 2009. The comparative earnings
 1151 yields (E/P), the inverse of the P/E ratios, provide a rough guide to the direction in the market
 1152 cost of equity over this time period. The forward E/P ratio of the S&P/TSX 60 has increased
 1153 from approximately 5.6% to 8.0%, implying that the market cost of equity has risen since late
 1154 2009. With Government of Canada bond yields having declined significantly between late 2009
 1155 and mid-2012, the corresponding implication is that the equity market risk premium is higher
 1156 currently than it was in late 2009.

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Table 8

	October 2009	July 2012
S&P/TSX Composite		
Price Index	10,911	11,665
Earnings	\$437.4	\$770.0
Dividends	\$316.0	\$362.0
Trailing P/E	24.9X	15.1X
Dividend Yield	2.9%	3.1%
S&P/TSX 60		
Price Index	648	665
Earnings	\$31.6	\$46.6
Dividends	\$17.7	\$20.8
Trailing P/E	20.5X	14.3X
Dividend Yield	2.7%	3.1%
Forward P/E ^{1/}	17.9X	12.5X
Forward Earnings Yield (E/P)	5.6%	8.0%
10-year Canada Bond Yield	3.4%	1.7%
E/P less 10-year Canada Bond	2.2%	6.3%

^{1/} Forward P/E ratio estimated as market-value weighted average of the month-end prices of equities in the S&P/TSX 60 divided by Thomson Reuters consensus forecast of earnings per share for next fiscal year (2010 and 2013).

Source: www.bankofcanada.ca, Thomson Reuters from S&P Research Insight, *TSX Review*.

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1165 As regards the cost of equity capital for utilities and the implication of the observed decline in
 1166 long-term Canada bond yields, before the onset of the financial crisis, publicly-traded Canadian
 1167 utility dividend yields generally tracked the long-term Government of Canada bond yield. On
 1168 average from 1998-2007, the median dividend yield of the five major publicly-traded Canadian
 1169 utilities⁵⁷ was, on average, 25% **lower** than the corresponding yield on the 30-year Government
 1170 of Canada bond. Since the beginning of 2008, the ratio of utility dividend yields to long-term
 1171 Canada bond yields has risen markedly. At the end of July 2012, the median Canadian utility
 1172 dividend yield was approximately 50% **higher** than the 30-year Canada bond yield.⁵⁸

1173

⁵⁷ Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada Corporation. Excludes Valener Inc., as it was previously a limited partnership (Gaz Métro LP), which converted to a conventional corporation in September 2010. Hereafter referred to as the “five major publicly-traded Canadian utilities”.

⁵⁸ The ratio of Canadian utility dividend yields to A-rated utility bond yields is also significantly higher than it was pre-crisis. At the end of July 2012, Canadian utility dividend yields were approximately 90% of A-rated utility bond yields, compared to approximately 60% from March 2002 (the starting date of the Bloomberg 30-year Canadian A-rated utility bond index) to the end of 2007.

1174 If the pre-crisis relationship between utility dividend yields and the yield on the 30-year Canada
1175 bond were still valid, at the end of July 2012 30-year Canada bond yield of 2.3%, the current
1176 Canadian utility dividend yield should be approximately 1.75% (75% of 2.3%). Instead, it is
1177 3.6%.⁵⁹

1178
1179 The observed change in the relationship between Canadian utility dividend yields (which
1180 represent a significant component of the cost of equity⁶⁰) and long-term Government of Canada
1181 bond yields represents compelling support for the following conclusions:

- 1182
- 1183 1. The estimation of a fair ROE for Newfoundland Power should be based on
1184 multiple tests, including tests that are not benchmarked to the long-term
1185 Government of Canada bond yield.
1186
 - 1187 2. In the application of equity risk premium tests that are benchmarked to the long-
1188 term Government of Canada bond yield, the abnormally low level of recent and
1189 forecast long-term Government of Canada bond yields needs to be taken into
1190 account in the assessment of what constitutes an appropriate equity risk premium.
1191

1192 In light of the persistently unsettled capital markets and the unstable relationships between the
1193 utility cost of equity and Government bond yields, it would be, in my view, difficult to construct
1194 an automatic adjustment mechanism for return on equity at this time that would successfully
1195 capture prospective changes in the utility cost of equity. In particular, an automatic adjustment
1196 formula tied to changes in government bond yields has the potential to unfairly suppress the
1197 allowed ROE.⁶¹

⁵⁹ Alternatively, based on the pre-crisis relationship, all other things equal, the observed 3.6% utility dividend yield would correspond to a 30-year Canada bond yield of approximately 4.8% (3.6%/0.75), rather than the much lower end of July 2012 yield of 2.3%.

⁶⁰ The utility cost of equity can be estimated as the sum of the expected dividend yield and the expected growth in dividends. For a utility with approximately industry average long-run growth potential, the dividend yield component can account for approximately one-half the total estimated cost of equity.

⁶¹ In October 2010 and November 2011 the Régie implemented automatic adjustment formulas for Gazifère and Gaz Métro respectively that change the allowed ROE by 75% of the change in forecast 30-year Government of Canada bond yields and 50% of the change in long-term A-rated utility bond yield spreads. Gaz Métro's allowed ROE for 2012 was set at 8.9%, reflecting a forecast long-term Government of Canada bond yield of 4.0% and a utility bond yield spread of 150 basis points. Based on the most recent forecast and spreads, Gaz Métro's 2013 allowed ROE

In developing a fair ROE for Newfoundland Power, I have proceeded on the premise that the ROE adopted in this proceeding will be in place for at least the proposed 2013-2014 test period. On that basis, in the application of equity risk premium tests, I have developed forecasts of long-term Government of Canada bond yields that encompass the two-year test period 2013-2014.

VI. FAIR ROE FOR NEWFOUNDLAND POWER

A. IMPORTANCE OF MULTIPLE TESTS

The key to determining the fair return on equity (i.e., ensuring that all three requirements of the fair return standard are met) is reliance on multiple tests. There are three different types of tests that have traditionally been used to estimate the fair return on equity:

1. Equity Risk Premium (including, but not limited to, the Capital Asset Pricing Model),
2. Discounted Cash Flow, and
3. Comparable Earnings.

Equity risk premium tests are market-based tests premised on the basic concept of finance that the higher the risk to which an investor is exposed, the higher is the return that the investor requires. Equity risk premium tests entail estimation of the additional premium or incremental return that an equity investor requires relative to a less risky security, e.g., government bonds or corporate bonds.

Discounted cash flow models are based on the proposition that the market price of a security or value of an investment is equal to the present value of all the future expected cash flows from the

will be close to a full percentage point lower than in 2012. The trend in Canadian utility dividend yields indicates the opposite: higher Canadian utility dividend yields in mid-2012 than when the Régie rendered its decision for Gaz Métro in November 2011 point to an increase in the cost of equity for Canadian utilities since late 2011.

1227 security or investment, discounted at a rate that reflects the riskiness of the cash flows. If the
1228 price of an equity share is known, and the expected cash flows can be estimated, the investor's
1229 expected rate of return can also be estimated.

1230
1231 The comparable earnings test is based on the proposition that capital should not be committed to
1232 a venture unless it can earn a return commensurate with that available prospectively in
1233 alternative ventures of comparable risk. The comparable earnings test estimates a fair return on
1234 equity by reference to returns achievable on the book value of companies subject to a similar
1235 level of investment risk to the regulated utility.

1236
1237 Each of the tests is based on different premises and brings a different perspective to the fair
1238 return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that
1239 all three requirements of the fair return standard are met; each of the tests has its own strengths
1240 and weaknesses. Individually, each of the tests can be characterized as a relatively inexact
1241 instrument; no single test can pinpoint the fair return.⁶² Changes to the inputs to individual tests
1242 may have different implications depending on the prevailing economic and capital market
1243 conditions.⁶³ These considerations emphasize the importance of reliance on multiple tests.

1244
1245 Each test has its own set of pros and cons. The discounted cash flow test directly measures
1246 expected utility returns by using utility-specific data only: prices, dividends and estimates of
1247 expected growth in the cash flows to investors. It is subject to an ongoing debate around the
1248 accuracy of investment analysts' forecasts as the measure of investor expectations of growth.
1249 The comparable earnings test explicitly recognizes that the objective of regulation is to emulate
1250 competition and measures returns on the same original cost basis on which utilities are regulated.
1251 It is subject to concerns around selection criteria and whether the results are representative of

⁶² For example, Bonbright states, "No single or group test or technique is conclusive. Therefore, it is generally accepted that commissions may apply their own judgment in arriving at their decisions." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, VA.: Public Utility Reports, Inc., March 1988, page 317).

⁶³ For example, see Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).
Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.

economic returns. The theoretical Capital Asset Pricing Model, an equity risk premium test framed in an elegant, simple construct, has an intuitive appeal. With only three components, it appears, on the surface, easy to apply. Nevertheless, it has its own set of challenges, which are summarized below.

The focus on the challenges of the theoretical CAPM is not to suggest that other tests are necessarily superior, but because a number of Canadian regulators have, in recent years, tended to favour CAPM in their estimation of the allowed ROEs, albeit, in some circumstances, with recognition of its shortcomings and adjustments to the model that may be required. The challenges in the application of the CAPM include:

1. The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require, in contrast to the return that the investor does require or what returns are actually available to investments of comparable risk.
2. The size of the market risk premium cannot be directly observed and is subject to a wide divergence of opinion. While historic risk premiums may provide a perspective on the size of the expected forward-looking market risk premium, historic results are sensitive to the country from which the data are drawn and the time period over which they are measured.
3. The market risk premium is not a fixed quantity; it changes with investor experience and expectations. It would be higher, for example, when investors perceive that the risk of the equity market has increased relative to that of the government bond market and vice versa. However, the model does not readily allow estimation of changes in the size of the market risk premium as economic or capital market conditions (e.g., interest rates) change. The typical application of the CAPM relies heavily on long-term average achieved equity risk premiums in

conjunction with a current or forecast risk-free rate.⁶⁴ In other words, the typical application of the model captures changes in interest rates, by using a current or forecast interest rate as the risk-free rate, but the model itself does not provide any insight into how the equity market risk premium changes when interest rates change.

The need to capture and measure changes in the size of the market risk premium due to changes in the required equity market return and the relative risk of the so-called risk-free security introduces a further complication in the application of the CAPM. This obstacle is particularly problematic with current and forecast long-term Canada bond yields at historically low levels.

4. The achieved equity market risk premium in Canada has been significantly influenced by historic long-term Government of Canada bond yields and returns. The improvement in Canada's fiscal performance over the past fifteen years contributed to a steady decline in long-term Government of Canada bond yields. This secular decline, combined with recent global factors that have led to further downward movement, has resulted in a wide gap between the historical average yields which underpin the calculation of achieved market risk premiums and the prevailing and forecast yields. Since the long-term historic average long-term Government of Canada bond yield exceeds the forecast yield by a wide margin, the long-term average achieved market risk premium is unlikely to be an accurate estimate of the required market risk premium.
5. The objective of using the CAPM (as with any cost of equity model) is to estimate the returns that investors expect or require. Empirical tests of the model have

⁶⁴ Theoretically, an underlying premise of the CAPM is that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the equity market return is highly correlated with the risk-free rate, that is, the equity market return and the risk-free rate move in tandem. Consequently the application of the test frequently proceeds on an assumption directly in conflict with an underlying premise of the model itself.

1307 shown in some cases that the model underestimates the returns for low beta stocks
1308 and overestimates them for high beta stocks and in other cases that there is no
1309 relationship between beta and return.⁶⁵
1310

1311 The challenges associated with the CAPM are of a sufficient magnitude to warrant the
1312 conclusion that it is not inherently superior to other approaches to the estimation of a fair return,
1313 particularly in light of the adjustments to the theoretical CAPM necessary to apply it to the utility
1314 industry.

1315
1316 The OEB and BCUC, in their 2009 utility cost of capital reviews, recognized the challenges of
1317 the CAPM, the need for adjustments, and the need to consider the results of multiple tests.

1318
1319 The OEB stated:

1320
1321 The Board's current formulaic approach for determining ROE is a modified Capital Asset
1322 Pricing Model methodology, and in his written comments, Dr. Booth recommended that
1323 this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on
1324 a risk based opportunity cost model, with overwhelming weight placed on a CAPM
1325 estimate".

1326
1327 This view was not shared by other participants in the consultation, who asserted that the
1328 Board should use a wide variety of empirical tests to determine the initial cost of equity,
1329 deriving the initial ERP [equity risk premium] directly by examining the relationship
1330 between bond yields and equity returns, and indirectly by backing out the implied ERP
1331 by deducting forward-looking bond yields from ROE estimates...

1332
1333 The Board agrees that **the use of multiple tests to directly and indirectly estimate the**
1334 **ERP is a superior approach to informing its judgment than reliance on a single**
1335 **methodology.** In particular, the Board is concerned that CAPM, as applied by Dr. Booth,
1336 does not adequately capture the inverse relationship between the ERP and the long
1337 Canada bond yield. As such, the Board does not accept the recommendation that it place
1338 overwhelming weight on a CAPM estimate in the determination of the initial ERP. (OEB,
1339 *EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated*
1340 *Utilities*, December 11, 2009, pages 45-46)
1341

⁶⁵ The beta is a statistical measure of the sensitivity of the return of a particular security or portfolio of securities to the return on the overall market portfolio. The return of a security with a beta of 0.50 will change by approximately 50% of the change in the return on the overall market portfolio, which by definition, has a beta of 1.0.

The BCUC noted:

that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.

The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd. (BCUC, 2009 ROE Decision, page 45).

All approaches to estimating a fair return require significant judgment in their application, the extent of which depends on the prevailing state of the capital markets. Any individual cost of equity model implicitly ascribes simplicity to a cost whose determination is inherently complex. No single model is powerful enough on its own to produce “the number” that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured.

B. DISTINCTION BETWEEN MARKET AND BOOK VALUES FOR FAIR ROE DETERMINATION

Discounted cash flow (DCF) and equity risk premium models represent conceptually different ways that investors might approach estimating the return they require on the market value of an equity investment. While the DCF and equity risk premium tests estimate the return required on the market value of common equity, regulatory convention applies that return to the book value of the assets included in rate base. The determination of a fair return on book equity needs to recognize the distinction between the market value of equity from which the cost of equity is derived and the book value of equity to which the ROE is applied.

In simple terms, assume that the cost of equity for a company whose stock value is \$200 is 10%. That means that investors require a return, in dollar terms, of \$20. If the book value of the stock

is \$100, and the 10% cost of equity is applied to the \$100 book value rather than the \$200 market value, the resulting return in dollar terms is only \$10, or half that which investors require.

The proxy companies used for the purpose of estimating the cost of equity for Newfoundland Power have market-to-book ratios of approximately 1.7X (U.S. sample) to 2.6X (Canadian sample),⁶⁶ well above the market-to-book ratio of 1.0 that conceptually would equate the return on book value (in dollar terms) to the return estimated by reference to the market-based DCF or equity risk premium tests.

When the allowed return is applied to an original cost book value, a market-derived cost of attracting capital should be converted to a fair and reasonable return on book equity so that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value. Failure to make such a conversion will produce an inadequate level of earnings which will discourage utilities from making investments in critical infrastructure.

It has been suggested that the observed market-to-book ratios of utilities are evidence that the allowed returns on equity are too high (or at least fair).⁶⁷ Such a conclusion is unwarranted.

Book values are accounting-based and reflect the historic impacts of various financial statement accounting conventions (and changes in those conventions over time) for recording such items as depreciation reserves, deferred taxes, pension assets and liabilities, unrealized gains and losses, etc. The sole impact of accounting conventions over time on the recorded amount of equity can cause the book value of equity to diverge significantly from the economic value, particularly in the presence of inflation, and as well as the going concern value of the corporation.

Market values reflect returns that investors expect to earn over the longer-term, not the returns that regulators have historically or recently allowed. Expected returns may be materially higher than allowed returns due to factors such as the anticipation of achievement of synergies among

⁶⁶ Based on daily average share price from May 1, 2012 to July 31, 2012 compared to fiscal year-end 2011 book value per share. Excluding Accumulated Other Comprehensive Income from equity, which reflects cumulative unrealized gains and losses, e.g., in the market value of pension assets, the median market/book ratio of the Canadian utilities is lower, at 2.3X.

⁶⁷ For example, AUC, *Decision 2009-216*, pages 77-78.

existing operations, of higher returns achieved from non-regulated operations, through performance-based regulation and/or growth in the customer or asset base, the perceived ability to improve shareholder returns by leveraging assets, and the ability of the firms to take advantage of growth opportunities beyond the existing asset base.

Further, investors are likely to value utility shares on a relative basis (to other equity securities) rather than on an absolute basis (relative to the utilities' own book values). Over time, the market-to-book ratios of publicly traded utilities companies have generally tracked the overall tenor or "mood" (and the market-to-book ratio) of the equity market as a whole.

Moreover, while some might contend that the market-to-book ratio of utilities should be 1.0 times or close thereto, economic principles suggest otherwise. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets. Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.⁶⁸

C. SELECTION OF COMPARABLE UTILITIES

The estimation of the cost of equity for Newfoundland Power is based in large part on estimates of the cost of equity of comparable risk utilities. Comparable risk companies are used as a proxy for Newfoundland Power to recognize that investors have alternatives for their investment

⁶⁸ See Appendix E for further discussion.

capital. Rational investors will commit funds to the investments that promise the highest return for a given level of investment (business plus financial) risk.

The cost of equity, as estimated using tests applied to proxy companies, reflects the composite of those proxy companies' business, regulatory and financial risks. The cost of equity estimated by reference to a sample of companies is applicable to a specific utility without adjustment if the magnitude of the total risks (business plus financial) of the sample and the specific utility is comparable. In principle, given a sufficiently large universe of utilities, different samples of proxy companies can be selected, each designed to be a proxy for a specific utility. If, however, the total risk of the sample and the specific utility is not equal, the solutions include: (1) changing the specific utility's capital structure; (2) making an adjustment to the proxy companies' cost of equity to reflect the relative total risk of the specific utility; or (3) some combination of (1) and (2). To minimize the extent to which such adjustments are required, the point of departure should be the selection of companies that are of relatively similar total risk to Newfoundland Power.

In Canada, there are only six publicly-traded Canadian companies whose operations are largely regulated.⁶⁹ These companies are relatively heterogeneous in terms of both operations⁷⁰ and size.⁷¹ The relatively small and heterogeneous universe of publicly-traded Canadian utilities means that it is impossible to select a sample of companies that would be considered directly comparable in total risk to any specific Canadian utility.

U.S. regulated companies represent a reasonable point of departure for the selection of a sample of proxies from which to estimate the cost of equity for an average risk Canadian utility. The operating (or business) environments are similar, the regulatory model in the U.S. is similar to

⁶⁹ Canadian Utilities Limited, Emera Inc., Enbridge Inc., Fortis Inc., TransCanada Corporation and Valener Inc.

⁷⁰ Their operations span all the major utility industries, including electricity distribution, transmission and power generation, natural gas distribution and transmission, and liquids pipeline transmission, as well as unregulated activities in varying proportions of their consolidated activities.

⁷¹ Ranging from an equity market capitalization of approximately \$550 million (Valener) to \$31.9 billion (Enbridge).

the Canadian model, Canadian and U.S. capital markets are significantly integrated and the cost of capital environment is similar.⁷²

Equity markets are global; investors are increasingly committing equity funds beyond domestic borders. Canadian investors looking to commit funds to utility equity shares will compare returns available from Canadian utilities to returns available from utility shares globally, including returns from U.S. utilities (both market and allowed). A review of the major Canadian public sector defined benefit pension funds which list all their equity holdings individually shows that the funds have invested in a significant number of U.S. utilities.

While market data for the Canadian utilities provide some perspective on the fair return for Newfoundland Power, a more accurate assessment can be made by reliance on a sample of U.S. utilities drawn from a much broader universe. Nevertheless, not all utilities in the U.S. would be considered of similar risk to Newfoundland Power, just as not all utilities in the U.S. would be similar to each other. Consequently, the sample of U.S. utilities which serve as a proxy for Newfoundland Power was selected according to criteria designed to (1) identify companies that are of relatively similar total risk to Newfoundland Power (2) produce a large enough sample of companies to ensure reliable cost of equity test results. None of the selected utilities will be identical to Newfoundland Power, just as none will be identical to each other, as every regulated

⁷² The OEB's *Report of the Board on the Cost of Capital*, pages 21-22, stated, "Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."^[fn] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed."

The NEB's *Reasons for Decision, Trans Québec and Maritimes Pipelines Inc., RH-1-2008*, page 71, concluded that "In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008."

The BCUC's *2009 ROE Decision*, page 16, found that, "In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics."

company has unique characteristics. What is required is that investors view the proxy companies as of reasonably comparable total (business plus financial) risk to Newfoundland Power.

To ensure comparability with Newfoundland Power, only relatively pure-play U.S. utilities were selected. The selected utilities are rated no lower than BBB+/Baa1 by both Standard & Poor's and Moody's. The median S&P debt rating of the U.S. utility sample is A-, identical to the A-rating accorded on average to the universe of Canadian utilities rated by S&P. The sample average S&P business risk category (Excellent) is the same as the assigned to the majority of Canadian utilities rated by S&P.⁷³ The median Moody's rating for the U.S. utility sample is Baa1 (Schedule 13, page 1 of 2), the same as Newfoundland Power's issuer rating, and equal to the median of the ratings that Moody's has assigned to Canadian gas and electric utilities.⁷⁴ The average and median *Value Line* Safety ranks of the U.S. utility sample are 1.5 and 2 respectively (Schedule 13, page 1 of 2); the Safety ranks of the two Canadian regulated companies covered by *Value Line* (Enbridge Inc. and TransCanada Corp.) are 1 and 2 respectively.⁷⁵ The average difference in the adjusted monthly betas of publicly-traded Canadian utilities and U.S. utility sample for five-year periods ending 1993-2011 has been minor (Schedule 12, pages 1 and 4 of 6). Even if equity investors viewed the U.S. utility sample as facing higher business (combined operating and regulatory) risk than an average risk Canadian utility, the U.S. utility sample has higher common equity ratios (lower financial risk). The average common equity ratio of the sample of U.S. utilities is approximately 50% (Schedule 6), compared to Newfoundland Power's 45% common equity ratio and the median 40% actual common equity ratio of investor-owned Canadian utilities with rated debt (Schedule 5).⁷⁶

⁷³ Standard & Poor's assigns a business risk ranking to each of the companies it rates. There are six business risk categories, ranging from "Excellent" to "Vulnerable".

⁷⁴ Including FortisBC Energy Inc. (A3), FortisBC Energy (Vancouver Island) Inc. (A3), FortisAlberta (Baa1), FortisBC Inc. (Baa1), Hydro One (Baa1 on a stand-alone basis), Newfoundland Power (Baa1), and Nova Scotia Power (Baa1).

⁷⁵ The Safety rank represents *Value Line's* assessment of the relative total risk of the stocks. The ranks range from "1" to "5", with stocks ranked "1" and "2" most suitable for conservative investors. The most important influences on the Safety rank are the company's financial strength, as measured by balance sheet and financial ratios, and the stability of its price over the past five years.

⁷⁶ Appendix B provides both details of the selection criteria and information on the selected U.S. utilities' operations and regulation, including for each a list of the regulatory mechanisms that have been adopted. Schedule 13, page 1 of 2 provides additional quantitative and qualitative data for the selected U.S. utilities. The most recently allowed ROEs and capital structures for the operating companies are found on Schedule 13, page 2 of 2.

D. EQUITY RISK PREMIUM TESTS

1. Conceptual Underpinnings

Equity risk premium tests are premised on the basic concept of finance that the higher the risk to which an investor is exposed, the higher is the return that the investor requires. Since an investor in common equity takes greater risk than an investor in bonds, the former requires a premium above bond yields in compensation for the greater risk. Equity risk premium tests are a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value.

Equity risk premium tests, similar to the other tests used to arrive at a fair return, are forward-looking, that is, they are intended to estimate investors' future equity return requirements. The magnitude of the differential between the required/expected return on equities and the risk-free rate is a function of investors' willingness to take risks and their views of such key factors as inflation, productivity and profitability. Because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic/capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data as the point of departure. An equity risk premium can be estimated relative to a risk-free rate, for which a government bond yield is typically the proxy, as well as relative to utility bond yields, depending on the type of equity risk premium test being conducted.

Three equity risk premium tests were used to estimate the utility cost of equity:

1. Risk-Adjusted Equity Market Risk Premium Test
2. DCF-Based Equity Risk Premium Test
3. Historic Utility Equity Risk Premium Test

2. Risk-Free Rate

The application of equity risk premium tests in relation to a risk-free rate requires a forecast of the risk-free rate to which the equity risk premium is applied. A forecast long-term (30-year) Government of Canada bond yield is most widely used as the risk-free rate, although long-term Government of Canada bond yields are not risk-free. They are considered to be free of default risk, but are subject to interest rate risk.⁷⁷ Use of the long-term government bond yield recognizes (1) the administered nature (determined by monetary policy) of short-term rates; and (2) the long-term nature of the assets to which the utility equity return is applicable.

For 2013-2014, the yield on the long-term (30-year) Government of Canada bond, based on the available forecasts, is expected to be approximately 3.5%.⁷⁸

Although the 30-year Government of Canada bond yield is expected to rise from its current historically and abnormally low levels over the next three years, it is still anticipated to average well below levels expected to prevail over the longer-term. Over the longer-term (2016-2022), Consensus Economics' survey of economists anticipates that the 10-year Canada bond yield will average close to 4.7%.⁷⁹ The corresponding 30-year Canada bond yield, assuming the historical long-term average spread between 30-year and 10-year Canada bonds of 35 basis points prevails, would be approximately 5.0%. At the relatively low expected level of the risk-free rate needs to be expressly recognized in the estimation of the magnitude of the market and utility equity risk premiums can be expected to be higher than their long-run average values.^{80, 81}

⁷⁷ If interest rates rise, the value of the bond will decline.

⁷⁸ Comprised of a forecast yield of 3.0% for 2013, based on the forecasts of BMO Capital Markets, CIBC World Markets, Desjardins Economic Studies, RBC Economics, ScotiaBank Group and TD Securities, and a forecast yield of 4.0% for 2014, based on Consensus Economics, *Consensus Forecasts*, April 2012. Consensus Economics publishes a long-term forecast twice annually, in April and October. Consensus Economics' April 2012 forecasts for the 10-year Government of Canada bond yield were 3.6% for 2014. A spread of 35 basis points (long-term average) to 60 basis points (July 2012) was added to the 10-year Government of Canada bond yield forecasts to arrive at the 30-year Government of Canada bond yield forecast for 2014.

⁷⁹ Consensus Economics, *Consensus Forecasts*, April 2012.

⁸⁰ In *Decision 2011-474*, the AUC concluded "it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates." (paragraph 56) Further, it considered that "it would not be correct to assume that the currently expected market equity risk premium is necessarily equal to its long-term average value"

3. Risk-Adjusted Equity Market Risk Premium Test

3.a. Conceptual and Empirical Considerations

The risk-adjusted equity market risk premium approach to estimating the required equity market risk premium for a utility entails (1) estimating the equity risk premium for the equity market as a whole; (2) estimating the relative risk adjustment; and (3) applying the relative risk adjustment to the equity market risk premium, to arrive at the required utility equity market risk premium. The cost of equity is thus estimated as:

$$\text{Risk-Free Rate} + \left\{ \text{Relative Risk Adjustment} \times \text{Market Risk Premium} \right\}$$

The risk-adjusted equity market risk premium test is a variant of the Capital Asset Pricing Model (CAPM). The CAPM attempts to measure, within the context of a diversified portfolio, what return an equity investor should require (in contrast to what the investor does require). Its focus is on the minimum return that will allow a company to attract equity capital.

In the CAPM, risk is measured using the beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on the S&P/TSX Composite, and the returns on individual stocks or portfolios of stocks.

(paragraph 57) concluding "that the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates." (paragraph 58)

⁸¹ As stated in the March 2012 *Barclays Capital Equity-Gilt Study* :

Our analysis suggests that current equity prices are consistent with future returns that are not far from historic norms. By contrast, rates of returns on risk-free assets stand out as abnormally low, as they are currently negative on an inflation adjusted basis in nearly all cases. An important reason for these low yields is the structural decrease in the supply of risk-free assets that is not likely to be corrected in the next few years. The implication is that equity risk premia - the difference between the expected yields on equities and risk free assets - are likely to remain historically high even if cyclical factors could lead them to reverse somewhat over the next few years. (page 4)

Barclays concluded that equity risk premia "are meaningfully higher than historical experience." (page 6)

3.b. Equity Market Risk Premium

3.b.(i) Overview

The estimation of the expected/required market risk premium from achieved market risk premiums is premised on the notion that investors' return expectations and requirements are linked to their past experience. Basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to reflect as broad a range of event types as possible to avoid overweighting periods that represent "unusual" circumstances. On the other hand, the objective of the analysis is to assess investor expectations in the current economic and capital market environment. Consequently, the analysis of historic returns and risk premiums focused on both the post-World War II period (1947-2011)⁸² and on longer periods. My analysis of historic returns and risk premiums was based on the Canadian experience as well as on the U.S. experience as a relevant benchmark for estimating the equity risk premium from the perspective of Canadian investors. The U.S. experience is relevant given the close relationship between the two economies, the fact that the U.S. has historically been the single largest alternative destination for Canadian portfolio investment (See Appendix A, page A-15) and the similarity between historical Canadian and U.S. equity market returns and equity return volatility.

⁸² Key structural economic changes have occurred since the end of World War II, including:

1. The globalization of the North American economies, which has been facilitated by the reduction in trade barriers of which GATT (1947) was a key driver;
2. Demographic changes, specifically suburbanization and the rise of the middle class, which have impacted on the patterns of consumption;
3. Transition from a resource-oriented/manufacturing economy to a service-oriented economy; and
4. Technological change, particularly in the areas of telecommunications and computerization, which have facilitated both market globalization and rising productivity.

3.b.(ii) Historic Returns and Risk Premiums

Table 9 below summarizes the achieved equity and government bond returns and the corresponding experienced risk premiums for Canada and the U.S.⁸³

Table 9

Period	Stock Return	Bond Total Returns	Bond Income Returns	Risk Premium Over Bond Total Returns	Risk Premium Over Bond Income Returns
Canada					
1924-2011	11.4%	6.6%	6.0%	4.8%	5.4%
1947-2011	11.8%	7.1%	6.7%	4.7%	5.0%
U.S.					
1926-2011	11.8%	6.1%	5.2%	5.6%	6.6%
1947-2011	12.3%	6.6%	5.9%	5.7%	6.4%

Source: Schedule 8.

The raw data in Table 9 show that, on average, equity returns in Canada have averaged approximately 11.5% to 11.75%, compared to average bond income⁸⁴ returns of approximately 6.0% to 7.0%, resulting in average achieved risk premiums relative to bond income returns in the range of approximately 5.0% to 5.5%.⁸⁵ The slightly lower achieved equity risk premium relative to bond income returns achieved during the post-World War II period reflects a slightly higher average equity return relative to the longer period, which was more than offset by higher bond income returns.

The corresponding raw data for the U.S. indicate average equity market returns of approximately 11.75% to 12.25%, corresponding to average bond income returns of approximately 5.25% to

⁸³ The equity and bond market returns in Table 9 represent arithmetic averages of historical returns. Appendix A explains the rationale for using arithmetic, rather than compound (geometric) averages for the purpose of estimating the expected return from historic returns.

⁸⁴ The bond income return reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. The bond income return is similar to the bond yield. The bond total return includes annual capital gains or losses and reinvestment of the bond coupons. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.

⁸⁵ The median risk premiums over the periods 1924-2011 and 1947-2011 were somewhat higher, 6.2% and 5.5%, respectively, relative to bond income returns.

6.0%, resulting in an average achieved equity risk premium of approximately 6.5% relative to bond income returns.

3.b.(iii) Canadian Equity and Government Bond Returns

To assess whether there has been a trend in the underlying returns which generate the achieved risk premiums, the returns and risk premiums for each decade over the period 1932 to 2011 were examined and are presented in Table 10 below.

Table 10

10-YEAR AVERAGE CANADIAN MARKET RETURNS					
	Canadian Stock Returns	Canadian Bond Total Returns	Canadian Risk Premium Over Bond Total Returns	Canadian Bond Income Returns	Canadian Risk Premium Over Bond Income Returns
1932-1941	9.1%	6.6%	2.5%	3.6%	5.5%
1942-1951	18.9%	2.4%	16.6%	2.9%	16.0%
1952-1961	13.2%	2.4%	10.7%	4.1%	9.1%
1962-1971	7.8%	4.5%	3.2%	6.1%	1.7%
1972-1981	13.6%	2.7%	11.0%	9.7%	3.9%
1982-1991	10.8%	16.5%	-5.7%	11.1%	-0.2%
1992-2001	11.4%	10.8%	0.6%	7.1%	4.3%
2002-2011	9.1%	8.8%	0.3%	4.4%	4.7%

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*.

Table 10 indicates a clear pattern in bond returns, reflecting:

1. rising bond yields in the 1950s through the early 1980s, which produced capital losses on bonds and low bond total returns;
2. high total bond returns and yields in the 1980s, reflecting the high rates of inflation; and,

3. high bond total returns in the 1990s and the 2000s, relative to income returns, reflecting the secular decline in long-term government bond yields, which resulted in capital gains and total bond returns, well in excess of the concurrent bond yields.⁸⁶

In contrast to the pattern in bond returns, Table 10 does not indicate a discernible pattern in equity market returns.⁸⁷

However, further analysis of the historical data indicates, as shown in Table 11 below, that, historically, lower bond income returns have been associated with higher achieved risk premiums.

Table 11

Bond Income Returns:	Averages for the Period: 1924-2011			Averages for the Period: 1947-2011		
	Equity Returns	Bond Income Returns	Risk Premium	Equity Returns	Bond Income Returns	Risk Premium
Below 4%	13.9%	3.2%	10.7%	17.9%	3.3%	14.7%
Below 5%	12.6%	3.7%	8.9%	13.8%	3.6%	10.2%
Below 6%	11.1%	4.2%	7.0%	11.6%	4.4%	7.2%
Below 7%	11.3%	4.3%	7.0%	11.9%	4.6%	7.3%
Below 8%	11.8%	4.6%	7.3%	12.6%	4.9%	7.6%
Below 9%	10.9%	4.9%	5.9%	11.0%	5.4%	5.6%
All Observations	11.4%	6.0%	5.4%	11.8%	6.7%	5.0%

Source: www.bankofcanada.ca, Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*.

Table 11 above indicates that, except at the lowest levels of long-term Government of Canada bond income returns, average equity returns have been broadly in the range of approximately 11.0% to 12.5% during the two periods. At bond income returns below 8% (average of 4.5% to 5.0%), the corresponding equity risk premium averaged approximately 7.25% to 7.5%. Only when the highest levels of bond income returns are included do the average achieved equity risk

⁸⁶ The long-term Government of Canada bond yield is equivalent to an estimate of the expected return on the bond.

⁸⁷ Slope coefficients of trend lines fitted to the annual equity return data for the periods 1924-2011 and 1947-2011 are estimated at 0.00 for both periods.

premiums drop to approximately 5.5% to 6.0% and then to approximately 5.0% to 5.5%. In other words, the historical data indicate that the equity risk premium has varied with bond yields, i.e., higher risk premiums at lower levels of bond yields and vice versa.

The forecast 3.5% 30-year Government of Canada bond yield for 2013-2014 is 2.5 percentage points lower than the long-term average bond income return (6.0%) and 3.2 percentage points lower than the post-World War II average bond income return (6.7%). The 2013-2014 forecast long-term Government of Canada bond yield of 3.5% suggests an equity risk premium, based on historical risk premiums at similar levels of interest rates, of no less than 8.0%.

3.b.(iv) Impact of Inflation on Equity Market Returns⁸⁸

Theoretically, the expected return on equity should be equal to the sum of the real risk-free cost of capital, the expected rate of inflation and an equity risk premium. Thus, the question arises whether the forward-looking equity nominal (inclusive of inflation expectations) market return should differ from the historic nominal returns due to differences in the historic versus expected rates of inflation. On average, historically, the actual rate of consumer price (CPI) inflation in Canada was higher than the rate of inflation currently forecast to prevail over the longer term. The arithmetic average CPI rate of inflation from 1926-2011 in Canada was 3.0%; the most recent consensus long-term (2013-2022) forecast of CPI inflation is 2.0%.⁸⁹ The lower forecast rate of inflation compared to the historical rate of inflation might suggest that expected nominal equity returns would be lower than they have been historically. However, an analysis of nominal equity returns, rates of inflation and real returns on equity shows that real equity returns have generally been higher when inflation was lower. Table 12 below summarizes the nominal and real rates of equity market returns historically at different levels of CPI inflation.

⁸⁸ The 1998-2002 equity market “bubble and bust” spawned a number of studies of the equity market risk premium that have speculated that the U.S. market risk premium will be lower in the future than in the past. The speculation stems in part from the hypothesis that the magnitude of the achieved risk premiums is due to an increase in price/earnings (P/E) ratios. That is, the historic U.S. equity market returns reflect appreciation in the value of stocks in excess of that supported by the underlying growth in earnings or dividends. The increase in P/E ratios, it has been argued, reflects a decline in the rate at which investors are discounting future earnings, i.e., a lower cost of capital. I analyzed the trends in P/E ratios and equity market returns and determined that there is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward. The analysis is summarized in Appendix A.

⁸⁹ Consensus Economics, *Consensus Forecasts*, April 2012.

Table 12

Inflation Range	Nominal Equity Return	Average Rate of Inflation	Real Equity Return
Less than 1%	15.7%	-1.4%	17.0%
1-3%	12.4%	1.9%	10.4%
3-5%	4.8%	4.1%	0.7%
Over 5%	12.5%	9.2%	3.3%
Avg. 1924-2011	11.4%	3.0%	8.4%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.statscan.ca.

The observed negative relationship between the real equity return and the rate of inflation does not support a reduction to the historic nominal equity rates of return for expected lower inflation for the purpose of estimating the future equity risk premium. The average nominal equity returns in Canada were approximately 11.4% over the longer-term and 11.8% since the end of World War II, or approximately 11.5% to 11.75%.

It also bears noting that, while the average real equity return in Canada over the longer period was 8.4%, the average is materially affected by the inclusion of high inflation years. When years in which inflation exceeded 10% are excluded (seven of 88 observations), the average real equity return is a full percentage point higher, i.e., 9.4%. The corresponding average rate of CPI inflation was 2.3%, similar to the forecast rate of inflation. The average real equity return is similar, at approximately 9.5%, when the years in which inflation exceeded 10% and the same number of abnormally low inflation years (average of -4.1%) are removed. At a real equity return of 9.5% and an inflation rate of 2.0%, the indicated nominal equity return is approximately 11.5%. At a nominal equity return of 11.5%, the market equity risk premium at the forecast long-term Canada bond yield of 3.5% is 8.0%.

3.b.(v) Comparison of Canadian and U.S. Returns and Risk Premiums

A comparison of the returns in Canada and the U.S. over the longer-term and the post-World War II period shows that the equity market returns in the two countries have been similar. On

average the achieved equity market returns in the two countries have been in the approximate range of 11.5% to 12.25% (see Table 9 above).

Despite relatively similar equity market returns, the achieved risk premium (equity market returns less bond income returns) in Canada has been approximately 1.2% to 1.4% lower than in the U.S. The difference in the equity market returns accounts for 0.4% to 0.5% of the difference in the observed risk premiums. Approximately two-thirds of the difference is attributable to higher bond yields historically in Canada. Over the period 1926-1997, the difference between long-term government bond yields in Canada and the U.S. averaged close to 100 basis points.

With the vastly improved economic fundamentals in Canada (e.g., lower inflation, balanced budgets), the risk of investing in Canadian government bonds (relative to equities) declined and the differential between Canadian and U.S. government bond yields that existed historically fell. Between 1998 and 2011, the average yield on 10-year Government of Canada bonds was only slightly higher (+6 basis points) than the corresponding average yield on 10-year U.S. Treasury bonds. The corresponding differential between the yields on the long-term (30-year) government bonds was -16 basis points.

With respect to the relative risk of the two equity markets, the historic annual volatility in the two markets over the longer-term has been quite similar. The table below compares the average arithmetic equity market returns and the corresponding standard deviations, as well as the compound (geometric) average returns from 1926-2011 and post-World War II (1947-2011) for the two countries.

Table 13

	Canada			United States		
	Arithmetic Average	Standard Deviation	Compound Average	Arithmetic Average	Standard Deviation	Compound Average
1926-2011	11.2%	18.9%	9.6%	11.8%	20.3%	9.8%
1947-2011	11.8%	17.1%	10.4%	12.3%	17.4%	10.9%

Source: Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*, Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

To put the differences in the relative risk of the two markets in perspective over these two time periods, it is useful to compare the differences between the arithmetic and compound average returns in the two markets. The difference between the arithmetic and compound average returns is approximately equal to one-half of the variance in the annual returns. The variance in the arithmetic average returns in turn is equal to the standard deviation squared. The larger the difference between the arithmetic and compound averages, the more volatility there has been in the annual returns.

For the longer period, 1926-2011, the difference in the arithmetic and compound average returns in Canada was 1.7%; the corresponding difference in the U.S. was 2.0%, a difference between the two of approximately 0.3%. During the post-World War II period, the difference in both Canada and the U.S. was approximately 1.4%. The two differentials between the Canadian and U.S. arithmetic and compound average returns can be interpreted as the difference in equity return required for the difference in volatility between the two markets. In other words, based on the longer period, the equity market return required would be 0.30% higher in the U.S. than in Canada and based on the post-World War II period, the equity market return required would be the same in the U.S. and in Canada. In sum, the differences are *de minimus*.⁹⁰

With similar government bond yields in the two countries for more than a decade, U.S. historical equity market risk premiums are a relevant benchmark for the estimation of the forward-looking equity market risk premium for Canadian investors. As shown in Table 9 above, the average achieved equity risk premium relative to bond income returns in the U.S. has been approximately 6.5%. Similar to Canada, however, as demonstrated in Table 14 below, higher risk premiums have been associated with lower bond income returns.

⁹⁰ Since the onset of the financial crisis (August 2007) to the end of July 2012, based on the standard deviations of weekly price changes in the S&P/TSX Composite (Canada) and the S&P 500 (United States), the two markets have exhibited similar volatility.

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Table 14

Bond Income Returns:	Averages for the Period: 1926-2011			Averages for the Period: 1947-2011		
	Equity Returns	Bond Income Returns	Risk Premium	Equity Returns	Bond Income Returns	Risk Premium
Below 4%	13.9%	2.9%	11.0%	19.0%	2.9%	16.1%
Below 5%	11.9%	3.3%	8.6%	13.2%	3.6%	9.6%
Below 6%	11.1%	3.6%	7.5%	11.7%	4.0%	7.6%
Below 7%	10.7%	3.9%	6.8%	11.0%	4.4%	6.6%
Below 8%	10.7%	4.4%	6.3%	10.9%	5.0%	6.0%
Below 9%	11.3%	4.7%	6.6%	11.7%	5.3%	6.4%
All Observations	11.8%	5.2%	6.6%	12.3%	5.9%	6.4%

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Source: Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*.

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As Table 14 shows, the 6.6% average historical equity risk premium corresponds to an average bond income return of 5.2%, approximately 1.7 percentage points higher than the 2013-2014 forecast 3.5% 30-year Canada bond yield. The experienced equity risk premium at levels of bond income returns similar to the 2013-2014 forecast 30-year Canada bond yield was in the range of approximately 7.5% to 9.5%.

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3.b.(vi) Equity Market Risk Premium

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Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis, and the observed negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the nominal equity market return is approximately 11.5%, based on Canadian equity market returns and supported by U.S. equity market returns. The analysis of Canadian equity risk premiums in conjunction with bond income returns supports a market equity risk premium of no less than 8.0% at the forecast 3.5% 30-year Government of Canada bond yield. Based on U.S. data, a similar analysis supports an equity risk premium of 7.5% to 9.5% (mid-point of 8.5%). With preponderant weight given to the Canadian data, the indicated equity market risk premium at the forecast 3.5% 30-year Government of Canada bond yield is no less than 8.0%.

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3.c. Relative Risk Adjustment

3.c.(i) Overview

The market risk premium result needs to be adjusted to recognize the relative risk of an average risk Canadian utility, e.g., Newfoundland Power. The theoretical CAPM holds that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments. In the simple, one risk variable CAPM, the non-diversifiable risk is captured in beta.

Impediments to reliance on the equity beta as the sole relative risk measure include:

1. The assumption that all risk for which investors require compensation can be captured and expressed in a single risk variable. The determination of the return on equity that investors require for bearing the risk of a particular investment is more complex than the single risk variable, beta, implies.
2. The only risk for which investors expect compensation is non-diversifiable equity market risk; no other risk is considered (and priced) by investors. This premise erroneously implies that investors are only concerned with the price volatility of their equity investments, not the underlying fundamental risks that may lead to loss of earning power and ultimately a failure to recover their invested capital.
3. The assumption that the observed calculated betas (which are simply a calculation of how closely a stock's or portfolio's price changes have mirrored those of the overall equity market) are a good measure of the relative return requirement. Empirical tests of the CAPM and experienced returns undermine the validity of that assumption.
4. Use of beta as the relative risk adjustment allows for the conclusion that the cost of equity capital for a firm can be lower than the risk-free rate, since stocks that move counter to the rest of the equity market could be expected to have betas that

are negative. In that case, the CAPM would posit that the cost of equity capital would be less than the risk-free rate, despite the fact that, on a total risk basis, the company's stock could be very volatile. The proposition that a firm's cost of equity could be lower than not only its own cost of debt, but even lower than the risk-free rate, is dubious at best.

5. Utilities are not investing in a portfolio of securities. They are committing capital to long-term assets. Once the capital is committed, it cannot be withdrawn and redeployed elsewhere. The CAPM does not capture that reality.

Thus, a risk measurement that reflects those considerations is relevant for estimating the equity risk premium applicable to an average risk Canadian utility.

3.c.(ii) Total Market Risk

These considerations support focusing on total market risk, as well as on beta, to estimate the relative risk adjustment for a utility. The absence of an observable relationship between "raw"⁹¹ betas and the achieved market returns on equity in the Canadian market⁹² provides further support for reliance on total market risk to estimate the relative risk adjustment.

The standard deviation of market returns is the principal measurement of total market risk. To estimate the relative total risk of an average risk Canadian utility, the S&P/TSX Utilities Index was used as a proxy. The standard deviations of monthly total market returns for each of the 10 major Sector Indices of the S&P/TSX Index, including the Utilities Index, were calculated over five-year periods ending 1997 through 2011 (Schedule 9).

To translate the standard deviation of market returns into a relative risk adjustment, utility standard deviations must be related to those of the overall market. The relative market volatility of Canadian utility stocks was measured by comparing the standard deviations of the Utilities

⁹¹ The term "raw" means that the beta is solely a statistical calculation of the historical relationship between the price movements of a stock and the corresponding price movements of the market portfolio.

⁹² See Appendix A, pages A-21 to A-22.

Index to the simple mean and median of the standard deviations of the 10 Sector Indices. Schedule 9 shows the ratios of the standard deviations of the Utilities Index to the mean and median standard deviations of the 10 S&P/TSX Sector Indices. The ratio of the standard deviation of the Utilities Index to the mean and median standard deviations of the 10 major Sector Indices suggests a relative risk adjustment for an average risk Canadian utility in the range of 0.55-0.85, with a central tendency of approximately 0.65-0.70.

3.c.(iii) Historical “Raw” Betas of Canadian Utilities

Schedule 12, pages 1 to 3 summarizes “raw” betas calculated using monthly and weekly price changes⁹³ for the five major publicly-traded Canadian utilities, the TSE Gas/Electric Index, and the S&P/TSX Utilities Index.⁹⁴

As Schedule 12, page 1 indicates, there was a significant decline in the calculated “raw” monthly five-year betas of the individual Canadian regulated utilities between 1994-1998 and 1999-2005 (from approximately 0.50 to 0.0 and slightly negative). Following an increase in 2007 to slightly above 0.50, the “raw” monthly betas for the individual Canadian regulated utilities again declined in 2008 to approximately 0.20 and have remained at a similar level through the end of 2011.

The observed levels and pattern of the calculated “raw” utility betas in 1999-2011 can be traced to four factors: (1) the technology sector bubble and subsequent bust; (2) the dominance in the TSE 300 of two firms during the early part of the “bubble and bust” period, Nortel Networks and BCE; (3) the greater sensitivity of utility stock prices than the equity market composite to rising and falling interest rates (e.g., during the equity market “bubble” of 1999 and early 2000 and

⁹³ The use of price betas for utilities has been criticized on the grounds that the exclusion of dividends from the calculated betas overestimates the betas. A comparison of price and total return (including dividends) betas for Canadian utilities showed that there was no material difference between the two.

⁹⁴ The S&P/TSX Utilities Sector was created in 2002 (with historic data calculated from year-end 1987), when the TSE 300 was revamped to create the S&P/TSX Composite. The Utilities Sector was essentially an amalgamation of the former TSE 300 Gas/Electric and Pipeline sub-indices. In May 2004, the pipelines were moved to the Energy Sector.

during the first half of 2006); and (4) the more extreme price changes of the market as a whole during the financial crisis and the subsequent market recovery.⁹⁵

There can be significant differences in measured “raw” betas depending on the interval over which the change in share price is calculated. Betas calculated using monthly changes in price can differ systematically from betas calculated using weekly changes in prices.⁹⁶ Table 15 below shows that, for the five large Canadian utilities whose shares are regularly traded, the mean and median five-year “raw” betas ending December 2008 to December 2011 calculated using weekly price changes were twice as high as the corresponding mean and median betas calculated using monthly price changes.⁹⁷ These large differences due solely to the choice of interval cast significant doubt on how meaningful calculated betas are as a measure of relative risk.

⁹⁵ Schedule 10 shows that utilities were not the only companies whose betas were negatively impacted by the technology sector bubble and subsequent market decline. To illustrate, the five-year monthly beta ending 1997 of the Consumer Staples Sector was 0.62; the corresponding betas ending 2003 and 2004 were -0.08 and -0.07 respectively. In contrast, over the same periods, the beta of the Information Technology Sector rose from 1.57 to 2.87. Schedule 10 also demonstrates how variable betas are generally. For example, between 2002 and 2011, the five-year monthly betas for the energy sector ranged from 0.17 to 1.44.

⁹⁶ There is no theoretically correct time interval for calculations of betas. Betas are frequently, but not exclusively, measured over five years using monthly price change intervals (60 observations). For example, Bloomberg calculates betas over three-year periods using weekly price change intervals (156 observations) whereas *Value Line*, which also utilizes weekly prices, estimates the beta over a period of 2.5 to 5 years (over 250 observations). The measurement of betas over a five-year period is simply a convention. In *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, 2nd Ed., Englewood Cliffs, New Jersey: Prentice-Hall, 1987, page 114, the author, Dr. Diana Harrington, noted that the CAPM itself provides no guidance with respect to the choice of a measurement horizon; the five-year estimation period (i.e., 60 monthly observations) became widely used because of the availability of monthly data in computer-readable form, and the need for a reasonably sized sample.

⁹⁷ A similar pattern can be observed for the proxy sample of U.S. utilities.

	<u>Weekly Data</u>		<u>Monthly Data</u>	
	<u>Mean</u>	<u>Median</u>	<u>Mean</u>	<u>Median</u>
2008	0.60	0.61	0.40	0.37
2009	0.60	0.62	0.42	0.40
2010	0.61	0.61	0.44	0.43
2011	0.60	0.63	0.44	0.39

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Table 15

	<u>Weekly Data</u>		<u>Monthly Data</u>	
	<u>Mean</u>	<u>Median</u>	<u>Mean</u>	<u>Median</u>
2008	0.46	0.45	0.25	0.21
2009	0.43	0.44	0.22	0.2
2010	0.44	0.44	0.23	0.21
2011	0.45	0.44	0.21	0.21

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1882 3.c.(iv) Canadian Regulated Company Returns and “Raw” Betas

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1884 The equity betas of traded Canadian utility company shares and of the S&P/TSX Utilities Index
 1885 explain a relatively small percentage of the actual achieved market returns over time. The
 1886 following analysis 1) estimates how much of the historical utility market returns can be
 1887 explained by the equity market, long-term Government of Canada bonds and other factors and 2)
 1888 uses these relationships to assist in the determination of an appropriate estimate of the required
 1889 relative risk adjustment.

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1891 In the context of the CAPM, the utility return should equal:

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$$\text{Risk-Free Rate} + \text{Beta} \times (\text{Equity Market Return} - \text{Risk-Free Rate})$$

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1895 A regression of the monthly returns on the TSX Utilities Index against the market risk premium
 1896 measured as the return on the TSX Composite less the risk-free rate as proxied by 90-day
 1897 Treasury bill returns over the period 1970-2011⁹⁸ shows the following:

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Table 16

Monthly TSX Utilities Index Return	=	0.009 + 0.465	{	Monthly TSX Composite Excess Return	}
t-statistics	=	5.4		13.8	
R ²	=	28%			

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⁹⁸ The Monthly TSX Utilities Index Returns are comprised of the monthly returns on the TSE Gas & Electric Index for the period January 1970 to April 2003 and the monthly returns on the S&P/TSX Utilities Index for the period May 2003 to December 2011.

The relationship quantified in the above equation suggests a long-term utility beta of 0.465. However, the R^2 , which measures how much of the variability in utility returns is explained by variability in the returns of the equity market as a whole, is only 28%. That means 72% of the monthly volatility in utility returns remains unexplained.⁹⁹ The intercept in the equation should, in principle, represent the risk-free rate. Over the entire 1970-2011 period, the average annual return on Treasury bills was 7.0%; the corresponding intercept in the equation above is 10.85%, when expressed on an annualized basis.¹⁰⁰ The difference between the calculated intercept and the average 90-day Treasury bill return of approximately 3.9% represents the component of the utility return incremental to what the CAPM would predict.

Since utility shares are interest sensitive, the regression was expanded to capture the impact of movements in long-term Canada bond prices on utility returns. The addition of monthly excess long-term Canada bond returns to the analysis indicates the following:

Table 17

Monthly TSX Utilities Index Return	= 0.0075 + .40	{	Monthly TSE Composite Excess Return over T-bills	}	+ .46	{	Monthly Excess Long Canada Bond Return over T-bills	}
t-statistics	= 5.0 12.4				8.6			
R^2	= 37%							

When government bond returns are added as a further explanatory variable, somewhat more of the observed volatility in utility stock prices is explained (37% versus 28%). The second regression equation suggests that utility returns have had approximately 40% of the volatility of equity market returns and approximately 46% of the volatility of government bond market returns, the latter consistent with utility common stocks' interest sensitivity. Nevertheless, the equation still leaves more than half of the utility return volatility unexplained.

⁹⁹ As shown in Schedule 12, page 2 of 6, the R^2 's of the monthly betas for individual Canadian utilities calculated over five-year periods ending 2004 to 2011 have been extremely low, averaging less than 10%. The low R^2 's indicate that very little of the volatility in the utility share prices is explained by the volatility in the equity market composite. It bears noting that, while the five-year "raw" monthly and weekly betas ending December 2011 of Canadian Utilities Limited, at 0.03 and 0.38 respectively, are the lowest of the individual Canadian utilities, its absolute price volatility, measured by the standard deviation of monthly price changes, was the highest of the group.

¹⁰⁰ The regression was performed using monthly data, so the intercept of 0.009 is equal to the monthly return on 90-day Treasury bills. The annualized return is equal to $(1+0.009)^{12}-1.0 = 0.1085 = 10.85\%$.

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In this equation, the market equity risk premium is equal to the return on the equity market composite less the Treasury bill return and the long-term Canada bond risk premium, or maturity premium, is equal to the return on the long-term Canada bond less the Treasury bill return. The intercept in the equation in Table 17 as was the case in Table 16, is the sum of the risk-free rate, as proxied by the 90-day Treasury bill return, and the component of the return which differs from what the CAPM would have predicted. As in Table 16, the equation intercept is a monthly number. When annualized, the intercept equals approximately 9.4%.¹⁰¹ Since the average annualized Treasury bill return over the 1970-2011 period of analysis was 7.0%, the indicated utility return was 2.5% higher than predicted by the two variable model.

To assess whether this unexplained component of the utility returns arises from a downward trend in utility risk over the period 1970-2011, I analyzed the trend in the relative total volatility of the S&P/TSX Utilities Index, measured by the ratio of five-year monthly standard deviations of the total market returns of the Utilities Index to those of Composite. The results of the analysis indicated that, although the relative volatility was not constant throughout the period, there has not been a statistically significant trend up or down in the relative total risk of the Utilities Index compared to the Composite over the period 1970-2011.

The objective of the relative risk adjustment is to predict the investors' required or expected return. To do so, the persistent large component of the achieved utility return, as reflected in the equations' intercepts, which is above what the CAPM or the two variable model would have predicted, should be explicitly accounted for. The use of the calculated "raw" Canadian betas alone as an estimate of the relative risk adjustment, without consideration of the extent to which the two models have underestimated the utility return, will result in the underestimation of expected utility returns.¹⁰²

¹⁰¹ $(1.0 + 0.0075)^{12} - 1.0 = .0944 = 9.44\%$.
¹⁰² The explicit recognition of the unexplained component of the return is consistent with the empirical observation that low beta stocks, including, but not limited to, utilities have historically earned returns higher than the CAPM predicts, with the converse observed for high beta stocks.

The equations in Tables 16 and 17 above can be solved in order to estimate a reasonable utility relative risk adjustment. To do so, values for the three independent variables (TSX equity market return, long-term Canada bond return and Treasury bill return) must be specified. For the TSX, the estimated equity market return of 11.5% developed above was used. For the long-term Canada bond return, the 3.5% yield forecast for 2013-2014 was used as a proxy. As regards the Treasury bill return, a normalized yield of 2.25% was used, reflecting the historical average yield spread between 30-year Government of Canada bonds and 90-day Treasury bills of approximately 1.25% (3.5% - 1.25% = 2.25%). In addition, estimates of the incremental utility return (i.e., the component of the return not captured by the models) are required. These estimates were based on two alternative assumptions: (1) the incremental expected utility return is the same in absolute terms as it was historically; and (2) the incremental expected utility return is in the same proportion to the total utility return as was the case historically.

Under the first assumption, the single and two variable models and the resulting indicated relative risk adjustments are as follows:

Table 18

Equity Market Return (EMR):	11.50%
Risk Free Rate (RF = T-Bill Yield):	2.25%
Equity Market Risk Premium (MRP = 11.5% - 2.25%):	9.25%

<u>Model</u>	<u>Utility Equity Beta</u>	<u>Utility Bond Beta</u>	<u>Incremental Utility Return</u>	<u>Utility Return</u>	<u>Utility Risk Premium</u>	<u>Relative Risk Adjustment</u>
	(1)	(2)	(3)	(4)	(5) = (4) - RF	(6) = (5) / MRP
Single Variable	0.465	N/A	3.9%	10.4% ^{1/}	8.2%	0.88
Two Variable	0.400	0.46	2.5%	9.0% ^{2/}	6.8%	0.73

^{1/} 10.4% = 3.9% + 2.25% + 0.465*MRP

^{2/} 9.0% = 2.5% + 2.25% + 0.40*MRP + 0.46*(1.25%), where 1.25% is the maturity risk premium.

These proportions are approximately 30%¹⁰³ in the case of the single variable model and 20%¹⁰⁴

¹⁰³ 3.9%/12.7% ≈ 30%.

1975 in the case of the two variable model. In these two cases, the expected utility returns are 9.4%
1976 (single variable) and 8.1% (two variable) respectively.¹⁰⁵ The indicated utility risk premiums
1977 above the Treasury bill yield are 7.2% and 5.5%, corresponding to relative risk adjustments of
1978 0.78 and 0.64, or a mid-point close to 0.71.¹⁰⁶

1979

1980 Based on all four approaches, the indicated relative risk adjustment is in the range of 0.64 to 0.88
1981 (mid-point of 0.76).

1982

1983 3.c.(v) Use of Adjusted Betas

1984

1985 From the calculated “raw” betas, the inference can readily be made that regulated companies are
1986 less risky than the equity market composite, which by construction has a beta of 1.0. The more
1987 difficult task is determining how the “raw” beta translates into a relative risk adjustment that
1988 captures utility investors’ return requirements. In order to arrive at a reasonable relative risk
1989 adjustment, the normative (“what should happen”) CAPM needs to be integrated with what has
1990 been empirically observed (“what does or has happened”). Empirical studies have shown that
1991 stocks with low betas (less than the equity market beta of 1.0) have achieved returns higher than
1992 predicted by the single variable (i.e., equity beta) CAPM. Conversely, stocks with betas higher
1993 than the equity market beta of 1.0 have achieved lower returns than the model predicts.¹⁰⁷

1994

1995 The use of betas that are adjusted toward the equity market beta of 1.0, rather than the calculated
1996 “raw” betas, is a partial recognition of the observed tendency of low (high) beta stocks to achieve
1997 higher (lower) returns than predicted by the simple CAPM. Adjusted historical betas are a
1998 standard means of estimating expected betas, and are widely disseminated to investors by
1999 investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of
2000 these firms use a similar methodology to adjust “raw” betas toward the equity market beta of 1.0.
2001 Their methodologies give approximately 2/3 weight to the calculated “raw” beta and 1/3 weight
2002 to the equity market beta of 1.0. While the rationale for the specific adjustment formula reflects

¹⁰⁴ 2.5%/12.7% $\approx$ 20%.

¹⁰⁵ 9.4% = (2.25% + 0.465*9.25%)/(1-30%); 8.1% = (2.25% + (0.40*9.25%) + (0.46*1.25%))/(1-20%).

¹⁰⁶ $\frac{9.4\% - 2.25\%}{11.5\% - 2.25\%} = 0.78$; $\frac{8.1\% - 2.25\%}{11.5\% - 2.25\%} = 0.64$.

¹⁰⁷ See Appendix A, page A-18.

the tendency for betas in general to drift toward the market mean beta of 1.0, the adjustment is also justified on the grounds that the adjusted betas are better predictors of returns than “raw” betas.¹⁰⁸

The following table presents recent reported Bloomberg adjusted betas for the five major Canadian utilities. Based solely on the recent Bloomberg betas, the relative risk adjustment would be approximately 0.63 to 0.64. The application of the same adjustment formula used by Bloomberg to the long-term calculated “raw” beta of 0.46 for the TSX Utilities Index shown in Table 16 above results in a relative risk adjustment of close to 0.65.¹⁰⁹

Table 19

Company	Bloomberg Beta
Canadian Utilities Ltd.	0.52
Emera Inc.	0.72
Enbridge Inc.	0.63
Fortis Inc.	0.74
TransCanada Corp.	0.58
Average	0.64
Median	0.63

Source: Bloomberg.

The widely disseminated *Value Line* adjusted betas (based on weekly price change intervals) for the comparable U.S. utility sample provide a further indicator of the relevant risk adjustment for an average risk Canadian utility. As summarized on Schedule 12, page 6 of 6, the reported *Value Line* betas for the sample of U.S. utilities have been approximately 0.675 on average for the five year periods ending 1996-2011, similar to the recent level.

¹⁰⁸ Pablo Fernandez and Vicente Bermejo, in an article entitled *$\beta = 1$ Does a Better Job than Calculated Betas*, May 19, 2009, find that adjusted betas ($0.67 \times \text{calculated beta} + 0.33 \times \text{Market Beta of 1.0}$) do a better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.

¹⁰⁹ Adjusted beta = $0.67 \times \text{“Raw” Beta} + 0.33 \times \text{Market Beta of 1.0}$.

3.c.(vi) Relative Risk Adjustment

A summary of the results of the preceding analysis is set out in the table below:

Table 20

Relative Risk Indicator	Relative Risk Factor
Total Market Risk (Standard Deviations)	0.65-0.70
Relative Historic Returns and Betas: Canadian Utilities	0.71-0.76
Recent Bloomberg Adjusted Beta: Canadian Utilities	0.63-0.64
Long-term Adjusted Beta: Canadian Utilities Index	0.65
Value Line Betas: U.S. Utility Sample	0.675

These results support a relative risk adjustment for an average risk Canadian utility in the approximate range of 0.65-0.70.

3.d. Risk-Adjusted Equity Market Risk Premium Test Results

The equity market risk premium was previously estimated to be no less than 8.0% at the forecast 3.5% 30-year Government of Canada bond yield. At an equity market risk premium of 8.0% and a relative risk adjustment of 0.65-0.70, the indicated equity risk premium for an average risk Canadian utility is in the range of approximately 5.2% to 5.6%. Based on the risk-adjusted equity market risk premium test, the corresponding cost of equity is in the range of approximately 8.7% to 9.0% (mid-point of 8.9%).

4. DCF-Based Equity Risk Premium Test

4.a. Overview

The Discounted Cash Flow-Based (DCF-Based) Equity Risk Premium Test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds.

The DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by explicitly analyzing regulated company equity return data. In contrast, the risk-

adjusted equity market risk premium test discussed above estimates the required utility equity risk premium indirectly, that is, it focuses on the risk-free rate and returns at the overall market level. Of the components of that test, only the relative risk adjustment is derived directly from utility-specific data.

The DCF-based equity risk premium test was applied to a sample of U.S. utilities.¹¹⁰ The DCF-based equity risk premium test was applied only to the sample of U.S. utilities, because its application requires a history of consensus long-term earnings growth rate forecasts, which is not available for Canadian utilities.¹¹¹

A key advantage of the DCF-based equity risk premium test relative to the other equity risk premium tests is that it can be used to test the relationship between the cost of equity (or risk premiums) and interest rates (and/or other variables).¹¹² In the application of this test, relationships between utility risk premiums, long-term government bond yields, the spread between the yields on long-term utility and government bond yields and utility bond yields were examined.

4.b. Constant Growth DCF-Based Equity Risk Premium Test

The constant growth DCF model was used to construct a monthly series of expected utility returns for each of the U.S. utilities in the sample from 1998-2012Q2.¹¹³ The construction of the monthly constant growth DCF costs of equity and the corresponding equity risk premiums is described in Appendix D.

¹¹⁰ The selection criteria for the sample of U.S. utilities to which the DCF-Based Equity Risk Premium Test was applied are found in Appendix B.

¹¹¹ Analysts' forecasts of long-term earnings growth for Canadian utilities are currently accessible, which permits the application of the DCF test to Canadian utilities. However, there is no readily accessible history of those forecasts which would permit the application of the DCF-based equity risk premium test to a sample of Canadian utilities.

¹¹² Of the three equity risk premium tests conducted, the DCF-based equity risk premium test is the only one that lends itself to explicitly estimating the relationship between utility equity risk premiums (or the utility cost of equity) and interest rates.

¹¹³ The choice of period 1998-2012Q2 reflects the years during which long-term Canada and U. S. Treasury bond yields have been broadly similar. It is also intended to balance the exclusion of periods that are dissimilar to current relationships between equity costs and government bond yields and the inclusion of sufficient observations to construct a reliable analysis.

For the sample of U.S. utilities, the constant growth DCF-based equity risk premium test indicates that the average 1998-2012Q2 utility risk premium was 5.2%, corresponding to an average long-term government bond yield of 4.9% (Schedule 14, page 1 of 4). The data also show that the risk premium averaged 4.8% when long-term government bond yields were 6.0% or higher and 6.7% when long-term government bond yields were below 4.0%.

The table below sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1998-2012Q2 constant growth analysis.

Table 21

Government Bond Yield	Below 4.0%	4.0%-5.0%	5.0%-6.0%	Above 6.0%
Utility Equity Risk Premium	6.7%	5.2%	4.7%	4.8%

Source: Schedule 14, page 1 of 4.

The data indicate that the utility equity risk premium is higher at lower levels of interest rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-term government bond yields and the utility equity risk premium.

4.c. Three-Stage DCF-Based Equity Risk Premium Test

The DCF-based risk premium test was also applied using a three-stage DCF model. The construction of the monthly three-stage DCF cost of equity estimates is described in Appendix D. The use of the three-stage model, which assumes that, in the long run, earnings growth for the utility sample will converge to the long-term rate of growth in the economy, effectively lessens the volatility of the monthly growth rates utilized in the constant growth analysis.¹¹⁴ Based on the three stage growth model, the average utility equity risk premium was 5.2% at an average 30-year government bond yield of 4.9% (Schedule 14, page 3 of 4). The table below

¹¹⁴ The standard deviation of the monthly sample analysts' forecast growth rates is approximately 0.5; the standard deviation of the monthly implied growth rates utilized in the three-stage DCF-based risk premium analysis is approximately 0.3.

sets out the observed utility equity risk premium at various levels of long-term government bond yields based on the results of the 1998-2012Q2 three-stage growth analysis.

Table 22

Government Bond Yield	Below 4.0%	4.0%-5.0%	5.0%-6.0%	Above 6.0%
Utility Equity Risk Premium	6.5%	5.3%	4.8%	4.6%

Source: Schedule 14, page 3 of 4.

4.d. Relationships between Equity Risk Premiums and Interest Rates

Using the constant growth and three-stage growth DCF models, the relationship between 30-year government bond yields (independent variable) and the corresponding utility equity risk premiums (dependent variable) was tested. The analysis indicated that, based on the constant growth model, over the 1998-2012Q2 period, on average, for each 100 basis point change in the long-term government bond yield, the utility equity risk premium moved in the opposite direction by approximately 73 basis points. The results using the three-stage model showed a 64 basis point increase (decrease) in the utility equity risk premium for every 100 basis point decrease (increase) in the long-term government bond yield.¹¹⁵

The table below sets out the utility equity risk premium at various levels of long-term government bond yields based on the regressions using long-term government bond yields as the sole independent variable.

Table 23

Government Bond Yield	3.0%	4.0%	5.0%	6.0%	7.0%
Utility Equity Risk Premium:					
Constant Growth	6.5%	5.8%	5.0%	4.3%	3.6%
Three-Stage Growth	6.4%	5.8%	5.1%	4.5%	3.9%

Source: Schedule 14, pages 2 and 4 of 4.

¹¹⁵ Expressed in terms of cost of equity, the cost of equity, as measured by the constant growth and three-stage DCF-based equity risk premium tests, increases (decreases) by approximately 30 to 35 basis points for every one percentage point increase (decrease) in the long-term government bond yield.

2120

2121 The analysis demonstrates that the utility equity risk premium is higher at lower levels of interest
2122 rates than it is at higher levels of interest rates, i.e., there is an inverse relationship between long-
2123 term government bond yields and the utility equity risk premium.

2124

2125 However, this specific analysis indicates that utility equity risk premiums are much more
2126 sensitive to, and the corresponding utility cost of equity much less sensitive to, long-term
2127 government bond yields than was assumed by the automatic ROE adjustment formula suspended
2128 by the PUB in 2011. That formula assumes that the ROE increases/decreases by 80 basis points
2129 for every one percentage decrease/increase in the long-term Government of Canada bond yield.

2130

2131 The single independent variable analysis reflects only the relationship between the equity risk
2132 premium and government bond yields to the exclusion of other factors which impact on the cost
2133 of equity.

2134

2135 To capture the impact of other factors, corporate bond yield spreads were incorporated into the
2136 analysis. The magnitude of the spread between corporate bond yields and government bond
2137 yields is frequently used as a proxy for changes in investors' risk perception or willingness to
2138 take risk. Various empirical studies have shown that there is a positive correlation between
2139 corporate yield spreads and the equity risk premium.¹¹⁶ In the two independent variable
2140 regression analysis, government bond yields and the spread between long-term A-rated utility
2141 and government bond yields were both used as independent variables and the utility equity risk
2142 premium was the dependent variable. The two independent variable analysis indicates that,
2143 while the utility risk premium has been negatively related to the level of government bond yields,
2144 it has been positively related to the spread between utility bond yields and government bond
2145 yields.

2146

2147 Specifically, over the 1998-2012Q2 period, the constant growth analysis showed that the utility
2148 equity risk premium increased or decreased by approximately 84 basis points when the

¹¹⁶ Examples include: N.F. Chen, R. Roll, and S. A. Ross, "Economic Forces and the Stock Market", *Journal of Business*, Vol. 59, No. 3, July 1986, pages 383-403 and R.S. Harris and F.C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts", *Financial Management*, Summer 1992, pages 63-70.

government bond yield decreased or increased by 100 basis points and increased or decreased by approximately 11 basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 14, page 2 of 4). The three-stage growth DCF model indicates that the utility equity risk premium increased or decreased by approximately 71 basis points when the government bond yield decreased or increased by 100 basis points and increased or decreased by approximately seven basis points for every ten basis point increase or decrease in the utility/government bond yield spread (Schedule 14, page 4 of 4).

The two independent variables (long-term government bond yields and the long-term A-rated utility bond/government bond yield spread) can be collapsed into a single independent variable, the long-term A-rated utility bond yield. That analysis shows the utility equity risk premium rising and falling by approximately 50% to 60% of the change in the A-rated utility bond yield using the constant growth and three-stage growth models (Schedule 14, pages 2 and 4 of 4).

To further test the sensitivity of the utility cost of equity to changes in long-term government bond yields and utility/government bond yield spreads, quarterly ROEs allowed for U.S. utilities¹¹⁷ were used as a proxy for the utility cost of equity. The average allowed ROEs can be viewed as a measure of the utility cost of equity as they represent the outcomes of multiple rate proceedings across multiple jurisdictions, which in turn reflect the application of various cost of equity tests by parties representing both the utility and ratepayers.

Initially, the risk premiums indicated by the quarterly allowed ROEs from 1998 to 2012Q2 were regressed against long-term Treasury bond yields lagged by six months.¹¹⁸ The result indicated that the utility equity risk premium increased or decreased by approximately 50 basis points for every one percentage point decrease or increase in long-term government bond yields (Schedule 15, page 2 of 2).

¹¹⁷ The analysis was not performed for Canadian utilities due to the widespread use of formulas over an extended period that specified the relationship between government bond yields and allowed ROEs. Thus, the analysis would provide no independent estimate of the relationship.

¹¹⁸ The government bond yields and the spread variables were lagged by six months behind the quarter of the ROE decisions to take account of the fact that the dates of the decisions will lag the period covered by the market data on which the ROE decisions would have been based.

When long-term A-rated utility/government bond yield spreads were added as a second independent variable, the analysis indicated that (1) the utility equity risk premium increased (decreased) by approximately 50 basis points for every one percentage point decrease or increase in long-term government bond yields; and (2) the utility risk premiums increased or decreased by approximately 26 basis points for every one percentage point increase or decrease in the long-term A-rated utility/government bond yield spread.

Collapsing the two independent variables into a single variable, long-term A-rated bond yields, and regressing those yields against the corresponding utility risk premiums (measured as the allowed ROE minus the Moody's long-term A-rated utility bond yield lagged six months), the analysis indicated that the utility risk premiums have decreased (increased) by under 60 basis points for every one percentage point increase (decrease) in the A-rated utility bond yield.¹¹⁹

4.e. DCF-Based Equity Risk Premium Test Results

The regressions were solved using the forecast 3.5% 30-year Canada bond yield. For the 30-year A-rated utility/Government of Canada bond yield spread, a spread of 155 basis points was used.¹²⁰

The table below summarizes the estimated relationships among equity risk premiums, long-term government bond yields and utility/government bond yield spreads applying the various models to the U.S. utility sample over the 1998-2012Q2 period and the resulting equity risk premiums and costs of equity at a forecast 3.5% long-term Canada bond yield and a long-term A rated utility/government bond yield spread of 155 basis points.

¹¹⁹ Details of all the regressions are found in Schedules 14 and 15. The greater sensitivity to interest rates indicated by the regressions using allowed ROEs as a proxy for the utility cost of equity compared to those using DCF costs of equity most likely reflects other models, in addition to the DCF, used by regulators in arriving at the allowed ROE. These models include risk premium models such as the CAPM, ECAPM, *ex ante* and *ex post* risk premium models, which are explicitly tied to interest rates. While the DCF cost of equity is sensitive to bond yields, it is also a function of factors unique to the equity market.

¹²⁰ Represents expectation that the spread between the yield on long-term A rated Canadian utility bonds and Government of Canada bonds will be approximately equal to recent levels (155 basis points during July 2012) as measured by the spread between the yield on the Bloomberg A-rated Canadian Utility 30 Year Index and the benchmark long-term Government of Canada bond) as yields on long-term Government of Canada bonds rise.

2201

Table 24

	Coefficients		Equity Risk Premium	Cost of Equity
	Government Bond	Bond Yield Spread		
Constant Growth				
Single Variable	-0.73	n/a	6.1%	9.6%
Two Variable	-0.84	1.14	6.2%	9.7%
Three-Stage Growth				
Single Variable	-0.64	n/a	6.1%	9.6%
Two Variable	-0.71	0.70	6.1%	9.6%
Allowed ROEs				
Single Variable	-0.48	n/a	6.4%	9.9%
Two Variable	-0.49	0.26	6.4%	9.9%

2202

2203

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Note: “Single Variable” refers to the regression analysis applied only to the long-term government bond yield and “Two Variable” refers to the addition of the spread variable to the regression analysis.

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Sources: Schedules 14 and 15

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While the indicated sensitivities of the models to changes in long-term government bond yields vary, they support the conclusion that the utility cost of equity does not vary with (or track) long-term government bond yields to the extent that has frequently been assumed in automatic ROE adjustment formulas that have been used in some regulatory jurisdictions in Canada.¹²¹

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2213

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Table 25 below summarizes the regression results using an A-rated bond yield of 5.05% (equal to the forecast 3.5% 30-year Canada bond yield plus a spread of 155 basis points):

¹²¹ The National Energy Board rescinded its automatic adjustment formula in October 2009. The Alberta Utilities Commission suspended its formula in November 2009 and opted not to reinstate a formula in its December 2011 Generic Cost of Capital Decision. The British Columbia Utilities Commission terminated its automatic adjustment formula in December 2009. The Ontario Energy Board significantly revised its automatic adjustment formula in December 2009, lowering the sensitivity of the allowed ROE to changes in long-term Canada bonds from 75% to 50% and adding a second explanatory variable, the spread between 30-year A-rated utility and Government of Canada bond yields, with a sensitivity factor of 50%. The OEB also reset the benchmark ROE. The Régie de l'énergie du Québec has continued to apply a 75% sensitivity factor to changes in long-term Government of Canada bond yields, but has added the same spread variable as in the OEB's revised formula with the same 50% sensitivity factor. The Island Regulatory and Appeals Commission declined to implement an automatic adjustment formula for Maritime Electric in 2010, stating “The Commission did not adopt a formula approach to ROE during a period of time when such an approach was used by regulators as the standard for setting ROE. The Commission sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated.” (Order UE10-03, July 12, 2010, page 22).

2216

Table 25

Model	Coefficient	Risk Premium over A-Rated Bond Yield	Cost of Equity
Constant Growth DCF	-0.50	4.3%	9.3%
Three-Stage DCF	-0.57	4.4%	9.5%
Allowed ROEs	-0.58	5.0%	10.0%

2217

Source: Schedules 14 and 15.

2218

I have not given any weight to the results of the allowed ROE analysis in deriving an estimate of the utility cost of equity from the DCF-based risk premium test, as the allowed ROEs do not represent my own estimates of the cost of equity. Nevertheless, the relationships among utility equity risks premiums and bond yields established by that analysis provide further support for the conclusion that the utility cost of equity does not track government bond yields nearly to the extent that has been embedded in most of the automatic adjustment formulas that have been used in Canada.

2225

2226

Based on the DCF-based regression analyses, at the forecast 30-year Canada and A-rated utility bond yields, the indicated utility cost of equity is in the range of approximately 9.3% to 9.7%, and approximately 9.5% based on all the DCF-based risk premium models.

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5. Historic Utility Equity Risk Premium Test

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5.a. Overview

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The historic experienced market returns for utilities provide an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. Similar to the DCF-based equity risk premium test, this test estimates the cost of equity for regulated companies directly by reference to return data for regulated companies. Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur.

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5.b. Historic Returns and Risk Premiums

As shown in Table 26 below, over the longest term available (1956-2011),¹²² the average achieved utility (electric and gas combined) equity risk premiums in Canada were 4.2% and 4.8% in relation to total and income returns for long-term Government of Canada bonds respectively.¹²³ For U.S. electric utilities, the average historic utility equity risk premiums in relation to total and income returns on bonds over the entire post-World War II period (1947-2011) were 4.4% and 5.1%. For U.S. gas utilities, the corresponding average historic utility equity risk premiums were 5.3% and 6.0% respectively.

Table 26

	Utility Equity Returns	Bond Total Returns	Bond Income Returns	Utility Risk Premium Relative To:	
				Bond Total Returns	Bond Income Returns
Canadian Utilities	12.1%	7.9%	7.3%	4.2%	4.8%
U.S. Electric Utilities	11.0%	6.6%	5.9%	4.4%	5.1%
U.S. Gas Utilities	11.9%	6.6%	5.9%	5.3%	6.0%

Source: Schedule 16.

5.c. Trends in Equity Returns and Bond Returns

Similar to the risk premiums for the market composite, the magnitude of achieved utility equity risk premiums is a function of both the equity returns and the bond returns. An analysis of the underlying data indicates there has been no secular upward or downward trend in the utility equity returns. Trend lines fitted to the historic utility equity returns for each of the three utility indices are flat (Schedule 16, pages 2 and 3 of 3). The historical average utility returns in both Canada and the U.S. have clustered in the range of 11.0-12.0%. However, the achieved government bond returns (total and income) in Canada over the period of analysis, at 7.3% to 7.9%, were materially higher than the 3.5% forecast yield on 30-year Government of Canada bonds.

¹²² The longest period for which Canadian utility index data are available from the Toronto Stock Exchange.

¹²³ Based on the Gas/Electric Index of the TSE 300 from 1956 to 1987 and on the S&P/TSX Utilities Index from 1988-2011.

A reasonable approach to interpreting the historical utility equity market return data is the recognition of the inverse relationship between utility equity risk premiums and government bond yields. Table 27 derives estimates of the utility equity risk premium for the longer term from the historical average risk premiums by applying a 50% sensitivity factor to the difference between the historical average bond income returns and the forecast Government of Canada bond yield forecast. A 50% sensitivity factor comports with the lower end of the range of the sensitivities of utility equity risk premiums to government bond yield changes estimated in Section VI.D.4. above.

Table 27

		Canadian Utilities	U.S. Electric Utilities	U.S. Gas Utilities
Equity Returns	(1)	12.1%	11.0%	11.9%
Bond Income Returns	(2)	7.3%	5.9%	5.9%
Utility Risk Premium (RP)	(3) = (1) – (2)	4.8%	5.1%	6.0%
Forecast 30-Year Canada Bond Yield (LCBY)	(4)	3.5%	3.5%	3.5%
Change in Bond Yield/Return	(5) = (4) – (2)	-3.8%	-2.4%	-2.4%
Change in Utility Equity RP	(6) = – (5) X 50%	+1.9%	+1.2%	+1.2%
Utility Equity Risk Premium at 3.5% LCBY	(7) = (3) + (6)	6.7%	6.3%	7.2%

Source: Schedule 16, page 1 of 3.

At the forecast 3.5% 30-year Government of Canada bond yield and a 50% sensitivity factor between utility equity risk premiums and long-term government bond yields, the indicated utility equity risk premium derived from historical averages is in the approximate range of 6.25% to 7.25% (mid-point of estimates of approximately 6.75%).

5.d. Historic Utility Equity Risk Premium Test Results

Recognizing the inverse relationship between utility equity risk premiums and long-term government bond yields, the historic utility equity risk premium approach indicates a utility equity risk premium of approximately 6.75% at the forecast 3.5% 30-year Government of Canada bond yield. The corresponding utility cost of equity is approximately 10.25%.

6. Cost of Equity Based on Equity Risk Premium Tests

The estimated utility risk premiums and corresponding costs of equity based on the three equity risk premium methodologies, at the 3.5% forecast 30-year Canada bond yield are summarized below:

Table 28

Risk Premium Test	Cost of Equity	Utility Risk Premium
Risk-Adjusted Equity Market	8.9%	5.4%
DCF-Based	9.5%	6.0%
Historic Utility	10.25%	6.75%

None of the individual tests, as performed, yields an inherently superior estimate of the returns that an investor expects or requires. Thus, each of the methods was accorded equal weight in the estimation of the cost of equity for an average risk Canadian utility, e.g., Newfoundland Power.

E. DISCOUNTED CASH FLOW TEST¹²⁴

1. Conceptual Underpinnings

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. This proposition is based, in turn, on the efficient

¹²⁴ See Appendix C for a more detailed discussion.

markets hypothesis, which states that the price of a stock today is determined by all of the available information about the stock. While the Dividend Discount Model, as it is now formally called, was not so named until the latter half of the twentieth century,¹²⁵ the concept of the discounted cash flow approach was first expressed in the early 20th century by Irving Fisher and later expanded on by J.B. Williams in his classic book, *The Theory of Investment Value* (Cambridge, Mass.: Harvard University Press, 1938) in which he stated:

A stock is worth the present value of all the dividends ever to be paid upon it, no more, no less ... Present earnings, outlook, financial condition, and capitalization should bear upon the price of a stock only as they assist buyers and sellers in estimating future dividends.

The DCF test allows the analyst to directly estimate the utility cost of equity, in contrast to the Capital Asset Pricing Model (CAPM), which estimates the cost of equity indirectly. The DCF model is widely used to estimate the utility cost of equity for the purpose of establishing the allowed ROE.

In simplest terms, the DCF cost of equity model is expressed as follows:

$$\text{Cost of Equity (k)} = \frac{D_1 + g}{P_0}$$

where,

$$\begin{aligned} D_1 &= \text{next expected dividend}^{126} \\ P_0 &= \text{current price} \\ g &= \text{expected growth in dividends} \end{aligned}$$

There are multiple versions of the discounted cash flow model available to estimate the investor's required return on equity, including the constant growth model and multiple period models to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

¹²⁵ Myron Gordon, *The Investment, Financing and Valuation of the Corporation*, Homewood, Illinois: Irwin, 1962.

¹²⁶ Alternatively expressed as $D_0(1 + g)$, where D_0 is the most recently paid dividend.

2. Application of the DCF Test

2.a. DCF Models

To estimate the DCF cost of equity, both the constant growth model and a multiple stage (three-stage) model were used. In both cases, the discounted cash flow test was applied to the sample of U.S. electric and gas utilities selected to serve as a proxy for an average risk Canadian utility (the same sample used in the DCF-based equity risk premium test), as well as to a sample of Canadian utilities.

2.b. Growth Estimates

The growth component of the DCF model is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. When the subject company does not have traded shares, a sample of proxies is required.¹²⁷

Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be. The constant growth model was applied to the U.S. sample using two estimates of long-term growth. The first estimate reflects the consensus of investment analysts' long-term earnings growth forecasts drawn from four sources: Bloomberg, Reuters, *Value Line* and Zacks. The second is an estimate of sustainable growth. The sustainable growth rate represents the growth in earnings that a utility can expect to achieve as a result of the ROE it is expected to earn and the proportion of the ROE it reinvests plus incremental earnings growth achievable as a result of external equity financing. The development of the sustainable growth rates is explained in detail in Appendix C.

¹²⁷ In addition, any cost of equity estimate that relies on data for only a single company is subject to measurement error.

In the application of the DCF test, the reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators, as some studies have concluded that analysts' earnings growth forecasts are optimistic. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns. That proposition can be tested indirectly. Three such tests are described in Appendix C. These tests indicate that the consensus of analysts' long-term earnings growth forecasts is not an upwardly biased estimate of investor expectations.

3. Results of the DCF Models

3.a. Results for the Sample of U.S. Utilities

The constant growth model applied to the U.S. utility sample using the consensus of analysts' long-term earnings growth forecasts indicates a cost of equity of approximately 9.4% (Schedule 17). The utility cost of equity based on the sustainable growth model is approximately 8.6% (Schedule 18).

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term to migrate to the expected long-run rate of nominal growth in the economy.¹²⁸ The three-stage DCF model is fully described in Appendix C. The three-stage model applied to the sample of U.S. utilities indicates a cost of equity of approximately 9.1% (Schedule 19).

¹²⁸ A three-stage, rather than two-stage, model was used, as the former incorporates the more likely assumption that investors would anticipate a gradual transition, rather than immediate shift, to the long-term perpetual growth rate.

3.b. Results for the Sample of Canadian Utilities

The constant growth and three-stage DCF models were also applied to the five major publicly-traded Canadian utilities.¹²⁹ The application of the constant growth model to the Canadian utilities indicated a cost of equity of approximately 11.0%; see Schedule 20. The cost of equity developed using the three-stage model indicates a cost of equity of approximately 8.6%; see Schedule 21.

3.c. DCF Cost of Equity

The table below summarizes the results of the DCF models applied to both the U.S. and Canadian utility samples.

Table 29

	Constant Growth		Three-Stage Model
	Analysts' EPS Forecasts	Sustainable Growth	
U.S. Utilities	9.4%	8.6%	9.1%
Canadian Utilities	11.0%	N/A	8.6%

Source: Schedules 19-23.

The constant growth and three-stage DCF models applied to the U.S. sample indicate a utility cost of equity of approximately 9.1%. For the Canadian utilities, the higher long-term earnings growth forecasts in conjunction with lower dividend yields lead to a wider range of DCF test results than for the U.S. utilities. Based on the mid-point of the range of the constant growth and three-stage models, the cost of equity for the Canadian utility sample is approximately 9.8%. The application of both constant growth and three-stage models to the two samples supports a DCF cost of equity of approximately 9.1% to 9.8% (mid-point of approximately 9.4%).

¹²⁹ For the five major publicly-traded Canadian utilities, the consensus long-term earnings growth forecasts were obtained from Reuters, as it provided the highest number of analysts' forecasts for each company. There are no widely available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth.

F. ALLOWANCE FOR FINANCING FLEXIBILITY¹³⁰

The equity risk premium tests (Section VI.D) and discounted cash flow tests (Section VI.E) indicate a “bare-bones” cost of equity for an average risk Canadian utility of approximately 9.5% (mid-point of range). The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the “fairness” principle. It is the normal practice of Canadian regulators to add an adjustment for financing flexibility to the estimated market-based utility cost of equity.

In the absence of an adjustment for financial flexibility, the application of a “bare-bones” cost of equity to the book value of equity, if earned, in theory, limits the market value of equity to its book value. The fairness principle recognizes the ability of competitive firms to maintain the real value of their assets in excess of book value and thus would not preclude utilities from achieving a degree of financial integrity that would be anticipated under competition. The market/book ratio of the S&P/TSX Composite averaged 2.1 times from 1995-2011; the corresponding average market/book ratio of the S&P 500 was 3.0 times.¹³¹

At a minimum, the financing flexibility allowance should be adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times. At this level, a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 times is approximately 50 basis points.¹³² As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard. The comparable returns standard can be addressed by applying and giving weight to the comparable

¹³⁰ See Appendix E for a more complete discussion.

¹³¹ The market to book ratio of the S&P 500 includes Utilities. The market to book ratio of the S&P Industrials alone has been higher.

¹³² Based on the DCF model as shown in Appendix E, footnote 2.

earnings test. Alternatively, if the comparable earnings test were not to be afforded the weight that it merits, the financing flexibility allowance applied to the market-based tests needs to be increased in order to arrive at a return that meets all three requirements of the fair return standard.

The cost of capital, as determined in the capital markets, is derived from market value capital structures. The cost of equity has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the corresponding book value capital structure. Regulatory convention applies the allowed equity return to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Utilities are entitled to the opportunity to earn a return that meets the fair return standard, namely one that provides the utility an opportunity to earn a return on investment commensurate with that of comparable risk enterprises, to maintain its financial integrity and to attract capital on reasonable terms. What must be fair is the overall return on capital. The recognition in the allowed return on equity of the impact of financial risk differences between the market value capital structures of the proxy companies and the ratemaking capital structure is required to ensure the opportunity to earn a return commensurate with that of comparable risk enterprises. A full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures warrants an adjustment to the “bare bones” cost of equity of approximately 160 basis points (See Appendix E).

A reasonable adjustment for financing flexibility to the “bare bones” cost of equity estimated solely by reference to market-based tests (that is, without reference to the comparable earnings test) would be the mid-point of the indicated range of 50 to 160 basis points. The addition of an allowance for financing flexibility of 50 to 160 basis points to the “bare-bones” return on equity

estimate of 9.5%, derived from the equity risk premium and DCF tests, results in an estimate of the fair return on equity for an average risk Canadian utility of approximately 10.5%.

G. COMPARABLE EARNINGS TEST

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test arises from the notion that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms facing similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Neither the equity risk premium results nor the DCF results, if left without adjustment, recognizes the discrepancy. The 50 basis point financing flexibility adjustment that has typically been applied by Canadian regulators to the market-based tests only minimally addresses the discrepancy.

The comparable earnings test is an implementation of the comparable returns standard, as distinguished from the cost of attracting capital standard. The comparable earnings test recognizes that utility costs are measured in vintaged dollars and rates are based on accounting costs, not economic costs. In contrast, the tests for estimating the cost of attracting capital rely on costs expressed in dollars of current purchasing power, i.e., a market-related cost of capital. In the absence of experienced inflation, the two concepts would be quite similar, but the impact of inflation has rendered them dissimilar and distinct.

The concept that regulation is a surrogate for competition may be interpreted to mean that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk. The fact that an original cost rate base provides a starting point for the application of a fair return does not mean that the

original cost of the assets is a measure of their fair value. The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The comparable returns standard, as well as the principle of fairness, suggests that, if competitive firms facing a level of total risk similar to utilities are able to maintain the value of their assets considerably above book value, the return allowed to utilities should not seek to maintain the value of utility assets at book value. It is critical that the regulator recognize the comparable returns standard when setting a fair return.

The comparable earnings test remains the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The persistence of moderate inflation continues to create systematic deviations between book and market values. Application of a market-derived cost of capital to book value ignores that distinction. The application of the results of the cost of attracting capital tests, i.e., equity risk premium and discounted cash flow to the book value of equity, unless adjusted, do not make any allowance for the discrepancy between the return on market value and the corresponding fair return on book value. The comparable earnings test, however, does. It applies “apples to apples”, i.e., a book value-measured return is applied to a book value-measured equity investment.

The principal issues in the application of the comparable earnings test are:¹³³

1. The selection of a sample of unregulated companies of reasonably comparable total risk to a Canadian utility.
2. The selection of an appropriate time period over which returns are to be measured in order to estimate prospective returns.
3. The need for any adjustment to the "raw" comparable earnings results if the selected unregulated companies are not of precisely equivalent risk to a utility.

¹³³ Full discussion in Appendix F.

4. The need for a downward adjustment for the unregulated companies' market/book ratios.

The application of the comparable earnings test first requires the selection of a sample of unregulated companies of reasonably comparable risk to an average risk Canadian utility. The selection should conform to investor perceptions of the risk characteristics of utilities, which are generally characterized by relative stability of earnings, dividends and market prices. These were the principal criteria for the selection of a sample of unregulated companies (from consumer-oriented industries). The criteria for selecting comparable unregulated low risk companies include industry, size, dividend history, capital structures, bond ratings and betas (See Appendix F).

Since the universe of Canadian unregulated companies is sufficiently large to produce a representative sample of sufficient size, the focus of the comparable earnings analysis was on Canadian firms. The application of the selection criteria to the Canadian universe produced a sample of 21 companies.

Next, since unregulated companies' returns on equity tend to be cyclical, the selection of an appropriate period for measuring their returns must be determined. The period selected should, in principle, encompass an entire business cycle, covering years of both expansion and decline. That cycle should be representative of a future normal cycle, e.g., the historic and forecast cycles should be similar in terms of inflation and real economic growth. The last full business cycle, encompassing 1995-2011, may overestimate the returns on equity achievable going forward as nominal economic growth was higher, on average, than is projected for the longer term. As a result, the focus of the test was on the period 2004-2011, which commences subsequent to the 2001 downturn and includes the 2008-2009 recession. The period 2004-2011 represents an appropriate proxy for the next business cycle, as the average experienced rates of inflation and economic growth were reasonably similar to the average rates projected by economists over the next decade. The experienced returns on equity of the sample of 21 Canadian low risk unregulated companies over this period were in the range of 12.25%-13.5% (see Appendix F and Schedule 25).

The next step is to assess whether or not there is a need to adjust the “raw” comparable earnings results to reflect the differential risk of a Canadian utility relative to the selected unregulated companies. The comparative risk data (including betas and bond ratings) indicate that the unregulated Canadian companies are of higher risk than an average risk Canadian utility. To recognize the unregulated companies’ higher risk, a downward adjustment of 125 to 150 basis points¹³⁴ to their returns on equity was made, resulting in a comparable earnings result in the range of 11.0% to 12.0%.

The final step is to assess the need for a market/book adjustment to the comparable earnings results. The sample results would warrant such an adjustment if their market/book ratios relative to the overall market indicated an ability to exert market power. In other words, a high market/book ratio (relative to that of the overall market) could suggest returns on equity that were higher than the levels achievable if market power were not present. The average market/book ratios of the sample of Canadian comparable unregulated companies over the both the full business cycle 1995-2011 and the shorter period 2004-2011 period were 2.3 and 2.2 times, similar to the market/book ratio of the S&P/TSX composite over the same periods and lower than the market/book ratio of the S&P 500 (see Appendix F). The similar to lower average market/book ratios of the Canadian sample of unregulated companies relative to both the Canadian and U.S. equity market composites indicate no evidence of market power. Thus there is no rationale for making an additional downward adjustment to the unregulated Canadian companies’ returns on equity due to their market/book ratios. As a result, a fair return on equity based on the comparable earnings test is approximately 11.0% to 12.0%.

¹³⁴ Based on the typical spread between DEX BBB-rated long-term industrial bond yields and long-term A-rated utility bond yields and the relative betas of the unregulated companies and Canadian utilities.

H. FAIR RETURN ON EQUITY FOR NEWFOUNDLAND POWER

Based solely on the market-based cost of equity tests, a fair return on equity for Newfoundland Power is approximately 10.5%, reflecting the following:

The results of the equity risk premium and discounted cash flow tests support a “bare-bones” cost of equity of approximately 9.5%, as summarized in the table below:

Table 30

Cost of Equity Test	Cost of Equity
Risk Premium Tests:	
Risk-Adjusted Equity Market	8.9%
Discounted Cash Flow-Based	9.5%
Historic Utility	10.25%
Discounted Cash Flow Test	9.4%

Adding an allowance for financing flexibility of 1.0%, reflecting the approximate mid-point of a range of 0.50% to 1.60%, results in a recommended ROE for Newfoundland Power of 10.5%. The lower end of the financing flexibility range represents the minimum required to notionally allow the utilities to maintain the market value of their investment at a small premium to book value. The upper end of the range represents full recognition of the disparity between the levels of financial risk in the market value capital structures and utility book value capital structures.

Alternatively, the fair ROE for Newfoundland Power can be viewed as falling within a range bounded by the market-based cost of equity inclusive of the minimal allowance for financing flexibility (10.0%) at the bottom end of the range and the comparable earnings test results (11.0% to 12.0%) at the upper end of the range. The specific weight to be given the comparable earnings test versus the market-based tests is largely a matter of judgment. The comparable earnings test is, in my opinion, entitled to significant weight. When preponderant weight is given to the market-based tests (75%), this alternative approach also indicates that an ROE of 10.5% for Newfoundland Power is reasonable.

APPENDICES
TO
OPINION
ON
CAPITAL STRUCTURE
AND
RETURN ON EQUITY
FOR
Newfoundland Power Inc.

Prepared by

KATHLEEN C. MCSHANE
FOSTER ASSOCIATES, INC.



September 2012

APPENDICES

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APPENDIX B: SELECTION OF U.S. LOW RISK UTILITY SAMPLE

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APPENDIX A

ADJUSTED

EQUITY MARKET RISK PREMIUM TEST

1. CONCEPTUAL UNDERPINNINGS OF THE CAPITAL ASSET PRICING MODEL

The Capital Asset Pricing Model (CAPM) is a theoretical, formal model of the equity risk premium test which posits that the investor requires a return on a security equal to:

$$R_F + \beta(R_M - R_F),$$

Where:

R_F = risk-free rate

β = covariability of the security with the market (M)

R_M = return on the market

The model is based on restrictive assumptions, including:

a. Perfect, or efficient, markets exist where,

- (1) each investor assumes he has no effect on security prices;
- (2) there are no taxes or transaction costs;
- (3) all assets are publicly traded and perfectly divisible;
- (4) there are no constraints on short-sales; and,
- (5) the same risk-free rate applies to both borrowing and lending.

- b. Investors are identical with respect to their holding period, their expectations and the fact that all choices are made on the basis of risk and return.**

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities whose expected returns are not perfectly correlated. Therefore, a shareholder requires no compensation to bear company-specific risks.

In the CAPM, non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or portfolio of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events that also change the required return on the market.

The CAPM is a normative model, that is, it estimates the equity return that an investor **should** require under the restrictive assumptions outlined above, based on the relative systematic risk of the stock.

The “father” of modern portfolio theory (and winner of the Nobel Prize for Economics) Harry Markowitz has stated that “The CAPM is a thing of beauty. Thanks to one or another counterfactual assumption, it achieves clean and simple conclusions.”¹ A key counter-factual assumption is the investor’s ability to borrow unlimited amounts at the risk-free rate. He concludes that because key assumptions of the model do not hold, then it no longer holds that expected returns are linearly related to beta. He does state that CAPM should be taught, despite its drawbacks. According to Dr. Markowitz:

It is like studying the motion of objects on Earth under the assumption that the Earth has no air. The calculations and results are much simpler if this assumption is made. But at some point, the obvious fact that, on Earth, cannonballs and feathers do not fall at the same rate should be noted and explained to some extent.²

2. RISK-FREE RATE

- a. The theoretical CAPM assumes that the risk-free rate is uncorrelated with the return on the market. In other words, the assumption is that there is no relationship between the risk-free rate and the equity market return (i.e., the risk-free rate has a zero beta). However, the application of the model frequently assumes that the return on the market is highly correlated with the risk-free rate, that is, that the equity market return and the risk-free rate move in tandem.
- b. The theoretical CAPM calls for using a risk-free rate, whereas the typical application of the model in the regulatory context employs a long-term government bond yield as a proxy for the risk-free rate. Long-term government bond yields may reflect various factors that render them problematic as an estimate of the “true” risk-free rate, including:
 - (1) The yield on long-term government bonds reflects the impact of monetary and fiscal policy; e.g., the potential existence of a scarcity premium. The Canadian federal government was in a surplus position from 1997/1998 to 2007/2008 (ten

¹ Markowitz, Harry M., “Market Efficiency: A Theoretical Distinction and So What?”, *Financial Analysts Journal*, September/October 2005, page 29.

² *Ibid.*, pages 28-29.

years), which reduced its financing requirements.³ In 2008/2009, despite a budget deficit, the federal debt/GDP ratio stood at 29%, its lowest level since 1980/81, and well below the 1995/1996 peak of 68%. In the twelve months ending May 2012, Government of Canada bonds accounted for a little over one-quarter of total Canadian dollar bonds outstanding,⁴ compared to almost half in 1996.⁵ However, the demand for long-term government securities by institutions that are “buy and hold” investors and that match the duration of their assets and liabilities (e.g., pension funds and insurance companies) has not declined. Thus, there is a potential for the prices of long-term government bonds to incorporate a scarcity premium reflecting an imbalance between demand and supply.

Further, with the credit downgrades of a number of advanced economy sovereign issuers in the last several years, the pool of high grade sovereign debt globally has shrunk over the past several years. The Government of Canada is one of relatively few advanced economy debt issuers with AAA ratings, and the third largest economy with AAA ratings by all three ratings agencies, in a global capital market with a high demand for safe haven assets. However, Canada is a relatively small economy, and accounts for only about 4% of the world capital market, and the supply of its debt is limited.⁶ As a result, the recent yields on long-term Government of Canada debt are likely to reflect a scarcity premium.

- (2) Yields on long-term government bonds may reflect shifting degrees of investors’ risk aversion; e.g., “flight to quality”. An increase in the equity risk premium arising from a reduction in bond yields due to a “flight to quality” is not likely to be captured in the typical application of the CAPM which focuses on a long-term

³Following budget deficits of \$55.6 billion and \$33.4 billion in fiscal years 2009/2010 and 2010/2011 respectively, the Department of Finance’s Budget 2012 (March 29, 2012) anticipated declining budget deficits through 2014/2015, with a small surplus (\$3.4 billion) in 2015/2016. Further, it forecast the deficit for the fiscal year 2011/2012 had declined to \$24.9 billion, compared to the Department’s November 2011 estimated deficit of \$31 billion. The Department of Finance’s projections show the federal debt to GDP peaking at approximately 35% in 2012/13, then declining to 28.5% in 2016/2017, in line with its pre-recession (2008/2009) level.

⁴ Includes provincial, municipal, corporate, foreign issuer, and term securitization bonds.

⁵ Statistics Canada, www.statcan.gc.ca

⁶ The demand for the February 2012 issue of \$3 billion in U.S. dollar-denominated five-year bonds by the Government of Canada was outstripped by supply by a factor of 3-to-1.

average market risk premium. Particularly in periods of capital market upheaval, e.g., the “Asian contagion” in the fall of 1998, during the technology sector sell-off beginning in mid-2000, the post 9/11 period, the wake of the subprime mortgage crisis commencing in late 2007, and the ongoing sovereign debt crisis in Europe, investors shifted to the safe haven of government securities perceived as default-free, pushing down government bond yields and increasing the required equity risk premium. The typical application of the CAPM, which relies heavily on long-term average achieved equity risk premiums, captures the lower government bond yields, but not the corresponding increase in the equity risk premium.

- (3) Long-term government bond yields are not risk-free; they are subject to interest rate risk. The size of the equity market risk premium at a given point in time depends in part on how risky long-term government bond yields are relative to the overall equity market. Changes in the risk of the “risk-free” security introduce further complexity to the application of the CAPM, particularly as the changes impact the measurement of the equity market risk premium.
- c. The radical change in Canada’s fiscal performance since the mid-1990s contributed to a steady decline in long-term government bond yields and a corresponding increase in total returns achieved by investors in long-term government securities. As a result, the achieved equity market risk premiums in Canada measured using total bond returns were squeezed by the performance of the government bond market. The low prevailing and forecast long-term Government of Canada bond yields relative to the historical total returns on those securities indicate that the historical returns on long-term Government of Canada bonds overstate the forward looking risk-free rate. The estimate of the equity market risk premium using historical data as a point of departure needs to recognize the much higher government bond returns historically than the forecast risk-free rate.
- d. Total returns on government bonds include capital gains and losses resulting from changes in interest rates over time. The income return on government bonds, in contrast,

reflects only the coupon payment portion of the total bond return. As such, the income return represents the riskless component of the total government bond return. In principle, using the bond income return in the calculation of historical risk premiums more accurately measures the historical equity risk premium above a true risk-free rate.⁷

3. USE OF ARITHMETIC AVERAGES OF HISTORIC RETURNS TO ESTIMATE THE EXPECTED EQUITY MARKET RISK PREMIUM

a. Rationale for the Use of Arithmetic Averages

In Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, “Best Practices in Estimating the Cost of Capital: Survey and Synthesis”, *Financial Practice and Education*, Spring/Summer 1998, pp. 13-28, the authors found that 71% of the texts and tradebooks in their survey supported use of an arithmetic mean for estimation of the cost of equity. One such textbook, Richard A. Brealey, Stewart C. Myers and Franklin Allen, *Principles of Corporate Finance*, Boston: Irwin/McGraw Hill, 2006 (p. 151), states, “Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return.”

The appropriateness of using arithmetic averages, as opposed to geometric averages, for estimation of the cost of equity is succinctly explained in Ibbotson Associates; *Stocks, Bonds, Bills and Inflation, 1998 Yearbook*, pp. 157-159:

The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values . . . in the investment markets, where returns are

⁷ As stated in Ibbotson *SBBi 2012 Valuation Yearbook* (page 55), “Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.”

described by a probability distribution, the arithmetic mean is the measure that accounts for uncertainty, and is the appropriate one for estimating discount rates and the cost of capital.

Triumph of the Optimists: 101 Years of Global Investment Returns by Elroy Dimson, Paul Marsh and Mike Staunton, Princeton: Princeton University Press, 2002 (p. 182), stated,

The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and -20 percent. Their arithmetic mean is 2½ percent, since $(25 - 20)/2 = 2½$. Their geometric mean is zero, since $(1 + 25/100) \times (1 - 20/100) - 1 = 0$. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.

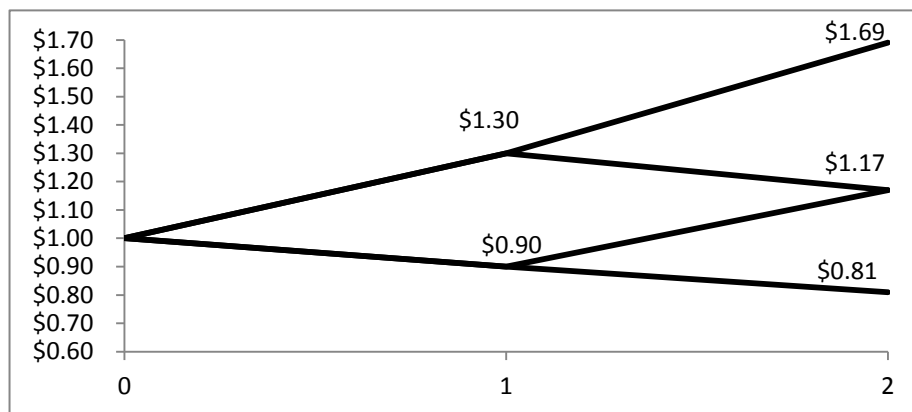
To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A \$1 stake would offer equal probabilities of receiving back \$1.25 or \$0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $\$1.25/1.025 = \$1.22$ and $\$0.80/1.025 = \$0.78$, each with equal probability, so the value is $\$1.22 \times \frac{1}{2} + \$0.80 \times \frac{1}{2} = \$1.00$. If there were a sequence of equally likely returns of +25 and -20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns.

b. Illustration of Why Arithmetic Average Should be Used

In Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: Valuation Edition, 2012*, the following discussion was included:

To illustrate how the arithmetic mean is more appropriate than the geometric mean in discounting cash flows, suppose the expected return on a stock is 10 percent per year with a standard deviation of 20 percent. Also assume that only two outcomes are possible each year: +30 percent and -10 percent (i.e., the mean plus or minus one standard deviation). The probability of occurrence for each outcome is equal. The growth of wealth over a two-year period is illustrated in Graph 5-3.

Graph 5-3 Growth of Wealth Example



The most common outcome of \$1.17 is given by the geometric mean of 8.2 percent. Compounding the possible outcomes as follows derives the geometric mean:

$$[(1+0.30) \times (1-0.10)]^{1/2} - 1 = 0.082$$

However, the expected value is predicted by compounding the arithmetic, not the geometric, mean. To illustrate this, we need to look at the probability-weighted average of all possible outcomes:

$$\begin{array}{rcl} (0.25 \times \$1.69) & = & \$0.4225 \\ + (0.50 \times \$1.17) & = & \$0.5850 \\ + (0.25 \times \$0.81) & = & \$0.2025 \\ \hline \text{Total} & & \$1.2100 \end{array}$$

Therefore, \$1.21 is the probability-weighted expected value. The rate that must be compounded to achieve the terminal value of \$1.21 after 2 years is 10 percent, the arithmetic mean.

$$\$1 \times (1+0.10)^2 = \$1.21$$

The geometric mean, when compounded, results in the median of the distribution:

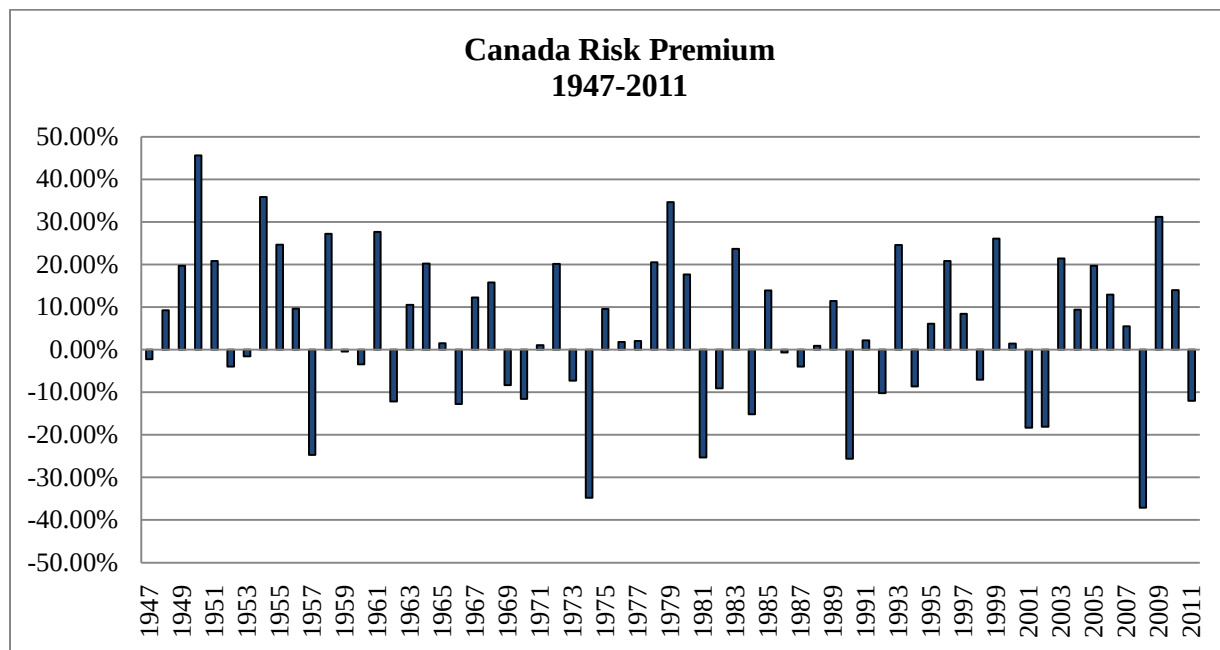
$$\$1 \times (1+0.082)^2 = \$1.17$$

The arithmetic mean equates the expected future value with the present value; it is therefore the appropriate discount rate.

c. Randomness of Annual Equity Market Risk Premiums

The use of arithmetic averages is premised on the unpredictability of future risk premiums. The following figures illustrate the uncertainty in the future risk premiums by reference to the historical post-World War II annual risk premiums (measured as the equity market return less the corresponding year's long-term government bond income return). The figures for both Canada and the U.S. suggest that each year's actual risk premium has been random, that is, not serially correlated with the preceding year's risk premium.⁸

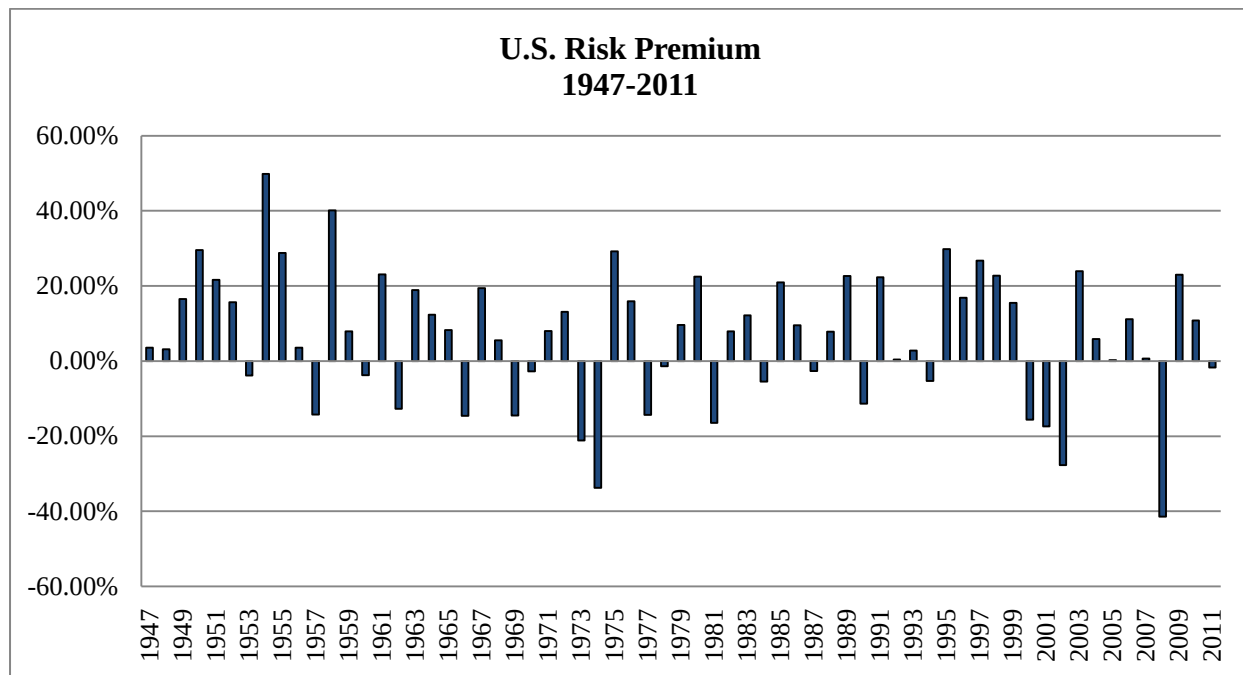
Chart A - 1



Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics, 1924-2011*.

⁸ A test for serial correlation between the year-to-year equity risk premiums shows that the serial correlations between the current year's risk premium (equity market return less bond income return) and that of the prior year for the period 1947-2011 are -0.052 for Canada and -0.029 for the U.S. For the period 1924-2011 the serial correlation in Canada is 0.119. For the period 1927-2011 the serial correlation in the U.S. is 0.020. If the current year's risk premium were predictable based on the prior year's risk premium, the serial correlation would be close to positive or negative 1.0.

Chart A - 2



Source: Ibbotson Associates, *Stocks, Bonds, Bills & Inflation, 2012 Yearbook*.

4. THE CANADIAN EQUITY MARKET

Several factors inherent in the Canadian equity market make historic Canadian equity risk returns problematic in estimating the forward-looking expected equity market return. First and foremost, the Canadian equity market has been, and continues to be dominated by a relatively small number of sectors; the returns do not reflect those of a fully diversified portfolio.

Historically, the Canadian equity market composite has been dominated by resource-based stocks. At the end of 1980, no less than 46% of the market value of the TSX Composite Index (previously the TSE 300), was resource-based stocks.⁹ The next largest sector, financial services, at less than 15% of the total market value of the composite, was a distant second. With the rise of the technology-based sectors and the increasing market presence of financial services, at the end of 2000, resource-based stocks had dropped to less than 20% of the total market value

⁹ As measured by the oil and gas, gold and precious minerals, metals/minerals, and pulp and paper products sectors. Excludes “the conglomerates sector”, which also contained stocks with significant commodity exposure.

of the TSX Composite Index. By comparison, as indicated in Table A-1 below, the technology-based and financial service sectors accounted for over half of the market value of the index.

Table A - 1

	1980	2000
Information Technology	0.9%	24.1%
Telecommunication Services	4.8%	6.5%
Financial Services	13.5%	24.1%
Total	19.2%	54.7%

Source: *TSE Review*, December 1980 and December 2000.

With the technology sector bust in 2000-2001, and the run-up in commodity prices commencing in 2004, the resource-based sectors reclaimed dominance. At the end of 2011, the energy and materials (largely mining) sectors accounted for over 45% of the total market value of the composite. Including the financial services sector, three sectors accounted for close to 80% of the total market value of the S&P/TSX Composite.

By comparison, the U.S. market has been significantly more diversified among industry sectors. A comparison of market weights in Canada and the U.S. of the major sectors at year-end 2011 illustrates the difference.

Table A - 2

Sector	S&P/TSX Canada	S&P 500 U.S.
Consumer Discretionary	4.0%	10.7%
Consumer Staples	2.8%	11.5%
Energy	27.1%	12.3%
Financials	29.4%	13.6%
Health Care	1.4%	11.9%
Industrials	5.8%	10.7%
Information Technology	1.3%	19.0%
Materials	21.1%	3.5%
Telecommunication Services	5.2%	3.0%
Utilities	2.0%	3.9%

Source: *TSX Review*, December 2011 and www.standardandpoors.com, (January 17, 2012).

Even within the remaining areas of the Canadian market (the less than 25% accounted for by the non-resource and non-financial sectors), there are various sectors of the economy that are relatively underrepresented, e.g., pharmaceuticals, health care and retailing.

Further, the performance of the Canadian equity market as the “market portfolio” has been, at different periods of time, unduly influenced by a small number of companies. In mid-2000, before the debacle in Nortel Networks’ stock value, Nortel shares alone accounted for almost 35% of the total market value of the TSX Composite Index, compared to the largest stock in the S&P 500 at that time (General Electric), which accounted for only 4% of total market value. In 2007, two stocks, Potash Corporation and Research in Motion, were responsible for approximately half of the gain in the S&P/TSX Composite Index. At the end of December 2011, the largest twenty stocks accounted for approximately 50% of the total market capitalization of the S&P/TSX Composite Index. Of the twenty, six (20% of Composite Index market capitalization) were financial and nine (22% of Composite Index market capitalization) were resource (energy and mining) companies.¹⁰ The undue influence of a small number of stocks requires caution in drawing conclusions from the history of the Composite Index regarding the forward-looking market risk premium.

Criticism of the former TSE 300 Index cited the lack of liquidity as well as questioned the quality and size of the stocks which comprised the index. In a speech in early 2002, Joseph Oliver, President and CEO of the Investment Dealers Association of Canada stated,

Over the last 25 years, the TSE 300 has steadily declined as a relevant benchmark index. Part of the problem relates to the illiquidity of the smaller component companies and part to the departure of larger companies that were merged or acquired. Over the last two years, 120 Canadian companies have been deleted from the TSE 300.

When a company disappears from a US index due to a merger or acquisition, that doesn’t affect the U.S. market’s liquidity. An ample supply of large cap, liquid U.S. companies can take its place. In Canada, when a company merges or is acquired by another company, it leaves the index and is replaced by a smaller, less liquid Canadian company. We have seen this over the last two years, -- notably in the energy sector. Over the next

¹⁰ By comparison, the largest 20 stocks in the S&P 500 accounted for 33% of the total index market capitalization, with no single sector represented among the top 20 stocks accounting for more than 10% of the total market capitalization of the index.

few years, we are likely to see it in financial services, where further consolidation is inevitable. Over time, Canada's senior index has become less diversified, with more smaller component companies. As a result, as many as 75 of the TSE 300 will not qualify for inclusion in the new S&P/TSE Composite Index.

Standard & Poor's and the TSX addressed some of these concerns when they overhauled the TSE 300 in May 2002, creating the S&P/TSX Composite Index. The overhaul of the index, which included more stringent criteria for inclusion, did not require that a specific number of companies be included in the index. As a result, only 275 companies were initially included instead of the previous 300. At December 31, 2011 there were 253 companies in the S&P/TSX Composite Index.

The addition of income trusts at the end of 2005 represented a significant change in the make-up of the Composite Index. From the beginning of the decade to their peak in late 2006, the market value of income trusts grew rapidly, from a market capitalization of approximately \$20 billion, to more than \$200 billion. At the end of September 2006, prior to the announced change in tax treatment for income trusts, they accounted for over 11.5% of the total market value of the S&P/TSX Composite. From 1998 (the first year for which returns were reported) to 2005, the annual compound total return for the S&P/TSX Capped Income Trust Index was 19%, compared to 8.5% for the S&P/TSX Composite Index.¹¹ As income trusts significantly outperformed "conventional" equities, their exclusion from the S&P/TSX Composite Index prior to 2005 means that the measured equity returns using the Composite Index understate the actual equity market returns achieved by Canadian investors.¹²

A further complication is created by the existence of restrictions on the foreign content of assets held in pension plans and tax deferred savings plans such as Registered Retirement Savings Plans (RRSPs) for approximately five decades (1957-2005). The restrictions on the ability of Canadians to invest globally negatively impacted their achieved returns. In 1957, when tax deferred savings plans were first established, no more than 10% of the income in pension plans

¹¹ The annual compound total return for the S&P/TSX Income Trust Index (previously the Capped Income Trust Index) over the 1998-2011 period averaged 14.8%, compared to 6.5% for the S&P/TSX Composite Index.

¹² With the change to the income tax treatment of income trusts announced in October 2006 (effective January 1, 2011), most of the income trusts in the S&P/TSX Composite Index have converted back to conventional corporations.

or RRSPs could come from foreign sources. The Foreign Property Rule was instated in 1971 and limited foreign content to 10% of the book value of assets in the funds. The limit was raised to 20% in 2% increments between 1990 and 1994.

In 1999, the Investment Funds Institute of Canada (IFIC) estimated that raising the cap to 20% had increased annual returns by 1% and that a 30% limit would increase returns a further 0.5%.¹³ The limit was raised to 30% in 5% increments between 2000 and 2001. In 2002, the Pension Investment Association of Canada (PIAC) and the Association of Canadian Pension Management (ACPM) published a report entitled *The Foreign Property Rule: A Cost-Benefit Analysis*,¹⁴ which supported the removal of the cap.¹⁵ At that time, the *Globe and Mail* reported that the removal of the foreign content cap was expected to “have the broadest long-term impact of any personal finance measure in the budget. Global stock markets, accessible to any investor through global equity mutual funds, have historically made higher returns than the Canadian market, which only accounts for just over 2 per cent of the world’s stock market value.”¹⁶ The Foreign Property Rule was eliminated in 2005.

Effectively, the combination of mediocre returns and small size of the Canadian market relative to the total global market put pressure on the government to increase and finally eliminate the cap on foreign investment that could be held in RRSPs and pension funds. From this perspective, historic Canadian equity returns therefore are likely to understate investor return requirements.

Investor reaction to the increasingly less restrictive FPR supports that conclusion. Equity investment outside of Canada grew rapidly as the barriers to foreign investment (in terms of

¹³ Tom Hockin, President and CEO IFIC, *Paving the Way for Change to RRSP Foreign Content Rules*, January 31, 2000.

¹⁴ David Burgess and Joel Fried, *The Foreign Property Rule: A Cost-Benefit Analysis*, The University of Western Ontario, November 2002.

¹⁵ The IFIC’s report *Year 2002 in Review* stated,

During the period of 1991-1998, the percentage of sales in equity mutual funds that were comprised of non-domestic equities has hovered around the 41-58% range. This has significantly increased in 1999 and onwards. While performance in the markets is the major factor affecting such an increase, these figures can also be attributed to increases in foreign content limits in registered retirement savings plans as well as increased interest and availability of foreign clone funds.

¹⁶ Rob Carrick, *Finance: Your Bottom Line*, www.globeandmail.com, February 23, 2005.

transactions and information costs as well as the foreign investment cap) declined. Foreign stock purchases by Canadians increased almost ten-fold between 1995 and 2007. Purchases of foreign stocks in 1995 were \$83 billion; in 2007, they were \$915 billion. Although purchases have declined from their 2007 peaks, in 2011 they were approximately \$493 billion, of which over 70% are U.S. stocks.¹⁷ As of 2011Q4, although the total percentage of foreign assets in trustee pension funds was approximately 30%, the percentage of foreign equity to total equity was close to 50%.¹⁸ In addition, the U.S. equity market has historically been the principal alternative for Canadian investors to domestic equity investments. Just over 40% of Canadian portfolio investment in foreign equities at the end of 2011 was in the U.S.¹⁹

5. TRENDS IN PRICE/EARNINGS RATIOS

Several studies of historic and equity risk premiums conclude that the equity returns generated historically are unsustainable, since they were achieved through an increase in price/earnings ratios that cannot be perpetuated.

With respect to the U.S. equity market, the preponderance of the increase in price/earnings ratios occurred during the 1990s. The P/E ratio²⁰ of the S&P 500 averaged 13.7 times from 1926-1988, with no discernible upward trend.²¹ From 11.6 times in late 1988, the P/E ratio gradually rose, peaking at over 46 times in early 2002. At the height of the equity market (1998 to mid-2000), frequently described as a “speculative bubble”, investors believed the only risk they faced was not being in the equity market. In mid-2000, the bubble burst, as the U.S. economy began to lose steam. The events of September 11, 2001, the threat of war, the loss of credibility on Wall Street, accounting misrepresentations and outright fraud, led to a loss of confidence in the market and a sense of pessimism about the equity market. These events led to a heightened appreciation of the inherent risk of investing in the equity market, all of which translated into a “bearish”

¹⁷ Statistics Canada, *International Transactions in Securities*, March 2012, May 2012, Table 12-2.

¹⁸ Based on market value. Statistics Canada, Table 280-0003, data through December 2011.

¹⁹ Statistics Canada, *Canada's International Investment Position – First Quarter 2012*, June 2012, Tables 2 and 5. The U.S. portion of Canadian direct investment abroad at the end of 2011 was approximately 40%.

²⁰ Price to trailing twelve month "as reported" earnings.

²¹ The average P/E ratio from 1947-1988 was 13 times.

outlook for the U.S. equity market and sent retail investors to the sidelines.²² By mid-2006, the P/E ratio had fallen to approximately 17 times.

As the market advanced from 2006 to late 2007, the P/E ratio expanded; when the S&P 500 was at its pre-crisis peak, the P/E ratio reached 22 times. As both the market and earnings collapsed during the financial crisis, the P/E ratio soared to above 120 times during the second quarter of 2009.²³ With recovery in both earnings and the equity market, the P/E ratio fell. At the end of March 2012, the P/E ratio of the S&P 500 was approximately 15.2 times, compared to the long-term (1926-2011) average of approximately 16.6 times.

To assess the impact of rising P/E ratios on achieved returns, I analyzed the equity returns of the S&P 500 achieved between 1926 and 1988, that is, prior to the observed upward trend in P/E ratios. The analysis indicates that the achieved arithmetic average equity return for the S&P 500 was 12.1% from 1926-1988. The corresponding average return from 1926-2011 was 11.8%. Hence, despite the increase in P/E ratios experienced during the 1990s, the average equity market returns were actually lower over the entire 1926-2011 period than over the 1926-1988 period. The results are similar for the post-World War II period. The average returns from 1947-1988, at 13.1%, are higher than the average of 12.3% over the entire 1947-2011 period. In other words, the increase in P/E ratios during the 1990s did not result in a higher and unsustainable level of equity market returns. Consequently, based on history, an expected value for the U.S. equity market return equal to the historic level of approximately 12.0% is not unreasonable.

A review of equity returns in Canada indicates similar results. The 1926-1988 arithmetic average return for the Canadian equity market was 11.8%, higher than the average 1936-2011 return of 11.2%. Similarly, the 1947-1988 equity market return of 12.9% was higher than the 1947-2011 return of 11.8%. There is no indication that rising P/E ratios during the bull market of the 1990s resulted in average equity market returns that are unsustainable going forward.

²² Weakness in the equity markets was partly responsible (along with low interest rates) for the burgeoning income trust market in Canada.

²³ Based on operating earnings, the increase was much less extreme; the P/E ratio based on operating earnings reached 27 times during third quarter 2009.

6. RELATIVE RISK ADJUSTMENT

a. Beta

The body of evidence on CAPM leads to the conclusion that, while betas²⁴ do measure relative volatility, the proportionate relationship between beta and return posited by the CAPM has not been established. A summary of various studies, published in a guide for practitioners, concluded,

Empirical tests of the CAPM have, in retrospect, produced results that are often at odds with the theory itself. Much of the failure to find empirical support for the CAPM is due to our lack of ex ante, expectational data. This, combined with our inability to observe or properly measure the return on the true, complete, market portfolio, has contributed to the body of conflicting evidence about the validity of the CAPM. It is also possible that the CAPM does not describe investors' behavior in the marketplace.

Theoretically and empirically, one of the most troubling problems for academics and money managers has been that the CAPM's single source of risk is the market. They believe that the market is not the only factor that is important in determining the return an asset is expected to earn. (Diana R. Harrington, *Modern Portfolio Theory, The Capital Asset Pricing Model & Arbitrage Pricing Theory: A User's Guide*, Second Edition, Prentice-Hall, Inc., 1987, page 188.)

²⁴ The beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

Where: R_E = Return on the individual stock or portfolio of stocks and R_M is the return on the equity market.

Alternatively, the beta can be expressed as:

$$\text{Standard Deviation of } R_E / \text{Standard Deviation of } R_M \times \text{Correlation Coefficient } (\rho)$$

Betas are typically calculated by reference to historical relative volatility using simple regression analysis of the change in the market portfolio return and the corresponding change in an individual stock or portfolio of stock returns.

Fama and French stated in “The CAPM: Theory and Evidence”, *Journal of Economic Perspectives*, Volume 18, Number 3 (Summer 2004), pp. 25-26:

The attraction of the CAPM is that it offers powerful and intuitively pleasing predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor – poor enough to invalidate the way it is used in applications. The CAPM’s empirical problems may reflect theoretical failings, the result of many simplifying assumptions. But they may also be caused by difficulties in implementing valid tests of the model. For example, the CAPM says that the risk of a stock should be measured relative to a comprehensive ‘market portfolio’ that in principle can include not just traded financial assets, but also consumer durables, real estate and human capital. Even if we take a narrow view of the model and limit its purview to traded financial assets, is it legitimate to limit further the market portfolio to U.S. common stocks (a typical choice), or should the market be expanded to include bonds, and other financial assets, perhaps around the world? In the end, we argue that whether the model’s problems reflect weaknesses in the theory or in its empirical implementation, the failure of the CAPM in empirical tests implies that most applications of the model are invalid.

The Fama French study found that the relationship between beta and average return is much flatter than the CAPM would predict. Specifically, based on analysis covering 1928 to 2003 for the U.S. market, they showed that the predicted return on the lowest beta stock portfolio was 2.8 percentage points lower than the actual return.²⁵

To quote Burton Malkiel in *A Random Walk Down Wall Street*, New York: W. W. Norton & Co., 2003:

Beta, the risk measure from the capital-asset pricing model, looks nice on the surface. It is a simple, easy-to-understand measure of market sensitivity. Alas, beta also has its warts. The actual relationship between beta and rate of return has not corresponded to the relationship predicted in theory during long periods of the twentieth century. Moreover, betas for individual stocks are not stable from period to period, and they are very sensitive to the particular market proxy against which they are measured.

I have argued here that no single measure is likely to capture adequately the variety of systematic risk influences on individual stocks and portfolios. Returns

²⁵ Fama and French developed an alternative model which incorporates two additional explanatory factors in an attempt to overcome the problems inherent in the single variable CAPM. The additional factors are size and book to market.

are probably sensitive to general market swings, to changes in interest and inflation rates, to changes in national income, and, undoubtedly, to other economic factors such as exchange rates. And if the best single risk estimate were to be chosen, the traditional beta measure is unlikely to be everyone's first choice. The mystical perfect risk measure is still beyond our grasp. (page 240)

One of the key developers of the Arbitrage Pricing Model, Dr. Stephen Ross, has stated,

Beta is not very useful for determining the expected return on a stock, and it actually has nothing to say about the CAPM. For many years, we have been under the illusion that the CAPM is the same as finding that beta and expected returns are related to each other. That is true as a theoretical and philosophical tautology, but pragmatically, they are miles apart.²⁶

In a May 2009 survey, "Betas Used by Professors: A Survey with 2,500 Answers," Dr. Pablo Fernandez cites nine different problems with betas including: (1) they have little correlation with stock returns; (2) a beta of 1.0 has a higher correlation with stock returns for many companies; (3) frequently we don't know if the beta of one company is higher than another; (4) the correlation coefficients of the regressions used to calculate the betas are very small; (5) and the relative magnitude of betas often makes very little sense. Based on the issues cited, Dr. Fernandez reaches two findings: the beta calculated with historical data is not a good approximation to the company's beta and the beta of a company (a common figure for all investors) does not exist. The two conclusions, Dr. Fernandez states, imply the CAPM does not work. Ultimately, Dr. Fernandez concludes: "We argue, as many professors mention, that historical betas (calculated from historical data) are useless to calculate the required return to equity (footnote omitted), to rank portfolios with respect to systematic risk, and to estimate the expected return of companies."

In an article released at approximately the same time entitled " $\beta = 1$ Does a Better Job than Calculated Betas", May 19, 2009, Dr. Fernandez and co-author, Vicente Bermejo find that adjusted betas ($0.67 \times$ calculated "raw" beta + $0.33 \times$ Market Beta of 1.0) do a

²⁶ Dr. Stephen A. Ross, "Is Beta Useful?" *The CAPM Controversy: Policy and Strategy Implications for Investment Management*, AIMR, 1993.

better job of predicting returns than the calculated beta. They also find that assuming a beta of 1.0 (i.e., the market beta) does a better job than the adjusted beta.

b. Relationship between Beta and Return in the Canadian Equity Market

To test the actual relationship between beta and return in a Canadian context, the betas (using monthly total return data) were calculated for various periods for each of the 15 major sub-indices of the “old” TSE 300 as were the corresponding actual geometric average total returns. Simple regressions of the betas on the achieved market returns were then conducted to determine if there was indeed the expected positive relationship. The regressions covered (a) 1956-2003, the longest period for which data for the TSE 300 and its sub-index components are available; (b) 1956-1997, which eliminates the major effects of the “technology bubble”, and (c) all potential non-overlapping 10-year periods from 2003 backwards.²⁷

The analysis showed the following:

Table A - 3

Returns Measured Over:	Coefficient on Beta	R²
1956-2003	-.088	47%
1956-1997	-.082	44%
1964-1973	-.020	1%
1974-1983	-.008	1%
1984-1993	-.056	11%
1994-2003	-.053	9%

Source: Schedule 11, page 1 of 2.

The analysis suggests that, over the longer term, the relationship between beta and return has been negative, rather than the positive relationship posited by the CAPM. For example, as indicated in Table A-3 above, for the period 1956-2003, the R² of 47% means that the betas explained 47% of the variation in returns among the key sectors of

²⁷ Non-overlapping periods were used so that each observation represents an independent time period. The length of the period was chosen to minimize the potential for random noise in the return data.

the TSE 300 index. However, since the coefficient on the beta was negative, this means that the higher beta companies actually earned lower returns than the low beta companies.

A series of regressions was also performed on the 10 major sectors of the S&P/TSX Composite. These regressions covered (a) 1988-2011, the longest period for which data for the new Composite and its sector components were available; (b) 1988-1997,²⁸ and (c) the 10-year period ending 2011.

That analysis showed the following:

Table A - 4

Returns Measured Over:	Coefficient on Beta	R²
1988-2011	-.063	52%
1988-1997	-.017	1%
2002-2011	-.094	18%

Source: Schedule 11, page 2 of 2.

These analyses indicate that, historically, the relationship between beta and return in the Canadian equity market has been the reverse (higher beta = lower return) than the posited relationship (lower beta = lower return).²⁹

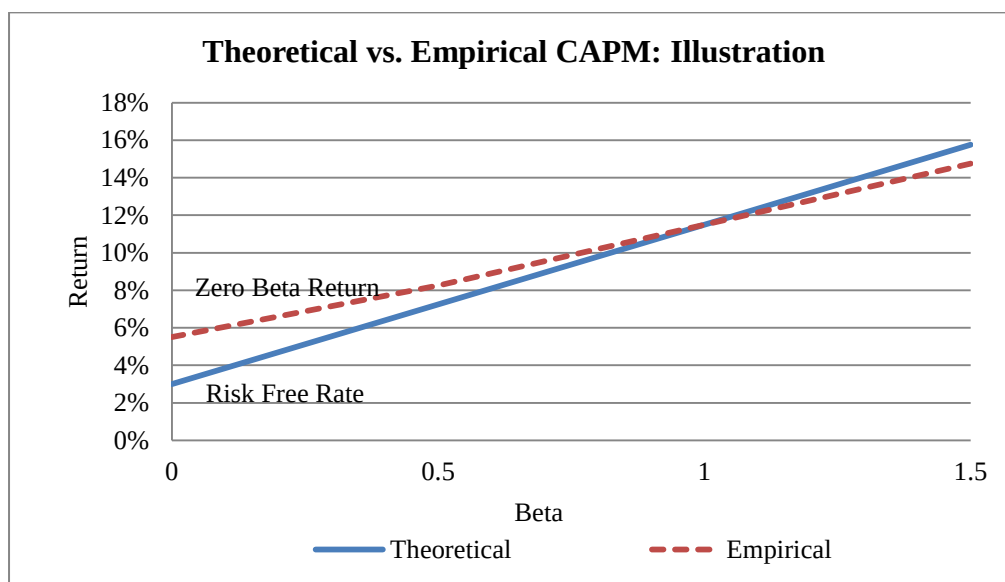
The theoretical CAPM posits a market security line with an intercept equal to a “risk-free rate” and returns for risky securities proportional to their beta. Empirical studies point to a higher intercept and a flatter market security line than the theoretical model posits. In other words, a “zero beta” stock has a higher return than the risk-free rate and low (high)

²⁸ The use of this sub-period was intended to eliminate the impacts of any anomalous market behavior during the technology “bubble and bust”, which occurred mainly from 1999 through mid-2002.

²⁹ In a 2011 article entitled “Benchmarks as Limits to Arbitrage: Understanding the Low-Volatility Anomaly”, *Financial Analysts’ Journal*, Vol. 67, No. 1, 2011, Drs. Malcolm Baker, Brendan Bradley and Jeffrey Wurgler conclude: “In an efficient market, investors realize above average returns only by taking above-average risks. Risky stocks have high returns, on average, and safe stocks do not. This simple empirical proposition has been hard to support on the basis of the history of U.S. stock returns. The most widely used measures of risk point rather strongly in the wrong direction.”

beta stocks have achieved higher returns than their “raw” betas imply, as illustrated in Chart A-3 below.

Chart A - 3



The empirical studies that have tested the CAPM typically rely on a short-term government bond return. To some extent, the application of the CAPM using a long-term government bond yield rather than a short-term instrument adjusts for the tendency of the CAPM to understate (overstate) returns for low (high) beta stocks. The use of a long-term risk-free rate rather than a short-term rate shifts the intercept of the market security line upward and decreases the slope of the line. The implication of this shift for a stock with a “raw” beta of 1.0 can be illustrated as follows:

In Canada, the spread between the three-month Treasury bill and the long-term government bond yield historically has been approximately 1.3%. If the three-month Treasury bill rate is 3.75%, the market return is 11.5% and the “raw” beta of a utility portfolio is 0.50, using the short-term rate as the risk-free rate produces a CAPM return of 7.625% ($3.75\% + 0.50 (11.5\% - 3.75\%)$). When a long-term Government of Canada bond yield of 5.0% is used as the risk-free rate, the CAPM return is equal to 8.25% ($5.0\% + 0.50 (11.5\% - 5.0\%)$). Replacing the short-term Treasury bill rate with the long-term

government bond yield adjusts the cost of equity of a stock with a 0.50 “raw” beta upward by 0.625 percentage points. Similarly, using the long-term government bond yield as the risk-free rate adjusts the cost of equity of a stock with a “raw” beta of 1.50 downward by 0.625 percentage points.

The indicated increase in returns for low beta stocks that is indicated by the replacement of the short-term rate with the long-term rate is well below the 2.8 percentage point difference between the actual and predicted return for the lowest beta portfolio that was identified in the Fama and French study referenced above.

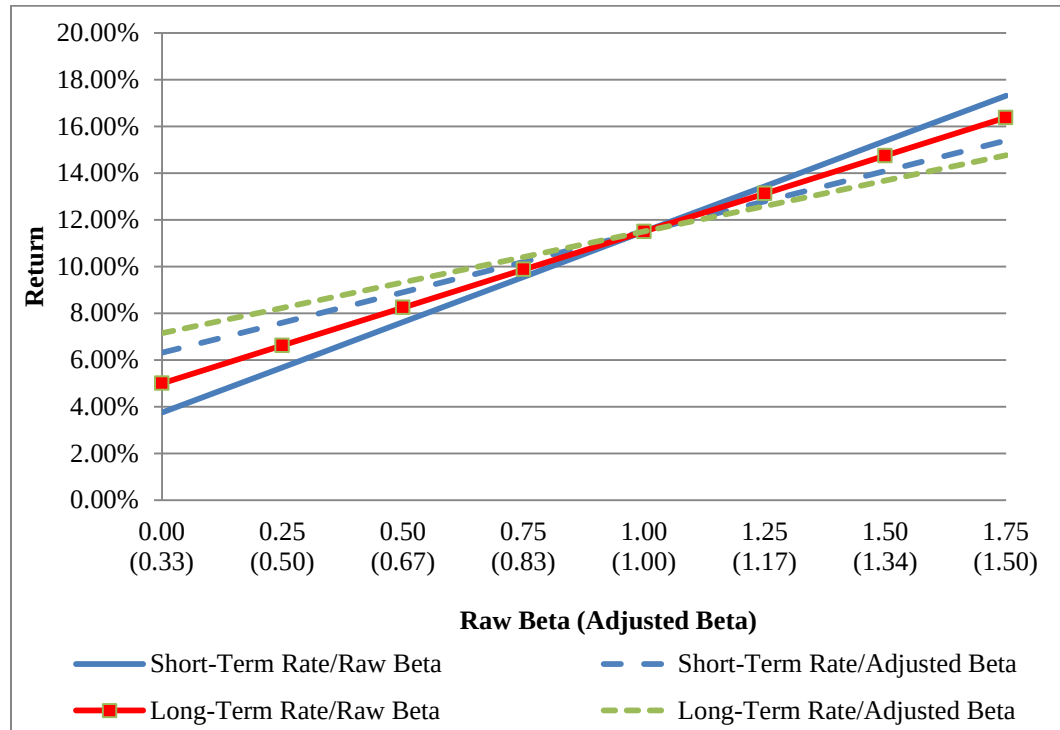
The use of adjusted betas in place of “raw” betas provides a further means of correcting for betas’ under (over) prediction of returns for low (high) beta stocks. Reliance on adjusted betas initially arose in response to the empirically documented failure of betas calculated from one period to be good predictors of betas calculated in a subsequent period. The standard adjustment formula for beta adjusts the “raw” beta toward the market mean beta of 1.0 as follows:

$$\text{Adjusted beta} = \text{“Raw Beta”} \times (2/3) + \text{Market Mean Beta of 1.0} \times (1/3)$$

While the standard beta adjustment formula was initially adopted to account for the observed tendency of betas generally to trend toward the market mean beta of 1.0, effectively its application acts to further adjust for the under and over prediction of returns of low and high beta stocks by the “classic” single variable CAPM. Reliance on betas adjusted using the formula set out above in conjunction with a long-term Government of Canada bond yield as the risk-free rate results in (1) a market security line intercept that lies above the long-term government bond yield and (2) a further flattening of the slope of the line. The implications are higher predicted returns for stocks with betas below the market mean beta of 1.0 and lower predicted returns for stocks with betas above the market mean beta of 1.0.

Chart A-4 below illustrates the differences in predicted returns arising from using (1) a short-term risk-free rate and a “raw” beta; (2) a short-term risk-free rate and an adjusted beta; (3) a long-term risk-free rate and a “raw” beta; and (4) a long-term risk-free rate and an adjusted beta. The key implications of using a long-term risk-free rate and an adjusted beta are: (1) a “zero beta” stock, i.e., one whose stock price movements are uncorrelated with those of the market portfolio would be expected to achieve a higher return than achievable by investing in government bonds; and (2) the trade-off between risk and return across the beta risk spectrum is less pronounced than suggested by either the short-term risk-free rate/“raw” beta or the long-term risk-free rate/“raw” beta approach.

Chart A - 4



Using the standard beta adjustment formula set out above moves a “raw” utility beta of 0.50 to 0.67. With the same inputs for market return (11.5%) and long-term government bond yield (5.0%) as in the previous example, the use of an adjusted beta rather than a “raw” beta increases the indicated utility equity return by close to 1.1%. The total

adjustment to the utility equity return of approximately 1.7% (0.625% for the difference between the long-term and short-term risk-free rates and 1.1% for the difference between the adjusted and “raw” betas) is materially lower than the total 2.8 percentage point under-prediction for the lowest beta portfolio identified in the Fama and French study.

APPENDIX B

SELECTION OF U.S. LOW RISK UTILITY SAMPLE

For the estimation of a fair ROE for an average risk Canadian utility using the Discounted Cash Flow-Based Equity Risk Premium Test and the Discounted Cash Flow Test, a sample of low risk U.S. utilities was selected.

The sample is comprised of all U.S. electric and natural gas utilities satisfying the following criteria:

1. Classified as either an electric or gas utility in *Value Line*;
2. Debt ratings of BBB+ or better and Baa1 or better by S&P and Moody's, respectively;
3. Consistent dividend history over the period 2002-2011;
4. Not being acquired or part of a merger;
5. Utility assets equal to or greater than 80% of total assets; and
6. Long-term earnings growth forecasts available from three of four sources: Bloomberg, Reuters, *Value Line* and Zacks.

The thirteen utilities that met these criteria are:

AGL Resources	Piedmont Natural Gas
ALLETE	Southern Co.
Alliant Energy	Vectren Corp.
Atmos Energy	WGL Holdings Inc.
Consolidated Edison	Wisconsin Energy
Integrus Energy	Xcel Energy Inc.
Northwest Natural Gas	

Utility-specific information is found on pages B-2 to B-34 of this Appendix and on Schedule 13.

AGL Resources

Operating Characteristics:											
Operations:	Completed merger with NICOR in December 2011. Nation's largest natural gas-only distribution company (4.5 million customers) Atlanta Gas Light - Georgia Chattanooga Gas - Tennessee Elizabethtown Gas - New Jersey Elkton Gas - Maryland Florida City Gas - Florida NICOR Gas - Illinois Virginia Natural Gas - Virginia Other non-regulated businesses include competitive gas operations including retail services, wholesale operations, and shipping.										
Total Assets:	\$12,015 million										
Percentage of Assets in Regulated Operations:	Approximately 81%										
State(s) of Operation:	Florida, Georgia, Illinois, Maryland, New Jersey, Tennessee and Virginia										
Number of Customers:	Utility Customers: <table> <tr> <td>IL</td><td>2.2 million</td></tr> <tr> <td>GA, FL & TN</td><td>1.7 million</td></tr> <tr> <td>MD, NJ & VA</td><td>0.6 million</td></tr> </table>	IL	2.2 million	GA, FL & TN	1.7 million	MD, NJ & VA	0.6 million				
IL	2.2 million										
GA, FL & TN	1.7 million										
MD, NJ & VA	0.6 million										
Customers by Type:	2010 Operating Revenues <table> <tr> <td>Residential</td><td>45.6%</td></tr> <tr> <td>Commercial</td><td>22.0%</td></tr> <tr> <td>Transportation</td><td>17.0%</td></tr> <tr> <td>Industrial</td><td>8.6%</td></tr> <tr> <td>Other</td><td>6.7%</td></tr> </table>	Residential	45.6%	Commercial	22.0%	Transportation	17.0%	Industrial	8.6%	Other	6.7%
Residential	45.6%										
Commercial	22.0%										
Transportation	17.0%										
Industrial	8.6%										
Other	6.7%										
Regulatory Environment:											
Test Year:	Partially Forecast - FL Forecast - GA, IL, TN Historic (adj. for known & measurable changes) - MD, NJ, VA										

(GAS cont'd)

Return on Equity (Latest Allowed):	Atlanta Gas Light - 10.75% (2010, GA) Chattanooga Gas - 10.05% (2010, TN) Elizabethtown Gas - 10.3% (2009, NJ) Elkton Gas- 8.33% overall return, settlement (2008, MD) Florida City Gas -11.25% (2004, FL) Nicor Gas - 10.17% (2009, IL) Virginia Natural Gas - 10.0% (2011, VA)
Equity Ratio (Latest Allowed):	Atlanta Gas Light - 51.0% (2010) Chattanooga Gas - 46.06% (2010) Elizabethtown Gas - 47.89% (2009) Florida City Gas -36.77% (2004) Nicor Gas - 51.07% (2009) Virginia Natural Gas - 45.36% (2011)
Earnings Sharing:	NJ - Elizabethtown Gas shares 50/50 up to \$1m annually between monthly benchmark and the actual cost of gas TN - Has interruptible margin credit rider where it shares equally with ratepayers margins resulting from transactions with non-regulated customers that utilize Chattanooga assets.
Deferral Mechanisms:ⁱ	Bad Debt Cost Recovery Mechanism - IL Infrastructure Cost Recovery Mechanism - GA, NJ Retirement benefit costs
Fuel/Gas Cost Recovery:	PGA - all states
Sales and Weather Normalization:	Revenue Decoupling - NJ (pending), TN Flat Monthly Fee Rate Design (SFV) - GA, IL Weather Normalization Adj - NJ, TN, VA
RRA Regulatory Climate:ⁱⁱ	Above Average 2 (VA) Average 1 (FL, GA, TN) Average 3 (NJ) Below Average 2 (IL and MD)

(GAS cont'd)

Moody's Rating Methodology:ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): Baa/A Financial Strength (40%): Baa
S&P's Regulatory Comment	"generally regard Illinois to be a challenging regulatory environment for utilities to manage. However, Nicor has historically enjoyed satisfactory regulatory relations due in large part to its competitive rates to customers and good operating efficiency statistics. The utility has an acceptable 10.2% authorized return on equity, favorable weather-normalization and cost-recovery mechanisms, and a bad debt tracker. We view regulation in Georgia more favorably. In Georgia, the company benefits from a straight-fixed-variable-rate design structure that minimizes revenue risk due to weather and conservation. Georgia is one of a few states where natural gas delivery is deregulated."

ALLETE Inc.

Operating Characteristics:			
Operations:	Principal subsidiaries are regulated utilities: <i>Minnesota Power (MP)</i> : electric distribution in northeastern Minnesota <i>Superior Water Light & Power (SWL&P)</i> : electric, natural gas and water service in northwestern Wisconsin		
	Investment (8%) in American Transmission Co. (ATC), a FERC regulated utility that owns and maintains electric transmission assets in Wisconsin, Michigan, Minnesota and Illinois		
	Unregulated subsidiaries represent 9% of assets; include coal mining operations (consumed primarily by two electric cooperatives, Minnkota and Square Butte, from whom MP purchases capacity and energy under contracts to 2026), real estate, emerging technology investments, and a small amount of non-rate base generation.		
Total Assets:	\$2,876 million		
Percentage of Assets in Regulated Operations:	Approximately 90%		
State(s) of Operation:	Northeastern Minnesota and northwestern Wisconsin		
Number of Customers:	MP – 144,000 electric customers and 16 municipalities in Minnesota SWL&P – 15,000 electric, 12,000 gas, and 10,000 water customers in Wisconsin		
Customers by Type:	Regulated Utility Sales by Customer Type	2010 % of KwH Sold	2011% of KwH Sold
	Residential	9%	9%
	Commercial	11%	11%
	Industrial	52%	56%
	Municipals	7%	7%
	Other Power Suppliers	21%	17%

(ALE cont'd)

Regulatory Environment:	
Test Year:	Partial forecast for Minnesota Forecast for Wisconsin
Return on Equity (Latest Allowed):	Electric: MP: 10.38% (Nov 2010) SWL&P: 10.9% (Dec 2010) Gas: SWL&P: 10.9% (Dec 2010)
Equity Ratio (Latest Allowed):	MP: 54.29% (Dec 2010) SWL&P: 54.9% (Dec 2010)
Earnings Sharing:	n/a
Deferral Mechanisms: ⁱ	Deferral of certain expenses; pension and OPEB. Rate riders provided for annual recovery of specific costs (transmission expenditures, emission reduction, conservation, environmental and renewable) as of 2010 rate case, moved to PP&E in rate base to be recovered in base rates.
Fuel/Gas Cost Recovery:	MN: fuel adjustment clause (FAC) that is adjusted monthly with a two-month lag. Allowed to recover through the FAC non-administrative Midwest Independent System Operator costs. WI: purchased power costs are forecast and compared on a monthly basis to annual range; if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (WI) Average 2 (MN)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Ba Financial Strength (40%): A
S&P's Regulatory Comment	"Regulatory support for various environmental upgrades should help bolster financial measures during ongoing construction."

Alliant Energy Corp.

Operating Characteristics:			
Operations:	Principal subsidiaries are regulated utilities: <i>Interstate Power and Light (IPL)</i> : electric generation and distribution, and gas distribution in Iowa and Minnesota; 2010 revenues 82% electric, 15% gas <i>Wisconsin Power and Light (WPL)</i> : electric generation and distribution, and gas distribution in Wisconsin; 2010 revenues 85% electric, 14% gas		
	IPL sold electric transmission assets in IA, MN and IL to ITC Holdings in 2007; WPL transferred transmission assets to American Transmission Company in 2001 in exchange for ownership interest (16%) in ATC.		
	IPL and WPL members in MISO, a FERC-approved regional transmission organization (RTO).		
	Unregulated subsidiaries represent 5% of assets; include RMT (environmental, consulting, engineering and renewable energy services), rail and barge transportation services, and non-regulated generation.		
	Total Assets: \$9,283 million (2010)		
Percentage of Assets in Regulated Operations:		Approximately 95%	
State(s) of Operations:		Iowa, southern Minnesota, and southern and central Wisconsin	
Number of Customers:		IPL – 526,000 electric customers and 234,000 gas customers in Iowa and southern Minnesota WPL – 455,000 electric and 179,000 gas customers in Wisconsin	
Customers by Type:		2010 %	2010%
	Customer Type	of Revenues	Sales (MWh)
	Residential	37%	26%
	Commercial	23%	21%
	Industrial	29%	37%
	Wholesale	7%	11%
	Bulk Power & Other	4%	5%

(LNT cont'd)

Regulatory Environment:	
Test Year:	Historical in Iowa Partial forecast for Minnesota Forecast for Wisconsin
Return on Equity (Latest Allowed):	Electric: IPL (Iowa): 10.44% blended ROE, including 10% on preponderance of rate base and 11.7% and 12.33% on specific generation investments (January 2011) IPL (Minnesota): 10.35% (Aug 2011) WPL (Wisconsin): 10.40% (Dec 2009) Gas: IPL (Iowa): 10.40% (Oct 2005) WPL (Wisconsin): 10.40% (Dec 2009)
Equity Ratio (Latest Allowed):	Electric: IPL (Iowa): 44.24% (Dec 2010) IPL (Minnesota): 47.74% (Aug 2011) WPL (Wisconsin): 50.38% (Dec 2009) Gas: IPL (Iowa): 49.35% (Oct 2005) WPL (Wisconsin): 50.38% (Dec 2009)
Earnings Sharing:	n/a
Deferral Mechanisms: ⁱ	Pension and OPEB, Energy Efficiency Cost Recovery (EECR), IPL was authorized (12/10) to implement a pilot transmission cost recovery mechanism (automatic rider) for a three-year term. The rider was implemented in conjunction with a 3-year base rate freeze and reduction in allowed ROE of 0.40%.
Fuel/Gas Cost Recovery:	IA: retail electric and gas tariffs contain automatic adjustment clause modified monthly. WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause.
Sales and Weather Normalization:	Jan 2009, Wisconsin PSC implemented 4-year, pilot revenue decoupling mechanisms for residential and small commercial electric and gas customers.

(LNT cont'd)

RRA Regulatory Climate: ⁱⁱ	Above Average 2 (WI) Above Average 3 (IA) Average 2 (MN)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A
S&P's Regulatory Comment	"More credit supportive regulatory jurisdictions"

Atmos Energy

Operating Characteristics:				
Operations:	Natural gas distribution – six divisions as follows: Atmos Energy Colorado-Kansas Atmos Energy Kentucky/Mid-States Atmos Energy Louisiana Atmos Energy Mid-Tex (includes Dallas and environs) Atmos Energy Mississippi Atmos Energy West Texas			
	Non-regulated businesses comprised of natural gas management and marketing services to municipalities, other LDCs and industrial customers, and natural gas transportation along with storage service to the own distribution divisions and third parties.			
Total Assets:	\$8,717 million			
Percentage of Assets in Regulated Operations:	Approximately 93%			
State(s) of Operation:	Primary service areas are in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. More limited service in Georgia, Illinois, Iowa, Missouri and Virginia. Sale of Illinois, Iowa and Missouri assets announced in May 2011 (84,000 customers).			
Number of Customers:	3 million customers in 12 states			
Customers by Type:	2011 % Operating Revenues			
	Residential	62.0%	Public Authority	2.7%
	Commercial	27.6%	Transportation Revenues	2.4%
	Industrial	4.2%	Other Revenue	1.1%
Regulatory Environment:				
Test Year:	Historic - CO, LA Historic (adj. for known and measurable changes) - IA, KS, KY, MO, TX and VA Partial Forecast - GA Forecast - IL, MS, TN			

ATO (cont'd)

Return on Equity (Latest Allowed):	Jurisdiction & Effective Date		ROE
	Colorado-Kansas	Colorado 01/04/2010	10.25%
		Kansas 08/01/2010	n/a
	Kentucky/Mid-States	Georgia 03/31/2010	10.70%
		Illinois 11/01/2000	11.56%
		Iowa 03/01/2001	11.00%
		Kentucky 06/01/2010	n/a
		Missouri 09/01/2010	n/a
		Tennessee 04/01/2009	10.30%
	Louisiana	Virginia 11/23/2009	9.50% -10.50%
		Trans LA 04/01/2011	10.00% -10.80%
		LGS 07/01/2011	10.40%
	Mid-Tex Settled Cities	Texas 09/01/2011	9.70%
	Mid-Tex Dallas	Texas 06/22/2011	10.10%
	Mid-Tex Environs GRIP	Texas 06/27/2011	10.40%
	Mississippi	Mississippi 04/05/2011	9.86%
	West Texas	Amarillo 08/01/2011	9.60%
		Lubbock 09/09/2011	9.60%
		West Texas 08/01/2011	9.60%
	^{1/} GRIP - Gas Reliability Infrastructure Program		
Equity Ratio (Latest Allowed):	Colorado-Kansas		Colorado 50%
		Kansas	na
	Kentucky/Mid-States	Georgia	48%
		Illinois	33%
		Iowa	43%
		Kentucky	na
		Missouri	51%
		Tennessee	48%
	Louisiana	Virginia	49%
		Trans LA	48%
		LGS	48%
	Mid-Tex Settled Cities	Texas	50%
	Mid-Tex Dallas & Environs	Texas	49%
	Mississippi	Mississippi	50%
	West Texas	Amarillo	48%
Lubbock		48%	
West Texas		48%	

(ATO cont'd)

Earnings Sharing:	Performance based rate programs in Georgia (if earnings outside range of 10.5%-10.9% then rates adjusted to change revenue to achieve the upper/lower earnings band; no rate change if earnings within the band), Kentucky and Tennessee whereby purchased gas costs savings are shared.
Deferral Mechanisms: ⁱ	Bad debt rider in CO, KS, KY, TN, TX and VA Infrastructure Cost Recovery in GA, KS, KY, MO and TX OPEB Cost Recovery in LA and MS
Fuel/Gas Cost Recovery:	All states
Sales and Weather Normalization:	Weather Normalization Adjustments approved for "94% of residential and commercial margins" in company's service areas (GA, KS, KY, LA, MS and TX) Innovative rate structures approved: MO: flat fee rate plus small variable charge: 75% costs recovered in monthly fee LA, MS & TX: Rate stabilization tariffs GA: Georgia Rate Adjustment Mechanism (GRAM) providing a non-gas cost revenue true-up implemented 12/2011.
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (VA) Above Average 3 (IA and MS) Average 1 (CO, GA, KY, LA, TN) Average 2 (KS and MO) Below Average 1 (TX) Below Average 2 (IL)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A Financial Strength (40%): A
S&P's Regulatory Comment	"geographic and regulatory diversity in regulatory operations"; "favorable regulatory oversight"

Consolidated Edison Inc

Operating Characteristics:																							
Operations:	Principal subsidiaries are regulated transmission and distribution utilities comprising largest utility system in New York State area: <i>Con Edison of New York:</i> electric, gas and steam distribution and transmission infrastructure <i>Orange & Rockland:</i> gas and electric distribution infrastructure. ORU in turn has two wholly owned electric subsidiaries - Rockland Electric (NJ) and Pike County Light & Power (PA) Unregulated subsidiaries represent less than 5% of assets; include retail and wholesale energy supply.																						
Total Assets:	\$35,600 million																						
Percentage of Assets in Regulated Operations:	Approximately 98%																						
State(s) of Operation:	New York including most of New York City; northern New Jersey and parts of eastern Pennsylvania																						
Number of Customers:	ConEd NY - 3.3 million electric customers, 1.1 million gas customers (New York City and Westchester County) and 23,000 steam customers Orange & Rockland – 0.3 million electric customers in NY, NJ and PA and over 0.1 million gas customers in southeastern NY and northeastern PA.																						
Customers by Type:	<table><tr><th colspan="3">2010 % Revenues</th></tr><tr><th>Customer Type</th><th>Electric</th><th>Gas</th></tr><tr><td>Residential</td><td>37%</td><td>47%</td></tr><tr><td>Com./Industrial</td><td>31%</td><td></td></tr><tr><td>Retail Access</td><td>25%</td><td></td></tr><tr><td>General</td><td></td><td>21%</td></tr><tr><td>Trans. & Other</td><td></td><td>32%</td></tr></table>		2010 % Revenues			Customer Type	Electric	Gas	Residential	37%	47%	Com./Industrial	31%		Retail Access	25%		General		21%	Trans. & Other		32%
2010 % Revenues																							
Customer Type	Electric	Gas																					
Residential	37%	47%																					
Com./Industrial	31%																						
Retail Access	25%																						
General		21%																					
Trans. & Other		32%																					
Regulatory Environment:																							
Test Year:	Forecast																						
Return on Equity (Latest Allowed):	Electric: ConEd NY: 3/10 - 10.15% 3 yr settlement (previously 10%, 2009) Orange & Rockland: 6/11 - 9.2% (fully litigated) Rockland Electric (NJ): 6/10 - settlement 10.3% (previously 9.75%, 2007) Gas: ConEd NY: 9/10 - 9.6%; (prev. 9.7% 3 yr plan) Orange & Rockland: 10/09 adopted 10.4%- 3 yr plan expiring Oct. 2012																						

(ED cont'd)

Equity Ratio (Latest Allowed):	ConEd NY: 48.0% (2010) Orange & Rockland: 48.0% (2011) Rockland Electric: 49.85% (2010)
Earnings Sharing:	<i>ConEd</i> Electric: 100bp over allowed ROE shared 50/50 Gas: 75bp over allowed ROE shared 60/40 (ratepayers/shareholders) <i>Orange & Rockland</i> Electric: Earnings between 10.2% & 11.2% ROE shared 50/50; above 11.2% shared 75/25 (ratepayers/shareholders) Gas: Earnings between 11.4% and 12.4% shared 50/50; 12.4% to 14% shared 65/35 (ratepayers/shareholders); over 14% allocated 90% to ratepayers. ROE threshold reduced 20 basis points in any rate year company fails to meet objectives of its retail choice program
Deferral Mechanisms: ⁱ	Deferral of certain expenses: property taxes (partial), interest on debt (partial), pension and OPEB, environmental remediation expenses, deferred derivative losses (long-term) gas rate plan deferral, World Trade restoration costs collected through rates/riders; bad debt recovery mechanism (NY) and relocation of facilities to accommodate government projects.
Fuel/Gas Cost Recovery:	With electric industry restructuring, transitioned from the fuel adjustment clause (FAC) to a market power adjustment clause (MAC) or a commodity adjustment clause (CAC). The MAC/CAC allows the distribution utilities to flow through the costs of power procured to serve customers who have not selected an alternative supplier. Changes in the clause are recognized in each customer bill (i.e., monthly, bi-monthly, etc.). Although the incumbent distributors retain the provider-of-last-resort (POLR) obligation, the operation of these clauses leaves the distributor insulated from any financial effects associated with changes in market prices. Recovery of gas commodity costs is through semi-automatic fuel adjustment clauses.

(ED cont'd)

Sales and Weather Normalization:	Revenue decoupling for both gas and electric; weather normalization adjustment clauses for gas companies
RRA Regulatory Climate: ⁱⁱ	Average 3 (NJ, NY and PA)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A Financial Strength (40%): Baa
S&P's Regulatory Comment	"Con Edison's subsidiaries have endeavored to reach constructive multiyear settlements in their rate case filings, reducing the need for regular rate filings and ensuring cash flow stability."

Integrys

Operating Characteristics:					
Operations:	Regulated Subsidiaries: <i>Wisconsin Public Service Corp (WPS)</i> <i>Peoples Gas Light & Coke Co. (PG)</i> <i>North Shore Gas Co. (NSG)</i> <i>Upper Peninsula Power Co.(UPP)</i> <i>Minnesota Energy Resources Corp.(MERC)</i> <i>Michigan Gas Utilities Corp (MGU)</i> Regulated Investments: 34% interest in <i>American Transmission Co.(ATC)</i> Non-rate-regulated: <i>Integrys Energy Services</i>				
Total Assets:	\$9,400 million.				
Percentage of Assets in Regulated Operations:	Approximately 87%				
State(s) of Operation:	Illinois (ATC, PG, NSG), Michigan (ATC, MGU, UPP), Minnesota (ATC, MERC) and Wisconsin (WPS, ATC),				
Number of Customers:	Integrys Energy - 1.7 million natural gas and 0.5 million electric customers				
	Customers	'000s	%	Gas	Electric
	Wisconsin Public Serv.	757	35%	19%	89%
	Peoples Gas	819	23%	49%	-
	Minnesota Energy Res.	212	6%	13%	-
	Michigan Gas Utilities	166	2%	10%	-
	North Shore Gas	158	8%	9%	-
Customers by Type:	Upper Peninsula Power	52	7%	-	11%
	Gas Throughput (therms)		Electric Sales (kWh)		
	Residential	40.1%	Residential	19%	
	Comm. & Industrial	12.2%	Comm. & Indus.	51%	
	Interruptible	1.1%	Wholesale	30%	
	Transport	46.3%	Other	<1%	
Regulatory Environment:					
Test Year:	Forecast- Illinois, Wisconsin Partial forecast - Michigan, Minnesota				

(TEG cont'd)

Return on Equity (Latest Allowed):	Gas Decisions: WPS: 10.3% (Jan 2011) PG, NSG: 10.45% (Jan 2012); MERC: 9.7%% (June 2012) MGU: 10.75% (Dec 2009) Electric Decisions: WPS: 10.3% (Jan 2011) UPP: 10.2% (Dec 2011)
Equity Ratio (Latest Allowed):	Gas Decisions: WPS: 51.65% (Jan 2011) PG, NSG: 49% and 50.0%, respectively (Jan 2012) MERC: 50.48% (June 2012) MGU: 46.49% (Dec 2009) Electric Decisions: WPS: 51.65% (Jan 2011) UPP: 45.74% (Dec 2011)
Earnings Sharing:	n/a
Deferral Mechanisms:ⁱ	MI: uncollectible expense true-up mechanism for MGU. MN: n/a IL: Gas - bad debt riders; infrastructure cost recovery WI: pension and other post retirement benefit costs related to 2008 losses (approved 2009)
Fuel/Gas Cost Recovery:	WI: purchased power costs are forecast and compared on a monthly basis to annual range, if likely outside that range (currently +/- 2%) the PSC may conduct a hearing to establish new rates. Gas tariffs contain an automatic adjustment clause. MN: fuel adjustment clause that is adjusted monthly with a two-month lag. Allowed to recover through the FAC non-administrative Midwest Independent System Operator costs. MI: The Power Supply Cost Recovery (PSCR) and Gas Cost Recovery (GCR) clauses require utilities to annually file projected costs, and a forward-looking PSCR or GCR supply factor is established at the beginning of the 12 month collection period. Annual reconciliation proceedings are required. IL: Electric - The power to meet the utilities' standard offer service (SOS) obligations is procured competitively; SOS costs and revenues are subject to an annual true-up mechanism. Gas - PGA clause

(TEG cont'd)

Sales and Weather Normalization:	Decoupling: WI - WPS' decoupling mechanism includes an annual cap for the deferral of any excess or shortfall from the rate case authorized margin (\$8m gas; \$14m electric) MI - UPP's decoupling mechanism terminated effective 1/2012 by settlement- new mechanism to commence 1/2013 IL - 1/2012 decision made permanent for both NSG & PG a decoupling mechanism (Volume Balancing Rider (VBA)) first approved in 2008; also established rate design permitting 67% (NSG) and 55% (PG) of fixed costs to be recovered in customer charges MN - MERC authorized in 6/2012 to start a 3-year pilot program for revenue decoupling.
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (WI) Average 1 (MI) Average 2 (MN) Below Average 2 (IL)
Moody's Rating Methodology:ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): Baa Diversification (10%): A/Baa Financial Strength (40%): A
S&P's Regulatory Comment	"Integritys has continued to effectively manage its regulatory risk--including its recent rate case orders for PG and NSG that will collectively raise rates by almost \$60 million--which we view as credit supportive. We expect that the company will continue to effectively manage its regulatory risk over the medium term with the goal of further reducing its regulatory lag."

Northwest Natural Gas Co.

Operating Characteristics:		
Operations:	<i>Utility</i> – local regulated gas distribution business <i>Gas Storage</i> – storage services to intrastate and interstate customers and asset optimization services <i>Other</i> – investments in gas pipelines (1% of assets)	
Total Assets:	\$2,600 million	
Percentage of Assets in Regulated Operations:	Approximately 99%	
State(s) of Operation:	90 communities in Oregon and southwest Washington, including Portland and Eugene OR, and Vancouver WA.	
Number of Customers:	674,000 customers (90% customer base in Oregon)	
Customers by Type:	Customer Type Residential Commercial Industrial	2010 % of Revenues 61% 30% 9%
Regulatory Environment:		
Test Year:	Partial or full forecast for Oregon Historic with adjustments for known and measurable changes for Washington	
Return on Equity (Latest Allowed):	10.2% (2003 OR) 10.1% (2008 WA)	
Equity Ratio (Latest Allowed):	49.50% (2003 OR) 50.74% (2008 WA)	
Earnings Sharing:	Tied to PGA option; see Fuel/Gas Cost Recovery	
Deferral Mechanisms:ⁱ	Pipeline integrity management program Pension expense and OPEB deferral Environmental cost deferral Infrastructure cost recovery mechanism	
Fuel/Gas Cost Recovery:	PGA in Oregon – contains an incentive mechanism whereby a percentage of various between companies' cost of gas in rates and actual cost is absorbed or retained by the LDC - subject to annual earnings review PGA in Washington requires 100% pass through of prudently incurred gas cost deferrals	
Sales and Weather Normalization:	Revenue decoupling in Oregon; Weather normalization adjustment in Oregon (through 2012).	

(NWN cont'd)

RRA Regulatory Climate: ⁱⁱ	Average 3 (OR and WA)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): Baa
S&P's Regulatory Comment	"..supportive rate design and incentive programs that allow exceptionally stable cash flows that are largely insulated from gas price, weather, and usage rate fluctuations."

Piedmont Natural Gas

Operating Characteristics:		
Operations:	<i>Regulated</i> – distribution of natural gas <i>Unregulated</i> – retail natural gas marketing, storage and transportation	
Total Assets:	\$3,050 million	
Percentage of Assets in Regulated Operations:	Approximately 97%	
State(s) of Operation:	North Carolina (72% net utility plant), South Carolina, Tennessee	
Number of Customers:	968,188 customers	
Customers by Type:	Customer Type Residential Commercial Industrial	2011 % of Revenues 56% 32% 9%
Regulatory Environment:		
Test Year:	Historic test period in NC and SC (adjusted for known and measurable changes) Forward test year in TN	
Return on Equity (Latest Allowed):	10.6% (2008 NC) 11.3% (2011 SC) 10.2% (2011 TN, stipulation)	
Equity Ratio (Latest Allowed):	51% (2008 NC) 61% (2011 SC) 52.71% (2011 TN, stipulation)	
Earnings Sharing:	Rate stabilization tariffs in SC: revenues adjusted annually such that earned ROE remains within a range of +/- 50 basis points of the allowed ROE of 11.3%.	
Deferral Mechanisms:ⁱ	Pension and retirement benefits expense Environmental remediation Demand side management Pipeline integrity expense Bad debt cost recovery mechanism (NC, SC & TN)	
Fuel/Gas Cost Recovery:	PGA recovers 100% of costs	

(PNY cont'd)

Sales and Weather Normalization:	Decoupling tariffs in NC only. In NC the Customer Utilization Tracker (CUT) is in effect, accounting for the impact of both weather and utilization. Weather normalization in all other areas.
RRA Regulatory Climate: ⁱⁱ	Above Average 3 (NC) Average 1 (SC and TN)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): A
S&P's Regulatory Comment	"Supportive regulatory environment"

Southern Co.

Operating Characteristics:													
Operations:	Traditional Operating Companies: Each own generation, transmission and distribution facilities: <i>Alabama Power</i> (Alabama) <i>Georgia Power</i> (Georgia) <i>Gulf Power</i> (Florida) <i>Mississippi Power</i> (Mississippi). Southern Power: Public utility which constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates. Subject to FERC regulation. Non-Utility Operations: Digital wireless communications, operates and provides services to utilities' nuclear plants, acquires, owns, and constructs renewable generation assets.												
Total Assets:	\$55,700 million												
Percentage of Assets in Regulated Operations:	Approximately 92%												
State(s) of Utility Operations:	Majority of operations in Alabama and Georgia, along with the northwestern portion of Florida and southeastern Mississippi.												
Number of Customers:	4.4 million customers (traditional operating companies)												
Customers by Type:	<table> <tr> <th>Customer Type</th><th>2010 % of Operating Revenues</th></tr> <tr> <td>Residential</td><td>38%</td></tr> <tr> <td>Commercial</td><td>31%</td></tr> <tr> <td>Industrial</td><td>19%</td></tr> <tr> <td>Other - Retail</td><td>1%</td></tr> <tr> <td>Wholesale</td><td>12%</td></tr> </table>	Customer Type	2010 % of Operating Revenues	Residential	38%	Commercial	31%	Industrial	19%	Other - Retail	1%	Wholesale	12%
Customer Type	2010 % of Operating Revenues												
Residential	38%												
Commercial	31%												
Industrial	19%												
Other - Retail	1%												
Wholesale	12%												
Regulatory Environment:													
Test Year:	AL: Historic with adjustments for known and measurable changes FL: Partial or full forecast GA: Partial forecast MS: Full forecast												

(SO cont'd)

Return on Equity (Latest Allowed):	13.75% (2005 AL) 10.25% (2012 FL) 11.15% (2010 GA) 10.701% (2011 MS) ROE is performance adjusted and reflects Alternative Rate Plan (ARP) filing
Equity Ratio (Latest Allowed):	45.00% (2005 AL) 46.26% (2012 FL) 51.67% (2001 GA) 47.51% (2011 MS) based on ARP filing
Earnings Sharing:	AL: Alabama Power operates under a Rate Stabilization and Equalization framework. Annual rate increases limited to 5% and rate increases for any two-year period, when averaged, cannot exceed 4% per year. If projected ROE is outside the allowed ROE range of 13%-14.5% rates are adjusted, subject to the limits above, to establish a 13.75% ROE. If actual earned ROE is above 14.5%, customers are refunded revenues that caused the earned ROE to exceed 14.5%. No provision for recovering shortfalls if the earned ROE is below 13%. GA: Georgia Power operating under an alternative rate plan since 1996; current version applies to years 2011-2013. Not permitted to file a general rate case unless earnings are projected to fall below a 10.25% ROE. Two-thirds of earnings above a 12.25% ROE are refunded to customers. No automatic recovery of any earnings shortfall below a 10.25% ROE, but may petition to utilize an Interim Cost Recovery Tariff to adjust earnings to a 10.25% ROE in lieu of filing a rate case. Permitted to retain 15% of the net present value of the net benefits generated by certain demand-side management programs.
Deferral Mechanisms:ⁱ	Pension and employee benefit expense, Environmental remediation costs, Storm damage cost recovery. AL: Rate Certificated New Plant (CNP) mechanism adjusts rates annually to recognize the cost of placing new generating facilities in retail service and recovery of retail costs associated with certificated PPAs. CNP includes environmental costs and return on invested capital. Plant outage costs. GA: CWIP in rate base; plant outage costs.

(SO cont'd)

Fuel/Gas Cost Recovery:	AL: Energy Cost Recovery (ECR) rate in place established on the basis of estimates of electric sales, fuel, and net purchased energy costs, and reflects accumulated over- or under-recovered amounts. GA: non-automatic fuel adjustment mechanism is in place. FL: the fuel and purchased power cost recovery clause provides for recovery of prudently incurred fuel and purchased power costs. Annual fuel factors are established base upon 12-month projections of fuel costs and energy purchases and sales. Hearings are held each November, during with the PSC sets fuel factors for the next calendar year. MS: an automatic electric fuel adjustment clause is in effect, with the energy component of purchased power recovered through the fuel clause and the capacity component recovered in base rates.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (AL) Above Average 3 (MS) Average 1 (FL and GA)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): A/Baa
S&P's Regulatory Comment	"Operations under generally constructive regulatory environments"

Vectren Corp

Operating Characteristics:									
Operations:	<i>Vectren Utility Holdings</i> – comprised of Indiana Gas, Southern Indiana Gas & Electric Company and Ohio operations. <i>Vectren Enterprises</i> – support services to utility operations.								
Total Assets:	\$4,795 million								
Percentage of Assets in Regulated Operations:	Approximately 82%								
State(s) of Operation:	Nearly 2/3 rd s of the state of Indiana (gas and electric) and part of Ohio (gas).								
Number of Customers:	681,000 gas and 142,000 electric customers in central and southern Indiana. 314,000 gas customers in west central Ohio.								
Customers by Type:	<table> <tr> <th>Customer Type</th><th>2010 % of Margin</th></tr> <tr> <td>Residential & Comm.</td><td>86%</td></tr> <tr> <td>Industrial</td><td>12%</td></tr> <tr> <td>Other</td><td>3%</td></tr> </table>	Customer Type	2010 % of Margin	Residential & Comm.	86%	Industrial	12%	Other	3%
Customer Type	2010 % of Margin								
Residential & Comm.	86%								
Industrial	12%								
Other	3%								
Regulatory Environment:									
Test Year:	Historic with adjustments for known and measurable changes for Indiana Partial forecast for Ohio								
Return on Equity (Latest Allowed):	Electric: SIGECO: 10.4% (2011) Vectren Energy Delivery Ohio: 8.89% overall return (2009) settlement Gas: Indiana Gas: 10.20% (2008) SIGECO: 10.15% (2007)								
Equity Ratio (Latest Allowed):	SIGECO: 49.93% (2011) Indiana Gas: 48.99% (2008 IN) Vectren Energy Delivery: 48.10% (2005 OH); 2009 not specified								
Earnings Sharing:	n/a								

(VVC cont'd)

Deferral Mechanisms: ⁱ	Employee benefit deferral Demand side management expense Pipeline integrity expense Bad debt recovery mechanism (IN, OH) Environmental CWIP tracker Infrastructure cost recovery (IN, OH)
Fuel/Gas Cost Recovery:	Electric utilities may adjust rates for changes in fuel and purchased power (energy component only) costs every three months, following hearings, through the fuel adjustment clause (FAC)
Sales and Weather Normalization:	Decoupling (gas) in IN through weather normalization and conservation tariffs Straight fixed variable rate design (OH)
RRA Regulatory Climate: ⁱⁱ	Above Average 3 (IN) Average 2 (OH)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses Note: Info for Vectren Utility Hldgs.	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%):A
S&P's Regulatory Comment	"... supportive regulation and a lack of competition"

WGL Holdings Inc.

Operating Characteristics:		
Operations:	<i>Regulated Utility</i> – Washington Gas (DC, MD & VA) and Hampshire (FERC) <i>Retail Energy-Marketing</i> – sales of natural gas and electric commodity <i>Design-Build energy systems</i> – energy efficiency solutions to government and commercial customers	
Total Assets:	\$3,930 million	
Percentage of Assets in Regulated Operations:	Approximately 87%	
State(s) of Operation:	District of Columbia, Maryland and Virginia	
Number of Customers:	1.1 Million – 14% DC, 41% MD, 45% VA	
Customers by Type:	Customer Type Residential Commercial and Industrial	2009 % of Therms Delivered 77.3% 22.7%
Regulatory Environment:		
Test Year:	Partial forecast for Maryland and Washington D.C. Historic with adjustments for known and measurable changes for Virginia	
Return on Equity (Latest Allowed):	District of Columbia: 10.0% (2006) Maryland: 9.6% (2011) Virginia: 10.0% (2011)	
Equity Ratio (Latest Allowed):	50.30% (2003 DC); unspecified in 2006 57.88% (2011 MD) 55.70% (2011 VA)	
Earnings Sharing:	n/a	
Deferral Mechanisms:ⁱ	Trackers for pension and OPEB; accelerated recovery mechanisms for costs of eligible infrastructure replacement programs in VA	
Fuel/Gas Cost Recovery:	PGAs recover 100% of costs. A Gas Administrative Charge (GAC) permits company to recover bad debts relating to gas costs through the purchased gas charge clause rather than base rates.	

(WGL cont'd)

Sales and Weather Normalization:	Weather normalization (VA) Decoupling (MD) Declining block rates (MD, VA)
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (VA) Average 2 (DC) Below Average 2 (MD)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses Note: Info for Washington Gas Light	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): A
S&P's Regulatory Comment	"excellent business risk profile reflects an affluent and stable service territory, supportive regulatory mechanisms, moderate regulatory and market diversification, and low operating risk. Supportive regulatory mechanisms enhance Washington Gas Light's cash flow stability, which further supports credit quality."

Wisconsin Energy Corp.

Operating Characteristics:			
Operations:	Utility Energy – electric and gas utilities operating together under the trade name of We Energies (Wisconsin Electric, Wisconsin Gas). Completed sale of Edison Sault in 2010. Non-Utility Energy –We Power designs, constructs, owns, and leases generating capacity.		
Total Assets:	\$14,911million		
Percentage of Assets in Regulated Operations:	Approximately 80%		
State(s) of Operation:	Wisconsin and the Upper Peninsula of Michigan		
Number of Customers:	1.1 million electric customers in Wisconsin & Michigan’s Upper Peninsula 1.0 million gas customers in Wisconsin 0.5 million steam customers in Milwaukee		
Customers by Type:	Customer Type	2010% Revenues	
	Residential	Electric 38%	Gas 63%
	Comm./Industrial	55%	31%
	Other	7%	6%
Regulatory Environment:			
Test Year:	MI: Partial forecast WI: Forecast		
Return on Equity (Latest Allowed):	Electric: 10.40% (2009 WI) 10.25% (2010 MI) Gas: 10.40% (2009 WI)		
Equity Ratio (Latest Allowed):	Electric: 53.02% (2009 WI) 52.48% (2010 MI) Gas: 53.02% (2009 WI)		
Earnings Sharing:	n/a		
Deferral Mechanisms: ⁱ	Bad debt expense, recovery of unrecovered transmission costs, pension and OPEB		

(WEC cont'd)

Fuel/Gas Cost Recovery:	Gas: Full recovery. One-for-one recovery measured against a monthly benchmark with 2% tolerance. Costs above the benchmark subject to further review. Fuel and Purchased Power: no automatic adjustments; no adjustments made to rates as long as fuel and purchased power costs are within a band of costs included in rates for a 12 month period. If costs are expected to fall outside the band, may file for a change in fuel recoveries on a prospective basis.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (WI) Average 1 (MI)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): A Ability to Recover Costs/Earn Return (25%): A Diversification (10%): Baa Financial Strength (40%): Baa
S&P's Regulatory Comment	"benefits from responsive regulation in Wisconsin, characterized by supportive cost-recovery ratemaking mechanisms"

Xcel Energy Inc.

Operating Characteristics:		
Operations:	Regulated Utilities: <i>Northern States Power Minnesota:</i> electric distribution in Minnesota, North Dakota, and South Dakota. Gas distribution in Minnesota and North Dakota <i>Northern States Power Wisconsin:</i> electric and gas distribution in Wisconsin and Michigan <i>Public Service Co. of Colorado:</i> electric and gas distribution in Colorado <i>Southwestern Public Service:</i> electric distribution in Texas and New Mexico WestGas InterState-a small interstate natural gas pipeline. WYCO Development-50% ownership, develops and leases natural gas pipeline, storage, and compression facilities. Unregulated subsidiaries-rental housing projects	
Total Assets:	\$30,000 million	
Percentage of Assets in Regulated Operations:	Approximately 95%	
State(s) of Operation:	Colorado, Michigan (western Upper Peninsula), Minnesota, New Mexico, North Dakota, South Dakota, Texas, northwestern Wisconsin and Texas	
Number of Customers:	3.4 million electric customers and 1.9 million gas customers.	
Customers by Type:	Electric Residential 31% Commercial and Industrial 53% Public Authorities & Other 2% Wholesale 11% Other 3% Gas Customer Type Residential 63% Commercial and Industrial 33% Transportation & Other 4%	2010 % of Revenues

(XEL cont'd)

Regulatory Environment:	
Test Year:	CO, NM, SD, TX: Historic with adjustments for known and measurable changes MN, MI: Partial forecast ND: Partial or full forecast WI: Full forecast
Return on Equity (Latest Allowed):	Electric: 10.0% (2012 CO) 10.37% (2012 MN) 10.40% (2012 ND) 10.18% (2008 NM) 8.32% (2010 SD) overall ROE, settlement 10.40% (2011 WI) Gas: 10.10% (2011 CO) 10.09% (2010 MN) 10.75% (2007 ND) 10.40% (2011 WI)
Equity Ratio (Latest Allowed):	Electric: 56.0% (2012 CO) 52.56% (2012 MN) 51.77% (2008 ND) 51.23% (2008 NM) 52.59% (2011 WI) Gas: 56.0% (2011 CO) 52.46% (2010 MN) 51.77% (2008 ND) 52.59% (2011 WI)
Earnings Sharing:	ND: earnings in excess of 10.75% ROE are shared with customers. If earnings are between 10.75%-11.25% ROE, they are shared equally. Earnings above 11.25% ROE are shared 75% to ratepayers and 25% to shareholders. CO: customers receive bill credits if company did not achieve certain performance targets relating to electric reliability, customer service, and natural gas leak repair time.

(XEL cont'd)

Deferral Mechanisms: ⁱ	Pension and OPEB CO, MN: Enhanced cost recovery for emissions reduction provides a return on CWIP and an incentive based ROE (energy savings goals) CO: specific retail rate rider for certain costs associated with renewable energy resources; Transmission Cost Adjustment recovers costs associated with investments in transmission facilities TX: recovery of certain transmission investments and other transmission costs through TCRF rider
Fuel/Gas Cost Recovery:	Cost-of-Energy Adjustment mechanisms for purchases of coal, nuclear fuel and natural gas in all states except Wisconsin: no automatic adjustments; no adjustments made to rates as long as fuel and purchased power costs are within a band of costs included in rates for a 12 month period. If costs are expected to fall outside the band, may file for a change in fuel recoveries on a prospective basis.
Sales and Weather Normalization:	n/a
RRA Regulatory Climate: ⁱⁱ	Above Average 2 (WI) Average 1 (CO, MI, ND) Average 2 (MN) Average 3 (SD) Below Average 1 (NM and TX)
Moody's Rating Methodology: ⁱⁱⁱ Weight accorded to category in parentheses	Regulatory Framework (25%): Baa Ability to Recover Costs/Earn Return (25%): A Diversification (10%): A Financial Strength (40%): A/Baa
S&P's Regulatory Comment	"credit-supportive regulation"

ⁱ Lost and Unaccounted for Gas Trackers (LUAFT) are in 47 of 50 states (excluding Michigan, Montana and South Dakota) (AGA, *Innovative Rates, Non-Volumetric Rates, and Tracking Mechanisms: Current List As of March 2012*)

ⁱⁱ RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects RRA's assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

ⁱⁱⁱ Financial strength is comprised 10% liquidity and four metrics each weighted 7.5% for a total of 40%. The four metrics measured are: i) (Cash from operations (CFO) pre-working capital (WC) plus interest) over interest expense; ii) CFO Pre-WC/Debt; iii) (CFO Pre-WC less dividends)/Debt; and iv) Debt/Book Capitalization.

APPENDIX C

DISCOUNTED CASH FLOW TEST

1. CONCEPTUAL UNDERPINNINGS

The discounted cash flow (DCF) approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the risk of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to approximate the investor's required return, which is the rate that equates the price of the stock to the discounted value of future cash flows.

2. DCF MODELS

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. To estimate the DCF cost of equity, both constant growth and a three-stage growth models were utilized. These two models are discussed below.

a. Constant Growth Model

The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. The assumption that investors expect a stock to grow at a constant rate over the long-term is most applicable to stocks in mature industries. Growth rates in these industries will vary from year to year and over the business cycle, but will tend to deviate around a long-term expected value.

The constant growth model is expressed as follows:

$$\text{Cost of Equity (k)} = \frac{D_1}{P_0} + g,$$

where,

$$\begin{aligned} D_1 &= \text{next expected dividend}^1 \\ P_0 &= \text{current price} \\ g &= \text{constant growth rate} \end{aligned}$$

This model, as set forth above, reflects a simplification of reality. First, it is based on the notion that investors expect all cash flows to be derived through dividends. Second, the underlying premise is that dividends, earnings, and price all grow at the same rate. However, it is likely that, in the near-term, investors expect growth in dividends to be lower than growth in earnings.

The model can be adapted to account for the potential disparity between earnings and dividend growth by recognizing that all investor returns must ultimately come from earnings. Hence, focusing on investor expectations of earnings growth will encompass all of the sources of investor returns (e.g., dividends and retained earnings).

b. Three-Stage Model

The three-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the near-term (Stage 1), to migrate to the expected long-run rate of growth in the economy (GDP Growth) (Stage 2) and to equal expected long-term GDP growth in the long term (Stage 3).

Using the three-stage DCF model, the DCF cost of equity is estimated as the internal rate of return that causes the price of the stock to equal the present value of all future cash flows to the investor where the cash flows are defined as follows:

¹ Alternatively expressed as $D_0 (1 + g)$, where D_0 is the most recently paid dividend.

The cash flow per share in Year 1 is equal to:

$$\text{Last Paid Annualized Dividend} \times (1 + \text{Stage 1 Growth})$$

For Years 2 through 5, cash flow is defined as:

$$\text{Cash Flow}_{t-1} \times (1 + \text{Stage 1 Growth})$$

For Years 6 through 10, cash flow is defined as:

$$\text{Cash Flow}_{t-1} \times (1 + \text{Stage 2 Growth})$$

Cash flows from Year 11 onward are estimated as:

$$\text{Cash Flow}_{t-1} \times (1 + \text{GDP Growth})$$

3. GROWTH COMPONENT OF THE DCF MODELS

The growth component of the DCF models is an estimate of what investors expect over the longer-term. For a regulated utility, whose growth prospects are tied to allowed returns, the estimate of growth expectations is subject to circularity because the analyst is, in some measure, attempting to project what returns the regulator will allow, and the extent to which the utilities will exceed or fall short of those returns. To mitigate that circularity, it is important to rely on a sample of proxies, rather than the subject company. (When the subject company does not have traded shares, a sample of proxies is required.) Further, to the extent feasible, one should rely on estimates of longer-term growth readily available to investors, rather than superimpose on the analysis one's own view of what growth should be.

a. Constant Growth Model Growth Rates

In the application of the constant growth model, two estimates of investors' expectations of long-term earnings growth were relied upon: a consensus of investment analysts' earnings forecasts and an estimate of the sustainable growth rate. The consensus earnings growth forecasts were obtained from four different sources, Bloomberg, Reuters, *Value Line* and Zacks. Bloomberg² and Reuters³ are both global providers of real time financial news and data. *Value Line* provides investment research and forecasts for approximately 1,700 large capitalization stocks as well as investment research on 1,800 mid and small capitalization stocks. Its publications are broadly accessible to both individual and institutional investors. Zacks provides consensus estimates and ratings for approximately 4,500 US and Canadian companies that have at least one sell-side analyst covering them. In general, all of these long-term earnings forecasts refer to a period of between three and five years and are intended to represent the normalized ("smoothed") rate of earnings growth over a business cycle. The consensus earnings forecasts are reflective of the analyst community's views and, therefore, are a reasonable proxy of (unobservable) investor growth expectations.

As an alternative to the consensus of investment analysts' earnings forecasts, constant growth DCF costs of equity for the sample were estimated based on sustainable growth rates derived from *Value Line* forecasts of returns on equity, earnings retention rates and earnings growth from external financing.

Sustainable growth, or earnings retention growth, is premised on the notion that future dividend growth depends on both internal and external financing. Internal growth is achieved by the firm retaining a portion of its earnings in order to produce earnings and dividends in the future. External growth measures the long-run expected stock financing undertaken by the utility and the percentage of funds from that investment that are

² Bloomberg data are available for a fee on the internet and through "Bloomberg terminals". Bloomberg has offices in more than 200 places around the world.

³ Reuters provides real time forecasts for over 20,000 active companies from over 600 contributing brokerage firms in more than 70 countries. Reuters is part of Thomson Reuters, which also publishes I/B/E/S and First Call consensus earnings growth estimates.

expected to accrue to existing investors. The internal growth rate is estimated as the fraction of earnings (B) expected to be retained multiplied by expected return on equity (R). The external financing portion of the sustainable growth rate is estimated as the forecast growth in the number of shares of common stock outstanding (S) multiplied by the equity accretion rate (V) which is the fraction of sales of new equity investment expected to accrue to existing stockholders. The V term is calculated as $1 - (\text{Book Value per Share} / \text{Market Price per Share})$. The sustainable growth rate is then calculated as the sum of BR and SV. The external growth component recognizes that investors may expect future growth to be achieved not only through the retention of earnings but also through the issuance of additional equity capital which is invested in projects that are accretive to earnings.

b. Expected Long-Term Growth in the Economy (Stage 3 Growth)

The use of forecast GDP growth in a multi-stage model as the proxy for the rate of growth to which companies will migrate over the longer term is a widely utilized approach. For example, the Merrill Lynch discounted cash flow model for valuation utilizes nominal GDP growth as a proxy for long-term growth expectations. The Federal Energy Regulatory Commission relies on GDP growth to estimate expected long-term nominal growth for conventional corporations in its standard DCF models for gas and oil pipelines.

The use of forecast long-term growth in the economy as the proxy for long-term growth in the DCF model recognizes that, while all industries go through various stages in their life cycle, mature industries are those whose growth parallels that of the overall economy. Utilities are considered to be the quintessential mature industry.

c. **Reliability of Analysts' Earnings Forecasts**

The reliability of the analysts' earnings growth forecasts as a measure of investor expectations has been questioned by some Canadian regulators. The issue of reliability arises because some studies have concluded that analysts' earnings growth forecasts have been optimistic. However, as long as investors have believed the forecasts, and have priced the securities accordingly, the resulting DCF costs of equity are an unbiased estimate of investors' expected returns.

Analyst optimism became a high profile issue during the irrational exuberance phase of the technology boom during the 1990s, when analysts were accused of fueling the market by exaggerating the prospects of dot.com firms. It was this behaviour that ultimately led to Regulation FD (Fair Disclosure) in 2000 and the Global Analyst Research Settlements of 2002 in the U.S. which removed incentives for sell-side analysts to curry favor with company management by issuing inflated earnings forecasts.

A study conducted after the Global Settlement found that following the settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared.⁴ There are also studies which have shown that analyst optimism is at least in part related to the difference between forecasting earnings for firms who report losses versus firms who report profits. For example, Jeffery Abarbanell and Reuven Lehavy, "Biased Forecasts or Biased Earnings? The Role of Reported Earnings in Explaining Apparent Bias and Over/Underreaction in Analysts' Earnings Forecasts", *Journal of Accounting and Economics* 36 (2003), pages 105-146, found that while, on an average basis, there appeared to be a forecast bias, the median forecast error was zero. The same article cited an earlier study, Michael P. Keane and David E. Runkle, "Are Financial Analysts' Forecasts of Corporate Profits Rational?", *Journal of Political Economy* 100 (1998), pages 768-805, which, when the authors eliminated observations from their data

⁴ Armen Hovakimian and Ekkachai Saenyasiri, "Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation", Arizona State University, April 20, 2009.

sample based on the size of negative special items “nearly eliminate evidence of mean optimism in their sample.”

Given the greater transparency of the utility business model (e.g., regulatory filing requirements) relative to some other industries, the more stable operations of utilities, and the value rather than “glamour” nature of utility shares, analyst optimism should be less of an issue with utility earnings forecasts.

The potential bias of the analysts’ growth rates for U.S. utilities was assessed in three separate ways. First, because utilities are quintessentially mature companies, it is reasonable to expect that investors would anticipate that, over the long-term, growth would parallel the long-term nominal rate of growth in the economy. In this context, the Thomson Reuters earnings growth forecasts, for which Foster Associates maintains a data base which contains monthly consensus forecasts for utilities back to 1976, were compared to the consensus forecasts of long-term growth. From 1998-2012Q2, the period of analysis used in the DCF-based risk premium test, the average consensus analysts’ forecast long-term earnings growth rate for the sample of low risk U.S. utilities was 5.1%. That growth rate is virtually identical to the average consensus forecast of long-term nominal growth in the economy over the same period. The average expected long-term nominal rate of growth in the U.S. economy, based on consensus forecasts (*Blue Chip Economic Indicators*, March and October editions, 1998-2012), was 5.1% from 1998-2012Q2. The similar expected nominal growth in the economy compared to the consensus analysts’ forecasts suggests that the consensus long-term earnings growth forecasts are not an upwardly biased measure of investor expectations.

Second, the consensus analysts’ forecasts were compared to the long-term earnings forecasts for the same companies made by *Value Line*. As an independent research firm, *Value Line* has no incentive to “inflate” its estimates of earnings growth in an attempt to make stocks more attractive to investors, which is the criticism frequently aimed at equity analysts. Since 1998, the average *Value Line* long-term earnings growth rate forecast for the sample of companies was 5.5%, compared to the average consensus analysts’ long-

term earnings growth rate forecast for the same companies of 5.1%. Again, the higher *Value Line* than the consensus analysts' forecasts suggest that the consensus long-term earnings forecasts are not upwardly biased.⁵

Third, allowed returns for U.S. utilities are derived in large part by reference to the results of the DCF model. Regulators in all jurisdictions, however, do not use the same form of the DCF model. For example, some regulators may rely on the constant growth model, while others prefer to use a multi-stage growth model. In addition, even if different jurisdictions use the same form (e.g., constant growth) of the model, the inputs to the model are not necessarily derived in equivalent ways. For example, two jurisdictions may use the constant growth model but one may favour the use of forecast growth, while another may favour the use of historic growth rates. In the aggregate, however, across all jurisdictions, the differences in approach likely balance out, resulting in the allowed returns reflecting neither an upwardly or downwardly biased measure of the utility cost of equity as a result of the underlying growth assumptions. When the allowed returns for all U.S. utilities published by Regulatory Research Associates (RRA) are compared to the estimated constant growth DCF costs of equity for the sample of U.S. utilities estimated using the consensus long-term earnings forecasts over the same period (1998-2012Q2), the comparison shows that the allowed returns for all U.S. utilities as reported by RRA exceeded the returns estimated using the constant growth DCF models as follows:

⁵ In British Columbia Utilities Commission, *In the Matter of Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure Decision*, December 16, 2009, (page 45), the BCUC stated:

The Commission Panel has considered the submission of the JIESC concerning “upward bias” of analysts’ estimates and considers that no allegations of upward bias have been levelled against utility analysts and that *Value Line* estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.

Table C-1

Average Allowed ROEs 1998-2012Q2^{1/}	10.5%	Average Difference From Allowed ROEs
Constant Growth DCF Cost of Equity 1998-2012Q2	10.0%	-0.5%

^{1/} Weighted average.

Sources: Regulatory Research Associates and Schedule 14, page 1 of 4.

The comparison of the DCF costs of equity to the ROEs allowed by regulators provides a further indication that the earnings forecasts are not an upwardly biased measure of investor expectations.

4. APPLICATION OF THE DCF MODELS

a. Constant Growth Model

The constant growth DCF model was applied to the sample of U.S. low risk utilities using the following inputs to calculate the dividend yield:

- (1) the most recent annualized dividend paid as of July 31, 2012 as D_0 ; and,
- (2) the average of the daily close prices for the period May 1, 2012 to July 31, 2012 as P_0 .

The constant growth model was applied using two estimates of long-term growth, the average of four investment analysts' consensus long-term earnings growth forecasts compiled by Bloomberg, Reuters, *Value Line* and Zacks, and estimates of sustainable growth. For the model based on investment analysts' earnings forecasts, the average of the four consensus earnings growth forecasts were used to estimate "g" in the growth component for each utility and to adjust the current dividend yield to the expected dividend yield. The sustainable growth rate was derived from the second and third quarter 2012 *Value Line* forecasts as described on page C-5 above.

b. Three-Stage Model

The three-stage DCF model applied to the sample of U.S. low risk utilities relied on the average of the four sources of analysts' earnings forecasts for the first five years (Stage 1), the average of the Stage 1 forecast and the forecast long-term growth in the economy for the next five years (Stage 2) and the long-term growth in the economy thereafter (Stage 3). In the three-stage DCF test, the long-run expected nominal rate of growth in GDP of 4.9% was based on the consensus of economists' forecasts for the period 2013-2023 found in Blue Chip *Financial Forecasts*, June 1, 2012.⁶

The three-stage DCF test determines the utility cost of equity as the internal rate of return derived from the forecast stream of annual cash flows.

⁶ Published twice annually in June and December.

APPENDIX D

DCF-BASED EQUITY RISK PREMIUM TEST

1. INTRODUCTION

The DCF-based equity risk premium is a forward-looking test which uses the discounted cash flow model and long-term government bond yields to estimate expected utility returns and risk premiums over time. The utility equity risk premium is measured as the difference between the DCF cost of equity and the yield on long-term government bond yields. The advantage of the DCF-based equity risk premium test is that it allows for testing of the relationship between the utility cost of equity (or the utility equity risk premium) and interest rates.

2. SAMPLE OF LOW RISK U.S. UTILITIES

The same sample of U.S. utilities was used to perform the DCF-based equity risk premium tests as for the DCF test. The selection criteria for the sample of U.S. utilities are described in Appendix B.

3. CONSTRUCTION OF THE CONSTANT GROWTH DCF-BASED EQUITY RISK PREMIUM TEST

To estimate each monthly sample DCF cost of equity, the monthly published long-term earnings growth rate forecast (**g**) for each of the sample utilities was retrieved from Thomson Reuters, and the monthly sample median was calculated. For each month of the analysis, the current dividend yield (**DY**) for each utility was calculated as the most recent quarterly dividend paid, annualized, divided by the monthly closing price. The expected dividend yield (**DY_e**) for the sample was then calculated by adjusting the monthly median dividend yield for the monthly median forecast earnings growth rate (**DY_e=DY x (1+g)**). The sample DCF cost of equity (DCF) in each month was calculated by combining the forecast growth rate and the expected dividend yield. The monthly utility sample equity risk premium (**ERP**) was calculated by subtracting the

corresponding 30-year Treasury bond yield (**TY**) from the DCF cost of equity (**ERP=DCF–TY**). The annual averages of the monthly utility sample constant growth DCF costs of equity, Treasury bond yields and utility equity risk premiums are found on Schedule 14, page 1 of 4.

4. CONSTRUCTION OF THE THREE-STAGE GROWTH DCF-BASED EQUITY RISK PREMIUM TEST

A three-stage growth model was also used in the application of the DCF-based equity risk premium test. As with the constant growth model, monthly estimates of the DCF cost of equity were made for the sample, using the sample median dividend yield as the point of departure.

For the forecast growth rates, the first stage (Years 1 to 5) of the model used the sample median analysts' consensus forecast long-term growth rate published in that month. For the third stage (Years 11 and beyond), the expected growth rate was represented by the most recent long-term nominal GDP growth rate forecast available in that month from Blue Chip *Financial Forecasts*. Blue Chip *Financial Forecasts* publishes long-term GDP growth forecasts in June and December of each year. Therefore, as examples, the Stage 3 expected growth rate for the months June through November 2009 was represented by the nominal GDP growth forecast published in June 2009. The Stage 3 expected growth rate for the months December 2009 through May 2010 was represented by the December 2009 long-term nominal GDP forecast. Similar to the three-stage DCF test, Stage 2 growth (Years 6 to 10) is equal to the average of Stage 1 and Stage 3 growth rates.

For each month of the analysis, the DCF cost of equity was then determined for the utility sample using the forecast stream of annual cash flows to derive the internal rate of return.

As with the constant growth DCF-based risk premium test, the utility sample monthly equity risk premium (ERP) was calculated by subtracting the corresponding 30-year Treasury bond yield (TY) from the monthly DCF cost of equity (**ERP=DCF–TY**). The annual averages of the three-stage DCF model costs of equity, Treasury bond yields and utility equity risk premiums are found on Schedule 14, page 3 of 4.

APPENDIX E

FINANCING FLEXIBILITY ADJUSTMENT

An adjustment to the equity risk premium and discounted cash flow test results for financing flexibility is required because the measurement of the return requirement based on market data results in a "bare-bones" cost. It is "bare-bones" in the sense that, theoretically, if this return is applied to (and earned on) the book equity of the rate base (assuming the expected return corresponds to the approved return), the market value of the utility would be kept close to book value.

The financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. The allowance is intended to cover three distinct aspects: (1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle. Fairness dictates that regulation should not seek to keep the market value of a utility stock close to book value when unregulated companies of comparable investment risk have been able to consistently maintain the real value of their assets considerably above book value.

The financing flexibility allowance recognizes that return regulation remains, fundamentally, a surrogate for competition. Competitive unregulated companies of reasonably similar risk to utilities have consistently been able to maintain the real value of their assets significantly in excess of book value, consistent with the proposition that, under competition, market value will tend to equal the replacement cost, not the book value, of assets.

Utility return regulation should not seek to target the market/book ratios achieved by such unregulated companies, but, at the same time, it should not preclude utilities from achieving a level of financial integrity that gives some recognition to the longer run tendency for the market value of unregulated companies to equate to the replacement cost of their productive capacity.

This is warranted not only on grounds of fairness, but also on economic grounds, to avoid misallocation of capital resources. To ignore these principles in determining an appropriate financing flexibility allowance is to ignore the basic premise of regulation. The adjustment for financing flexibility recognizes that the market return derived from the equity risk premium test needs to be translated into a return that is fair and reasonable when applied to book value. The concept of a financing flexibility or flotation cost allowance has been accepted by most Canadian regulators.

This premise was recognized by the Independent Assessment Team (IAT), retained by the Alberta Department of Resource Development to determine the cost parameters for the Power Purchase Arrangement (PPAs) for existing regulated generating plants, concluded in its 1999 report, regarding flotation costs,

This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada. No such adjustment has ever been made in UK utility regulation cases which tend to use market values or current cost values.¹

The Report of the IAT was accepted by the Alberta Energy and Utilities Board in Decision U99113 (December 1999).

¹*Independent Assessment Team Power Purchase Arrangement Report*, July 1999, page XLV, footnote 99.

At a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times. At this level, a utility will be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 times is approximately 50 basis points.²

Further, the financing flexibility allowance should also recognize that both the equity risk premium and DCF cost of equity estimates are derived from market values of equity capital. The cost of capital reflects the market value of the firms' capital, both debt and equity. The market value capital structures may be quite different from the book value capital structures. When the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is "on the books" as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.

To put this concept in common sense terms, assume that I purchased my home 10 years ago for \$100,000 and took out a mortgage for the full amount. My home is currently worth \$250,000 and my mortgage is now \$85,000. If I were applying for a loan, the bank would consider my net worth (equity) to be \$165,000 (market value of \$250,000 less the \$85,000 unpaid mortgage), not the "book value" of the equity in my home of \$15,000, which reflects the original purchase price

² The minimum financing flexibility allowance can be estimated using the following formula developed from the discounted cash flow formula:

$$\text{Return on Book Equity} = \frac{\text{Market/Book Ratio} \times \text{"bare-bones" Cost of Equity}}{1 + [\text{retention rate} (M/B - 1.0)]}$$

For a market/book ratio of 1.075 (mid-point of 1.05 and 1.10), assuming a retention rate of 25% and a "bare-bones" cost of equity of 9.5%, the indicated ROE is:

$$\begin{aligned} \text{ROE} &= \frac{1.075 \times 9.5\%}{1 + [.25(1.075 - 1.0)]} \\ \text{ROE} &= 10.0\% \end{aligned}$$

The difference of 50 basis points between the ROE and the "bare-bones" cost of equity is the financing flexibility allowance.

less the unpaid mortgage loan amount. It is the market value of my home that determines my financial risk to the bank, not the original purchase price. The same principle applies when the cost of common equity is estimated. The book value of the common equity shares is not the relevant measure of financial risk to equity investors; it is their market value, that is, the value at which the shares could be sold.

The rationale for the differences in the required return on equity for companies of similar business risk but different financial risk begins with the recognition that the overall cost of capital for a firm is primarily a function of business risk. In the absence of both the deductibility of interest expense for corporate income tax purposes and costs associated with excessive debt (e.g., bankruptcy), the overall cost of capital to a firm would not change when a firm changes its capital structure.³

The use of debt creates a class of investors whose claims on the resources of the firm take precedence over those of the equity holder. However, in a competitive environment, the sum of the available cash flows does not change when debt is added to the capital structure. The available cash flows are now split between debt and equity holders. Since there are fixed debt costs that must be paid before the equity shareholder receives any return, the variability of the equity return increases as debt rises. The higher the debt ratio, the higher the potential volatility of the equity return and the greater the risk that equity shareholders will not recover their invested capital and a compensatory return thereon. Hence, as the debt ratio rises, the cost of equity rises. The higher cost rates of both the debt and equity offset the higher proportion of debt in the capital structure, so that the overall cost of capital does not change.

The deductibility of interest expense for corporate income tax purposes alters the conclusion that the cost of capital is constant across all capital structures. The deductibility of interest expense for income tax purposes means that there is a cash flow advantage to equity holders from the

³ The seminal theory, which was premised on no risk to excessive debt, was set out in Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48: 261-297 (June 1958).

assumption of debt. In the absence of offsetting factors, when interest expense is deductible for corporate income tax purposes, the after-tax cost of capital declines as more debt is used.⁴

Offsetting some of the advantage of debt at the corporate level are the higher personal tax rates on interest income than on dividend income and capital gains. When personal income tax rates on dividends and capital gains are lower than the personal income tax rate on interest income, all other things equal, taxable investors would prefer firms to use equity rather than debt. If taxes were the only consideration, there are combinations of corporate and personal income taxes at which the corporate tax advantages of using debt are completely offset by the personal tax advantages to holding equity rather than debt.⁵

However, factors other than taxes impact the choice of capital structure. The addition of debt to the capital structure is not risk-free. There is a loss of financial flexibility and an increasing potential for bankruptcy as the debt ratio rises. The result is an increase in the cost of capital as leverage is increased. For example, as the percentage of debt in the capital structure increases, the company's credit rating may decline and its cost of debt will increase. When the loss of financing flexibility and costs of financial distress impair a firm's ability to operate efficiently, e.g., to pursue opportunities to grow the business or even to obtain trade credit as required, the cost of equity and the overall cost of capital will likely increase more than pure theory would indicate.

It is impossible to state with precision whether, within a specific range of capital structures, raising the debt ratio will leave the overall cost of capital unchanged or result in some decline. However, what is indisputable is that the cost of equity does change when the debt ratio changes, increasing when the debt ratio increases and, conversely, decreasing when the debt ratio falls.

⁴ Franco Modigliani and Merton H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53: 433-443 (June 1963).

⁵ The offsetting impacts of lower personal tax rates on equity income compared to interest income were examined in Merton H. Miller, "Debt and Taxes," *The Journal of Finance*, 32: 261-276 (May 1977). At the 2011 marginal corporate and personal income tax rates (on interest, dividends and capital gains) in Canada, the gain from corporate leverage is relatively small.

The cost of equity has been estimated using samples of comparable proxy companies with a lower level of financial risk, as reflected in their market value capital structures, than the financial risk reflected in the book value capital structure. Regulatory convention applies the allowed ROE to a book value capital structure. When the market value equity ratios of the proxy utilities are well in excess of their book value common equity ratios, the failure to recognize the higher level of financial risk in the book value capital structure relative to the financial risk of the proxy samples of utilities, as recognized by equity investors, results in an underestimation of the cost of equity.

Three approaches can be used to quantify the range of the impact of a change in financial risk on the cost of equity when interest expense is deductible for income tax purposes.

Approach 1 is based on the theory that the overall after-tax cost of capital and the pre-tax cost of capital do not change materially over a relatively broad range of capital structures. This approach effectively assumes that the benefit of the deductibility of interest expense for corporate income tax purposes (which would tend to lower the overall cost of capital) is offset by personal income taxes on interest.

Approach 2 is based on the theoretical model which assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. The second approach does not account for any of the factors that offset the corporate income tax advantage of debt, including the costs of bankruptcy/loss of financing flexibility, the impact of personal income taxes on the attractiveness of issuing debt, or the flow-through of the benefits of interest expense deductibility to ratepayers. Thus, the results of applying the second approach will overestimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity.

Approach 3 assumes for utility cost of capital purposes that the corporate income tax rate is zero. The underlying premise is that the benefits of the corporate tax deductibility of interest accrue to rate payers, not shareholders, as is the case with unregulated companies. As with the first approach, the overall cost of capital remains unchanged as the capital structure changes.

However, since the cost of capital contains no income tax component, the impact on the cost of equity due to changing leverage is less than in the presence of corporate income tax and interest deductibility.

Table E-1 below shows the adjustments to the cost of equity that are required to recognize the difference in financial risk between the market value capital structures of the Canadian and U.S. utility samples and the book value capital structures under the three approaches. Schedule 23 provides the formulas for estimating the change in the cost of equity due to capital structure differences under Approaches 1 and 2. When the corporate income tax rate is zero, Approach 1 and 2 result in the same adjustment to the ROE as Approach 3.

Table E-1

	Cost of Equity	Market Value Equity Ratio	Book Value Equity Ratio	Adjustment to ROE for Book Value Capital Structure		
				Approach 1 (26% tax rate)	Approach 2 (26% tax rate)	Approach 3 (0% tax rate)
Canadian Utilities	9.5%	57%	40%	2.5%	1.6%	1.9%
U.S. Utilities	9.5%	63%	50%	1.5%	1.0%	1.2%

Source: Schedules 22 and 23

Notes: Based on incremental utility cost of long-term debt of 5.05%.

Corporate income tax rate of 26% is estimated combined federal/provincial 2013 rate for Canada.

Full recognition of the difference in financial risk between the market value equity ratios of the publicly-traded Canadian utilities (57%) and the U.S. utilities (63%) and the average book value common equity ratio of investor-owned Canadian regulated utilities (40%) and the U.S. utilities (50%) equity (Schedules 5, 6, and 22) results in an adjustment to the “bare bones” cost of equity in the range of approximately 1.2% to 2.0% (mid-point of approximately 1.6% or 160 basis points).

APPENDIX F

COMPARABLE EARNINGS TEST

1. SELECTION OF CANADIAN UNREGULATED COMPANIES

The selection process starts with the recognition that unregulated companies generally are exposed to higher business risk, but lower financial risk, than the typical utility. The selection of unregulated companies focuses on total investment risk, i.e., the combined business and financial risks. The unregulated companies' higher business risks are offset by a more conservative capital structure, i.e., higher equity ratios, thus permitting the selection of samples of reasonably comparable investment risk to utilities.

As a point of departure, the selection was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of all firms on the TSX in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.¹ The resulting universe contained 516 firms. Companies were removed which:

- For which no common equity balance data was reported for any year 2000-2010 by S&P's Research Insight data base,
- Had negative common equity for any year from 1994-2011 for which data were available from S&P's Research Insight data base,

¹ Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

- Are income trusts or incorporated outside Canada,
- Paid no dividends in any year 2007 to 2011,
- Had less than five years of market data,
- Had total assets less than \$500 million,
- Had a 2010 equity ratio (including short term debt) less than 50%,
- Had an average 2010-2011 “raw” beta over 1.0, and
- Had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor’s.

The final sample of low risk Canadian unregulated companies is comprised of 21 companies (Schedule 24).

2. TIME PERIOD FOR MEASURING RETURNS

Since unregulated companies’ returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1995-2011 constitutes a full business cycle, commencing with 1995 (the third full year of expansion following the 1991-1992 recession), including the 2008-2009 recession and the first two full years of recovery (2010-2011). Over the period 1995-2011, the experienced returns on equity of the sample of 21 low risk unregulated Canadian companies were as follows.

Table F-1

ROEs for Low Risk Canadian Unregulated Companies (1995-2011)	
Average	13.7%
Median	12.8%
Average of Annual Medians	13.4%

Source: Schedule 25.

Based on these data, the ROEs for the low risk Canadian unregulated companies are in the approximate range of 12.75-13.75%.

The annual nominal economic compound growth for Canada during the 1995-2011 business cycle was 4.8%. The historic annual nominal compound growth rate over the full business cycle is somewhat higher than the forecast nominal GDP growth rate of approximately 4.3% from 2013 to 2022.²

In light of the lower forecast economic growth compared to the historical level, the achieved equity returns for the sample were also calculated over a shorter and more recent period of time (2004 to 2011) with a rate of economic growth closer to the forecast rate. This period commences with the third full year following the 2001 economic downturn, and, similar to the longer period, includes the 2008-2009 recession and the first two full years of recovery. Over the period 2004-2011, the nominal economic compound growth in Canada was 4.5%, slightly higher than the average rate of growth forecast for the period 2012-2022.

The experienced returns on equity of the sample of 21 low risk unregulated Canadian companies during 2004-2011 were as follows.

Table F-2

ROEs for Low Risk Canadian Unregulated Companies (2004-2011)	
Average	13.2%
Median	12.3%
Average of Annual Medians	13.5%

Source: Schedule 25

Since nominal growth is forecast to be only slightly higher than that experienced rate during 2004-2011, the experienced returns on book equity for this period of approximately 12.25% to 13.5%, absent extraordinary events, provide a reasonable proxy for the future.

² Based on Consensus Economics, *Consensus Forecasts*, April 2012, which anticipate real GDP growth of 2.25% and CPI inflation of 2.0% from 2013 to 2022.

3. RELATIVE RISK COMPARISON

With respect to the investment risk of the Canadian unregulated companies relative to Canadian utilities, comparisons of debt ratings and betas indicate that the unregulated companies are of somewhat higher risk than the utilities. For the unregulated companies with debt ratings, the median S&P and DBRS ratings are BBB and BBB/BBB(high) respectively, compared to Canadian utilities' median ratings of A- and A (See Schedules 4 and 24). Based on medians, the average adjusted monthly beta for the unregulated companies for the five-year periods ending December 2004-2011 was 0.64 (see Schedule 24), compared to a 0.48 adjusted monthly beta for the major publicly-traded Canadian utilities over the same time period (Schedule 12 page 1 of 6).

There is no universally accepted methodology for making a downward adjustment to the unregulated low risk company returns on common equity for the lower risk of utilities. The difference in yields on A-rated utility bonds and BBB-rated corporate bonds provides one measure of a reasonable downward adjustment. Historically the average difference has been close to 75 basis points. Relative adjusted betas of the unregulated companies and Canadian utilities were also used as an alternative indicator of the magnitude of the downward adjustment warranted, with the caveat that the recent low calculated Canadian utility betas may result in an overestimate of the downward adjustment required. When applied to the difference between the achieved ROEs and the longer-term forecast 30-year Canada bond yield of approximately 5.0%, the relative historic adjusted betas suggest a downward adjustment of approximately 2.0%. Together the bond yield spreads and relative adjusted betas indicate that a downward adjustment to the unregulated companies' ROEs in the range of 0.75% to 2.0% (mid-point of approximately 1.25% to 1.50%) would be reasonably conservative. The resulting fair ROE for the benchmark BC utility based on the comparable earnings test is approximately 11.0% to 12.0%.

4. MARKET/BOOK RATIOS

The argument that a downward adjustment to the comparable earnings test results for the market/book ratios of the unregulated companies has been made on the following bases:

- a. The market/book ratio of utility common shares should be approximately 1.0 times, i.e., that the fair market value of utility shares is equal to their book value.
- b. Market/book ratios of unregulated firms well in excess of 1.0 times is evidence that the companies are earning returns in excess of their cost of capital, and thus are exerting market power.

Both of these arguments are without merit. With respect to the notion that the market/book ratio of utility shares should be approximately 1.0 times, that conclusion is incompatible with the standard of comparable returns. The comparable returns standard requires that a utility have the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

Regulation is intended to be a surrogate for competition. If unregulated competitive enterprises of corresponding risks to utilities are able to maintain market/book ratios in excess of 1.0, it would be patently contrary to the objective of regulation and to the comparable earnings standard to reduce the returns of unregulated comparable firms in order to target a particular market/book ratio for a utility.

With respect to the second rationale, the question that needs to be addressed is whether the market/book ratios of the sample of comparable unregulated companies are evidence of market power.

To address this question, the first issue is whether the market/book ratios of competitive companies should, in principle, trend toward 1.0. Regulation is intended to be a surrogate for competition. The competitive model indicates that equity market values tend to gravitate toward

the replacement cost of the underlying assets. This is due to the economic proposition that, if the discounted present value of expected returns (market value) exceeds the cost of adding capacity, firms will expand until an equilibrium is reached, i.e., when the market value equals the replacement cost of the productive capacity of the assets.

The ratio of market value to replacement cost is called the “Q Ratio”, a term coined by the Nobel Prize winning economist James Tobin in the late 1960s.³ Essentially, the economic theory is that the market value of assets in the aggregate should equate to their replacement cost, that is, the “Q Ratio” (market value/replacement cost) should trend toward 1.0.

The “Q Ratio” has since gained stature as an investment tool,⁴ whose importance was underscored in a March 2002 *New York Times* article which stated, referring to Tobin’s obituaries:

Great emphasis was placed on how revolutionary his insights were three, four or five decades ago. Yet most were relatively silent on how those insights can lead us to be more successful investors today. It is a shame. Investors greatly handicap themselves if they ignore Dr. Tobin’s work.

Consider Tobin’s Q, the ratio for which Dr. Tobin, at least at one time, was most famous among investors. This is the ratio of a company’s total market capitalization to the replacement value of that company’s total assets. While the Q ratio – as Tobin’s Q is often called – is conceptually similar to the price-to-book ratio, it avoids the myriad accounting difficulties associated with book value. For example, while book value carries assets at depreciated original cost, replacement value focuses on how much it would cost to buy those assets today. [emphasis added]

Absent inflation and technological change, the market value and replacement cost of firms operating in a competitive environment would tend to equal their book value or cost. However, the fact that inflation has occurred, and continues to occur, renders that relationship invalid. With inflation, under competition, the market value of a firm trends toward the current cost of its assets. The book value of the assets, in contrast, reflects the historic depreciated cost of the

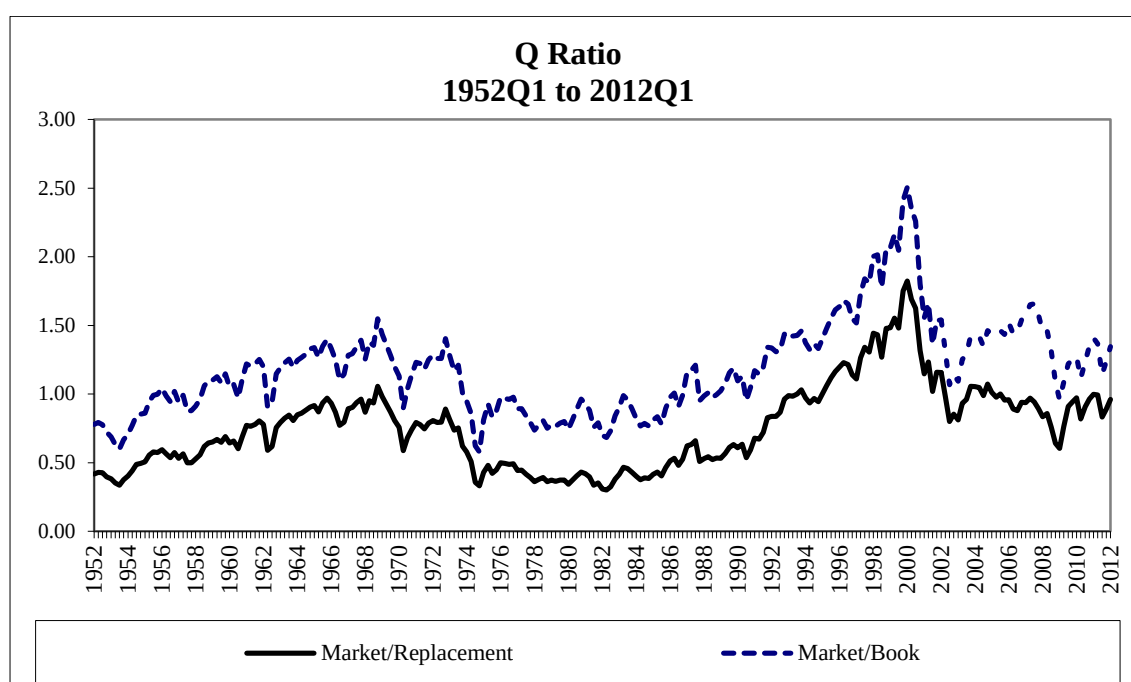
³ The general idea had been expressed decades earlier by the economist John Keynes.

⁴ The Federal Reserve Board tracks the “Q Ratio” of the U.S. equity market. It was the level of the “Q Ratio”, along with the price/dividend ratio, that led Fed Chairman Alan Greenspan to warn of a speculative bubble in the equity market as early as 1996.

assets. Since there have been moderate to relatively high levels of inflation over the past twenty-five years, it is reasonable to expect market values to exceed the book value of those assets.

As indicated in Figure F-1 below, market/replacement cost ratios for U.S. firms, as derived from the flow of funds accounts, have been systematically lower than the market to original cost ratios. For the U.S., the market/replacement cost ratio for corporations⁵ has averaged approximately 30% lower than the market/book ratio over the business cycle 1995-2012Q1.

Figure F- 1

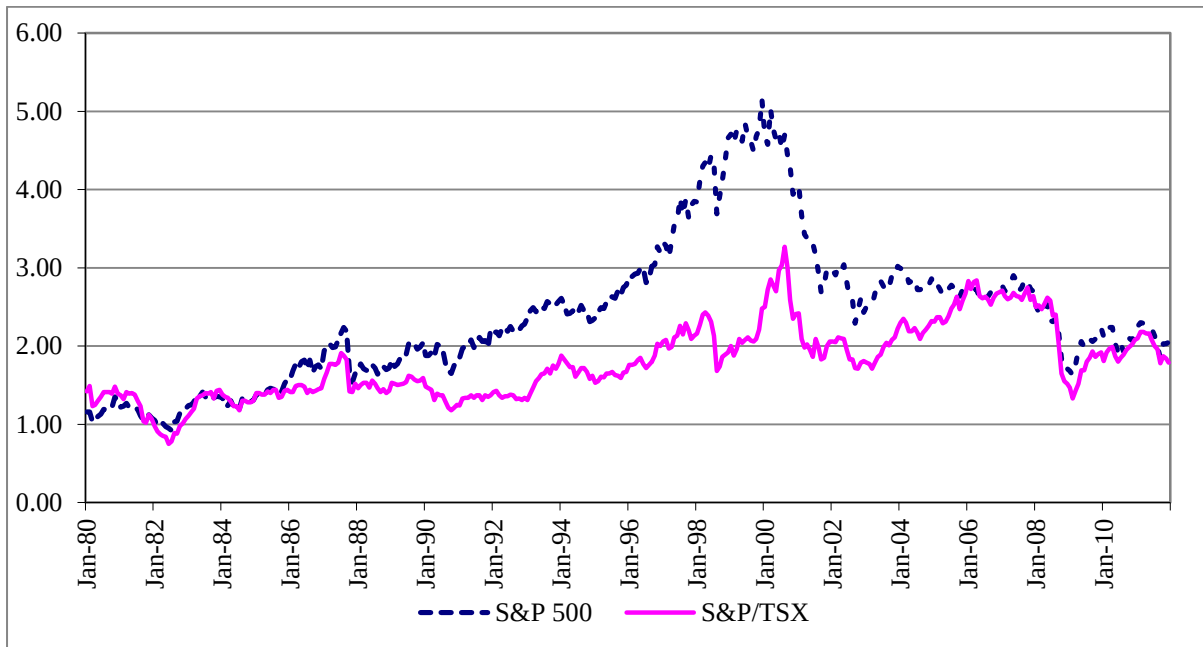


Source: US Federal Reserve Flow of Funds (B102).

To test the potential for market power in the achieved returns of the sample of low risk unregulated Canadian firms used in the comparable earnings test, their market/book ratios were compared to those of Canadian and U.S. equity market composites. The figure below tracks the market/book values for the S&P/TSX Composite and the S&P 500 from 1980-2011.

⁵ Based on non-farm, non-financial corporate businesses.

Figure F- 2



Source: RBC Capital Markets Quantitative Research

The data from which the table was created indicate that the market/book ratio for the overall Canadian equity market has averaged approximately 1.8 times from 1980-2011, and 2.1 times from 1995-2011, the last full business cycle and 2.2 times from 2004-2011, the period over which the comparable earnings test was conducted. Based on over three decades of data, the market/book ratio for the Canadian equity market has varied around an average of close to 1.8 times, not 1.0 times. For the S&P 500, the market/book ratios were approximately 2.4 times, 3.0 times, and 2.4 times respectively, over the same three periods. Over the periods 1995-2011 and 2004-2011, the market/book ratios for the sample of comparable Canadian unregulated companies averaged 2.3 times and 2.2 times, respectively, approximately equal to the average market/book ratios for the S&P/TSX Composite and lower than the market/book ratio of the S&P 500. The similar to lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian and U.S. equity market composites permit the inference that the sample average returns are not characterized by market power. Thus, no adjustment to the comparable earnings results is warranted for the market/book ratios of the low risk unregulated companies.

APPENDIX G

QUALIFICATIONS OF KATHLEEN C. MCSHANE

At Foster Associates, Ms. McShane has worked in the areas of financial analysis, energy economics and cost allocation. Ms. McShane has presented testimony in more than 200 proceedings on rate of return and capital structure before federal, state, provincial and territorial regulatory boards, on behalf of U.S. and Canadian electric utilities, gas distributors and pipelines, and telephone companies. These testimonies include the assessment of the impact of business risk factors (e.g., competition, rate design, contractual arrangements) on capital structure and equity return requirements. She has also testified on various ratemaking issues, including deferral accounts, rate stabilization mechanisms, excess earnings accounts, cash working capital, and rate base issues. Ms. McShane has provided consulting services for numerous U.S. and Canadian companies on financial and regulatory issues, including financing, financial performance measures, dividend policy, corporate structure, cost of capital, automatic adjustments for return on equity, form of regulation (including performance-based regulation), unbundling, corporate separations, stand-alone cost of debt, regulatory climate, income tax allowance for partnerships, change in fiscal year end, treatment of inter-corporate financial transactions, and the impact of weather normalization on risk.

Ms. McShane was principal author of a study on the applicability of alternative incentive regulation proposals to Canadian gas pipelines. She was instrumental in the design and preparation of a study of the profitability of 25 major U.S. gas pipelines, in which she developed estimates of rate base, capital structure, profit margins, unit costs of providing services, and various measures of return on investment. Other studies performed by Ms. McShane include a comparison of municipal and privately owned gas utilities, an analysis of the appropriate capitalization and financing for a new gas pipeline, risk/return analyses of proposed water and gas distribution companies and an independent power project, pros and cons of performance-

based regulation, and a study on pricing of a competitive product for the U.S. Postal Service. She has also conducted seminars on cost of capital and related regulatory issues for public utilities, with focus on the Canadian regulatory arena.

Ms. McShane worked for the University of Florida and its Public Utility Research Center, functioning as a research and teaching assistant, before joining Foster Associates. She taught both undergraduate and graduate classes in financial management and assisted in the preparation of a financial management textbook.

PUBLICATIONS, PAPERS AND PRESENTATIONS:

- *Utility Cost of Capital: Canada vs. U.S.*, presented at the CAMPUT Conference, May 2003.
- *The Effects of Unbundling on a Utility's Risk Profile and Rate of Return*, (co-authored with Owen Edmondson, Vice President of ATCO Electric), presented at the Unbundling Rates Conference, New Orleans, Louisiana sponsored by Infocast, January 2000.
- *Atlanta Gas Light's Unbundling Proposal: More Unbundling Required?* presented at the 24th Annual Rate Symposium, Kansas City, Missouri, sponsored by several commissions and universities, April 1998.
- *Incentive Regulation: An Alternative to Assessing LDC Performance*, (co-authored with Dr. William G. Foster), presented at the Natural Gas Conference, Chicago, Illinois sponsored by the Center for Regulatory Studies, May 1993.
- *Alternative Regulatory Incentive Mechanisms*, (co-authored with Stephen F. Sherwin), prepared for the National Energy Board, Incentive Regulation Workshop, October 1992.
- "The Fair Return", (co-authored with Michael Cleland), *Energy Law and Policy*, Gordon Kaiser and Bob Heggie, eds., Toronto: Carswell Legal Publications, 2011.

EXPERT TESTIMONY/OPINIONS
ON
RATE OF RETURN AND CAPITAL STRUCTURE

Alberta Natural Gas
1994

Alberta Utilities
Generic Cost of Capital
2011

AltaGas Utilities
2000

Ameren (Central Illinois Public Service)
2000, 2002, 2005, 2007 (2 cases),
2009 (2 cases)

Ameren (Central Illinois Light Company)
2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Illinois Power)
2004, 2005, 2007 (2 cases), 2009 (2 cases)

Ameren (Union Electric)
2000 (2 cases), 2002 (2 cases), 2003,
2006 (2 cases)

ATCO and AltaGas Utilities
Generic Cost of Capital, Alberta
2003

ATCO Electric
1989, 1991, 1993, 1995
1998, 1999, 2000, 2003

ATCO Gas
2000, 2003, 2007

ATCO Pipelines
2000, 2003, 2007, 2011

ATCO Utilities
Generic Cost of Capital
2008

Bell Canada
1987, 1993

Benchmark Utility Cost of Capital
(British Columbia)
1994, 1999, 2012

Canadian Western Natural Gas
1989, 1996, 1998, 1999

Centra Gas B.C.
1992, 1995, 1996, 2002

Centra Gas Ontario
1990, 1991, 1993, 1994, 1995

Direct Energy Regulated Services
2005

Dow Pool A Joint Venture
1992

Electricity Distributors Association
2009

Enbridge Gas Distribution
1988, 1989, 1991, 1992, 1993, 1994
1995, 1996, 1997, 2001, 2002

Enbridge Gas New Brunswick
2000, 2010

Enbridge Pipelines (Line 9)
2007, 2009

Enbridge Pipelines (Southern Lights)
2007

EPCOR Water Services Inc.
1994, 2000, 2006, 2008, 2011

FortisBC Inc.
1995, 1999, 2001, 2004

FortisBC Energy Inc.
1992, 2005, 2009, 2011

FortisBC Energy (Whistler) Inc.
2008

Gas Company of Hawaii
2000, 2008

Gaz Métro
1988

Gazifère
1993-1998, 2010

Heritage Gas
2004, 2008, 2011

Hydro One
1999, 2001, 2006 (2 cases)

***Insurance Bureau of Canada
(Newfoundland)***
2004

Laclede Gas Company
1998, 1999, 2001, 2002, 2005

Laclede Pipeline
2006

Mackenzie Valley Pipeline
2005

Maritime Electric
2010

***Maritimes NRG
(Nova Scotia and New Brunswick)***
1999

MidAmerican Energy Company
2009

***Multi-Pipeline Cost of Capital Hearing
(National Energy Board)***
1994

Natural Resource Gas
1994, 1997, 2006, 2010

New Brunswick Power Distribution
2005

Newfoundland & Labrador Hydro
2001, 2003

Newfoundland Power
1998, 2002, 2007, 2009, 2012

Newfoundland Telephone
1992

<i>Northland Utilities</i> 2008 (2 cases)	<i>Tecumseh Gas Storage</i> 1989, 1990
<i>Northwestel, Inc.</i> 2000, 2006	<i>Telus Québec</i> 2001
<i>Northwestern Utilities</i> 1987, 1990	<i>TransCanada PipeLines</i> 1988, 1989, 1991 (2 cases), 1992, 1993
<i>Northwest Territories Power Corp.</i> 1990, 1992, 1993, 1995, 2001, 2006	<i>TransGas and SaskEnergy LDC</i> 1995
<i>Nova Scotia Power Inc.</i> 2001, 2002, 2005 2008, 2011, 2012	<i>Trans Québec & Maritimes Pipeline</i> 1987
<i>Ontario Power Generation</i> 2007, 2010	<i>Union Gas</i> 1988, 1989, 1990, 1992 1994, 1996, 1998, 2001
<i>Ozark Gas Transmission</i> 2000	<i>Westcoast Energy</i> 1989, 1990, 1992 (2 cases), 1993, 2005
<i>Pacific Northern Gas</i> 1990, 1991, 1994, 1997 1999, 2001, 2005, 2009	<i>Yukon Electrical Company</i> 1991, 1993, 2008
<i>Plateau Pipe Line Ltd.</i> 2007	<i>Yukon Energy</i> 1991, 1993
<i>Platte Pipeline Co.</i> 2002	
<i>St. Lawrence Gas</i> 1997, 2002	
<i>Southern Union Gas</i> 1990, 1991, 1993	
<i>Stentor</i> 1997	

EXPERT TESTIMONY/OPINIONS
ON
OTHER ISSUES

<u>Client</u>	<u>Issue</u>	<u>Date</u>
Greater Toronto Airport Authority	Financial Performance Measures	2012
Heritage Gas	Criteria for a Mature Utility	2011
Alberta Utilities	Management Fee on CIAC	2011
ATCO Electric	Construction Work in Progress (CWIP) Recovery of Future Income Tax (FIT)	2010
Maritimes & Northeast Pipeline	Return on Escrow Account	2010
Nova Scotia Power	Calculation of ROE	2009
Alberta Oilsands Pipeline	Cash Working Capital	2007
New Brunswick Power Distribution	Interest Coverage/Capital Structure	2007
Heritage Gas	Revenue Deficiency Account	2006
Hydro Québec	Cash Working Capital	2005
Nova Scotia Power	Cash Working Capital	2005
Ontario Electricity Distributors	Stand-Alone Income Taxes	2005
Caisse Centrale de Réassurance	Collateral Damages	2004
Hydro Québec	Cost of Debt	2004
Enbridge Gas New Brunswick	AFUDC	2004
Heritage Gas	Deferral Accounts	2004
ATCO Electric	Carrying Costs on Deferral Account	2001
Newfoundland & Labrador Hydro	Rate Base, Cash Working Capital	2001
Gazifère Inc.	Cash Working Capital	2000
Maritime Electric	Rate Subsidies	2000
Enbridge Gas Distribution	Principles of Cost Allocation	1998
Enbridge Gas Distribution	Unbundling/Regulatory Compact	1998

Maritime Electric	Form of Regulation	1995
Northwest Territories Power	Rate Stabilization Fund	1995
Canadian Western Natural Gas	Cash Working Capital/ Compounding Effect	1989
Gaz Métro/Province of Québec	Cost Allocation/ Incremental vs. Rolled-In Tolling	1984

SELECTED INDICATORS OF ECONOMIC ACTIVITY
(1989 = 100)

Canada								United States						
Year	Gross Domestic Product		Industrial Production (3)	GDP Deflator Index (4)	Consumer Price Index (5)	After-Tax Profits		Gross Domestic Product		Industrial Production (10)	Implicit Price Index (11)	Consumer Price Index (12)	After-Tax Profits	
	Constant	Current Dollars				Billions of	As Percent	Constant	Current Dollars				Billions of	As Percent
	Dollars (1)	(2)				Dollars (6)	of GDP (7)	Dollars (8)	(9)				Dollars (13)	of GDP (14)
1989	100.0	100.0	100.0	100.0	100.0	41	6.3%	100.0	100.0	100.0	100.0	100.0	244	4.5%
1990	100.2	103.4	97.2	103.2	104.8	28	4.1%	101.9	105.8	101.0	103.9	105.4	266	4.6%
1991	98.1	104.2	93.5	106.2	110.7	18	2.6%	101.6	109.3	99.4	107.5	109.8	287	4.8%
1992	99.0	106.5	94.5	107.6	112.3	18	2.6%	105.1	115.7	102.2	110.1	113.2	326	5.1%
1993	101.3	110.6	98.8	109.2	114.4	25	3.4%	108.1	121.6	105.6	112.5	116.5	348	5.2%
1994	106.1	117.2	105.1	110.4	114.6	46	6.0%	112.5	129.2	111.1	114.9	119.5	406	5.7%
1995	109.1	122.7	109.9	112.9	117.1	54	6.7%	115.3	135.3	116.4	117.3	122.9	466	6.3%
1996	110.9	126.8	111.8	114.7	118.9	54	6.5%	119.6	143.0	121.6	119.5	126.5	509	6.5%
1997	115.6	133.5	118.0	116.1	120.8	56	6.3%	125.0	152.0	130.4	121.6	129.5	556	6.7%
1998	120.3	139.2	122.2	115.6	122.0	55	6.0%	130.4	160.4	137.9	123.0	131.5	475	5.4%
1999	127.0	149.4	129.8	117.6	124.2	71	7.3%	136.7	170.6	143.9	124.8	134.4	522	5.6%
2000	133.6	163.5	139.6	122.5	127.5	88	8.1%	142.4	181.5	149.6	127.5	138.9	507	5.1%
2001	136.0	168.5	134.6	123.9	130.8	91	8.2%	143.9	187.6	144.5	130.4	142.8	509	5.0%
2002	140.0	175.3	137.5	125.2	133.7	99	8.6%	146.5	194.1	144.7	132.5	145.1	573	5.4%
2003	142.6	184.4	137.7	129.4	137.4	105	8.6%	150.2	203.2	146.5	135.3	148.4	570	5.9%
2004	147.0	196.3	139.8	133.5	139.9	122	9.4%	155.4	216.2	149.9	139.1	152.3	923	7.8%
2005	151.5	208.9	142.1	137.9	143.0	138	10.0%	160.2	230.3	154.8	143.7	157.5	1,228	9.7%
2006	155.8	220.5	142.1	141.6	145.9	140	9.7%	164.5	244.0	158.2	148.4	162.6	1,349	10.1%
2007	159.2	232.6	141.4	146.1	149.0	146	9.5%	167.6	255.9	162.1	152.7	167.2	1,293	9.2%
2008	160.3	243.8	137.1	152.1	152.6	168	10.5%	167.0	260.7	156.4	156.1	173.6	1,051	7.3%
2009	155.8	232.5	124.1	149.2	153.0	96	6.3%	161.9	254.9	138.5	157.4	173.0	1,171	8.4%
2010	160.9	247.0	130.2	153.6	155.7	126	7.7%	165.8	264.5	146.0	159.5	175.9	1,443	10.0%
2011	164.7	261.6	134.7	158.8	160.3	154	8.9%	168.8	275.0	152.0	162.9	181.4	1,475	9.8%
2007	Q1	157.6	227.6	142.4	144.4	139	9.3%	165.7	251.0	160.5	151.5	164.3	1,264	9.2%
	Q2	158.9	232.5	142.3	146.3	144	9.4%	167.2	255.0	162.3	152.5	167.5	1,316	9.4%
	Q3	159.7	233.4	141.4	146.2	149.6	9.6%	168.4	257.7	162.7	153.0	167.9	1,284	9.1%
	Q4	160.5	236.7	139.7	147.4	149.5	9.8%	169.1	260.0	163.0	153.7	169.1	1,308	9.2%
2008	Q1	160.3	240.3	138.2	150.0	150.0	10.3%	168.4	260.4	162.5	154.6	171.0	1,188	8.3%
	Q2	160.5	246.5	137.6	153.6	153.1	11.2%	168.9	263.0	160.1	155.7	174.8	1,208	8.4%
	Q3	160.9	249.3	138.0	155.0	154.7	11.4%	167.4	262.6	154.8	156.9	176.8	1,163	8.1%
	Q4	159.4	239.0	134.4	150.0	152.4	9.0%	163.5	256.9	148.2	157.1	171.8	644	4.6%
2009	Q1	156.1	230.7	128.0	147.8	151.9	6.9%	161.3	254.0	140.4	157.4	171.0	1,010	7.3%
	Q2	154.7	229.3	122.6	148.3	153.2	6.2%	161.2	253.3	136.2	157.1	172.8	1,087	7.8%
	Q3	155.3	232.0	121.6	149.5	153.4	6.0%	161.8	254.5	137.9	157.3	174.0	1,232	8.8%
	Q4	157.2	237.8	124.1	151.3	153.6	6.0%	163.4	257.8	139.8	157.8	174.3	1,355	9.6%
2010	Q1	159.4	243.4	127.3	152.7	154.4	6.8%	164.3	260.3	142.4	158.4	175.0	1,434	10.0%
	Q2	160.3	244.8	130.1	152.8	155.3	7.1%	165.2	262.9	145.4	159.1	175.8	1,405	9.7%
	Q3	161.3	247.1	131.0	153.3	156.2	8.2%	166.3	265.9	147.8	159.9	176.0	1,465	10.1%
	Q4	162.5	252.7	132.3	155.6	157.1	8.8%	167.3	268.8	148.6	160.7	176.5	1,468	10.0%
2011	1Q	163.9	257.8	134.5	157.3	158.4	9.0%	167.3	270.2	150.2	161.5	178.8	1,403	9.5%
	2Q	163.5	259.2	132.8	158.5	160.6	8.5%	168.4	273.7	150.6	162.6	181.9	1,455	9.7%
	3Q	165.3	262.8	135.4	159.0	160.9	8.9%	168.9	276.6	152.7	163.8	182.6	1,477	9.7%
	4Q	166.1	266.7	136.2	160.6	161.3	9.4%	170.6	279.5	154.6	163.8	182.3	1,566	10.2%
2012	1Q	166.9	268.4	135.8	160.9	162.1	9.0%	171.4	282.3	156.8	164.7	183.8	1,671	10.8%

Note: Data are based on Chain Weighted Indexes.

Source: www.bea.gov, www.cansim2.statcan.ca and www.federalreserve.gov

TRENDS IN INTEREST RATES, DIVIDEND YIELDS, AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Canada

	Government Securities											Moody's	
	T-Bills		10 Year		Long-Term		Bonds Over	Inflation	A-Rated	Median Utility	A-Rated Utility/ Long Canada Bond	U.S. Utility Long-Term	Exchange Rate
Year	Canadian	U.S. ^{1/}	Canadian	U.S.	Canadian	U.S. ^{2/}	10 Years ^{3/}	Indexed Bonds	Utility Bonds ^{4/}	Dividend Yield ^{5/}	Yield Spread	A-Rated Bonds	(Cdn\$/US\$)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Annual													
1990	12.81	7.49	10.76	8.55	10.69	8.61	10.85		12.13		1.44	9.86	0.86
1991	8.73	5.38	9.42	7.86	9.72	8.14	9.76		11.00		1.28	9.36	0.84
1992	6.59	3.43	8.05	7.01	8.68	7.67	8.77	4.62	10.01		1.33	8.69	0.82
1993	4.84	3.02	7.22	5.87	7.86	6.59	7.85	4.28	9.08	6.08	1.22	7.59	0.77
1994	5.54	4.34	8.43	7.08	8.69	7.39	8.63	4.41	9.81	6.12	1.12	8.30	0.73
1995	6.89	5.44	8.08	6.58	8.41	6.85	8.28	4.68	9.29	6.42	0.88	7.89	0.73
1996	4.21	5.04	7.20	6.44	7.75	6.73	7.50	4.61	8.38	5.66	0.63	7.75	0.73
1997	3.26	5.11	6.11	6.32	6.66	6.58	6.42	4.14	7.19	4.57	0.53	7.60	0.72
1998	4.73	4.79	5.30	5.26	5.59	5.54	5.47	4.02	6.38	4.23	0.79	7.04	0.68
1999	4.69	4.71	5.55	5.68	5.72	5.91	5.69	4.07	6.92	5.00	1.20	7.62	0.67
2000	5.45	5.85	5.89	5.98	5.71	5.88	5.89	3.69	7.05	5.63	1.34	8.24	0.67
2001	3.78	3.34	5.49	4.99	5.77	5.50	5.76	3.59	7.10	4.57	1.33	7.74	0.65
2002	2.55	1.63	5.27	4.56	5.67	5.41	5.65	3.49	7.08	3.97	1.41	7.34	0.64
2003	2.86	1.03	4.78	4.02	5.31	5.03	5.26	3.04	6.65	3.80	1.33	6.54	0.72
2004	2.21	1.44	4.55	4.27	5.11	5.08	5.05	2.34	6.14	3.69	1.03	6.14	0.77
2005	2.73	3.29	4.04	4.27	4.38	4.52	4.36	1.81	5.43	3.23	1.05	5.62	0.83
2006	4.05	4.86	4.21	4.79	4.26	4.87	4.28	1.67	5.36	3.19	1.09	6.06	0.89
2007	4.13	4.42	4.25	4.58	4.30	4.80	4.31	1.95	5.52	3.26	1.22	6.06	0.94
2008	2.26	1.28	3.56	3.61	4.04	4.22	4.03	1.90	6.29	3.62	2.26	6.54	0.94
2009	0.31	0.15	3.27	3.29	3.85	4.10	3.85	1.86	6.10	4.20	2.24	5.99	0.88
2010	0.59	0.14	3.17	3.14	3.70	4.17	3.63	1.36	5.20	3.78	1.51	5.38	0.97
2011	0.91	0.06	2.76	2.75	3.26	3.86	3.19	0.92	4.82	3.50	1.56	5.00	1.02
2012 (July)	0.94	0.08	1.88	1.82	2.47	2.93	2.36	0.43	4.07	3.62	1.60	4.21	1.00

^{1/} Rates on new issues.

^{2/} 30-year maturities through January 2002. Theoretical 30-year yield, February 2002 to January 2006, when no 30-year Treasury bonds were issued. The theoretical 30-year Treasury bond yield represents the yield on all outstanding Treasury bonds with a term to maturity greater than 25 years plus an extrapolation factor published by the U.S. Department of the Treasury to allow the estimation of a 30-year rate; 30-year maturities February 2006 forward.

^{3/} Terms to maturity of 10 years or more.

^{4/} Series is comprised of the CBRS Utilities Index through 1995; CBRS 30-year Utilities Index from 1996- August 2000; a series of long-term utility bonds maintained by Foster Associates from September 2000 forward.

^{5/} Monthly dividend yields of Canadian Utilities, Emera Inc., Enbridge Inc., Fortis Inc., and Transcanada Corp.

Source: www.bankofcanada.ca; www.federalreserve.gov; www.globeandmail.com; www.moodys.com and www.ustreas.gov

TRENDS IN INTEREST RATES, DIVIDEND YIELDS, AND OUTSTANDING BOND YIELDS
(Percent Per Annum)

Canada														Moody's	
Government Securities														U.S. Utility	
Year	T-Bills		10 Year		Long-Term		Bonds Over	Inflation	A-Rated	Median Utility	A-Rated Utility/	Long-Term	U.S. Utility	Exchange Rate	
	Canadian	U.S. ^{1/}	Canadian	U.S.	Canadian	U.S. ^{2/}	10 Years ^{3/}	Indexed Bonds	Utility Bonds ^{4/}	Dividend Yield ^{5/}	Long Canada Bond	A-Rated Bonds	(Cdn\$/US\$)		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)		
2005	Q1	2.47	2.67	4.27	4.33	4.72	4.70	4.69	2.05	5.78	3.58	1.06	5.72	0.82	
	Q2	2.46	3.01	3.93	4.05	4.39	4.36	4.35	1.86	5.47	3.38	1.09	5.43	0.81	
	Q3	2.73	3.50	3.88	4.21	4.20	4.39	4.19	1.75	5.20	2.92	0.99	5.49	0.84	
	Q4	3.25	4.00	4.07	4.49	4.19	4.63	4.21	1.59	5.25	3.04	1.06	5.82	0.85	
2006	Q1	3.70	4.57	4.18	4.65	4.23	4.70	4.25	1.53	5.32	3.28	1.09	5.92	0.87	
	Q2	4.17	4.84	4.51	5.11	4.54	5.19	4.57	1.81	5.65	3.39	1.10	6.41	0.90	
	Q3	4.14	5.00	4.14	4.79	4.21	4.91	4.23	1.67	5.34	3.18	1.12	6.09	0.89	
	Q4	4.16	5.04	4.00	4.59	4.07	4.70	4.08	1.68	5.13	2.92	1.06	5.82	0.87	
2007	Q1	4.17	5.11	4.10	4.68	4.17	4.82	4.18	1.77	5.23	3.19	1.06	5.92	0.86	
	Q2	4.29	4.82	4.39	4.85	4.35	4.98	4.38	1.94	5.49	3.34	1.14	6.08	0.92	
	Q3	4.17	4.26	4.43	4.64	4.45	4.86	4.46	2.09	5.75	3.36	1.30	6.19	0.97	
	Q4	3.90	3.48	4.09	4.16	4.21	4.53	4.21	2.01	5.61	3.13	1.39	6.05	1.02	
2008	Q1	2.76	1.73	3.65	3.55	4.07	4.35	4.03	1.80	5.65	3.31	1.58	6.16	0.99	
	Q2	2.60	1.74	3.68	3.94	4.10	4.58	4.07	1.60	5.84	3.63	1.74	6.30	0.99	
	Q3	2.23	1.44	3.66	3.89	4.11	4.44	4.13	1.78	6.21	3.66	2.10	6.58	0.95	
	Q4	1.45	0.19	3.26	3.06	3.88	3.50	3.91	2.42	7.47	3.87	3.60	7.13	0.82	
2009	Q1	0.61	0.24	2.99	2.87	3.68	3.62	3.65	2.13	7.06	4.38	3.38	6.44	0.80	
	Q2	0.21	0.16	3.28	3.39	3.90	4.24	3.86	1.97	6.27	4.37	2.37	6.35	0.87	
	Q3	0.22	0.16	3.38	3.41	3.89	4.17	3.94	1.76	5.49	4.14	1.60	5.54	0.92	
	Q4	0.21	0.06	3.42	3.49	3.95	4.35	3.96	1.57	5.56	3.91	1.62	5.65	0.94	
2010	Q1	0.20	0.12	3.43	3.69	4.01	4.59	3.94	1.54	5.45	3.91	1.44	5.80	0.96	
	Q2	0.46	0.17	3.36	3.32	3.80	4.22	3.73	1.45	5.37	4.09	1.57	5.46	0.96	
	Q3	0.74	0.15	2.88	2.65	3.49	3.73	3.42	1.35	5.00	3.71	1.51	4.96	0.96	
	Q4	0.97	0.14	2.99	2.91	3.48	4.15	3.42	1.11	4.98	3.42	1.50	5.31	0.99	
2011	Q1	0.95	0.13	3.31	3.44	3.73	4.53	3.68	1.25	5.18	3.42	1.46	5.56	1.02	
	Q2	0.96	0.04	3.13	3.18	3.58	4.33	3.50	1.00	5.07	3.56	1.49	5.37	1.04	
	Q3	0.88	0.05	2.48	2.32	3.05	3.54	2.96	0.83	4.65	3.58	1.60	4.74	1.01	
	Q4	0.86	0.01	2.13	2.05	2.70	3.04	2.61	0.58	4.37	3.46	1.67	4.35	0.99	
2012	Q1	0.91	0.07	1.99	2.01	2.59	3.12	2.48	0.44	4.10	3.62	1.51	4.35	1.00	
	Q2	0.95	0.09	1.84	1.74	2.41	2.85	2.31	0.45	4.08	3.62	1.67	4.17	0.99	
2008	Jan	3.38	1.96	3.88	3.67	4.18	4.35	4.16	1.96	5.67	3.07	1.49	6.07	1.00	
	Feb	3.04	1.85	3.64	3.53	4.09	4.41	4.04	1.85	5.66	3.44	1.57	6.22	1.02	
	Mar	1.87	1.38	3.43	3.45	3.94	4.30	3.88	1.60	5.63	3.42	1.69	6.20	0.97	
	Apr	2.68	1.43	3.58	3.77	4.08	4.49	4.02	1.72	5.78	3.60	1.70	6.22	0.99	
	May	2.64	1.89	3.71	4.06	4.13	4.72	4.09	1.61	5.83	3.66	1.70	6.36	0.99	
	Jun	2.48	1.90	3.74	3.99	4.08	4.53	4.10	1.47	5.89	3.65	1.81	6.32	0.98	
	Jul	2.39	1.68	3.70	3.99	4.10	4.59	4.11	1.54	5.92	3.63	1.82	6.44	0.98	
	Aug	2.40	1.72	3.53	3.83	4.01	4.43	4.02	1.57	6.09	3.58	2.08	6.32	0.94	
	Sep	1.89	0.92	3.75	3.85	4.23	4.31	4.25	2.23	6.64	3.77	2.41	6.98	0.94	
	Oct	1.85	0.46	3.76	4.01	4.28	4.35	4.33	2.51	7.61	3.80	3.33	8.01	0.82	
	Nov	1.67	0.01	3.32	2.93	3.90	3.45	3.96	2.65	7.48	3.74	3.58	7.18	0.81	
	Dec	0.83	0.11	2.69	2.25	3.45	2.69	3.45	2.10	7.33	4.07	3.88	6.20	0.82	
2009	Jan	0.86	0.24	3.06	2.87	3.77	3.58	3.80	2.27	7.33	4.11	3.56	6.52	0.81	
	Feb	0.59	0.26	3.12	3.02	3.70	3.71	3.70	2.32	7.07	4.33	3.37	6.38	0.79	
	Mar	0.39	0.21	2.79	2.71	3.57	3.56	3.46	1.81	6.78	4.70	3.21	6.41	0.79	
	Apr	0.20	0.14	3.09	3.16	3.84	4.05	3.74	2.05	6.71	4.70	2.87	6.55	0.84	
	May	0.20	0.14	3.39	3.47	3.99	4.34	3.93	2.00	6.14	4.33	2.15	6.53	0.91	
	Jun	0.24	0.19	3.36	3.53	3.86	4.32	3.91	1.86	5.94	4.09	2.08	5.96	0.86	
	Jul	0.24	0.18	3.46	3.52	3.95	4.31	4.01	1.73	5.54	4.08	1.59	5.68	0.93	
	Aug	0.20	0.15	3.37	3.40	3.89	4.18	3.94	1.81	5.45	4.18	1.56	5.54	0.91	
	Sep	0.22	0.14	3.31	3.31	3.84	4.03	3.87	1.74	5.49	4.16	1.65	5.41	0.93	
	Oct	0.22	0.05	3.42	3.41	3.92	4.23	3.95	1.60	5.49	4.11	1.57	5.55	0.93	
	Nov	0.21	0.06	3.22	3.21	3.84	4.20	3.83	1.58	5.50	3.98	1.66	5.54	0.95	
	Dec	0.19	0.06	3.61	3.85	4.08	4.63	4.09	1.53	5.69	3.63	1.61	5.86	0.96	
2010	Jan	0.16	0.08	3.34	3.63	3.94	4.51	3.90	1.49	5.42	3.75	1.48	5.73	0.94	
	Feb	0.16	0.13	3.39	3.61	4.02	4.55	3.94	1.58	5.49	4.11	1.47	5.77	0.95	
	Mar	0.28	0.16	3.56	3.84	4.07	4.72	3.99	1.56	5.44	3.88	1.37	5.89	0.98	
	Apr	0.39	0.16	3.65	3.69	4.01	4.53	3.94	1.49	5.40	3.99	1.39	5.60	0.99	
	May	0.50	0.16	3.36	3.31	3.73	4.22	3.65	1.45	5.46	4.15	1.73	5.57	0.96	
	Jun	0.50	0.18	3.08	2.97	3.65	3.91	3.59	1.42	5.24	4.12	1.59	5.21	0.94	
	Jul	0.66	0.15	3.11	2.94	3.69	3.98	3.62	1.51	5.17	3.83	1.48	5.17	0.97	
	Aug	0.70	0.14	2.78	2.47	3.44	3.52	3.36	1.34	5.01	3.80	1.57	4.78	0.94	
	Sep	0.87	0.16	2.75	2.53	3.35	3.69	3.27	1.20	4.82	3.51	1.47	4.93	0.97	
	Oct	0.92	0.12	2.80	2.63	3.44	3.99	3.32	1.09	4.89	3.46	1.45	5.21	0.98	
	Nov	1.01	0.17	3.07	2.81	3.48	4.12	3.45	1.12	5.04	3.49	1.56	5.28	0.97	
	Dec	0.97	0.12	3.11	3.30	3.52	4.34	3.48	1.11	5.00	3.30	1.48	5.45	1.01	
2011	Jan	0.96	0.15	3.27	3.42	3.73	4.58	3.68	1.38	5.18	3.25	1.45	5.61	1.00	
	Feb	0.96	0.15	3.30	3.42	3.70	4.49	3.65	1.22	5.14	3.52	1.44	5.51	1.03	
	Mar	0.93	0.09	3.35	3.47	3.75	4.51	3.70	1.15	5.23	3.50	1.48	5.57	1.03	
	Apr	0.98	0.04	3.20	3.32	3.69	4.40	3.62	1.00	5.19	3.57	1.50	5.46	1.05	
	May	0.96	0.06	3.07	3.05	3.49	4.22	3.38	0.98	4.97	3.51	1.48	5.23	1.03	
	Jun	0.93	0.03	3.11	3.18	3.55	4.38	3.49	1.03	5.04	3.59	1.49	5.41	1.04	
	Jul	0.91	0.10	2.79	2.82	3.29	4.12	3.21	0.79	4.73	3.66	1.44	5.09	1.05	
	Aug	0.93	0.02	2.49	2.23	3.10	3.60	3.00	0.88	4.74	3.55	1.64	4.74	1.02	
	Sep	0.80	0.02	2.15	1.92	2.77	2.90	2.68	0.82	4.49	3.52	1.72	4.38	0.96	
	Oct	0.89	0.01	2.29	2.17	2.92	3.16	2.81	0.67	4.54	3.44	1.62	4.42	1.01	
	Nov	0.86	0.01	2.15	2.08	2.69	3.06	2.61	0.61	4.41	3.46	1.72	4.38	0.98	
	Dec	0.82	0.02	1.94	1.89	2.49	2.89	2.41	0.45	4.17	3.48	1.68	4.24	0.98	
2012	Jan	0.88	0.06	1.89	1.83	2.50	2.94	2.40	0.38	4.05	3.47	1.55	4.22	0.99	
	Feb	0.93	0.08	1.98	1.98	2.60	3.08	2.48	0.44	4.10	3.68	1.50	4.30	1.01	
	Mar	0.91	0.07	2.11	2.23	2.66	3.35	2.55	0.51	4.14	3.72	1.48	4.54	1.00	
	Apr	1.05	0.10	2.04	1.95	2.61	3.12	2.51	0.57	4.22	3.50	1.61	4.33	1.01	
	May	0.93													

EQUITY RETURN AWARDS AND CAPITAL STRUCTURES ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES
(Percentages)

	Decision Date	Regulator	Order/ File Number	Debt	Preferred Stock	Common Stock Equity	Equity Return	Forecast 30-Year Bond Yield	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Electric Utilities									
AltaLink	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
ATCO Electric									
Transmission	12/11	AUC	2011-474	52.81	10.19	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	50.95	10.05	39.00	8.75	3.60	
ENMAX									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
EPCOR									
Transmission	12/11	AUC	2011-474	63.00	0.00	37.00	8.75	3.60	
Distribution	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisAlberta Inc.	12/11	AUC	2011-474	59.00	0.00	41.00	8.75	3.60	
FortisBC Inc.	5/05; 12/09	BCUC	G-52-05; G-158-09	60.00	0.00	40.00	9.90	4.30	
Hydro One Transmission	12/10; 3/12	OEB	EB-2010-0002; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.12	2.93	
Maritime Electric	7/10	IRAC	UE-10-03	59.50	0.00	40.50	9.75	n/a	1/
Newfoundland Power	12/09; 6/12	NLPub	P.U. 46 (2009); P.U. 17(2012)	54.27	1.04	44.69	8.80	n/a	
Nova Scotia Power	11/11	NSUARB	2011 NSUARB 184	58.80	3.60	37.50	9.20	n/a	
Ontario Electricity Distributors	12/09; 3/12	OEB	EB-2009-0084; Letter Cost of Capital Parameters	60.00	0.00	40.00	9.12	2.93	
Ontario Power Generation	3/11	OEB	EB-2010-0008	53.00	0.00	47.00	9.55	3.85	
Gas Distributors									
AltaGas Utilities	12/11	AUC	2011-474	57.00	0.00	43.00	8.75	3.60	
ATCO Gas	12/11	AUC	2011-474	53.09	7.91	39.00	8.75	3.60	
Enbridge Gas Distribution Inc	1/04; 7/07; 2/08	OEB	RP-2002-0158; EB-2006-0034; EB-2007-0615	61.33	2.67	36.00	8.39	4.23	
FortisBC Energy Inc.	12/09	BCUC	G-158-09	60.00	0.00	40.00	9.50	4.30	
FortisBC Energy (Vancouver Island)	12/09	BCUC	G-14-06; G-158-09	60.00	0.00	40.00	10.00	4.30	
FortisBC Energy Inc (Whistler)	4/09; 12/09	BCUC	G-35-09; G-158-09	60.00	0.00	40.00	10.00	4.30	
Gazifère	11/10; 12/11	Régie	D-2010-147; D-2011-189	60.00	0.00	40.00	8.29	3.10	
Gaz Métro	11/11	Régie	D-2011-182	54.00	7.50	38.50	8.90	4.00	
Pacific Northern Gas-West	12/09; 5/10	BCUC	G-158-09; G-84-10	51.15	3.85	45.00	10.15	4.30	
Pacific Northern Gas-Fort St. John/Dawson	12/09; 5/10	BCUC	G-158-09; G-84-10	60.00	0.00	40.00	9.90	4.30	
Pacific Northern Gas-Tumbler Ridge	12/09; 5/10	BCUC	G-158-09; G-84-10	60.00	0.00	40.00	10.15	4.30	
Union Gas	1/04; 5/06; 1/08	OEB	RP-2002-0158; EB-2006-0520; EB-2007-0606	60.60	3.40	36.00	8.54	4.23	2/
Gas Pipelines									
Foothills Pipe Lines Ltd.	6/10	NEB	TG-03-2010	60.00	0.00	40.00	9.70	n/a	
Nova Gas Transmission Ltd.	9/10	NEB	TG-05-2010	60.00	0.00	40.00	9.70	n/a	
TransCanada PipeLines	5/07; 11/10	NEB	RH-2-94; TG-06-2007; NEB Letter 11-10	60.00	0.00	40.00	8.08	3.72	
Trans Québec & Maritimes Pipeline	3/09; 11/10	NEB	RH-1-2008; TG-07-2010	60.00	0.00	40.00	9.70	n/a	3/
Westcoast Energy	1/11	NEB	TG-01-2011	60.00	0.00	40.00	9.70	n/a	

1/ In 2010, the Electric Power Amendment Act reduced electricity rates and froze them until March 2013.

2/ Settlement adopted in July 2012 agreed to adoption of OEB revised ROE formula.

3/ Settlement for 2010-2012 does not specify return on rate base; AFUDC rate, income taxes and capital variances based on a 9.7% ROE, 60%/40% debt/equity capital structure and TQM's embedded cost of debt.

RATES OF RETURN ON COMMON EQUITY ADOPTED BY REGULATORY BOARDS FOR CANADIAN UTILITIES

	<u>1990</u>	<u>1991</u>	<u>1992</u>	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>
Electric Utilities																							
AltaLink	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
ATCO Electric	13.50	13.50	13.25	11.88	NA	NA	11.25	^{2/}	^{2/}	^{2/}	^{2/}	^{2/}	^{2/}	9.40	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
FortisAlberta Inc.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.50	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
FortisBC Inc. ^{1/}	13.50	NA	11.75	11.50	11.00	12.25	11.25	10.50	10.25	9.50	10.00	9.75	9.53	9.82	9.55	9.43	9.20	8.77	9.02	8.87	9.90	9.90	9.90
Newfoundland Power	13.95	13.25	NA	NA	NA	NA	11.00	NA	9.25	9.25	9.59	9.59	9.05	9.75	9.75	9.24	9.24	8.60	8.95	8.95	9.00	8.38	8.80
Nova Scotia Power	NA	NA	NA	11.75	NA	NA	10.75	NA	NA	NA	NA	NA	10.15	NA	NA	9.55	9.55	9.55	NA	9.35	NA	NA	9.20
Ontario Electricity Distributors	NA	NA	NA	NA	NA	NA	NA	NA	NA	9.35	9.88	9.88	9.88	9.88	9.88	9.88	9.00	9.00	8.57	8.01	9.85	9.58	9.42
TransAlta Utilities	13.50	13.50	13.25	11.88	NA	12.25	11.25	^{2/}	^{3/}	9.25	9.25	NA	9.40	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Mean of Electric Utilities	13.61	13.42	12.75	11.75	11.00	12.25	11.10	10.50	9.75	9.34	9.68	9.74	9.59	9.63	9.66	9.51	9.11	8.78	8.80	8.88	9.29	9.02	9.08
Gas Distributors																							
AltaGas Utilities	NA	13.50	13.25	NA	NA	12.00	11.75	11.75	11.75	11.75	9.90	9.70	9.70	9.50	9.60	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
ATCO Gas	13.25	13.25	12.25	12.25	NA	NA	NA	10.50	9.38	NA	NA	9.75	9.75	9.50	9.50	9.50	8.93	8.51	8.75	9.00	9.00	8.75	8.75
Enbridge Gas Distribution	13.25	13.13	13.13	12.30	11.60	11.65	11.88	11.50	10.30	9.51	9.73	9.54	9.66	9.69	NA	9.57	8.74	8.39	8.39	8.39	8.39	8.39	8.39
FortisBC Energy ^{1/}	NA	NA	12.25	NA	10.65	12.00	11.00	10.25	10.00	9.25	9.50	9.25	9.13	9.42	9.15	9.03	8.80	8.37	8.62	8.47	9.50	9.50	9.50
Gaz Métro	14.25	14.25	14.00	12.50	12.00	12.00	12.00	11.50	10.75	9.64	9.72	9.60	9.67	9.89	9.45	9.69	8.95	8.73	9.05	8.76	9.20	9.09	8.90
Pacific Northern Gas ^{1/}	15.00	14.00	13.25	NA	11.50	12.75	11.75	11.00	10.75	10.00	10.25	10.00	9.88	10.17	9.80	9.68	9.45	9.02	9.27	9.12	10.15	10.15	10.15
Union Gas	13.75	13.50	13.50	13.00	12.50	11.75	11.75	11.00	10.44	9.61	9.95	9.95	9.95	9.95	9.62	9.62	8.89	8.54	8.54	8.54	8.54	8.54	8.54
Mean of Gas Distributors	13.90	13.60	13.09	12.51	11.65	12.03	11.69	11.07	10.48	9.96	9.84	9.68	9.68	9.73	9.52	9.51	8.96	8.58	8.77	8.75	9.11	9.02	9.00
Gas Pipelines (NEB)																							
TransCanada PipeLines	13.25	13.50	13.25	12.25	11.25	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52	8.08	NA ^{4/}
Westcoast Energy	13.25	13.75	12.50	12.25	11.50	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52	9.70	9.70
Mean of Gas Pipelines	13.25	13.63	12.88	12.25	11.38	12.25	11.25	10.67	10.21	9.58	9.90	9.61	9.53	9.79	9.56	9.46	8.88	8.46	8.72	8.57	8.52	8.89	9.70
Mean of All Companies	13.68	13.56	12.97	12.16	11.50	12.12	11.39	10.93	10.30	9.69	9.80	9.69	9.62	9.70	9.59	9.51	9.01	8.65	8.77	8.79	9.10	9.00	9.08

^{1/} Allowed ROE for 2009 for first six months

^{2/} Negotiated settlement, details not available.

^{3/} Negotiated settlement, implicit ROE made public is 10.5%.

^{4/} Rate case ongoing for 2012.

DEBT RATINGS OF CANADIAN UTILITIES

Company	Ratings					
	DBRS		Moody's		S&P	
	Issuer Rating	Debt Rating	Issuer Rating	Debt Rating	Corporate Credit Rating	S&P Business Risk Profile
Electric Utilities						
AltaLink L.P.		A (Senior Secured)			A-	A- (Senior Secured) Excellent
CU Inc.		A(high) (Unsecured)			A	A (Senior Unsecured) Excellent
Enersource	A	A (Senior Unsecured)				
ENMAX Corp.		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured) Strong
ENTEGRUS Inc. ^{1/}					A	Excellent
EPCOR Utilities Inc.		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured) Strong
FortisAlberta Inc.		A(low) (Senior Unsecured)		Baa1 (Senior Unsecured)	A-	A- (Senior Unsecured) Excellent
FortisBC Inc.		A(low) (Unsecured)		Baa1 (Senior Unsecured)		
Guelph Hydro Electric Systems					A	A (Senior Unsecured) Excellent
Hamilton Utilities					A	A (Senior Unsecured) Excellent
Hydro One Inc.		A(high) (Senior Unsecured)		A1 (Senior Unsecured) ^{2/}	A+ ^{2/}	A+ (Senior Unsecured) ^{2/} Excellent
Hydro Ottawa Holding Inc.		A (Senior Unsecured)			A	A (Senior Unsecured) Excellent
London Hydro					A	Excellent
Maritime Electric					BBB+	A- (Senior Secured) Strong
Newfoundland Power		A (First Mortgage)	Baa1	A2 (First Mortgage)		
Nova Scotia Power		A(low) (Unsecured)	^{3/}	^{3/}	BBB+	BBB+ (Senior Unsecured) Strong
Ontario Power Generation		A(low) (Unsecured)			A-	Strong
Toronto Hydro		A(high) (Senior Unsecured)			A	A (Senior Unsecured) Excellent
Veridian Corp.	A					
Median		A		A3	A	A/A- Excellent
Gas Distributors						
Enbridge Gas Distribution		A (Unsecured)			A-	A- (Senior Unsecured) ^{4/} Excellent
FortisBC Energy Inc.		A (Unsecured)		A3 (Senior Unsecured) A1 (Senior Secured)		
FortisBC Energy Inc. (Vancouver Island)		BBB(high) (Debentures)		A3 (Senior Unsecured)		
Gaz Métro Inc.		A (First Mortgage)			A-	A (Senior Secured) Excellent
Pacific Northern Gas		^{5/}				
Union Gas Limited		A (Unsecured)			BBB+	BBB+ (Senior Unsecured) Strong
Median		A		A3	A-	A- Excellent
Pipelines						
Enbridge Pipelines Inc.		A (Unsecured)			A-	A- (Senior Unsecured) Excellent
NOVA Gas Transmission Ltd.		A (Unsecured)		A3 (Senior Unsecured)	A-	A- (Senior Unsecured)
Trans Québec & Maritimes Pipeline		A(low) (Senior Unsecured)			BBB+	BBB+ (Senior Unsecured) Strong
TransCanada PipeLines Ltd.		A (Unsecured)	A3	A3 (Senior Unsecured)	A-	A- (Senior Unsecured) Excellent
Westcoast Energy Inc.		A(low) (Unsecured)			BBB+	BBB+ (Senior Unsecured) Strong
Median		A		A3	A-	A- Excellent/Strong
Medians						
All Companies		A		A3	A-	A- Excellent
All Investor-Owned Companies		A		A3	A-	A- Excellent
All Electric & Gas Investor-Owned Companies						
Currently Rated by DBRS excl. NP		A		A3	A-	A- Excellent

^{1/} Previously Chatham-Kent Energy Inc.^{2/} Moody's rating reflects application of methodology for government-related issuers. Implied senior unsecured rating of Baa1. S&P stand-alone rating is A.^{3/} Ratings withdrawn at request of company March 2010; unsecured debt previously rated Baa1.^{4/} S&P ratings affirmed at AA- for Senior Secured Debt and A for Unsecured Debt, then withdrawn September 23, 2010.^{5/} DBRS rating discontinued March 12, 2012. Previously BBB(low) for Senior Secured.

**TOTAL CAPITAL STRUCTURE RATIOS OF CANADIAN UTILITIES WITH RATED DEBT
(2011)**

	<u>Total Debt</u> ^{1/}	<u>Preferred Stock</u> ^{2/}	<u>Common Stock</u> <u>Equity</u> ^{3/}
	(1)	(2)	(3)
Electric Utilities			
AltaLink L.P.	56.7%	0.0%	43.3%
CU Inc.	56.0%	6.9%	37.2%
Enersource	56.0%	0.0%	44.0%
ENMAX Corp.	45.6%	0.0%	54.4%
ENTEGRUS Inc.	43.7%	0.0%	56.3%
EPCOR Utilities Inc.	42.0%	0.0%	58.0%
FortisAlberta Inc.	57.4%	0.0%	42.6%
FortisBC Inc.	58.4%	0.0%	41.6%
Guelph Hydro Electric Systems	45.6%	0.0%	54.4%
Hamilton Utilities	37.4%	0.0%	62.6%
Hydro One Inc.	55.5%	2.2%	42.3%
Hydro Ottawa Holding Inc.	41.7%	0.0%	58.3%
London Hydro	43.2%	0.0%	56.8%
Maritime Electric	56.5%	0.0%	43.5%
Newfoundland Power	54.7%	1.0%	44.2%
Nova Scotia Power ^{4/}	57.9%	3.8%	38.3%
Ontario Power Generation	36.4%	0.0%	63.6%
Toronto Hydro	57.0%	0.0%	43.0%
Veridian Corp.	51.9%	0.0%	48.1%
Median	54.7%	0.0%	44.2%
Gas Distributors ^{5/}			
Enbridge Gas Distribution	57.3%	2.1%	40.5%
FortisBC Energy Inc.	59.7%	0.0%	40.3%
Gaz Métro L.P.	60.0%	0.0%	40.0%
Pacific Northern Gas	48.0%	2.6%	49.3%
Union Gas Limited	61.5%	2.5%	36.0%
Median	59.7%	2.1%	40.3%
Pipelines			
Enbridge Pipelines Inc.	52.9%	0.0%	47.1%
Nova Gas Transmission Ltd.	65.4%	0.0%	34.6%
Trans Québec & Maritimes Pipeline	59.9%	0.0%	40.1%
TransCanada PipeLines Ltd.	53.3%	0.9%	45.8%
Westcoast Energy Inc.	59.0%	3.6%	37.4%
Median	59.0%	0.0%	40.1%
Medians			
All Companies	56.0%	0.0%	43.5%
All Investor-Owned Companies	57.4%	0.0%	40.5%
All Electric & Gas Investor-Owned Companies Currently Rated by DBRS excl. NP	58.2%	0.0%	40.2%

^{1/} Includes preferred securities classified as debt.

^{2/} Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

^{3/} Includes non-controlling interests in common shares of subsidiary companies.

^{4/} Common equity ratio excludes Accumulated Other Comprehensive Income.

^{5/} The average of the four quarters ending December 2011 for gas distributors was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.

Notes:

Financial statements for FortisBC Energy (Vancouver Island) are not publicly available.

TOTAL CAPITAL STRUCTURE RATIOS OF INVESTOR-OWNED CANADIAN UTILITIES WITH RATED DEBT
(Short-Term and Long-Term Debt Separated)

	2008				2009			
	Long-Term <u>Debt</u> ^{1/}	Short-Term <u>Debt</u>	Preferred <u>Stock</u> ^{2/}	Common Stock <u>Equity</u> ^{3/}	Long-Term <u>Debt</u> ^{1/}	Short-Term <u>Debt</u>	Preferred <u>Stock</u> ^{2/}	Common Stock <u>Equity</u> ^{3/}
Electric Utilities								
AltaLink L.P.	61.7%	0.0%	0.0%	38.3%	54.1%	0.0%	0.0%	45.9%
CU Inc.	56.4%	0.3%	5.1%	38.2%	53.6%	0.1%	7.7%	38.6%
FortisAlberta Inc.	60.0%	0.5%	0.0%	39.4%	56.4%	0.9%	0.0%	42.7%
FortisBC Inc.	59.1%	0.0%	0.0%	40.9%	59.2%	0.0%	0.0%	40.8%
Maritime Electric	53.6%	6.2%	0.0%	40.2%	52.4%	6.1%	0.0%	41.5%
Newfoundland Power	53.4%	0.0%	1.1%	45.5%	55.1%	0.0%	1.0%	43.8%
Nova Scotia Power ^{4/}	54.3%	0.8%	4.7%	40.1%	51.3%	6.8%	4.6%	37.2%
Median	56.4%	0.3%	0.0%	40.1%	54.1%	0.1%	0.0%	41.5%
Gas Distributors ^{5/}								
Enbridge Gas Distribution	49.0%	9.6%	2.1%	39.2%	48.7%	6.6%	2.3%	42.4%
FortisBC Energy Inc.	56.1%	9.5%	0.0%	34.5%	59.4%	4.8%	0.0%	35.8%
Gaz Métro L.P.	62.4%	1.4%	0.0%	36.2%	62.0%	1.0%	0.0%	37.0%
Pacific Northern Gas	44.9%	2.4%	3.0%	49.7%	45.9%	0.4%	3.0%	50.8%
Union Gas Limited	56.6%	4.0%	2.9%	36.5%	59.7%	0.0%	0.0%	40.3%
Median	56.1%	4.0%	2.1%	36.5%	59.4%	1.0%	0.0%	40.3%
Pipelines								
Enbridge Pipelines Inc.	52.7%	7.0%	0.0%	40.4%	44.4%	12.7%	0.0%	42.9%
Nova Gas Transmission Ltd.	61.4%	0.6%	0.0%	38.0%	63.8%	0.5%	0.0%	35.7%
Trans Québec & Maritimes Pipeline	69.9%	0.0%	0.0%	30.1%	62.9%	0.0%	0.0%	37.1%
TransCanada PipeLines Ltd.	54.4%	5.0%	1.1%	39.5%	51.8%	4.7%	1.1%	42.4%
Westcoast Energy Inc.	51.3%	3.6%	4.8%	40.3%	57.1%	1.5%	5.4%	36.0%
Pipelines	54.4%	3.6%	0.0%	39.5%	57.1%	1.5%	0.0%	37.1%
Median								
All Companies	56.1%	1.4%	0.0%	39.4%	55.1%	0.9%	0.0%	40.8%
All Electric & Gas Investor-Owned								
Companies Currently Rated by DBRS								
excl. NP	56.6%	0.8%	0.0%	38.3%	56.4%	0.9%	0.0%	40.3%
Company	2010				2011			
	Long-Term <u>Debt</u> ^{1/}	Short-Term <u>Debt</u>	Preferred <u>Stock</u> ^{2/}	Common Stock <u>Equity</u> ^{3/}	Long-Term <u>Debt</u> ^{1/}	Short-Term <u>Debt</u>	Preferred <u>Stock</u> ^{2/}	Common Stock <u>Equity</u> ^{3/}
Electric Utilities								
AltaLink L.P.	56.0%	0.0%	0.0%	44.0%	52.3%	4.5%	0.0%	43.3%
CU Inc.	52.4%	1.0%	8.3%	38.3%	55.6%	0.4%	6.9%	37.2%
FortisAlberta Inc.	56.8%	0.5%	0.0%	42.7%	57.1%	0.3%	0.0%	42.6%
FortisBC Inc.	59.5%	0.0%	0.0%	40.5%	58.4%	0.0%	0.0%	41.6%
Maritime Electric	47.1%	9.6%	0.0%	43.3%	55.6%	0.9%	0.0%	43.5%
Newfoundland Power	53.7%	0.0%	1.0%	45.2%	54.7%	0.0%	1.0%	44.2%
Nova Scotia Power ^{4/}	58.1%	1.5%	4.1%	36.4%	56.1%	1.8%	3.8%	38.3%
Median	56.0%	0.5%	0.0%	42.7%	55.6%	0.4%	0.0%	42.6%
Gas Distributors ^{5/}								
Enbridge Gas Distribution	49.7%	6.7%	2.2%	41.3%	50.3%	7.0%	2.1%	40.5%
FortisBC Energy Inc.	56.2%	3.8%	0.0%	40.0%	56.6%	3.1%	0.0%	40.3%
Gaz Métro L.P.	61.7%	1.7%	0.0%	36.7%	59.0%	1.0%	0.0%	40.0%
Pacific Northern Gas	47.3%	1.6%	2.7%	48.4%	46.2%	1.8%	2.6%	49.3%
Union Gas Limited	55.4%	4.7%	2.5%	37.4%	57.0%	4.5%	2.5%	36.0%
Median	55.4%	3.8%	2.2%	40.0%	56.6%	3.1%	2.1%	40.3%
Pipelines								
Enbridge Pipelines Inc.	46.7%	7.7%	0.0%	45.6%	47.0%	4.8%	0.0%	48.2%
Nova Gas Transmission Ltd.	55.8%	7.2%	0.0%	37.1%	61.7%	3.7%	0.0%	34.6%
Trans Québec & Maritimes Pipeline	60.0%	0.0%	0.0%	40.0%	59.9%	0.0%	0.0%	40.1%
TransCanada PipeLines Ltd.	51.5%	5.5%	1.0%	42.0%	47.7%	4.4%	0.9%	47.0%
Westcoast Energy Inc.	57.6%	0.4%	5.2%	36.9%	55.9%	2.9%	3.6%	37.6%
Median	55.8%	5.5%	0.0%	40.0%	55.9%	3.7%	0.0%	40.1%
Medians								
All Companies	55.8%	1.6%	0.0%	40.5%	55.9%	1.8%	0.0%	40.5%
All Electric & Gas Investor-Owned								
Companies Currently Rated by DBRS								
excl. NP	56.2%	1.5%	0.0%	40.0%	56.6%	1.8%	0.0%	40.3%

^{1/} Includes preferred securities classified as debt.

^{2/} Includes preferred securities classified as equity and non-controlling interests in subsidiary company

^{3/} Includes non-controlling interests in common shares of subsidiary companies.

^{4/} 2011 Common equity ratio excludes Accumulated Other Comprehensive Income.

^{5/} The average of the four quarters ending December for gas distributors was used to better measure the actual sources of funds over the year due to the seasonal pattern of use of short-term debt.

Notes:

FortisBC Energy (Vancouver Island) excluded as financial statements not publicly available.

Source: Reports to Shareholders

CAPITAL STRUCTURE RATIOS OF SAMPLE OF U.S. UTILITIES
(Four Quarters Ending December 2011)

	<u>Total Debt</u> ^{1/}	<u>Preferred Stock</u> ^{2/}	Common Stock <u>Equity</u> ^{3/}
	(1)	(2)	(3)
AGL Resources Inc.	56.6%	0.0%	43.4%
ALLETE Inc.	44.1%	0.0%	55.9%
Alliant Energy Corp.	47.3%	2.6%	50.1%
Atmos Energy Corp.	50.3%	0.0%	49.7%
Consolidated Edison	48.3%	1.0%	50.8%
Integrus Energy Group Inc.	43.9%	0.9%	55.2%
Northwest Natural Gas	53.0%	0.0%	47.0%
Piedmont Natural Gas ^{4/}	48.6%	0.0%	51.4%
Southern Company	53.9%	1.8%	44.3%
Vectren Corp.	54.8%	0.0%	45.2%
WGL Holdings Inc.	36.5%	1.4%	62.1%
Wisconsin Energy Corp.	51.6%	0.6%	47.8%
Xcel Energy Inc.	54.3%	0.4%	45.3%
Median	50.3%	0.4%	49.7%

^{1/} Includes preferred securities classified as debt.

^{2/} Includes preferred securities classified as equity and non-controlling interests in subsidiary company preferred shares.

^{3/} Includes non-controlling interests in common shares of subsidiary companies.

^{4/} Trailing four quarters ending October 31, 2011.

Source: Reports to Shareholders.

CREDIT METRICS OF CANADIAN UTILITIES WITH RATED DEBT

Company	EBIT Coverage (X) ^{1/}				EBITDA Coverage (X) ^{1/}				FFO To Debt (%) ^{1/}				Debt/EBITDA (%) ^{1/}			
	2009	2010	2011	3 Year Average	2009	2010	2011	3 Year Average	2009	2010	2011	3 Year Average	2009	2010	2011	3 Year Average
Electric Utilities																
AltaLink L.P.	1.80	2.20	2.40	2.13	3.10	3.80	3.80	3.57	12.70	13.70	12.90	13.10	7.40	6.40	6.90	6.90
CU Inc.	2.40	2.40	2.80	2.53	3.40	3.40	4.00	3.60	17.70	13.50	14.10	15.10	4.30	4.60	4.90	4.60
Enersource	2.20	2.20	2.30	2.23	4.00	4.10	3.70	3.93	18.40	19.40	17.80	18.53	4.70	3.60	4.70	4.33
ENMAX Corp.	2.30	1.90	1.90	2.03	3.60	3.50	3.50	3.53	13.60	13.70	14.80	14.03	4.80	4.90	5.20	4.97
ENTEGRUS Inc.	3.70	4.00	3.00	3.57	6.20	6.60	7.50	6.77	29.50	29.70	27.00	28.73	2.40	2.30	2.40	2.37
EPCOR Utilities Inc.	2.10	1.80	2.20	2.03	2.70	2.80	2.10	2.53	16.40	14.60	14.40	15.13	3.90	6.90	7.10	5.97
FortisAlberta Inc.	2.10	2.00	2.10	2.07	3.80	4.40	4.10	4.10	13.20	13.90	15.50	14.20	3.00	4.10	4.70	3.93
FortisBC Inc.	2.03	2.11	2.42	2.19	^{2/} 3.07	3.22	3.56	3.28	^{2/} 12.20	12.40	13.30	12.63	^{4/} 4.89	5.66	5.64	5.40
Guelph Hydro Electric Systems	3.50	3.80	2.50	3.27	5.90	5.40	3.90	5.07	22.70	16.30	12.90	17.30	3.00	4.10	4.70	3.93
Hamilton Utilities	3.30	3.10	3.30	3.23	6.00	5.90	5.90	5.93	29.60	27.00	27.10	27.90	2.10	2.80	2.50	2.47
Hydro One Inc.	2.10	2.30	2.70	2.37	3.30	3.50	3.90	3.57	11.40	12.20	11.70	11.77	5.40	5.20	5.10	5.23
Hydro Ottawa Holding Inc.	4.30	4.30	3.60	4.07	7.40	7.70	7.70	7.60	27.70	28.20	28.20	28.03	2.60	2.60	2.80	2.67
London Hydro	3.30	3.10	2.50	2.97	6.50	6.10	5.40	6.00	27.50	25.60	27.00	26.70	2.40	3.00	2.90	2.77
Maritime Electric	2.30	2.40	2.40	2.37	3.20	3.40	3.50	3.37	16.30	13.60	13.60	14.50	4.10	4.10	4.10	4.10
Newfoundland Power	2.59	2.76	2.88	2.74	^{2/} 3.78	3.95	4.07	3.93	^{2/} 15.00	18.60	18.10	17.23	^{4/} 3.63	3.32	3.23	3.39
Nova Scotia Power	2.40	1.90	1.80	2.03	4.00	3.50	3.20	3.57	13.70	14.50	13.50	13.90	4.50	5.50	5.90	5.30
Ontario Power Generation	3.20	2.50	2.10	2.60	5.50	4.40	3.90	4.60	9.60	10.10	10.30	10.00	3.40	4.60	5.90	4.63
Toronto Hydro	1.60	1.90	2.00	1.83	3.40	3.70	3.60	3.57	16.30	16.00	14.80	15.70	4.50	4.80	5.10	4.80
Veridian Corp.	3.59	3.49	2.34	3.14	^{2/} 5.71	5.46	5.58	5.58	^{2/} 33.50	29.00	20.40	27.63	^{4/} 4.16	3.46	3.10	3.57
Median	2.40	2.40	2.40	2.37	3.80	3.95	3.90	3.93	16.30	14.60	14.80	15.13	4.10	4.10	4.70	4.33
Gas Distributors																
Enbridge Gas Distribution	2.40	2.30	2.40	2.37	3.50	3.50	3.70	3.57	18.10	16.30	17.70	17.37	3.90	4.30	4.20	4.13
FortisBC Energy Inc.	1.96	2.17	2.17	2.10	^{2/} 2.72	3.04	3.00	2.92	^{2/} 10.30	10.90	11.80	11.00	^{4/} 5.30	5.41	5.85	5.52
Gaz Métro L.P.	2.40	2.40	2.50	2.43	3.80	3.60	3.80	3.73	21.90	20.20	21.30	21.13	4.20	4.70	4.40	4.43
Pacific Northern Gas ^{5/}	2.59	2.49	1.70	2.26	^{2/} 4.02	3.85	2.39	3.42	^{2/} 11.70	19.60	9.40	13.57	^{4/} 3.40	3.88	6.08	4.45
Union Gas Limited	2.40	2.60	2.70	2.57	3.50	3.80	4.00	3.77	14.80	16.50	15.50	15.60	3.80	4.20	4.10	4.03
Median	2.40	2.40	2.40	2.37	3.50	3.60	3.70	3.57	14.80	16.50	15.50	15.60	3.90	4.30	4.40	4.43
Pipelines																
Enbridge Pipelines Inc.	2.70	2.30	3.90	2.97	1.80	2.00	3.00	2.27	8.10	13.20	14.50	11.93	11.70	8.00	7.00	8.90
NOVA Gas Transmission Ltd.	1.94	2.18	na	2.06	^{2/} 3.00	3.32	na	3.16	14.20	14.30	13.50	14.00	^{4/} na	na	na	na
Trans Québec & Maritimes Pipeline	3.50	3.00	3.10	3.20	4.90	4.60	5.50	5.00	20.20	16.50	16.90	17.87	3.70	4.00	4.70	4.13
TransCanada PipeLines Ltd.	1.90	1.80	2.20	1.97	2.80	2.70	3.30	2.93	12.40	11.90	13.90	12.73	10.70	10.00	15.80	12.17
Westcoast Energy Inc.	2.40	2.60	2.80	2.60	3.60	3.80	4.10	3.83	13.30	15.80	14.00	14.37	3.90	4.30	4.40	4.20
Median	2.40	2.30	2.95	2.60	3.00	3.32	3.70	3.16	13.30	14.30	14.00	14.00	7.30	6.15	5.85	6.55
Medians																
All Companies	2.40	2.40	2.41	2.37	3.60	3.80	3.85	3.60	15.00	15.80	14.50	15.10	4.00	4.30	4.70	4.38
All Investor Owned Companies	2.40	2.30	2.41	2.37	3.50	3.50	3.75	3.57	13.70	14.30	14.00	14.20	4.15	4.45	4.80	4.44
All Electric & Gas Investor-Owned Companies Currently Rated by DBRS excl. NP																
	2.40	2.30	2.40	2.31	3.45	3.50	3.70	3.57	13.50	14.10	13.95	14.10	4.20	4.60	4.90	4.45

^{1/} Data from Fall 2012 S&P Credit Stats

EBIT Coverage: Earnings before Interest and Taxes divided by Interest

EBITDA Coverage: Earnings before Interest, Taxes, Depreciation and Amortization divided by Interest

Funds from Operations are equal to net income plus or minus non-cash items.

FFO/Debt: FFO divided by Total Debt

FFO/EBITDA: FFO divided by EBITDA as defined above.

^{2/} Data from DBRS.

^{3/} Calculated from DBRS data for EBITDA and Total Debt.

^{4/} DBRS Cash flow to debt.

^{5/} PNG 2011 data calculated from financial statements.

Source: Standard & Poor's Credit Stats except where noted

DBRS CREDIT METRICS OF INVESTOR-OWNED CANADIAN UTILITIES

	EBIT Coverage (X)						EBITDA Coverage (X)					
	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2007-11 Average</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2007-11 Average</u>
Newfoundland Power	2.20	2.73	2.59	2.76	2.88	2.63	3.34	3.93	3.78	3.95	4.07	3.81
AltaLink L.P.	1.78	1.84	1.94	2.31	2.51	2.08	3.44	3.60	3.79	3.99	4.02	3.77
CU Inc.	2.30	2.20	2.00	2.40	3.00	2.38	3.76	3.87	3.02	3.88	4.05	3.72
Enbridge Gas Distribution	2.62	2.55	2.87	2.62	2.69	2.67	4.06	3.92	4.51	4.41	4.65	4.31
FortisAlberta Inc.	2.05	2.02	2.17	2.09	2.06	2.08	4.17	4.02	4.12	4.28	4.11	4.14
FortisBC Inc.	2.04	2.05	2.04	2.10	2.40	2.13	3.04	3.09	3.06	3.21	3.52	3.18
FortisBC Energy Inc	1.99	1.92	1.96	2.17	2.17	2.04	2.72	2.62	2.72	3.04	3.00	2.82
Gaz Metro	2.52	2.52	2.43	2.37	2.41	2.45	4.16	4.18	4.21	3.97	4.08	4.12
Nova Scotia Power	2.83	2.67	2.69	2.04	1.67	2.38	4.30	4.22	4.42	3.72	3.23	3.98
Union Gas Limited	2.18	2.36	2.35	2.55	2.66	2.42	3.29	3.56	3.54	3.81	3.99	3.64
Median (Excluding NP)	2.18	2.20	2.17	2.31	2.41	2.38	3.76	3.87	3.79	3.88	4.02	3.77
	Cash Flow/Total Debt (%)											
	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2007-11 Average</u>						
Newfoundland Power	12.9	16.2	15.0	18.6	18.1	16.2						
AltaLink L.P.	12.6	13.3	14.8	14.8	13.2	13.7						
CU Inc.	17.9	18.5	13.2	18.3	17.7	17.1						
Enbridge Gas Distribution	16.8	17.1	21.7	19.5	19.4	18.9						
FortisAlberta Inc.	18.2	15.7	15.9	17.4	16.5	16.7						
FortisBC Inc.	11.4	11.4	12.2	12.4	13.3	12.1						
FortisBC Energy Inc	8.9	10.1	10.3	10.9	11.8	10.4						
Gaz Metro	29.9	21.5	22.3	18.4	24.0	23.2						
Nova Scotia Power	21.7	19.6	17.1	12.6	15.1	17.2						
Union Gas Limited	15.1	14.9	14.1	16.7	16.2	15.4						
Median (Excluding NP)	16.8	15.7	14.8	16.7	16.2	16.7						

Source: DBRS Reports

CREDIT METRICS OF SAMPLE OF U.S. UTILITIES

	EBIT Coverage (X)					EBITDA Coverage (X)				
	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>3 Year Average</u>		<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>3 Year Average</u>	
AGL Resources Inc.	4.10	4.40	3.60	4.03	^{1/}	5.50	5.80	4.90	5.40	^{1/}
ALLETE Inc.	3.30	3.60	3.50	3.47		4.90	4.80	4.82	4.84	
Alliant Energy Corp.	2.60	3.30	3.00	2.97	^{1/}	3.90	4.90	4.90	4.57	^{1/}
Atmos Energy Corp.	2.60	2.90	2.90	2.80		3.90	4.20	4.30	4.13	
Consolidated Edison	3.10	3.50	3.90	3.50	^{1/}	4.30	4.80	5.40	4.83	^{1/}
Integrus Energy Group Inc.	3.10	3.70	3.50	3.43	^{1/}	4.10	5.00	4.90	4.67	^{1/}
Northwest Natural Gas	3.80	3.80	3.60	3.73	^{1/}	5.10	5.10	5.10	5.10	^{1/}
Piedmont Natural Gas	4.90	4.90	2.90	4.23	^{1/}	6.20	5.30	4.40	5.30	^{1/}
Southern Company	3.20	3.60	4.00	3.60	^{1/}	4.50	4.90	5.60	5.00	^{1/}
Vectren Corp.	2.90	2.90	2.90	2.90	^{1/}	4.80	5.00	5.50	5.10	^{1/}
WGL Holdings Inc.	5.20	5.20	5.50	5.30		7.20	7.50	7.45	7.38	
Wisconsin Energy Corp.	2.20	2.80	3.90	2.97	^{1/}	3.50	3.80	4.80	4.03	^{1/}
Xcel Energy Inc.	2.70	2.90	3.04	2.88		4.00	4.20	4.40	4.20	
Median	3.10	3.60	3.50	3.47		4.50	4.90	4.90	4.84	
	FFO To Debt (%)					Debt/EBITDA (%)				
	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>3 Year Average</u>		<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>3 Year Average</u>	
AGL Resources Inc.	20.90	20.00	11.30	17.40	^{1/}	3.80	3.90	7.00	4.90	^{1/}
ALLETE Inc.	20.00	21.70	21.70	21.13		5.50	4.60	4.40	4.83	^{2/}
Alliant Energy Corp.	22.70	24.80	23.30	23.60	^{1/}	4.20	3.60	3.80	3.87	^{2/}
Atmos Energy Corp.	21.40	25.50	22.00	22.97		3.60	3.30	3.60	3.50	
Consolidated Edison	16.40	21.00	23.20	20.20	^{1/}	4.90	4.40	4.30	4.53	^{2/}
Integrus Energy Group Inc.	25.50	25.20	26.60	25.77	^{1/}	4.40	3.80	4.20	4.13	^{2/}
Northwest Natural Gas	17.40	21.90	22.40	20.57	^{1/}	3.20	3.90	3.90	3.67	^{2/}
Piedmont Natural Gas	24.80	26.20	26.40	25.80	^{1/}	3.40	3.10	4.40	3.63	^{2/}
Southern Company	18.10	20.10	23.00	20.40	^{1/}	4.60	4.30	4.10	4.33	^{2/}
Vectren Corp.	21.40	25.50	24.20	23.70	^{1/}	3.90	3.50	3.30	3.57	^{1/}
WGL Holdings Inc.	30.40	26.90	30.40	29.23		2.80	2.90	2.80	2.83	^{2/}
Wisconsin Energy Corp.	16.70	18.40	21.20	18.77	^{1/}	6.40	5.40	4.30	5.37	^{2/}
Xcel Energy Inc.	18.80	19.00	21.10	19.63		4.30	4.30	4.10	4.23	
Median	20.90	21.90	23.00	21.13		4.20	3.90	4.10	4.13	

^{1/} 2011 data from S&P Credit Stats.

^{2/} Data from S&P Credit Stats.

Source: Standard & Poor's Debt Rating Reports except where noted.

**HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)**

**Canada
(1947-2011)**

<u>Stock Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
11.8	7.1	4.7
<u>Stock Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
11.8	6.7	5.0

**United States
(1947-2011)**

<u>Stock Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
12.3	6.6	5.7
<u>Stock Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
12.3	5.9	6.4

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011* ; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook* .

HISTORIC EQUITY MARKET RISK PREMIUMS
(Arithmetic Averages)

Canada
(1924-2011)

<u>Stock Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
11.4	6.6	4.8
<u>Stock Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
11.4	6.0	5.4

United States
(1926-2011)

<u>Stock Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
11.8	6.1	5.6
<u>Stock Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
11.8	5.2	6.6

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011* ;
www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook* .

**FIVE-YEAR STANDARD DEVIATIONS OF MARKET RETURNS FOR 10 SECTOR INDICES OF S&P/TSX COMPOSITE
(Percentages)**

<u>Five Year Periods Ending:</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>Average</u>
S&P / TSX Composite	3.57	4.68	4.84	5.40	5.87	5.83	4.97	4.59	4.04	3.24	2.86	4.35	4.88	4.88	4.95	4.60
<u>10 Sector Indices</u>																
Consumer Discretionary	3.69	4.36	4.62	4.99	5.38	5.73	5.35	5.00	4.35	3.69	3.08	3.84	4.07	4.04	4.13	4.42
Consumer Staples	3.57	4.01	3.70	4.04	4.17	4.76	4.45	4.37	4.05	3.88	2.97	3.24	3.36	3.68	3.54	3.85
Energy	5.60	6.16	7.31	7.97	8.30	8.10	6.98	5.72	5.56	5.46	5.40	7.04	7.37	6.71	6.72	6.69
Financials	4.27	5.89	5.92	6.22	6.17	6.06	4.58	4.23	3.77	3.36	2.97	3.99	5.38	5.59	5.62	4.93
Health Care	6.62	7.73	8.19	9.38	9.00	9.39	8.93	8.68	6.98	6.57	5.45	4.92	5.38	5.89	7.47	7.37
Industrials	4.13	4.93	4.69	5.12	6.50	7.18	6.92	6.87	6.48	5.16	4.08	4.87	5.48	5.51	5.66	5.57
Information Technology	7.99	9.17	10.35	12.27	15.16	17.12	16.64	17.09	15.81	13.36	10.20	11.82	11.68	12.14	12.60	12.89
Materials	5.87	6.98	7.22	7.29	7.40	7.25	5.89	5.65	5.67	5.88	5.59	7.96	8.48	8.60	8.69	6.96
Telecommunication Services	3.66	5.82	7.37	7.87	8.46	8.71	7.54	5.74	4.97	4.64	4.18	5.08	5.07	4.93	4.59	5.91
Utilities	3.12	3.80	4.00	4.80	5.06	4.88	4.49	4.09	3.36	3.13	3.49	4.04	4.32	4.30	4.09	4.07
Mean	4.85	5.89	6.34	7.00	7.56	7.92	7.18	6.75	6.10	5.51	4.74	5.68	6.06	6.14	6.31	6.27
Median	4.20	5.85	6.57	6.76	6.95	7.21	6.41	5.68	5.27	4.90	4.13	4.90	5.38	5.55	5.64	5.69

Ratios of Standard Deviations

S&P/TSX Utilities Index as a Percent of:																
10 Sector Indices (Mean)	0.64	0.65	0.63	0.69	0.67	0.62	0.63	0.61	0.55	0.57	0.74	0.71	0.71	0.70	0.65	0.65
10 Sector Indices (Median)	0.74	0.65	0.61	0.71	0.73	0.68	0.70	0.72	0.64	0.64	0.85	0.82	0.80	0.77	0.73	0.72

Source: *TSX Review*

5-YEAR PRICE BETAS FOR S&P/TSX SECTOR INDICES

	<u>Consumer Discretionary</u> (1)	<u>Consumer Staples</u> (2)	<u>Energy</u> (3)	<u>Financials</u> (4)	<u>Health Care</u> (5)	<u>Industrials</u> (6)	<u>Information Technology</u> (7)	<u>Materials</u> (8)	<u>Telecommunication Services</u> (9)	<u>Utilities</u> (10)
1997	0.82	0.62	0.97	0.94	0.60	0.97	1.57	1.32	0.64	0.53
1998	0.80	0.60	0.85	1.12	1.01	0.93	1.41	1.12	0.92	0.55
1999	0.73	0.44	0.90	1.00	1.00	0.78	1.55	1.04	1.11	0.30
2000	0.69	0.23	0.66	0.78	1.09	0.72	1.78	0.74	0.92	0.14
2001	0.68	0.10	0.49	0.66	0.98	0.82	2.13	0.60	0.94	-0.03
2002	0.73	0.08	0.43	0.66	0.99	0.86	2.28	0.57	0.93	-0.06
2003	0.74	-0.08	0.26	0.38	0.85	0.91	2.74	0.43	0.83	-0.25
2004	0.80	-0.07	0.17	0.39	0.82	1.05	2.87	0.41	0.58	-0.13
2005	0.83	0.07	0.48	0.56	0.72	1.13	2.68	0.77	0.74	0.00
2006	0.86	0.37	1.03	0.68	0.85	1.06	2.07	1.32	0.52	0.25
2007	0.73	0.54	1.44	0.51	0.54	0.96	1.12	1.45	0.62	0.46
2008	0.59	0.32	1.43	0.61	0.48	0.81	1.43	1.30	0.55	0.49
2009	0.56	0.28	1.35	0.80	0.41	0.83	1.22	1.24	0.47	0.41
2010	0.55	0.33	1.24	0.85	0.39	0.87	1.37	1.22	0.46	0.42
2011	0.52	0.31	1.25	0.85	0.37	0.89	1.49	1.19	0.45	0.43

Source: *TSX Review*

**TSE 300 SUB-INDEX COMPOUND RETURNS AND BETAS
(1956-2003)**

	Sub-Index Compound Returns ^{1/}						Sub-Index Betas					
	<u>56-03</u>	<u>56-97</u>	<u>64-73</u>	<u>74-83</u>	<u>84-93</u>	<u>94-03</u>	<u>56-03</u>	<u>56-97</u>	<u>64-73</u>	<u>74-83</u>	<u>84-93</u>	<u>94-03</u>
Metals/Minerals	7.8	7.6	7.5	11.2	6.8	7.2	1.15	1.23	1.14	1.22	1.37	0.87
Gold/Precious Metals	9.5	10.4	16.2	16.0	11.0	-2.7	0.85	0.96	0.36	1.31	1.24	0.64
Oil and Gas	9.5	8.4	14.6	11.9	4.5	15.3	1.06	1.20	1.25	1.40	0.98	0.52
Paper/Forest Products	7.1	7.4	4.8	11.8	10.3	2.6	1.02	1.07	1.15	1.00	1.27	0.85
Consumer Products	11.3	11.9	10.2	13.8	11.2	9.6	0.83	0.86	0.84	0.90	0.89	0.73
Industrial Products	7.2	9.6	8.3	10.9	6.0	1.1	1.17	1.02	1.11	0.87	1.08	1.69
Real Estate ^{2/}	5.3	5.5	0.7	16.7	-2.3	1.3	1.00	1.18	1.21	1.28	1.06	0.46
Transportation/Environmental	10.1	11.4	12.7	18.4	3.0	8.8	0.94	1.04	0.94	1.08	1.22	0.62
Pipelines	11.7	12.1	5.2	13.8	13.7	13.1	0.68	0.85	0.80	0.92	0.76	0.02
Utilities	11.0	10.7	3.3	17.8	11.0	16.3	0.54	0.48	0.50	0.47	0.40	0.79
Communications/Media	13.5	15.0	19.1	15.3	12.9	7.5	0.77	0.77	0.96	0.69	0.95	0.80
Merchandising	10.1	10.7	10.6	12.2	8.7	7.2	0.78	0.86	0.93	0.84	0.83	0.46
Finance	12.4	12.8	12.0	11.7	11.6	17.9	0.83	0.85	0.95	0.71	0.93	0.77
Conglomerates	10.8	10.8	12.8	15.2	9.5	13.9	0.94	1.03	1.26	0.97	1.20	0.68
Adjusted R Square ^{3/}							47%	44%	1%	1%	11%	9%
Beta ^{4/}							-0.088	-0.082	-0.020	-0.008	-0.056	-0.053

^{1/} Annualized rate of return at which capital has compounded over time.

^{2/} Data only available starting July 1961

^{3/} Represents percentage of variation in sub-index returns explained by the sub-index betas.

^{4/} Represents relationship between sub-index returns and sub-index betas.

Source: *TSX Review*

**S&P/TSX COMPOSITE SECTOR COMPOUND RETURNS AND BETAS
(1988-2011)**

	Sector Compound Returns ^{1/}			Sector Betas		
	<u>88-11</u>	<u>88-97</u>	<u>02-11</u>	<u>88-11</u>	<u>88-97</u>	<u>02-11</u>
Consumer Discretionary	5.9	10.2	1.3	0.72	0.90	0.63
Consumer Staples	11.2	12.7	7.5	0.34	0.73	0.34
Energy	10.2	8.4	13.3	0.82	0.76	1.19
Financials	12.4	18.3	8.4	0.80	1.04	0.80
Health Care	6.4	15.5	-0.9	0.73	0.81	0.50
Industrials	6.3	8.3	4.7	0.94	1.13	0.92
Information Technology	2.2	21.8	-19.8	1.72	1.21	1.68
Materials	6.6	3.4	13.6	0.99	1.26	1.23
Telecommunication Services	13.0	15.4	4.4	0.66	0.58	0.46
Utilities	10.4	11.5	12.3	0.29	0.62	0.38
Adjusted R Square ^{2/}				52%	1%	18%
Beta ^{3/}				-0.063	-0.017	-0.094

^{1/} Data only available starting December 1987. Annualized rate of return at which capital has compounded over time.

^{2/} Represents percentage of variation in sector returns explained by the sector betas.

^{3/} Represents relationship between sector returns and sector betas.

Source: *TSX Review*

MONTHLY BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Monthly Price Betas
Five Year Period Ending:

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
Canadian Utilities Limited	0.46	0.54	0.48	0.55	0.63	0.62	0.54	0.38	0.27	0.19	0.05	0.03	0.20	0.32	0.58	0.19	0.06	0.06	0.03
Emera Inc.	na	na	na	0.52	0.40	0.55	0.41	0.27	0.20	0.15	-0.05	0.01	0.07	0.12	0.24	0.17	0.16	0.21	0.21
Enbridge Inc.	0.35	0.53	0.46	0.44	0.43	0.48	0.26	0.07	-0.10	-0.18	-0.37	-0.32	-0.19	0.22	0.54	0.30	0.30	0.32	0.30
Fortis Inc.	0.35	0.44	0.51	0.37	0.30	0.49	0.33	0.23	0.14	0.13	-0.06	0.01	0.21	0.48	0.65	0.21	0.20	0.16	0.14
TransCanada Corporation	0.40	0.57	0.56	0.52	0.36	0.55	0.21	0.15	-0.08	-0.09	-0.38	-0.16	-0.15	0.34	0.52	0.38	0.39	0.39	0.37
Mean	0.39	0.52	0.50	0.48	0.42	0.54	0.35	0.22	0.08	0.04	-0.16	-0.08	0.03	0.30	0.51	0.25	0.22	0.23	0.21
Median	0.38	0.54	0.50	0.52	0.40	0.55	0.33	0.23	0.14	0.13	-0.06	0.01	0.07	0.32	0.54	0.21	0.20	0.21	0.21
TSE Gas/Electric Index	0.42	0.48	0.52	0.52	0.46	0.55	0.38	0.21	0.17	0.14	NA	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.55	0.63	0.67	0.65	0.53	0.55	0.30	0.14	-0.03	-0.06	-0.25	-0.13	0.00	0.25	0.46	0.49	0.41	0.42	0.43

Adjusted Betas ^{1/}
Five Year Period Ending:

	<u>1993</u>	<u>1994</u>	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
Canadian Utilities Limited	0.64	0.69	0.65	0.70	0.75	0.75	0.69	0.58	0.51	0.46	0.37	0.35	0.47	0.54	0.72	0.45	0.37	0.37	0.35
Emera Inc.	NA	NA	NA	0.68	0.60	0.70	0.60	0.51	0.46	0.43	0.29	0.33	0.38	0.41	0.49	0.44	0.44	0.47	0.47
Enbridge Inc.	0.56	0.69	0.64	0.62	0.62	0.65	0.50	0.38	0.26	0.21	0.08	0.12	0.21	0.48	0.69	0.53	0.53	0.54	0.53
Fortis Inc.	0.57	0.62	0.67	0.58	0.53	0.66	0.55	0.48	0.42	0.41	0.29	0.34	0.47	0.65	0.77	0.47	0.46	0.44	0.42
TransCanada Corporation	0.60	0.71	0.71	0.68	0.57	0.70	0.47	0.43	0.28	0.27	0.08	0.22	0.23	0.56	0.68	0.58	0.59	0.59	0.58
Mean	0.59	0.68	0.67	0.65	0.61	0.69	0.56	0.48	0.39	0.36	0.22	0.27	0.35	0.53	0.67	0.50	0.48	0.48	0.47
Median	0.58	0.69	0.66	0.68	0.60	0.70	0.55	0.48	0.42	0.41	0.29	0.33	0.38	0.54	0.69	0.47	0.46	0.47	0.47
TSE Gas/Electric Index	0.61	0.65	0.68	0.68	0.64	0.70	0.59	0.47	0.44	0.42	NA	NA	NA	NA	NA	NA	NA	NA	NA
S&P/TSX Utilities	0.70	0.76	0.78	0.77	0.69	0.70	0.53	0.42	0.31	0.29	0.16	0.24	0.33	0.50	0.64	0.66	0.60	0.61	0.62

^{1/} Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

MONTHLY BETAS AND R²s FOR REGULATED CANADIAN UTILITIES

Beta Ending:	Canadian Utilities Limited		Emera Inc.		Enbridge Inc.		Fortis Inc.		TransCanada Corp.		S&P/TSX Utilities	
	Beta	R²	Beta	R²	Beta	R²	Beta	R²	Beta	R²	Beta	R²
2004	0.03	0.1%	0.01	0.0%	-0.32	7.0%	0.01	0.0%	-0.16	1.6%	-0.13	2.3%
2005	0.20	4.2%	0.07	0.5%	-0.19	2.8%	0.21	3.0%	-0.15	2.5%	0.00	0.0%
2006	0.32	4.9%	0.12	1.1%	0.22	4.2%	0.48	9.0%	0.34	10.0%	0.25	6.8%
2007	0.58	10.1%	0.24	3.2%	0.54	12.5%	0.65	11.8%	0.52	14.8%	0.46	14.3%
2008	0.19	1.9%	0.17	3.5%	0.30	7.8%	0.21	2.8%	0.38	16.4%	0.49	28.1%
2009	0.06	0.2%	0.16	3.3%	0.30	10.0%	0.20	2.9%	0.39	19.7%	0.41	21.5%
2010	0.06	0.2%	0.21	4.9%	0.32	11.2%	0.16	2.3%	0.39	19.1%	0.42	22.3%
2011	0.03	0.1%	0.21	5.4%	0.30	10.3%	0.14	2.4%	0.37	17.7%	0.43	27.1%

Source: Standard and Poor's *Research Insight*

WEEKLY BETAS FOR REGULATED CANADIAN UTILITIES

"Raw" Weekly Price Betas Five Year Period Ending:								
	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
Canadian Utilities Limited	0.14	0.25	0.32	0.50	0.42	0.40	0.39	0.38
Emera Inc.	0.19	0.03	0.11	0.20	0.32	0.35	0.40	0.43
Enbridge Inc.	0.01	0.21	0.47	0.64	0.58	0.52	0.49	0.49
Fortis Inc.	-0.06	0.21	0.26	0.38	0.50	0.46	0.50	0.53
TransCanada Corporation	-0.02	0.14	0.35	0.48	0.45	0.44	0.44	0.44
Mean	0.05	0.17	0.30	0.44	0.46	0.43	0.44	0.45
Median	0.01	0.21	0.32	0.48	0.45	0.44	0.44	0.44
S&P/TSX Utilities	0.04	0.16	0.31	0.42	0.53	0.53	0.55	0.56
Adjusted Betas ^{1/} Five Year Period Ending:								
	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
Canadian Utilities Limited	0.43	0.49	0.55	0.66	0.61	0.60	0.59	0.59
Emera Inc.	0.46	0.35	0.40	0.47	0.54	0.56	0.59	0.62
Enbridge Inc.	0.34	0.47	0.65	0.76	0.72	0.68	0.66	0.66
Fortis Inc.	0.29	0.47	0.50	0.59	0.67	0.64	0.66	0.68
TransCanada Corporation	0.31	0.42	0.57	0.65	0.63	0.62	0.63	0.62
Mean	0.37	0.44	0.53	0.63	0.64	0.62	0.63	0.63
Median	0.34	0.47	0.55	0.65	0.63	0.62	0.63	0.62
S&P/TSX Utilities	0.36	0.44	0.53	0.61	0.69	0.69	0.70	0.70

^{1/} Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

Source: Standard and Poor's *Research Insight* and *TSX Review*.

MONTHLY BETAS FOR THE SAMPLE OF U.S. UTILITIES

		"Raw" Monthly Price Betas																		
		Five Year Period Ending:																		
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.		0.33	0.40	0.39	0.45	0.62	0.60	0.45	0.29	0.29	0.24	0.21	0.30	0.37	0.36	0.50	0.31	0.40	0.46	0.45
ALLETE Inc.		0.59	0.60	0.58	0.41	0.41	0.15	0.09	0.03	-0.12	0.02	0.26	0.40	0.47	0.94	1.19	0.84	0.66	0.66	0.68
Alliant Energy Corp.		0.46	0.55	0.61	0.46	0.26	0.18	0.08	0.09	-0.02	0.10	0.24	0.34	0.40	0.80	0.72	0.59	0.57	0.53	0.53
Atmos Energy Corp.		0.32	0.32	0.50	0.76	0.08	0.16	0.19	0.00	-0.17	-0.02	-0.03	0.05	0.18	0.41	0.85	0.51	0.50	0.52	0.52
Consolidated Edison		0.57	0.55	0.53	0.59	0.66	0.32	0.18	0.09	-0.04	-0.16	-0.14	-0.05	0.00	0.14	0.39	0.25	0.29	0.31	0.26
Integrys Energy Group Inc.		0.34	0.31	0.38	0.25	0.29	0.16	0.10	0.01	-0.03	-0.01	0.06	0.15	0.17	0.37	0.56	0.48	0.91	0.89	0.87
Northwest Natural Gas		0.21	0.19	0.19	0.14	0.38	0.46	0.18	0.11	0.06	-0.11	-0.19	0.01	0.04	0.14	0.74	0.36	0.25	0.31	0.31
Piedmont Natural Gas		0.35	0.43	0.39	0.27	0.32	0.51	0.28	0.13	0.15	0.09	-0.03	0.13	0.28	0.35	0.58	0.06	0.19	0.23	0.31
Southern Company		0.51	0.47	0.39	0.53	0.42	0.15	0.11	-0.05	-0.36	-0.45	-0.47	-0.47	-0.49	-0.06	0.34	0.37	0.34	0.35	0.30
Vectren Corp.		0.22	0.23	0.23	0.64	0.57	0.34	0.16	0.24	0.20	0.23	0.35	0.46	0.32	0.49	0.56	0.25	0.37	0.42	0.41
WGL Holdings Inc.		0.29	0.36	0.39	0.75	0.62	0.47	0.28	0.25	0.19	0.14	0.11	0.22	0.21	0.27	0.69	0.24	0.17	0.25	0.28
Wisconsin Energy Corp.		0.47	0.53	0.52	0.58	0.43	0.31	0.14	0.11	-0.02	-0.10	-0.09	0.06	0.02	0.18	0.56	0.45	0.39	0.37	0.34
Xcel Energy Inc.		0.63	0.62	0.37	0.60	0.50	0.34	0.27	0.19	-0.01	0.41	0.56	0.70	0.80	1.48	0.60	0.56	0.46	0.44	0.39
Mean		0.41	0.43	0.42	0.50	0.43	0.32	0.19	0.11	0.01	0.03	0.06	0.17	0.21	0.45	0.64	0.41	0.42	0.44	0.43
Median		0.35	0.43	0.39	0.53	0.42	0.32	0.18	0.11	-0.02	0.02	0.06	0.15	0.21	0.36	0.58	0.37	0.39	0.42	0.39
		Adjusted Betas ^{1/}																		
		Five Year Period Ending:																		
		1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
AGL Resources Inc.		0.55	0.60	0.59	0.63	0.74	0.73	0.63	0.52	0.53	0.49	0.47	0.53	0.58	0.57	0.66	0.54	0.60	0.64	0.63
ALLETE Inc.		0.73	0.73	0.72	0.61	0.61	0.43	0.39	0.35	0.25	0.35	0.50	0.60	0.65	0.96	1.13	0.89	0.77	0.77	0.78
Alliant Energy Corp.		0.64	0.70	0.74	0.64	0.50	0.45	0.38	0.39	0.31	0.40	0.49	0.56	0.60	0.87	0.81	0.73	0.71	0.68	0.68
Atmos Energy Corp.		0.55	0.54	0.66	0.84	0.38	0.44	0.46	0.33	0.22	0.32	0.31	0.36	0.45	0.61	0.90	0.67	0.66	0.68	0.68
Consolidated Edison		0.71	0.70	0.68	0.73	0.77	0.54	0.45	0.39	0.30	0.22	0.24	0.30	0.33	0.43	0.59	0.50	0.53	0.54	0.51
Integrys Energy Group Inc.		0.56	0.54	0.59	0.50	0.52	0.44	0.40	0.34	0.31	0.32	0.37	0.43	0.45	0.58	0.71	0.65	0.94	0.93	0.91
Northwest Natural Gas		0.47	0.46	0.46	0.42	0.58	0.64	0.45	0.41	0.37	0.26	0.20	0.33	0.36	0.43	0.83	0.57	0.50	0.54	0.54
Piedmont Natural Gas		0.56	0.62	0.59	0.51	0.54	0.67	0.52	0.42	0.43	0.39	0.31	0.42	0.52	0.57	0.72	0.37	0.46	0.49	0.54
Southern Company		0.67	0.65	0.59	0.69	0.61	0.43	0.40	0.30	0.09	0.03	0.02	0.01	0.00	0.29	0.55	0.58	0.56	0.57	0.53
Vectren Corp.		0.48	0.48	0.48	0.76	0.71	0.56	0.43	0.49	0.46	0.48	0.56	0.64	0.55	0.66	0.71	0.49	0.58	0.61	0.61
WGL Holdings Inc.		0.52	0.57	0.59	0.83	0.75	0.64	0.52	0.50	0.46	0.42	0.41	0.47	0.47	0.51	0.79	0.49	0.44	0.50	0.52
Wisconsin Energy Corp.		0.64	0.68	0.68	0.72	0.62	0.54	0.42	0.40	0.32	0.26	0.27	0.37	0.34	0.45	0.71	0.63	0.59	0.58	0.56
Xcel Energy Inc.		0.75	0.75	0.58	0.73	0.67	0.56	0.51	0.46	0.32	0.60	0.70	0.80	0.87	1.32	0.73	0.70	0.64	0.62	0.59
Mean		0.60	0.62	0.61	0.66	0.62	0.54	0.46	0.41	0.34	0.35	0.37	0.45	0.47	0.63	0.76	0.60	0.61	0.63	0.62
Median		0.56	0.62	0.59	0.69	0.61	0.54	0.45	0.40	0.32	0.35	0.37	0.43	0.47	0.57	0.72	0.58	0.59	0.61	0.59

^{1/} Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

WEEKLY BETAS FOR THE SAMPLE OF U.S. UTILITIES

"Raw" Weekly Price Betas
Five Year Period Ending:

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
AGL Resources Inc.	0.44	0.56	0.63	0.74	0.70	0.70	0.68	0.68
ALLETE Inc.	0.55	0.62	0.65	0.90	0.64	0.63	0.65	0.66
Alliant Energy Corp.	0.38	0.52	0.72	0.70	0.72	0.74	0.78	0.75
Atmos Energy Corp.	0.50	0.50	0.59	0.70	0.66	0.64	0.67	0.65
Consolidated Edison	0.25	0.29	0.39	0.48	0.50	0.50	0.51	0.47
Integrus Energy Group Inc.	0.29	0.42	0.50	0.63	0.64	0.82	0.83	0.80
Northwest Natural Gas	0.34	0.46	0.54	0.83	0.54	0.51	0.54	0.53
Piedmont Natural Gas	0.42	0.52	0.61	0.77	0.61	0.60	0.61	0.63
Southern Company	0.05	0.19	0.29	0.42	0.42	0.41	0.41	0.38
Vectren Corp.	0.73	0.55	0.74	0.79	0.60	0.64	0.64	0.63
WGL Holdings Inc.	0.43	0.52	0.63	0.78	0.68	0.62	0.61	0.61
Wisconsin Energy Corp.	0.36	0.41	0.48	0.67	0.58	0.52	0.52	0.49
Xcel Energy Inc.	0.54	0.68	0.81	0.60	0.55	0.53	0.53	0.51
Mean	0.41	0.48	0.58	0.69	0.60	0.60	0.61	0.60
Median	0.42	0.52	0.61	0.70	0.61	0.62	0.61	0.63

Adjusted Betas ^{1/}
Five Year Period Ending:

	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
AGL Resources Inc.	0.62	0.71	0.75	0.82	0.80	0.80	0.79	0.79
ALLETE Inc.	0.70	0.75	0.77	0.93	0.76	0.75	0.77	0.77
Alliant Energy Corp.	0.58	0.68	0.81	0.80	0.81	0.83	0.85	0.83
Atmos Energy Corp.	0.66	0.66	0.72	0.80	0.78	0.76	0.78	0.77
Consolidated Edison	0.50	0.53	0.59	0.65	0.66	0.66	0.67	0.64
Integrus Energy Group Inc.	0.53	0.61	0.66	0.75	0.76	0.88	0.89	0.86
Northwest Natural Gas	0.56	0.64	0.69	0.89	0.69	0.67	0.69	0.68
Piedmont Natural Gas	0.61	0.68	0.74	0.85	0.74	0.73	0.74	0.75
Southern Company	0.37	0.46	0.52	0.61	0.61	0.60	0.60	0.59
Vectren Corp.	0.82	0.70	0.83	0.86	0.73	0.76	0.76	0.75
WGL Holdings Inc.	0.62	0.68	0.75	0.85	0.78	0.74	0.74	0.74
Wisconsin Energy Corp.	0.57	0.60	0.65	0.78	0.72	0.68	0.68	0.66
Xcel Energy Inc.	0.69	0.79	0.87	0.73	0.70	0.68	0.69	0.67
Mean	0.60	0.65	0.72	0.79	0.73	0.74	0.74	0.73
Median	0.61	0.68	0.74	0.80	0.74	0.74	0.74	0.75

^{1/} Adjusted beta = "raw" beta * 67% + market beta of 1.0 * 33%.

HISTORICAL VALUE LINE BETAS FOR THE SAMPLE OF U.S. UTILITIES

	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
AGL Resources Inc.	0.75	0.75	0.65	0.65	0.60	0.60	0.75	0.75	0.80	0.90	0.95	0.85	0.75	0.75	0.75	0.75
ALLETE Inc.	0.65	0.70	0.60	0.45	0.50	0.45	0.60	0.70	nmf	nmf	0.90	0.95	0.75	0.70	0.70	0.70
Alliant Energy Corp.	0.60	0.55	nmf	nmf	0.55	0.55	0.65	0.70	0.80	0.85	0.95	0.80	0.70	0.70	0.70	0.75
Atmos Energy Corp.	0.65	0.55	0.55	0.55	0.55	0.55	0.60	0.65	0.70	0.70	0.80	0.85	0.65	0.65	0.65	0.70
Consolidated Edison	0.75	0.75	0.60	0.50	0.55	0.50	0.55	0.60	0.60	0.60	0.75	0.75	0.65	0.65	0.65	0.60
Integrus Energy Group Inc.	0.65	0.65	0.65	0.50	0.55	0.55	0.60	0.70	0.75	0.75	0.85	0.80	0.70	0.95	0.90	0.90
Northwest Natural Gas	0.45	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.70	0.75	0.90	0.60	0.60	0.60	0.60
Piedmont Natural Gas	0.65	0.60	0.55	0.55	0.60	0.60	0.70	0.70	0.75	0.75	0.80	0.85	0.70	0.65	0.65	0.70
Southern Company ^{1/}	0.70	0.70	0.50	0.45	0.50	nmf	nmf	0.60	0.65	0.65	0.70	0.70	0.55	0.55	0.55	0.55
Vectren Corp.	0.70	0.75	0.75	0.55	nmf	nmf	0.70	0.75	0.75	0.80	0.90	0.90	0.85	0.75	0.70	0.70
WGL Holdings Inc.	0.70	0.75	0.60	0.60	0.60	0.60	0.65	0.70	0.75	0.80	0.85	0.85	0.75	0.65	0.65	0.65
Wisconsin Energy Corp.	0.70	0.70	0.65	0.45	0.50	0.50	0.55	0.60	0.70	0.70	0.80	0.85	0.65	0.65	0.65	0.65
Xcel Energy Inc.	na	na	na	na	nmf	nmf	0.60	0.70	0.80	0.80	0.90	1.05	0.75	0.65	0.65	0.65
Mean	0.66	0.67	0.61	0.53	0.55	0.55	0.63	0.67	0.73	0.75	0.84	0.85	0.70	0.68	0.68	0.68
Median	0.68	0.70	0.60	0.55	0.55	0.55	0.60	0.70	0.75	0.75	0.85	0.85	0.70	0.65	0.65	0.70

^{1/} 1996 number is from 1st quarter 1997.

Source: Value Line fourth quarter issues

INDIVIDUAL COMPANY RISK DATA FOR SAMPLE OF U.S. UTILITIES

	Value Line					"Raw" Weekly Betas ^{1/}	Adjusted Weekly Betas	Common Equity Ratio 2011Q4 Trailing Four Quarters	2007-2011 Average Earned Returns	S & P		Moody's
	<u>Safety</u>	Forecast Common Equity Ratio	Forecast Return On Average Common Equity	Dividend Payout Forecast	2012Q3					Business Risk Profile	Debt Rating	Debt Rating ^{2/}
		<u>2015-2017</u>	<u>2015-2017</u>	<u>2015-2017</u>	<u>Beta</u>							
AGL Resources Inc.	1	57.0%	11.6%	48.8%	0.75	0.63	0.76	43.4%	11.7%	Excellent	BBB+	Baa1
ALLETE Inc.	2	60.0%	10.4%	57.1%	0.70	0.59	0.73	55.9%	9.4%	Strong	BBB+	Baa1
Alliant Energy Corp.	2	50.5%	11.0%	62.9%	0.75	0.66	0.78	50.1%	10.2%	Excellent	BBB+	Baa1
Atmos Energy Corp.	2	51.0%	7.9%	54.8%	0.70	0.60	0.73	49.7%	9.2%	Excellent	BBB+	Baa1
Consolidated Edison	1	54.5%	9.2%	58.8%	0.60	0.41	0.60	50.8%	10.2%	Excellent	A-	Baa1
Integrus Energy Group Inc.	2	55.5%	9.9%	65.9%	0.90	0.72	0.81	55.2%	5.5%	Excellent	A-	Baa1
Northwest Natural Gas	1	63.0%	12.0%	57.1%	0.60	0.46	0.64	47.0%	11.1%	Excellent	A+	A3
Piedmont Natural Gas	2	50.0%	12.8%	73.0%	0.70	0.56	0.71	51.4%	12.9%	Excellent	A	A3
Southern Company	1	46.0%	12.6%	69.2%	0.55	0.31	0.54	44.3%	13.1%	Excellent	A	Baa1
Vectren Corp.	2	48.0%	12.2%	64.0%	0.75	0.57	0.71	45.2%	10.1%	Excellent	A-	A3
WGL Holdings Inc.	1	70.5%	10.0%	62.5%	0.65	0.53	0.69	62.1%	10.8%	Excellent	A+	A2
Wisconsin Energy Corp.	1	46.5%	13.9%	65.5%	0.65	0.44	0.62	47.8%	11.9%	Excellent	A-	A3
Xcel Energy Inc.	2	50.0%	10.6%	60.0%	0.65	0.44	0.63	45.3%	9.7%	Excellent	A-	Baa1
Mean	1.5	54.0%	11.1%	61.5%	0.69	0.53	0.69	49.8%	10.4%	Excellent	A-	Baa1
Median	2.0	51.0%	11.0%	62.5%	0.70	0.56	0.71	49.7%	10.2%	Excellent	A-	Baa1

^{1/} "Raw" betas calculated using weekly price changes against the NYSE Composite (260 weeks ending July 23, 2012).

^{2/} Rating for Vectren Corp. is for Vectren Utility Holdings. Rating for WGL Holdings is Washington Gas Light.

Source: www.Moodys.com; Standard and Poor's, *Issuer Ranking: U.S. Regulated Utilities, Strongest To Weakest* (April 20, 2012); Standard and Poor's Research Insight; Value Line (May, June, and August 2012); *Value Line Index*, August 3, 2012; and www.yahoo.com.

EQUITY RETURN AWARDS AND COMMON EQUITY RATIOS ADOPTED FOR THE SAMPLE OF U.S. UTILITIES
2009-2012

<u>Parent</u>	<u>Subsidiary</u>	<u>Service</u>	<u>State</u>	<u>Decision Date</u>	<u>Allowed ROE</u>	<u>Allowed Common Equity Ratio</u>
	(1)	(2)	(3)	(4)	(5)	(6)
AGL Resources Inc.	Atlanta Gas Light Co.	Gas	GA	2010/11/03	10.75	51.00
	Northern Illinois Gas Co.	Gas	IL	2009/03/25	10.17	51.07
	Pivotal Utility Holdings Inc.	Gas	NJ	2009/12/17	10.30	47.89
	Chattanooga Gas Co.	Gas	TN	2010/05/24	10.05	46.06
	Virginia Natural Gas Inc.	Gas	VA	2011/12/20	10.00	45.36
ALLETE Inc.	ALLETE (Minnesota Power)	Electric	MN	2010/11/02	10.38	54.29
Alliant Energy Corp.	Interstate P&L	Electric	IA	2010/12/15	10.44	44.24
	Interstate P&L	Electric	MN	2011/08/12	10.35	47.74
	Wisconsin P&L	Electric	WI	2012/06/15	10.40	49.31
	Wisconsin P&L	Gas	WI	2012/06/15	10.40	49.31
Atmos Energy Corp.	Atmos Energy Corp.	Gas	GA	2010/03/31	10.70	47.70
	Atmos Energy Corp.	Gas	TN	2009/03/09	10.30	48.12
	Atmos Energy Corp.	Gas	TX	2010/01/26	10.40	48.91
Consolidated Edison	Rockland Electric Co.	Electric	NJ	2010/05/12	10.30	49.85
	Consolidated Edison Co. of NY	Gas	NY	2010/09/16	9.60	48.00
	Consolidated Edison Co. of NY	Electric	NY	2010/03/25	10.15	48.00
	Orange & Rockland Utilities Inc.	Electric	NY	2012/06/14	9.40	48.00
	Orange & Rockland Utilities Inc.	Gas	NY	2009/10/16	10.40	48.00
Integrus Energy Group Inc.	North Shore Gas Co.	Gas	IL	2012/01/10	9.45	50.00
	Peoples Gas Light & Coke Co.	Gas	IL	2012/01/10	9.45	49.00
	Michigan Gas Utilities Corp.	Gas	MI	2009/12/16	10.75	47.27
	Upper Peninsula Power	Electric	MI	2011/12/20	10.20	54.90
	Minnesota Energy Resources	Gas	MN	2012/05/24	9.70	50.48
	Wisconsin Public Service	Electric	WI	2011/01/13	10.30	51.65
	Wisconsin Public Service	Gas	WI	2011/01/13	10.30	51.65
Piedmont Natural Gas Co.	Piedmont Natural Gas Co.	Gas	TN	2012/01/23	10.20	52.71
Southern Co.	Gulf Power Co.	Electric	FL	2012/02/27	10.25	46.26
	Georgia Power	Electric	GA	2010/12/29	11.15	51.67
Vectren Corp.	Southern Indiana G&E	Electric	IN	2011/04/27	10.40	49.93
WGL Holdings Inc.	Washington Gas Light Co.	Gas	MD	2011/11/14	9.60	57.88
	Washington Gas Light Co.	Gas	VA	2012/07/02	9.75	59.63
Wisconsin Energy Corp.	Wisconsin Electric Power	Electric	MI	2012/06/26	10.10	43.51
	Wisconsin Electric Power	Electric	WI	2009/12/18	10.40	53.02
	Wisconsin Electric Power	Gas	WI	2009/12/18	10.40	53.02
	Wisconsin Gas LLC	Gas	WI	2009/12/18	10.50	46.62
Xcel Energy Inc.	Public Service of CO	Electric	CO	2012/04/26	10.00	56.00
	Public Service of CO	Gas	CO	2011/09/01	10.10	56.00
	Northern States Power-MN	Electric	MN	2012/03/29	10.37	52.56
	Northern States Power-MN	Gas	MN	2010/12/06	10.09	52.46
	Northern States Power-MN	Electric	ND	2012/02/29	10.40	51.77
	Northern States Power-MN	Electric	SD	2012/06/19	9.25	53.04
	Southwestern Public Service	Electric	TX	2011/03/25	NA	NA ^{1/}
	Northern States Power-WI	Gas	WI	2011/12/22	10.40	52.59
	Northern States Power-WI	Electric	WI	2011/12/22	10.40	52.59

2009-2012:

Mean 10.20 50.44

Median 10.30 50.00

2011-2012:

Mean 10.05 51.33

Median 10.20 51.65

^{1/} A 10% ROE and 51% equity ratio are to be used, per the settlement, solely for purposes of any Transmission Cost Recovery Factor filings before the next PUC rate case and for AFUDC purposes only.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
CONSTANT GROWTH DCF MODEL
(Annual Averages of Monthly Data)

Year	Expected Dividend Yield ^{1/} (1)	Analysts' Forecast EPS Growth Forecast (2)	DCF Cost of Equity (3)	Long-Term Treasury Yield (4)	Equity Risk Premium (5)	Moody's Spread ^{2/} (6)
1998	5.1	4.3	9.4	5.5	3.9	1.5
1999	5.6	4.7	10.3	5.9	4.4	1.7
2000	6.0	5.4	11.4	5.9	5.6	2.4
2001	5.3	5.4	10.7	5.5	5.2	2.3
2002	5.2	5.9	11.0	5.4	5.6	1.9
2003	5.1	5.1	10.2	5.0	5.1	1.5
2004	4.6	4.5	9.1	5.1	4.1	1.0
2005	4.3	4.5	8.8	4.5	4.3	1.1
2006	4.5	4.8	9.2	4.9	4.3	1.2
2007	4.2	5.0	9.2	4.8	4.4	1.3
2008	4.8	5.3	10.1	4.2	5.9	2.3
2009	5.6	5.5	11.1	4.1	7.0	1.9
2010	4.9	5.1	10.0	4.2	5.9	1.2
2011	4.5	5.3	9.7	3.9	5.9	1.1
2012 (Through Q2)	4.3	5.0	9.3	3.0	6.3	1.3
Means for Long Treasury Yields:						
Below 4.0%	4.8	5.2	10.0	3.3	6.7	1.7
4.0-4.99%	4.7	5.0	9.7	4.6	5.2	1.4
Below 5.0%	4.7	5.1	9.8	4.3	5.5	1.5
5.0-5.99%	5.2	5.0	10.2	5.5	4.7	1.7
6.0% and above	6.1	4.9	11.0	6.2	4.8	1.9
Means:						
1998 - 2012Q2	4.9	5.1	10.0	4.9	5.2	1.6

^{1/} Dividend Yield adjusted for analysts' forecast growth (DY (1+g)).

^{2/} Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year Treasury yield.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
CONSTANT GROWTH DCF MODEL

Regression Analysis Results 1998-2012Q2

EQUATION 1:

$$\text{Equity Risk Premium} = 8.67 - 0.73 (30\text{-Year Treasury Yield})$$

t-statistics:

$$30\text{-Year Treasury Yield} = -8.76$$

$$R^2 = 31\%$$

Equity Risk Premium at Long-Term Government Bond Yield of 3.50% = **6.1%**

ROE at Long-Term Government Bond Yield of 3.50% = **9.6%**

EQUATION 2:

$$\text{Equity Risk Premium} = 7.40 - 0.84 (30\text{-Year Treasury Yield}) + 1.14 (\text{Spread})$$

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

$$30\text{-Year Treasury Yield} = -14.20$$

$$\text{Spread} = 13.26$$

$$R^2 = 66\%$$

Equity Risk Premium at Long-term Government Bond Yield of 3.50% and Spread of 1.55% = **6.2%**

ROE at Long-Term Government Bond Yield of 3.50% and Spread of 1.55% = **9.7%**

EQUATION 3:

$$\text{Equity Risk Premium} = 6.81 - 0.50 (\text{A-rated Utility Bond Yield})$$

t-statistics:

$$\text{A-rated Utility Bond Yield} = -9.29$$

$$R^2 = 33\%$$

Equity Risk Premium at A-rated Utility Bond Yield of 5.05% = **4.3%**

ROE at A-rated Utility Bond Yield of 5.05% = **9.3%**

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
THREE STAGE MODEL
(Annual Averages of Monthly Data)

<u>Year</u>	<u>Dividend Yield</u> (1)	<u>Implied Growth Rate</u> (2)	<u>DCF Cost of Equity</u> ^{1/} (3)	<u>Long-Term Treasury Yield</u> (4)	<u>Equity Risk Premium</u> (5)	<u>Moody's Spread</u> ^{2/} (6)
1998	4.9	4.8	9.7	5.5	4.2	1.5
1999	5.3	4.9	10.2	5.9	4.3	1.7
2000	5.7	5.5	11.2	5.9	5.4	2.4
2001	5.0	5.7	10.7	5.5	5.3	2.3
2002	4.9	5.8	10.7	5.4	5.3	1.9
2003	4.8	5.7	10.5	5.0	5.4	1.5
2004	4.4	5.5	9.9	5.1	4.9	1.0
2005	4.1	5.4	9.5	4.5	5.0	1.1
2006	4.3	5.5	9.7	4.9	4.9	1.2
2007	4.0	5.3	9.3	4.8	4.5	1.3
2008	4.5	5.3	9.9	4.2	5.6	2.3
2009	5.3	5.5	10.8	4.1	6.7	1.9
2010	4.7	5.2	9.9	4.2	5.7	1.2
2011	4.2	5.2	9.5	3.9	5.6	1.1
2012 (Through Q2)	4.1	5.0	9.1	3.0	6.2	1.3
Means for Long Treasury Yields:						
Below 4.0%	4.5	5.2	9.8	3.3	6.5	1.7
4.0-4.99%	4.5	5.4	9.9	4.6	5.3	1.4
Below 5.0%	4.5	5.4	9.8	4.3	5.5	1.5
5.0-5.99%	4.9	5.4	10.3	5.5	4.8	1.7
6.0% and above	5.8	5.0	10.8	6.2	4.6	1.9
Means:						
1998 - 2012Q2	4.7	5.4	10.1	4.9	5.2	1.6

^{1/} Internal Rate of Return: Stage 1 growth rate, analysts' forecast EPS growth, applies for first 5 years; Stage 2 growth rate, average of Stage 1 and 3 growth rates, applies for years 6-10; Stage 3 growth, equal to the forecast nominal GDP growth rate, applies thereafter.

^{2/} Moody's Spread is the yield on Moody's long-term A rated Utility Index minus the 30-year Treasury yield.

Source: www.federalreserve.gov; I/B/E/S; www.Moodys.com; Standard & Poor's *Research Insight*; www.reuters.com; and www.ustreas.gov.

DCF-BASED EQUITY RISK PREMIUM STUDY FOR SAMPLE OF U.S. UTILITIES
THREE STAGE MODEL
Regression Analysis Results 1998-2012Q2

EQUATION 1:

$$\text{Equity Risk Premium} = 8.33 - 0.64 (\text{30-Year Treasury Yield})$$

t-statistics:

$$30\text{-Year Treasury Yield} = -11.32$$

$$R^2 = 43\%$$

Equity Risk Premium at Long-Term Government Bond Yield of 3.50% = 6.1%

ROE at Long-Term Government Bond Yield of 3.50% = 9.6%

EQUATION 2:

$$\text{Equity Risk Premium} = 7.54 - 0.71 (\text{30-Year Treasury Yield}) + 0.70 (\text{Spread})$$

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

$$30\text{-Year Treasury Yield} = -16.18$$

$$\text{Spread} = 11.03$$

$$R^2 = 67\%$$

Equity Risk Premium at Long-term Government Bond Yield of 3.50% and Spread of 1.55% = 6.1%

ROE at Long-Term Government Bond Yield of 3.50% and Spread of 1.55% = 9.6%

EQUATION 3:

$$\text{Equity Risk Premium} = 7.29 - 0.57 (\text{A-rated Utility Bond Yield})$$

t-statistics:

$$\text{A-rated Utility Bond Yield} = -15.85$$

$$R^2 = 59\%$$

Equity Risk Premium at A-rated Utility Bond Yield of 5.05% = 4.4%

ROE at A-rated Utility Bond Yield of 5.05% = 9.5%

Note: t-statistics measure the statistical significance of an independent variable in explaining the dependent variable. The higher the t-value, the greater the confidence in the coefficient as a predictor. R^2 is the proportion of the variability in the dependent variable that is explained by the independent variable(s).

APPROVED U.S. ELECTRIC AND GAS UTILITY ROES, BOND YIELDS AND SPREADS

	<u>Approved Electric and Gas ROEs</u>	<u>Moody's A-Rated Utility Bond Yield</u>	<u>30-Year Treasury Yield</u>	<u>A-Rated Utility/ Treasury Yield Spread</u>		<u>Approved Electric and Gas ROEs</u>	<u>Moody's A-Rated Utility Bond Yield</u>	<u>30-Year Treasury Yield</u>	<u>A-Rated Utility/ Treasury Yield Spread</u>
	(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)
1997 Q3		7.49	6.44	1.05	2005 Q1	10.54	5.72	4.70	1.02
1997 Q4		7.25	6.04	1.21	2005 Q2	10.25	5.43	4.36	1.07
1998 Q1	11.31	7.11	5.89	1.21	2005 Q3	10.63	5.49	4.39	1.10
1998 Q2	11.58	7.12	5.79	1.32	2005 Q4	10.55	5.82	4.63	1.18
1998 Q3	11.57	6.99	5.33	1.65	2006 Q1	10.55	5.92	4.70	1.22
1998 Q4	11.75	6.97	5.11	1.86	2006 Q2	10.64	6.41	5.19	1.22
1999 Q1	10.68	7.11	5.43	1.68	2006 Q3	10.18	6.09	4.91	1.18
1999 Q2	10.89	7.48	5.83	1.64	2006 Q4	10.31	5.82	4.70	1.13
1999 Q3	10.63	7.85	6.08	1.77	2007 Q1	10.36	5.92	4.82	1.10
1999 Q4	10.76	8.05	6.31	1.74	2007 Q2	10.23	6.08	4.98	1.10
2000 Q1	11.00	8.29	6.16	2.13	2007 Q3	10.03	6.19	4.86	1.33
2000 Q2	11.09	8.45	5.96	2.49	2007 Q4	10.42	6.05	4.53	1.52
2000 Q3	11.43	8.20	5.78	2.42	2008 Q1	10.42	6.16	4.35	1.81
2000 Q4	12.25	8.03	5.62	2.41	2008 Q2	10.46	6.30	4.58	1.72
2001 Q1	11.23	7.74	5.45	2.29	2008 Q3	10.48	6.58	4.44	2.14
2001 Q2	10.84	7.93	5.77	2.16	2008 Q4	10.34	7.13	3.50	3.63
2001 Q3	10.78	7.64	5.44	2.20	2009 Q1	10.27	6.44	3.62	2.82
2001 Q4	11.29	7.61	5.21	2.39	2009 Q2	10.35	6.35	4.24	2.11
2002 Q1	10.80	7.63	5.66	1.98	2009 Q3	10.23	5.54	4.17	1.37
2002 Q2	11.50	7.48	5.72	1.76	2009 Q4	10.41	5.65	4.35	1.30
2002 Q3	11.25	7.14	5.13	2.01	2010 Q1	10.51	5.80	4.59	1.20
2002 Q4	10.94	7.12	5.11	2.01	2010 Q2	10.04	5.46	4.22	1.24
2003 Q1	11.43	6.84	4.93	1.91	2010 Q3	10.17	4.96	3.73	1.23
2003 Q2	11.26	6.37	4.71	1.67	2010 Q4	10.21	5.31	4.15	1.16
2003 Q3	10.28	6.61	5.28	1.33	2011 Q1	10.26	5.56	4.53	1.03
2003 Q4	10.93	6.34	5.22	1.13	2011 Q2	10.04	5.37	4.33	1.04
2004 Q1	11.06	6.06	4.96	1.09	2011 Q3	9.92	4.74	3.54	1.20
2004 Q2	10.47	6.45	5.39	1.05	2011 Q4	10.22	4.35	3.04	1.31
2004 Q3	10.36	6.11	5.08	1.03	2012 Q1 ^{1/}	10.02	4.35	3.12	1.23
2004 Q4	10.80	5.95	4.93	1.01	2012 Q2	9.89	4.17	2.85	1.32

^{1/} The first quarter 2012 average awarded ROE reported by RRA excluding ROEs granted for regulated generation investments.

**APPROVED ROES FOR U.S. ELECTRIC AND GAS UTILITIES
(ANNUAL AVERAGES OF MONTHLY DATA)**

Regression Analysis Results 1998-2012Q2

EQUATION 1:

$$\text{Equity Risk Premium} = 8.08 - 0.48 (\text{6 Months Lagged 30-Year Treasury Yield})$$

t-statistics:

$$\text{6 Months Lagged 30-Year Treasury Yield} = -7.92$$

$$R^2 = 53\%$$

$$\begin{aligned} \text{Equity Risk Premium at Long-Term} & \\ \text{Government Bond Yield of 3.50\%} & = 6.4\% \end{aligned}$$

$$\begin{aligned} \text{ROE at Long-Term Government Bond Yield} & = 9.9\% \\ \text{of 3.50\%} & \end{aligned}$$

EQUATION 2:

$$\text{Equity Risk Premium} = 7.73 - 0.49 (\text{6 Months Lagged 30-Year Treasury Yield}) + 0.26 (\text{Spread})$$

Where Spread = Spread between A-rated Utility Bond Yields and 30-year Treasury Yields

t-statistics:

$$\text{6 Months Lagged 30-Year Treasury Yield} = -8.91$$

$$\text{Spread} = 3.50$$

$$R^2 = 62\%$$

$$\begin{aligned} \text{Equity Risk Premium at Long-term} & \\ \text{Government Bond Yield of 3.50\% and} & = 6.4\% \\ \text{Spread of 1.55\%} & \end{aligned}$$

$$\begin{aligned} \text{ROE at Long-Term Government Bond Yield} & \\ \text{of 3.50\% and Spread of 1.55\%} & = 9.9\% \end{aligned}$$

EQUATION 3:

$$\text{Equity Risk Premium} = 7.92 - 0.58 (\text{6 Months Lagged Moody's A-Rated})$$

t-statistics:

$$\text{6 Months Lagged Moody's A-Rated} = -12.92$$

$$R^2 = 75\%$$

$$\begin{aligned} \text{Equity Risk Premium at A-rated Utility Bond} & \\ \text{Yield of 5.05\%} & = 5.0\% \end{aligned}$$

$$\begin{aligned} \text{ROE at A-rated Utility Bond Yield of 5.05\%} & = 10.0\% \end{aligned}$$

**HISTORIC UTILITY EQUITY RISK PREMIUMS
(Arithmetic Averages)**

**Canada
(1956-2011)**

<u>Utilities Index Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
12.1	7.9	4.2
<u>Utilities Index Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
12.1	7.3	4.8

**United States
(1947-2011)**

<u>S&P Moody's Electric Index Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
11.0	6.6	4.4
<u>S&P Moody's Electric Index Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
11.0	5.9	5.1
<u>S&P / Moody's Gas Distribution Index Return</u>	<u>Bond Total Return</u>	<u>Risk Premium</u>
11.9	6.6	5.3
<u>S&P / Moody's Gas Distribution Index Return</u>	<u>Bond Income Return</u>	<u>Risk Premium</u>
11.9	5.9	6.0

Notes:

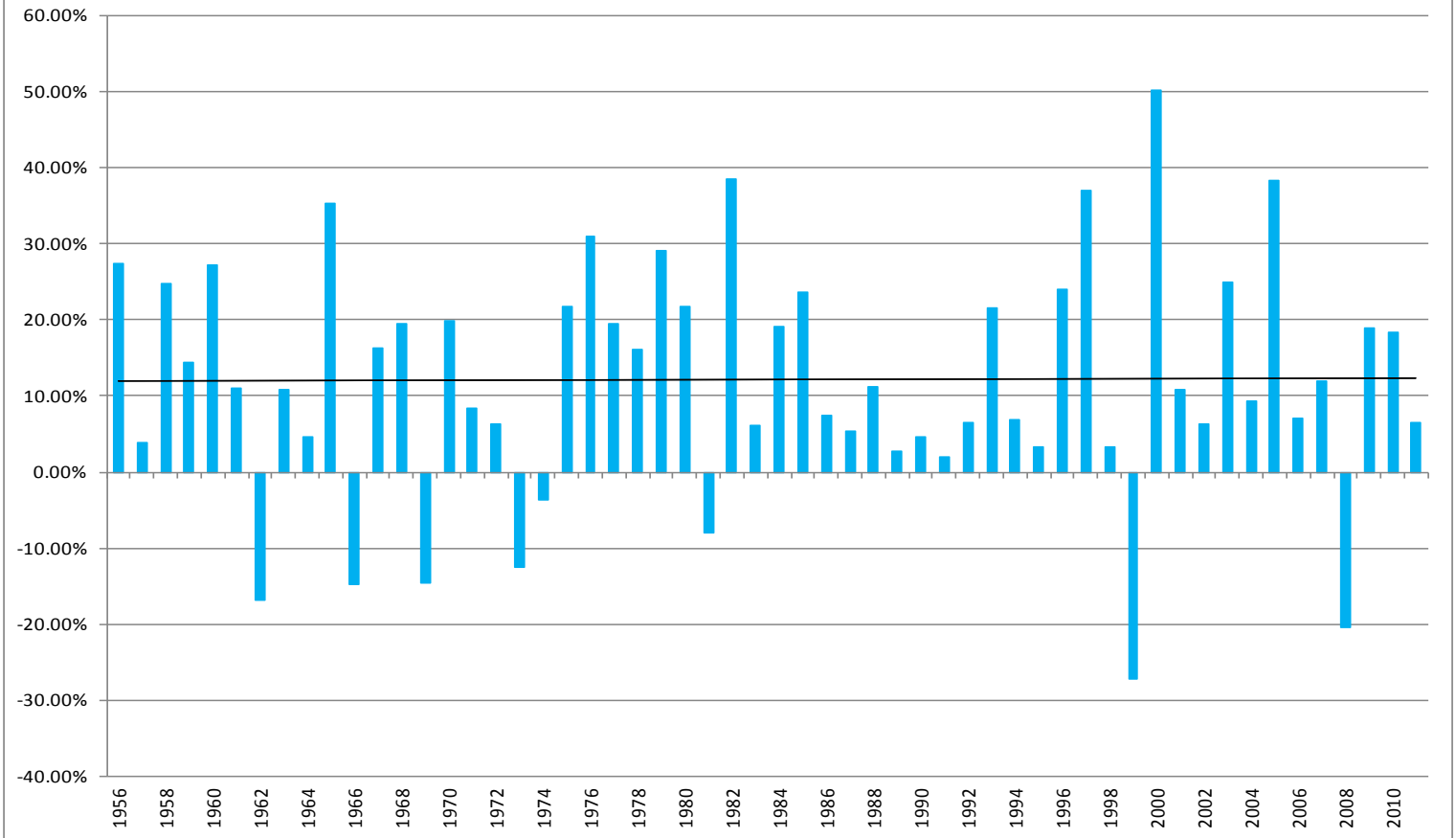
The Canadian Utilities Index is based on the Gas/Electric Index of the TSE 300 (from 1956 to 1987) and on the S&P/TSX Utilities Index from 1988-2011.

The S&P/Moody's Electric Index reflects S&P's Electric Index from 1947 to 1998 and Moody's Electric Index from 1999 to 2001. The 2002 to 2011 data were estimated using simple average of the prices and dividends for the utilities, and their successors, included in Moody's Electric Index as of the end of 2001.

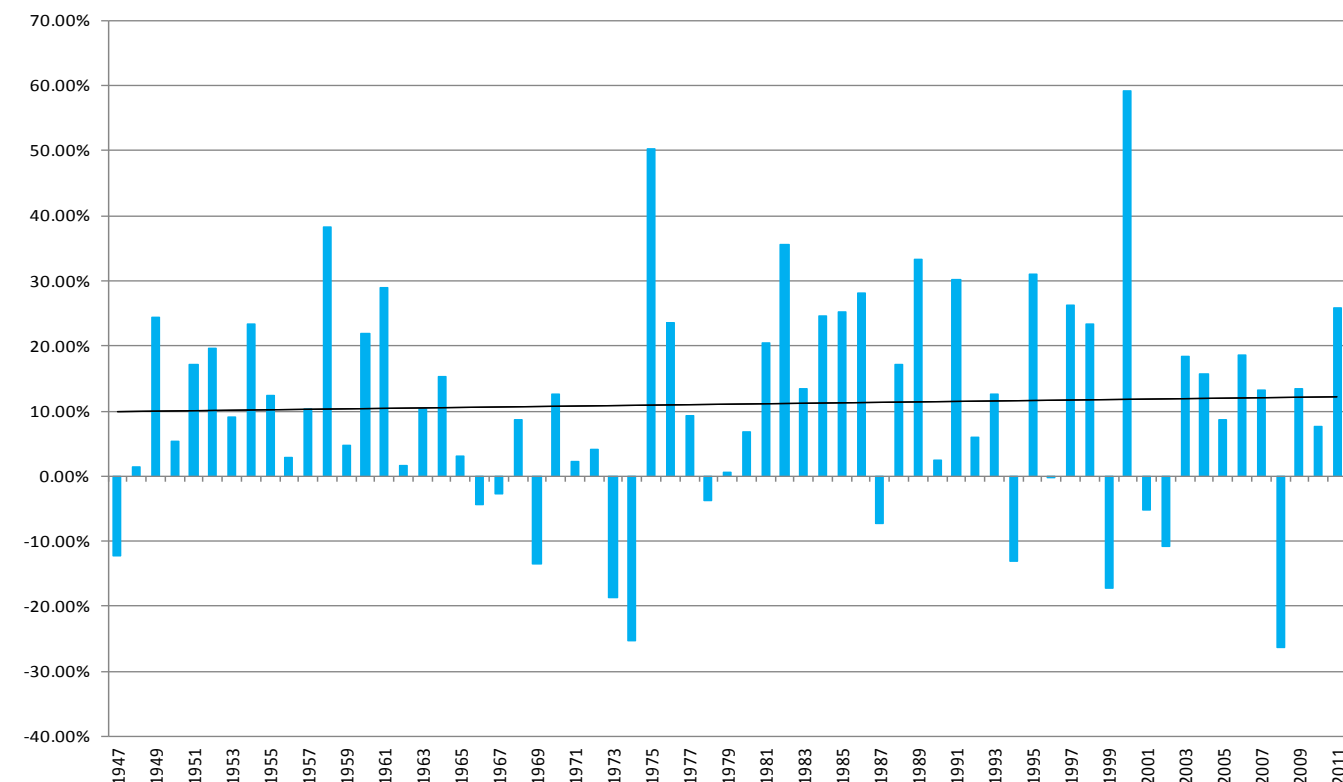
The S&P/Moody's Gas Distribution Index reflects S&P's Natural Gas Distributors Index from 1947 to 1984, when S&P eliminated its gas distribution index. The 1985-2001 data are for Moody's Gas index. The index was terminated in July 2002. The 2002-2011 returns were estimated using simple averages of the prices and dividends for the utilities, and their successors, that were included in Moody's Gas Index as of the end of 2001.

Source: www.bankofcanada.ca; Canadian Institute of Actuaries, *Report on Canadian Economic Statistics 1924-2011*; www.federalreserve.gov; Ibbotson Associates, *Stocks, Bonds, Bills and Inflation: 2012 Yearbook*; www.standardandpoors.com; and *TSX Review*.

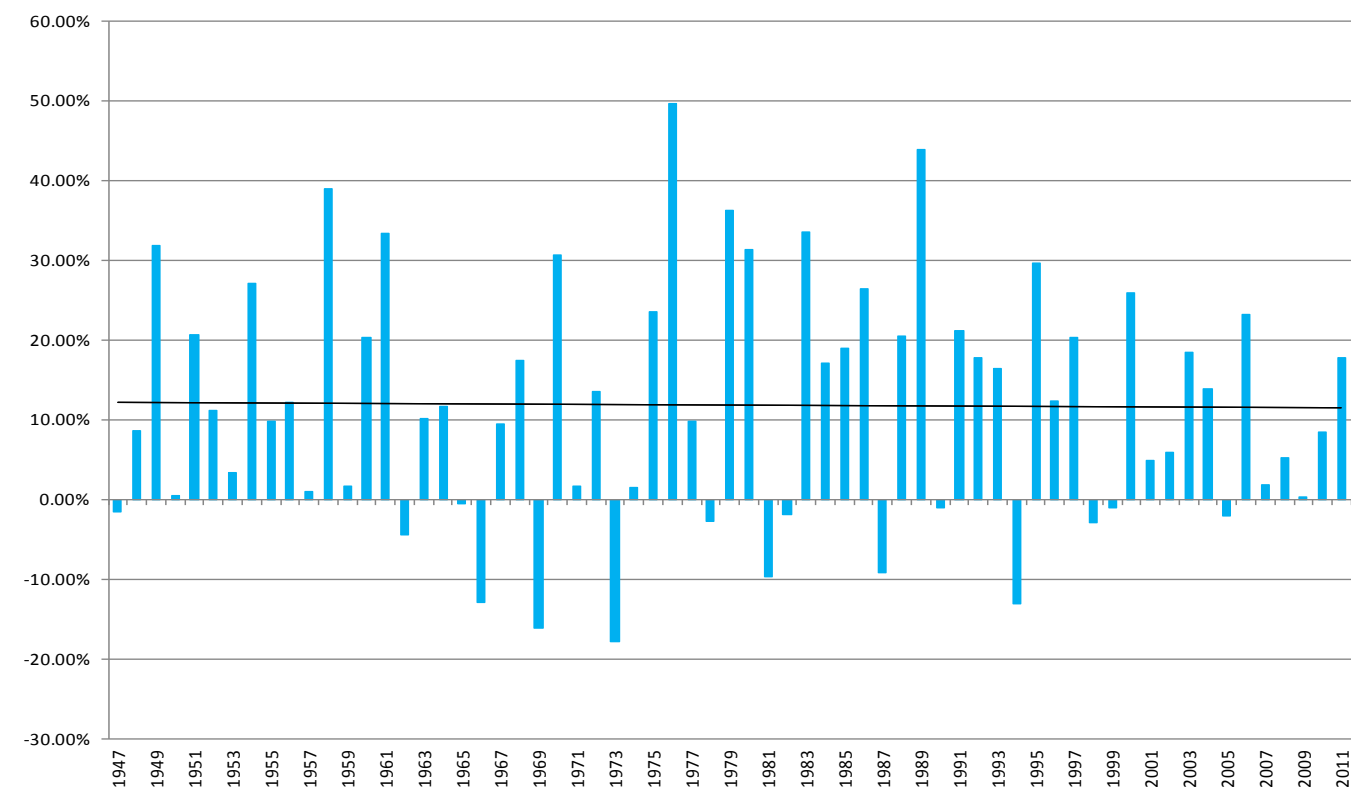
S&P/TSX Utilities Returns 1956-2011



S&P/Moody's Electric Returns 1947-2011



S&P/Moody's Gas Distributors Returns 1947-2011



**DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)**

	Annualized Last Paid Dividend	Average Daily Close Prices 5/1/12-7/31/2012	Expected Dividend Yield ^{1/}	Analyst Forecast Long-Term Growth Rates				Average of All EPS Estimates	DCF Cost of Equity ^{2/}
				Bloomberg	Reuters	Value Line	Zacks		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources Inc.	1.84	38.49	5.0	4.0	5.0	5.5	4.3	4.7	9.7
ALLETE Inc.	1.84	40.63	4.8	6.0	6.5	7.5	5.0	6.3	11.1
Alliant Energy Corp.	1.80	45.13	4.2	5.0	5.9	6.0	6.2	5.8	10.0
Atmos Energy Corp.	1.38	34.27	4.2	6.0	5.4	4.0	5.0	5.1	9.3
Consolidated Edison	2.42	61.47	4.1	3.5	3.3	4.0	3.5	3.6	7.6
Integrus Energy Group Inc.	2.72	56.16	5.1	4.3	7.2	7.0	4.7	5.8	10.9
Northwest Natural Gas	1.78	47.04	3.9	3.8	4.2	4.0	4.1	4.0	7.9
Piedmont Natural Gas	1.20	31.19	4.0	4.0	5.2	2.5	4.7	4.1	8.1
Southern Company	1.96	46.62	4.4	5.7	5.4	5.0	5.1	5.3	9.7
Vectren Corp.	1.40	29.43	5.0	5.6	5.5	6.5	4.5	5.5	10.5
WGL Holdings Inc.	1.60	39.70	4.2	5.5	4.8	3.0	4.9	4.6	8.8
Wisconsin Energy Corp.	1.20	38.73	3.3	5.0	6.9	6.5	5.5	6.0	9.2
Xcel Energy Inc.	1.08	28.20	4.0	5.5	4.9	6.0	4.9	5.3	9.4
Mean	1.71	41.31	4.3	4.9	5.4	5.2	4.8	5.1	9.4
Median	1.78	39.70	4.2	5.0	5.4	5.5	4.9	5.3	9.4

^{1/} Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))

^{2/} Expected Dividend Yield (Col (3)) + Average of All EPS Estimates (Col (8))

Source: Bloomberg, www.reuters.com, *Value Line* (May, June, and August 2012), www.yahoo.com, and www.zacks.com.

**DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(SUSTAINABLE GROWTH)**

	Annualized Last Paid Dividend	Average Daily Close Prices 5/1/12-7/31/2012	Expected Dividend Yield ^{1/}	Forecast Return on Common Equity	Forecast Earnings Retention Rate	BR Growth ^{2/} (2012Q2)	SV Growth ^{3/} (2012Q2)	Sustainable Growth ^{4/} (2012Q2)	DCF Cost of Equity ^{5/}
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
AGL Resources Inc.	1.84	38.49	5.1	11.6	51.2	5.9	0.28	6.2	11.3
ALLETE Inc.	1.84	40.63	4.7	10.4	42.9	4.4	0.29	4.7	9.5
Alliant Energy Corp.	1.80	45.13	4.2	11.0	37.1	4.1	0.25	4.3	8.5
Atmos Energy Corp.	1.38	34.27	4.2	7.9	45.2	3.6	0.03	3.6	7.8
Consolidated Edison	2.42	61.47	4.1	9.2	41.2	3.8	0.00	3.8	7.9
Integrus Energy Group Inc.	2.72	56.16	5.0	9.9	34.1	3.4	0.00	3.4	8.4
Northwest Natural Gas	1.78	47.04	4.0	12.0	42.9	5.1	1.47	6.6	10.7
Piedmont Natural Gas	1.20	31.19	4.0	12.8	27.0	3.5	-0.71	2.8	6.7
Southern Company	1.96	46.62	4.4	12.6	30.8	3.9	0.70	4.6	9.0
Vectren Corp.	1.40	29.43	5.0	12.2	36.0	4.4	0.64	5.0	10.0
WGL Holdings Inc.	1.60	39.70	4.2	10.0	37.5	3.7	0.10	3.8	8.0
Wisconsin Energy Corp.	1.20	38.73	3.2	13.9	34.5	4.8	-0.33	4.5	7.7
Xcel Energy Inc.	1.08	28.20	4.0	10.6	40.0	4.2	0.32	4.5	8.5
Mean	1.71	41.31	4.3	11.08	38.50	4.22	0.23	4.5	8.8
Median	1.78	39.70	4.2	11.04	37.50	4.10	0.25	4.5	8.5

^{1/} Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (8))

^{2/} BR Growth = Col (4) * (Col (5) / 100)

^{3/} SV Growth = Percent expected growth in number of shares of stock * Percent of funds from new equity financing that accrues to existing shareholders [1- B/M].

^{4/} Col (6) + Col (7)

^{5/} Expected Dividend Yield Col (3) + Sustainable Growth Col (8)

Source: *Value Line* (May, June, and August 2012) and www.yahoo.com.

**DCF COSTS OF EQUITY FOR SAMPLE OF U.S. UTILITIES
(THREE-STAGE MODEL)**

	Annualized Last Paid Dividend	Average Daily Close Prices 5/1/12-7/31/2012	Growth Rates			DCF Cost of Equity ^{2/}
			Stage 1: Average of All EPS Forecasts	Stage 2: Average of Stage 1 & 3	Stage 3: GDP Growth ^{1/}	
	(1)	(2)	(3)	(4)	(5)	(6)
AGL Resources Inc.	1.84	38.49	4.7	4.8	4.9	9.8
ALLETE Inc.	1.84	40.63	6.3	5.6	4.9	10.0
Alliant Energy Corp.	1.80	45.13	5.8	5.3	4.9	9.2
Atmos Energy Corp.	1.38	34.27	5.1	5.0	4.9	9.1
Consolidated Edison	2.42	61.47	3.6	4.2	4.9	8.6
Integrus Energy Group Inc.	2.72	56.16	5.8	5.4	4.9	10.2
Northwest Natural Gas	1.78	47.04	4.0	4.5	4.9	8.5
Piedmont Natural Gas	1.20	31.19	4.1	4.5	4.9	8.6
Southern Company	1.96	46.62	5.3	5.1	4.9	9.3
Vectren Corp.	1.40	29.43	5.5	5.2	4.9	10.0
WGL Holdings Inc.	1.60	39.70	4.6	4.7	4.9	8.9
Wisconsin Energy Corp.	1.20	38.73	6.0	5.4	4.9	8.2
Xcel Energy Inc.	1.08	28.20	5.3	5.1	4.9	8.9
Mean	1.71	41.31	5.1	5.0	4.9	9.2
Median	1.78	39.70	5.3	5.1	4.9	9.1

^{1/} Forecast nominal rate of GDP growth, 2013-23

^{2/} Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Bloomberg, Blue Chip *Financial Forecast* (June 2012), www.reuters.com, *Value Line* (May, June, and August 2012), www.yahoo.com, and www.zacks.com.

**DCF COST OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(BASED ON ANALYSTS' EARNINGS GROWTH FORECASTS)**

	<u>Annualized Last Paid Dividend</u>	<u>Average Daily Close Prices 5/1/12-7/31/2012</u>	<u>Expected Dividend Yield ^{1/}</u>	<u>Reuters Long- Term EPS Forecasts</u>	<u>DCF Cost of Equity ^{2/}</u>
	(1)	(2)	(3)	(4)	(5)
Canadian Utilities Limited	1.77	68.24	2.8	6.2	9.0
Emera Inc.	1.35	33.87	4.2	6.5	10.7
Enbridge Inc.	1.13	40.38	3.1	10.4	13.5
Fortis Inc.	1.20	33.10	3.9	7.0	10.9
TransCanada Corp.	1.76	42.99	4.4	7.3	11.7
Mean	1.44	43.72	3.7	7.5	11.2
Median	1.35	40.38	3.9	7.0	10.9

^{1/} Expected Dividend Yield = (Col (1) / Col (2)) * (1 + Col (4))

^{2/} Expected Dividend Yield (Col (3)) + EPS Estimate (Col (4))

Source: www.reuters.com and www.yahoo.com.

**DCF COSTS OF EQUITY FOR SAMPLE OF CANADIAN UTILITIES
(THREE-STAGE MODEL)**

	Annualized Last Paid Dividend	Average Daily Close Prices 5/1/12-7/31/2012	Growth Rates			DCF Cost of Equity ^{2/}
			Stage 1: Reuters Long-Term EPS Forecasts	Stage 2: Average of Stage 1 & 3	Stage 3: GDP Growth ^{1/}	
	(1)	(2)	(3)	(4)	(5)	(6)
Canadian Utilities Limited	1.77	68.24	6.2	5.3	4.3	7.2
Emera Inc.	1.35	33.87	6.5	5.4	4.3	9.0
Enbridge Inc.	1.13	40.38	10.4	7.4	4.3	8.5
Fortis Inc.	1.20	33.10	7.0	5.7	4.3	8.7
TransCanada Corp.	1.76	42.99	7.3	5.8	4.3	9.4
Mean	1.44	43.72	7.5	5.9	4.3	8.5
Median	1.35	40.38	7.0	5.7	4.3	8.7

^{1/} Forecast nominal rate of GDP growth, 2013-22

^{2/} Internal Rate of Return: Stage 1 growth rate applies for first 5 years; Stage 2 growth rate applies for years 6-10; Stage 3 growth thereafter.

Source: Consensus Economics, *Consensus Forecasts* (April 2012), www.reuters.com, and www.yahoo.com.

MARKET VALUE CAPITAL STRUCTURES FOR SAMPLE OF CANADIAN UTILITIES

	Debt and Preferred Shares at Par <u>(Millions \$, March 2012)</u>	Common Share Price Average Daily Close <u>5/1/12-7/31/2012</u>	Common Shares Outstanding <u>(Millions, June 2012)</u>	Total Market Capitalization <u>(Millions \$)</u>	Market Value Common Equity Ratio
	(1)	(2)	(3)	(4)	(5)
Canadian Utilities Limited	5,395	68.24	128	8,710	61.8%
Emera Inc.	3,700	33.87	124	4,196	53.1%
Enbridge Inc.	22,107	40.38	795	32,098	59.2%
Fortis Inc.	6,889	33.10	189	6,267	47.6%
TransCanada Corp.	22,406	42.99	704	30,279	57.5%
Mean				\$16,310	55.8%
Median				\$8,710	57.5%

MARKET VALUE CAPITAL STRUCTURES FOR SAMPLE OF U.S. UTILITIES

	Debt and Preferred Shares at Par <u>(Millions \$, March 2012)</u>	Common Share Price Average Daily Close <u>5/1/12-7/31/2012</u>	Common Shares Outstanding <u>(Millions, June 2012)</u>	Total Market Capitalization <u>(Millions \$)</u>	Market Value Common Equity Ratio
	(1)	(2)	(3)	(4)	(5)
AGL Resources Inc.	4,288	38.49	118	4,523	51.3%
ALLETE Inc.	864	40.63	38	1,550	64.2%
Alliant Energy Corp.	2,992	45.13	111	5,008	62.6%
Atmos Energy Corp.	2,380	34.27	90	3,085	56.4%
Consolidated Edison	11,071	61.47	293	18,005	61.9%
Integrus Energy Group Inc.	2,479	56.16	78	4,375	63.8%
Northwest Natural Gas	755	47.04	27	1,261	62.5%
Piedmont Natural Gas	1,133	31.19	72	2,242	66.4%
Southern Company	22,668	46.62	875	40,792	64.3%
Vectren Corp.	1,796	29.43	82	2,413	57.3%
WGL Holdings Inc.	771	39.70	52	2,046	72.6%
Wisconsin Energy Corp.	5,224	38.73	230	8,925	63.1%
Xcel Energy Inc.	10,247	28.20	487	13,732	57.3%
Mean				\$8,304	61.8%
Median				\$4,375	62.6%

Source: Reports to Shareholders, www.yahoo.com

QUANTIFICATION OF IMPACT ON EQUITY RETURN REQUIREMENT FOR DIFFERENCE BETWEEN MARKET VALUE AND BOOK VALUE CAPITAL STRUCTURES:

Formula for After-Tax Weighted Average Cost of Capital:

$$WACC_{AT} = (\text{Debt Cost})(1 - \text{tax rate})(\text{Debt Ratio}) + (\text{Equity Cost})(\text{Equity Ratio})$$

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases,

$$WACC_{AT(LL)} = WACC_{AT(ML)}$$

Where LL = less levered (lower debt ratio)

ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	5.05%
Equity Cost	=	9.50%
Tax Rate	=	26.00%
CEQ Ratio	Step (1)	57.0%
Debt Ratio	Step (1)	43.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered (common equity ratio of 57.0%)

$$\begin{aligned} WACC_{AT} &= (5.05\%)(1 - .260)(43.0\%) + (9.50\%)(57.0\%) \\ &= 7.02\% \end{aligned}$$

2. Estimate Cost of Equity for sample at 40.0% common equity r_E ; $WACC_{AT}$ unchanged at 7.02%

$$\begin{aligned} WACC_{AT} &= (\text{Debt Cost})(1 - \text{tax rate})(\text{Debt Ratio}) + (\text{Equity Cost})(\text{Equity Ratio}) \\ 7.02\% &= (5.05\%)(1 - .260)(60.0\%) + (X)(40.0\%) \\ \text{Cost of Equity at 40.0\% Equity Ratio} &= 11.95\% \end{aligned}$$

3. Difference between Equity Return at 57.0% and 40.0% common equity ratios:
 $11.95\% - 9.50\% = 2.45\%$ (245 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before

t = tax rate

D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	5.05%
Equity Cost	=	9.50%
Tax Rate	=	26.0%
CEQ Ratio	Step (1)	57.0%
Debt Ratio	Step (1)	43.0%
CEQ Ratio	Step (2)	40.0%
Debt Ratio	Step (2)	60.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 57.0%)

$$\begin{aligned} WACC_{AT} &= (5.05\%)(1-.260)(43.0\%) + (9.50\%)(57.0\%) \\ &= 7.02\% \end{aligned}$$

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 40.0%)

$$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1-t \times \text{Debt Ratio}_{ML}) / (1-t \times \text{Debt Ratio}_{LL})$$

$$WACC_{AT(ML)} = 7.02\% \times \frac{(1-.260 \times 60.0\%)}{(1-.260 \times 43.0\%)}$$

$$WACC_{AT(ML)} = 6.67\%$$

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$$WACC_{AT(ML)} = (\text{Debt Cost})(1-\text{tax rate})(\text{Debt Ratio}_{ML}) + (\text{Equity Cost})(\text{Equity Ratio}_{ML})$$

$$6.67\% = (5.05\%)(1-.260)(60.0\%) + (X)(40.0\%)$$

$$\text{Cost of Equity at 40.0\% Equity Ratio} = 11.08\%$$

4. Difference between Equity Return at 57.0% and 40.0% common equity ratios:

$$11.08\% - 9.50\% = 1.58\% \text{ (158 basis points)}$$

RISK MEASURES FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

	<u>Debt Ratings</u>		<u>Average of Five Year Betas Ending:</u>		<u>2010 Common Stock Equity</u>	<u>Average Market to Book Ratio</u>	
	<u>S&P</u>	<u>DBRS</u>	<u>2010-2011</u>	<u>2004-2011</u>	<u>(Total Capital)</u>	<u>1995-2011</u>	<u>2004-2011</u>
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
ALGOMA CENTRAL CORP			0.92	0.73	79.3%	1.01	1.03
ASTRAL MEDIA INC			0.68	0.74	69.5%	1.75	1.78
CANADA BREAD CO LTD			0.64	0.63	98.5%	1.98	2.18
CANADIAN NATIONAL RAILWAY CO	A-	A(low)	0.64	0.73	65.0%	2.22	2.71
CANADIAN PACIFIC RAILWAY LTD	BBB-	BBB(low)	0.88	0.76	52.8%	1.66	1.81
CANADIAN TIRE CORP	BBB+	BBB(high)	0.71	0.72	76.9%	1.68	1.72
EMPIRE CO LTD			0.45	0.56	73.9%	1.40	1.31
LEON'S FURNITURE LTD			0.80	0.69	100.0%	2.45	2.52
LOBLAW COMPANIES LTD	BBB	BBB	0.58	0.54	58.7%	3.07	2.16
MAPLE LEAF FOODS INC			0.46	0.50	59.1%	2.09	1.60
METRO INC	BBB	BBB	0.45	0.57	70.7%	2.43	2.17
REITMANS (CANADA)			0.77	0.74	97.9%	1.82	2.62
RITCHIE BROS AUCTIONEERS INC			0.65	0.47	80.8%	4.84	4.84
SAPUTO INC			0.51	0.55	79.5%	3.65	3.26
SHOPPERS DRUG MART CORP	BBB+	A(low)	0.62	0.65	77.1%	3.32	3.28
THOMSON-REUTERS CORP	A-	A(low)	0.56	0.61	71.9%	2.36	1.84
TOROMONT INDUSTRIES LTD		BBB(high)	0.84	0.76	74.2%	2.79	2.67
TORSTAR CORP		BBB	0.91	0.67	63.7%	1.99	1.46
TRANSCONTINENTAL INC	BBB	BBB(high)	0.96	0.82	58.2%	1.52	1.37
UNI-SELECT INC			0.64	0.58	68.9%	2.07	1.86
WESTON (GEORGE) LTD	BBB	BBB	0.28	0.36	52.2%	2.69	2.17
Mean	BBB+/BBB	BBB(high)	0.66	0.63	72.8%	2.32	2.21
Median	BBB	BBB(high)/BBB	0.65	0.64	71.9%	2.09	2.16

Source: Standard and Poor's Research Insight and DBRS

RETURNS ON AVERAGE COMMON STOCK EQUITY FOR 21 CANADIAN LOW RISK UNREGULATED COMPANIES

	<u>1995</u>	<u>1996</u>	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>Average 1995-2011</u>	<u>Average 2004-2011</u>
ALGOMA CENTRAL CORP	13.3	12.3	52.7	8.5	3.8	1.1	14.8	9.3	4.7	9.2	11.2	13.4	15.1	10.3	8.8	7.3	14.9	12.4	11.3
ASTRAL MEDIA INC	1.3	-9.5	7.1	7.8	6.4	4.4	8.2	10.0	10.0	10.9	12.1	13.1	13.0	14.7	-12.6	14.8	13.4	7.4	9.9
CANADA BREAD CO LTD	12.6	12.8	14.2	1.3	2.7	7.4	8.6	13.9	9.6	14.3	14.5	9.5	13.7	9.7	10.6	8.0	7.2	10.0	10.9
CANADIAN NATIONAL RAILWAY CO	-43.7	6.1	13.9	2.8	12.6	14.4	12.5	8.9	11.2	18.8	18.8	21.9	21.6	18.3	17.0	18.7	22.4	11.5	19.7
CANADIAN PACIFIC RAILWAY LTD	-13.0	13.5	18.0	10.3	7.3	20.2	6.6	15.2	11.3	10.8	13.0	17.2	18.3	10.8	9.6	11.3	12.0	11.3	12.9
CANADIAN TIRE CORP	10.2	10.4	11.4	13.0	11.2	10.6	11.5	11.9	12.8	13.6	13.9	13.4	14.2	11.2	9.2	11.7	11.0	11.8	12.3
EMPIRE CO LTD	3.9	11.9	17.9	21.7	13.3	69.1	16.4	11.4	11.6	11.4	16.2	10.3	14.0	10.5	10.7	11.9	9.2	16.0	11.8
LEON'S FURNITURE LTD	14.0	13.4	15.1	16.7	21.1	19.3	17.3	17.1	16.5	18.9	19.2	19.6	19.2	18.8	15.6	16.1	13.6	17.1	17.6
LOBLAW COMPANIES LTD	13.3	14.2	15.3	12.8	13.7	15.7	16.8	18.9	19.1	19.1	13.2	-3.9	6.0	9.6	10.8	10.4	11.9	12.8	9.6
MAPLE LEAF FOODS INC	-6.7	14.8	14.7	-6.3	17.9	8.0	10.3	12.2	4.8	13.0	9.9	0.5	19.2	-3.2	4.5	2.1	7.9	7.3	6.7
METRO INC	22.6	22.8	24.7	20.5	20.8	22.8	24.1	23.9	23.8	21.0	16.1	15.6	15.1	14.7	16.4	16.6	15.4	19.8	16.4
REITMANS (CANADA)	6.2	0.8	8.9	9.4	30.1	10.2	12.6	10.5	15.4	22.0	23.5	20.0	24.7	16.9	13.0	16.8	9.4	14.7	18.3
RITCHIE BROS AUCTIONEERS INC	nc	35.6	19.9	38.8	18.2	12.4	13.1	15.5	14.7	12.4	17.2	16.5	17.5	24.8	17.2	11.5	12.9	18.6	16.3
SAPUTO INC	nc	37.3	18.9	19.3	18.6	16.0	19.4	18.1	19.5	18.8	14.1	16.2	18.3	15.5	19.1	21.7	21.5	19.5	18.2
SHOPPERS DRUG MART CORP	na	na	na	na	nc	2.5	2.0	13.8	15.0	15.8	16.0	16.5	17.0	17.2	16.1	14.7	14.5	13.4	16.0
THOMSON-REUTERS CORP	22.4	14.2	12.9	34.7	8.0	17.9	10.2	7.3	8.8	10.3	9.3	11.0	31.1	9.1	4.0	4.6	-7.9	12.2	8.9
TOROMONT INDUSTRIES LTD	27.1	24.3	47.5	22.5	16.6	15.4	16.4	12.7	16.9	17.8	17.6	19.0	20.0	19.6	14.8	9.6	30.5	20.5	18.6
TORSTAR CORP	6.7	11.3	38.4	-0.7	12.8	5.4	-14.6	21.3	17.8	14.6	14.5	9.2	11.3	-22.7	5.3	8.7	30.6	10.0	8.9
TRANSCONTINENTAL INC	9.3	0.8	10.6	11.2	11.4	13.7	4.0	18.9	17.5	13.9	13.3	12.2	10.3	0.7	-7.7	15.4	6.5	9.5	8.1
UNI-SELECT INC	21.4	19.9	20.7	20.6	18.7	15.2	16.1	16.7	19.2	15.5	16.3	15.4	13.7	13.6	10.3	12.0	13.0	16.4	13.7
WESTON (GEORGE) LTD	12.9	15.1	14.5	37.3	14.0	17.4	18.5	18.3	19.4	10.2	16.2	1.6	12.7	17.5	17.6	7.1	11.9	15.4	11.9
Average	7.4	14.1	19.9	15.1	14.0	15.2	11.7	14.6	14.3	14.9	15.1	12.8	16.5	11.3	10.0	12.0	13.4	13.7	13.2
Median	11.4	13.5	15.2	12.9	13.5	14.4	12.6	13.9	15.0	14.3	14.5	13.4	15.1	13.6	10.7	11.7	12.9	12.8	12.3
Average of Annual Medians																		13.4	13.5

Source: Standard and Poor's Research Insight.

**NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES**

WRITTEN EVIDENCE OF

JAMES H. VANDER WEIDE, PH.D.

FOR

NEWFOUNDLAND POWER INC.

SEPTEMBER 2012

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1 **I. Introduction**

2 Q 1 What is your name, occupation, and business address?

3 A 1 My name is James H. Vander Weide. I am Research Professor of
4 Finance and Economics at Duke University, Fuqua School of Business. I
5 am also President of Financial Strategy Associates, a firm that provides
6 strategic and financial consulting services to corporate clients. My
7 business address is 3606 Stoneybrook Drive, Durham, North Carolina
8 27705.

9 Q 2 Please summarize your qualifications.

10 A 2 I graduated from Cornell University with a Bachelor's Degree in
11 Economics and from Northwestern University with a Ph.D. in Finance.
12 After joining the faculty of the School of Business at Duke University, I
13 was named Assistant Professor, Associate Professor, Professor, and
14 then Research Professor. I have published research in the areas of
15 finance and economics and taught courses in these fields at Duke for
16 more than thirty-five years. I am now retired from my teaching duties at
17 Duke. A summary of my research, teaching, and other professional
18 experience is presented in my Statement of Qualifications at the end of
19 my evidence.

20 Q 3 Have you previously testified on financial and economic issues?

21 A 3 Yes. As an expert on financial and economic theory and practice, I have
22 participated in more than four hundred regulatory and legal proceedings
23 before the Canadian National Energy Board, the Federal Energy
24 Regulatory Commission, the Canadian Radio-Television and
25 Telecommunications Commission, the U.S. Federal Communications
26 Commission, the U.S. Congress, the National Telecommunications and
27 Information Administration, the public utility commissions of forty-three
28 states and four Canadian provinces, the insurance commissions of five
29 states, the Iowa State Board of Tax Review, the National Association of
30 Securities Dealers, and the North Carolina Property Tax Commission. In
31 addition, I have prepared expert testimony in proceedings before the U.S.
32 Tax Court, the U.S. District Court for the District of Nebraska; the U.S.
33 District Court for the District of New Hampshire; the U.S. District Court for

1 the District of Northern Illinois; the U.S. District Court for the Eastern
2 District of North Carolina; the Montana Second Judicial District Court,
3 Silver Bow County; the U.S. District Court for the Northern District of
4 California; the Superior Court, North Carolina; the U.S. Bankruptcy Court
5 for the Southern District of West Virginia; and the U. S. District Court for
6 the Eastern District of Michigan.

7 Q 4 What is the purpose of your written evidence in this proceeding?

8 A 4 I have been asked by Newfoundland Power Inc. ("Newfoundland Power"
9 or "NP") to: (1) prepare an independent analysis of Newfoundland
10 Power's cost of equity for the period 2013 – 2014; (2) recommend an
11 appropriate fair rate of return on equity ("ROE") and deemed equity ratio
12 for Newfoundland Power; and (3) assess the fairness of the returns
13 provided by the Automatic Adjustment Formula ("the ROE Formula") of
14 the Newfoundland and Labrador Board of Commissioners of Public
15 Utilities ("the Board").

16 **II. The Fair Rate of Return Standard**

17 Q 5 Are you familiar with the fair rate of return standard?

18 A 5 Yes. The fair rate of return standard is a standard for determining whether
19 a regulated company's allowed rate of return is just and reasonable.
20 According to the fair rate of return standard, a regulated company's
21 allowed return is considered to be just and reasonable, or fair, if it is:
22 (1) equal to the returns investors expect to earn on other investments of
23 comparable risk; (2) sufficient to allow the regulated company to attract
24 capital on reasonable terms; and (3) sufficient to allow the regulated
25 company to maintain its financial integrity.

26 Q 6 Are these economic principles regarding the fair return on capital
27 recognized in any Supreme Court cases?

28 A 6 Yes. These economic principles regarding the fair rate of return on capital
29 are recognized in at least one Canadian and two United States Supreme
30 Court cases: (1) *Northwestern Utilities Ltd. v. Edmonton*, (1929);
31 (2) *Bluefield Water Works and Improvement Co. v. Public Service*

1 *Commission; and (3) Federal Power Commission v. Hope Natural Gas*
2 *Co. In Northwestern Utilities Ltd. v. Edmonton*, Mr. Justice Lamont states:

3 The duty of the Board was to fix fair and reasonable rates; rates
4 which, under the circumstances, would be fair to the consumer on
5 the one hand, and which, on the other hand, would secure to the
6 company a fair return for the capital invested. By a fair return is
7 meant that the company will be allowed as large a return on the
8 capital invested in its enterprise (which will be net to the
9 company) as it would receive if it were investing the same
10 amount in other securities possessing an attractiveness, stability
11 and certainty equal to that of the company's enterprise.
12 [*Northwestern Utilities Ltd. v. Edmonton*, [1929] S.C.R. 186.]

13 The Court clearly recognizes here that a regulated utility must be allowed
14 to earn a return on the value of its property that is at least equal to its cost
15 of capital.

16 Q 7 Is the fair rate of return standard consistent with the economic principles
17 of resource allocation in a market economy?

18 A 7 Yes. In a market economy, resources will only be allocated efficiently
19 when the expected rate of return on investments of similar risk is equal.
20 For example, if the expected rate of return on Investment A is greater
21 than the expected rate of return on a similar risk Investment B, investors
22 will allocate a larger share of their investment dollars to Investment A and
23 a smaller share of their investment dollars to Investment B, thus
24 increasing their overall return on investment. In addition to benefiting
25 investors, the reallocation of investment dollars to Investment A will also
26 benefit society as a whole because Investment A's higher return is an
27 indication that Investment A is more productive than Investment B in
28 using society's resources.

29 Q 8 What is the economic definition of the required rate of return, or cost of
30 capital, associated with particular investment decisions, such as the
31 decision to invest in electric and natural gas utility facilities?

32 A 8 The economic definition of the cost of capital is similar to the definition of
33 a fair return, namely, the cost of capital is the return investors expect to
34 receive on alternative investments of comparable risk.

1 Q 9 Given the similarity of the definitions of “fair return” and “cost of capital,”
2 how do commissioners and economists generally determine whether a
3 particular allowed return satisfies the fair return standard?

4 A 9 Commissioners and economists generally determine whether a particular
5 allowed return satisfies the fair return standard by comparing the allowed
6 return to one or more estimates of the regulated utility’s cost of capital.

7 Q 10 How does the cost of capital affect a firm’s investment decisions?

8 A 10 From an economic perspective, a firm should only invest in a specific
9 project if the expected return on the investment is greater than or equal to
10 the company’s cost of capital. Thus, the cost of capital serves as a hurdle
11 rate for the firm’s investment decisions.

12 Q 11 How does the cost of capital affect investors’ willingness to invest in a
13 company?

14 A 11 The cost of capital measures the return investors can expect to earn on
15 other investments of comparable risk. Because rational investors will not
16 invest in a particular investment if the expected return on that investment
17 is less than the cost of capital, the cost of capital is also a hurdle rate for
18 investors’ decision to invest in a company. If investors cannot earn a
19 return that is at least equal to the return they expect to earn on other
20 investments of comparable risk, they will not invest in the company.

21 Q 12 Do all investors have the same position in the firm?

22 A 12 No. Bond investors have a fixed claim on a firm’s assets and income that
23 must be paid prior to any payment to the firm’s equity investors. Since the
24 firm’s equity investors have a residual claim on the firm’s assets and
25 income, equity investments are riskier than bond investments. Thus, the
26 cost of equity exceeds the cost of debt.

27 Q 13 What is the overall or average cost of capital?

28 A 13 The overall or average cost of capital is a weighted average of the cost of
29 debt and cost of equity, where the weights are the percentages of debt
30 and equity in a firm’s capital structure.

31 Q 14 Can you illustrate the calculation of the overall or weighted average cost
32 of capital?

1 A 14 Yes. Assume that the cost of debt is 6 percent, the cost of equity is
2 11 percent, and the percentages of debt and equity in the firm's capital
3 structure are 50 percent and 50 percent, respectively. Then the weighted
4 average cost of capital is expressed by .50 times 6 percent plus .50 times
5 11 percent, or 8.5 percent.^[1]

6 Q 15 How do economists define the cost of equity?

7 A 15 Economists define the cost of equity as the return investors expect to
8 receive on alternative equity investments of comparable risk. Since the
9 return on an equity investment of comparable risk is not a contractual
10 return, the cost of equity is more difficult to measure than the cost of debt.
11 However, as I have already noted, the cost of equity is greater than the
12 cost of debt. The cost of equity, like the cost of debt, is both forward
13 looking and market based.

14 Q 16 How do economists measure the percentages of debt and equity in a
15 firm's capital structure?

16 A 16 Economists measure the percentages of debt and equity in a firm's
17 capital structure by first calculating the market value of the firm's debt and
18 the market value of its equity. The percentage of debt is then calculated
19 by the ratio of the market value of debt to the combined market value of
20 debt and equity, and the percentage of equity by the ratio of the market
21 value of equity to the combined market values of debt and equity. For
22 example, if a firm's debt has a market value of \$25 million and its equity
23 has a market value of \$75 million, then its total market capitalization is
24 \$100 million, and its capital structure contains 25 percent debt and
25 75 percent equity.

26 Q 17 Why do economists measure a firm's capital structure in terms of the
27 market values of its debt and equity?

[1] The weighted average cost of capital may be calculated on either an after-tax or a before-tax basis. The difference between these calculations is that the after-tax cost of debt is used to calculate the weighted average cost of capital in an after-tax calculation. For simplicity, I present a before-tax calculation of the weighted average cost of capital in this example.

1 A 17 Economists measure a firm's capital structure in terms of the market
2 values of its debt and equity because: (1) the weighted average cost of
3 capital is equal to the return investors expect to earn on a portfolio of the
4 company's debt and equity securities; (2) investors measure the expected
5 return on their portfolios using market value weights, not book value
6 weights; and (3) market values are the best measures of the amounts of
7 debt and equity investors have invested in the company on a going
8 forward basis.

9 Q 18 Why do investors measure the expected return on their investment
10 portfolios using market value weights rather than book value weights?

11 A 18 Investors measure the expected return on their investment portfolios
12 using market value weights because they calculate the expected return
13 by dividing the expected future value of the investment by the current
14 value of the investment, and market value is the best measure of the
15 current value of the investment. From the point of view of investors, the
16 historical cost or book value of their investment is entirely irrelevant to
17 their calculation of their expected return on investment because they
18 would receive market value, not historical cost, if they were to sell their
19 investments. Thus, the expected return can only be measured in terms of
20 market values.

21 Q 19 Do investors also use market value weights to measure the risk of their
22 investments?

23 A 19 Yes. Investors measure risk by calculating the variance of their actual
24 investment return from their expected investment return. Because
25 investors measure both actual and expected investment returns using
26 market value weights, they also measure risk using market value weights.

27 Q 20 Is the economic definition of the weighted average cost of capital
28 consistent with regulators' traditional definition of the average cost of
29 capital?

30 A 20 No. The economic definition of the weighted average cost of capital is
31 based on the market costs of debt and equity, the market value
32 percentages of debt and equity in a company's capital structure, and the
33 future expected risk of investing in the company. In contrast, regulators

1 have traditionally defined the weighted average cost of capital using the
2 embedded cost of debt and the book values of debt and equity in a
3 company's capital structure.

4 Q 21 Should the Board recognize the difference between the economic and
5 traditional regulatory definitions of the weighted average cost of capital
6 when it determines an appropriate allowed return on equity for
7 Newfoundland Power?

8 A 21 Yes. The Board should recognize that the cost of equity evidence
9 presented in this proceeding reflects investors' estimates of the
10 comparable companies' financial risk as measured by the market value
11 percentages of debt and equity in the comparable companies' capital
12 structures. In assessing the relevance of this cost of equity evidence for
13 Newfoundland Power, the Board should also recognize that the cost of
14 equity estimate for the comparable companies likely reflects a lower level
15 of financial risk than is embedded in Newfoundland Power's book value
16 capital structure. The Board can only satisfy the fair return standard if it
17 recognizes financial risk when it determines Newfoundland Power's fair
18 rate of return on equity.

19 **III. Business and Financial Risks**

20 Q 22 The fair return standard requires that investors in public utilities be given
21 an opportunity to earn a return that is commensurate with returns on other
22 investments of similar risk. Are the returns on investment opportunities,
23 such as an investment in Newfoundland Power, known with certainty at
24 the time an investment is made?

25 A 22 No. The return on an investment in a company depends on the
26 company's expected future cash flows over the life of the investment.
27 Since the company's expected future cash flows are uncertain at the time
28 the investment is made, the return on the investment is also uncertain.

29 Q 23 Investors require a return on investment that is equal to the return they
30 expect to receive on other investments of similar risk. Does the required
31 return on an investment depend on the risk of that investment?

1 A 23 Yes. Since investors are averse to risk, they require a higher rate of
2 return on investments with greater risk.

3 Q 24 What fundamental risk do investors face when they invest in a company
4 such as Newfoundland Power?

5 A 24 Investors face the fundamental risk that their realized, or actual, return on
6 investment over the life of the investment (including the return of and on
7 investment) will be less than their required return on investment.

8 Q 25 How do investors attempt to measure investment risk?

9 A 25 Investors generally attempt to measure investment risk by estimating the
10 probability, or likelihood, of earning an actual return on the investment
11 that is less than their required return on investment. For investments or
12 projects with potential returns distributed symmetrically about the
13 expected, or mean, return, investors can also measure investment risk by
14 estimating the variance, or volatility, of the potential return on investment.

15 Q 26 Can investment risk be measured precisely?

16 A 26 No. Because the risk of earning an actual return that is less than an
17 investor's required return depends on the investor's estimate of the
18 probability distribution of future cash flows in all future years, and the
19 probability distribution of future cash flows is difficult to estimate, the risk
20 of earning less than the required return cannot be measured precisely.

21 Q 27 Do investors distinguish between business and financial risk?

22 A 27 Yes. Business risk is the fundamental risk that investors will earn an
23 operating return on their investment (that is, a return prior to financing
24 costs) that is less than their required return on investment. Financial risk
25 is the additional risk of earning less than the required return on equity
26 when an investment is partially financed with fixed-cost debt.

27 Q 28 Does the use of fixed-cost debt generally increase the expected return on
28 the equity-financed portion of an investment?

29 A 28 Yes. The use of fixed-cost debt increases both the expected and the
30 realized return on equity when the operating return on investment
31 exceeds the cost of debt. The use of fixed-cost debt financing is generally
32 called "financial leverage."

1 Q 29 You note that financial leverage increases the risk of investors in electric
2 and natural gas utilities. How do economists measure financial leverage?

3 A 29 Economists generally measure financial leverage by the percentages of
4 debt and equity in a company's market value capital structure.
5 Companies with a high percentage of debt compared to equity are
6 considered to have high financial leverage.

7 Q 30 Why does high financial leverage affect the risk of investing in an electric
8 utility's stock?

9 A 30 High financial leverage is a source of additional risk to utility stock
10 investors because it increases the percentage of the firm's costs that are
11 fixed, and the presence of higher fixed costs increases the variability of
12 the equity investors' return on investment.

13 Q 31 You note above that investors require a higher rate of return on more
14 risky investments than less risky investments. Because financial risk is a
15 key component of total risk, does a company with greater financial risk
16 generally have a higher required rate of return on equity?

17 A 31 Yes. Holding business risk constant, a company with higher financial risk
18 would have a higher required rate of return on equity.

19 Q 32 You also note above that financial risk reflects the impact of having a
20 higher percentage of debt in a company's capital structure. Does the
21 relationship between the cost of equity and the percentage of debt in the
22 capital structure also require that the allowed return on equity and the
23 percentage of debt in the capital structure be considered together?

24 A 32 Yes.

25 Q 33 Does the fair rate of return standard require that comparable risk
26 investments be comparable with respect to both business and financial
27 risk?

28 A 33 No. The fair rate of return standard only requires that comparable risk
29 investments have comparable total risk. Thus, an investment with greater
30 business risk can be risk comparable to an investment with lower
31 business risk as long as the first investment's greater business risk is
32 offset by its lower financial risk.

1 **IV. Comparable Risk Utilities**

2 Q 34 Recognizing that risk cannot be measured precisely, how do you analyze
3 Newfoundland Power's cost of equity?

4 A 34 I analyze Newfoundland Power's cost of equity by: (1) identifying several
5 groups of utilities that are broadly comparable in risk to Newfoundland
6 Power's risk; (2) estimating the cost of equity for each group of
7 comparable risk utilities using cost of equity methodologies such as the
8 discounted cash flow ("DCF"), risk premium and CAPM; and (3) adjusting
9 the cost of equity results for my comparable groups to reflect possible
10 differences between the risk of the comparable group and the risk of
11 Newfoundland Power.

12 Q 35 Why do you apply your cost of equity methods to one or more groups of
13 comparable risk utilities, rather than solely to Newfoundland Power?

14 A 35 I apply my cost of equity methods to one or more groups of comparable
15 risk utilities because standard cost of equity methods, such as the DCF,
16 risk premium, and CAPM, require inputs of quantities that are not easily
17 measured. Since these inputs can only be estimated, there is naturally
18 some degree of uncertainty surrounding the estimate of the cost of equity
19 for each utility. However, the uncertainty in the estimate of the cost of
20 equity for a single utility can be greatly reduced by applying cost of equity
21 methods to samples of comparable risk utilities. Intuitively, unusually high
22 estimates for some utilities are offset by unusually low estimates for other
23 utilities. Thus, financial economists invariably apply cost of equity
24 methods to one or more groups of comparable risk utilities. In utility
25 regulation, the practice of using a group of comparable risk utilities, called
26 the comparable company approach, is further supported by the Supreme
27 Court of Canada standard that the utility should be allowed to earn a
28 return on its investment that is commensurate with returns being earned
29 on other investments of the same risk.[2]

[2] See *Northwestern Utilities Ltd. v. Edmonton* [1929] S.C.R. 186.]

1 Q 36 Why do you apply your cost of equity methods to several groups of
2 comparable risk utilities, rather than to a single group of comparable risk
3 utilities?

4 A 36 I apply my cost of equity methods to several groups of comparable risk
5 utilities because, as discussed above, risk cannot be measured precisely.
6 Recognizing that risk cannot be measured precisely, the use of several
7 groups of comparable risk utilities provides insight on the impact of
8 alternative definitions of risk comparability on cost of equity results.

9 Q 37 What criteria do you use to select your groups of comparable risk
10 companies?

11 A 37 I use the criteria that similar risk companies must be broadly similar in
12 risk, must have sufficient data to estimate the cost of equity, and must
13 constitute a relatively large sample of companies. Specifically, I require
14 that comparable risk companies: (1) must have stock that is publicly
15 traded; (2) must have sufficient available data to reasonably apply
16 standard cost of equity estimation techniques; (3) must have regulated
17 electric and/or natural gas utility operations; and (4) taken together, must
18 constitute a relatively large sample of companies. In this proceeding, I
19 also refine the criterion that comparable risk companies must have
20 regulated electric and/or natural gas utility operations to specify that a
21 company must have at least 80 percent of total assets devoted to
22 regulated utility service and must have a bond rating of BBB or above.

23 Q 38 Is Newfoundland Power included in your comparable company group?

24 A 38 No. Newfoundland Power is not included in my comparable company
25 group because its stock is not publicly traded.

26 Q 39 Why must comparable companies be publicly traded?

27 A 39 Comparable companies must be publicly traded because information on a
28 company's stock price is a key input in standard cost of equity estimation
29 methods. If the company is not publicly traded, the information required to
30 estimate the cost of equity will not be available.

31 Q 40 Why is data availability a concern in estimating the cost of equity for
32 Newfoundland Power?

1 A 40 Data availability is a concern because standard cost of equity estimation
2 methods like the DCF, risk premium, and CAPM require estimates of
3 inputs, such as the expected growth rate, required risk premium, and the
4 beta, that are inherently uncertain. If there are insufficient data available
5 to estimate these inputs, there is little basis for arriving at a reasonable
6 estimate of the cost of equity for the comparable risk companies.

7 Q 41 Recognizing the inherent difficulties in selecting comparable risk
8 companies, what companies do you consider as potential risk-
9 comparable companies for the purpose of estimating Newfoundland
10 Power's cost of equity?

11 A 41 I consider two groups of Canadian utilities and two groups of U.S. utilities.

12 Q 42 What two groups of Canadian utilities do you consider?

13 A 42 I consider the small group of Canadian utilities included in the BMO CM
14 basket of utility and pipeline companies and a larger group consisting of
15 the companies in the S&P/TSX utilities index.

16 Q 43 What companies are included in the BMO CM basket of Canadian utility
17 stocks?

18 A 43 The BMO CM basket of Canadian utility stocks includes Canadian Utilities
19 Ltd., Emera Inc., Enbridge Inc., Fortis Inc., and TransCanada
20 Corporation. The BMO CM basket also includes return data for Westcoast
21 Energy Inc. until December 2001 and Terasen Inc. through July 2005.

22 Q 44 Does the BMO CM basket of Canadian utilities include all large publicly-
23 traded Canadian operating utilities with a significant percentage of assets
24 devoted to regulated utility services?

25 A 44 Yes. The five companies in the BMO CM basket of Canadian utilities are
26 the only large publicly-traded Canadian operating utilities with a
27 significant percentage of assets devoted to regulated utility services.

28 Q 45 Can you provide a general overview of the business operations of the
29 companies in the BMO CM basket of Canadian utilities?

30 A 45 Yes. The business operations of the companies in the BMO CM basket of
31 Canadian utilities may be summarized as follows.

32 Canadian Utilities Ltd. An international energy company with
33 business operations in Canada, Great Britain, and Australia. Major

1 business segments include Utilities (pipelines, natural gas and electricity
2 transmission and distribution), Energy (power generation, natural gas
3 gathering, processing, storage, and liquids extraction); Structure &
4 Logistics (manufacturing, logistics, and noise abatement); and
5 Technologies (business systems solutions). Canadian Utilities has
6 approximately 68 percent of total assets devoted to its utilities segment.

7 Emera Inc. Invests in electricity generation, transmission, and
8 distribution, gas transmission, and utility energy services. Its business
9 segments include NSPI, Maine Utility Operations, Caribbean Utility
10 Operations, and Brunswick Pipelines. Emera has approximately
11 56 percent of total assets associated with its electric utility operations in
12 Nova Scotia and an additional 26 percent associated with its electric utility
13 operations in Maine and the Caribbean.

14 Enbridge Inc. A leader in energy transportation and distribution in
15 North America and internationally. Enbridge has approximately
16 38 percent of its total assets associated with its Liquids Pipelines
17 segment and 25 percent of total assets associated with its Gas
18 Distribution segment.

19 Fortis Inc. Invests in regulated electric and gas utility operations,
20 non-regulated electric generation operations, and real estate operations.
21 Fortis Inc. has approximately 85 percent of its total assets associated with
22 its Canadian utility operations. Fortis Inc. is the parent of Newfoundland
23 Power.

24 TransCanada Corp. Operates the most extensive natural gas
25 pipeline in Canada, owns and operates large natural gas and oil pipeline
26 systems in North America, and invests in unregulated power projects.
27 TransCanada has approximately 48 percent of its total assets associated
28 with its natural gas pipeline operations, 19 percent with its oil pipeline
29 operations, and 29 percent with its power generation and energy
30 infrastructure operations.

31 Specific segment information for each of these companies is
32 shown in Exhibit 1.

1 Q 46 What are the advantages of using the BMO CM basket of Canadian
2 utilities as risk comparables for the purpose of estimating the cost of
3 equity for Newfoundland Power?

4 A 46 The primary advantage of the BMO CM basket of Canadian utilities is that
5 it only includes Canadian companies that receive a significant portion of
6 their revenues from regulated utility operations.

7 Q 47 What are the disadvantages of using the BMO CM basket of Canadian
8 utilities as risk comparables for the purpose of estimating the cost of
9 equity for Newfoundland Power?

10 A 47 The primary disadvantage of the BMO CM basket of Canadian utilities is
11 that at least two of the five companies also have significant investments in
12 unregulated operations; and some of their investments in regulated
13 operations are pipeline operations rather than electric or natural gas utility
14 operations.

15 Q 48 What companies are included in the S&P/TSX utilities index?

16 A 48 The companies currently included in the S&P/TSX utilities stock index are
17 ATCO Ltd., Atlantic Power Corporation, Algonquin Power & Utilities
18 Corp., Capital Power Corporation, Canadian Utilities Limited, Emera
19 Incorporated, Fortis Inc., Just Energy Group Inc., Northland Power Inc.,
20 and TransAlta Corporation.

21 Q 49 Are any of the companies in the S&P/TSX utilities index related to one
22 another?

23 A 49 Yes. ATCO Ltd. is a utility holding company that owns 52 percent of
24 Canadian Utilities Limited. Since ATCO has a majority interest in
25 Canadian Utilities and only a small amount of assets that are not jointly
26 owned with Canadian Utilities, ATCO's financial statements reflect
27 essentially the same information as Canadian Utilities' financial
28 statements.

29 Q 50 The S&P/TSX utilities index contains six other companies that are not
30 included in the BMO CM basket of Canadian utilities. Can you provide a
31 general overview of the companies in the S&P/TSX utilities index that are
32 not included either directly or indirectly in the BMO CM basket of
33 Canadian utilities?

1 A 50 Yes. The business operations of these six companies can be summarized
2 as follows.

3 Atlantic Power Corporation. An independent electric power
4 producer that owns interests in a diversified portfolio of independent non-
5 utility power generation projects and one transmission line in the United
6 States.

7 Algonquin Power & Utilities Corp. Owns and operates a
8 diversified portfolio of renewable energy and utility businesses through its
9 subsidiary companies. Algonquin has two business segments: Algonquin
10 Power Company generates and sells electric energy; and Liberty Utilities
11 provides utility services related to electricity, natural gas, water, and
12 wastewater. Algonquin has approximately 51 percent of its total assets
13 that are related to its unregulated electric power generation and
14 marketing segment and 34 percent related to its utilities segment.

15 Capital Power Corporation. An independent North American
16 power producer that develops, acquires, and operates power generation
17 from a variety of energy sources.

18 Just Energy Group Inc. Primarily involved in the sale of natural
19 gas, electricity, and green energy products to residential and commercial
20 customers under long-term contracts in the United States and Canada.

21 Northland Power Inc. Operates power generating stations and
22 wind farms, sells electricity and steam, and implements environmental
23 and monitoring systems.

24 TransAlta Corporation. A wholesale power generator and
25 marketer with operations in Canada, the United States, and Australia.

26 Exhibit 2 shows segment information for the two companies in the
27 S&P/TSX Utilities index with regulated utility operations that are not in the
28 BMO CM data set. The remaining six companies' total assets are only
29 associated with unregulated business operations.

30 Q 51 What are the advantages of using the S&P/TSX utilities index as
31 comparables in this proceeding?

32 A 51 The primary advantage of using the S&P/TSX utilities index is that there
33 are more companies in the index and return data for this index is

1 available for a longer period of time than for the BMO CM basket of utility
2 stocks.

3 Q 52 Are there any disadvantages of using the S&P/TSX Utilities as risk
4 comparables for Newfoundland Power?

5 A 52 Yes. The primary disadvantage is that six of the ten companies in this
6 group do not have a significant percentage of assets devoted to regulated
7 utility service, and the financial statements of two of the companies with a
8 significant percentage of regulated assets reflect essentially the same
9 information.

10 Q 53 What two groups of U.S. utilities do you consider?

11 A 53 I consider a large utility company group that includes all publicly-traded
12 electric and natural gas utilities with sufficient data to reasonably estimate
13 Newfoundland Power's cost of equity and a smaller group of electric and
14 natural gas utilities that includes only utilities that have at least 80 percent
15 of total assets devoted to regulated utility operations and S&P bond
16 ratings equal to or greater than BBB.

17 Q 54 What are the advantages of using U.S. utility groups to estimate the cost
18 of equity for Newfoundland Power?

19 A 54 The primary advantages of using U.S. utility groups to estimate
20 Newfoundland Power's cost of equity are that: (1) they include a
21 significantly larger sample of companies with traditional utility operations
22 than my Canadian groups; (2) reasonable estimates of expected growth
23 rates are available for these companies, whereas the same data are not
24 available for the Canadian utilities; and (3) historical data for the U.S.
25 utilities are available for a much longer period of time than for the
26 Canadian utilities.

27 Q 55 Is there a significant difference in the business risk of Canadian and U.S.
28 utilities?

29 A 55 No. Generally speaking, the business risk of electric and natural gas
30 utilities is approximately the same in the U.S. as it is in Canada.

31 Q 56 Why is the business risk of electric and natural gas utilities approximately
32 the same in the U.S. as it is in Canada?

1 A 56 The business risk of electric and natural gas utilities is approximately the
2 same in the U.S. and Canada because: (1) U.S. electric and natural gas
3 utilities rely on essentially the same natural gas and electric technologies
4 to deliver their services to the public as electric and natural gas utilities in
5 Canada; (2) the economics of natural gas and electric transmission and
6 distribution is similar in the U.S. and Canada; and (3) U.S. electric and
7 natural gas utilities are regulated under similar cost-based regulatory
8 structures and fair rate of return principles as Canadian utilities.

9 Q 57 Some observers have argued that Canadian utilities have lower
10 regulatory risk than U.S. utilities because Canadian regulators generally
11 make greater use of cost adjustment and revenue stabilization
12 mechanisms than U.S. regulators. Do you agree with this argument?

13 A 57 No. U.S. utilities have many of the same cost adjustment and revenue
14 stabilization mechanisms as Canadian utilities. For example, U.S. electric
15 utilities generally have cost adjustment mechanisms for costs of fuel and
16 purchased power, pension expenses, storm damage expenses,
17 environmental expenses, decommissioning expenses, demand-side
18 management program costs, FERC-approved transmission costs, and
19 new generation plant investment; and revenue stabilization mechanisms
20 for unusual weather and customer usage. U.S. natural gas distribution
21 companies typically have cost adjustment mechanisms for the cost of
22 purchased gas, removal expenses, and bad debt expenses; and revenue
23 stabilization mechanisms for weather normalization and declining
24 customer usage. In addition, U.S. natural gas utilities increasingly have
25 rate designs that allow them to recover higher percentages of their fixed
26 costs through fixed monthly rates rather than through variable rates.

27 Q 58 Are there other factors that reduce the risk of investing in U.S. utilities?

28 A 58 Yes. U.S. utilities' regulatory risk may be reduced because U.S. utilities
29 frequently operate in several regulatory jurisdictions; for example, an
30 unfavorable economic or regulatory event in one jurisdiction can be offset
31 by favorable events in other jurisdictions. In addition, U.S. utilities' risk
32 may be reduced because U.S. utilities are generally allowed to normalize

1 the benefits of deferred taxes, whereas Canadian utilities are generally
2 required to flow such benefits through to rate payers.

3 Q 59 Do cost recovery and revenue stabilization mechanisms guarantee that a
4 public utility will earn its cost of equity?

5 A 59 No. Regulatory risk is associated with the possibility that a utility will be
6 unable to earn its required rate of return as a result of regulation.
7 Although cost recovery and revenue stabilization mechanisms generally
8 reduce the gap between a utility's actual and allowed returns, they do not
9 necessarily reduce the gap between a utility's actual and required returns.
10 If a utility's allowed ROE is less than its required ROE, the utility may
11 have high regulatory risk, even if it is able to earn its allowed ROE.

12 Q 60 You note above that financial risk is the additional variability in return on
13 investment that equity investors experience due to the company's use of
14 debt financing or leverage. How does the financial risk of Canadian
15 utilities compare to the financial risk of U.S. utilities?

16 A 60 Canadian utilities generally have greater financial risk than U.S. utilities
17 because, as shown below, they rely more heavily on debt financing than
18 U.S. utilities.

19 Q 61 What percent of total assets in your U.S. utility groups are devoted to
20 regulated utility services?

21 A 61 On average, the companies in my larger U.S. utility sample have
22 82 percent of total assets associated with regulated utility operations (see
23 Exhibit 3). Approximately 94 percent of total assets of my smaller U.S.
24 utility group are devoted to regulated utility services (see Exhibit 4).

25 Q 62 What are the average bond ratings for the companies in your U.S. utility
26 groups?

27 A 62 The average bond rating for the companies in my comprehensive U.S.
28 utility group is BBB+, and the average bond rating for the companies in
29 my smaller U.S. sample is BBB+ to A- (see Exhibit 5).

30 Q 63 What do bond ratings measure?

31 A 63 Bond ratings measure the risk that a company will be unable to pay the
32 interest and principal on its debt. Hence, bond ratings are frequently

1 considered to be a measure of the likelihood of a company declaring
2 bankruptcy.

3 Q 64 Are bond ratings a reasonable measure of the risk of investing in a
4 company's stock?

5 A 64 No. As discussed above, the risk of investing in a company's stock is best
6 measured by the expected variability in the return on the stock
7 investment.

8 Q 65 Do you have evidence that bond ratings are a poor indicator of the risk of
9 investing in a company's equity?

10 A 65 Yes. I have examined the average allowed rate of return on equity for
11 U.S. utilities in different bond rating categories, based on decisions
12 beginning January 2010 through February 2012, to determine whether
13 the allowed ROE depends on the utility's bond rating. If bond ratings are
14 an indicator of the risk of investing in a utility's equity, one would expect
15 that there would be an inverse relationship between a utility's bond rating
16 and its allowed ROE, that is, that utilities with higher bond ratings would
17 have lower allowed ROEs and vice versa. However, I find no significant
18 difference in allowed ROEs for utilities in different bond rating categories
19 (see Table 1 below).

TABLE 1
COMPARISON OF ALLOWED RATES OF RETURN
TO BOND RATING CATEGORY

BOND RATING CATEGORY	NUMBER OF DECISIONS IN CATEGORY	RETURN ON EQUITY	EQUITY RATIO
A- and above	55	10.3	50.7
BBB+	39	10.2	48.6
BBB	39	10.3	47.9
BBB-	28	10.1	48.5
Below investment grade	11	10.0	47.5
Total/Average	172	10.2	49.1

20 Q 66 Based on the evidence you have reviewed, should the Board give weight
21 to cost of equity results for U.S. utilities?

22 A 66 Yes. As discussed above, the U.S. utilities included in my cost of equity
23 studies are generally comparable in business risk to the Canadian

1 utilities. Furthermore, the U.S. utilities included in my studies are more
2 involved in traditional utility operations than most of the companies
3 included in the Canadian utilities indices. In addition, the sample of U.S.
4 regulated utilities is significantly larger than the sample of Canadian
5 regulated utilities, and the data required to estimate the cost of equity are
6 more readily available for the U.S. utilities than for the Canadian utilities.
7 For these reasons, the U.S. data provide important information on the
8 cost of equity for Newfoundland Power and should be considered along
9 with Canadian-specific evidence to estimate the cost of equity for
10 Newfoundland Power.

11 Q 67 Have other Canadian utility commissions expressed an opinion on the
12 use of U.S. utility data for the purpose of estimating the cost of equity for
13 Canadian utilities?

14 A 67 Yes. For example, the National Energy Board ("NEB"), the Ontario
15 Energy Board ("OEB"), and the British Columbia Utilities Commission
16 ("BCUC") have each recognized the usefulness of U.S. data for the
17 purpose of estimating the cost of equity for Canadian utilities. In Decision
18 RH-1-2008 relating to the determination of the cost of equity for Trans
19 Québec & Maritimes Pipeline Inc. ("TQM"), the NEB finds:

20 In light of the Board's views expressed above on the integration
21 of U.S. and Canadian financial markets, the problems with
22 comparisons to either Canadian negotiated or litigated returns,
23 and the Board's view that risk differences between Canada and
24 the U.S. can be understood and accounted for, the Board is of
25 the view that U.S. comparisons are very informative for
26 determining a fair return for TQM for 2007 and 2008. [RH-1-2008
27 at 71.]

28 In the Report of the Board on the Cost of Capital for Ontario's
29 Regulated Utilities, EB-2009-0084, December 11, 2009, ("2009 Cost of
30 Capital Report") the OEB states:

31 Second, there was a general presumption held by participants
32 representing ratepayer groups in the consultation that Canadian
33 and U.S. utilities are not comparators, due to differences in the
34 "time value of money, the risk value of money and the tax value
35 of money." In other words, because of these differences,
36 Canadian and U.S. utilities cannot be comparators. The Board

disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. ...

The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking. [2009 Cost of Capital Report at 21 – 23]

In the BCUC's Terasen Gas Decision on Return on Equity and Capital Structure, December 16, 2009, the BCUC states:

As for the US data, the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so. In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics. [In the Matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure Decision, December 16, 2009, pp. 15 – 16]

Q 68 What conclusions do you draw from your investigation of alternative groups of comparable utilities?

A 68 I conclude that my groups of Canadian and U.S. utilities are reasonable proxies for the purpose of estimating Newfoundland Power's cost of equity.

V. Estimates of Comparable Utilities' Cost of Equity

Q 69 What methods do you use to estimate your comparable utilities' cost of equity?

1 A 69 I use three generally accepted methods: the discounted cash flow
2 ("DCF"), the risk premium, and the CAPM. The DCF method assumes
3 that the current market price of a firm's stock is equal to the discounted
4 value of all expected future cash flows. The risk premium method
5 assumes that the investor's required rate of return on an equity
6 investment is equal to the interest rate on a long-term bond plus an
7 additional equity risk premium to compensate the investor for the risks of
8 investing in equities compared to bonds. The CAPM assumes that the
9 investors' required rate of return is equal to a risk-free rate of interest plus
10 the product of a company-specific risk factor, beta, and the expected risk
11 premium on the market portfolio.

12 **A. Discounted Cash Flow Estimate**

13 Q 70 Please describe the DCF model.

14 A 70 The DCF model is based on the assumption that investors value an asset
15 on the basis of the future cash flows they expect to receive from owning
16 the asset. Thus, investors value an investment in a bond because they
17 expect to receive a sequence of semi-annual coupon payments over the
18 life of the bond and a terminal payment equal to the bond's face value at
19 the time the bond matures. Likewise, investors value an investment in a
20 firm's stock because they expect to receive a sequence of dividend
21 payments and, perhaps, expect to sell the stock at a higher price
22 sometime in the future.

23 A second fundamental principle of the DCF method is that investors
24 value a dollar received in the future less than a dollar received today. A
25 future dollar is valued less than a current dollar because investors could
26 invest a current dollar in an interest earning account and increase their
27 wealth. This principle is called the time value of money.

28 Applying the two fundamental DCF principles noted above to an
29 investment in a bond leads to the conclusion that investors value their
30 investment in the bond on the basis of the present value of the bond's
31 future cash flows. Thus, the price of the bond should be equal to:

1

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \dots + \frac{C+F}{(1+i)^n}$$

2

where:

3

P_B = Bond price;

4

C = Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);

5

6

F = Face value of the bond;

7

i = The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and

8

9

n = The number of periods before the bond matures.

10

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

11

12

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_n + P_n}{(1+k)^n}$$

13

where:

14

P_s = Current price of the firm's stock;

15

$D_1, D_2 \dots D_n$ = Expected annual dividend per share on the firm's stock;

16

P_n = Price per share of stock at the time the investor expects to sell the stock; and

17

18

k = Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

19

20

21

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant

22

23

1 annual rate, g , this equation can be solved for k , the cost of equity. The
2 resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of
3 equity, D_1 is the expected next period annual dividend, P_s is the current
4 price of the stock, and g is the constant annual growth rate in earnings,
5 dividends, and book value per share. The term D_1/P_s is called the
6 dividend yield component of the annual DCF model, and the term g is
7 called the growth component of the annual DCF model.

8 Q 71 Are you recommending that the annual DCF model be used to estimate
9 Newfoundland Power's cost of equity?

10 A 71 No. The DCF model assumes that a company's stock price is equal to the
11 present discounted value of all expected future dividends. The annual
12 DCF model is only a correct expression for the present discounted value
13 of future dividends if dividends are paid annually at the end of each year.
14 Because the companies in my proxy group all pay dividends quarterly, the
15 current market price that investors are willing to pay reflects the expected
16 quarterly receipt of dividends. Therefore, a quarterly DCF model should
17 be used to estimate the cost of equity for these firms. The quarterly DCF
18 model differs from the annual DCF model in that it expresses a
19 company's price as the present discounted value of a quarterly stream of
20 dividend payments. A complete analysis of the implications of the
21 quarterly payment of dividends on the DCF model is provided in
22 Appendix 1. For the reasons cited there, I employ the quarterly DCF
23 model throughout my calculations.

24 Q 72 How do you estimate the dividend component of the DCF model?

25 A 72 The quarterly DCF model requires an estimate of the dividends, d_1 , d_2 , d_3 ,
26 and d_4 , investors expect to receive over the next four quarters. I estimate
27 the next four quarterly dividends by multiplying the previous four quarterly
28 dividends by the factor, $(1 + \text{the growth rate, } g)$.

29 Q 73 How do you estimate the growth component of the quarterly DCF model?

30 A 73 I use the analysts' estimates of future earnings per share ("EPS") growth
31 reported by I/B/E/S Thomson Reuters.

32 Q 74 What is I/B/E/S?

1 A 74 I/B/E/S is a firm (now owned by Thomson Reuters) that reports analysts'
2 EPS growth forecasts for a broad group of companies. The forecasts are
3 expressed in terms of a mean forecast and a standard deviation of
4 forecast for each firm. Investors use the mean forecast as a consensus
5 estimate of future firm performance.

6 Q 75 Why do you use the I/B/E/S growth estimates?

7 A 75 The I/B/E/S growth rates: (1) are widely circulated in the financial
8 community, (2) include the projections of multiple reputable financial
9 analysts who develop estimates of future EPS growth, (3) are reported on
10 a timely basis to investors, and (4) are widely used by institutional and
11 other investors.

12 Q 76 Why do you rely on analysts' projections of future EPS growth to estimate
13 the growth component of the DCF model rather than looking at past
14 historical growth rates?

15 A 76 I rely on analysts' projections of future EPS growth because: (1) the DCF
16 model assumes that a company's stock price is equal to the present value
17 of all expected *future* cash flows from investing in the stock; (2) stock
18 prices are determined by investors in the marketplace; and (3) I have
19 found that analysts' growth forecasts are the best proxy for investor
20 growth expectations.

21 Q 77 Does the DCF model require that analysts' growth forecasts be perfectly
22 accurate?

23 A 77 No. The DCF model recognizes that all growth forecasts necessarily
24 involve uncertainty. The DCF model only requires that the growth
25 forecasts used in the model are reasonable proxies for investors' growth
26 expectations.

27 Q 78 What price do you use in your DCF model?

28 A 78 I use a simple average of the monthly high and low stock prices for each
29 firm for the three-month period ending June 2012. These high and low
30 stock prices were obtained from I/B/E/S Thomson Reuters.

31 Q 79 Why do you use a three-month average stock price in applying the DCF
32 method?

1 A 79 I use a three-month average stock price in applying the DCF method
2 because stock prices fluctuate daily, while financial analysts' forecasts for
3 a given company are generally changed less frequently, often on a
4 quarterly basis. Thus, to match the stock price with an earnings forecast,
5 it is appropriate to average stock prices over a three-month period.

6 Q 80 How do you use the DCF model to estimate the cost of equity on an
7 investment in your comparable risk companies?

8 A 80 As discussed above, I apply the DCF model to two groups of U.S. utilities.

9 Q 81 How do you select your larger comparable group of U.S. utilities?

10 A 81 I select the publicly-traded electric and natural gas utilities that: (1) paid
11 dividends during every quarter and did not decrease dividends during any
12 quarter of the past two years; (2) have at least two analysts included in
13 the I/B/E/S mean growth forecast; (3) are not in the process of being
14 acquired; (4) have a Value Line Safety Rank of 1, 2, or 3;^[3] and (5) have
15 an investment grade S&P bond rating.

16 Q 82 How do you select your smaller group of U.S. utilities?

17 A 82 Beginning with the larger group that has been selected, I select only
18 those companies from the larger group that have at least 80 percent of
19 total assets devoted to regulated utility operations and that have an S&P
20 bond rating of BBB or higher.

21 Q 83 Why do you use U.S. utilities rather than Canadian utilities in your DCF
22 studies?

23 A 83 As noted above, the DCF model requires estimates of investors' growth
24 expectations, which are best measured from the average of analysts'
25 growth forecasts for each company. The difficulty with using Canadian
26 utilities is that there are very few, if any, analysts' growth forecasts
27 available for the Canadian utilities. In addition, the number of publicly-
28 traded Canadian utilities is significantly less than the number of publicly-
29 traded U.S. utilities.

[3] The Value Line Investment Survey is a widely used independent investment information service that provides comprehensive reference information on approximately 1,700 publicly-traded stocks.

1 Q 84 Why do you eliminate companies that have either decreased or
2 eliminated their dividend during the past two years?

3 A 84 The DCF model requires the assumption that dividends will grow at a
4 constant positive rate into the indefinite future. If a company has
5 decreased its dividend in recent years, an assumption that the company's
6 dividend will grow at a positive rate into the indefinite future is
7 questionable.

8 Q 85 Why do you eliminate companies that have fewer than two analysts'
9 estimates included in the I/B/E/S mean forecast?

10 A 85 The DCF model also requires a reliable estimate of a company's
11 expected future growth. For most companies, the I/B/E/S mean growth
12 forecast is the best available estimate of the growth term in the DCF
13 Model. However, the I/B/E/S estimate may be less reliable if the mean
14 estimate is based on the inputs of very few analysts. On the basis of my
15 professional judgment, I believe that at least two analysts' estimates are a
16 reasonable minimum number.

17 Q 86 Why do you eliminate companies that are being acquired in transactions
18 that are not yet completed?

19 A 86 A merger announcement generally increases the target company's stock
20 price. Analysts' growth forecasts for the target company, on the other
21 hand, are necessarily related to the company as it currently exists. The
22 use of a stock price that includes the growth-enhancing prospects of
23 potential mergers in conjunction with growth forecasts that do not include
24 the growth-enhancing prospects of potential mergers produces DCF
25 results that tend to distort a company's cost of equity.

26 Q 87 For your smaller utility group, why do you retain only companies that have
27 equal to or greater than 80 percent of total assets devoted to regulated
28 utility operations and bond ratings equal to or greater than BBB?

29 A 87 For my smaller utility group, I retain only those companies in order to
30 assess the impact of selection criteria relating to regulated assets and
31 bond ratings on my estimate of the cost of equity.

32 Q 88 Please summarize the results of your application of the DCF model to
33 your comparable groups of utilities.

1 A 88 My application of the DCF model to my comprehensive group of utilities
2 produces a result of 10.3 percent, and to my smaller group of utilities,
3 10.1 percent (see Exhibit 6 and Exhibit 7).

4 **B. Risk Premium Method**

5 Q 89 Please describe the risk premium method of estimating Newfoundland
6 Power's cost of equity.

7 A 89 The risk premium method is based on the principle that investors expect
8 to earn a return on an equity investment in Newfoundland Power that
9 reflects a "premium" over and above the return they expect to earn on an
10 investment in a portfolio of bonds. This equity risk premium compensates
11 equity investors for the additional risk they bear in making equity
12 investments versus bond investments.

13 Q 90 Does the risk premium approach specify what debt instrument should be
14 used to estimate the interest rate component in the methodology?

15 A 90 No. The risk premium approach can be implemented using virtually any
16 debt instrument. However, the risk premium approach does require that
17 the debt instrument used to estimate the risk premium be the same as the
18 debt instrument used to calculate the interest rate component of the risk
19 premium approach. For example, if the risk premium on equity is
20 calculated by comparing the returns on stocks and the returns on A-rated
21 utility bonds, then the interest rate on A-rated utility bonds must be used
22 to estimate the interest rate component of the risk premium approach.

23 Q 91 How do you measure the required risk premium on an equity investment
24 in Newfoundland Power?

25 A 91 I use two methods to estimate the required risk premium on an equity
26 investment in Newfoundland Power. The first is called the ex post risk
27 premium method and the second is called the ex ante risk premium
28 method.

29 **1. Ex Post Risk Premium Method**

30 Q 92 Please describe your ex post risk premium method for estimating the
31 required risk premium on an equity investment in your comparable
32 utilities.

1 A 92 My ex post risk premium method estimates the required risk premium on
2 an equity investment in my comparable utilities from historical data on the
3 returns experienced by investors in Canadian utility stocks compared to
4 investors in long-term Canada bonds.

5 Q 93 How do you measure the returns experienced by investors in Canadian
6 utility stocks?

7 A 93 I measure the returns experienced by investors in Canadian utility stocks
8 from historical data on returns earned by investors in: (1) the S&P/TSX
9 utilities stock index^[4]; and (2) a basket of Canadian utility stocks created
10 by the BMO CM.

11 Q 94 What companies are currently included in these indices of Canadian utility
12 stock performance?

13 A 94 As discussed above, the companies included in the S&P/TSX utilities
14 stock index are ATCO Ltd., Atlantic Power Corporation, Algonquin Power
15 & Utilities Corp., Capital Power Corporation, Canadian Utilities Limited,
16 Emera Incorporated, Fortis Inc., Just Energy Group Inc., Northland Power
17 Inc., and TransAlta Corporation.

18 The BMO CM basket of utility and pipeline companies includes
19 Canadian Utilities Ltd., Emera Inc., Enbridge Inc., Fortis Inc., and
20 TransCanada Corporation. The BMO CM basket also includes return data
21 for Westcoast Energy Inc. until December 2001 and Terasen Inc. through
22 July 2005.

23 Q 95 What time periods are covered in your Canadian utility stock return data?

24 A 95 The S&P/TSX utilities stock return data cover the period 1956 through
25 2011, and the BMO CM stock return data cover the period 1983 through
26 2011.

[4] The legacy S&P/TSX utilities index was discontinued by Standard & Poor's in Spring 2002 when Standard & Poor's introduced a new S&P/TSX Composite utilities index that included the GICs 5500 utilities. Standard & Poor's provided total return index value data going back to 1999. The historical data on returns earned by investors in the S&P/TSX utilities index therefore includes total returns on the S&P/TSX legacy utilities index through 1998 and total returns on the new S&P/TSX composite utilities index from 1999 through 2011.

1 Q 96 Why do you analyze investors' experienced returns over such long time
2 periods?

3 A 96 I analyze investors' experienced returns over long time periods because
4 experienced returns over short periods can deviate significantly from
5 expectations. However, I also recognize that experienced returns over
6 long periods may also deviate from expected returns if the data in some
7 portion of the long time period are unreliable.

8 Q 97 Would your study provide different risk premium results if you had
9 included different time periods?

10 A 97 Yes. The risk premium results vary somewhat depending on the historical
11 time period chosen. My policy is to go back as many years as it is
12 possible to obtain reliable data. With regard to the S&P/TSX utilities
13 index, the data begin in 1956, and for the BMO CM utility stock data set,
14 the data begin in 1983.

15 Q 98 Why do you choose two sets of Canadian utilities stock return
16 performance data rather than simply relying entirely on either the
17 S&P/TSX utilities stock index data or the BMO CM utility stock data set?

18 A 98 I choose two sets of Canadian utility stock return performance data
19 because each data set provides different information on Canadian utility
20 stock returns. The S&P/TSX utilities index is valuable because it provides
21 information on the returns experienced by investors in a portfolio of
22 Canadian utility stocks over a relatively long period of time. However, six
23 of the ten companies included in the S&P/TSX utility index operate mainly
24 in non-traditional utility markets. The BMO CM utility stock return
25 database is valuable because it provides information on the experienced
26 returns for a sample of Canadian companies that receive a significantly
27 higher percentage of revenues from traditional utility operations than the
28 companies in the S&P/TSX index. However, the time period covered is
29 not as long as the period covered by the S&P/TSX utility index.

30 Q 99 How are the experienced returns on an investment in each utility data set
31 calculated?

32 A 99 The experienced returns on an investment in each utility data set are
33 calculated from the historical record of stock prices and dividends for the

1 companies in the data set. From the historical record of stock prices and
2 dividends, the index sponsors construct an index of investors' wealth at
3 the end of each period, assuming a \$100 investment in the index at the
4 time the index was constructed. An annual rate of return is calculated
5 from the wealth index by dividing the wealth index at the end of each
6 period by the wealth index at the beginning of the period and subtracting
7 one [$r_t = (W_t \div W_{t-1}) - 1$].

8 Q 100 How do you measure the interest rate earned on long-term Canada
9 bonds in your experienced, or ex post, risk premium studies?

10 A 100 I use the interest rate data on long-term Canada bonds reported by the
11 Bank of Canada.

12 Q 101 What average risk premium results do you obtain from your analysis of
13 returns experienced by investors in Canadian utility stocks?

14 A 101 The average experienced risk premium is 6.7 percent, as shown below in
15 Table 2. (The annual data that produce these results are shown in
16 Exhibit 8 and Exhibit 9.)

TABLE 2
EX POST RISK PREMIUM RESULTS

COMPARABLE GROUP	PERIOD OF STUDY	AVERAGE STOCK RETURN	AVERAGE BOND YIELD	RISK PREMIUM
S&P/TSX Utilities	1956 – 2011	11.99	7.33	4.7
BMO CM Utilities Stock Data Set	1983 – 2011	16.01	7.24	8.8
Average				6.7

17 Q 102 What conclusions do you draw from your experienced, or ex post, risk
18 premium studies about the required risk premium on an investment in
19 Canadian utility stocks?

20 A 102 My ex post risk premium studies provide evidence that investors require
21 an equity return that is at least 6.7 percentage points above the interest
22 rate on long-term Canada bonds. The Consensus Economics-based
23 forecast interest rate on long-term Canada bonds for 2013 as of June
24 2012 is 2.73 percent. Adding a 6.7 percentage point risk premium to an

1 expected yield of 2.73 percent on long-term Canada bonds and including
2 a conservative 50-basis point allowance for flotation costs and financial
3 flexibility produces an expected return on equity equal to 9.9 percent from
4 my ex post risk premium studies.

5 Q 103 Do you have any evidence that the required equity risk premium may
6 actually be greater than 6.7 percentage points?

7 A 103 Yes. I provide evidence below that the required equity risk premium
8 increases when interest rates decline and decreases when interest rates
9 rise. Since the expected 2.73 percent yield on long Canada bonds is
10 significantly less than the 7.3 percent average yield on long Canada
11 bonds over the period of my ex post risk premium studies, the current
12 required equity risk premium should be significantly higher than the
13 average 6.7 percent equity risk premium I obtain from my ex post risk
14 premium studies.

15 2. Ex Ante Risk Premium Estimate

16 Q 104 Please describe your ex ante risk premium approach for measuring the
17 required risk premium on an equity investment in Newfoundland Power.

18 A 104 My ex ante risk premium method is based on studies of the expected
19 return on comparable groups of utilities in each month of my study period
20 compared to the interest rate on long-term government bonds.

21 Q 105 How do you estimate the forward-looking required equity risk premium on
22 an equity investment in utility stocks in each month of your study period.

23 A 105 My estimate of the required equity risk premium is based on studies of the
24 discounted cash flow ("DCF") expected return on comparable groups of
25 utilities in each month of my study period compared to the interest rate on
26 long-term government bonds. Specifically, for each month in my study
27 period, I calculate the risk premium using the equation,

$$28 \quad RP_{\text{COMP}} = DCF_{\text{COMP}} - I_B$$

29 where:

30 RP_{COMP} = the required risk premium on an equity investment in
31 the comparable utilities,

32 DCF_{COMP} = average DCF expected rate of return on a portfolio of
33 comparable utilities; and

1 I_B = the yield to maturity on an investment in long-term
2 U.S. Treasury bonds.

3 Q 106 What comparable utilities do you use in your forward-looking equity risk
4 premium studies?

5 A 106 I use two sets of comparable U.S. utilities, a natural gas utilities company
6 group and an electric utilities company group. For my natural gas
7 company group, I select all the utilities in Standard & Poor's natural gas
8 company group that: (1) paid dividends during every quarter and did not
9 decrease dividends during any quarter of the past two years; (2) have at
10 least two analysts included in the I/B/E/S mean growth forecast; (3) are
11 not in the process of being acquired; (4) have a Value Line Safety Rank
12 of 1, 2, or 3; and (5) have investment grade S&P bond ratings. For my
13 electric group, I use the Moody's group of 24 electric companies because
14 they are a widely-followed group of utilities, and the use of this constant
15 group greatly simplifies the data collection task required to estimate the
16 ex ante risk premium over the months of my study. Simplifying the data
17 collection task is desirable because my forward-looking equity risk
18 premium studies require that the DCF model be estimated for every
19 company in every month of the study period.

20 Q 107 Why do you use U.S. utilities rather than Canadian utilities in your
21 forward-looking, or ex ante, risk premium studies?

22 A 107 My ex ante risk premium studies rely on the DCF model to determine the
23 expected risk premium on utility stocks. As noted above, the DCF model
24 requires estimates of investors' growth expectations, which are best
25 measured from the average of analysts' growth forecasts for each
26 company. The difficulty with using Canadian utilities is that there are very
27 few, if any, analysts' growth forecasts available for each Canadian utility
28 over the time periods of my studies.

29 Q 108 How do you test whether your forward-looking required equity risk
30 premium estimates are sensitive to changes in interest rates?

31 A 108 To test whether my estimated monthly equity risk premiums are sensitive
32 to changes in interest rates, I perform a regression analysis of the

relationship between the forward-looking equity risk premium and the yield to maturity on twenty-year U.S. Treasury bonds using the equation:

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

RP_{COMP} = risk premium on comparable company group;

I_B = yield to maturity on long-term U.S. Treasury bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Q 109 What risk premium estimates do you obtain from your forward-looking risk premium studies?

A 109 For my electric utility comparable group, I obtain a forward-looking risk premium equal to approximately 7.7 percent, and for my natural gas comparable group, I obtain a forward-looking risk premium equal to 8.1 percent.

Q 110 What cost of equity results do you obtain from your ex ante risk premium studies?

A 110 As described above, in the ex ante risk premium approach, one must add the expected interest rate on long-term government bonds to the estimated risk premium to calculate the cost of equity. Since Newfoundland Power is a Canadian utility, I estimate the expected yield on long-term government bonds using the forecast interest rate on long-term Canada bonds at the time of my studies, 2.73 percent. Adding this 2.73 percent interest rate to my 7.7 percent and 8.1 percent ex ante risk premium estimates, and adding a fifty-basis-point adjustment for flotation costs and financial flexibility, I obtain cost of equity estimates of 10.9 percent and 11.3 percent ($2.7 + 7.7 + 0.5 = 10.9$ and $2.7 + 8.1 + 0.5 = 11.3$). The data underlying these estimates are contained in Exhibit 10 and Exhibit 11, which compare DCF expected returns on electric and

1 natural gas utilities to the interest rate on long-term government bonds. A
2 detailed description of my ex ante risk premium approach and results is
3 contained in Appendix 2.

4 **C. Capital Asset Pricing Model (“CAPM”)**

5 Q 111 What is the CAPM?

6 A 111 The CAPM is an equilibrium model of the security markets in which the
7 expected or required return on a given security is equal to the risk-free
8 rate of interest, plus the company equity “beta”, times the market risk
9 premium:

10
$$\text{Cost of equity} = \text{Risk-free rate} + \text{Equity beta} \times \text{Market risk premium}$$

11 The risk-free rate in this equation is the expected rate of return on a risk-
12 free government security, the equity beta is a measure of the company’s
13 risk relative to the market as a whole, and the market risk premium is the
14 premium investors require to invest in the market basket of all securities
15 compared to the risk-free security.

16 Q 112 How do you use the CAPM to estimate the cost of equity for your proxy
17 companies?

18 A 112 The CAPM requires an estimate of the risk-free rate, the company-
19 specific risk factor or beta, and the expected return on the market
20 portfolio. For my estimate of the risk-free rate, I use the 2.73 percent
21 forecasted yield to maturity on long Canada bonds. For my estimate of
22 the company-specific risk, or beta, I use the average Value Line beta of
23 0.73 for my large proxy utility group. For my estimate of the expected risk
24 premium on the market portfolio, I use the Ibbotson® SBBI® 6.6 percent
25 risk premium on the market portfolio, which is measured from the
26 difference between the arithmetic mean return on the S&P 500 and the
27 income return on twenty-year Treasury bonds.

28 Q 113 Why do you recommend that the risk premium on the market portfolio be
29 estimated using the arithmetic mean return, rather than the geometric
30 mean return, on the S&P 500?

1 A 113 As explained in Ibbotson® SBBI®, the arithmetic mean return is the best
2 approach for calculating the return investors expect to receive in the
3 future:

4 The equity risk premium data presented in this book are
5 arithmetic average risk premia as opposed to geometric
6 average risk premia. The arithmetic average equity risk
7 premium can be demonstrated to be most appropriate when
8 discounting future cash flows. For use as the expected equity
9 risk premium in either the CAPM or the building block
10 approach, the arithmetic mean or the simple difference of the
11 arithmetic means of stock market returns and riskless rates is
12 the relevant number. This is because both the CAPM and the
13 building block approach are additive models, in which the cost
14 of capital is the sum of its parts. The geometric average is
15 more appropriate for reporting past performance, since it
16 represents the compound average return.^[5]

17 Q 114 Why do you recommend that the risk premium on the market portfolio be
18 estimated using the income return on twenty-year Treasury bonds rather
19 than the total return on these bonds?

20 A 114 As discussed above, the CAPM requires an estimate of the risk-free rate
21 of interest. When Treasury bonds are issued, the income return on the
22 bond is risk free, but the total return, which includes both income and
23 capital gains or losses, is not. Thus, the income return should be used in
24 the CAPM because it is only the income return that is risk free.

25 Q 115 What CAPM result do you obtain when you estimate the expected return
26 on the market portfolio from the arithmetic mean difference between the
27 return on the market and the yield on twenty-year Treasury bonds?

28 A 115 I obtain a CAPM estimate of 8.05 percent based on a risk-free rate of
29 2.73 percent, a beta of .73, a market risk premium of 6.6 percent, and a
30 fifty basis point allowance for flotation costs and financial flexibility (see
31 Exhibit 12).

32 Q 116 Is there any evidence from the finance literature that the CAPM may
33 underestimate the cost of equity?

34 A 116 Yes. There is substantial evidence that: (1) the CAPM tends to
35 underestimate the cost of equity for companies whose equity beta is less

[5] Ibbotson® SBBI® 2011 Valuation Edition Yearbook, p. 56.

1 than 1.0; and (2) the CAPM is less reliable the further the estimated beta
2 is from 1.0.

3 Q 117 What is the evidence that the CAPM tends to underestimate the cost of
4 equity for companies with betas less than 1.0 and is less reliable the
5 further the estimated beta is from 1.0?

6 A 117 The original evidence that the CAPM tends to underestimate the cost of
7 equity for companies whose equity beta is less than 1.0 and is less
8 reliable the further the estimated beta is from 1.0 was presented in a
9 paper by Black, Jensen, and Scholes (1972), "The Capital Asset Pricing
10 Model: Some Empirical Tests." Numerous subsequent papers have
11 validated the Black, Jensen, and Scholes findings, including those by
12 Litzenberger and Ramaswamy (1979), Banz (1981), Fama and French
13 (1992), Fama and French (2004), Fama and MacBeth (1973), and
14 Jegadeesh and Titman (1993).[6]

15 Q 118 Can you briefly summarize these articles?

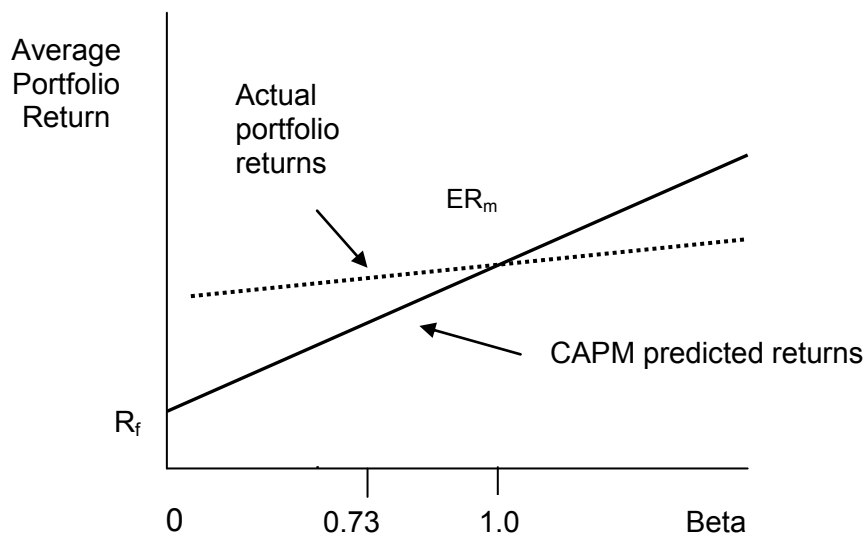
16 A 118 Yes. The CAPM conjectures that security returns increase with increases
17 in security betas in line with the equation

$$ER_i = R_f + \beta_i (ER_m - R_f),$$

[6] Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in *Studies in the Theory of Capital Markets*, M. Jensen, ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and Dividends on Capital Asset Prices: Theory and Empirical Evidence," *Journal of Financial Economics* 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," *Journal of Financial Economics* (March 1981), pp. 3-18; Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Returns," *Journal of Finance* (June 1992), 47:2, pp. 427-465; Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives* (Summer 2004), 18:3, pp. 25 – 46; Narasimhan Jegadeesh and Sheridan Titman, "Returns to Buying Winners and Selling Losers: Implications for Stock Market Efficiency," *The Journal of Finance*, Vol. 48, No. 1. (Mar., 1993), pp. 65-91.

where ER_i is the expected return on security or portfolio i , R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and β_i is a measure of the risk of investing in security or portfolio i (see Figure 1 below).

FIGURE 1
AVERAGE RETURNS COMPARED TO BETA
FOR PORTFOLIOS FORMED ON PRIOR BETA



Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that the relationship between returns and betas is inconsistent with the relationship posited by the CAPM.

If the CAPM correctly predicts achieved returns in the marketplace, the actual portfolio returns should fall on the straight line from R_f through ER_m . However, as described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 1 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 1 than the straight line, they generally agree that the dotted line lies above the straight line for portfolios with betas less

1 than 1.0 and below the straight line for portfolios with betas greater than
2 1.0. Thus, in practice, scholars generally agree that the CAPM
3 underestimates portfolio returns for companies with betas less than 1.0
4 and is less reliable the further the estimated beta is from 1.0.

5 Q 119 Do you have evidence that the CAPM tends to underestimate the cost of
6 equity for utility companies?

7 A 119 Yes. Over the period 1937 to 2012, investors in the S&P Utilities Stock
8 Index have earned an average risk premium over the yield on long-term
9 U.S. Treasury bonds equal to 5.21 percent, while investors in the
10 S&P 500 have earned an average risk premium over the yield on long-
11 term U.S. Treasury bonds equal to 5.67 percent. According to the CAPM,
12 investors in utility stocks should expect to earn a risk premium over the
13 yield on long-term Treasury bonds equal to the average utility beta times
14 the expected risk premium on the S&P 500. Thus, the ratio of the average
15 risk premium on the utility portfolio to the average risk premium on the
16 S&P 500 should equal the utility beta (that is, utility beta = average risk
17 premium on utility stocks ÷ average risk premium S&P 500). However, the
18 average Value Line utility beta at the time of my studies is 0.73, whereas
19 the historical ratio of the average utility risk premium to the average
20 S&P 500 risk premium is 0.92 ($5.21 \div 5.67 = 0.92$) (see Exhibit 13). In
21 short, an application of the CAPM using the average 0.73 Value Line beta
22 significantly underestimates the cost of equity for utility companies.

23 Q 120 What CAPM result would you obtain with a 0.92 beta, rather than the
24 average Value Line 0.73 beta of your proxy utilities?

25 A 120 I would obtain a CAPM estimate of 9.3 percent, based on a risk-free rate
26 of 2.73 percent, a beta of .92, a market risk premium of 6.6 percent, and a
27 fifty basis point allowance for flotation costs and financial flexibility (see
28 Exhibit 14).

29 Q 121 You note that, according to the CAPM, the utility beta is equal to the
30 average or expected risk premium on utility stocks divided by the average
31 or expected risk premium on the market index. Have you compared the
32 average risk premiums on Canadian utility stocks to the average risk
33 premium on the Canadian market index?

1 A 121 Yes. I find that the average historical risk premiums on Canadian utility
2 stocks over the periods 1956 to 2012 and 1983 to 2012 have exceeded
3 the average historical risk premium on the S&P TSX Composite over the
4 same periods (see Exhibit 15). In its 2009 Order, the Board concluded
5 that the CAPM cost of equity for Newfoundland Power was 9.0 percent
6 based primarily on CAPM evidence, using a beta for Canadian utility
7 stocks of approximately 0.60. In contrast, my results indicate that the beta
8 for Canadian utilities could, in fact, be greater than 1.0. From these
9 results, I conclude either that the Board's short-run 0.60 measured beta
10 underestimates the long run risk of investing in Canadian utility stocks, or
11 that the CAPM is unable to predict the returns on Canadian utility stocks;
12 and, thus, the CAPM should not be used to estimate the cost of equity.

13 Q 122 Are factors other than those you discuss above causing CAPM estimates
14 of the cost of equity to be unrealistically low at this time?

15 A 122 Yes. In addition to the reasons discussed above, the CAPM produces
16 unrealistically low results because the CAPM results are highly sensitive
17 to the estimate of the risk-free rate as measured by the yield on long-term
18 government bonds. At this time, the yield on long-term government bonds
19 is unusually low, reflecting policy decisions of Canadian and U.S.
20 governments, the Bank of Canada, and the U.S. Federal Reserve Bank to
21 keep interest rates low in order to stimulate their economies. The use of
22 an unusually low risk-free rate in the CAPM is an additional factor that
23 causes the CAPM to underestimate the cost of equity.

24 Q 123 What conclusions do you draw from your review of the CAPM literature
25 and the evidence that available utility estimated betas are significantly
26 less than the historical ratio of the utility risk premium to the risk premium
27 on the market portfolio?

28 A 123 From my review of the literature, I conclude that the CAPM
29 underestimates the cost of equity for companies with betas significantly
30 less than 1.0 and is less reliable the further the estimated beta is from
31 1.0. From my review of historical risk premiums on utility stocks versus
32 the risk premiums on the market portfolios, I conclude that either:
33 (1) actual utility betas are significantly higher than published historical

betas; or (2) the CAPM fails to explain actual utility returns in the marketplace. Thus, I conclude that the cost of equity model results from applying the CAPM should be given little or no weight in estimating Newfoundland Power's cost of equity in this proceeding.

D. Cost of Equity Conclusion

Q 124 Based on your application of the DCF, risk premium, and CAPM methods to your comparable risk companies, what is your conclusion regarding your comparable risk companies' cost of equity?

A 124 I conclude that my comparable utilities' cost of equity is 10.4 percent based on my application of the DCF, Ex Post Risk Premium, and Ex Ante Risk Premium methods to my proxy groups of utilities (see Table 3). For the reasons expressed above, I give no weight to the results of the CAPM.

**TABLE 3
SUMMARY OF COST OF EQUITY RESULTS**

METHOD	MODEL RESULT
Discounted Cash Flow	10.2
Ex Post Risk Premium	9.9
Ex Ante Risk Premium	11.1
Average	10.4

VI. Allowed ROEs and Equity Ratios for Comparable Risk Utilities

Q 125 Do you have evidence on recent allowed rates of return on equity for U.S. utilities?

A 125 Yes. I have evidence on recent allowed rates of return on equity for U.S. electric and natural gas utilities from January 2010 through June 2012. Since January 2010, the average allowed ROE for electric utilities has been 10.5 percent, and for natural gas utilities, 10.1 percent (see Exhibit 16 and Exhibit 17).

Q 126 Why do you examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities?

A 126 I examine data on allowed rates of return on equity for U.S. utilities rather than Canadian utilities because: (1) there are significantly more allowed ROE and equity ratio decisions for U.S. utilities than for Canadian utilities;

1 (2) U.S. utilities are broadly comparable in risk to Canadian utilities; and
2 (3) information on U.S. allowed ROEs and equity ratios provide an
3 independent test of the fairness of the allowed ROEs and equity ratios for
4 Canadian utilities such as Newfoundland Power.

5 Q 127 Are allowed rates of return on equity the best measure of the cost of
6 equity at each point in time?

7 A 127 No. Since the cost of equity is determined by investors in the
8 marketplace, not by regulators, the cost of equity is best measured using
9 market models such as the equity risk premium and the discounted cash
10 flow model. However, as noted above, because allowed rates of return
11 are based on regulators' judgments regarding the cost of equity and fair
12 rate of return, they provide additional information on the reasonableness
13 of Newfoundland Power's recommended ROE.

14 Q 128 How do the approved equity ratios for U.S. utilities compare to
15 Newfoundland Power's current 45 percent allowed equity ratio?

16 A 128 The average approved equity ratio for U.S. electric and natural gas
17 utilities during the period January 2010 through June 2012 is 49 percent
18 (see Exhibit 18 and Exhibit 19). Thus, the average approved equity ratio
19 for U.S. utilities is significantly higher than Newfoundland Power's current
20 45 percent allowed equity ratio.

21 Q 129 How does Newfoundland Power's current 45 percent allowed equity ratio
22 compare to the approved equity ratios for other Canadian gas and electric
23 distribution utilities?

24 A 129 Newfoundland Power's requested equity ratio is higher than the average
25 approved equity ratio of Canadian gas and electric distribution utilities
26 (see TABLE 4).

TABLE 4
DEEMED EQUITY RATIOS FOR CANADIAN UTILITIES

Company	Deemed Equity Ratio
AltaGas	43%
ATCO Electric Disco	39%
ATCO Gas	39%
Enbridge Gas	36%
ENMAX Disco	41%
EPCOR Disco	41%
FortisAlberta	41%
Gaz Metro	38.5%
Gazifère	38.5%
Heritage Gas Ltd.	45%
Newfoundland Power	45%
Nova Scotia Power	40%
Pacific Northern Gas	40% - 45%
Terasen (FortisBC Energy)	40%
Union	36%

1 Q 130 How does Newfoundland Power's current 45 percent allowed equity ratio
2 compare to the market value equity ratios for your comparable groups of
3 U.S. utilities at June 2012?

4 A 130 The average market value equity ratio for my comprehensive group of
5 U.S. utilities at June 2012 is 61 percent, and for my smaller group of U.S.
6 utilities, 63 percent (see Exhibit 20 and Exhibit 21). Thus, Newfoundland
7 Power's 45 percent allowed equity ratio is significantly less than the
8 average market value equity ratios for my groups of U.S. utilities.

9 Q 131 Why do you present evidence on market value equity ratios for U.S.
10 utilities as well as evidence on book value equity ratios?

11 A 131 I present evidence on market value equity ratios as well as book value
12 equity ratios because, as discussed above, financial risk depends on the
13 market value percentages of debt and equity in a company's capital
14 structure rather than on the book value percentages of debt and equity in
15 the company's capital structure.

16 Q 132 What conclusions do you draw from your evidence that allowed ROEs
17 and equity ratios for comparable U.S. utilities are significantly higher than
18 Newfoundland Power's allowed ROE and equity ratio?

1 A 132 My evidence on allowed ROEs and allowed equity ratios for U.S. utilities
2 provides support for the conclusion that neither Newfoundland Power's
3 formula-generated ROE of 7.59 percent nor its 2011 settlement ROE of
4 8.38 percent, in combination with its allowed equity ratio, produces a
5 return that satisfies the fair rate of return standard.

6 **VII. The Board's ROE Formula**

7 Q 133 Are you familiar with the Board's ROE formula for Newfoundland Power?

8 A 133 Yes. The Board's ROE formula for Newfoundland Power has two parts:
9 (1) an estimate of Newfoundland Power's cost of equity in a specific year,
10 based primarily on the application of the Capital Asset Pricing Model
11 ("CAPM"); and (2) an automatic adjustment formula that "adjusts" the cost
12 of equity in subsequent years for changes in the forecast interest rate on
13 long-term Canadian government bonds.

14 Q 134 What is the CAPM?

15 A 134 The CAPM is an equilibrium model of the security markets in which the
16 expected or required return on a given security is equal to the risk-free
17 rate of interest, plus the company equity "beta," times the market risk
18 premium:

19
$$\text{Cost of equity} = \text{Risk-free rate} + \text{Equity beta} \times \text{Market risk premium}$$

20 The risk-free rate in this equation is the expected rate of return on a risk-
21 free government security, the equity beta is a measure of the company's
22 risk relative to the market as a whole, and the market risk premium is the
23 premium investors require to invest in the market basket of all securities
24 compared to the risk-free security.

25 Q 135 When did the Board last apply the CAPM to estimate Newfoundland
26 Power's cost of equity?

27 A 135 The Board last applied the CAPM to estimate Newfoundland Power's cost
28 of equity for 2010 in Order No. P. U. 43 (2009).

29 Q 136 What CAPM cost of equity did the Board find for Newfoundland Power in
30 Order No. P. U. 43?

31 A 136 The Board found a CAPM cost of equity equal to 8.6 percent, based on a
32 forecast long-term Canada government bond yield equal to 4.5 percent,

1 an equity beta equal to 0.60, a market risk premium equal to 6.0 percent,
2 and an allowance for financing flexibility equal to 0.50 percent ($8.6 = 4.5 +$
3 $0.60 \times 6 + 0.50$).

4 Q 137 Did the Board rely entirely on the results of the CAPM to estimate
5 Newfoundland Power's cost of equity for 2010?

6 A 137 No. The Board adjusted its 8.6 percent CAPM cost of equity result
7 upward to 9.0 percent, based on its review of (1) the results of other cost
8 of equity methodologies; (2) recent decisions of other regulators in
9 Canada; and (3) Newfoundland Power's credit metrics.

10 Q 138 You mention that the Board's ROE formula also includes an automatic
11 adjustment formula. Does the Board consider the continued use of the
12 automatic adjustment formula in Order No. P. U. 43?

13 A 138 Yes. In Order No. P. U. 43, the Board concludes that the automatic
14 adjustment formula should be continued in 2011 and 2012. As the Order
15 states:

16 Formulaic approaches to the determination of a return on equity
17 do not allow for the exercise of discretion based on a
18 comprehensive review of all the relevant circumstances at the
19 time. The Board believes that the benefit of a cost of capital
20 hearing must be weighed against the significant costs to
21 customers. While it is clear that financial market conditions were
22 unstable in late 2008 and early 2009 Newfoundland Power did
23 not demonstrate that the use of the automatic adjustment formula
24 is inappropriate for future years. Discontinuing the formula at this
25 time would in the Board's view, be an excessive response to
26 financial market conditions which, while severe in the fall of 2008
27 and spring of 2009, appear to be settling. The Board believes that
28 it is appropriate to continue to use a formula to adjust
29 Newfoundland Power's return on rate base for several years
30 following a full review in a general rate application. Therefore the
31 Board will order the continued use of the automatic adjustment
32 formula for 2011 and 2012. [P. U. 43, p. 29]

33 Q 139 What is the Board's most recent ROE Formula for Newfoundland Power?

34 A 139 The Board's most recent ROE Formula is given by the equation:

1 ROE = 9.00% + [0.80 x (RFR – 4.50)]

2 where:

- 3 • 9.00 is the return on equity approved for rate making purposes in
- 4 2010;
- 5 • 0.80 is the adjustment coefficient for the change in the forecast
- 6 risk-free rate;
- 7 • RFR is the risk-free rate; and
- 8 • 4.50 is the risk-free rate approved by the Board for the 2010 Test
- 9 Year.

10 Q 140 The ROE Formula uses an adjustment coefficient equal to 0.80. How
11 should this coefficient be interpreted?

12 A 140 The 0.80 adjustment coefficient reflects the Board's opinion that
13 Newfoundland Power's required ROE changes by eighty percent of the
14 forecasted change in long-term Canada government bond yields.
15 Specifically, the 0.80 adjustment coefficient suggests that Newfoundland
16 Power's required ROE increases by eighty basis points when the
17 forecasted long-term Canada bond yield increases by one hundred basis
18 points and declines by eighty basis points when the forecasted long-term
19 Canada bond yield decreases by one hundred basis points.

20 Q 141 What does a 0.80 adjustment coefficient suggest about the equity
21 investor's required risk premium on an investment in Newfoundland
22 Power?

23 A 141 The 0.80 adjustment coefficient suggests that the equity investor's equity
24 risk premium increases by twenty basis points when the interest rate on
25 long-term Canada bonds declines by one hundred basis points.

26 Q 142 How is the risk-free rate determined in the ROE formula?

27 A 142 The risk-free rate is determined by adding the average of the three-month
28 and twelve-month forecast of ten-year Government of Canada Bonds as
29 published by Consensus Forecasts in the preceding November to the
30 average observed spread between ten-year and thirty-year Government
31 of Canada Bonds for all trading days in the preceding October.

32 Q 143 What is the value of the forecast risk-free rate at June 2012?

33 A 143 At June 2012, the forecast risk-free rate is 2.73 percent.

1 Q 144 Using a 2.73 percent forecast yield on long-term Canada bonds, what
2 ROE is obtained using the ROE Formula?

3 A 144 The ROE Formula produces an ROE equal to 7.59 percent. This result is
4 calculated as follows: $7.59 = 9.00 + [0.80 \times (2.73 - 4.50)]$.

5 Q 145 What equity risk premium is suggested by the ROE Formula?

6 A 145 The ROE Formula indicates an equity risk premium equal to 4.86 percent
7 $(7.59 - 2.73 = 4.86)$.

8 **VIII. Tests of the Fairness of the 7.59 Percent Formula ROE**

9 Q 146 Have you performed any tests of the fairness of the 7.59 percent allowed
10 ROE provided by the ROE Formula?

11 A 146 Yes. I have performed seven tests of the fairness of the 7.59 percent
12 ROE provided by the ROE Formula. First, I have examined evidence on
13 the experienced returns achieved by equity investors in two groups of
14 Canadian utilities compared to interest rates on long-term Canada bonds.
15 My studies indicate that the average experienced equity risk premium on
16 an investment in Canadian utility stocks, 6.7 percent (see Table 2), is
17 approximately 180 basis points higher than the 4.86 percent risk premium
18 produced by the ROE Formula. This evidence supports the conclusion
19 that the ROE Formula does not provide a fair ROE for Newfoundland
20 Power.

21 Second, I have examined evidence on my comparable utilities' cost of
22 equity as measured by the DCF, ex post risk premium, and ex ante risk
23 premium models. From this evidence, I conclude that Newfoundland
24 Power's cost of equity is approximately 10.4 percent. My estimate of
25 Newfoundland Power's cost of equity is approximately 280 basis points
26 higher than the 7.59 percent allowed ROE that would be provided by the
27 Board's ROE Formula.

28 Third, I have examined evidence on the allowed rates of return on
29 equity and allowed common equity ratios for U.S. electric and natural gas
30 utilities. My studies indicate that average allowed rates of return on equity
31 for U.S. utilities since 2010 are in the range 10.1 percent to 10.5 percent,
32 and the average allowed equity ratio is approximately 49 percent (see

1 Section VI above). Since the Board's ROE Formula would produce a
2 7.59 percent ROE on an allowed equity ratio of 45 percent, this evidence
3 supports the conclusion that the ROE Formula would fail to provide a
4 return that is commensurate with returns on other investments of
5 comparable risk.

6 Fourth, I have examined evidence on the historical risk premium on
7 an investment in utility stocks compared to the historical risk premium on
8 the market index. The Board's ROE Formula is based in part on the
9 Board's conclusion that the CAPM is the best method for estimating a
10 company's cost of equity, and that the beta for Canadian utility stocks is
11 approximately 0.60. In the CAPM, the utility beta is equal to the ratio of
12 the expected risk premium on utility stocks to the expected risk premium
13 on the market index. My studies indicate that the ratio of the average
14 historical risk premium on U.S. utility stocks to the average historical risk
15 premium on the S&P 500 is 0.92, while the ratio of the average historical
16 risk premium on Canadian utility stocks to the average historical risk
17 premium on the S&P/TSX Composite is greater than 1.0. This evidence
18 supports the conclusion that either: (1) the Board's 0.60 beta
19 underestimates the long-run risk of investing in Canadian utility stocks; or
20 (2) the CAPM is unable to predict the return on utility stocks; and, thus,
21 the CAPM should not be used to estimate Newfoundland Power's cost of
22 equity.

23 Fifth, I have examined evidence on the sensitivity of the forward-
24 looking, or ex ante, required equity risk premium on utility stocks to
25 changes in interest rates. The ROE Formula suggests that Newfoundland
26 Power's required ROE declines by eighty basis points when the risk-free
27 rate declines by one hundred basis points. Contrary to the eighty-basis-
28 point decline provided by the ROE Formula, my studies indicate that NP's
29 required ROE declines by less than fifty basis points for every one
30 hundred basis point decline in the risk-free rate. From my ex ante risk
31 premium studies, I find that the forward-looking required equity risk
32 premium on utility stocks, 7.9 percent, is approximately 300 basis points
33 higher than the 4.86 percent risk premium suggested by the ROE

1 Formula. This evidence further supports the conclusion that the ROE
2 Formula does not provide a fair ROE for Newfoundland Power.

3 Sixth, I have examined evidence on the sensitivity of the equity risk
4 premium implied by U.S. utility allowed rates of return on equity to
5 changes in the interest rate on long-term government bonds. My studies
6 indicate that U.S. utility allowed ROEs are significantly less sensitive to
7 changes in interest rates on long-term government bonds than the
8 allowed ROE established by the ROE Formula. Specifically, while the
9 ROE Formula reduces the allowed ROE by eighty basis points when the
10 forecasted yield to maturity on long-term government bonds declines by
11 one hundred basis points, U.S. regulators typically reduce the allowed
12 ROE by approximately fifty basis points when the yield to maturity on
13 long-term government bonds declines by one hundred basis points (see
14 Exhibit 22). This evidence also supports the conclusion that the ROE
15 Formula is not working.

16 Seventh, I have examined evidence on the volatility of returns on
17 Canadian utility stocks compared to the volatility of returns on the
18 Canadian market index. My studies indicate that the volatility of returns on
19 Canadian utility stocks exceeds or approximates the volatility of returns
20 on the Canadian market index (see [Exhibit 15](#)). Because investors
21 demand a higher return for bearing more risk, this evidence also supports
22 the conclusion that the equity risk premium on Canadian utility stocks is
23 higher than the equity risk premium implied by the ROE Formula.

24 **IX. Summary and Recommendations**

25 Q 147 Please summarize your written evidence in this proceeding.

26 A 147 My written evidence may be summarized as follows:

- 27 1. The business risk of Canadian utilities such as Newfoundland Power is
28 approximately equal to the business risk of the average U.S. utility,
29 while the financial risk of Canadian utilities, as measured by their equity
30 ratios, is greater than the financial risk of the average U.S. utility.
- 31 2. It is reasonable to use information on required ROEs for both Canadian
32 and U.S. utilities to estimate Newfoundland Power's cost of equity

1 because: (i) the sample of publicly-traded Canadian regulated utilities is
2 significantly smaller than the sample of publicly-traded U.S. regulated
3 utilities; (ii) the average publicly-traded U.S. utility is more involved in
4 traditional utility operations than the average publicly-traded Canadian
5 utility; and (iii) the data required to estimate the cost of equity is more
6 readily available for U.S. utilities than for Canadian utilities.

7 3. The cost of equity for investments in comparable risk Canadian and
8 U.S. utilities is 10.4 percent based on DCF, Ex Post Risk Premium, and
9 Ex Ante Risk Premium studies.

10 4. Recent average allowed returns on equity for U.S. utilities are in the
11 range 10.1 percent to 10.5 percent.

12 5. Recent average allowed equity ratios for U.S. utilities are approximately
13 49 percent, whereas the allowed equity ratio for Newfoundland Power is
14 45 percent.

15 6. Recent average market value equity ratios for U.S. utilities are in the
16 range 61 percent to 63 percent.

17 7. The Board's ROE Formula currently would produce an allowed return
18 on equity equal to 7.59 percent.

19 Q 148 What conclusion do you reach from this evidence?

20 A 148 I conclude that Newfoundland Power's current 8.8 percent allowed ROE
21 on a 45 percent deemed equity ratio and its 7.59 percent Formula ROE
22 on a 45 percent deemed equity ratio both produce an allowed return on
23 rate base that is significantly less than the overall rate of return that
24 investors could earn on other investments of similar risk.

25 Q 149 What is your specific recommendation regarding the rate of return on
26 equity and equity ratio for Newfoundland Power?

27 A 149 I conservatively recommend that Newfoundland Power be awarded an
28 allowed ROE of 10.4 percent on an equity ratio of 45 percent.

29 Q 150 Does this conclude your written evidence?

30 A 150 Yes, it does.

EXHIBIT 1
SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

CANADIAN UTILITIES LIMITED						
Segment Assets (\$Canadian millions)						
Year	Total	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations
2011	\$11,696	\$7,903	\$1,891	\$1,340	\$728	-\$166
Percentage of Total Assets						
Year	Total	Utilities	Energy	ATCO Australia	Corporate and Other	Intersegment Eliminations
2011	100.00%	68%	16%	11%	6%	-1%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

EMERA INCORPORATED						
Segment Assets (\$Canadian millions)						
Year	Total	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other
2011	\$6,924	\$3,897	\$963	\$849	\$546	\$669
Percentage of Total Assets						
Year	Total	NSPI	Maine Utility Operations	Caribbean Utility Operations	Brunswick Pipeline	Other
2011	100.00%	56%	14%	12%	8%	10%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

ENBRIDGE INC.						
Segment Assets (\$Canadian millions)						
Year	Total	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing, & Energy Services	Sponsored Investments	Corporate
2011	\$30,220	\$11,508	\$7,594	\$5,536	\$3,833	\$1,749
Percentage of Total Assets						
Year	Total	Liquids Pipelines	Gas Distribution	Gas Pipelines, Processing, & Energy Services	Sponsored Investments	Corporate
2011	100.00%	38%	25%	18%	13%	6%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

FORTIS INC.						
Segment Assets (\$Canadian millions)						
Year	Total	Regulated Gas Utilities - Canadian	Regulated Electric Utilities - Canadian	Regulated Electric Utilities - Caribbean	Non-Regulated - Fortis Generation	Non-Regulated Fortis Properties
2011	\$13,471	\$5,316	\$6,143	\$856	\$542	\$614
Percentage of Total Assets						
Year	Total	Regulated Gas Utilities - Canadian	Regulated Electric Utilities - Canadian	Regulated Electric Utilities - Caribbean	Non-Regulated - Fortis Generation	Non-Regulated Fortis Properties
2011	100.00%	39%	46%	6%	4%	5%

SEGMENT INFORMATION
BMO CM CANADIAN UTILITIES COMPANIES

TRANSCANADA CORPORATION					
Segment Assets (\$Canadian millions)					
Year	Total	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate
2011	\$48,995	\$23,669	\$9,439	\$14,276	\$1,611
Percentage of Total Assets					
Year	Total	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate
2011	100.00%	48%	19%	29%	3%

EXHIBIT 2
SEGMENT INFORMATION
S&P/TSX UTILITIES

ATCO LIMITED						
Segment Assets (\$Canadian millions)						
Year	Total	Structures & Logistics	Utilities	Energy	ATCO Australia	Corporate & Other
2011	\$12,555	\$721	\$7,903	\$1,891	\$1,340	\$700
Percentage of Total Assets						
Year	Total	Structures & Logistics	Utilities	Energy	ATCO Australia	Corporate & Other
2011	100.00%	6%	63%	15%	11%	6%

EXHIBIT 2
SEGMENT INFORMATION
S&P/TSX UTILITIES

ALGONQUIN POWER & UTILITIES CORP.				
Segment Assets (\$Canadian millions)				
Year	Total	Algonquin Power	Liberty Utilities	Corporate
2011	\$1,283	\$659	\$441	\$183
Percentage of Total Assets				
Year	Total	Algonquin Power	Liberty Utilities	Corporate
2011	100.00%	51%	34%	14%

EXHIBIT 3
PERCENT OF TOTAL ASSETS
FOR REGULATED UTILITY SERVICES
COMPREHENSIVE U.S. UTILITY GROUP

LINE NO.	COMPANY	STATUS	% REGULATED
1	AGL Resources	R	80%
2	Alliant Energy	R	87%
3	Amer. Elec. Power	R	97%
4	Atmos Energy	R	97%
5	CenterPoint Energy	MR	72%
6	CMS Energy Corp.	R	89%
7	Consol. Edison	R	89%
8	Dominion Resources	MR	63%
9	DTE	R	81%
10	Duke Energy	MR	77%
11	Exelon Corp.	MR	59%
12	FirstEnergy Corp.	MR	65%
13	Great Plains	R	104% ^[7]
14	Hawaiian Elec.	D	48%
15	NextEra Energy	MR	54%
16	NiSource Inc.	MR	58%
17	Northeast Utilities	R	95%
18	Pepco Holdings	MR	73%
19	Piedmont Natural Gas	R	97%
20	Pinnacle West Capital	R	99%
21	PNM Resources	R	94%
22	Portland General	R	100%
23	Public Serv. Enterprise	MR	56%
24	SCANA Corp.	MR	77%
25	Sempra Energy	MR	66%
26	Southern Co.	R	93%
27	TECO Energy	R	94%
28	Vectren Corp.	R	98%
29	Westar Energy	R	100%
30	WGL Holdings Inc.	R	89%
31	Wisconsin Energy	R	92%
32	Xcel Energy Inc.	R	95%
33	Average		82%

^[7] Great Plains' percent of assets is greater than 104 percent due to intercompany accounting eliminations.

EXHIBIT 4
PERCENT OF TOTAL ASSETS
FOR REGULATED UTILITY SERVICES
U.S. UTILITIES WITH MOSTLY REGULATED ASSETS
AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB

LINE NO.	COMPANY	STATUS	% REGULATED
1	AGL Resources	R	80%
2	Alliant Energy	R	87%
3	Amer. Elec. Power	R	97%
4	Atmos Energy	R	97%
5	Consol. Edison	R	89%
6	DTE	R	81%
7	Great Plains	R	104%
8	Northeast Utilities	R	95%
9	Piedmont Natural Gas	R	97%
10	Pinnacle West Capital	R	99%
11	Portland General	R	100%
12	Southern Co.	R	93%
13	TECO Energy	R	94%
14	Vectren Corp.	R	98%
15	Westar Energy	R	100%
16	WGL Holdings Inc.	R	89%
17	Wisconsin Energy	R	92%
18	Xcel Energy Inc.	R	95%
19	Average		94%

EXHIBIT 5
STANDARD & POOR'S BOND RATINGS
COMPREHENSIVE U.S. UTILITY GROUP

LINE NO.	COMPANY	SAFETY RANK	S&P BOND RATING	S&P BOND RATING (NUMERICAL)
1	AGL Resources	1	BBB+	6
2	Alliant Energy	2	BBB+	6
3	Amer. Elec. Power	3	BBB	7
4	Atmos Energy	2	BBB+	6
5	CenterPoint Energy	3	BBB+	6
6	CMS Energy Corp.	3	BBB-	8
7	Consol. Edison	1	A-	5
8	Dominion Resources	2	A-	5
9	DTE	3	BBB+	6
10	Duke Energy	2	A-	5
11	Exelon Corp.	2	BBB	7
12	FirstEnergy Corp.	2	BBB-	8
13	Great Plains	3	BBB	7
14	Hawaiian Elec.	3	BBB-	8
15	NextEra Energy	2	A-	5
16	NiSource Inc.	3	BBB-	8
17	Northeast Utilities	2	A-	5
18	Pepco Holdings	3	BBB+	6
19	Piedmont Natural Gas	2	A	4
20	Pinnacle West Capital	2	BBB	7
21	PNM Resources	3	BBB-	8
22	Portland General	2	BBB	7
23	Public Serv. Enterprise	2	BBB	7
24	SCANA Corp.	2	BBB+	6
25	Sempra Energy	2	BBB+	6
26	Southern Co.	1	A	4
27	TECO Energy	2	BBB+	6
28	Vectren Corp.	2	A-	5
29	Westar Energy	2	BBB	7
30	WGL Holdings Inc.	1	AA-	2
31	Wisconsin Energy	1	A-	5
32	Xcel Energy Inc.	2	A-	5
33	Average	2	BBB+	6

**STANDARD & POOR'S BOND RATINGS
U.S. UTILITIES WITH MOSTLY REGULATED ASSETS
AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB**

LINE NO.	COMPANY	SAFETY RANK	S&P BOND RATING	S&P BOND RATING (NUMERICAL)
1	AGL Resources	1	BBB+	6
2	Alliant Energy	2	BBB+	6
3	Amer. Elec. Power	3	BBB	7
4	Atmos Energy	2	BBB+	6
5	Consol. Edison	1	A-	5
6	DTE	3	BBB+	6
7	Great Plains	3	BBB	7
8	Northeast Utilities	2	A-	5
9	Piedmont Natural Gas	2	A	4
10	Pinnacle West Capital	2	BBB	7
11	Portland General	2	BBB	7
12	Southern Co.	1	A	4
13	TECO Energy	2	BBB+	6
14	Vectren Corp.	2	A-	5
15	Westar Energy	2	BBB	7
16	WGL Holdings Inc.	1	AA-	2
17	Wisconsin Energy	1	A-	5
18	Xcel Energy Inc.	2	A-	5
19	Average	2	BBB+ - A-	5.6

EXHIBIT 6
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR COMPREHENSIVE GROUP OF U.S. UTILITIES

LINE NO.	COMPANY	D ₀	P ₀	GROWTH	MODEL RESULT
1	AGL Resources	0.460	38.403	3.57%	8.6%
2	Alliant Energy	0.450	44.199	6.35%	10.7%
3	Amer. Elec. Power	0.470	38.510	3.54%	8.7%
4	Atmos Energy	0.345	32.962	4.37%	8.9%
5	CenterPoint Energy	0.203	19.963	4.18%	8.5%
6	CMS Energy Corp.	0.240	22.820	5.96%	10.3%
7	Consol. Edison	0.605	59.853	3.15%	7.4%
8	Dominion Resources	0.528	52.065	5.40%	9.7%
9	DTE	0.588	56.540	4.30%	8.8%
10	Duke Energy	0.750	65.155	3.50%	8.4%
11	Exelon Corp.	0.525	37.993	2.40%	8.2%
12	FirstEnergy Corp.	0.550	47.017	3.15%	8.1%
13	Great Plains	0.213	20.217	9.75%	14.6%
14	Hawaiian Elec.	0.310	26.833	8.03%	13.3%
15	NextEra Energy	0.600	64.657	5.24%	9.1%
16	NiSource Inc.	0.230	24.667	8.00%	12.2%
17	Northeast Utilities	0.343	36.610	6.17%	9.7%
18	Pepco Holdings	0.270	18.882	4.85%	11.1%
19	Piedmont Natural Gas	0.300	30.502	4.55%	8.7%
20	Pinnacle West Capital	0.525	48.697	6.22%	11.0%
21	PNM Resources	0.145	18.569	9.25%	12.4%
22	Portland General	0.270	25.348	3.77%	8.3%
23	Public Serv. Enterprise	0.355	31.027	3.60%	8.4%
24	SCANA Corp.	0.495	46.095	4.50%	9.1%
25	Sempra Energy	0.600	64.373	7.05%	10.8%
26	Southern Co.	0.490	45.923	5.58%	10.1%
27	TECO Energy	0.220	17.623	4.11%	9.4%
28	Vectren Corp.	0.350	29.103	5.00%	10.2%
29	Westar Energy	0.330	28.375	5.80%	10.8%
30	WGL Holdings Inc.	0.400	39.522	4.80%	9.1%
31	Wisconsin Energy	0.300	37.158	5.35%	8.6%
32	Xcel Energy Inc.	0.270	27.438	5.27%	9.4%
33	Average				9.8%
34	Financial Flexibility				0.50%
35	Average				10.3%

Notes:

- d_0 = Most recent quarterly dividend
- d_1, d_2, d_3, d_4 = Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor $(1 + g)$
- P_0 = Average of the monthly high and low stock prices during the three months ending June 2012 per Thomson Reuters
- g = I/B/E/S forecast of future earnings growth June 2012
- k = Cost of equity using the quarterly version of the DCF model:

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0} + g$$

EXHIBIT 7
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR U.S. UTILITIES WITH MOSTLY REGULATED ASSETS
AND S&P BOND RATING EQUAL TO OR GREATER THAN BBB

LINE NO.	COMPANY	D ₀	P ₀	GROWTH	MODEL RESULT
1	AGL Resources	0.460	38.403	3.57%	8.6%
2	Alliant Energy	0.450	44.199	6.35%	10.7%
3	Amer. Elec. Power	0.470	38.510	3.54%	8.7%
4	Atmos Energy	0.345	32.962	4.37%	8.9%
5	Consol. Edison	0.605	59.853	3.15%	7.4%
6	DTE	0.588	56.540	4.30%	8.8%
7	Great Plains	0.213	20.217	9.75%	14.6%
8	Northeast Utilities	0.343	36.610	6.17%	9.7%
9	Piedmont Natural Gas	0.300	30.502	4.55%	8.7%
10	Pinnacle West Capital	0.525	48.697	6.22%	11.0%
11	Portland General	0.270	25.348	3.77%	8.3%
12	Southern Co.	0.490	45.923	5.58%	10.1%
13	TECO Energy	0.220	17.623	4.11%	9.4%
14	Vectren Corp.	0.350	29.103	5.00%	10.2%
15	Westar Energy	0.330	28.375	5.80%	10.8%
16	WGL Holdings Inc.	0.400	39.522	4.80%	9.1%
17	Wisconsin Energy	0.300	37.158	5.35%	8.6%
18	Xcel Energy Inc.	0.270	27.438	5.27%	9.4%
19	Average				9.6%
20	Financial Flexibility				0.50%
21	Average				10.1%

Notes:

- d₀ = Most recent quarterly dividend.
d₁, d₂, d₃, d₄ = Next four quarterly dividends, calculated by multiplying the last four quarterly dividends per *Value Line* by the factor (1 + g)
P₀ = Average of the monthly high and low stock prices during the three months ending June 2012 per Thomson Reuters
g = I/B/E/S forecast of future earnings growth June 2012
k = Cost of equity using the quarterly version of the DCF model

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0} + g$$

EXHIBIT 8
EXPERIENCED RISK PREMIUMS ON
S&P/TSX CANADIAN UTILITIES STOCK INDEX
1956—2011

LINE	YEAR	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	YIELD LONG- TERM CANADA BOND	RISK PREMIUM
1	1956	0.17	3.63	-3.45
2	1957	-3.43	4.11	-7.54
3	1958	9.81	4.15	5.66
4	1959	0.21	5.08	-4.86
5	1960	26.81	5.19	21.62
6	1961	19.17	5.05	14.12
7	1962	-0.72	5.11	-5.83
8	1963	6.19	5.09	1.10
9	1964	21.59	5.18	16.41
10	1965	4.23	5.21	-0.98
11	1966	-13.17	5.69	-18.86
12	1967	5.07	5.94	-0.87
13	1968	7.41	6.75	0.66
14	1969	-8.62	7.58	-16.20
15	1970	23.34	7.91	15.43
16	1971	4.29	6.95	-2.66
17	1972	-0.44	7.23	-7.68
18	1973	-4.14	7.56	-11.70
19	1974	14.38	8.90	5.48
20	1975	5.75	9.04	-3.28
21	1976	15.02	9.18	5.84
22	1977	19.00	8.70	10.30
23	1978	27.28	9.27	18.01
24	1979	12.61	10.21	2.40
25	1980	5.74	12.48	-6.74
26	1981	-0.55	15.22	-15.77
27	1982	35.90	14.26	21.65
28	1983	40.97	11.79	29.17
29	1984	24.31	12.75	11.56
30	1985	10.04	11.04	-1.00
31	1986	11.48	9.52	1.96
32	1987	1.07	9.95	-8.88
33	1988	5.63	10.22	-4.59
34	1989	22.07	9.92	12.15
35	1990	0.58	10.85	-10.28
36	1991	27.02	9.76	17.25
37	1992	-2.24	8.77	-11.00
38	1993	23.52	7.85	15.67

LINE	YEAR	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	YIELD LONG- TERM CANADA BOND	RISK PREMIUM
39	1994	-6.04	8.63	-14.68
40	1995	18.44	8.28	10.16
41	1996	32.68	7.50	25.18
42	1997	37.33	6.42	30.91
43	1998	36.55	5.47	31.09
44	1999	-27.14	5.69	-32.83
45	2000	50.06	5.89	44.17
46	2001	10.83	5.78	5.05
47	2002	6.33	5.66	0.67
48	2003	24.94	5.28	19.66
49	2004	9.42	5.08	4.34
50	2005	38.29	4.39	33.90
51	2006	7.01	4.30	2.71
52	2007	11.89	4.34	7.55
53	2008	-20.46	4.04	-24.50
54	2009	19.00	3.89	15.11
55	2010	18.39	3.66	14.73
56	2011	6.47	3.21	3.26
57	Average	11.99	7.33	4.66

EXHIBIT 9
EXPERIENCED RISK PREMIUMS ON BMO CAPITAL MARKETS
UTILITIES STOCK DATA SET
1983—2011

LINE	YEAR	BMO CAPITAL MARKETS UTILITIES & PIPELINE TOTAL RETURN	YIELD LONG- TERM CANADA BOND	RISK PREMIUM
1	1983	25.84	11.79	14.05
2	1984	6.89	12.75	-5.86
3	1985	20.09	11.04	9.04
4	1986	-1.22	9.52	-10.74
5	1987	11.98	9.95	2.03
6	1988	6.67	10.22	-3.56
7	1989	23.80	9.92	13.88
8	1990	10.00	10.85	-0.86
9	1991	12.92	9.76	3.16
10	1992	0.75	8.77	-8.02
11	1993	33.00	7.85	25.15
12	1994	-1.22	8.63	-9.85
13	1995	15.13	8.28	6.85
14	1996	31.66	7.50	24.15
15	1997	50.16	6.42	43.74
16	1998	4.12	5.47	-1.34
17	1999	-24.11	5.69	-29.80
18	2000	59.57	5.89	53.69
19	2001	16.05	5.78	10.27
20	2002	14.46	5.66	8.80
21	2003	28.74	5.28	23.46
22	2004	15.56	5.08	10.48
23	2005	33.36	4.39	28.97
24	2006	17.77	4.30	13.47
25	2007	4.90	4.34	0.57
26	2008	-4.21	4.04	-8.25
27	2009	20.24	3.89	16.35
28	2010	5.39	3.66	1.73
29	2011	25.89	3.21	22.68
30	Average	16.01	7.24	8.77

EXHIBIT 10
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN
ELECTRIC UTILITIES TO THE INTEREST RATE
ON LONG-TERM GOVERNMENT BONDS

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Sep-99	0.1124	0.0650	0.0474
2	Oct-99	0.1128	0.0666	0.0462
3	Nov-99	0.1158	0.0648	0.0510
4	Dec-99	0.1200	0.0669	0.0531
5	Jan-00	0.1186	0.0686	0.0500
6	Feb-00	0.1232	0.0654	0.0578
7	Mar-00	0.1274	0.0638	0.0636
8	Apr-00	0.1203	0.0618	0.0585
9	May-00	0.1194	0.0655	0.0539
10	Jun-00	0.1209	0.0628	0.0581
11	Jul-00	0.1213	0.0620	0.0593
12	Aug-00	0.1197	0.0602	0.0595
13	Sep-00	0.1137	0.0609	0.0528
14	Oct-00	0.1143	0.0604	0.0539
15	Nov-00	0.1164	0.0598	0.0566
16	Dec-00	0.1140	0.0564	0.0576
17	Jan-01	0.1167	0.0565	0.0602
18	Feb-01	0.1176	0.0562	0.0614
19	Mar-01	0.1180	0.0549	0.0631
20	Apr-01	0.1208	0.0578	0.0630
21	May-01	0.1254	0.0592	0.0662
22	Jun-01	0.1261	0.0582	0.0679
23	Jul-01	0.1269	0.0575	0.0694
24	Aug-01	0.1275	0.0558	0.0717
25	Sep-01	0.1294	0.0553	0.0741
26	Oct-01	0.1286	0.0534	0.0752
27	Nov-01	0.1268	0.0533	0.0735
28	Dec-01	0.1264	0.0576	0.0688
29	Jan-02	0.1246	0.0569	0.0677
30	Feb-02	0.1256	0.0561	0.0695
31	Mar-02	0.1221	0.0593	0.0628
32	Apr-02	0.1201	0.0585	0.0616
33	May-02	0.1208	0.0581	0.0627
34	Jun-02	0.1225	0.0565	0.0660
35	Jul-02	0.1305	0.0551	0.0754
36	Aug-02	0.1269	0.0519	0.0750
37	Sep-02	0.1241	0.0487	0.0754
38	Oct-02	0.1258	0.0500	0.0758
39	Nov-02	0.1210	0.0504	0.0706

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
40	Dec-02	0.1195	0.0501	0.0694
41	Jan-03	0.1166	0.0502	0.0664
42	Feb-03	0.1200	0.0487	0.0713
43	Mar-03	0.1179	0.0482	0.0697
44	Apr-03	0.1138	0.0491	0.0647
45	May-03	0.1066	0.0452	0.0614
46	Jun-03	0.1019	0.0434	0.0585
47	Jul-03	0.1043	0.0492	0.0551
48	Aug-03	0.1034	0.0539	0.0495
49	Sep-03	0.1000	0.0521	0.0479
50	Oct-03	0.0981	0.0521	0.0460
51	Nov-03	0.0957	0.0517	0.0440
52	Dec-03	0.0919	0.0511	0.0408
53	Jan-04	0.0896	0.0501	0.0395
54	Feb-04	0.0892	0.0494	0.0398
55	Mar-04	0.0888	0.0472	0.0416
56	Apr-04	0.0900	0.0516	0.0384
57	May-04	0.0935	0.0546	0.0389
58	Jun-04	0.0934	0.0545	0.0389
59	Jul-04	0.0927	0.0524	0.0403
60	Aug-04	0.0940	0.0507	0.0433
61	Sep-04	0.0925	0.0489	0.0436
62	Oct-04	0.0928	0.0485	0.0443
63	Nov-04	0.0894	0.0489	0.0405
64	Dec-04	0.0896	0.0488	0.0408
65	Jan-05	0.0900	0.0477	0.0423
66	Feb-05	0.0893	0.0461	0.0432
67	Mar-05	0.0894	0.0489	0.0405
68	Apr-05	0.0899	0.0475	0.0424
69	May-05	0.0886	0.0456	0.0430
70	Jun-05	0.0888	0.0435	0.0453
71	Jul-05	0.0877	0.0448	0.0429
72	Aug-05	0.0878	0.0453	0.0425
73	Sep-05	0.0901	0.0451	0.0450
74	Oct-05	0.0911	0.0474	0.0437
75	Nov-05	0.0957	0.0483	0.0474
76	Dec-05	0.0956	0.0473	0.0483
77	Jan-06	0.0957	0.0465	0.0492
78	Feb-06	0.1048	0.0473	0.0575
79	Mar-06	0.1031	0.0491	0.0540
80	Apr-06	0.1050	0.0522	0.0528
81	May-06	0.1063	0.0535	0.0528
82	Jun-06	0.1093	0.0529	0.0564
83	Jul-06	0.1087	0.0525	0.0562
84	Aug-06	0.1050	0.0508	0.0542

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
85	Sep-06	0.1088	0.0493	0.0595
86	Oct-06	0.1052	0.0494	0.0558
87	Nov-06	0.1057	0.0478	0.0579
88	Dec-06	0.1050	0.0478	0.0572
89	Jan-07	0.1075	0.0495	0.0580
90	Feb-07	0.1065	0.0493	0.0572
91	Mar-07	0.1073	0.0481	0.0592
92	Apr-07	0.1021	0.0495	0.0526
93	May-07	0.1047	0.0498	0.0549
94	Jun-07	0.1101	0.0529	0.0572
95	Jul-07	0.1108	0.0519	0.0589
96	Aug-07	0.1083	0.0500	0.0583
97	Sep-07	0.1056	0.0484	0.0572
98	Oct-07	0.1061	0.0483	0.0578
99	Nov-07	0.1093	0.0456	0.0637
100	Dec-07	0.1110	0.0457	0.0653
101	Jan-08	0.1171	0.0435	0.0736
102	Feb-08	0.1109	0.0449	0.0660
103	Mar-08	0.1144	0.0436	0.0708
104	Apr-08	0.1133	0.0444	0.0689
105	May-08	0.1138	0.0460	0.0678
106	Jun-08	0.1112	0.0474	0.0638
107	Jul-08	0.1147	0.0462	0.0685
108	Aug-08	0.1165	0.0453	0.0712
109	Sep-08	0.1159	0.0432	0.0727
110	Oct-08	0.1249	0.0445	0.0804
111	Nov-08	0.1280	0.0427	0.0853
112	Dec-08	0.1270	0.0318	0.0952
113	Jan-09	0.1211	0.0346	0.0865
114	Feb-09	0.1237	0.0383	0.0854
115	Mar-09	0.1250	0.0378	0.0872
116	Apr-09	0.1230	0.0384	0.0846
117	May-09	0.1206	0.0422	0.0784
118	Jun-09	0.1185	0.0451	0.0734
119	Jul-09	0.1142	0.0438	0.0704
120	Aug-09	0.1127	0.0433	0.0694
121	Sep-09	0.1122	0.0414	0.0708
122	Oct-09	0.1122	0.0416	0.0706
123	Nov-09	0.1166	0.0424	0.0742
124	Dec-09	0.1065	0.0440	0.0625
125	Jan-10	0.1082	0.0450	0.0632
126	Feb-10	0.1060	0.0448	0.0612
127	Mar-10	0.1045	0.0449	0.0596
128	Apr-10	0.1081	0.0453	0.0628
129	May-10	0.1062	0.0411	0.0651

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
130	Jun-10	0.1059	0.0395	0.0664
131	Jul-10	0.1049	0.0380	0.0669
132	Aug-10	0.1029	0.0352	0.0677
133	Sep-10	0.1031	0.0347	0.0684
134	Oct-10	0.1017	0.0352	0.0665
135	Nov-10	0.1023	0.0382	0.0641
136	Dec-10	0.1026	0.0417	0.0609
137	Jan-11	0.1018	0.0428	0.0590
138	Feb-11	0.1014	0.0442	0.0572
139	Mar-11	0.1017	0.0427	0.0590
140	Apr-11	0.0994	0.0428	0.0566
141	May-11	0.0969	0.0401	0.0568
142	Jun-11	0.1017	0.0391	0.0626
143	Jul-11	0.0993	0.0395	0.0598
144	Aug-11	0.1023	0.0324	0.0699
145	Sep-11	0.0991	0.0283	0.0708
146	Oct-11	0.1006	0.0287	0.0719
147	Nov-11	0.0989	0.0272	0.0717
148	Dec-11	0.1000	0.0267	0.0733
149	Jan-12	0.0991	0.0270	0.0721
150	Feb-12	0.0963	0.0275	0.0688
151	Mar-12	0.0960	0.0294	0.0666
152	Apr-12	0.0968	0.0282	0.0686
153	May-12	0.0967	0.0253	0.0714
154	Jun-12	0.0930	0.0231	0.0699

Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 2 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

d_0 = Latest quarterly dividend per Value Line, Thomson Reuters

P_0 = Average of the monthly high and low stock prices for each month per Thomson Reuters

g = I/B/E/S forecast of future earnings growth for each month

k = Cost of equity using the quarterly version of the DCF model

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

EXHIBIT 11
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN
NATURAL GAS UTILITIES TO THE INTEREST RATE
ON LONG-TERM GOVERNMENT BONDS

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Jun-98	0.1130	0.0580	0.0550
2	Jul-98	0.1162	0.0578	0.0584
3	Aug-98	0.1208	0.0566	0.0642
4	Sep-98	0.1247	0.0538	0.0709
5	Oct-98	0.1233	0.0530	0.0703
6	Nov-98	0.1185	0.0548	0.0637
7	Dec-98	0.1159	0.0536	0.0623
8	Jan-99	0.1168	0.0545	0.0623
9	Feb-99	0.1214	0.0566	0.0648
10	Mar-99	0.1227	0.0587	0.0640
11	Apr-99	0.1230	0.0582	0.0648
12	May-99	0.1193	0.0608	0.0585
13	Jun-99	0.1180	0.0636	0.0544
14	Jul-99	0.1195	0.0628	0.0567
15	Aug-99	0.1193	0.0643	0.0550
16	Sep-99	0.1199	0.0650	0.0549
17	Oct-99	0.1205	0.0666	0.0539
18	Nov-99	0.1212	0.0648	0.0564
19	Dec-99	0.1249	0.0669	0.0580
20	Jan-00	0.1269	0.0686	0.0583
21	Feb-00	0.1310	0.0654	0.0656
22	Mar-00	0.1312	0.0638	0.0674
23	Apr-00	0.1287	0.0618	0.0669
24	May-00	0.1264	0.0655	0.0609
25	Jun-00	0.1268	0.0628	0.0640
26	Jul-00	0.1289	0.0620	0.0669
27	Aug-00	0.1264	0.0602	0.0662
28	Sep-00	0.1233	0.0609	0.0624
29	Oct-00	0.1235	0.0604	0.0631
30	Nov-00	0.1228	0.0598	0.0630
31	Dec-00	0.1217	0.0564	0.0653
32	Jan-01	0.1238	0.0565	0.0673
33	Feb-01	0.1237	0.0562	0.0675
34	Mar-01	0.1251	0.0549	0.0702
35	Apr-01	0.1203	0.0578	0.0625
36	May-01	0.1280	0.0592	0.0688
37	Jun-01	0.1281	0.0582	0.0699
38	Jul-01	0.1313	0.0575	0.0738
39	Aug-01	0.1301	0.0558	0.0743
40	Sep-01	0.1241	0.0553	0.0688
41	Oct-01	0.1243	0.0534	0.0709
42	Nov-01	0.1243	0.0533	0.0710
43	Dec-01	0.1229	0.0576	0.0653

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
44	Jan-02	0.1211	0.0569	0.0642
45	Feb-02	0.1215	0.0561	0.0654
46	Mar-02	0.1165	0.0593	0.0572
47	Apr-02	0.1136	0.0585	0.0551
48	May-02	0.1139	0.0581	0.0558
49	Jun-02	0.1146	0.0565	0.0581
50	Jul-02	0.1214	0.0551	0.0663
51	Aug-02	0.1208	0.0519	0.0689
52	Sep-02	0.1233	0.0487	0.0746
53	Oct-02	0.1224	0.0500	0.0724
54	Nov-02	0.1195	0.0504	0.0691
55	Dec-02	0.1191	0.0501	0.0690
56	Jan-03	0.1194	0.0502	0.0692
57	Feb-03	0.1206	0.0487	0.0719
58	Mar-03	0.1169	0.0482	0.0687
59	Apr-03	0.1137	0.0491	0.0646
60	May-03	0.1103	0.0452	0.0651
61	Jun-03	0.1092	0.0434	0.0658
62	Jul-03	0.1103	0.0492	0.0611
63	Aug-03	0.1114	0.0539	0.0575
64	Sep-03	0.1104	0.0521	0.0583
65	Oct-03	0.1100	0.0521	0.0579
66	Nov-03	0.1066	0.0517	0.0549
67	Dec-03	0.1048	0.0511	0.0537
68	Jan-04	0.1037	0.0501	0.0536
69	Feb-04	0.1017	0.0494	0.0523
70	Mar-04	0.1014	0.0472	0.0542
71	Apr-04	0.1018	0.0516	0.0502
72	May-04	0.1021	0.0546	0.0475
73	Jun-04	0.1013	0.0545	0.0468
74	Jul-04	0.0989	0.0524	0.0465
75	Aug-04	0.0986	0.0507	0.0479
76	Sep-04	0.0956	0.0489	0.0467
77	Oct-04	0.0954	0.0485	0.0469
78	Nov-04	0.0942	0.0489	0.0453
79	Dec-04	0.0950	0.0488	0.0462
80	Jan-05	0.0969	0.0477	0.0492
81	Feb-05	0.0958	0.0461	0.0497
82	Mar-05	0.0958	0.0489	0.0469
83	Apr-05	0.0969	0.0475	0.0494
84	May-05	0.0961	0.0456	0.0505
85	Jun-05	0.0958	0.0435	0.0523
86	Jul-05	0.0948	0.0448	0.0500
87	Aug-05	0.0951	0.0453	0.0498
88	Sep-05	0.0963	0.0451	0.0512
89	Oct-05	0.0971	0.0474	0.0497
90	Nov-05	0.1030	0.0483	0.0547
91	Dec-05	0.1026	0.0473	0.0553

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
92	Jan-06	0.0963	0.0465	0.0498
93	Feb-06	0.1108	0.0473	0.0635
94	Mar-06	0.1111	0.0491	0.0620
95	Apr-06	0.1082	0.0522	0.0560
96	May-06	0.1038	0.0535	0.0503
97	Jun-06	0.1032	0.0529	0.0503
98	Jul-06	0.1071	0.0525	0.0546
99	Aug-06	0.1026	0.0508	0.0518
100	Sep-06	0.1037	0.0493	0.0544
101	Oct-06	0.1014	0.0494	0.0520
102	Nov-06	0.1018	0.0478	0.0540
103	Dec-06	0.1021	0.0478	0.0543
104	Jan-07	0.0998	0.0495	0.0503
105	Feb-07	0.1003	0.0493	0.0510
106	Mar-07	0.1004	0.0481	0.0523
107	Apr-07	0.0994	0.0495	0.0499
108	May-07	0.0955	0.0498	0.0457
109	Jun-07	0.0957	0.0529	0.0428
110	Jul-07	0.0995	0.0519	0.0476
111	Aug-07	0.1008	0.0500	0.0508
112	Sep-07	0.1002	0.0484	0.0518
113	Oct-07	0.1068	0.0483	0.0585
114	Nov-07	0.1071	0.0456	0.0615
115	Dec-07	0.1072	0.0457	0.0615
116	Jan-08	0.1100	0.0435	0.0665
117	Feb-08	0.1127	0.0449	0.0678
118	Mar-08	0.1134	0.0436	0.0698
119	Apr-08	0.1155	0.0444	0.0711
120	May-08	0.1056	0.0460	0.0596
121	Jun-08	0.1049	0.0474	0.0575
122	Jul-08	0.1073	0.0462	0.0611
123	Aug-08	0.1108	0.0453	0.0655
124	Sep-08	0.1114	0.0432	0.0682
125	Oct-08	0.1193	0.0445	0.0748
126	Nov-08	0.1200	0.0427	0.0773
127	Dec-08	0.1139	0.0318	0.0821
128	Jan-09	0.1108	0.0346	0.0762
129	Feb-09	0.1131	0.0383	0.0748
130	Mar-09	0.1172	0.0378	0.0794
131	Apr-09	0.1123	0.0384	0.0739
132	May-09	0.1196	0.0422	0.0774
133	Jun-09	0.1180	0.0451	0.0729
134	Jul-09	0.1119	0.0438	0.0681
135	Aug-09	0.1086	0.0433	0.0653
136	Sep-09	0.1085	0.0414	0.0671
137	Oct-09	0.1125	0.0416	0.0709
138	Nov-09	0.1127	0.0424	0.0703
139	Dec-09	0.1103	0.0440	0.0663

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
140	Jan-10	0.1174	0.0450	0.0724
141	Feb-10	0.1141	0.0448	0.0693
142	Mar-10	0.1049	0.0449	0.0600
143	Apr-10	0.0912	0.0453	0.0459
144	May-10	0.0947	0.0411	0.0536
145	Jun-10	0.0931	0.0395	0.0536
146	Jul-10	0.1028	0.0380	0.0648
147	Aug-10	0.1017	0.0352	0.0665
148	Sep-10	0.1013	0.0347	0.0666
149	Oct-10	0.1027	0.0352	0.0675
150	Nov-10	0.1019	0.0382	0.0637
151	Dec-10	0.1007	0.0417	0.0590
152	Jan-11	0.0998	0.0428	0.0570
153	Feb-11	0.0984	0.0442	0.0542
154	Mar-11	0.0994	0.0427	0.0567
155	Apr-11	0.1034	0.0428	0.0606
156	May-11	0.0998	0.0401	0.0597
157	Jun-11	0.0998	0.0391	0.0607
158	Jul-11	0.1038	0.0395	0.0643
159	Aug-11	0.1156	0.0324	0.0832
160	Sep-11	0.1133	0.0283	0.0850
161	Oct-11	0.1128	0.0287	0.0841
162	Nov-11	0.1099	0.0272	0.0827
163	Dec-11	0.1072	0.0267	0.0805
164	Jan-12	0.1058	0.0270	0.0788
165	Feb-12	0.1060	0.0275	0.0785
166	Mar-12	0.1060	0.0294	0.0766
167	Apr-12	0.0970	0.0282	0.0688
168	May-12	0.1048	0.0253	0.0795
169	Jun-12	0.0990	0.0231	0.0759

Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 2 for a description of my ex ante risk premium approach. DCF results are calculated using a quarterly DCF model as follows:

- d_0 = Latest quarterly dividend per Value Line, Thomson Reuters
- P_0 = Average of the monthly high and low stock prices for each month per Thomson Reuters
- g = I/B/E/S forecast of future earnings growth for each month
- k = Cost of equity using the quarterly version of the DCF model

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

EXHIBIT 12
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING SBBI® 6.6 PERCENT RISK PREMIUM

LINE	FACTOR	VALUE	SOURCE
1	Risk-free Rate	2.73%	Long-term Canada Bond Forecast
2	Beta	0.73	Average Beta Proxy Companies
3	Risk Premium	6.60%	Long-horizon SBBI risk premium
4	Beta x Risk Premium	4.82%	
5	Flotation Cost Allowance	0.50%	
6	Cost of Equity	8.05%	

Forecast bond yield from Consensus Economics, June 2012; SBBI® risk premium from Ibbotson® SBBI 2011® Valuation Edition Yearbook, average Value Line beta for proxy utilities (see following page).

EXHIBIT 12 (CONTINUED)
VALUE LINE BETAS FOR PROXY UTILITIES

LINE NO.	COMPANY	VALUE LINE BETA
1	AGL Resources	0.75
2	Alliant Energy	0.75
3	Amer. Elec. Power	0.70
4	Atmos Energy	0.70
5	CenterPoint Energy	0.80
6	CMS Energy Corp.	0.75
7	Consol. Edison	0.60
8	Dominion Resources	0.70
9	DTE	0.75
10	Duke Energy	0.65
11	Exelon Corp.	0.80
12	FirstEnergy Corp.	0.80
13	Great Plains	0.75
14	Hawaiian Elec.	0.70
15	NextEra Energy	0.75
16	NiSource Inc.	0.85
17	Northeast Utilities	0.70
18	Pepco Holdings	0.75
19	Piedmont Natural Gas	0.70
20	Pinnacle West Capital	0.70
21	PNM Resources	0.95
22	Portland General	0.75
23	Public Serv. Enterprise	0.80
24	SCANA Corp.	0.70
25	Sempra Energy	0.80
26	Southern Co.	0.55
27	TECO Energy	0.85
28	Vectren Corp.	0.75
29	Westar Energy	0.75
30	WGL Holdings Inc.	0.65
31	Wisconsin Energy	0.65
32	Xcel Energy Inc.	0.65
33	Average	0.73

EXHIBIT 13
COMPARISON OF RISK PREMIA ON
S&P500 AND S&P UTILITIES 1937 – 2012

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
2011	0.1999	0.0325	0.0278	0.1721	0.0047
2010	0.0704	0.1618	0.0322	0.0382	0.1296
2009	0.1071	0.3291	0.0326	0.0745	0.2965
2008	-0.2590	-0.3519	0.0367	-0.2957	-0.3886
2007	0.1656	-0.0127	0.0463	0.1193	-0.0590
2006	0.2076	0.1320	0.0479	0.1597	0.0841
2005	0.1605	0.1001	0.0429	0.1176	0.0572
2004	0.2284	0.0594	0.0427	0.1857	0.0167
2003	0.2348	0.2822	0.0401	0.1947	0.2421
2002	-0.1473	-0.2005	0.0461	-0.1934	-0.2466
2001	-0.1790	-0.1347	0.0502	-0.2292	-0.1849
2000	0.3278	-0.0513	0.0603	0.2675	-0.1116
1999	-0.0172	0.1546	0.0564	-0.0736	0.0982
1998	0.1547	0.3125	0.0526	0.1021	0.2599
1997	0.1858	0.2768	0.0635	0.1223	0.2133
1996	0.0383	0.2702	0.0644	-0.0261	0.2058
1995	0.3749	0.3493	0.0658	0.3091	0.2835
1994	-0.0383	0.0105	0.0708	-0.1091	-0.0603
1993	0.1095	0.1156	0.0587	0.0508	0.0569
1992	0.1246	0.0750	0.0701	0.0545	0.0049
1991	0.1425	0.3165	0.0786	0.0639	0.2379
1990	0.0033	-0.0085	0.0855	-0.0822	-0.0940
1989	0.3468	0.2276	0.0850	0.2618	0.1426
1988	0.1480	0.1761	0.0884	0.0596	0.0877
1987	-0.0574	-0.0213	0.0838	-0.1412	-0.1051
1986	0.3787	0.3095	0.0768	0.3019	0.2327
1985	0.3000	0.2583	0.1062	0.1938	0.1521
1984	0.1995	0.0741	0.1244	0.0751	-0.0503
1983	0.2016	0.2012	0.1110	0.0906	0.0902
1982	0.3020	0.2896	0.1300	0.1720	0.1596
1981	0.0940	-0.0700	0.1391	-0.0451	-0.2091
1980	0.1301	0.2534	0.1146	0.0155	0.1388
1979	0.0879	0.1652	0.0944	-0.0065	0.0708
1978	0.0396	0.1580	0.0841	-0.0445	0.0739
1977	0.0416	-0.0906	0.0742	-0.0326	-0.1648
1976	0.2270	0.1096	0.0761	0.1509	0.0335
1975	0.3224	0.3856	0.0799	0.2425	0.3057
1974	-0.1429	-0.2086	0.0756	-0.2185	-0.2842
1973	-0.1345	-0.1614	0.0684	-0.2029	-0.2298
1972	0.0512	0.1758	0.0621	-0.0109	0.1137
1971	-0.0007	0.1381	0.0616	-0.0623	0.0765

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
1970	0.1945	0.0708	0.0735	0.1210	-0.0027
1969	-0.1438	-0.0840	0.0667	-0.2105	-0.1507
1968	0.0528	0.1045	0.0565	-0.0037	0.0480
1967	0.0022	0.1605	0.0507	-0.0485	0.1098
1966	-0.0172	-0.0648	0.0492	-0.0664	-0.1140
1965	0.0134	0.1135	0.0428	-0.0294	0.0707
1964	0.1611	0.1570	0.0419	0.1192	0.1151
1963	0.0947	0.2082	0.0400	0.0547	0.1682
1962	0.0425	-0.0284	0.0395	0.0030	-0.0679
1961	0.2247	0.1894	0.0388	0.1859	0.1506
1960	0.2252	0.0618	0.0412	0.1840	0.0206
1959	0.0500	0.0757	0.0433	0.0067	0.0324
1958	0.3688	0.3974	0.0332	0.3356	0.3642
1957	0.0790	-0.0518	0.0365	0.0425	-0.0883
1956	0.0716	0.0714	0.0318	0.0398	0.0396
1955	0.1016	0.2840	0.0282	0.0734	0.2558
1954	0.2237	0.4552	0.0240	0.1997	0.4312
1953	0.0962	0.0270	0.0281	0.0681	-0.0011
1952	0.1536	0.1405	0.0248	0.1288	0.1157
1951	0.1710	0.2039	0.0241	0.1469	0.1798
1950	0.0460	0.3230	0.0205	0.0255	0.3025
1949	0.2783	0.1610	0.0193	0.2590	0.1417
1948	0.0541	0.0928	0.0215	0.0326	0.0713
1947	-0.1041	0.0199	0.0185	-0.1226	0.0014
1946	-0.0700	-0.1203	0.0174	-0.0874	-0.1377
1945	0.5789	0.3818	0.0173	0.5616	0.3645
1944	0.2065	0.1879	0.0209	0.1856	0.1670
1943	0.3745	0.2298	0.0207	0.3538	0.2091
1942	0.1736	0.2087	0.0211	0.1525	0.1876
1941	-0.2838	-0.0898	0.0199	-0.3037	-0.1097
1940	-0.1652	-0.0965	0.0220	-0.1872	-0.1185
1939	0.1126	0.0189	0.0235	0.0891	-0.0046
1938	0.1954	0.1836	0.0255	0.1699	0.1581
1937	-0.3693	-0.3136	0.0269	-0.3962	-0.3405
Risk Premium 1937—2012				0.0521	0.0567
RP Utilities/RP SP500				0.92	

EXHIBIT 14
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING SBBI® 6.6 PERCENT RISK PREMIUM AND 0.92 HISTORICAL UTILITY BETA

LINE	FACTOR	VALUE	SOURCE
1	Risk-free Rate	2.73%	Long-term Canada Bond Forecast
2	Beta	0.92	RP utility stocks/RP S&P500
3	Risk Premium	6.60%	Long-horizon SBBI risk premium
4	Beta x Risk Premium	6.07%	
5	Flotation Cost Allowance	0.50%	
6	Cost of Equity	9.30%	

Forecast bond yield from Consensus Economics, June 2012; SBBI® risk premium from *Ibbotson® SBBI 2011® Valuation Edition Yearbook*, beta calculated as ratio of S&P Utilities stock risk premium compared to S&P 500 stock risk premium—see [Exhibit 13](#).

EXHIBIT 15
COMPARISON OF RISK PREMIA ON
S&P TSX COMPOSITE, S&P TSX UTILITIES,
AND BMO CAPITAL MARKETS UTILITY GROUP

LINE	YEAR	TOTAL RETURN TSX COMPOSITE	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	BMO CAPITAL MARKETS UTILITY GROUP TOTAL RETURN	YIELD LONG- TERM CANADA BOND	RISK PREMIUM/TSX COMPOSITE	RISK PREMIUM SP/TSX UTILITIES	RISK PREMIUM BMO CM UTILITY GROUP
1	1956	13.22	0.17		3.63	9.59	-3.45	
2	1957	-20.58	-3.43		4.11	-24.69	-7.54	
3	1958	31.25	9.81		4.15	27.10	5.66	
4	1959	4.59	0.21		5.08	-0.49	-4.86	
5	1960	1.78	26.81		5.19	-3.40	21.62	
6	1961	32.75	19.17		5.05	27.70	14.12	
7	1962	-7.09	-0.72		5.11	-12.21	-5.83	
8	1963	15.60	6.19		5.09	10.51	1.10	
9	1964	25.43	21.59		5.18	20.25	16.41	
10	1965	6.68	4.23		5.21	1.47	-0.98	
11	1966	-7.07	-13.17		5.69	-12.76	-18.86	
12	1967	18.09	5.07		5.94	12.15	-0.87	
13	1968	22.45	7.41		6.75	15.70	0.66	
14	1969	-0.81	-8.62		7.58	-8.39	-16.20	
15	1970	-3.57	23.34		7.91	-11.48	15.43	
16	1971	8.01	4.29		6.95	1.06	-2.66	
17	1972	27.38	-0.44		7.23	20.15	-7.68	
18	1973	0.27	-4.14		7.56	-7.29	-11.70	
19	1974	-25.93	14.38		8.90	-34.83	5.48	
20	1975	18.48	5.75		9.04	9.45	-3.28	
21	1976	11.02	15.02		9.18	1.85	5.84	
22	1977	10.71	19.00		8.70	2.01	10.30	
23	1978	29.72	27.28		9.27	20.45	18.01	
24	1979	44.77	12.61		10.21	34.56	2.40	
25	1980	30.13	5.74		12.48	17.65	-6.74	
26	1981	-10.25	-0.55		15.22	-25.47	-15.77	
27	1982	5.54	35.90		14.26	-8.71	21.65	
28	1983	35.49	40.97	25.84	11.79	23.70	29.17	14.05
29	1984	-2.39	24.31	6.89	12.75	-15.14	11.56	-5.86
30	1985	25.07	10.04	20.09	11.04	14.02	-1.00	9.04
31	1986	8.95	11.48	-1.22	9.52	-0.57	1.96	-10.74
32	1987	5.88	1.07	11.98	9.95	-4.07	-8.88	2.03
33	1988	11.08	5.63	6.67	10.22	0.86	-4.59	-3.56
34	1989	21.37	22.07	23.80	9.92	11.45	12.15	13.88
35	1990	-14.80	0.58	10.00	10.85	-25.65	-10.28	-0.86
36	1991	12.02	27.02	12.92	9.76	2.25	17.25	3.16
37	1992	-1.43	-2.24	0.75	8.77	-10.20	-11.00	-8.02
38	1993	32.55	23.52	33.00	7.85	24.70	15.67	25.15
39	1994	-0.18	-6.04	-1.22	8.63	-8.81	-14.68	-9.85
40	1995	14.53	18.44	15.13	8.28	6.25	10.16	6.85
41	1996	28.35	32.68	31.66	7.50	20.84	25.18	24.15

LINE	YEAR	TOTAL RETURN TSX COMPOSITE	S&P/TSX CANADIAN UTILITIES STOCK INDEX TOTAL RETURN	BMO CAPITAL MARKETS UTILITY GROUP TOTAL RETURN	YIELD LONG- TERM CANADA BOND	RISK PREMIUM/TSX COMPOSITE	RISK PREMIUM SP/TSX UTILITIES	RISK PREMIUM BMO CM UTILITY GROUP
42	1997	14.98	37.33	50.16	6.42	8.55	30.91	43.74
43	1998	-1.58	36.55	4.12	5.47	-7.05	31.09	-1.34
44	1999	31.71	-27.14	-24.11	5.69	26.02	-32.83	-29.80
45	2000	7.41	50.06	59.57	5.89	1.52	44.17	53.69
46	2001	-12.57	10.83	16.05	5.78	-18.35	5.05	10.27
47	2002	-12.44	6.33	14.46	5.66	-18.10	0.67	8.80
48	2003	26.72	24.94	28.74	5.28	21.45	19.66	23.46
49	2004	14.48	9.42	15.56	5.08	9.40	4.34	10.48
50	2005	24.13	38.29	33.36	4.39	19.74	33.90	28.97
51	2006	17.26	7.01	17.77	4.30	12.96	2.71	13.47
52	2007	9.83	11.89	4.90	4.34	5.50	7.55	0.57
53	2008	-33.00	-20.46	-4.21	4.04	-37.04	-24.50	-8.25
54	2009	35.06	19.00	20.24	3.89	31.17	15.11	16.35
55	2010	17.61	18.39	5.39	3.66	13.95	14.73	1.73
56	2011	-8.71	6.47	25.89	3.21	-11.92	3.26	22.68
57	Average 1956 – 2011	10.53	11.99		7.33	3.20	4.66	
58	Average 1983 - 2011	10.60	15.12	16.01	7.24	3.36	7.88	8.77
59	Std. Dev. 1956 – 2011	16.67	15.26					
60	Std. Dev. 1983 - 2011	16.58	17.40	16.41				

EXHIBIT 16
ALLOWED RETURNS ON EQUITY
U.S. ELECTRIC UTILITIES
JANUARY 2010 – JUNE 2012^[8]

LINE	COMPANY	STATE	DATE OF ORDER	ALLOWED ROE
1	Indiana Michigan Power Co.	Michigan	11-Jan-10	10.2
2	Interstate Power & Light Co.	Minnesota	11-Jan-10	10.4
3	Kansas City Power & Light	Missouri	20-Jan-10	10.0
4	Indiana Michigan Power Co.	Indiana	21-Jan-10	10.5
5	Portland General Electric Co.	Oregon	26-Jan-10	10.0
6	CenterPoint Energy Houston	Texas	26-Jan-10	10.0
7	South Carolina Electric & Gas	South Carolina	27-Jan-10	11.0
8	Duke Energy Carolinas LLC	South Carolina	9-Feb-10	10.5
9	Union Electric Co.	Missouri	10-Feb-10	10.2
10	PacifiCorp	Utah	18-Feb-10	10.6
11	PacifiCorp	Oregon	24-Feb-10	10.1
12	Virginia Electric & Power Co.	Virginia	4-Mar-10	11.4
13	Virginia Electric & Power Co.	Virginia	11-Mar-10	12.3
14	Virginia Electric & Power Co.	Virginia	11-Mar-10	12.3
15	Cheyenne Light Fuel Power Co.	Wyoming	19-Mar-10	9.6
16	Consolidated Edison Co. of NY	New York	25-Mar-10	10.0
17	Pacific Gas and Electric Co.	California	1-Apr-10	11.4
18	Madison Gas and Electric Co.	Wisconsin	2-Apr-10	10.3
19	Appalachian Power Co.	Virginia	8-Apr-10	10.9
20	PacifiCorp	Wyoming	27-Apr-10	10.0
21	Commonwealth Edison Co.	Illinois	29-Apr-10	10.1
22	Ameren Illinois	Illinois	29-Apr-10	10.1
23	Ameren Illinois	Illinois	29-Apr-10	10.3
24	Consumers Energy Co.	Michigan	17-May-10	10.7
25	Oklahoma Gas and Electric Co.	Arkansas	28-May-10	10.0
26	Union Electric Co.	Missouri	28-May-10	10.8
27	PacifiCorp	Utah	15-Jun-10	10.6
28	Central Hudson Gas & Electric	New York	16-Jun-10	10.0
29	Rockland Electric Company	New Jersey	18-Jun-10	10.3
30	Kansas City Power & Light	Kansas	23-Jun-10	10.0
31	Unitil Energy Systems Inc.	New Hampshire	28-Jun-10	9.7
32	ALLETE (Minnesota Power)	Minnesota	1-Jul-10	10.4
33	Northern States Power Co. – MN	South Dakota	7-Jul-10	9.3
34	Appalachian Power Co.	Virginia	15-Jul-10	10.6
35	Entergy Texas Inc.	Texas	30-Jul-10	10.1
36	Public Service Co. of CO	Colorado	4-Aug-10	10.0
37	Entergy Arkansas Inc.	Arkansas	9-Aug-10	10.2
38	Southern Indiana Gas & Elec Co	Indiana	25-Aug-10	10.4
39	Sierra Pacific Power Co.	California	3-Sep-10	10.7
40	Maui Electric Company Ltd	Hawaii	14-Sep-10	10.0
41	Orange & Rockland Utilts Inc.	New York	16-Sep-10	9.4

[8] Data from Regulatory Research Associates, SNL Financial, July 5, 2012.

LINE	COMPANY	STATE	DATE OF ORDER	ALLOWED ROE
42	Consolidated Edison Co. of NY	New York	16-Sep-10	10.2
43	Cleveland Elec Illuminating Co	Ohio	16-Sep-10	10.5
44	Avista Corp.	Idaho	21-Sep-10	10.5
45	South Carolina Electric & Gas	South Carolina	30-Sep-10	10.7
46	Hawaiian Electric Co.	Hawaii	28-Oct-10	10.0
47	ALLETE (Minnesota Power)	Minnesota	2-Nov-10	10.7
48	Northern IN Public Svc Co.	Indiana	4-Nov-10	9.9
49	Avista Corp.	Washington	19-Nov-10	10.2
50	Connecticut Light & Power Co.	Connecticut	1-Dec-10	9.4
51	Northern States Power Co. – MN	Minnesota	6-Dec-10	10.9
52	MDU Resources Group Inc.	North Dakota	13-Dec-10	10.8
53	PacifiCorp	Oregon	14-Dec-10	10.1
54	Texas-New Mexico Power Co.	Texas	14-Dec-10	10.1
55	Interstate Power & Light Co.	Iowa	15-Dec-10	10.8
56	Kentucky Utilities Co.	Virginia	17-Dec-10	10.3
57	Upper Peninsula Power Co.	Michigan	21-Dec-10	10.9
58	Hawaii Electric Light Co	Hawaii	29-Dec-10	10.0
59	Georgia Power Co.	Georgia	30-Dec-10	11.2
60	Public Service Co. of OK	Oklahoma	5-Jan-11	10.5
61	Upper Peninsula Power Co.	Michigan	6-Jan-11	10.2
62	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	10.4
63	Appalachian Power Co.	West Virginia	13-Jan-11	10.0
64	Florida Power & Light Co.	Florida	18-Jan-11	10.0
65	Union Electric Co.	Missouri	19-Jan-11	10.1
66	Baltimore Gas and Electric Co.	Maryland	31-Jan-11	9.9
67	Hawaiian Electric Co.	Hawaii	25-Feb-11	10.7
68	Puget Sound Energy Inc.	Washington	15-Mar-11	10.1
69	Virginia Electric & Power Co.	Virginia	22-Mar-11	11.9
70	Virginia Electric & Power Co.	Virginia	22-Mar-11	12.3
71	Atlantic City Electric Co.	New Jersey	26-Apr-11	10.3
72	KCP&L Greater Missouri Op Co	Missouri	4-May-11	10.0
73	PacifiCorp	California	13-May-11	10.6
74	Consumers Energy Co.	Michigan	26-May-11	10.7
75	Northern States Power Co. – MN	North Dakota	8-Jun-11	10.4
76	Oklahoma Gas and Electric Co.	Arkansas	17-Jun-11	10.3
77	Delmarva Power & Light Co.	Delaware	21-Jun-11	10.0
78	Potomac Electric Power Co.	District of Columbia	29-Jun-11	9.6
79	Delmarva Power & Light Co.	Maryland	8-Jul-11	10.0
80	Massachusetts Electric Co.	Massachusetts	1-Aug-11	10.4
81	NorthWestern Corp.	Montana	2-Aug-11	10.3
82	Public Service Co. of NM	New Mexico	8-Aug-11	10.5
83	Oncor Electric Delivery Co.	Texas	19-Aug-11	10.3
84	Public Service Co. of CO	Colorado	1-Sep-11	10.5
85	Alaska Electric Light Power	Alaska	2-Sep-11	12.9
86	South Carolina Electric & Gas	South Carolina	30-Sep-11	11.0
87	Wisconsin Electric Power Co.	Wisconsin	6-Oct-11	10.4
88	Kentucky Utilities Co.	Virginia	12-Oct-11	10.5
89	Detroit Edison Co.	Michigan	20-Oct-11	11.0

LINE	COMPANY	STATE	DATE OF ORDER	ALLOWED ROE
90	Appalachian Power Co.	Virginia	30-Nov-11	11.4
91	UNS Electric Inc.	Arizona	13-Dec-11	9.8
92	Toledo Edison Co.	Ohio	14-Dec-11	10.5
93	Duke Energy Ohio Inc.	Ohio	14-Dec-11	10.6
94	Avista Corp.	Washington	16-Dec-11	10.2
95	Upper Peninsula Power Co.	Michigan	20-Dec-11	10.3
96	Northern States Power Co – WI	Wisconsin	22-Dec-11	10.4
97	Black Hills Colorado Electric	Colorado	22-Dec-11	10.5
98	Nevada Power Co.	Nevada	23-Dec-11	10.8
99	Idaho Power Co.	Idaho	30-Dec-11	10.5
100	Appalachian Power Co.	Virginia	3-Jan-12	10.5
101	PacifiCorp	Idaho	10-Jan-12	9.9
102	Ameren Illinois	Illinois	10-Jan-12	9.9
103	Duke Energy Carolinas LLC	South Carolina	25-Jan-12	10.7
104	Duke Energy Carolinas LLC	North Carolina	27-Jan-12	10.7
105	Public Service Co. of NM	New Mexico	31-Jan-12	10.0
106	Virginia Electric & Power Co.	Virginia	2-Feb-12	12.3
107	Indiana Michigan Power Co.	Michigan	15-Feb-12	10.4
108	Florida Power Corp.	Florida	22-Feb-12	10.5
109	Idaho Power Co.	Oregon	23-Feb-12	10.2
110	Otter Tail Power Co.	North Dakota	29-Feb-12	10.8
111	Virginia Electric & Power Co.	Virginia	16-Mar-12	11.4
112	Virginia Electric & Power Co.	Virginia	20-Mar-12	11.4
113	Duke Energy Carolinas LLC	North Carolina	21-Mar-12	10.5
114	Virginia Electric & Power Co.	Virginia	23-Mar-12	12.4
115	PacifiCorp	Washington	30-Mar-12	9.8
116	Hawaii Electric Light Co	Hawaii	4-Apr-12	10.7
117	Westar Energy Inc.	Kansas	18-Apr-12	10.4
118	Public Service Co. of NH	New Hampshire	24-Apr-12	9.7
119	Maui Electric Company Ltd	Hawaii	2-May-12	10.7
120	Arizona Public Service Co.	Arizona	15-May-12	11.0
121	Commonwealth Edison Co.	Illinois	29-May-12	10.5
122	Consumers Energy Co.	Michigan	7-Jun-12	10.3
123	Orange & Rockland Utilts Inc.	New York	14-Jun-12	9.2
124	Wisconsin Power and Light Co	Wisconsin	15-Jun-12	10.4
125	MDU Resources Group Inc.	Wyoming	18-Jun-12	10.0
126	Wisconsin Electric Power Co.	Michigan	26-Jun-12	10.3
127	Hawaiian Electric Co.	Hawaii	29-Jun-12	10.0
183		Average		10.5

EXHIBIT 17
ALLOWED RETURNS ON EQUITY
U.S. NATURAL GAS UTILITIES
JANUARY 2010 – JUNE 2012^[9]

LINE	COMPANY	STATE	DATE	ALLOWED ROE
1	Atmos Energy Corp.	Tennessee	5-Jan-10	10.3
2	Northern Illinois Gas Co.	Illinois	21-Jan-10	10.2
3	Delmarva Power & Light Co.	Delaware	2-Mar-10	10.0
4	Florida Public Utilities Co.	Florida	5-Mar-10	10.9
5	Virginia Natural Gas Inc.	Virginia	11-Mar-10	10.0
6	North Shore Gas Co.	Illinois	24-Mar-10	9.5
7	Puget Sound Energy Inc.	Washington	2-Apr-10	10.1
8	Ameren Illinois	Illinois	29-Apr-10	9.2
9	Ameren Illinois	Illinois	29-Apr-10	9.4
10	Ameren Illinois	Illinois	29-Apr-10	9.4
11	Pivotal Utility Holdings Inc.	New Jersey	12-May-10	10.3
12	South Jersey Gas Co.	New Jersey	12-May-10	10.3
13	Piedmont Natural Gas Co.	Tennessee	24-May-10	10.2
14	Michigan Gas Utilities Corp	Michigan	3-Jun-10	10.8
15	Public Service Electric Gas	New Jersey	7-Jun-10	10.3
16	Central Hudson Gas & Electric	New York	16-Jun-10	10.0
17	CT Natural Gas Corp.	Connecticut	30-Jun-10	9.3
18	Washington Gas Light Co.	Maryland	6-Aug-10	9.6
19	SourceGas Distribution LLC	Nebraska	17-Aug-10	9.6
20	Missouri Gas Energy	Missouri	18-Aug-10	10.0
21	NY State Electric & Gas Corp.	New York	16-Sep-10	10.0
22	Rochester Gas & Electric Corp.	New York	16-Sep-10	10.0
23	UNS Gas Inc.	Arizona	30-Sep-10	9.8
24	Michigan Consolidated Gas Co.	Michigan	14-Oct-10	11.0
25	Duke Energy Kentucky Inc.	Kentucky	21-Oct-10	10.4
26	Colonial Gas Co.	Massachusetts	2-Nov-10	9.8
27	Columbia Gas of Massachusetts	Massachusetts	2-Nov-10	10.0
28	Atmos Energy Corp.	Georgia	3-Nov-10	10.7
29	Consumers Energy Co.	Michigan	4-Nov-10	10.6
30	Avista Corp.	Washington	19-Nov-10	10.2
31	Baltimore Gas and Electric Co.	Maryland	6-Dec-10	9.6
32	NorthWestern Corp.	Montana	9-Dec-10	10.3
33	Sierra Pacific Power Co.	Nevada	20-Dec-10	10.1
34	Southwest Gas Corp.	Nevada	20-Dec-10	10.2
35	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	10.3
36	Wisconsin Public Service Corp.	Wisconsin	13-Jan-11	10.3
37	Niagara Mohawk Power Corp.	New York	20-Jan-11	10.2
38	CenterPoint Energy Resources	Texas	3-Feb-11	10.1
39	Black Hills Iowa Gas Utility	Iowa	10-Feb-11	10.1

^[9] Data from Regulatory Research Associates, SNL Financial, July 5, 2012.

LINE	COMPANY	STATE	DATE	ALLOWED ROE
40	EnergyNorth Natural Gas Inc.	New Hampshire	10-Mar-11	9.5
41	Avista Corp.	Oregon	10-Mar-11	10.1
42	Hope Gas Inc	West Virginia	30-Mar-11	9.5
43	New England Gas Company	Massachusetts	31-Mar-11	10.1
44	CenterPoint Energy Resources	Texas	18-Apr-11	10.5
45	Pacific Gas and Electric Co.	California	13-May-11	11.4
46	MidAmerican Energy Co.	Illinois	24-May-11	10.1
47	Orange & Rockland Utilts Inc.	New York	16-Jun-11	10.4
48	Fitchburg Gas & Electric Light	Massachusetts	1-Aug-11	9.2
49	Minnesota Energy Resources	Minnesota	12-Aug-11	9.7
50	ENSTAR Natural Gas Co.	Alaska	2-Sep-11	12.6
51	Wisconsin Gas LLC	Wisconsin	6-Oct-11	10.5
52	Consumers Energy Co.	Michigan	8-Nov-11	10.3
53	Columbia Gas of Virginia Inc	Virginia	28-Nov-11	10.1
54	Washington Gas Light Co.	Virginia	20-Dec-11	9.8
55	Northern States Power Co – WI	Wisconsin	22-Dec-11	10.4
56	Ameren Illinois	Illinois	5-Jan-12	9.1
57	Peoples Gas Light & Coke Co.	Illinois	10-Jan-12	10.2
58	North Shore Gas Co.	Illinois	10-Jan-12	10.3
59	Atmos Energy Corp.	Texas	23-Jan-12	10.4
60	Peoples Gas System	Florida	27-Feb-12	10.8
61	Northern States Power Co. – MN	Minnesota	29-Mar-12	10.1
62	UNS Gas Inc.	Arizona	24-Apr-12	9.5
63	Public Service Co. of CO	Colorado	26-Apr-12	10.1
64	Puget Sound Energy Inc.	Washington	7-May-12	9.8
65	SourceGas Distribution LLC	Nebraska	22-May-12	9.6
66	Minnesota Energy Resources	Minnesota	24-May-12	10.2
67	Consumers Energy Co.	Michigan	7-Jun-12	10.5
68	Wisconsin Power and Light Co	Wisconsin	15-Jun-12	10.4
69	Cheyenne Light Fuel Power Co.	Wyoming	18-Jun-12	9.6
70	Washington Gas Light Co.	Virginia	2-Jul-12	10.0
71		Average		10.1

EXHIBIT 18
ALLOWED EQUITY RATIOS
U.S. ELECTRIC UTILITIES
JANUARY 2010 – JUNE 2012^[10]

LINE	COMPANY	STATE	DATE OF ORDER	COMMON EQUITY /TOTAL CAP (%)
1	Entergy Arkansas Inc.	Arkansas	9-Aug-10	29.3
2	Oklahoma Gas and Electric Co.	Arkansas	28-May-10	34.9
3	Oklahoma Gas and Electric Co.	Arkansas	17-Jun-11	36.0
4	Detroit Edison Co.	Michigan	20-Oct-11	39.5
5	Oncor Electric Delivery Co.	Texas	19-Aug-11	40.0
6	Consumers Energy Co.	Michigan	17-May-10	40.5
7	Appalachian Power Co.	Virginia	15-Jul-10	41.5
8	Appalachian Power Co.	Virginia	3-Jan-12	41.5
9	Consumers Energy Co.	Michigan	26-May-11	41.6
1	Indiana Michigan Power Co.	Michigan	11-Jan-10	42.1
2	Consumers Energy Co.	Michigan	7-Jun-12	42.1
3	Appalachian Power Co.	West Virginia	13-Jan-11	42.2
4	Appalachian Power Co.	Virginia	8-Apr-10	42.7
5	Southern Indiana Gas & Elec Co	Indiana	25-Aug-10	43.5
6	Ameren Illinois	Illinois	29-Apr-10	43.6
7	Ameren Illinois	Illinois	10-Jan-12	43.6
8	Sierra Pacific Power Co.	California	3-Sep-10	43.7
9	Public Service Co. of OK	Oklahoma	5-Jan-11	44.1
10	Indiana Michigan Power Co.	Michigan	15-Feb-12	44.1
11	Nevada Power Co.	Nevada	23-Dec-11	44.2
12	CenterPoint Energy Houston	Texas	26-Jan-10	45.0
13	Texas-New Mexico Power Co.	Texas	14-Dec-10	45.0
14	Unitil Energy Systems Inc.	New Hampshire	28-Jun-10	45.5
15	Upper Peninsula Power Co.	Michigan	6-Jan-11	45.7
16	UNS Electric Inc.	Arizona	13-Dec-11	45.8
17	Indiana Michigan Power Co.	Indiana	21-Jan-10	45.8
18	Puget Sound Energy Inc.	Washington	15-Mar-11	46.0
19	Commonwealth Edison Co.	Illinois	29-Apr-10	46.2
20	Potomac Electric Power Co.	District of Columbia	29-Jun-11	46.2
21	Kansas City Power & Light	Missouri	20-Jan-10	46.3
22	Avista Corp.	Washington	19-Nov-10	46.5
23	Avista Corp.	Washington	16-Dec-11	46.5
24	KCP&L Greater Missouri Op Co	Missouri	4-May-11	46.6
25	Florida Power Corp.	Florida	22-Feb-12	46.7
26	Central Hudson Gas & Electric	New York	16-Jun-10	47.0
27	Florida Power & Light Co.	Florida	18-Jan-11	47.0
28	Commonwealth Edison Co.	Illinois	29-May-12	47.3
29	Virginia Electric & Power Co.	Virginia	11-Mar-10	47.4

[10] Data from Regulatory Research Associates, SNL Financial July 2012.

LINE	COMPANY	STATE	DATE OF ORDER	COMMON EQUITY /TOTAL CAP (%)
30	Delmarva Power & Light Co.	Delaware	21-Jun-11	47.5
31	Wisconsin Electric Power Co.	Michigan	26-Jun-12	47.6
32	Virginia Electric & Power Co.	Virginia	11-Mar-10	47.7
33	Interstate Power & Light Co.	Minnesota	11-Jan-10	47.7
34	Consolidated Edison Co. of NY	New York	25-Mar-10	48.0
35	Orange & Rockland Utilts Inc.	New York	16-Sep-10	48.0
36	Consolidated Edison Co. of NY	New York	16-Sep-10	48.0
37	NorthWestern Corp.	Montana	2-Aug-11	48.0
38	Orange & Rockland Utilts Inc.	New York	14-Jun-12	48.0
39	Ameren Illinois	Illinois	29-Apr-10	48.7
40	Cleveland Elec Illuminating Co	Ohio	16-Sep-10	49.0
41	Toledo Edison Co.	Ohio	14-Dec-11	49.0
42	Atlantic City Electric Co.	New Jersey	26-Apr-11	49.1
43	PacifiCorp	Washington	30-Mar-12	49.1
44	Connecticut Light & Power Co.	Connecticut	1-Dec-10	49.2
45	Idaho Power Co.	Idaho	30-Dec-11	49.3
46	Virginia Electric & Power Co.	Virginia	22-Mar-11	49.4
47	Virginia Electric & Power Co.	Virginia	2-Feb-12	49.4
48	Interstate Power & Light Co.	Iowa	15-Dec-10	49.5
49	Upper Peninsula Power Co.	Michigan	21-Dec-10	49.5
50	Kansas City Power & Light	Kansas	23-Jun-10	49.7
51	MDU Resources Group Inc.	Wyoming	18-Jun-12	49.8
52	Idaho Power Co.	Oregon	23-Feb-12	49.8
53	Rockland Electric Company	New Jersey	18-Jun-10	49.9
54	Delmarva Power & Light Co.	Maryland	8-Jul-11	49.9
55	Northern IN Public Svc Co.	Indiana	4-Nov-10	50.0
56	Massachusetts Electric Co.	Massachusetts	1-Aug-11	50.0
57	Portland General Electric Co.	Oregon	26-Jan-10	50.0
58	Avista Corp.	Idaho	21-Sep-10	50.0
59	Westar Energy Inc.	Kansas	18-Apr-12	50.1
60	Wisconsin Power and Light Co	Wisconsin	15-Jun-12	50.4
61	Upper Peninsula Power Co.	Michigan	20-Dec-11	50.4
62	Public Service Co. of NM	New Mexico	8-Aug-11	50.5
63	PacifiCorp	Utah	18-Feb-10	51.0
64	PacifiCorp	Oregon	24-Feb-10	51.0
65	PacifiCorp	Utah	15-Jun-10	51.0
66	PacifiCorp	Oregon	14-Dec-10	51.0
67	Hawaii Electric Light Co	Hawaii	4-Apr-12	51.2
68	Union Electric Co.	Missouri	19-Jan-11	51.3
69	Public Service Co. of NM	New Mexico	31-Jan-12	51.3
70	Duke Energy Ohio Inc.	Ohio	14-Dec-11	51.6
71	Baltimore Gas and Electric Co.	Maryland	31-Jan-11	51.9
72	Pacific Gas and Electric Co.	California	1-Apr-10	52.0
73	Black Hills Colorado Electric	Colorado	22-Dec-11	52.0
74	Union Electric Co.	Missouri	28-May-10	52.0

LINE	COMPANY	STATE	DATE OF ORDER	COMMON EQUITY /TOTAL CAP (%)
75	PacifiCorp	Idaho	10-Jan-12	52.1
76	PacifiCorp	California	13-May-11	52.2
77	Union Electric Co.	Missouri	10-Feb-10	52.2
78	PacifiCorp	Wyoming	27-Apr-10	52.3
79	Northern States Power Co – WI	Wisconsin	22-Dec-11	52.3
80	Public Service Co. of NH	New Hampshire	24-Apr-12	52.4
81	Northern States Power Co. – MN	Minnesota	6-Dec-10	52.5
82	Duke Energy Carolinas LLC	North Carolina	27-Jan-12	52.5
83	South Carolina Electric & Gas	South Carolina	30-Sep-10	53.0
84	Duke Energy Carolinas LLC	South Carolina	9-Feb-10	53.0
85	Duke Energy Carolinas LLC	South Carolina	25-Jan-12	53.0
86	Duke Energy Carolinas LLC	North Carolina	21-Mar-12	53.0
87	Wisconsin Electric Power Co.	Wisconsin	6-Oct-11	53.0
88	Northern States Power Co. – MN	South Dakota	7-Jul-10	53.0
89	Virginia Electric & Power Co.	Virginia	4-Mar-10	53.3
90	Virginia Electric & Power Co.	Virginia	16-Mar-12	53.3
91	Virginia Electric & Power Co.	Virginia	20-Mar-12	53.3
92	Virginia Electric & Power Co.	Virginia	23-Mar-12	53.3
93	Otter Tail Power Co.	North Dakota	29-Feb-12	53.3
94	MDU Resources Group Inc.	North Dakota	13-Dec-10	53.3
95	Kentucky Utilities Co.	Virginia	17-Dec-10	53.4
96	South Carolina Electric & Gas	South Carolina	30-Sep-11	53.5
97	Kentucky Utilities Co.	Virginia	12-Oct-11	53.6
98	Arizona Public Service Co.	Arizona	15-May-12	53.8
99	Alaska Electric Light Power	Alaska	2-Sep-11	53.8
100	Cheyenne Light Fuel Power Co.	Wyoming	19-Mar-10	54.0
101	ALLETE (Minnesota Power)	Minnesota	1-Jul-10	54.3
102	South Carolina Electric & Gas	South Carolina	27-Jan-10	54.7
103	ALLETE (Minnesota Power)	Minnesota	2-Nov-10	54.8
104	Maui Electric Company Ltd	Hawaii	2-May-12	54.9
105	Hawaiian Electric Co.	Hawaii	25-Feb-11	55.1
106	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	55.3
107	Hawaiian Electric Co.	Hawaii	29-Jun-12	55.8
108	Hawaii Electric Light Co	Hawaii	29-Dec-10	55.9
109	Public Service Co. of CO	Colorado	4-Aug-10	56.0
110	Hawaiian Electric Co.	Hawaii	28-Oct-10	56.3
111	Maui Electric Company Ltd	Hawaii	14-Sep-10	56.9
112	Madison Gas and Electric Co.	Wisconsin	2-Apr-10	58.1
113	Public Service Co. of CO	Colorado	1-Sep-11	58.6
114		Average		49.2

EXHIBIT 19
ALLOWED EQUITY RATIOS
U.S. NATURAL GAS UTILITIES
JANUARY 2010 – JUNE 2012^[11]

LINE	COMPANY	STATE	DATE	COMMON EQUITY /TOTAL CAP (%)
1	Atmos Energy Corp.	Tennessee	5-Jan-10	48.1
2	Northern Illinois Gas Co.	Illinois	21-Jan-10	51.1
3	Florida Public Utilities Co.	Florida	5-Mar-10	42.2
4	Virginia Natural Gas Inc.	Virginia	11-Mar-10	45.4
5	North Shore Gas Co.	Illinois	24-Mar-10	50.0
6	Puget Sound Energy Inc.	Washington	2-Apr-10	46.0
7	Ameren Illinois	Illinois	29-Apr-10	43.6
8	Ameren Illinois	Illinois	29-Apr-10	43.6
9	Ameren Illinois	Illinois	29-Apr-10	48.7
10	Pivotal Utility Holdings Inc.	New Jersey	12-May-10	47.9
11	South Jersey Gas Co.	New Jersey	12-May-10	51.2
12	Piedmont Natural Gas Co.	Tennessee	24-May-10	52.7
13	Michigan Gas Utilities Corp	Michigan	3-Jun-10	47.3
14	Public Service Electric Gas	New Jersey	7-Jun-10	51.2
15	Central Hudson Gas & Electric	New York	16-Jun-10	48.0
16	CT Natural Gas Corp.	Connecticut	30-Jun-10	52.5
17	Washington Gas Light Co.	Maryland	6-Aug-10	57.9
18	SourceGas Distribution LLC	Nebraska	17-Aug-10	51.2
19	Missouri Gas Energy	Missouri	18-Aug-10	38.7
20	NY State Electric & Gas Corp.	New York	16-Sep-10	48.0
21	Rochester Gas & Electric Corp.	New York	16-Sep-10	48.0
22	UNS Gas Inc.	Arizona	30-Sep-10	50.8
23	Michigan Consolidated Gas Co.	Michigan	14-Oct-10	38.8
24	Duke Energy Kentucky Inc.	Kentucky	21-Oct-10	49.9
25	Colonial Gas Co.	Massachusetts	2-Nov-10	50.0
26	Columbia Gas of Massachusetts	Massachusetts	2-Nov-10	53.6
27	Atmos Energy Corp.	Georgia	3-Nov-10	47.7
28	Consumers Energy Co.	Michigan	4-Nov-10	40.8
29	Avista Corp.	Washington	19-Nov-10	46.5
30	Baltimore Gas and Electric Co.	Maryland	6-Dec-10	51.9
31	NorthWestern Corp.	Montana	9-Dec-10	48.0
32	Sierra Pacific Power Co.	Nevada	20-Dec-10	44.1
33	Southwest Gas Corp.	Nevada	20-Dec-10	47.1
34	Madison Gas and Electric Co.	Wisconsin	12-Jan-11	58.1
35	Wisconsin Public Service Corp.	Wisconsin	13-Jan-11	51.7
36	Niagara Mohawk Power Corp.	New York	20-Jan-11	43.7
37	CenterPoint Energy Resources	Texas	3-Feb-11	55.4
38	Black Hills Iowa Gas Utility	Iowa	10-Feb-11	51.4

[11] Data from Regulatory Research Associates, SNL Financial, February 17, 2012.

LINE	COMPANY	STATE	DATE	COMMON EQUITY /TOTAL CAP (%)
39	EnergyNorth Natural Gas Inc.	New Hampshire	10-Mar-11	50.0
40	Avista Corp.	Oregon	10-Mar-11	50.0
41	Hope Gas Inc	West Virginia	30-Mar-11	42.3
42	New England Gas Company	Massachusetts	31-Mar-11	34.2
43	CenterPoint Energy Resources	Texas	18-Apr-11	55.6
44	Pacific Gas and Electric Co.	California	13-May-11	52.0
45	MidAmerican Energy Co.	Illinois	24-May-11	47.1
46	Orange & Rockland Utlts Inc.	New York	16-Jun-11	48.0
47	Fitchburg Gas & Electric Light	Massachusetts	1-Aug-11	42.9
48	ENSTAR Natural Gas Co.	Alaska	2-Sep-11	51.4
49	Wisconsin Gas LLC	Wisconsin	6-Oct-11	46.6
50	Columbia Gas of Virginia Inc	Virginia	28-Nov-11	42.7
51	Washington Gas Light Co.	Virginia	20-Dec-11	59.6
52	Northern IN Public Svc Co.	Indiana	21-Dec-11	46.3
53	Northern States Power Co - WI	Wisconsin	22-Dec-11	52.6
54	Ameren Illinois	Illinois	5-Jan-12	53.3
55	Peoples Gas Light & Coke Co.	Illinois	10-Jan-12	56.0
56	North Shore Gas Co.	Illinois	10-Jan-12	56.0
57	Atmos Energy Corp.	Texas	23-Jan-12	48.9
58	Peoples Gas System	Florida	27-Feb-12	48.5
59	Northern States Power Co. - MN	Minnesota	29-Mar-12	52.5
60	UNS Gas Inc.	Arizona	24-Apr-12	49.9
61	Public Service Co. of CO	Colorado	26-Apr-12	56.0
62	Puget Sound Energy Inc.	Washington	7-May-12	48.0
63	SourceGas Distribution LLC	Nebraska	22-May-12	50.0
64	Minnesota Energy Resources	Minnesota	24-May-12	48.8
65	Wisconsin Power and Light Co	Wisconsin	15-Jun-12	49.3
66	Cheyenne Light Fuel Power Co.	Wyoming	18-Jun-12	54.0
67	Washington Gas Light Co.	Virginia	2-Jul-12	55.7
68		Average		49.1

EXHIBIT 20
MARKET VALUE EQUITY RATIOS FOR COMPREHENSIVE GROUP
OF U.S. UTILITIES AT JUNE 2012

LINE NO.	COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP \$ (MIL)	% LONG-TERM DEBT	% PREFERRED	% MARKET EQUITY
1	AGL Resources	3,561	0	4,576	43.8%	0.0%	56.2%
2	Alliant Energy	2,703	205	5,132	33.6%	2.6%	63.8%
3	Amer. Elec. Power	15,083	0	19,559	43.5%	0.0%	56.5%
4	Atmos Energy	2,206	0	3,230	40.6%	0.0%	59.4%
5	CenterPoint Energy	8,641	0	8,871	49.3%	0.0%	50.7%
6	CMS Energy Corp.	6,207	44	6,171	50.0%	0.4%	49.7%
7	Consol. Edison	10,145	213	18,369	35.3%	0.7%	63.9%
8	Dominion Resources	17,394	257	31,084	35.7%	0.5%	63.8%
9	DTE	7,187	0	10,097	41.6%	0.0%	58.4%
10	Duke Energy	18,679	0	31,151	37.5%	0.0%	62.5%
11	Exelon Corp.	12,189	87	32,089	27.5%	0.2%	72.3%
12	FirstEnergy Corp.	15,716	0	20,869	43.0%	0.0%	57.0%
13	Great Plains	2,742	39	2,952	47.8%	0.7%	51.5%
14	Hawaiian Elec.	1,275	34	2,786	31.1%	0.8%	68.0%
15	NextEra Energy	20,810	0	28,711	42.0%	0.0%	58.0%
16	NiSource Inc.	5,936	0	7,051	45.7%	0.0%	54.3%
17	Northeast Utilities	4,727	116	12,262	27.6%	0.7%	71.7%
18	Pepco Holdings	4,062	0	4,467	47.6%	0.0%	52.4%
19	Piedmont Natural Gas	675	0	2,334	22.4%	0.0%	77.6%
20	Pinnacle West Capital	3,019	0	5,720	34.5%	0.0%	65.5%
21	PNM Resources	1,672	12	1,591	51.1%	0.4%	48.6%
22	Portland General	1,635	0	2,031	44.6%	0.0%	55.4%
23	Public Serv. Enterprise	7,461	0	16,492	31.1%	0.0%	68.9%
24	SCANA Corp.	4,622	0	6,320	42.2%	0.0%	57.8%
25	Sempra Energy	10,078	99	16,725	37.5%	0.4%	62.2%
26	Southern Co.	18,647	1,082	40,577	30.9%	1.8%	67.3%
27	TECO Energy	2,687	0	3,932	40.6%	0.0%	59.4%
28	Vectren Corp.	1,560	0	2,443	39.0%	0.0%	61.0%
29	Westar Energy	2,740	21	3,818	41.6%	0.3%	58.0%
30	WGL Holdings Inc.	587	28	2,073	21.8%	1.0%	77.1%
31	Wisconsin Energy	4,614	30	9,253	33.2%	0.2%	66.6%
32	Xcel Energy Inc.	8,849	0	13,989	38.7%	0.0%	61.3%
33	Average				38.5%	0.3%	61.1%

EXHIBIT 21
MARKET VALUE EQUITY RATIOS AT JUNE 2012
FOR U.S. UTILITIES WITH MOSTLY REGULATED ASSETS AND
S&P BOND RATING EQUAL TO OR GREATER THAN BBB

LINE NO.	COMPANY	LONG-TERM DEBT	PREFERRED EQUITY	MARKET CAP \$ (MIL)	% LONG-TERM DEBT	% PREFERRED	% MARKET EQUITY
1	AGL Resources	3,561	0	4,576	43.8%	0.0%	56.2%
2	Alliant Energy	2,703	205	5,132	33.6%	2.6%	63.8%
3	Amer. Elec. Power	15,083	0	19,559	43.5%	0.0%	56.5%
4	Atmos Energy	2,206	0	3,230	40.6%	0.0%	59.4%
5	Consol. Edison	10,145	213	18,369	35.3%	0.7%	63.9%
6	DTE	7,187	0	10,097	41.6%	0.0%	58.4%
7	Great Plains	2,742	39	2,952	47.8%	0.7%	51.5%
8	Northeast Utilities	4,727	116	12,262	27.6%	0.7%	71.7%
9	Piedmont Natural Gas	675	0	2,334	22.4%	0.0%	77.6%
10	Pinnacle West Capital	3,019	0	5,720	34.5%	0.0%	65.5%
11	Portland General	1,635	0	2,031	44.6%	0.0%	55.4%
12	Southern Co.	18,647	1,082	40,577	30.9%	1.8%	67.3%
13	TECO Energy	2,687	0	3,932	40.6%	0.0%	59.4%
14	Vectren Corp.	1,560	0	2,443	39.0%	0.0%	61.0%
15	Westar Energy	2,740	21	3,818	41.6%	0.3%	58.0%
16	WGL Holdings Inc.	587	28	2,073	21.8%	1.0%	77.1%
17	Wisconsin Energy	4,614	30	9,253	33.2%	0.2%	66.6%
18	Xcel Energy Inc.	8,849	0	13,989	38.7%	0.0%	61.3%
19	Average				36.7%	0.4%	62.8%

Data are from The Value Line Investment Analyzer, July 2012.

EXHIBIT 22
IMPLIED ALLOWED EQUITY RISK PREMIUM^[12]

YEAR	AVERAGE ALLOWED RETURN ELECTRIC UTILITIES	20-YEAR U.S. TREASURY BOND	RISK PREMIUM
1988	12.80	9.12	3.68
1989	12.97	8.59	4.38
1990	12.70	8.83	3.87
1991	12.54	8.19	4.35
1992	12.09	7.56	4.53
1993	11.46	6.69	4.77
1994	11.21	7.54	3.67
1995	11.58	6.90	4.68
1996	11.40	6.84	4.57
1997	11.33	6.66	4.67
1998	11.77	5.69	6.08
1999	10.72	6.23	4.49
2000	11.58	6.14	5.44
2001	11.07	5.61	5.46
2002	11.21	5.42	5.79
2003	10.96	4.95	6.02
2004	10.81	5.02	5.79
2005	10.51	4.62	5.89
2006	10.32	4.98	5.34
2007	10.30	4.87	5.43
2008	10.41	4.34	6.07
2009	10.52	4.13	6.39
2010	10.37	3.97	6.40
2011	10.25	3.54	6.71

**IMPLIED ALLOWED EQUITY RISK PREMIUM
REGRESSION RESULTS**

1	INTERCEPT COEFFICIENT	8.356
2	Slope Coefficient	(0.520)
3	Canada Forecast LT Yield	3.06
4	Slope x Bond Yield	-1.590
5	Forecast Risk Premium (Line 1 + Line 4)	6.77

^[12] Average annual allowed returns on equity from Regulatory Research Associates, SNL Financial; yield on long-term U.S. Treasury bonds from Ibbotson Associates.

APPENDIX 1

DERIVATION OF THE QUARTERLY DISCOUNTED CASH FLOW MODEL

The discounted cash flow (“DCF”) model is based on the assumption that investors value an asset on the basis of the future cash flows they expect to receive from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond’s face value at the time the bond matures. Likewise, investors value an investment in a firm’s stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF method is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond’s future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \dots + \frac{C+F}{(1+i)^n}$$

where:

- P_B = Bond price;
- C = Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
- F = Face value of the bond;
- i = The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
- n = The number of periods before the bond matures.

Applying these same principles to an investment in a firm's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_n + P_n}{(1+k)^n}$$

where:

- P_s = Current price of the firm's stock;
- $D_1, D_2 \dots D_n$ = Expected annual dividend per share on the firm's stock;
- P_n = Price per share of stock at the time the investor expects to sell the stock; and
- k = Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, g , this equation can be solved for k , the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the dividend yield component of the annual DCF model, and the term g is called the growth component of the annual DCF model.

The annual DCF model is only a correct expression for the present value of future dividends if dividends are paid annually at the end of each year. Since most industrial and utility firms pay dividends quarterly, the annual DCF model produces downwardly biased estimates of the cost of equity. Investors can expect to earn a higher annual effective return on an investment in a firm that pays quarterly dividends than in one which pays the same amount of dollar dividends once at the end of each year.

The Dividend Component

The quarterly DCF model requires an estimate of the expected dividends for the next four quarters. I estimate the expected dividends for the next four quarters by

multiplying the actual dividends for the last four quarters by the factor, $(1 + \text{the growth rate, } g)$.

The Growth Component

To estimate the growth component of the DCF model, I use the analysts' estimates of future earnings per share (EPS) growth reported by I/B/E/S Thomson Reuters. As part of their research, financial analysts working at Wall Street firms periodically estimate EPS growth for each firm they follow. The EPS forecasts for each firm are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent five-year forecasts of EPS growth. I/B/E/S is a firm that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each firm. Investors use the mean forecast as a consensus estimate of future firm performance. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

I rely on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' forecasts to estimate future earnings growth. To test whether investors use analysts' growth forecasts to estimate future dividend and earnings growth, I prepared a study in conjunction with Willard T. Carleton, Karl Eller Professor of Finance at the University of Arizona, on why analysts' forecasts are the best estimate of investors' expectation of future long-term growth. This study is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus Historical Growth Extrapolation," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

In our paper, we describe how we first performed a correlation analysis to identify the historically-oriented growth rates which best described a firm's stock price. Then we did a regression study comparing the historical growth rates with the consensus analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982).

These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented growth measures in predicting a firm's stock price.

My study has been updated to include more recent data. Researchers at State Street Financial Advisors updated my study using data through year-end 2003. Their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a firm's stock price.

The Price Component

To measure the price component of the DCF model, I use a simple average of the monthly high and low stock prices for each firm over a three-month period. These high and low stock prices were obtained from Thomson Reuters. I use the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to average stock prices over a three-month period.

APPENDIX 2
THE SENSITIVITY OF THE FORWARD-LOOKING
REQUIRED EQUITY RISK PREMIUM ON UTILITY STOCKS
TO CHANGES IN INTEREST RATES

My estimate of the required equity risk premium on utility stocks is based on studies of the discounted cash flow ("DCF") expected return on comparable groups of utilities in each month of my study period compared to the interest rate on long-term government bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation

$$RP_{COMP} = DCF_{COMP} - I_B$$

where:

RP_{COMP}	=	the required risk premium on an equity investment in the comparable utilities,
DCF_{COMP}	=	average DCF expected rate of return on a portfolio of comparable utilities; and
I_B	=	the yield to maturity on an investment in long-term U.S. Treasury bonds.

Electric Company Ex Ante Risk Premium Analysis. For my electric company ex ante risk premium analysis, I begin with the Moody's group of twenty-four electric companies shown in Table 1. I use the Moody's group of electric companies because they are a widely followed group of electric utilities, and use of this constant group greatly simplifies the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. The exhibit in the testimony displays the average DCF expected return on an investment in the portfolio of electric companies and the yield to maturity on long-term Treasury bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I perform a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on long-term Treasury bonds, using the equation,

$$RP_{COMP} = a + (b \times I_B) + e$$

where:

- RP_{COMP} = risk premium on comparable company group;
I_B = yield to maturity on long-term U.S. Treasury bonds;
e = a random residual; and
a, b = coefficients estimated by the regression procedure.

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals revealed that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I make adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, r . Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my regression analysis of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy electric company group as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = \begin{matrix} 10.04 \\ (13.77) \end{matrix} - \begin{matrix} .872 \times I_B \\ (-7.83)^{[13]} \end{matrix} R^2 = 28.9 \text{ percent.}$$

Using the forecast 2.73 percent yield to maturity on long-term Canada bonds obtained from Consensus Economics data as of June 2012, the regression equation produces an ex ante risk premium equal to 7.65 percent ($10.04 - .872 \times 2.73 = 7.65$).

Natural Gas Company Ex Ante Risk Premium Analysis. I also conduct an ex ante risk premium study applied to a natural gas proxy group following the procedures described above. To select my ex ante risk premium natural gas proxy group of companies, I use the same criteria that I use when estimating the DCF cost of equity, namely, I select all the companies in Value Line's groups of natural gas companies that: (1) paid dividends during every quarter of the last two years; (2) did not decrease dividends during any quarter of the past two years; (3) have at least two analysts included in the I/B/E/S mean growth forecast; (4) have an investment grade bond rating and a Value Line Safety

[13] The t-statistics are shown in parentheses.

Rank of 1, 2, or 3; and (5) are not the subject of a merger that has not been completed. The exhibit in the testimony displays the results of my ex ante risk premium study, showing the average DCF expected return on an investment in the portfolio of natural gas companies and the yield to maturity on long-term Treasury bonds in each month.^[14]

Based on my knowledge of the statistical relationship between the yield to maturity on long-term Treasury bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy natural gas companies as compared to an investment in long-term Treasury bonds is given by the equation:

$$RP_{COMP} = \frac{10.64}{(16.25)} - .927 \times I_B. \quad (-7.46)^{[15]} \quad R^2 = 25.13 \text{ percent}$$

Using the 2.73 percent forecast yield to maturity on long-term Canada bonds, the regression equation produces an ex ante risk premium equal to 8.1 percent ($10.64 - .927 \times 2.73 = 8.1$).

[14] My two ex ante risk premium studies cover slightly different time periods, with the natural gas company risk premium study extending over a longer period of time, because I began doing an ex ante study using natural gas companies before I began performing a similar study for the electric companies.

[15] The t-statistics are shown in parentheses.

TABLE 1
MOODY'S ELECTRIC COMPANIES

American Electric Power
Constellation Energy
Progress Energy
CH Energy Group
Cinergy Corp.
Consolidated Edison Inc.
DPL Inc.
DTE Energy Co.
Dominion Resources Inc.
Duke Energy Corp.
Energy East Corp.
FirstEnergy Corp.
Reliant Energy Inc.
IDACORP. Inc.
IPALCO Enterprises Inc.
NiSource Inc.
OGE Energy Corp.
Exelon Corp.
PPL Corp.
Potomac Electric Power Co.
Public Service Enterprise Group
Southern Company
Teco Energy Inc.
Xcel Energy Inc.

Source of data: *Mergent Public Utility Manual*, August 2002. Of these twenty-four companies, I do not include companies in my ex ante risk premium DCF analysis in months in which there are insufficient data to perform a DCF analysis. In addition, since the beginning period of my study, several companies have disappeared through mergers and acquisitions.

**STATEMENT OF QUALIFICATIONS
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James H. Vander Weide is Research Professor of Finance and Economics at Duke University, the Fuqua School of Business. Dr. Vander Weide is also founder and President of Financial Strategy Associates, a consulting firm that provides strategic, financial, and economic consulting services to corporate clients, including cost of capital and valuation studies.

Educational Background and Prior Academic Experience

Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts in Economics from Cornell University. He joined the faculty at Duke University and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

Since joining the faculty at Duke, Dr. Vander Weide has taught courses in corporate finance, investment management, and management of financial institutions. He has also taught courses in statistics, economics, and operations research, and a Ph.D. seminar on the theory of public utility pricing. In addition, Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, real options, capital budgeting, cash management, measuring corporate performance, valuation, short-run financial planning, depreciation policies, financial strategy, and competitive strategy. Dr. Vander Weide has designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union.

Publications

Dr. Vander Weide has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc. He has also written a chapter titled, "Financial Management in the Short Run" for *The Handbook of Modern Finance*; a chapter titled "Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory" for *The Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques*; and research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of

public utilities, and cash management. His articles have been published in *American Economic Review*, *Financial Management*, *International Journal of Industrial Organization*, *Journal of Finance*, *Journal of Financial and Quantitative Analysis*, *Journal of Bank Research*, *Journal of Portfolio Management*, *Journal of Accounting Research*, *Journal of Cash Management*, *Management Science*, *Atlantic Economic Journal*, *Journal of Economics and Business*, and *Computers and Operations Research*.

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the telecommunications, electric, gas, insurance, and water industries for more than thirty-five years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, depreciation, accounting, valuation, and other financial and economic issues in more than 400 cases before the United States Congress, the Canadian Radio-Television and Telecommunications Commission, the Federal Communications Commission, the National Energy Board (Canada), the National Telecommunications and Information Administration, the Federal Energy Regulatory Commission, the public service commissions of forty-three states, the District of Columbia, four Canadian provinces, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in telecommunications-related proceedings before the United States District Court for the District of New Hampshire, United States District Court for the Northern District of California, United States District Court for the Northern District of Illinois, Montana Second Judicial District Court Silver Bow County, the United States Bankruptcy Court for the Southern District of West Virginia, and United States District Court for the Eastern District of Michigan. He also testified as an expert before the United States Tax Court, United States District Court for the Eastern District of North Carolina; United States District Court for the District of Nebraska, and Superior Court of North Carolina. Dr. Vander Weide has testified in thirty states on issues relating to the pricing of unbundled network elements and universal service cost studies and has consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. He has also provided expert testimony on issues related to electric and natural gas restructuring. He has worked for Bell Canada/Nortel on a special task force to study the effects of vertical integration in the Canadian telephone industry and has worked for Bell Canada as an expert witness on the cost of capital. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

ELECTRIC, GAS, WATER, OIL COMPANIES	
Alcoa Power Generating, Inc.	Maritimes & Northeast Pipeline
Alliant Energy and subsidiaries	MidAmerican Energy and subsidiaries
AltaLink, L.P.	National Fuel Gas
Ameren	Newfoundland Power Inc.
American Water Works	Nevada Power Company
Atmos Energy and subsidiaries	NICOR
BP p.l.c.	North Carolina Natural Gas
Central Illinois Public Service	North Shore Gas
Citizens Utilities	Northern Natural Gas Company
Consolidated Natural Gas and subsidiaries	NOVA Gas Transmission Ltd.
Dominion Resources and subsidiaries	PacifiCorp
Duke Energy and subsidiaries	Peoples Energy and its subsidiaries
Empire District Electric Company	PG&E
EPCOR Distribution & Transmission Inc.	Progress Energy
EPCOR Energy Alberta Inc.	PSE&G
FortisAlberta Inc.	Public Service Company of North Carolina
FortisBC Utilities	Sempra Energy/San Diego Gas and Electric
Hope Natural Gas	South Carolina Electric and Gas
Interstate Power Company	Southern Company and subsidiaries
Iberdrola Renewables	Tennessee-American Water Company
Iowa Southern	The Peoples Gas, Light and Coke Co.
Iowa-American Water Company	TransCanada
Iowa-Illinois Gas and Electric	Trans Québec & Maritimes Pipeline Inc.
Kentucky Power Company	Union Gas
Kentucky-American Water Company	United Cities Gas Company
Kinder Morgan Energy Partners	Virginia-American Water Company
	Xcel Energy

TELECOMMUNICATIONS COMPANIES	
ALLTEL and subsidiaries	Phillips County Cooperative Tel. Co.
Ameritech (now AT&T new)	Pine Drive Cooperative Telephone Co.
AT&T (old)	Roseville Telephone Company (SureWest)
Bell Canada/Nortel	SBC Communications (now AT&T new)
BellSouth and subsidiaries	Sherburne Telephone Company
Centel and subsidiaries	Siemens
Cincinnati Bell (Broadwing)	Southern New England Telephone
Cisco Systems	Sprint/United and subsidiaries
Citizens Telephone Company	Telefónica
Concord Telephone Company	Tellabs, Inc.
Contel and subsidiaries	The Stentor Companies
Deutsche Telekom	U S West (Qwest)
GTE and subsidiaries (now Verizon)	Union Telephone Company
Heins Telephone Company	United States Telephone Association
JDS Uniphase	Valor Telecommunications (Windstream)
Lucent Technologies	Verizon (Bell Atlantic) and subsidiaries

TELECOMMUNICATIONS COMPANIES	
Minnesota Independent Equal Access Corp.	Woodbury Telephone Company
NYNEX and subsidiaries (Verizon)	
Pacific Telesis and subsidiaries	

INSURANCE COMPANIES
Allstate
North Carolina Rate Bureau
United Services Automobile Association (USAA)
The Travelers Indemnity Company
Gulf Insurance Company

Other Professional Experience

Dr. Vander Weide conducts in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

Early in his career, Dr. Vander Weide helped found University Analytics, Inc., which was one of the fastest growing small firms in the country. As an officer at University Analytics, he designed cash management models, databases, and software packages that are still used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

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**SUMMARY EXPERT TESTIMONY
JAMES H. VANDER WEIDE**

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Empire District Electric Company	Missouri	Jul-12	ER2012-0345
Atmos Energy	Tennessee	Jul-12	12-00064
Mississippi Power Company	Mississippi	Jun-12	
Tennessee-American Water Company	Tennessee	May-12	12-00049
Empire District Electric Company	FERC	May-12	ER12-0345
Newfoundland Power Inc.	Newfoundland and Labrador	Mar-12	
Virginia-American Water Company	Virginia	Feb-11	PUE-2011-00127
SFPP, L.P.	FERC	Dec-11	IS11-444-001
Union Gas	Ontario Energy Board	Nov-11	
Mississippi Power Company	FERC	Nov-11	ER12-337
National Fuel Gas	FERC	Oct-11	RP12-888-000
Gulf Power Florida	Florida	Jul-11	110138-EI
Empire District Electric Company	Oklahoma Corporation Commission	Jul-11	11-EPDE-856-RTS
Atmos Energy (West Texas)	Railroad Commission of Texas	Jun-11	
Atmos Energy (Lubbock)	Railroad Commission of Texas	Jun-11	
Iberdrola Renewables Holdings, Inc.	United States Tax Court	Apr-11	525-10
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Jan-11	
Atmos Energy	Railroad Commission of Texas	Dec-10	GUD 10041
Mississippi Power Company	FERC	Oct-10	
Empire District Electric Company	Missouri	Sep-10	ER-2011-0004
Tennessee-American Water Company	Tennessee	Sep-10	10-00189
Empire District Electric Company	Arkansas	Aug-10	10-052-U
Maritimes & Northeast Pipelines Limited Partnership	National Energy Board (Canada)	Jul-10	RH 4-2010
Georgia Power Company	Georgia	Jun-10	31958
West Virginia American Water Company	West Virginia	Jun-10	Case No. 10-0920-W-42T
Atmos Energy	Mississippi	Apr-10	2005-UN-503
BP Pipelines (Alaska) Inc.	FERC	Apr-10	IS09-348-000
Empire District Electric Company	FERC	Mar-10	ER10-877-000
Kentucky-American Water Company	Kentucky	Feb-10	2010-00036
Virginia-American Water Company	Virginia	Feb-10	PUE-2010-00001
Virginia Electric and Power	North Carolina	Feb-10	E-22 SUB 459
SFPP, L.P.	FERC	Dec-09	ISO9-437-000
Atmos Energy	Missouri	Dec-09	Gr-2010-0192
Empire District Electric Company	Kansas	Nov-09	10-EPDE-314-RTS
Empire District Electric Company	Missouri	Nov-09	ER-2010-0130
Atmos Energy	Kentucky	Oct-09	2009-00354
Atmos Energy	Georgia	Oct-09	30442
SFPP, L.P. and Calnev Pipeline, L.L.C.	California	Sep-09	09-05-014 et al
Union Gas	Ontario Energy Board	Sep-09	EB-2009-0084
Atmos Energy	Mississippi	Sep-09	05-UN-503
North Carolina Rate Bureau (workers)	North Carolina Dept. of Insurance	Sep-09	
Sidley Austin LLP, Tellabs, Inc. Securities Litigation	U.S. District Court Northern Dist. Illinois	Aug-09	C.A. No. 02-C-4356
Duke Energy Carolinas	South Carolina	Jul-09	2009-226-E
MidAmerican Energy Company	Iowa	Jul-09	RPU-2009-0003
Duke Energy Carolinas	North Carolina	Jun-09	E-7, SUB 909
Empire District Electric Company	Missouri	Jun-09	ER-2008-009
Terasen Gas Inc.	British Columbia Utilities Commission	May-09	
Atmos Energy	Railroad Commission of Texas	Apr-09	GUD-9869

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Progress Energy	Florida	Mar-09	090079-EI
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-09	
EPCOR, FortisAlberta, AltaLink	Alberta Utilities Commission	Nov-08	1578571, ID-85
Trans Québec & Maritimes Pipeline Inc.	Alberta Utilities Commission	Nov-08	1578571, ID-85
Kentucky-American Water Company	Kentucky Public Service Commission	Oct-08	2008-00427
Atmos Energy	Tennessee Regulatory Authority	Oct-08	0800197
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-08	
Dorsey & Whitney LLP-Williams v. Gannon	Montana 2nd Judicial Dist. Ct. Silver Bow County	Apr-08	DV-02-201
Atmos Energy	Georgia	Mar-08	27163-U
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-08	
Trans Québec & Maritimes Pipeline Inc.	National Energy Board (Canada)	Dec-07	RH-1-2008
Xcel Energy	North Dakota	Dec-07	PU-07-776
Verizon Southwest	Texas	Nov-07	34723
Empire District Electric Company	Missouri	Oct-07	ER-2008-0093
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Sep-07	
Verizon North Inc. Contel of the South Inc.	Michigan	Aug-07	Case No. U-15210
Georgia Power Company	Georgia	Jun-07	25060-U
Duke Energy Carolinas	North Carolina	May-07	E-7 Sub 828 et al
MidAmerican Energy Company	Iowa	May-07	SPU-06-5 et al
Morrison & Foerster LLP-JDS Uniphase Securities Litigation	U.S. District Court Northern District California	Feb-07	C-02-1486-CW
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Dec-06	
San Diego Gas & Electric	FERC	Nov-06	ER07-284-000
North Carolina Rate Bureau (workers compensation)	North Carolina Dept. of Insurance	Aug-06	
Union Electric Company d/b/a AmerenUE	Missouri	Jun-06	ER-2007-0002
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	May-06	
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Mar-06	
Empire District Electric Company	Missouri	Feb-06	ER-2006-0315
PacifiCorp Power & Light Company	Washington	Jan-06	UE-050684
Verizon Maine	Maine	Dec-05	2005-155
Winston & Strawn LLP-Cisco Systems Securities Litigation	U.S. District Court Northern District California	Nov-05	C-01-20418-JW
Dominion Virginia Power	Virginia	Nov-05	PUE-2004-00048
Bryan Cave LLP--Omniplex Comms. v. Lucent Technologies	U.S. District Court Eastern District Missouri	Sep-05	04CV00477 ERW
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-05	
Empire District Electric Company	Kansas	Sep-05	05-EPDE-980-RTS
Verizon Southwest	Texas	Jul-05	29315
PG&E Company	FERC	Jul-05	ER-05-1284
Dominion Hope	West Virginia	Jun-05	05-034-G42T
Empire District Electric Company	Missouri	Jun-05	EO-2005-0263
Verizon New England	U.S. District Court New Hampshire	May-05	04-CV-65-PB
San Diego Gas & Electric	California	May-05	05-05-012
Progress Energy	Florida	May-05	50078
Verizon Vermont	Vermont	Feb-05	6959
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Feb-05	
Verizon Florida	Florida	Jan-05	050059-TL
Verizon Illinois	Illinois	Jan-05	00-0812
Dominion Resources	North Carolina	Sep-04	E-22 Sub 412
Tennessee-American Water Company	Tennessee	Aug-04	04-00288
Valor Telecommunications of Texas, LP.	New Mexico	Jul-04	3495 Phase C
Alcoa Power Generating Inc.	North Carolina Property Tax Commission	Jul-04	02 PTC 162 and 02 PTC 709

SPONSOR	JURISDICTION	DATE	DOCKET NO.
PG&E Company	California	May-04	04-05-21
Verizon Northwest	Washington	Apr-04	UT-040788
Verizon Northwest	Washington	Apr-04	UT-040788
Kentucky-American Water Company	Kentucky	Apr-04	2004-00103
MidAmerican Energy	South Dakota	Apr-04	NG4-001
Empire District Electric Company	Missouri	Apr-04	ER-2004-0570
Interstate Power and Light Company	Iowa	Mar-04	RPU-04-01
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-04	
Northern Natural Gas Company	FERC	Feb-04	RP04-155-000
Verizon New Jersey	New Jersey	Jan-04	TO00060356
Verizon	FCC	Jan-04	03-173, FCC 03-224
Verizon	FCC	Dec-03	03-173, FCC 03-224
Verizon California Inc.	California	Nov-03	R93-04-003,I93-04-002
Phillips County Telephone Company	Colorado	Nov-03	03S-315T
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Oct-03	
PG&E Company	FERC	Oct-03	ER04-109-000
Allstate Insurance Company	Texas Department of Insurance	Sep-03	2568
Verizon Northwest Inc.	Washington	Jul-03	UT-023003
Empire District Electric Company	Oklahoma	Jul-03	Case No. PUD 200300121
Verizon Virginia Inc.	FCC	Apr-03	CC-00218,00249,00251
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Apr-03	
Northern Natural Gas Company	FERC	Apr-03	RP03-398-000
MidAmerican Energy	Iowa	Apr-03	RPU-03-1, WRU-03-25-156
PG&E Company	FERC	Mar-03	ER03666000
Verizon Florida Inc.	Florida	Feb-03	981834-TP/990321-TP
Verizon North	Indiana	Feb-03	42259
San Diego Gas & Electric	FERC	Feb-03	ER03-601000
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-03	
Gulf Insurance Company	Superior Court, North Carolina	Jan-03	2000-CVS-3558
PG&E Company	FERC	Jan-03	ER03409000
Verizon New England Inc. New Hampshire	New Hampshire	Dec-02	DT 02-110
Verizon Northwest	Washington	Dec-02	UT 020406
PG&E Company	California	Dec-02	
MidAmerican Energy	Iowa	Nov-02	RPU-02-3, 02-8
MidAmerican Energy	Iowa	Nov-02	RPU-02-10
Verizon Michigan	US District Court Eastern District of Michigan	Sep-02	Civil Action No. 00-73208
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-02	
Verizon New England Inc. New Hampshire	New Hampshire	Aug-02	DT 02-110
Interstate Power Company	Iowa Board of Tax Review	Jul-02	832
PG&E Company	California	May-02	A 02-05-022 et al
Verizon New England Inc. Massachusetts	FCC	May-02	EB 02 MD 006
Verizon New England Inc. Rhode Island	Rhode Island	May-02	Docket No. 2681
NEUMEDIA, INC.	US Bankruptcy Court Southern District W. Virginia	Apr-02	Case No. 01-20873
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Mar-02	
MidAmerican Energy Company	Iowa	Mar-02	RPU 02 2
North Carolina Natural Gas Company	North Carolina	Feb-02	G21 Sub 424
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jan-02	
Verizon Pennsylvania	Pennsylvania	Dec-01	R-00016683
Verizon Florida	Florida	Nov-01	99064B-TP
PG&E Company	FERC	Nov-01	ER0166000
Verizon Delaware	Delaware	Oct-01	96-324 Phase II
Florida Power Corporation	Florida	Sep-01	000824-EL
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-01	
Verizon Washington DC	District of Columbia	Jul-01	962

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Verizon Virginia	FCC	Jul-01	CC-00218,00249,00251
Sherburne County Rural Telephone Company	Minnesota	Jul-01	P427/CI-00-712
Verizon New Jersey	New Jersey	Jun-01	TO01020095
Verizon Maryland	Maryland	May-01	8879
Verizon Massachusetts	Massachusetts	May-01	DTE 01-20
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Apr-01	
PG&E Company	FERC	Mar-01	ER011639000
Maupin Taylor & Ellis P.A.	National Association of Securities Dealers	Jan-01	99-05099
USTA	FCC	Oct-00	RM 10011
Verizon New York	New York	Oct-00	98-C-1357
Verizon New Jersey	New Jersey	Oct-00	TO00060356
PG&E Company	FERC	Oct-00	ER0166000
Verizon New Jersey	New Jersey	Sep-00	TO99120934
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-00	
PG&E Company	California	Aug-00	00-05-018
Verizon New York	New York	Jul-00	98-C-1357
PG&E Company	California	May-00	00-05-013
PG&E Company	FERC	Mar-00	ER00-66-000
PG&E Company	FERC	Mar-00	ER99-4323-000
Bell Atlantic	New York	Feb-00	98-C-1357
USTA	FCC	Jan-00	94-1, 96-262
MidAmerican Energy	Iowa	Nov-99	SPU-99-32
PG&E Company	California	Nov-99	99-11-003
PG&E Company	FERC	Nov-99	ER973255,981261,981685
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-99	
MidAmerican Energy	Illinois	Sep-99	99-0534
PG&E Company	FERC	Sep-99	ER99-4323-000
MidAmerican Energy	FERC	Jul-99	ER99-3887
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-99	
Bell Atlantic	Vermont	May-99	6167
Nevada Power Company	FERC	May-99	
Bell Atlantic, GTE, US West	FCC	Apr-99	CC98-166
Nevada Power Company	Nevada	Apr-99	
Bell Atlantic, GTE, US West	FCC	Mar-99	CC98-166
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-99	
PG&E Company	FERC	Mar-99	ER99-2326-000
MidAmerican Energy	Illinois	Mar-99	099-0310
PG&E Company	FERC	Feb-99	ER99-2358,2087,2351
MidAmerican Energy	US District Court, District of Nebraska	Feb-99	8:97 CV 346
Bell Atlantic, GTE, US West	FCC	Jan-99	CC98-166
The Southern Company	FERC	Jan-99	ER98-1096
Deutsche Telekom	Germany	Nov-98	
Telefonica	Spain	Nov-98	
Cincinnati Bell Telephone Company	Ohio	Oct-98	96899TPALT
MidAmerican Energy	Iowa	Sep-98	RPV 98-5
MidAmerican Energy	South Dakota	Sep-98	NG98-011
MidAmerican Energy	Iowa	Sep-98	SPV 98-8
GTE Florida Incorporated	Florida	Aug-98	980696-TP
GTE North and South	Illinois	Jun-98	960503
GTE Midwest Incorporated	Missouri	Jun-98	TO98329
GTE North and South	Illinois	May-98	960503
MidAmerican Energy	Iowa Board of Tax Review	May-98	835
San Diego Gas & Electric	California	May-98	98-05-024
GTE Midwest Incorporated	Nebraska	Apr-98	C1416

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Carolina Telephone	North Carolina	Mar-98	P100Sub133d
GTE Southwest	Texas	Feb-98	18515
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-98	P100sub133d
Public Service Electric & Gas	New Jersey	Feb-98	PUC734897N,- 734797N,BPUEO97070461,-07070462
GTE North	Minnesota	Dec-97	P999/M97909
GTE Northwest	Oregon	Dec-97	UM874
The Southern Company	FERC	Dec-97	ER981096000
GTE North	Pennsylvania	Nov-97	A310125F0002
Bell Atlantic	Rhode Island	Nov-97	2681
GTE North	Indiana	Oct-97	40618
GTE North	Minnesota	Oct-97	P442,407/5321/CI961541
GTE Southwest	New Mexico	Oct-97	96310TC,96344TC
GTE Midwest Incorporated	Iowa	Sep-97	RPU-96-7
North Carolina Rate Bureau (workers)	North Carolina Dept. of Insurance	Sep-97	
GTE Hawaiian Telephone	Hawaii	Aug-97	7702
The Stentor Companies	Canadian Radio-television and Telecommunications Commission	Jul-97	CRTC97-11
New England Telephone	Vermont	Jul-97	5713
Bell-Atlantic-New Jersey	New Jersey	Jun-97	TX95120631
Nevada Bell	Nevada	May-97	96-9035
New England Telephone	Maine	Apr-97	96-781
GTE North, Inc.	Michigan	Apr-97	U11281
Bell Atlantic-Virginia	Virginia	Apr-97	970005
Cincinnati Bell Telephone	Ohio	Feb-97	96899TPALT
Bell Atlantic - Pennsylvania	Pennsylvania	Feb-97	A310203,213,236,258F002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-97	
Bell Atlantic-Washington, D.C.	District of Columbia	Jan-97	962
Pacific Bell, Sprint, US West	FCC	Jan-97	CC 96-45
United States Telephone Association	FCC	Jan-97	CC 96-262
Bell Atlantic-Maryland	Maryland	Jan-97	8731
Bell Atlantic-West Virginia	West Virginia	Jan-97	961516, 1561, 1009TPC,961533TT
Poe, Hoof, & Reinhardt	Durham Cnty Superior Court Kountis vs. Circle K	Jan-97	95CVS04754
Bell Atlantic-Delaware	Delaware	Dec-96	96324
Bell Atlantic-New Jersey	New Jersey	Nov-96	TX95120631
Carolina Power & Light Company	FERC	Nov-96	OA96-198-000
New England Telephone	Massachusetts	Oct-96	DPU 96-73/74,-75, -80/81, -83, -94
New England Telephone	New Hampshire	Oct-96	96-252
Bell Atlantic-Virginia	Virginia	Oct-96	960044
Citizens Utilities	Illinois	Sep-96	96-0200, 96-0240
Union Telephone Company	New Hampshire	Sep-96	95-311
Bell Atlantic-New Jersey	New Jersey	Sep-96	TO-96070519
New York Telephone	New York	Sep-96	95-C-0657, 94-C-0095,91-C-1174
North Carolina Rate Bureau (workers comp)	North Carolina Dept. of Insurance	Sep-96	
MidAmerican Energy Company	Illinois	Sep-96	96-0274
MidAmerican Energy Company	Iowa	Sep-96	RPU96-8
United States Telephone Association	FCC	Mar-96	AAD-96.28
United States Telephone Association	FCC	Mar-96	CC 94-1 PhaseIV
Bell Atlantic - Maryland	Maryland	Mar-96	8715
Nevada Bell	Nevada	Mar-96	96-3002
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Mar-96	
Carolina Tel. and Telegraph Co, Central Tel Co	North Carolina	Feb-96	P7 sub 825, P10 sub 479
Oklahoma Rural Telephone Coalition	Oklahoma	Oct-95	PUD950000119
BellSouth	Tennessee	Oct-95	95-02614
Wake County, North Carolina	US District Court, Eastern Dist. NC	Oct-95	594CV643H2

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Bell Atlantic - District of Columbia	District of Columbia	Sep-95	814 Phase IV
South Central Bell Telephone Company	Tennessee	Aug-95	95-02614
GTE South	Virginia	Jun-95	95-0019
Roseville Telephone Company	California	May-95	A.95-05-030
Bell Atlantic - New Jersey	New Jersey	May-95	TX94090388
Cincinnati Bell Telephone Company	Ohio	May-95	941695TPACE
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	May-95	727
Northern Illinois Gas	Illinois	May-95	95-0219
South Central Bell Telephone Company	Kentucky	Apr-95	94-121
Midwest Gas	South Dakota	Mar-95	
Virginia Natural Gas, Inc.	Virginia	Mar-95	PUE940054
Hope Gas, Inc.	West Virginia	Mar-95	95-0003G42T
The Peoples Natural Gas Company	Pennsylvania	Feb-95	R-943252
and Coke Co., North Shore Gas, Iowa-Illinois Gas	Illinois	Jan-95	94-0403
and Electric, Central Illinois Public Service,	Illinois	Jan-95	94-0403
Northern Illinois Gas, The Peoples Gas, Light	Illinois	Jan-95	94-0403
United Cities Gas, and Interstate Power	Illinois	Jan-95	94-0403
Cincinnati Bell Telephone Company	Kentucky	Oct-94	94-355
Midwest Gas	Nebraska	Oct-94	
Midwest Power	Iowa	Sep-94	RPU-94-4
Bell Atlantic	FCC	Aug-94	CS 94-28, MM 93-215
Midwest Gas	Iowa	Jul-94	RPU-94-3
Bell Atlantic	FCC	Jun-94	CC 94-1
Nevada Power Company	Nevada	Jun-94	93-11045
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-551-TP-CSS
Cincinnati Bell Telephone Company	Ohio	Mar-94	93-432-TP-ALT
GTE South/Contel	Virginia	Feb-94	PUC9300036
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Feb-94	689
Bell of Pennsylvania	Pennsylvania	Jan-94	P930715
GTE South	South Carolina	Jan-94	93-504-C
United Telephone-Southeast	Tennessee	Jan-94	93-04818
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Sep-93	PUC920029
Bell Atlantic, NYNEX, Pacific Companies	FCC	Aug-93	MM 93-215
C&P, Centel, Contel, GTE, & United	Virginia	Aug-93	PUC920029
Chesapeake & Potomac Tel Virginia	Virginia	Aug-93	93-00-
GTE North	Illinois	Jul-93	93-0301
Midwest Power	Iowa	Jul-93	INU-93-1
Midwest Power	South Dakota	Jul-93	EL93-016
Chesapeake & Potomac Tel. Co. DC	District of Columbia	Jun-93	926
Cincinnati Bell	Ohio	Jun-93	93432TPALT
North Carolina Rate Bureau (dwelling fire)	North Carolina Dept. of Insurance	Jun-93	671
North Carolina Rate Bureau (homeowners)	North Carolina Dept. of Insurance	Jun-93	670
Pacific Bell Telephone Company	California	Mar-93	92-05-004
Minnesota Independent Equal Access Corp.	Minnesota	Mar-93	P3007/GR931
South Central Bell Telephone Company	Tennessee	Feb-93	92-13527
South Central Bell Telephone Company	Kentucky	Dec-92	92-523
Southern New England Telephone Company	Connecticut	Nov-92	92-09-19
Chesapeake & Potomac Tel. Co.CDC	District of Columbia	Nov-92	814
Diamond State Telephone Company	Delaware	Sep-92	PSC 92-47
New Jersey Bell Telephone Company	New Jersey	Sep-92	TO-92030958
Allstate Insurance Company	New Jersey Dept. of Insurance	Sep-92	INS 06174-92
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Aug-92	650
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-92	647
Midwest Gas Company	Minnesota	Aug-92	G010/GR92710

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Pennsylvania-American Water Company	Pennsylvania	Jul-92	R-922428
Central Telephone Co. of Florida	Florida	Jun-92	920310-TL
C&P of VA, GTE South, Contel, United Tel. SE	Virginia	Jun-92	PUC920029
Chesapeake & Potomac Tel. Co. Maryland	Maryland	May-92	8462
Pacific Bell Telephone Company	California	Apr-92	92-05-004
Iowa Power Inc.	Iowa	Mar-92	RPU-92-2
Contel of Texas	Texas	Feb-92	10646
Southern Bell Telephone Company	Florida	Jan-92	880069-TL
Nevada Power Company	Nevada	Jan-92	92-1067
GTE South	Georgia	Dec-91	4003-U
GTE South	Georgia	Dec-91	4110-U
Allstate Insurance Company (property)	Texas Dept. of Insurance	Dec-91	1846
IPS Electric	Iowa	Oct-91	RPU-91-6
GTE South	Tennessee	Aug-91	91-05738
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-91	609
Midwest Gas Company	Iowa	Jul-91	RPU-91-5
Pennsylvania-American Water Company	Pennsylvania	Jun-91	R-911909
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-91	606
Allstate Insurance Company	California Dept. of Insurance	May-91	RCD-2
Nevada Power Company	Nevada	May-91	91-5055
Kentucky Power Company	Kentucky	Apr-91	91-066
Chesapeake & Potomac Tel. Co.CD.C.	District of Columbia	Feb-91	850
Allstate Insurance Company	New Jersey Dept. of Insurance	Jan-91	INS-9536-90
GTE South	South Carolina	Nov-90	90-698-C
Southern Bell Telephone Company	Florida	Oct-90	880069-TL
GTE South	West Virginia	Aug-90	90-522-T-42T
North Carolina Rate Bureau (workers' comp)	North Carolina Dept. of Insurance	Aug-90	R90-08-
The Travelers Indemnity Company	Pennsylvania Dept. of Insurance	Aug-90	R-90-06-23
Chesapeake & Potomac Tel. Co.-Maryland	Maryland	Jul-90	8274
Allstate Insurance Company	Pennsylvania Dept. of Insurance	Jul-90	R90-07-01
Central Tel. Co. of Florida	Florida	Jun-90	89-1246-TL
Citizens Telephone Company	North Carolina	Jun-90	P-12, SUB 89
North Carolina Rate Bureau (auto)	North Carolina Dept. of Insurance	Jun-90	568
Iowa Resources, Inc. and Midwest Energy	Iowa	Jun-90	SPU-90-5
Contel of Illinois	Illinois	May-90	90-0128
Southern New England Tel. Co.	Connecticut	Apr-90	89-12-05
Bell Atlantic	FCC	Apr-90	89-624 II
Pennsylvania-American Water Company	Pennsylvania	Mar-90	R-901652
Bell Atlantic	FCC	Feb-90	89-624
GTE South	Tennessee	Jan-90	
Allstate Insurance Company	California Dept. of Insurance	Jan-90	REB-1002
Bell Atlantic	FCC	Nov-89	87-463 II
Allstate Insurance Company	California Dept. of Insurance	Sep-89	REB-1006
Pacific Bell	California	Mar-89	87-11-0033
Iowa Power & Light	Iowa	Dec-88	RPU-88-10
Pacific Bell	California	Oct-88	88-05-009
Southern Bell	Florida	Apr-88	880069TL
Carolina Independent Telcos.	North Carolina	Apr-88	P-100, Sub 81
United States Telephone Association	U. S. Congress	Apr-88	
Carolina Power & Light	South Carolina	Mar-88	88-11-E
New Jersey Bell Telephone Co.	New Jersey	Feb-88	87050398
Carolina Power & Light	FERC	Jan-88	ER-88-224-000
Carolina Power & Light	North Carolina	Dec-87	E-2, Sub 537
Bell Atlantic	FCC	Nov-87	87-463

SPONSOR	JURISDICTION	DATE	DOCKET NO.
Diamond State Telephone Co.	Delaware	Jul-87	86-20
Central Telephone Co. of Nevada	Nevada	Jun-87	87-1249
ALLTEL	Florida	Apr-87	870076-PU
Southern Bell	Florida	Apr-87	870076-PU
Carolina Power & Light	North Carolina	Apr-87	E-2, Sub 526
So. New England Telephone Co.	Connecticut	Mar-87	87-01-02
Northern Illinois Gas Co.	Illinois	Mar-87	87-0032
Bell of Pennsylvania	Pennsylvania	Feb-87	860923
Carolina Power & Light	FERC	Jan-87	ER-87-240-000
Bell South	NTIA	Dec-86	61091-619
Heins Telephone Company	North Carolina	Oct-86	P-26, Sub 93
Public Service Co. of NC	North Carolina	Jul-86	G-5, Sub 207
Bell Atlantic	FCC	Feb-86	84-800 III
BellSouth	FCC	Feb-86	84-800 III
ALLTEL Carolina, Inc	North Carolina	Feb-86	P-118, Sub 39
ALLTEL Georgia, Inc.	Georgia	Jan-86	3567-U
ALLTEL Ohio	Ohio	Jan-86	86-60-TP-AIR
Western Reserve Telephone Co.	Ohio	Jan-86	85-1973-TP-AIR
New England Telephone & Telegraph	Maine	Dec-85	
ALLTEL-Florida	Florida	Oct-85	850064-TL
Iowa Southern Utilities	Iowa	Oct-85	RPU-85-11
Bell Atlantic	FCC	Sep-85	84-800 II
Pacific Telesis	FCC	Sep-85	84-800 II
Pacific Bell	California	Apr-85	85-01-034
United Telephone Co. of Missouri	Missouri	Apr-85	TR-85-179
South Carolina Generating Co.	FERC	Apr-85	85-204
South Central Bell	Kentucky	Mar-85	9160
New England Telephone & Telegraph	Vermont	Mar-85	5001
Chesapeake & Potomac Telephone Co.	West Virginia	Mar-85	84-747
Chesapeake & Potomac Telephone Co.	Maryland	Jan-85	7851
Central Telephone Co. of Ohio	Ohio	Dec-84	84-1431-TP-AIR
Ohio Bell	Ohio	Dec-84	84-1435-TP-AIR
Carolina Power & Light Co.	FERC	Dec-84	ER85-184000
BellSouth	FCC	Nov-84	84-800 I
Pacific Telesis	FCC	Nov-84	84-800 I
New Jersey Bell	New Jersey	Aug-84	848-856
Southern Bell	South Carolina	Aug-84	84-308-C
Pacific Power & Light Co.	Montana	Jul-84	84.73.8
Carolina Power & Light Co.	South Carolina	Jun-84	84-122-E
Southern Bell	Georgia	Mar-84	3465-U
Carolina Power & Light Co.	North Carolina	Feb-84	E-2, Sub 481
Southern Bell	North Carolina	Jan-84	P-55, Sub 834
South Carolina Electric & Gas	South Carolina	Nov-83	83-307-E
Empire Telephone Co.	Georgia	Oct-83	3343-U
Southern Bell	Georgia	Aug-83	3393-U
Carolina Power & Light Co.	FERC	Aug-83	ER83-765-000
General Telephone Co. of the SW	Arkansas	Jul-83	83-147-U
Heins Telephone Co.	North Carolina	Jul-83	No.26 Sub 88
General Telephone Co. of the NW	Washington	Jul-83	U-82-45
Leeds Telephone Co.	Alabama	Apr-83	18578
General Telephone Co. of California	California	Apr-83	83-07-02
North Carolina Natural Gas	North Carolina	Apr-83	G21 Sub 235
Carolina Power & Light	South Carolina	Apr-83	82-328-E
Eastern Illinois Telephone Co.	Illinois	Feb-83	83-0072
Carolina Power & Light	North Carolina	Feb-83	E-2 Sub 461

SPONSOR	JURISDICTION	DATE	DOCKET NO.
New Jersey Bell	New Jersey	Dec-82	8211-1030
Southern Bell	Florida	Nov-82	820294-TP
United Telephone of Missouri	Missouri	Nov-82	TR-83-135
Central Telephone Co. of NC	North Carolina	Nov-82	P-10 Sub 415
Concord Telephone Company	North Carolina	Nov-82	P-16 Sub 146
Carolina Telephone & Telegraph	North Carolina	Aug-82	P-7, Sub 670
Central Telephone Co. of Ohio	Ohio	Jul-82	82-636-TP-AIR
Southern Bell	South Carolina	Jul-82	82-294-C
General Telephone Co. of the SW	Arkansas	Jun-82	82-232-U
General Telephone Co. of Illinois	Illinois	Jun-82	82-0458
General Telephone Co. of the SW	Oklahoma	Jun-82	27482
Empire Telephone Co.	Georgia	May-82	3355-U
Mid-Georgia Telephone Co.	Georgia	May-82	3354-U
General Telephone Co. of the SW	Texas	Apr-82	4300
General Telephone Co. of the SE	Alabama	Jan-82	18199
Carolina Power & Light Co.	South Carolina	Jan-82	81-163-E
Elmore-Coosa Telephone Co.	Alabama	Nov-81	18215
General Telephone Co. of the SE	North Carolina	Sep-81	P-19, Sub 182
United Telephone Co. of Ohio	Ohio	Sep-81	81-627-TP-AIR
General Telephone Co. of the SE	South Carolina	Sep-81	81-121-C
Carolina Telephone & Telegraph	North Carolina	Aug-81	P-7, Sub 652
Southern Bell	North Carolina	Aug-81	P-55, Sub 794
Woodbury Telephone Co.	Connecticut	Jul-81	810504
Central Telephone Co. of Virginia	Virginia	Jun-81	810030
United Telephone Co. of Missouri	Missouri	May-81	TR-81-302
General Telephone Co. of the SE	Virginia	Apr-81	810003
New England Telephone	Vermont	Mar-81	4546
Carolina Telephone & Telegraph	North Carolina	Aug-80	P-7, Sub 652
Southern Bell	North Carolina	Aug-80	P-55, Sub 784
General Telephone Co. of the SW	Arkansas	Jun-80	U-3138
General Telephone Co. of the SE	Alabama	May-80	17850
Southern Bell	North Carolina	Oct-79	P-55, Sub 777
Southern Bell	Georgia	Mar-79	3144-U
General Telephone Co. of the SE	Virginia	Mar-76	810038
General Telephone Co. of the SW	Arkansas	Feb-76	U-2693, U-2724
General Telephone Co. of the SE	Alabama	Sep-75	17058
General Telephone Co. of the SE	South Carolina	Jun-75	D-18269

NEWFOUNDLAND POWER INC.
ST. JOHN'S, NEWFOUNDLAND

DEPRECIATION STUDY
CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AT DECEMBER 31, 2010



Gannett Fleming
Valuation and Rate Division

Harrisburg, Pennsylvania

Calgary, Alberta

Valley Forge, Pennsylvania

NEWFOUNDLAND POWER INC.
St. John's, Newfoundland

DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS

RELATED TO ELECTRIC PLANT

AT DECEMBER 31, 2010

GANNETT FLEMING, INC. - VALUATION AND RATE DIVISION

Harrisburg, Pennsylvania



Gannett Fleming

*Excellence Delivered **As Promised***

August 15, 2012

Newfoundland Power Inc.
55 Kenmount Road
St. John's, Newfoundland A1B 3P6

Attention Jocelyn Perry
Vice President, Finance and CFO

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Newfoundland Power Inc. as of December 31, 2010. This report is an update of the previous report submitted to Newfoundland Power. The revised report contains a pro forma adjustment to reflect the sale of joint-use poles and anchors to Bell Aliant that was approved in 2011. The attached report presents a description of the methods used in the estimation of depreciation and the summary of annual and accrued depreciation.

A separately bound volume includes appendices which set forth the statistical support for the life and net salvage estimates and the detailed tabulations of annual and accrued depreciation.

We gratefully acknowledge the assistance of Newfoundland Power Inc. personnel in the conduct of the study.

Respectfully submitted,

GANNETT FLEMING, INC.

JOHN F. WIEDMAYER, CDP
Project Manager, Depreciation Studies
Valuation and Rate Division

JFW:krm

052862

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PART I. INTRODUCTION

NEWFOUNDLAND POWER INC.
DEPRECIATION STUDY
CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AT DECEMBER 31, 2010

PART I. INTRODUCTION

PLAN OF REPORT

This report sets forth the results of the depreciation study for Newfoundland Power Inc., to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of electric plant at December 31, 2010. Part I Introduction, contains statements with respect to the plan of the report, the basis of the study, the study and a brief summary of the study results. Part II Methods Used in the Estimation of Depreciation, presents the methods used in the estimation of average service lives, survivor curves and salvage and in the calculation of depreciation. Part III Results of Study, presents summaries by depreciable group of annual and accrued depreciation. The statistical analyses of service live and net salvage and the detailed tabulations of annual and accrued depreciation are set forth in a separately bound volume "Appendices to Depreciation Study."

BASIS OF THE STUDY

For most accounts, the annual and accrued depreciation were calculated by the straight line method using the equal life group procedure. For certain General and Communication Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and salvage. Variances between the calculated

accrued depreciation or amortization and the book accumulated depreciation which exceed five percent of the calculated accrued depreciation are amortized over the composite remaining life of the assets. Accounts for which the composite remaining lives are less than five years, the amortization period used to minimize the reserve variance was set at five years which is the period of time between depreciation studies. This was done to reduce the annual fluctuations to depreciation expense related to the reserve variance amortizations for accounts with short composite remaining lives.

The straight line equal life group method has been used by the Company for a number of years and we recommend its continued use. The equal life group procedure provides for a better match of depreciation expense and loss in service value than the average service life procedure.

Amortization accounting for certain General and Communication accounts was approved in 1996 by Newfoundland and Labrador Board of Commissioners of Public Utilities ("Board"). Amortization accounting for these accounts is appropriate because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. Many electric utilities in North America have received approval to adopt amortization accounting for these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page II-35 of the report.

The service life and salvage estimates used in the depreciation and amortization calculations were based on judgment which incorporated analyses of available historical data, a review of policies and outlook with management, a general knowledge of the electric utility industry, and comparisons of the service life and salvage estimates from

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 life span groups, the estimates of survivor curves are consistent because the calculations of the lives of the units within each group are obtained by using a single probable retirement date for the entire group. The estimates of net salvage are expressed as the average net salvage percent of the investment to be incurred or recovered upon its retirement.

CHANGES SUBSEQUENT TO THE PRIOR DEPRECIATION STUDY REPORT

The depreciation calculations included in the prior depreciation study report submitted to the Board were based on electric plant in service as of December 31, 2005. The depreciation calculations included with this report are based on electric plant in service as of December 31, 2010. The annual accrual rate calculations were based on the same group procedures and bases as those used in the prior depreciation report.

The calculated accrued depreciation as of December 31, 2010 is \$563.0 million and the book accumulated depreciation is \$553.1 million, a difference of \$9.9 million or 1.8 percent. The calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount. The calculated accrued depreciation should not be viewed in exact terms as the correct reserve amount. Rather it should be viewed as a benchmark or a tool used by the depreciation professional to assess the standing of the book accumulated depreciation amount based on the most recent available information. The reserve variance that exceeds the 5 percent tolerance

threshold is approximately \$2.6 million and is set forth on Schedule 2, column 7 in Part III of the report. Gannett Fleming recommends that Newfoundland Power amortize the reserve variance in excess of the five percent tolerance threshold over a period equal to the composite remaining life of the assets. This is the industry's most commonly used method for adjusting depreciation. Also it decreases the probability of large fluctuations in depreciation expense that can occur with relatively short amortization periods, such as five years, and is the method that Gannett Fleming considers appropriate for Newfoundland Power. The remaining lives of the various accounts range from a few years to over forty years. An explanation of the monitoring of the accumulated depreciation reserve and the calculation of the reserve variance amortization is presented beginning on page II-36 of the report.

SUMMARY

Summaries of the study results by plant account are presented in the schedules in Part III of the report. The continued use of annual accrual rates and the maintenance and monitoring of the accumulated depreciation reserve by plant account is appropriate for Newfoundland Power.

The following summary of composite whole life accrual rates at the functional level is provided only for purposes of comparing the results of the current and previous study. The amortization of the reserve variance has not been incorporated in the rates below.

<u>Function</u>	<u>Composite Annual Accrual Rates</u>	
	<u>Previous Study</u>	<u>Current Study</u>
Hydro Production	2.17	2.41
Other Production	4.73	5.09
Substation	2.63	2.67
Transmission	3.28	3.23
Distribution	3.14	3.18

<u>Function</u>	<u>Composite Annual Accrual Rates</u>	
	<u>Previous Study</u>	<u>Current Study</u>
General		
Computer - Hardware	20.00	20.00
Computer - Software	10.00	10.00
Transportation	10.28	9.73
Other	2.94	2.97
Communications	6.18	5.37

PART II. METHODS USED IN
THE ESTIMATION OF DEPRECIATION

PART II. METHODS USED IN THE ESTIMATION OF DEPRECIATION

DEPRECIATION

Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric 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 the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authority.

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 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 depreciation based on the straight line method requires the estimation of average life and salvage. These subjects are discussed in the sections which follow.

SERVICE LIFE AND NET SALVAGE ESTIMATION

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 years 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 and is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

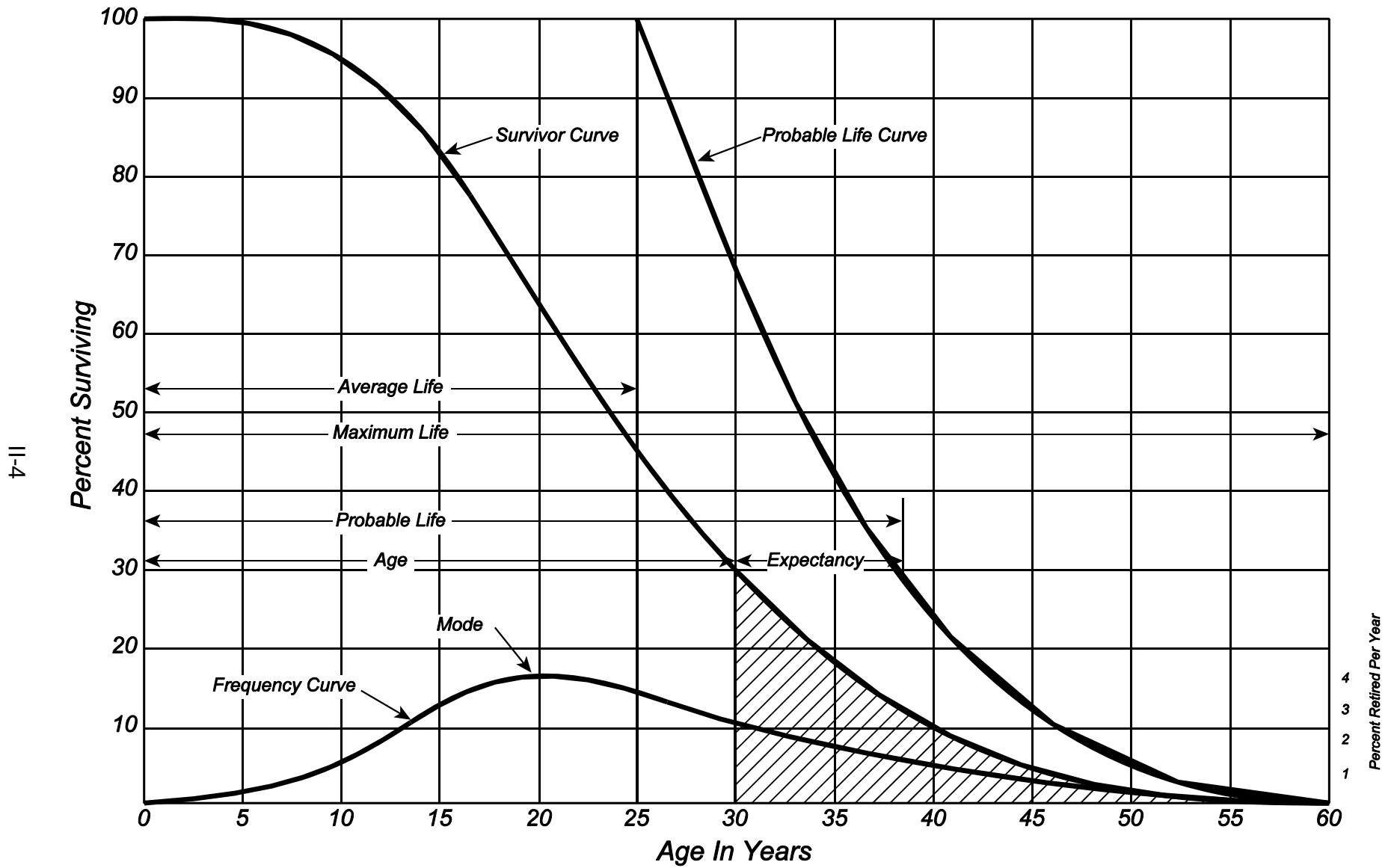


Figure 1. A Typical Survivor Curve and Derived Curves

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 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 of retirement 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 numerical subscripts 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 constitutes

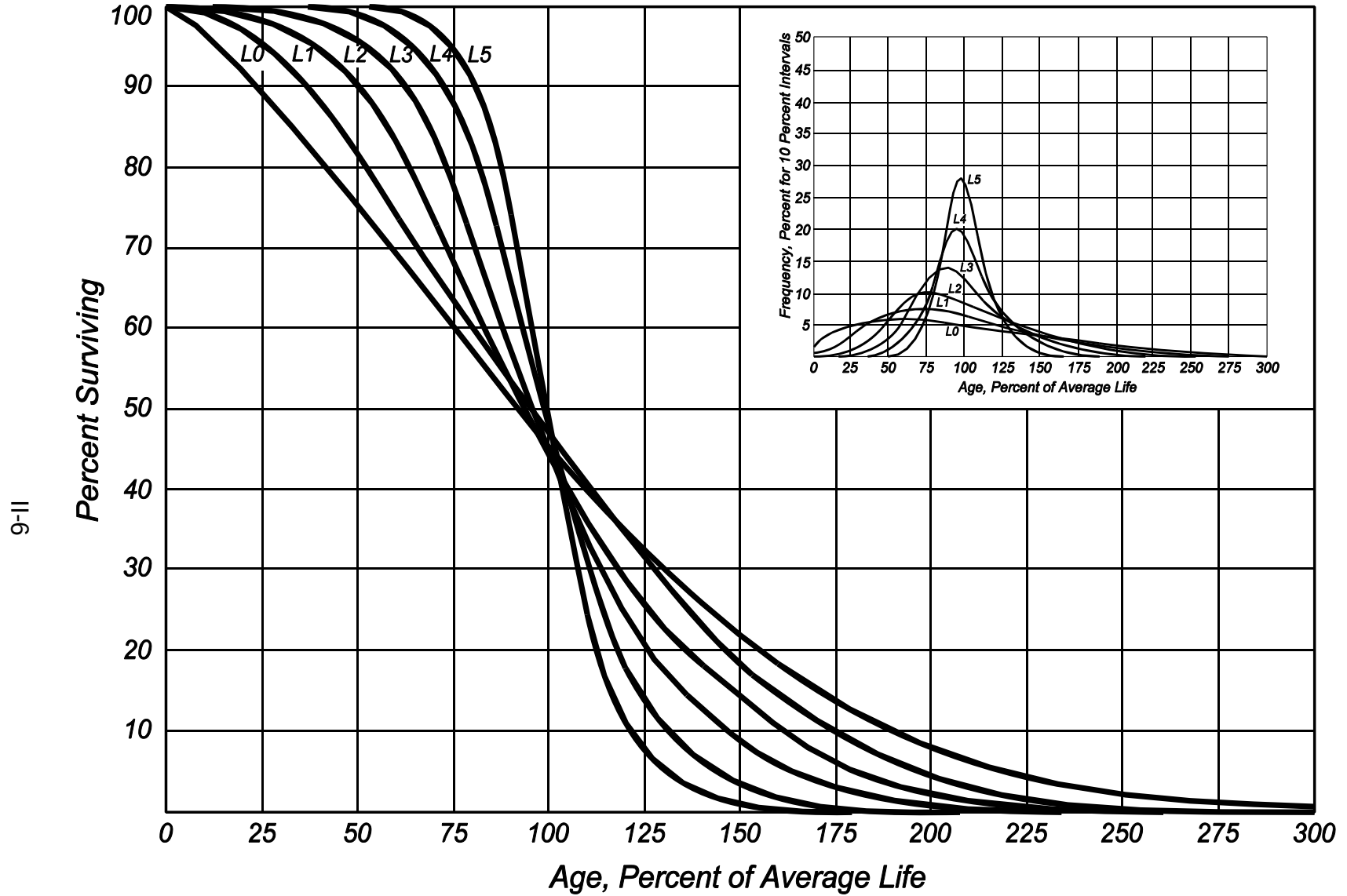


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

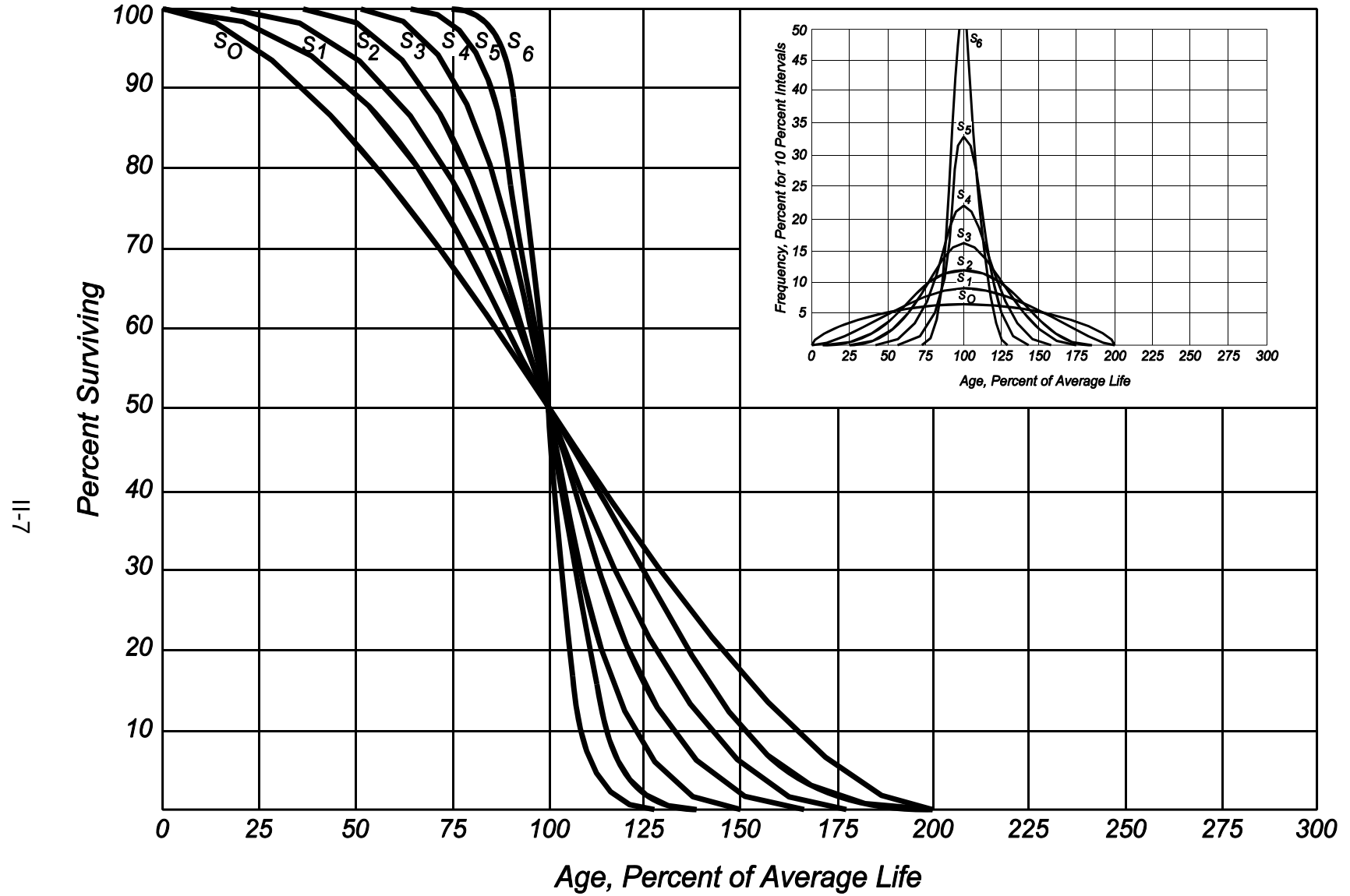


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

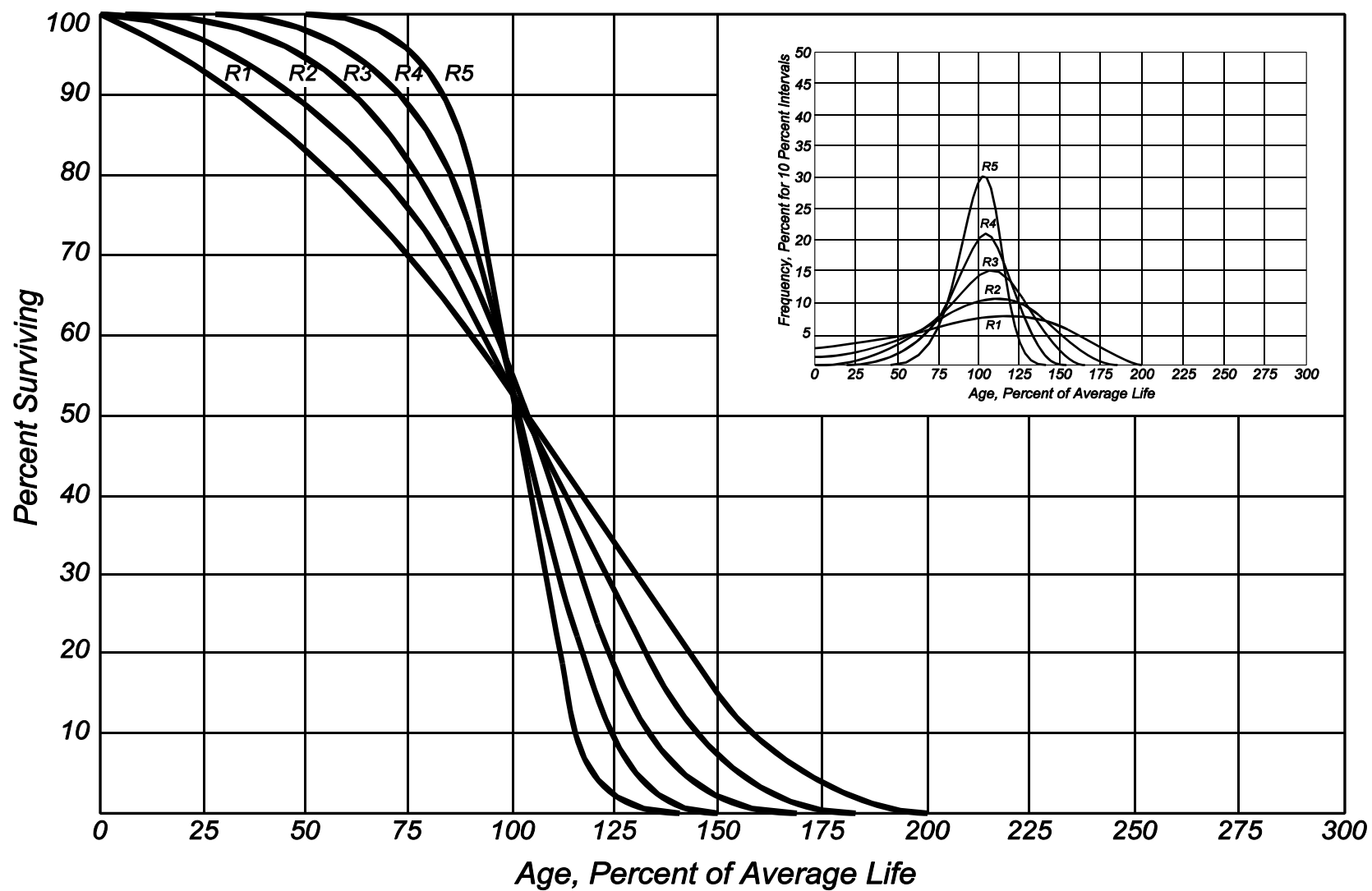


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

6-11

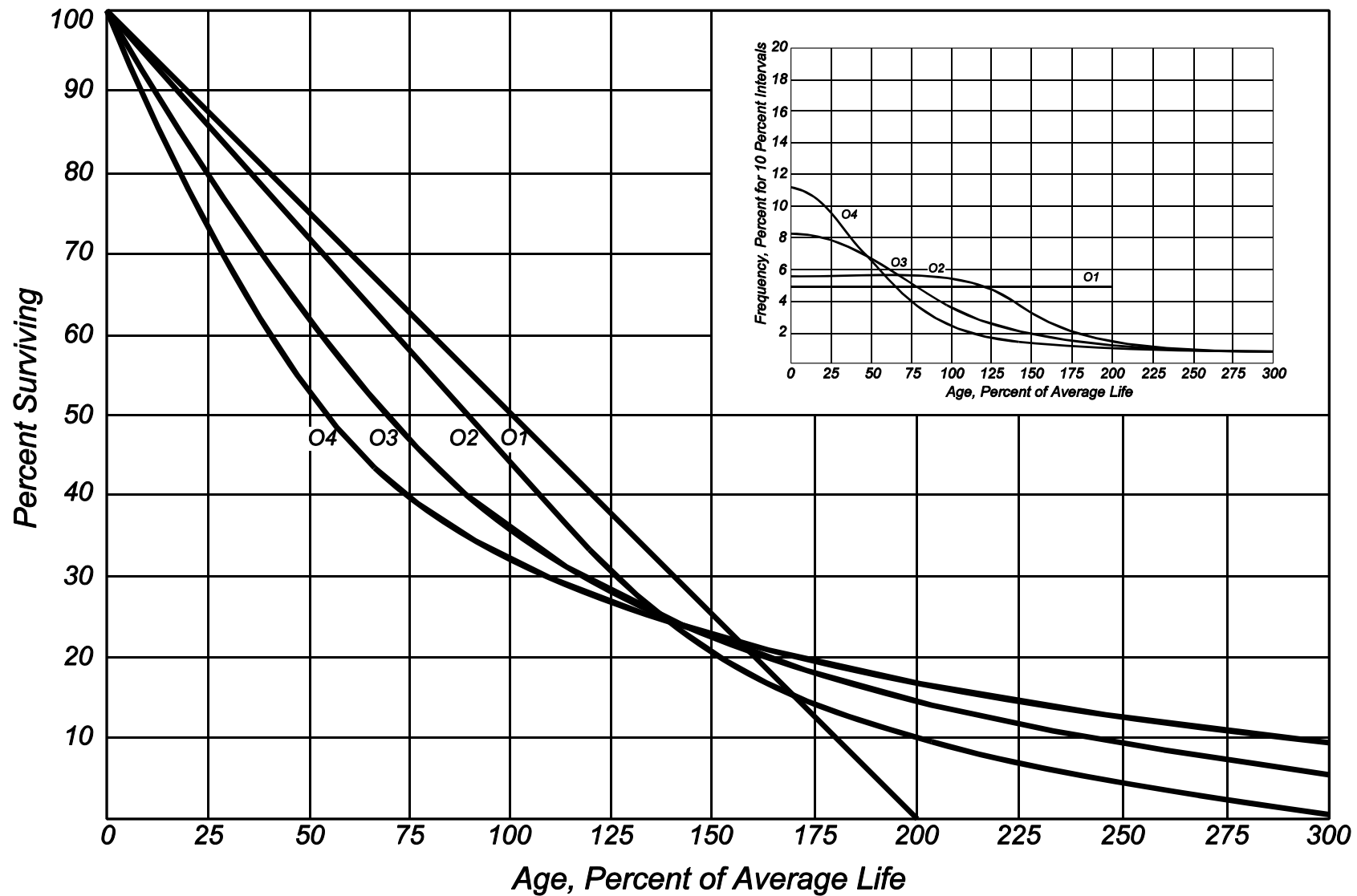


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.¹ These type curves 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 thesis³ presenting his development of the fourth family consisting of the four O 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 or for which aged accounting experience is developed by statistically aging unaged amounts 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

¹Winfrey, Robley. Statistical Analyses of Industrial Property Retirements. Iowa State College, Engineering Experiment Station, Bulletin 125. 1935.

²Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

³Couch, 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.

⁴Winfrey, Robley, Supra Note 1.

⁵Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 2.

⁶Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994

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 on pages II-12 and II-13. 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 2001-2010 during which there were placements during the years 1996-2010. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Tables 1 and 2 on pages II-12 and II-13. In Table 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 1996 were retired in 2001. 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

TABLE 1. RETIREMENTS FOR EACH YEAR 2001-2010
SUMMARIZED BY AGE INTERVAL

Experience Band 2001-2010

Placement Band 1996-2010

Year Placed (1)	Retirements, Thousands of Dollars										Total During Age Interval (12)	Age Interval (13)
	During Year											
	<u>2001</u> (2)	<u>2002</u> (3)	<u>2003</u> (4)	<u>2004</u> (5)	<u>2005</u> (6)	<u>2006</u> (7)	<u>2007</u> (8)	<u>2008</u> (9)	<u>2009</u> (10)	<u>2010</u> (11)		
1996	10	11	12	13	14	16	23	24	25	26	26	13½-14½
1997	11	12	13	15	16	18	20	21	22	19	44	12½-13½
1998	11	12	13	14	16	17	19	21	22	18	64	11½-12½
1999	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2000	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2001	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2002		5	11	12	13	14	15	16	18	20	113	7½-8½
2003			6	12	13	15	16	17	19	19	124	6½-7½
2004				6	13	15	16	17	19	19	131	5½-6½
2005					7	14	16	17	19	20	143	4½-5½
2006						8	18	20	22	23	146	3½-4½
2007							9	20	22	25	150	2½-3½
2008								11	23	25	151	1½-2½
2009									11	24	153	½-1½
2010	—	—	—	—	—	—	—	—	—	13	80	0-½
Total	<u>53</u>	<u>68</u>	<u>86</u>	<u>106</u>	<u>128</u>	<u>157</u>	<u>196</u>	<u>231</u>	<u>273</u>	<u>308</u>	<u>1,606</u>	

TABLE 2. OTHER TRANSACTIONS FOR EACH YEAR 2001-2010
SUMMARIZED BY AGE INTERVAL

Experience Band 2001-2010

Placement Band 1996-2010

Year Placed (1)	Acquisitions, Transfers and Sales, Thousands of Dollars										Total During Age Interval (12)	Age Interval (13)
	During Year											
	<u>2001</u> (2)	<u>2002</u> (3)	<u>2003</u> (4)	<u>2004</u> (5)	<u>2005</u> (6)	<u>2006</u> (7)	<u>2007</u> (8)	<u>2008</u> (9)	<u>2009</u> (10)	<u>2010</u> (11)		
1996	-	-	-	-	-	-	60 ^a	-	-	-	-	13½-14½
1997	-	-	-	-	-	-	-	-	-	-	-	12½-13½
1998	-	-	-	-	-	-	-	-	-	-	-	11½-12½
1999	-	-	-	-	-	-	-	(5) ^b	-	-	60	10½-11½
2000	-	-	-	-	-	-	-	6 ^a	-	-	-	9½-10½
2001		-	-	-	-	-	-	-	-	-	(5)	8½-9½
2002		-	-	-	-	-	-	-	-	-	6	7½-8½
2003			-	-	-	-	-	-	-	-	-	6½-7½
2004				-	-	-	-	(12) ^b	-	-	-	5½-6½
2005					-	-	-	-	22 ^a	-	-	4½-5½
2006						-	-	(19) ^b	-	-	10	3½-4½
2007							-	-	-	-	-	2½-3½
2008								-	-	(102) ^c	(121)	1½-2½
2009									-	-	-	½-1½
2010	—	—	—	—	—	—	—	—	—	—	—	0-½
Total	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>60</u>	<u>(30)</u>	<u>22</u>	<u>(102)</u>	<u>(50)</u>	

^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.

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 Table 1 immediately above the stairstep line drawn on the table beginning with the 2001 retirements of 1996 installations and ending with the 2010 retirements of the 2005 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 Table 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 Table 3 on page II-15.

The surviving plant at the beginning of each year from 2001 through 2010 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 Table 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net

TABLE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2001-2010
SUMMARIZED BY AGE INTERVAL

Experience Band 2001-2010

Placement Band 1996-2010

11-15

Year Placed (1)	Exposures, Thousands of Dollars										Total at Beginning of Age Interval (12)	Age Interval (13)
	Annual Survivors at the Beginning of the Year											
	2001 (2)	2002 (3)	2003 (4)	2004 (5)	2005 (6)	2006 (7)	2007 (8)	2008 (9)	2009 (10)	2010 (11)		
1996	255	245	234	222	209	195	239	216	192	167	167	13½-14½
1997	279	268	256	243	228	212	194	174	153	131	323	12½-13½
1998	307	296	284	271	257	241	224	205	184	162	531	11½-12½
1999	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2000	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2001	420 ^a	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2002		460 ^a	455	444	432	419	405	390	374	356	1,952	7½-8½
2003			510 ^a	504	492	479	464	448	431	412	2,463	6½-7½
2004				580 ^a	574	561	546	530	501	482	3,057	5½-6½
2005					660 ^a	653	639	623	628	609	3,789	4½-5½
2006						750 ^a	742	724	685	663	4,332	3½-4½
2007							850 ^a	841	821	799	4,955	2½-3½
2008								960 ^a	949	926	5,719	1½-2½
2009									1,080 ^a	1,069	6,579	½-1½
2010										1,220 ^a	7,490	0-½
Total	<u>1,975</u>	<u>2,382</u>	<u>2,824</u>	<u>3,318</u>	<u>3,872</u>	<u>4,494</u>	<u>5,247</u>	<u>6,017</u>	<u>6,852</u>	<u>7,799</u>	<u>44,780</u>	

^a Additions during the year.

entries shown on Tables 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 2001-2010, 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 (Table 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 Table 4 on page II-17, is developed from the totals shown on the schedules of retirements and exposures, Tables 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

TABLE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2001-2010

Placement Band 1996-2010

(Exposure and Retirement Amounts are in Thousands of Dollars)

<u>Age at Beginning of Interval</u> (1)	<u>Exposures at Beginning of Age Interval</u> (2)	<u>Retirements During Age Interval</u> (3)	<u>Retirement Ratio</u> (4)	<u>Survivor Ratio</u> (5)	<u>Percent Surviving at Beginning of Age Interval</u> (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	<u>167</u>	<u>26</u>	0.1557	0.8443	42.24
					35.66
Total	<u>44,780</u>	<u>1,606</u>			

Column 2 from Table 3, Column 12, Plant Exposed to Retirement.

Column 3 from Table 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.

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 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 Tables 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, Table 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.

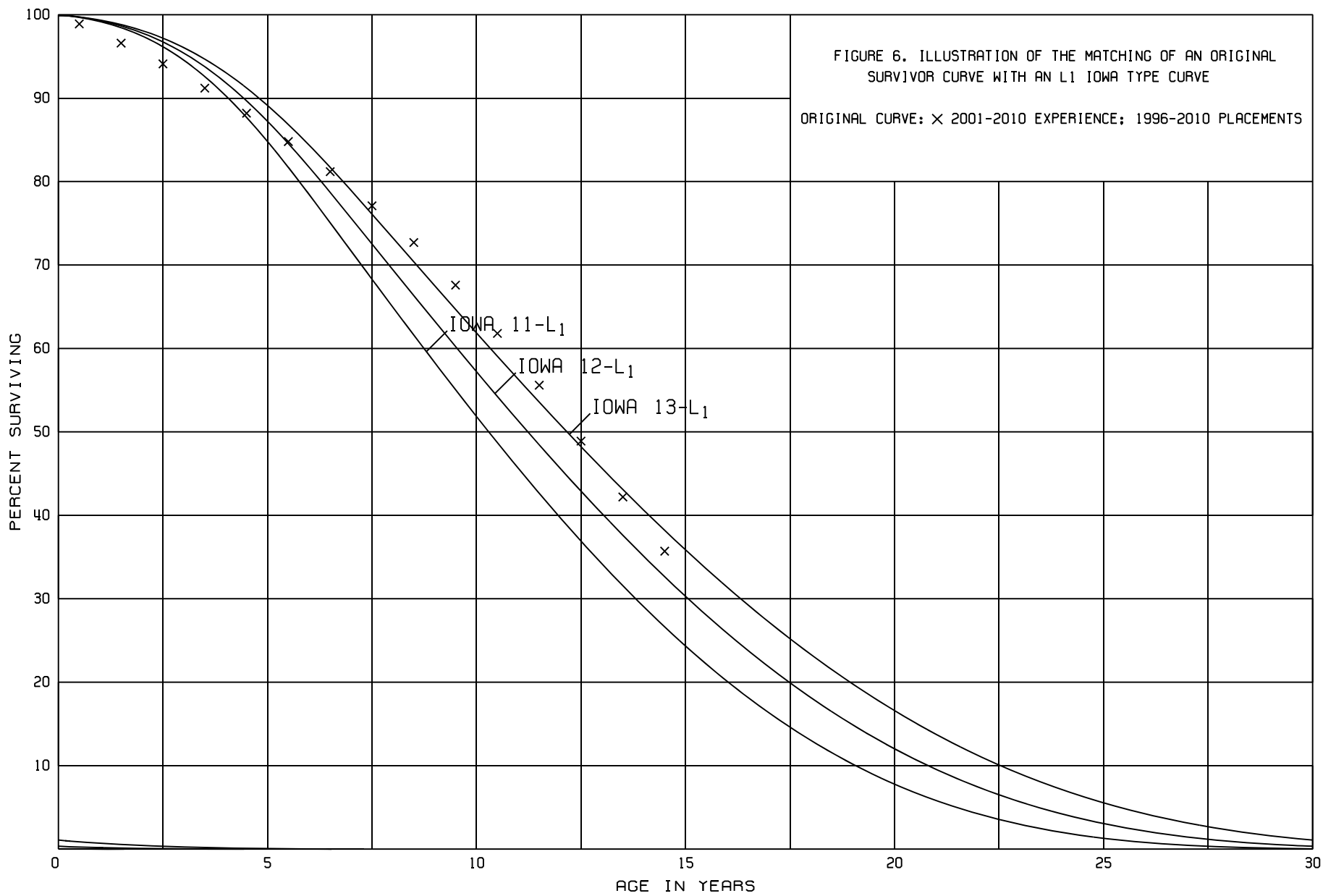
Smoothing the Original Survivor Curve. The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, 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.

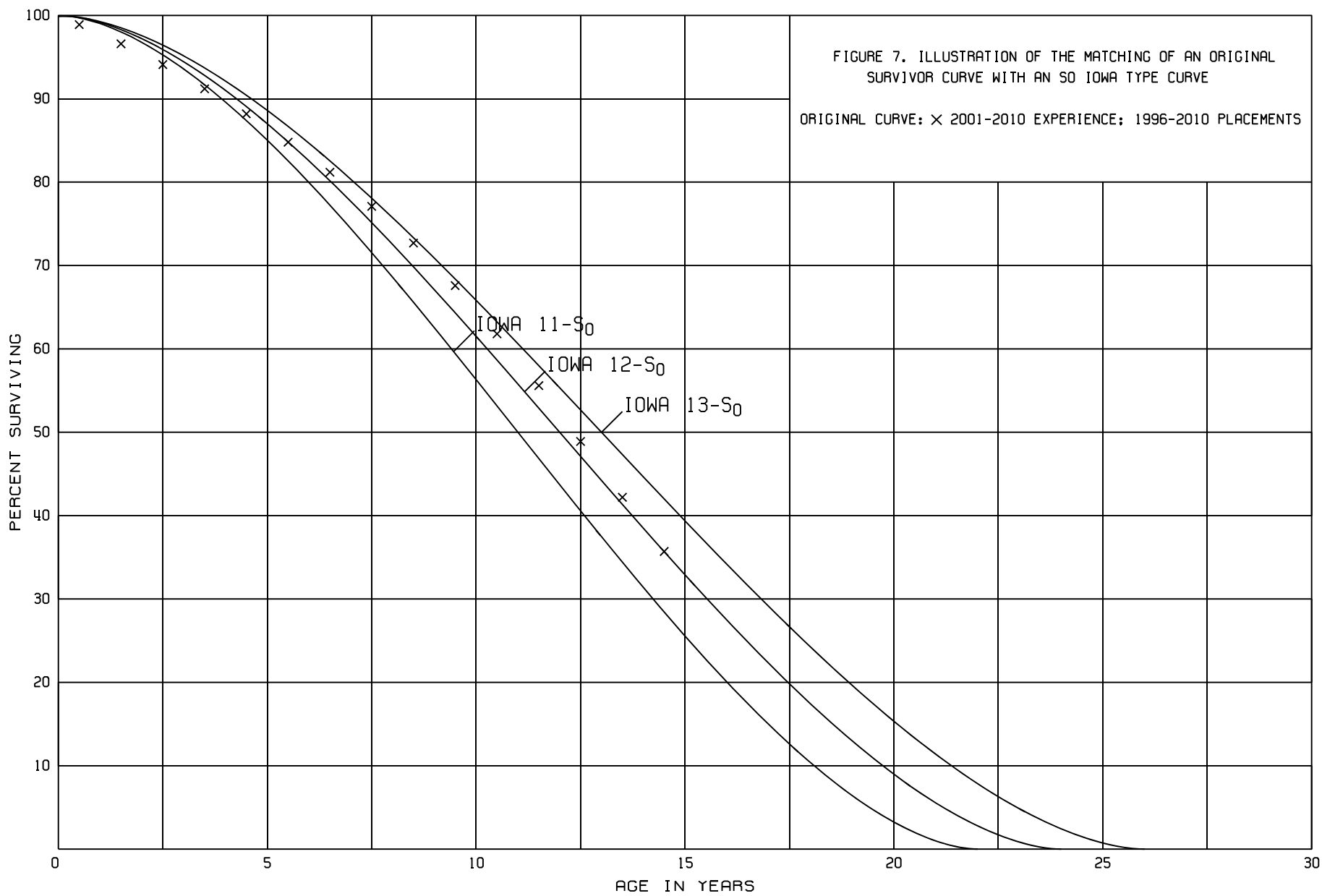
The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8 the original curve developed in Table 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, assuming no contrary relevant factors external to the analysis of historical data.

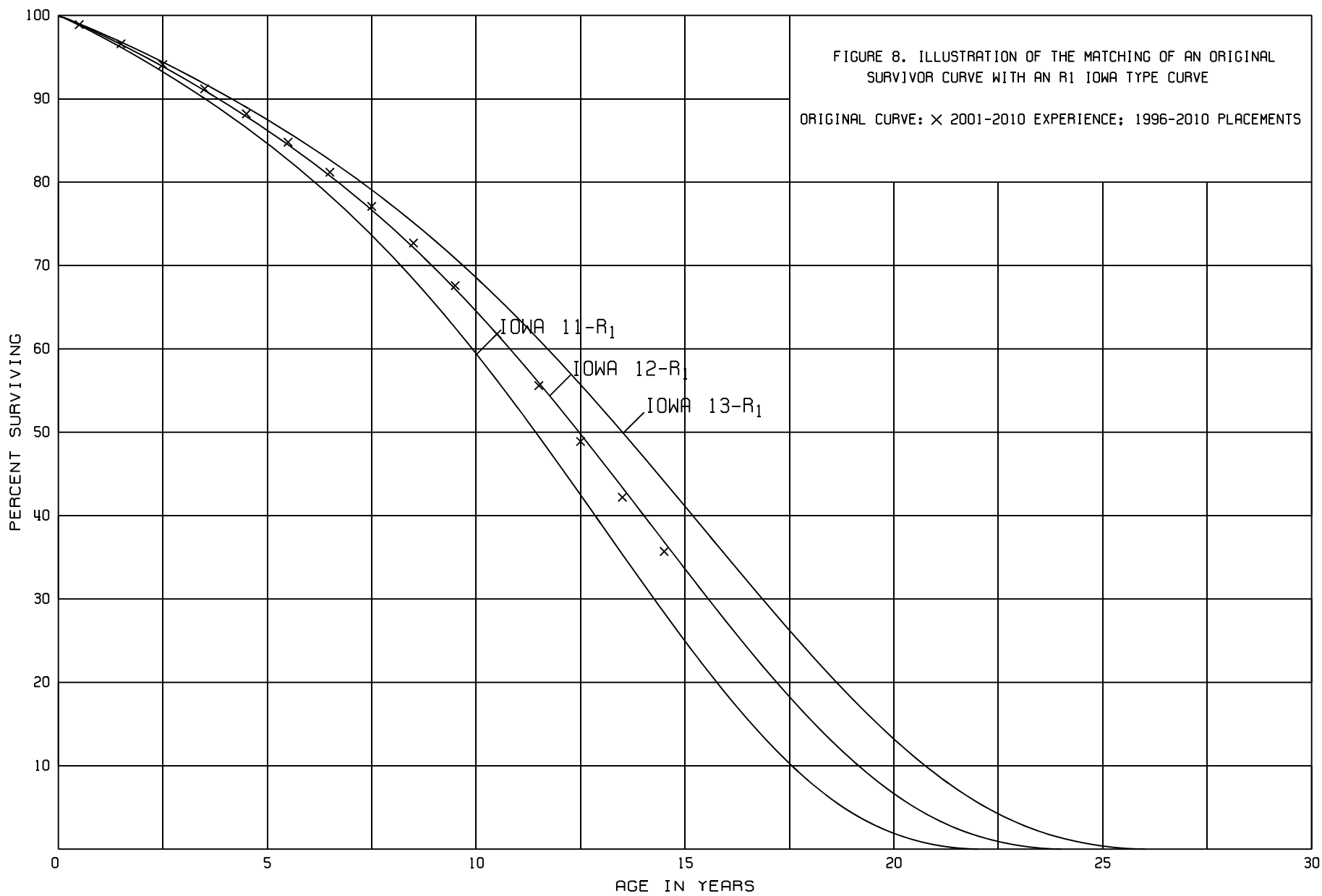
Service Life Considerations

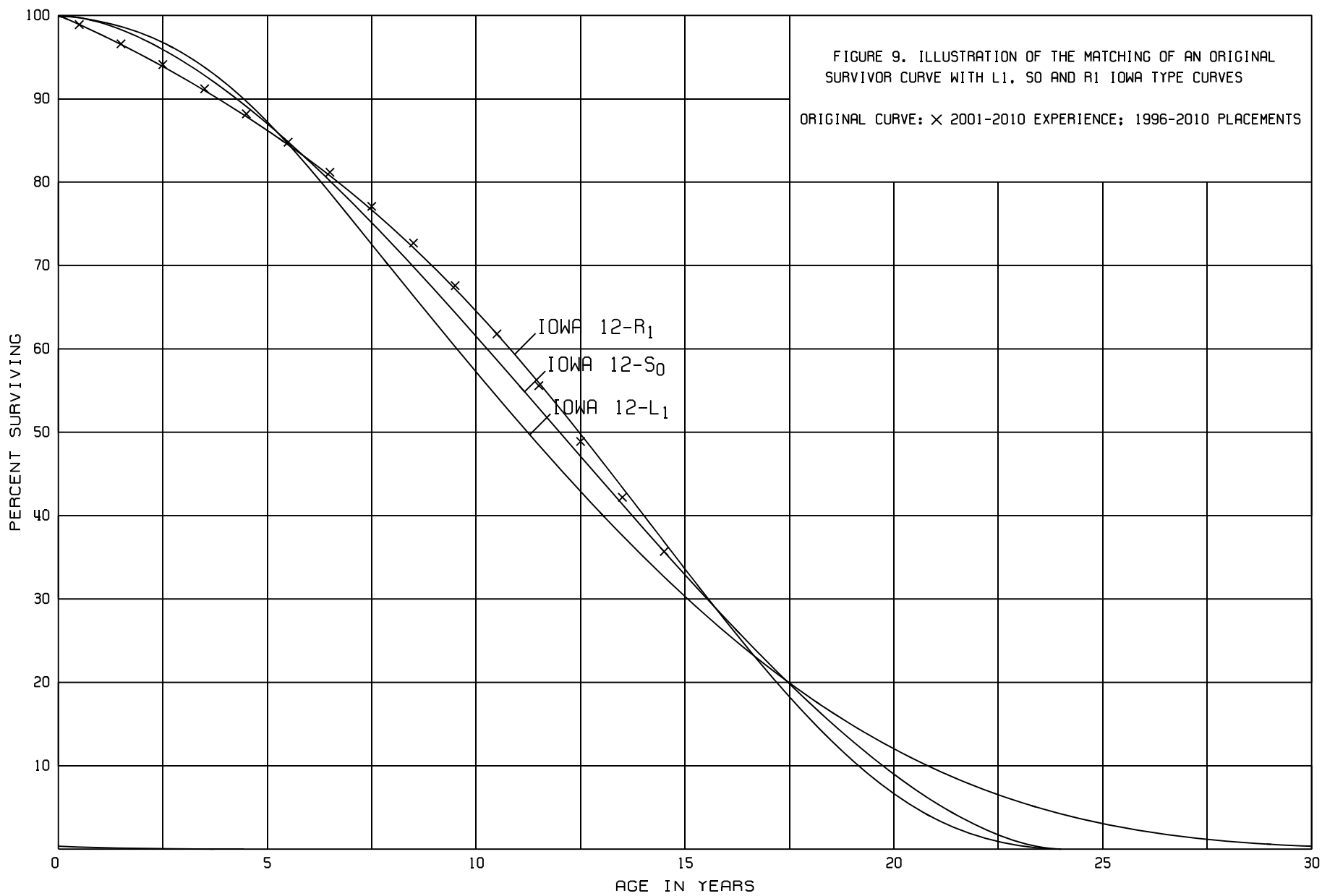
The service life estimates were based on judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during field reviews of the property and other conversations with management; and the survivor curve estimates from previous studies of this Company and other electric companies.

Several subaccounts were combined and analyzed as a single depreciable group based on discussions with operating and management personnel. These subaccounts









include assets which have similar service life characteristics or which perform similar or related operating functions. The following is a list of subaccounts that were combined and analyzed as a single depreciable group:

<u>Account No.</u>	<u>Account Description</u>
355.1 and 355.2	Poles and Pole Fixtures
361.14 and 361.30	Aerial Cable and Special Insulated Copper Cable
361.20 and 367.20	U/G Cable and U/G Switches and Switchgear
362.1, 362.2, and 361.1	Poles - Wood - All Sizes and O/H Conductor - Bare
364.10, 364.11, 364.20, 364.30 and 364.40	Line Transformers - All Ratings, Voltage Regulators Capacitor Banks and Reclosers
365.1, 361.11 and 361.15	O/H Services, W/P Copper and Duplex, Triplex and Quadruplex
366.3 and 366.4	Instrument Transformers and Metering Tanks
378.31 and 378.4	Transportation Equipment - Cab and Chassis and Large Trucks with Line and Stake Bodies

For most of the mass plant accounts and subaccounts, the statistical analyses resulted in good to excellent indications of complete survivor patterns. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in Appendix A.

HYDRO PRODUCTION

321	Roads, Trails and Bridges
323	Canals, Penstocks, Surge Tanks and Tailraces
324	Dams and Reservoirs
325	Prime Movers, Generators and Auxiliaries
326	Switching, Metering and Control Equipment

SUBSTATION

342	Equipment

TRANSMISSION

- 353.1 Overhead Conductors
- 355.1 Poles
- 355.2 Pole Fixtures
- 355.3 Insulators

DISTRIBUTION

- 361.10 Overhead Conductors - Bare Copper
- 361.11 Overhead Conductors - Weather-Proof Copper
- 361.12 Overhead Conductors - Bare Aluminum
- 361.13 Overhead Conductors - Weather-Proof Aluminum
- 361.14 Overhead Conductors - Aerial Cable
- 361.15 Overhead Conductors - Duplex, Triplex, and Quadruplex
- 361.2 Underground Cables
- 361.3 Special Insulated Copper Cable
- 362.1 Poles and Fixtures - Wood - Under 35 ft.
- 362.2 Poles and Fixtures - Wood - 35 ft. and Over
- 362.3 Poles and Fixtures - Concrete and Steel
- 363 Street Lights
- 364.10 Transformers and Mountings - Up to and Including 15 kVA
- 364.11 Transformers and Mountings - Over 15 kVA
- 364.2 Voltage Regulators
- 364.3 Capacitor Banks
- 364.4 Reclosers
- 365.1 Services Overhead
- 366.1 Meters - Watt-Hour
- 366.2 Meters - Demand
- 366.3 Meters - Instrument Transformers
- 366.4 Meters - Metering Tanks
- 367.2 Underground Switches and Switchgear

GENERAL PROPERTY

- 371.1 Buildings and Structures - Small
- 378.1 Transportation - Sedans and Station Wagons
- 378.2 Transportation - Pick-Up Trucks, Window Vans
- 378.31 Transportation - Cab and Chassis
- 378.32 Transportation - Equipment
- 378.4 Transportation - Trucks with Line and Stake Bodies
- 378.5 Transportation - Miscellaneous

COMMUNICATIONS

- 382 Radio Sites

Accounts 355.1, Poles and Account 355.2, Pole Fixtures, are used to illustrate the manner in which the study was conducted for the group of accounts in the preceding list. These depreciable groups were combined for life analysis purposes. Aged plant accounting

data have been compiled for the years 1948 through 2009. These data have been coded in the course of the Company's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

Discussions with management indicated the primary causes of retirements have been inadequacy, deterioration and pole relocations. That is, poles are retired for clearance issues, their inability to support heavier conductors, the requirements of others in addition to the degradation of the poles caused by natural forces, i.e., decay and wear and tear. These causes of retirement are expected to continue in the foreseeable future. The previous estimate was the Iowa 44-R2.5 for Poles and Pole Fixtures.

During the past 5 years many improvements and enhancements have been made to the NFP transmission system. Design and material standards are better, the maintenance program has improved and there is a greater focus on rebuilding deteriorated lines some of which were built before there were design standards for transmission poles. For instance, the use of larger class poles and fixtures in areas prone to high wind and severe ice loading that often exceed Canadian Standards Association criteria are expected to result in longer lives for poles and pole fixtures. This means stronger and longer lasting lines are being built. The survivor curve estimate for these accounts is the Iowa 47-R2 and is based on the statistical indication for the period 1975 through 2009. The Iowa 47-R2 is a good fit of the significant portion of the original survivor curve as set forth in Appendix A and is within the typical service life range of 35 to 50 years for transmission poles and fixtures.

There are a couple of plant accounts where the historical life indications are not representative of future service life expectations due to operational and maintenance

changes implemented by Newfoundland Power. The two plant accounts that I will discuss are Street Lights and Pole Mounted Line Transformers.

The historical life indication for Street Lights from a study of past retirements experienced by the company is approximately 16 years. The 16 year average service life indication was significantly influenced by the planned replacement of mercury vapor lights over the past 10 years or so. The company has had a program to replace mercury vapor lights with high pressure sodium lights which use less electricity. As of December 31, 2008 7,000 mercury vapor lights were in service and all 7,000 mercury vapor lights will be replaced by December 31, 2011. The 16-year average service life for street lights is not considered representative of the service life in the future. The company has also switched from using Philips Ceramalux lamps to Sylvania lamps which offer a 25% increase in life. Additionally, maintenance of street lights has been contracted out starting in 2010. The company expects an increased focus on street light maintenance going forward which will decrease replacement of street lights due to more timely maintenance. As a result, we have estimated a 20 year average service life for street lights.

Another plant account where the future service life expectations differ from the historical life indications is pole-top line transformers. One of the primary causes of retirement for line transformers was due to rust on the steel tank of the line transformer. In coastal areas, the corrosion of the steel tank was so significant that some of the line transformers needed to be replaced after 10 years or less. Typically a line transformer can expect to be in service 35 to 40 years or more. The historical life indications for line transformers at Newfoundland Power were 30 to 35 years. Engineering management expects the service lives of line transformers to increase based upon changes that they have implemented in the past 10 years or so. Since 2001, the company has been installing line

transformers with stainless steel tanks and has concentrated the installation of line transformers with stainless steel tanks in areas where the corrosion effect is the greatest, mostly in coastal areas. Line transformers with stainless steel tanks are expected to have a substantially longer life than units with steel tanks. The stainless steel tanks are resistant to rust and that cause of retirement should be greatly reduced. In 2005, approximately 20 percent of the pole top line transformers had stainless steel tanks. Now in 2011, over 50 percent of the pole top line transformers have stainless steel tanks. In addition, it was not economical in the past to refurbish a pole mounted line transformer that had a steel tank. However, it is economical to refurbish stainless steel units and it is expected that the number of line transformers scrapped will be reduced and that a longer service life will be realized. Also, since the mid 1990's all new line transformers were installed with lightning arrestors and this should reduce the numbers of units retired prematurely. Based on this, we have estimated a 40 year average service life for line transformers.

For Other Production Plant accounts and General Plant, Large Buildings and Structures, the life span technique was employed in conjunction with the use of interim survivor curves. Interim survivor curves reflect retirements that occur prior to the ultimate retirement of the major unit or building. An interim survivor curve was estimated for each plant account, inasmuch as the rate of interim retirements differs from account to account. The interim survivor curves estimated for other production plant were based on the retirement rate method of life analysis which incorporated experienced aged retirements for the period 1948 through 2009. The statistical support for the interim rates of retirement for other production plant accounts are set forth in Appendix A.

The life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general

operating characteristics of the units, major refurbishing, and discussions with management personnel, concerning the outlook for the units.

A summary of the year in service, probable retirement year for depreciation purposes, and life span for each power production facility follows:

<u>Depreciable Group</u>	<u>Year in Service</u>	<u>Probable Retirement Year</u>	<u>Life Span</u>
<u>Other Production Plant</u>			
Green Hill Gas Turbine	1975	2021	46
Wesleyville Gas Turbine	1969/2003	2021	52/18
Portable Gas Turbine	1974/2003	2016	42/13
Port Union Diesel	1972	2010	38
Port Aux Basques Diesel	1969	2016	47
Mobile Diesel #3	2004	2036	32

The Wesleyville Gas Turbine and Portable Gas Turbine were significantly refurbished to like-new condition in 2003. In the table above, the year of major refurbishment and the life span from the year of major refurbishment to its expected terminal date also are presented for these two units.

Amortization accounting is used for certain General and Communication Plant accounts that represent numerous units of property, but a small portion of the depreciable electric plant in service. A discussion of the basis for the amortization periods is presented in the section "Calculation of Annual and Accrued Amortization."

Generally, the survivor curve estimates for the remaining accounts, were based on judgments which considered the nature of the plant and equipment, reviews of available historical data, and a general knowledge of service lives for similar equipment in other electric companies.

Salvage Analysis

The estimates of net salvage were based in part on historical data compiled for the years 1976 through 2009. Cost of removal and salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates are expressed as a percent of the original cost of plant retired.

The experienced net salvage data were available by account for Distribution, General and Communication Plant accounts. The historical net salvage data through 2009 for the two Substation accounts and the six Transmission accounts were available only in total for the function as is typical when the depreciation reserve is maintained by function.

For Distribution Plant, there were several depreciable groups where the net salvage data were not readily available at the depreciable group level as it is impractical to segregate salvage receipts between such groups. The following presents the depreciable groups for which net salvage was analyzed as one group in order to develop historical indications of net salvage.

<u>Account Number</u>	<u>Account Description</u>
361.10, 361.11, 361.14 and 361.3	O/H Conductors - Bare Copper, Weather-Proof Copper, Aerial Cable and Special Insulated Copper Cable
361.12, 361.13 and 361.15 361.2 and 361.4	O/H Conductors - Bare Aluminum, Weather-Proof Aluminum and Duplex, Triplex and Quadruplex U/G Cable and Submarine Cable
362.10 and 362.20	Poles - Under 35 ft. and Poles - 35 ft. and Over
364.10, 364.11, 364.2, 364.3, and 364.4	Line Transformers (Includes all groups in Account 364)
365.10 and 365.20	O/H Service and U/G Services

<u>Account Number</u>	<u>Account Description</u>
366.1, 366.2, 366.3 and 366.4	Watt-Hour Meters, Demand Meters, Instrument Transformers, Metering Tanks
378.31 and 378.4	Transportation Equipment - Trucks with Derricks - Cab and Chassis and Transportation Equipment - Trucks with Line and Stake Bodies

Net Salvage Considerations

The cost of removal related to Substation, Transmission and Distribution asset replacement projects has trended up during the period 2005 – 2009 in comparison to previous periods. During this period Newfoundland Power implemented new strategies for the replacement, refurbishment and modernization of deteriorated and aged assets in Distribution (2004), Transmission (2006) and Substations (2007).

Newfoundland Power's management believes the trend seen during 2005 – 2009 is not representative of the future. In 2010 a review of costs in these capital projects identified some inconsistency in the allocation of total project labor to the cost of removal for deteriorated and aged assets and the installation of the replacement assets. As a result the company implemented new guidelines in 2011 regarding the allocation of cost for capital projects involving the replacement, refurbishment and modernization of deteriorated and aged assets. The cost of removal amounts were adjusted for the years 2005 through 2009 as if the new guidelines implemented in 2011 had been in place during those years. The pro forma cost of removal amounts for accounts affected by the new 2011 guidelines are set forth in the section of the report beginning on page B-53.

This change in allocation will have an impact on future cost of removal and net salvage, expressed as a percent of plant retirements. The net salvage estimates selected for the plant accounts affected by these guidelines reflect the expectation of lower removal costs in the future.

The estimates of salvage were based primarily on judgment which considered a number of factors. The primary factors were the analyses of historical data; the net salvage characteristics of other electric utility properties, a knowledge of management's plans and operating policies; and net salvage estimates from previous studies of this Company and other electric companies. The accounts for which the historical analyses were representative of expectations for future net salvage levels are presented below:

SUBSTATION

All Accounts as a Group.

TRANSMISSION

All Accounts as a Group.

DISTRIBUTION

- 361.12 Overhead Conductors - Bare Aluminum
- 361.13 Overhead Conductors - Weather-Proof Aluminum
- 361.15 Overhead Conductors - Duplex, Triplex, and Quadruplex
- 363 Street Lights

DISTRIBUTION, cont.

- 364.10 Transformers and Mountings - Up to and Including 15 kVA
- 364.11 Transformers and Mountings - Over 15 kVA
- 364.2 Voltage Regulators
- 364.3 Capacitor Banks
- 364.4 Reclosers

DISTRIBUTION

- 365.1 Services - Overhead
- 365.2 Services - Underground
- 366.1 Meters - Watt-Hour
- 366.2 Meters - Demand
- 366.3 Meters - Instrument Transformers
- 366.4 Meters - Metering Tanks

GENERAL PROPERTY

- 378.1 Transportation - Sedans and Station Wagons
- 378.2 Transportation - Pick-Up Trucks, Window Vans
- 378.31 Transportation - Cab and Chassis
- 378.4 Transportation - Trucks with Line and Stake Bodies
- 378.5 Transportation - Miscellaneous

Account 361.12, Overhead Conductors - Bare Aluminum, are used to illustrate the manner in which the study was conducted for the group of accounts in the preceding list. Depreciation reserve accounting data were compiled for the years 1976 through 2009. These data include the retirements, cost of removal and salvage.

Discussions with management indicated that overhead conductors are removed for a variety of reasons based on their age, condition and capacity. The removed overhead lines are mostly sold for scrap although at times can be reused. The previous estimate of net salvage for Account 361.12, Overhead Conductors - Bare Aluminum was negative 30 percent. The range of typical net salvage estimates for overhead conductors and devices is negative 20 percent to negative 50 percent.

The net salvage estimate for Account 361.12, Overhead Conductors - Bare Aluminum, is negative 30 percent and is based on the experienced net salvage data for the years 1976 through 2009. The three-year moving average for cost of removal remained fairly level during the period 1976 through 2009 ranging from negative 30 percent to negative 60 percent while the three-year moving average for gross salvage ranged from positive 5 percent to positive 25 percent. The midpoint of these two ranges, i.e., negative 45 percent for cost of removal and positive 15 percent for gross salvage, results in net salvage of negative 30 percent. The overall net salvage percent experienced by Newfoundland Power during the period 1976 through 2009 was negative 37 percent as shown in the tabulation in Appendix B. The net salvage estimate of negative 30 percent is appropriate for Account 361.12, Overhead Conductors - Bare Aluminum, since it is consistent with company experience and is within typical industry range.

The net salvage estimates for production plant reflect estimated decommissioning costs associated with each generating station. The decommissioning cost estimate for each

NEWFOUNDLAND POWER, INC.

Summary of the Calculation of Net Salvage Percent Related to Production Plant Facilities

Plant	Decommissioning Costs Stated in 2009 Dollars	Decommissioning Costs Stated in 2010 Dollars	Average Remaining Life	Inflation Factor	Decommissioning Costs Inflated to the Probable Retirement Date	Original Cost at 12/31/09	Net Salvage Percent
Hydroelectric Plant	(14,954,620)	(15,253,712)	37.4	2.10	(32,032,796)	152,035,725	(21.07)
Diesel Plants							
Port Union	(50,900)	(51,918)	0.0	1.00	(51,918)	80,286	(64.67)
Port Aux Basques	(146,200)	(149,124)	5.3	1.11	(165,528)	935,784	(17.69)
Gas Turbines	(608,800)	(620,976)	9.9	1.22	(757,591)	15,799,453	(4.80)

Column (3) = (100% + 2%) x Column (2)

Column (5) = (100% + 2%) x Column (4)

location was based on the results of a decommissioning study conducted by the Company's engineering department. The Company's decommissioning cost estimates were stated in current (2009) dollars. The decommissioning of the hydroelectric, gas turbines and diesel units are projected to occur at various dates in the future. The decommissioning cost estimates were adjusted for the effect of inflation between 2009 and the projected retirement date to develop the net salvage percent estimate as shown in the table on the following page. Amortization accounting is used for certain General and Communication Plant accounts. Future gross salvage and removal cost for these accounts will be recorded as revenue and expense, respectively. Inasmuch as there will be no depreciation reserve entries related to salvage, the estimate of net salvage for accounts subject to amortization is zero percent.

Generally, the net salvage estimates for the remaining accounts were based on judgments which considered the nature of the plant and equipment, the Company's accounting policies and practices, reviews of available historical data, and a general knowledge of net salvage percents for similar equipment, in other electric companies.

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.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were the same as those presented and approved in the previous depreciation report. The amortization periods 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 under depreciation accounting.

Amortization accounting is used for certain General and Communication Plant accounts that represent numerous units of property, but a very small portion of depreciable electric plant in service. The accounts and their amortization periods are as follows:

	<u>Account</u>	<u>Amortization Period, Years</u>
372	Furniture and Equipment	25
373	Stores Equipment	25
374	Shop Equipment	25
375	Laboratory and Testing Equipment	25
376	Miscellaneous Equipment	15
377	Engineering Equipment	25
379.1	Computer Equipment - Hardware	5
379.2	Computer Equipment - Software	10
381	Mobile Radio	15
383	Radio Equipment	15

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 original cost by the period of amortization for the account.

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 reserve variance amortization developed in this study is based on the variance between the book accumulated depreciation and the calculated accrued depreciation where the variance exceeds five percent of the calculated accrued depreciation and an amortization period equal to the composite remaining life for each property group. The calculated accrued depreciation or theoretical reserve is based on the mid-year convention. This accounting convention assumes that property is in service for six months in the year it is installed.

The composite remaining life for use in reducing accumulated depreciation variances is derived by compositing the individual equal life group remaining lives in accordance with the following equation:

$$\text{Composite Remaining Life} = \frac{\left(\frac{\text{Book Cost}}{\text{Life}} \times \text{Remaining Life} \right)}{\frac{\text{Book Cost}}{\text{Life}}}.$$

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:

$$\text{Composite Remaining Life} = \frac{\text{Whole Life Future Accruals}}{\text{Whole Life Annual Accruals}}$$

or

$$\text{Composite Remaining Life} = \frac{\text{Book Cost} \quad \text{Calc. Reserve}}{\text{Whole Life Annual Accrual}}.$$

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation and the annual provision for true-up (a.k.a., amortization of the accumulated depreciation variance) 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 equal life group method of depreciation based on estimates which reflect considerations of current historical evidence and expected future conditions.

The calculated accrued depreciation represents that portion of the depreciable cost which will not be allocated to future annual expense through depreciation accruals, if current forecasts of service life and salvage materialize and are used as a basis for straight line equal life group depreciation accounting.

DESCRIPTION OF STATISTICAL SUPPORT

The service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management, the previous estimates used for Newfoundland Power and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in Appendix A of the companion volume to this report.

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

The analyses of salvage data are presented in Appendix B titled, "Net Salvage Statistics." The tabulations present annual cost of removal and salvage data, three-year moving averages and the most recent five-year average. Data are shown in dollars and as percentages of original costs retired.

DESCRIPTION OF DEPRECIATION TABULATIONS

Summaries of the results of the study, as applied to the original cost of electric plant at December 31, 2010 are presented on pages III-4 through III-14 of this report. Schedules 1 through 2 present the study results. Schedule 1 is a summary of the calculated annual and accrued depreciation by account based on the straight line whole life method of depreciation. Schedule 2 compares the calculated accrued depreciation with the book depreciation reserve and calculates amortization amounts that correct the variance.

The tables of the calculated annual and accrued depreciation are presented in account sequence in Appendix C of the companion volume. The tables indicate the estimated survivor curve and salvage percent for the account and set forth for each installation year the original cost, the calculated annual accrual rate and amount, and the calculated accrued depreciation factor and amount.

NEWFOUNDLAND POWER INC.

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Annual Depreciation
Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/10	Annual Accrual Amount	Annual Accrual Rate	Calculated Accrued Depreciation
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
DEPRECIABLE PLANT							
Hydro Production							
320 Land and Land Clearing		75 - R2.5	0	973,085	13,864	1.42	356,362
321 Roads, Trails, and Bridges		55 - R3	(10)	3,589,122	75,691	2.11	1,342,495
322 Buildings and Structures		75 - R2.5	(25)	9,063,594	166,617	1.84	3,557,957
323 Canals, Penstocks, Surge Tanks and Tailraces		60 - L2.5	(25)	57,163,996	1,350,401	2.36	18,588,665
324 Dams and Reservoirs		70 - S0.5	(25)	31,450,495	658,454	2.09	12,325,536
325 Prime Movers, Generators and Auxiliaries		65 - R2	(25)	33,721,346	757,208	2.25	11,264,705
326 Switching, Metering and Control Equipment		40 - S0	(25)	15,045,954	616,362	4.10	4,358,313
327 Miscellaneous Power Plant Equipment		50 - R2	(25)	1,028,134	28,941	2.81	409,305
Total Hydro Production				152,035,725	3,667,538	2.41	52,203,338
Other Production							
331 <i>Buildings and Structures</i>							
Port Aux Basques Diesel	6-2016	60 - S0	(20)	266,733	15,343	5.75	237,788
Green Hill Gas Turbine	6-2021	60 - S0	(3)	461,618	23,348	5.06	242,771
Wesleyville Gas Turbine	6-2021	60 - S0	(3)	73,725	3,007	4.08	46,155
<i>Total Account 331</i>				<i>802,076</i>	<i>41,698</i>		<i>526,714</i>
332 <i>Electrical Plant</i>							
Port Union Diesel	12-2010	70 - L0	(65)	10,147	-	-	16,742
Port Aux Basques Diesel	6-2016	70 - L0	(20)	110,821	4,214	3.80	110,577
Green Hill Gas Turbine	6-2021	70 - L0	(3)	632,493	32,075	5.07	335,042
Wesleyville Gas Turbine	6-2021	70 - L0	(3)	223,216	12,460	5.58	106,966
Mobile Diesel #3	6-2036	70 - L0	0	1,352,165	49,933	3.69	323,676
<i>Total Account 332</i>				<i>2,328,841</i>	<i>98,682</i>		<i>893,003</i>

NEWFOUNDLAND POWER INC.

**Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Annual Depreciation
Related to Original Cost of Electric Plant at December 31, 2010**

Depreciable Group		Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/10	Annual Accrual Amount	Annual Accrual Rate	Calculated Accrued Depreciation
(1)		(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
333	<i>Prime Movers, Generators and Auxiliaries</i>							
	Port Union Diesel	12-2010	50 - L1	(65)	52,594	-	-	86,781
	Port Aux Basques Diesel	6-2016	50 - L1	(20)	455,975	20,323	4.46	440,940
	Portable Gas Turbine	6-2016	50 - L1	0	2,443,732	183,010	7.49	1,460,019
	Green Hill Gas Turbine	6-2021	50 - L1	(3)	5,894,244	213,217	3.62	4,028,222
	Wesleyville Gas Turbine	6-2021	50 - L1	(3)	7,773,362	451,834	5.81	3,514,971
	Mobile Diesel #3	6-2036	50 - L1	0	666,660	24,746	3.71	160,522
	<i>Total Account 333</i>				<u>17,286,568</u>	<u>893,130</u>		<u>9,691,455</u>
334	<i>Fuel Holders</i>							
	Port Union Diesel	12-2010	Square	(65)	17,545	-	-	28,949
	Port Aux Basques Diesel	6-2016	Square	(20)	95,357	11,388	11.94	51,793
	Green Hill Gas Turbine	6-2021	Square	(3)	539,385	27,818	5.16	263,389
	Wesleyville Gas Turbine	6-2021	Square	(3)	201,410	9,932	4.93	103,128
	<i>Total Account 334</i>				<u>853,697</u>	<u>49,138</u>		<u>447,259</u>
335	<i>Miscellaneous Power Plant Equipment</i>							
	Port Aux Basques Diesel	6-2016	Square	(20)	6,898	144	2.09	7,485
	<i>Total Account 335</i>							
	Total Other Production				21,278,080	1,082,792	5.09	11,565,916
Substation								
341	Buildings and Structures		50 - R2.5	(15)	8,542,104	219,032	2.56	2,960,223
342	Equipment		50 - R1.5	(15)	144,737,625	3,875,508	2.68	55,781,275
	Total Substation				153,279,729	4,094,540	2.67	58,741,498

NEWFOUNDLAND POWER INC.

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Annual Depreciation
Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group		Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/10	Annual Accrual Amount	Annual Accrual Rate	Calculated Accrued Depreciation
(1)		(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
Transmission								
350.01	ROW Clearing and Easement Survey		65 - R4	0	6,864,004	109,220	1.59	2,874,405
350.02	Roads, Trails and Bridges		65 - R4	0	76,200	1,217	1.60	30,598
353.1	Overhead Conductors		55 - R3	(35)	24,324,145	629,266	2.59	12,476,441
353.2	Underground Cables		50 - R4	(25)	1,034,644	25,791	2.49	783,771
355.1	Poles		47 - R2	(35)	32,354,167	1,005,641	3.11	17,292,743
355.2	Pole Fixtures		47 - R2	(35)	23,125,858	748,630	3.24	10,542,216
355.3	Insulators		31 - S1	(35)	20,944,929	988,746	4.72	11,356,715
Total Transmission					108,723,947	3,508,511	3.23	55,356,889
Distribution								
<i>Overhead Conductors and Underground Cables</i>								
361.1	Bare Copper		48 - R1.5	(25)	667,917	14,513	2.17	588,525
361.11	Weather-Proof Copper		44 - R2	(25)	1,737,353	38,919	2.24	1,756,262
361.12	Bare Aluminum		55 - R2.5	(30)	105,695,941	2,762,546	2.61	43,202,211
361.13	Weather-Proof Aluminum		32 - R1.5	(30)	28,794,084	1,264,327	4.39	15,841,574
361.14	Aerial Cable		26 - R1	(25)	709,872	28,684	4.04	570,798
361.15	Duplex, Triplex, and Quadruplex		44 - R2	(30)	4,817,731	168,244	3.49	1,674,769
361.2	Underground Cables		45 - R3	(5)	20,889,633	509,558	2.44	8,989,411
361.3	Special Insulated Copper Cable		26 - R1	(25)	102,076	3,504	3.43	101,564
361.4	Submarine Cable		40 - R3	0	3,607,249	91,509	2.54	1,911,451
<i>Total Account 361</i>					<i>167,021,857</i>	<i>4,881,804</i>		<i>74,636,565</i>

NEWFOUNDLAND POWER INC.

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Annual Depreciation
Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group		Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/10	Annual Accrual Amount	Annual Accrual Rate	Calculated Accrued Depreciation
(1)		(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
<i>Poles and Fixtures</i>								
362.1	Wood - Under 35 ft.		48 - R1.5	(25)	63,894,788	1,805,697	2.83	31,054,512
362.2	Wood - 35 ft. and Over		48 - R1.5	(25)	265,218,896	8,007,693	3.02	108,372,728
362.3	Concrete and Steel		40 - R2.5	(25)	6,898,961	226,862	3.29	3,623,285
362.4	Steel Towers		45 - R3	(25)	184,774	4,943	2.68	150,752
<i>Total Account 362</i>					<u>336,197,419</u>	<u>10,045,195</u>		<u>143,201,277</u>
363	Street Lights		20 - R0.5	(10)	19,911,084	1,170,301	5.88	10,542,120
<i>Transformers and Mountings</i>								
364.1	Up to and Including 15 kVA		40 - S1	(2)	8,805,292	257,254	2.92	2,742,919
	Over 15 kVA		40 - S1	(2)	98,259,183	2,901,643	2.95	27,972,283
<i>Total Account 364.1</i>					<u>107,064,475</u>	<u>3,158,897</u>	2.95	<u>30,715,202</u>
364.2	Voltage Regulators		40 - S1	(2)	3,004,698	77,286	2.57	1,520,529
364.3	Capacitor Banks		40 - S1	(2)	299,652	8,883	2.96	85,347
364.4	Reclosers		40 - S1	(2)	653,968	18,764	2.87	239,332
365.1	Services Overhead		44 - R2	(60)	76,514,238	3,050,688	3.99	45,747,046
365.2	Services Underground		45 - R3	(10)	6,873,773	178,402	2.60	2,717,166
<i>Meters</i>								
366.1	Watt-hour		25 - S1	(5)	14,090,711	628,881	4.46	5,841,130
366.2	Demand		22 - S0.5	(5)	5,192,669	273,751	5.27	2,089,499
366.3	Instrument Transformers		36 - R2.5	(5)	2,179,679	64,374	2.95	1,110,059
366.4	Metering Tanks		36 - R2.5	(5)	1,097,696	29,870	2.72	730,585
<i>Total Account 366</i>					<u>22,560,754</u>	<u>996,876</u>	4.42	<u>9,771,273</u>
367.1	Underground Ducts and Manholes		60 - R4	(5)	5,193,022	93,472	1.80	2,396,147
367.2	Underground Switches and Switchgear		45 - R3	(5)	1,741,339	44,010	2.53	527,795
Total Distribution					747,036,280	23,724,578	3.18	322,099,799

NEWFOUNDLAND POWER INC.

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Annual Depreciation
Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group		Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/10	Annual Accrual Amount	Annual Accrual Rate	Calculated Accrued Depreciation
(1)		(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
General Property								
371.1	Buildings and Structures - Small		35 - S0	(5)	1,883,109	50,348	2.67	1,187,176
371.2	<i>Buildings and Structures - Large</i>							
	Topsail Road - Transformer Storage	6-2026	70 - R1	0	1,203,457	38,004	3.16	656,061
	Topsail Road - System Control Center	6-2054	70 - R1	0	1,410,482	35,468	2.51	300,724
	Kenmount Road	6-2046	70 - R1	0	7,128,803	159,778	2.24	2,789,040
	Duffy Place	6-2060	70 - R1	0	12,219,416	235,033	1.92	3,976,108
	Carbonear - Office/Warehouse	6-2030	70 - R1	0	1,840,956	47,762	2.59	999,840
	Whitbourne	6-2023	70 - R1	0	595,812	16,797	2.82	397,249
	Salt Pond	6-2023	70 - R1	0	871,771	33,030	3.79	482,826
	Clareville Regional Building	6-2042	70 - R1	0	2,047,763	46,559	2.27	828,427
	Gander	6-2037	70 - R1	0	1,447,139	35,555	2.46	633,446
	Grand Falls Service Building	6-2056	70 - R1	0	1,444,095	34,598	2.40	326,370
	Corner Brook - Maple Valley Service Buildings	6-2057	70 - R1	0	1,565,272	37,844	2.42	340,349
	Stephenville Office and Service Build	6-2028	70 - R1	0	1,083,243	30,110	2.78	601,698
	Port Aux Basques	6-2026	70 - R1	0	271,474	6,815	2.51	173,260
	<i>Total Account 371.2</i>				<u>33,129,684</u>	<u>757,353</u>		<u>12,505,398</u>
372	Office Equipment		25 - SQ	0	6,727,366	262,773	4.00 (a)	4,144,907
373	Store Equipment		25 - SQ	0	608,024	23,557	4.00 (a)	420,805
374	Shop Equipment		25 - SQ	0	718,269	28,422	4.00 (a)	446,251
375	Laboratory and Testing Equipment		25 - SQ	0	5,913,584	234,296	4.00 (a)	3,031,184
376	Miscellaneous Equipment		15 - SQ	0	2,678,699	174,914	6.67 (a)	1,210,760
377	Engineering Equipment		25 - SQ	0	297,792	11,729	4.00 (a)	239,004

NEWFOUNDLAND POWER INC.

**Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Annual Depreciation
Related to Original Cost of Electric Plant at December 31, 2010**

Depreciable Group		Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/10	Annual Accrual Amount	Annual Accrual Rate	Calculated Accrued Depreciation
(1)		(2)	(3)	(4)	(5)	(6)	(7)=(6)/(5)	(8)
<i>Transportation</i>								
378.1	Sedans and Station Wagons		5 - R1.5	16	98,663	12,324	12.49	67,776
378.2	Pick-up Trucks, Window Vans		6 - S2.5	16	5,888,718	834,727	14.18	2,521,894
378.3	Large Trucks with Hydraulic Derricks		11 - R2.5	8	13,452,389	1,126,354	8.37	6,336,538
378.4	Large Trucks with Line and Stake Bodies		11 - R2.5	8	3,351,228	288,649	8.61	1,419,567
378.5	Miscellaneous		15 - L1.5	8	1,284,885	79,720	6.20	570,918
<i>Total Account 378</i>					<u>24,075,883</u>	<u>2,341,774</u>	9.73	<u>10,916,693</u>
379.1	Computers - Hardware		5 - SQ	0	8,368,060	1,399,368	20.00 (a)	4,580,198
379.2	Computers - Software		10 - SQ	0	29,453,949	2,707,639	10.00 (a)	17,368,838
Total General Property					113,854,418	7,992,173	7.02	56,051,214
Telecommunications								
381.1	Mobile Radios		15 - SQ	0	336,948	22,474	6.67 (a)	236,294
381.2	Portable Radios		15 - SQ	0	158,801	7,823	6.67 (a)	118,288
381.3	Base Stations		15 - SQ	0	6,882	371	6.67 (a)	6,697
382.1	Radio Sites - Roads		30 - R4	0	141,801	4,492	3.17	87,857
382.2	Radio Sites - Buildings		30 - R4	(5)	385,158	12,444	3.23	322,428
383	Radio Equipment		15 - SQ	0	952,652	63,542	6.67 (a)	600,313
384	Communication Cables		25 - R3	(5)	2,675,790	116,935	4.37	1,145,661
386	SCADA Equipment		14 - L2	0	4,265,598	241,908	5.67	3,036,203
389.1	Telephone and Data Collection Equipment		10 - L2.5	0	1,080,217	72,369	6.70	881,700
390	Power Line Carrier							
391	Communication Test Equipment		15 - R3	0	636,653	29,044	4.56	593,177
Total Telecommunications					<u>10,640,500</u>	<u>571,402</u>	5.37	<u>7,028,618</u>
TOTAL DEPRECIABLE PLANT					<u>1,306,848,679</u>	<u>44,641,534</u>		<u>563,047,272</u>
TOTAL NONDEPRECIABLE PLANT					<u>9,594,385</u>			
TOTAL ELECTRIC PLANT					<u>1,316,443,064</u>			

(a) Amortization rate shown is applicable to vintages that are not fully amortized. (Amortization Rate=1/Amortization Period, Years)

Note: The December 31, 2010 original cost amounts shown on this schedule for Accounts 362.1 and 362.2 do not include poles sold to Alliant in 2011.

NEWFOUNDLAND POWER INC.

Schedule 2. Calculated Accrued Depreciation, Book Accumulated Depreciation and Determination of Reserve
Variance Amortizations Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group		Original Cost at 12/31/10	Calculated Accrued Depreciation	Book Accumulated Depreciation	Accumulated Reserve			Probable Remaining Life	Reserve Variance Amortization
					Amount	Percent	Amount > Threshold		
(1)		(2)	(3)	(4)	(5)=(3)-(4)	(6)=(5)/(3)	(7)=(3)-(4) (a)	(8)	(9)=(5)/(8)
DEPRECIABLE PLANT									
Steam Production Plant									
Steam Plant - Retired				(105,245)	105,245		105,245		21,049 (d)
Hydro Production									
320	Land and Land Clearing	973,085	356,362	375,172.91	(18,811)	(5.3)	(18,811)	44.5	(423)
321	Roads, Trails, and Bridges	3,589,122	1,342,495	1,367,392	(24,897)	(1.9)	-	34.4	- (b)
322	Buildings and Structures	9,063,594	3,557,957	3,898,288	(340,331)	(9.6)	(340,331)	46.6	(7,297)
323	Canals, Penstocks, Surge Tanks and Tailraces	57,163,996	18,588,665	16,954,331	1,634,334	8.8	1,634,334	39.2	41,745
324	Dams and Reservoirs	31,450,495	12,325,536	12,072,961	252,576	2.0	-	41.0	- (b)
325	Prime Movers, Generators and Auxiliaries	33,721,346	11,264,705	9,781,320	1,483,385	13.2	1,483,385	40.8	36,366
326	Switching, Metering and Control Equipment	15,045,954	4,358,313	3,462,742	895,571	20.5	895,571	23.4	38,207
327	Miscellaneous Power Plant Equipment	1,028,134	409,305	335,278	74,027	18.1	74,027	30.3	2,446
Total Hydro Production		152,035,725	52,203,338	48,247,484	3,955,854		3,728,175		111,044
Other Production									
331	Buildings and Structures								
	Port Aux Basques Diesel	266,733	237,788	232,308	5,480	2.3	-	5.4	- (b)
	Green Hill Gas Turbine	461,618	242,771	228,307	14,464	6.0	14,464	10.0	1,451
	Wesleyville Gas Turbine	73,725	46,155	45,097	1,058	2.3	-	9.9	- (b)
	Total Account 331	802,076	526,714	505,711	21,003		14,464		1,451
332	Electrical Plant								
	Port Union Diesel	10,147	16,742	4,141	12,601	75.3	12,601	0.0	2,520 (c)
	Port Aux Basques Diesel	110,821	110,577	112,605	(2,028)	(1.8)	-	5.3	- (b)
	Green Hill Gas Turbine	632,493	335,042	373,621	(38,579)	(11.5)	(38,579)	9.9	(3,909)
	Wesleyville Gas Turbine	223,216	106,966	132,367	(25,401)	(23.7)	(25,401)	9.9	(2,574)
	Mobile Diesel #3	1,352,165	323,676	346,469	(22,793)	(7.0)	(22,793)	20.6	(1,106)
	Total Account 332	2,328,841	893,003	969,203	(76,200)		(74,172)		(5,069)
333	Prime Movers, Generators and Auxiliaries								
	Port Union Diesel	52,594	86,781	70,810	15,971	18.4	15,971	0.0	3,194 (c)
	Port Aux Basques Diesel	455,975	440,940	447,654	(6,714)	(1.5)	-	5.2	- (b)
	Portable Gas Turbine	2,443,732	1,460,019	924,084	535,935	36.7	535,935	5.4	99,616
	Green Hill Gas Turbine	5,894,244	4,028,222	4,683,675	(655,453)	(16.3)	(655,453)	9.6	(68,419)
	Wesleyville Gas Turbine	7,773,362	3,514,971	2,843,763	671,208	19.1	671,208	9.9	67,526
	Mobile Diesel #3	666,660	160,522	158,322	2,200	1.4	-	20.5	- (b)
	Total Account 333	17,286,568	9,691,455	9,128,308	563,147		567,661		101,917

NEWFOUNDLAND POWER INC.

Schedule 2. Calculated Accrued Depreciation, Book Accumulated Depreciation and Determination of Reserve
Variance Amortizations Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group (1)	Original Cost at 12/31/10 (2)	Calculated Accrued Depreciation (3)	Book Accumulated Depreciation (4)	Accumulated Reserve Variance			Probable Remaining Life (8)	Reserve Variance Amortization (9)=(5)/(8)
				Amount (5)=(3)-(4)	Percent (6)=(5)/(3)	Amount > Threshold (7)=(3)-(4) (a)		
334								
Fuel Holders								
Port Union Diesel	17,545	28,949	27,825	1,124	3.9	-	0.0	- (b)
Port Aux Basques Diesel	95,357	51,793	16,059	35,734	69.0	35,734	5.5	6,497
Green Hill Gas Turbine	539,385	263,389	265,233	(1,844)	(0.7)	-	10.5	- (b)
Wesleyville Gas Turbine	201,410	103,128	85,394	17,734	17.2	17,734	10.5	1,689
Total Account 334	853,697	447,259	394,512	52,747		53,468		8,186
335								
Miscellaneous Power Plant Equipment								
Port Aux Basques Diesel	6,898	7,485	7,583	(98)	(1.3)	-	5.5	- (b)
Total Account 335	6,898	7,485	7,583	(98)		-		-
Total Other Production	21,278,080	11,565,916	11,005,317	560,599		561,421		106,485
Substation								
341 Buildings and Structures	8,542,104	2,960,223	2,719,332	240,891	8.1	240,891	31.3	7,689
342 Equipment	144,737,625	55,781,275	54,584,514	1,196,761	2.1	-	28.6	- (b)
Total Substation	153,279,729	58,741,498	57,303,845	1,437,653		240,891		7,689
Transmission								
350.01 ROW Clearing and Easement Survey	6,864,004	2,874,405	2,852,061	22,344	0.8	-	36.5	- (b)
350.02 Roads, Trails and Bridges	76,200	30,598	34,031	(3,433)	(11.2)	(3,433)	37.5	(92)
353.1 Overhead Conductors	24,324,145	12,476,441	11,643,947	832,494	6.7	832,494	32.4	25,726
353.2 Underground Cables	1,034,644	783,771	714,913	68,858	8.8	68,858	19.8	3,485
355.1 Poles	32,354,167	17,292,743	14,768,395	2,524,348	14.6	2,524,348	26.2	96,202
355.2 Pole Fixtures	23,125,858	10,542,216	12,595,164	(2,052,948)	(19.5)	(2,052,948)	27.6	(74,328)
355.3 Insulators	20,944,929	11,356,715	10,907,435	449,280	4.0	-	17.1	- (b)
Total Transmission	108,723,947	55,356,889	53,515,947	1,840,942		1,369,319		50,993

NEWFOUNDLAND POWER INC.

**Schedule 2. Calculated Accrued Depreciation, Book Accumulated Depreciation and Determination of Reserve
Variance Amortizations Related to Original Cost of Electric Plant at December 31, 2010**

Depreciable Group (1)		Original Cost at 12/31/10 (2)	Calculated Accrued Depreciation (3)	Book Accumulated Depreciation (4)	Accumulated Reserve			Probable Remaining Life (8)	Reserve Variance Amortization (9)=(5)/(8)
					Variance				
					Amount (5)=(3)-(4) (5)	Percent (6)=(5)/(3) (6)	Amount > Threshold (7)=(3)-(4) (a) (7)		
Distribution									
Overhead Conductors and Underground Cables									
361.1	Bare Copper	667,917	588,525	766,547	(178,022)	(30.2)	(178,022)	17.0	(10,484)
361.11	Weather-Proof Copper	1,737,353	1,756,262	2,311,771	(555,509)	(31.6)	(555,509)	10.7	(52,063)
361.12	Bare Aluminum	105,695,941	43,202,211	45,707,706	(2,505,495)	(5.8)	(2,505,495)	34.1	(73,475)
361.13	Weather-Proof Aluminum	28,794,084	15,841,574	15,175,341	666,233	4.2	-	17.1	- (b)
361.14	Aerial Cable	709,872	570,798	770,501	(199,703)	(35.0)	(199,703)	11.0	(18,089)
361.15	Duplex, Triplex, and Quadruplex	4,817,731	1,674,769	1,952,695	(277,926)	(16.6)	(277,926)	27.3	(10,192)
361.2	Underground Cables	20,889,633	8,989,411	9,792,239	(802,828)	(8.9)	(802,828)	25.4	(31,607)
361.3	Special Insulated Copper Cable	102,076	101,564	134,217	(32,653)	(32.2)	(32,653)	7.4	(4,395)
361.4	Submarine Cable	3,607,249	1,911,451	1,917,873	(6,422)	(0.3)	-	18.5	- (b)
Total Account 361		167,021,857	74,636,565	78,528,889	(3,892,324)		(4,552,136)		(200,305)
Poles and Fixtures									
362.1	Wood - Under 35 ft.	63,894,788	31,054,512	27,135,455	3,919,057	12.6	3,919,057	27.0	144,989
362.2	Wood - 35 ft. and Over	265,218,896	108,372,728	104,199,505	4,173,223	3.9	-	27.9	- (b)
362.3	Concrete and Steel	6,898,961	3,623,285	3,897,999	(274,714)	(7.6)	(274,714)	22.0	(12,464)
362.4	Steel Towers	184,774	150,752	125,142	25,610	17.0	25,610	16.2	1,578
Total Account 362		336,197,419	143,201,277	135,358,101	7,843,176		3,669,953		134,103
363	Street Lights	19,911,084	10,542,120	9,439,337	1,102,783	10.5	1,102,783	9.7	113,572
Transformers and Mountings									
364.1	Up to and Including 15 kVA	8,805,292	2,742,919	2,179,667	563,252	20.5	563,252	24.3	23,227
	Over 15 kVA	98,259,183	27,972,283	26,086,452	1,885,831	6.7	1,885,831	24.9	75,736
Total Account 364.1		107,064,475	30,715,202	28,266,119	2,449,083		2,449,083		98,963
364.2	Voltage Regulators	3,004,698	1,520,529	1,393,782	126,747	8.3	126,747	20.0	6,344
364.3	Capacitor Banks	299,652	85,347	97,883	(12,536)	(14.7)	(12,536)	24.8	(505)
364.4	Reclosers	653,968	239,332	252,626	(13,294)	(5.6)	(13,294)	22.8	(583)
365.1	Services Overhead	76,514,238	45,747,046	54,522,622	(8,775,576)	(19.2)	(8,775,576)	25.1	(349,207)
365.2	Services Underground	6,873,773	2,717,166	2,756,217	(39,051)	(1.4)	-	27.2	- (b)
Meters									
366.1	Watt-hour	14,090,711	5,841,130	2,467,233	3,373,897	57.8	3,373,897	14.2	236,931
366.2	Demand	5,192,669	2,089,499	1,544,074	545,425	26.1	545,425	12.3	44,416
366.3	Instrument Transformers	2,179,679	1,110,059	1,121,760	(11,701)	(1.1)	-	18.3	- (b)
366.4	Metering Tanks	1,097,696	730,585	752,805	(22,220)	(3.0)	-	14.1	- (b)
Total Account 366		22,560,754	9,771,273	5,885,873	3,885,401		3,919,322		281,347
367.1	Underground Ducts and Manholes	5,193,022	2,396,147	2,256,703	139,444	5.8	139,444	32.7	4,264
367.2	Underground Switches and Switchgear	1,741,339	527,795	539,694	(11,899)	(2.3)	-	29.6	- (b)
Total Distribution		747,036,280	322,099,799	319,297,847	2,801,952		(1,946,210)		87,993

NEWFOUNDLAND POWER INC.

Schedule 2. Calculated Accrued Depreciation, Book Accumulated Depreciation and Determination of Reserve
Variance Amortizations Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group (1)		Original Cost at 12/31/10 (2)	Calculated Accrued Depreciation (3)	Book Accumulated Depreciation (4)	Accumulated Reserve			Probable Remaining Life (8)	Reserve	
					Variance		Amount > Threshold (7)=(3)-(4) (a)		Variance	Amortization (9)=(5)/(8)
					Amount (5)=(3)-(4)	Percent (6)=(5)/(3)				
General Property										
371.1	Buildings and Structures - Small	1,883,109	1,187,176	1,248,252	(61,076)	(5.1)	(61,076)	15.7	(3,893)	
371.2	Buildings and Structures - Large									
	Topsail Road - Transformer Storage	1,203,457	656,061	700,767	(44,706)	(6.8)	(44,706)	14.4	(3,105)	
	Topsail Road - System Control Center	1,410,482	300,724	316,976	(16,252)	(5.4)	(16,252)	31.3	(519)	
	Kenmount Road	7,128,803	2,789,040	2,539,205	249,835	9.0	249,835	27.2	9,199	
	Duffy Place	12,219,416	3,976,108	3,890,350	85,758	2.2	-	35.1	-	
	Carbonear - Office/Warehouse	1,840,956	999,840	1,083,062	(83,222)	(8.3)	(83,222)	17.6	(4,726)	
	Whitbourne	595,812	397,249	347,965	49,284	12.4	49,284	11.8	4,170	
	Salt Pond	871,771	482,826	500,390	(17,564)	(3.6)	-	11.8	-	
	Clarenville Regional Building	2,047,763	828,427	750,663	77,764	9.4	77,764	26.2	2,969	
	Gander	1,447,139	633,446	956,182	(322,736)	(50.9)	(322,736)	22.9	(14,099)	
	Grand Falls Office Building			62,971	(62,971)		(62,971)		(12,594) (d)	
	Grand Falls Service Building	1,444,095	326,370	309,282	17,088	5.2	17,088	32.3	529	
	Corner Brook - West Street			137,842	(137,842)		(137,842)		(27,568) (d)	
	Corner Brook - Maple Valley Service Buildings	1,565,272	340,349	249,937	90,412	26.6	90,412	32.4	2,793	
	Stephenville Office and Service Build	1,083,243	601,698	640,063	(38,365)	(6.4)	(38,365)	16.0	(2,399)	
	Port Aux Basques	271,474	173,260	182,797	(9,537)	(5.5)	(9,537)	14.4	(662)	
	Total Account 371.2	33,129,684	12,505,398	12,668,452	(163,054)		(231,248)		(46,012)	
372	Office Equipment	6,727,366	4,144,907	4,130,778	14,129	0.3	-	9.8	-	(b)
373	Store Equipment	608,024	420,805	417,133	3,672	0.9	-	8.0	-	(b)
374	Shop Equipment	718,269	446,251	461,774	(15,523)	(3.5)	-	9.6	-	(b)
375	Laboratory and Testing Equipment	5,913,584	3,031,184	2,948,509	82,675	2.7	-	12.3	-	(b)
376	Miscellaneous Equipment	2,678,699	1,210,760	1,286,358	(75,598)	(6.2)	(75,598)	8.4	(9,010)	
377	Engineering Equipment	297,792	239,004	252,522	(13,518)	(5.7)	(13,518)	5.0	(2,698)	
Transportation										
378.1	Sedans and Station Wagons	98,663	67,776	51,844	15,932	23.5	15,932	1.2	3,186 (c)	
378.2	Pick-up Trucks, Window Vans	5,888,718	2,521,894	2,201,680	320,214	12.7	320,214	2.9	64,043 (c)	
378.3	Large Trucks with Hydraulic Derricks	13,452,389	6,336,538	7,436,169	(1,099,631)	(17.4)	(1,099,631)	5.4	(205,155)	
378.4	Large Trucks with Line and Stake Bodies	3,351,228	1,419,567	1,181,647	237,920	16.8	237,920	5.8	41,306	
378.5	Miscellaneous	1,284,885	570,918	202,586	368,332	64.5	368,332	7.7	48,022	
	Total Account 378	24,075,883	10,916,693	11,073,925	(157,232)		(157,233)		(48,598)	
379.1	Computers - Hardware	8,368,060	4,580,198	4,742,459	(162,261)	(3.5)	-	2.7	-	(b)
379.2	Computers - Software	29,453,949	17,368,838	16,785,531	583,307	3.4	-	4.5	-	(b)
Total General Property		113,854,418	56,051,214	56,015,693	35,521		(538,673)		(110,211)	

NEWFOUNDLAND POWER INC.

Schedule 2. Calculated Accrued Depreciation, Book Accumulated Depreciation and Determination of Reserve
Variance Amortizations Related to Original Cost of Electric Plant at December 31, 2010

Depreciable Group (1)		Original Cost at 12/31/10 (2)	Calculated Accrued Depreciation (3)	Book Accumulated Depreciation (4)	Accumulated Reserve Variance		Probable Remaining Life (8)	Reserve Variance Amortization (9)=(5)/(8)	
					Amount (5)=(3)-(4) (5)	Percent (6)=(5)/(3) (6)			Amount > Threshold (7)=(3)-(4) (a) (7)
Telecommunications									
381.1	Mobile Radios	336,948	236,294	226,799	9,495	4.0	-	4.5	- (b)
381.2	Portable Radios	158,801	118,288	124,751	(6,463)	(5.5)	(6,463)	5.2	(1,248)
381.3	Base Stations	6,882	6,697	6,742	(45)	(0.7)	-	0.5	- (b)
382.1	Radio Sites - Roads	141,801	87,857	96,193	(8,336)	(9.5)	(8,336)	12.0	(694)
382.2	Radio Sites - Buildings	385,158	322,428	346,659	(24,231)	(7.5)	(24,231)	6.6	(3,677)
383	Radio Equipment	952,652	600,313	571,286	29,027	4.8	-	5.5	- (b)
384	Communication Cables	2,675,790	1,145,661	1,034,395	111,266	9.7	111,266	14.2	7,819
386	SCADA Equipment	4,265,598	3,036,203	3,651,799	(615,596)	(20.3)	(615,596)	5.1	(121,180)
389.1	Telephone and Data Collection Equipment	1,080,217	881,700	1,088,091	(206,391)	(23.4)	(206,391)	2.7	(41,278) (c)
391	Communication Test Equipment	636,653	593,177	721,690	(128,513)	(21.7)	(128,513)	1.5	(25,703) (c)
Total Telecommunications		10,640,500	7,028,618	7,868,404	(839,786)		(878,264)		(185,961)
TOTAL DEPRECIABLE PLANT IN SERVICE		1,306,848,679	563,047,272	553,149,293	9,897,979		2,641,905		89,081
Accounts Not Studied									
371.2	Other Production - Retired	-		27,141	(27,141)		(27,141)		(27,141) (e)
389.3	Buildings - Retired	-		22,604	(22,604)		(22,604)		(22,604) (e)
390.0	Telephone Equipment	-		(1)	1		1		1 (e)
	Power Line Carrier	-		(12,203)	12,203		12,203		12,203 (e)
Total Accounts Not Studied		-		37,540	(37,540)		(37,540)		(37,540)
TOTAL DEPRECIABLE PLANT		1,306,848,679		553,186,834	9,860,438		2,604,364		51,541
TOTAL NONDEPRECIABLE PLANT		9,594,385							
TOTAL ELECTRIC PLANT		1,316,443,064							

(a) The reserve variance for accounts that exceed the 5% tolerance threshold are listed.

(b) No reserve variance amortization calculated when reserve variance is less than five percent.

(c) Reserve variance is amortized over five years for those accounts with a composite remaining life of less than 5 years.

(d) No assets remain in this account and no future dismantling or gross salvage costs are expected. Reserve variance is amortized over 5 years.

(e) No assets remain in this account. The true-up from the previous depreciation study will eliminate any reserve variance by year end 2011.

Note: The December 31, 2010 original cost and book accumulated depreciation amounts shown on this schedule for Accounts 362.1 and 362.2 do not include poles sold to Alliant in 2011.

NEWFOUNDLAND POWER INC.

ST. JOHN'S, NEWFOUNDLAND

APPENDICES TO

DEPRECIATION STUDY

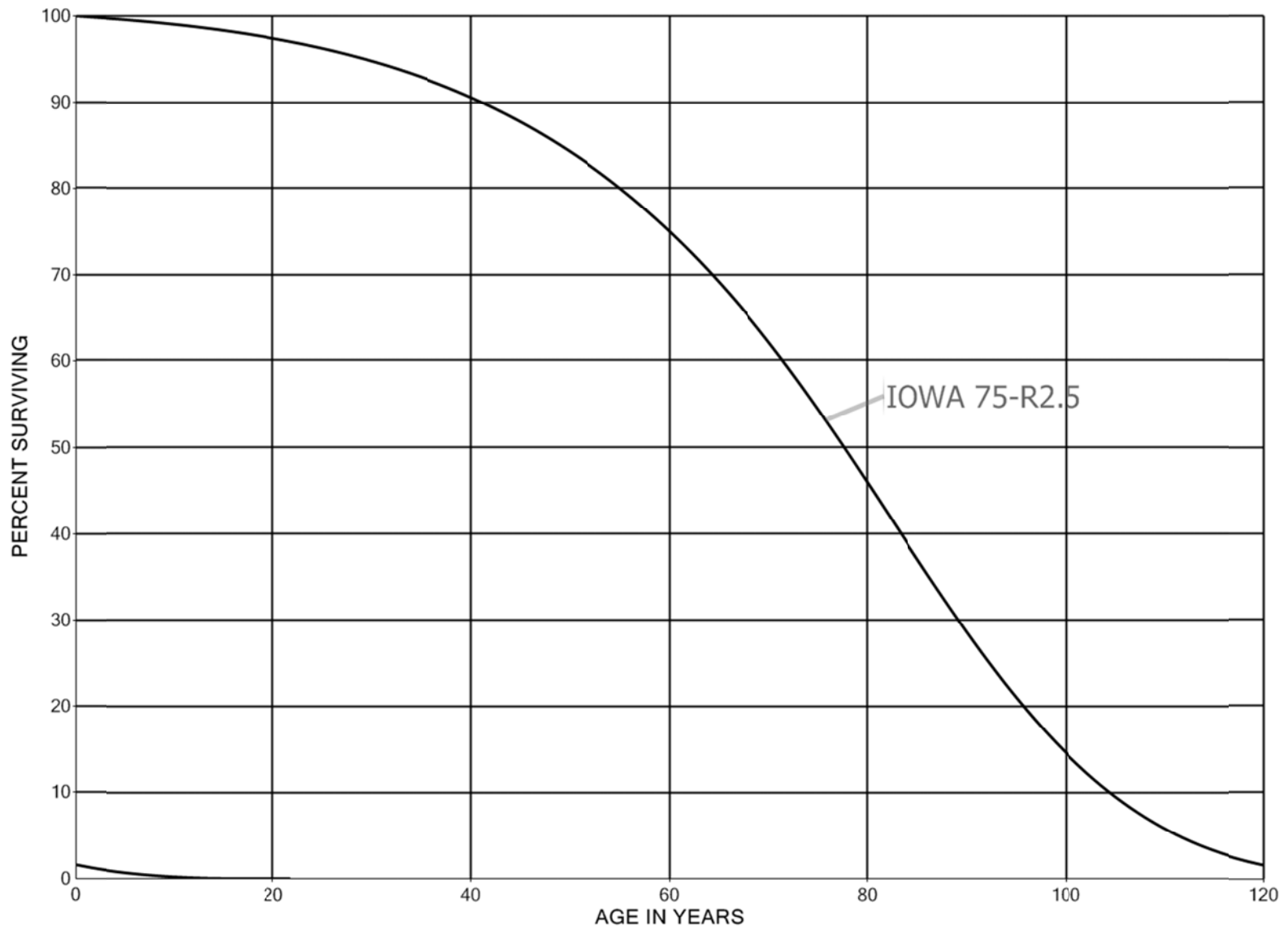
CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AT DECEMBER 31, 2010



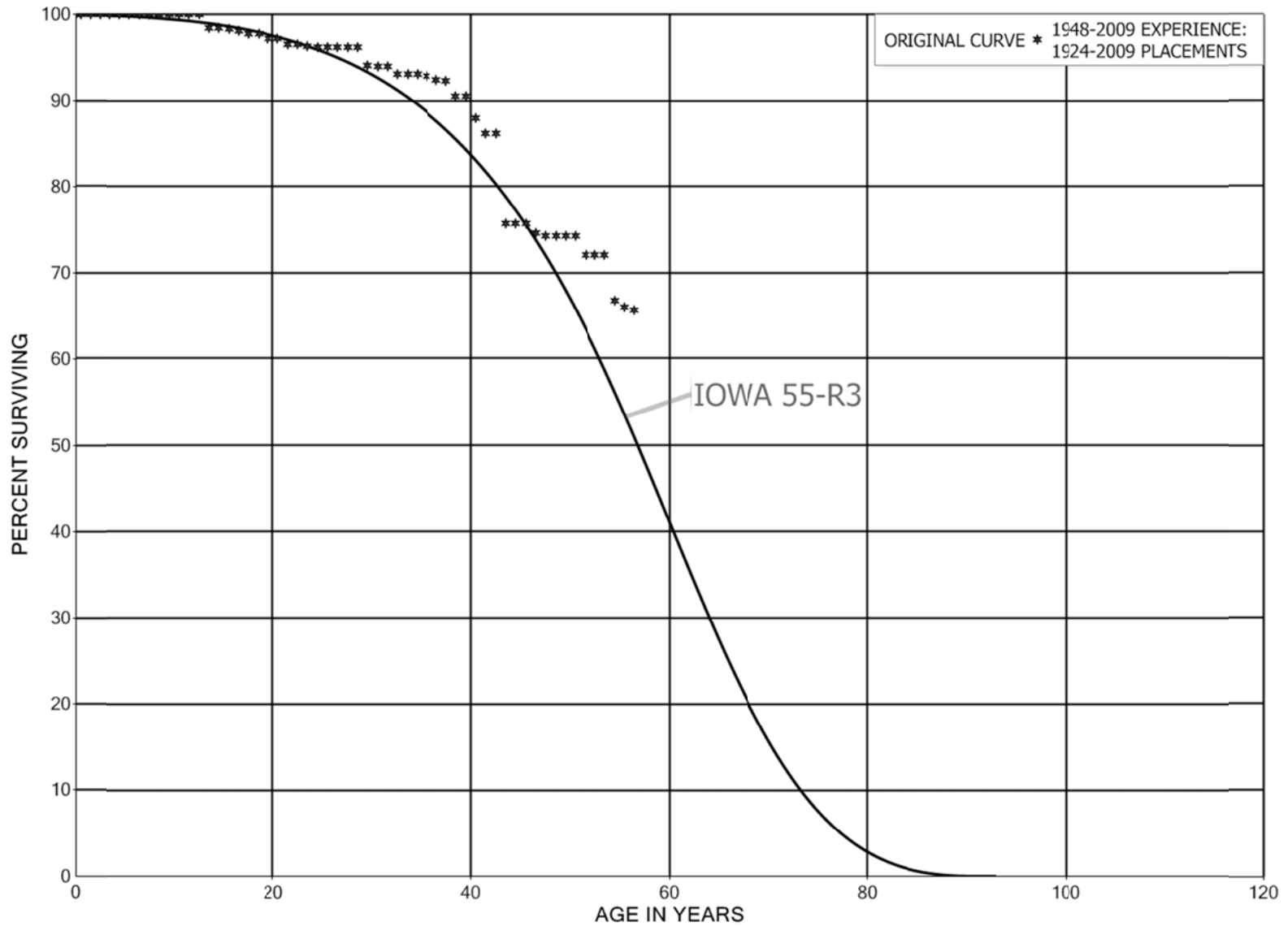
Gannett Fleming
Valuation and Rate Division

APPENDIX A — SERVICE LIFE STATISTICS

NEWFOUNDLAND POWER INC.
ACCOUNT 320.00 - LAND AND LAND CLEARING
SMOOTH SURVIVOR CURVE



NEWFOUNDLAND POWER INC.
ACCOUNT 321.00 - ROADS, TRAILS, AND BRIDGES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 321.00 - ROADS, TRAILS, AND BRIDGES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2009			EXPERIENCE BAND 1948-2009		
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	2,226,908		0.0000	1.0000	100.00
0.5	2,181,365		0.0000	1.0000	100.00
1.5	2,127,479		0.0000	1.0000	100.00
2.5	2,053,266		0.0000	1.0000	100.00
3.5	2,084,750		0.0000	1.0000	100.00
4.5	2,071,541		0.0000	1.0000	100.00
5.5	2,026,121		0.0000	1.0000	100.00
6.5	1,816,577		0.0000	1.0000	100.00
7.5	2,635,455		0.0000	1.0000	100.00
8.5	2,434,080		0.0000	1.0000	100.00
9.5	2,419,014	1,500	0.0006	0.9994	100.00
10.5	2,423,169		0.0000	1.0000	99.94
11.5	1,673,097		0.0000	1.0000	99.94
12.5	1,172,855	18,445	0.0157	0.9843	99.94
13.5	1,302,707		0.0000	1.0000	98.37
14.5	1,302,707	600	0.0005	0.9995	98.37
15.5	1,247,226	2,994	0.0024	0.9976	98.32
16.5	1,277,528	4,000	0.0031	0.9969	98.08
17.5	1,009,028		0.0000	1.0000	97.78
18.5	1,005,163	6,105	0.0061	0.9939	97.78
19.5	1,023,108		0.0000	1.0000	97.18
20.5	981,106	7,000	0.0071	0.9929	97.18
21.5	975,087		0.0000	1.0000	96.49
22.5	986,536	1,571	0.0016	0.9984	96.49
23.5	1,014,021	1,220	0.0012	0.9988	96.34
24.5	1,007,191		0.0000	1.0000	96.22
25.5	1,009,191		0.0000	1.0000	96.22
26.5	931,268		0.0000	1.0000	96.22
27.5	928,060		0.0000	1.0000	96.22
28.5	928,060	20,900	0.0225	0.9775	96.22
29.5	895,085	1,104	0.0012	0.9988	94.05
30.5	897,781		0.0000	1.0000	93.94
31.5	897,781	8,825	0.0098	0.9902	93.94
32.5	888,956		0.0000	1.0000	93.01
33.5	888,956		0.0000	1.0000	93.01
34.5	888,956	2,000	0.0022	0.9978	93.01
35.5	886,956	4,412	0.0050	0.9950	92.81
36.5	825,728	610	0.0007	0.9993	92.34
37.5	844,445	15,778	0.0187	0.9813	92.28
38.5	826,762		0.0000	1.0000	90.55

NEWFOUNDLAND POWER INC.

ACCOUNT 321.00 - ROADS, TRAILS, AND BRIDGES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2009			EXPERIENCE BAND 1948-2009		
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	826,762	23,912	0.0289	0.9711	90.55
40.5	801,635	15,530	0.0194	0.9806	87.93
41.5	787,320		0.0000	1.0000	86.23
42.5	787,320	95,916	0.1218	0.8782	86.23
43.5	690,663		0.0000	1.0000	75.72
44.5	690,663	251	0.0004	0.9996	75.72
45.5	687,801	10,316	0.0150	0.9850	75.70
46.5	591,473	2,000	0.0034	0.9966	74.56
47.5	589,473		0.0000	1.0000	74.31
48.5	589,473		0.0000	1.0000	74.31
49.5	587,826		0.0000	1.0000	74.31
50.5	498,480	15,000	0.0301	0.9699	74.31
51.5	442,500		0.0000	1.0000	72.07
52.5	431,218		0.0000	1.0000	72.07
53.5	410,818	30,517	0.0743	0.9257	72.07
54.5	346,473	4,100	0.0118	0.9882	66.72
55.5	230,946	990	0.0043	0.9957	65.93
56.5	194,073		0.0000	1.0000	65.65
57.5	160,417		0.0000	1.0000	65.65
58.5	153,875		0.0000	1.0000	65.65
59.5	168,875		0.0000	1.0000	65.65
60.5	168,875		0.0000	1.0000	65.65
61.5	160,788		0.0000	1.0000	65.65
62.5	191,305		0.0000	1.0000	65.65
63.5	148,995		0.0000	1.0000	65.65
64.5	152,980		0.0000	1.0000	65.65
65.5	152,980		0.0000	1.0000	65.65
66.5	112,360		0.0000	1.0000	65.65
67.5	101,929		0.0000	1.0000	65.65
68.5	74,679	1,500	0.0201	0.9799	65.65
69.5	73,179		0.0000	1.0000	64.33
70.5	73,179		0.0000	1.0000	64.33
71.5	71,679		0.0000	1.0000	64.33
72.5	71,679		0.0000	1.0000	64.33
73.5	71,679		0.0000	1.0000	64.33
74.5	84,721		0.0000	1.0000	64.33
75.5	84,721		0.0000	1.0000	64.33
76.5	84,721		0.0000	1.0000	64.33
77.5	86,221		0.0000	1.0000	64.33
78.5	52,934		0.0000	1.0000	64.33

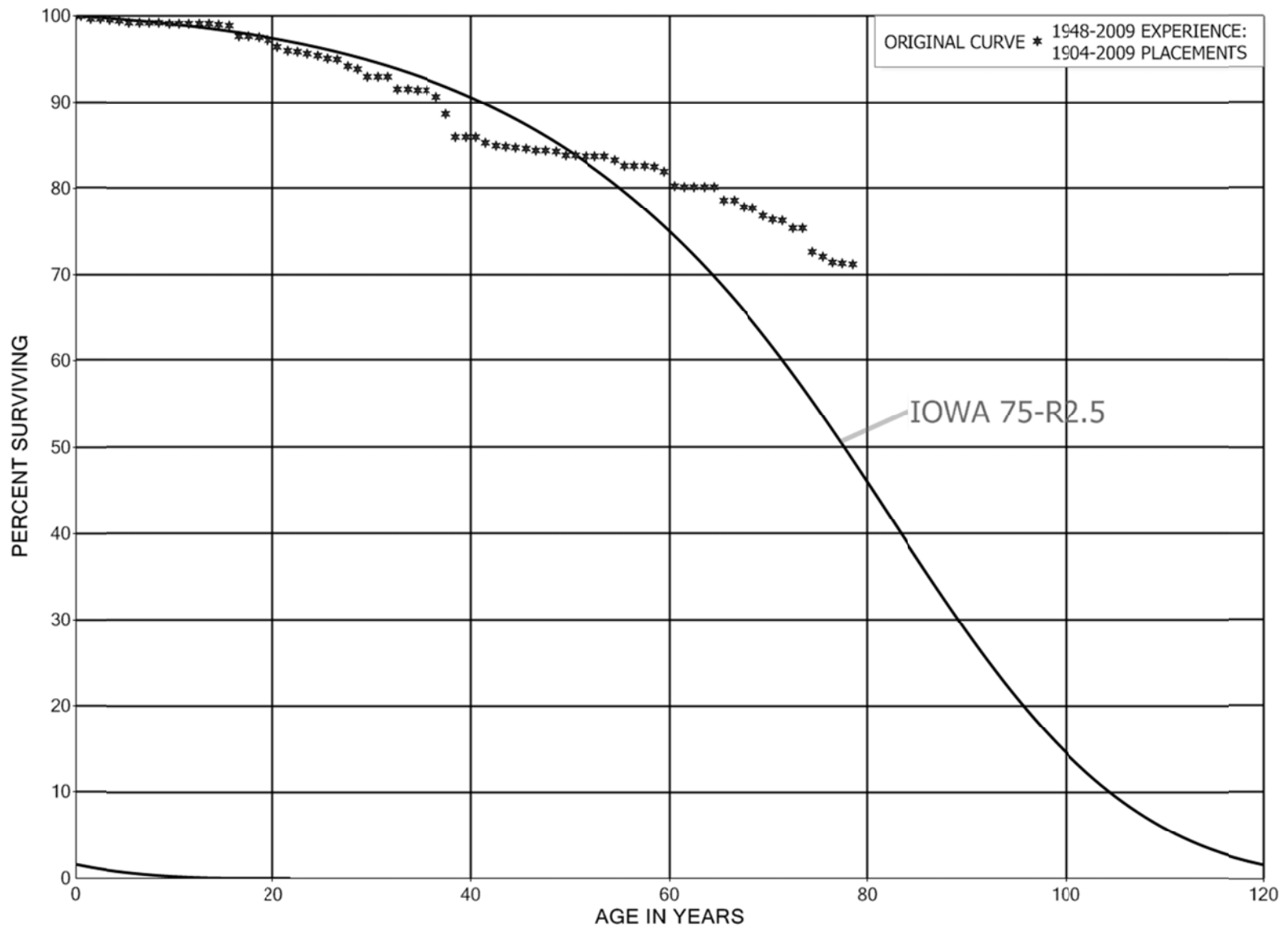
NEWFOUNDLAND POWER INC.

ACCOUNT 321.00 - ROADS, TRAILS, AND BRIDGES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2009			EXPERIENCE BAND 1948-2009		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	52,934		0.0000	1.0000	64.33
80.5	52,934		0.0000	1.0000	64.33
81.5	34,107		0.0000	1.0000	64.33
82.5	4,370		0.0000	1.0000	64.33
83.5	4,370		0.0000	1.0000	64.33
84.5	4,370		0.0000	1.0000	64.33
85.5					64.33

NEWFOUNDLAND POWER INC.
ACCOUNT 322.00 - BUILDINGS AND STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 322.00 - BUILDINGS AND STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2009

EXPERIENCE BAND 1948-2009

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	4,782,781		0.0000	1.0000	100.00
0.5	4,607,316	17,199	0.0037	0.9963	100.00
1.5	4,271,378	648	0.0002	0.9998	99.63
2.5	4,039,849	3,970	0.0010	0.9990	99.61
3.5	3,826,645	2,702	0.0007	0.9993	99.51
4.5	3,814,731	8,977	0.0024	0.9976	99.44
5.5	3,753,487	1,200	0.0003	0.9997	99.21
6.5	3,924,854	741	0.0002	0.9998	99.18
7.5	5,534,076		0.0000	1.0000	99.16
8.5	5,526,859	5,159	0.0009	0.9991	99.16
9.5	5,208,218	108	0.0000	1.0000	99.07
10.5	5,172,870	500	0.0001	0.9999	99.06
11.5	3,482,761	75	0.0000	1.0000	99.05
12.5	3,482,686		0.0000	1.0000	99.05
13.5	3,490,273	4,245	0.0012	0.9988	99.05
14.5	3,457,516	4,571	0.0013	0.9987	98.93
15.5	3,416,179	40,147	0.0118	0.9882	98.80
16.5	3,475,591	308	0.0001	0.9999	97.64
17.5	3,398,404	3,095	0.0009	0.9991	97.63
18.5	3,356,704	13,791	0.0041	0.9959	97.54
19.5	3,740,877	27,227	0.0073	0.9927	97.14
20.5	3,697,588	17,144	0.0046	0.9954	96.43
21.5	3,305,982	4,221	0.0013	0.9987	95.99
22.5	3,309,110	9,426	0.0028	0.9972	95.87
23.5	3,460,096	6,500	0.0019	0.9981	95.59
24.5	3,374,005	11,535	0.0034	0.9966	95.41
25.5	3,137,930	5,008	0.0016	0.9984	95.09
26.5	2,414,802	20,368	0.0084	0.9916	94.93
27.5	2,605,031	7,146	0.0027	0.9973	94.13
28.5	2,524,945	23,318	0.0092	0.9908	93.88
29.5	2,249,328	2,227	0.0010	0.9990	93.01
30.5	2,215,777	362	0.0002	0.9998	92.92
31.5	2,160,789	32,360	0.0150	0.9850	92.90
32.5	2,099,620	723	0.0003	0.9997	91.51
33.5	2,126,040	1,992	0.0009	0.9991	91.48
34.5	2,116,083	50	0.0000	1.0000	91.39
35.5	2,112,504	17,040	0.0081	0.9919	91.39
36.5	2,119,464	47,705	0.0225	0.9775	90.65
37.5	2,068,511	61,269	0.0296	0.9704	88.61
38.5	2,007,242	200	0.0001	0.9999	85.99

NEWFOUNDLAND POWER INC.

ACCOUNT 322.00 - BUILDINGS AND STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2009			EXPERIENCE BAND 1948-2009		
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	2,006,147		0.0000	1.0000	85.98
40.5	2,006,647	17,350	0.0086	0.9914	85.98
41.5	1,988,457	6,250	0.0031	0.9969	85.24
42.5	2,045,386	2,950	0.0014	0.9986	84.97
43.5	2,059,521	2,942	0.0014	0.9986	84.85
44.5	2,059,749	3,500	0.0017	0.9983	84.72
45.5	2,000,998	4,100	0.0020	0.9980	84.58
46.5	1,896,226	735	0.0004	0.9996	84.41
47.5	1,894,070	2,700	0.0014	0.9986	84.37
48.5	1,918,077	9,100	0.0047	0.9953	84.25
49.5	1,906,547		0.0000	1.0000	83.85
50.5	1,426,481	3,000	0.0021	0.9979	83.85
51.5	1,341,438		0.0000	1.0000	83.68
52.5	1,196,665		0.0000	1.0000	83.68
53.5	1,107,465	5,057	0.0046	0.9954	83.68
54.5	1,102,408	8,840	0.0080	0.9920	83.30
55.5	791,336		0.0000	1.0000	82.63
56.5	791,336		0.0000	1.0000	82.63
57.5	791,336	1,500	0.0019	0.9981	82.63
58.5	690,004	4,138	0.0060	0.9940	82.47
59.5	690,266	13,982	0.0203	0.9797	81.98
60.5	676,284	1,027	0.0015	0.9985	80.32
61.5	697,157		0.0000	1.0000	80.19
62.5	697,157		0.0000	1.0000	80.19
63.5	638,847	300	0.0005	0.9995	80.19
64.5	638,133	12,541	0.0197	0.9803	80.16
65.5	625,092		0.0000	1.0000	78.58
66.5	613,392	5,400	0.0088	0.9912	78.58
67.5	597,742	1,000	0.0017	0.9983	77.89
68.5	418,780	4,858	0.0116	0.9884	77.76
69.5	413,922	2,300	0.0056	0.9944	76.86
70.5	411,622	1,000	0.0024	0.9976	76.43
71.5	410,622	4,700	0.0114	0.9886	76.24
72.5	405,256		0.0000	1.0000	75.37
73.5	408,225	14,940	0.0366	0.9634	75.37
74.5	388,285	2,760	0.0071	0.9929	72.61
75.5	385,525	4,000	0.0104	0.9896	72.10
76.5	381,525	500	0.0013	0.9987	71.35
77.5	366,805	500	0.0014	0.9986	71.26
78.5	288,883		0.0000	1.0000	71.16

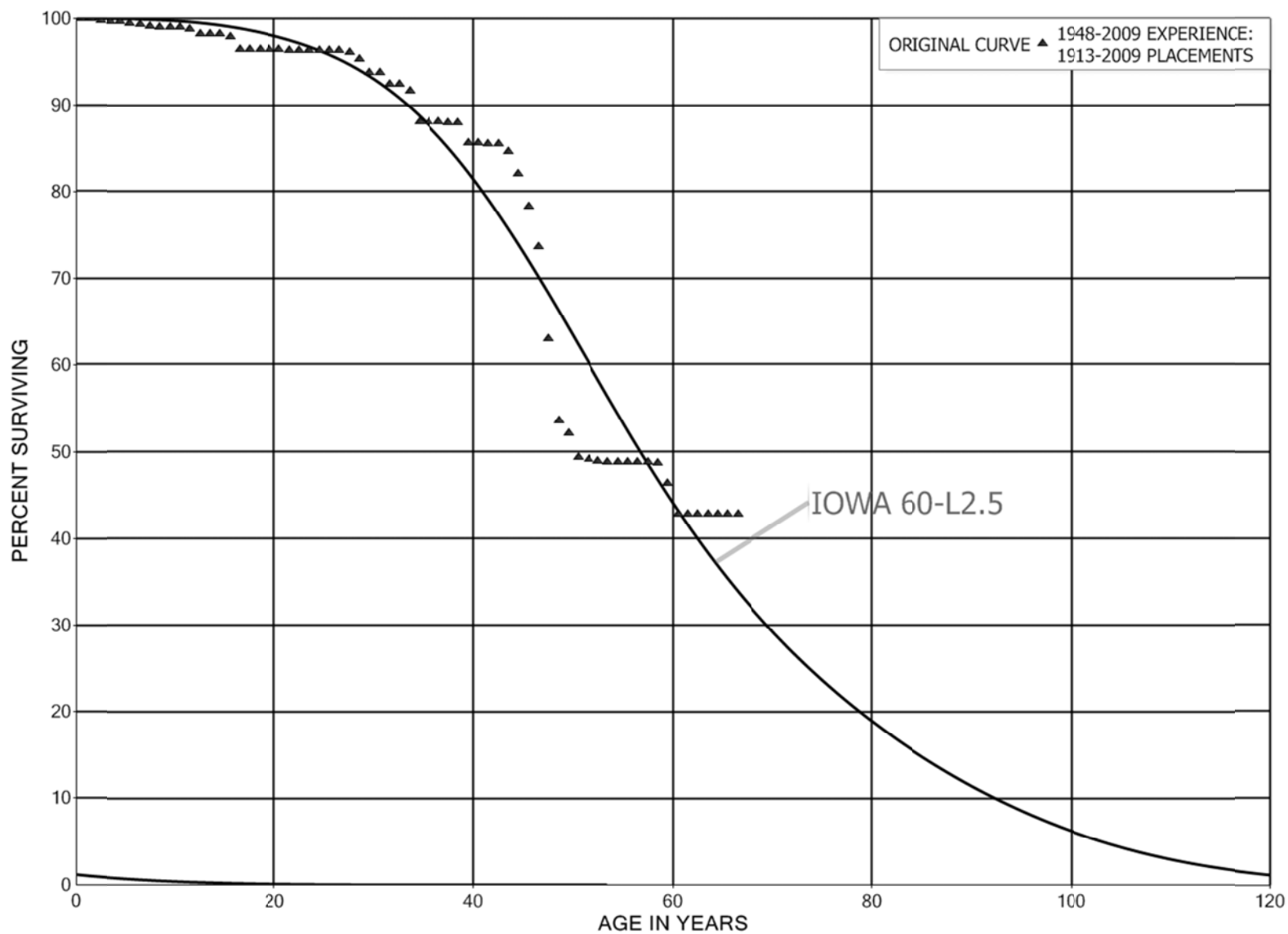
NEWFOUNDLAND POWER INC.

ACCOUNT 322.00 - BUILDINGS AND STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2009			EXPERIENCE BAND 1948-2009		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	288,883		0.0000	1.0000	71.16
80.5	272,383		0.0000	1.0000	71.16
81.5	272,383		0.0000	1.0000	71.16
82.5	272,383		0.0000	1.0000	71.16
83.5	272,383		0.0000	1.0000	71.16
84.5	272,383	500	0.0018	0.9982	71.16
85.5	85,570		0.0000	1.0000	71.03
86.5	40,650		0.0000	1.0000	71.03
87.5	40,650		0.0000	1.0000	71.03
88.5	34,639		0.0000	1.0000	71.03
89.5	34,639		0.0000	1.0000	71.03
90.5	34,639		0.0000	1.0000	71.03
91.5	34,639		0.0000	1.0000	71.03
92.5	16,500		0.0000	1.0000	71.03
93.5	16,500		0.0000	1.0000	71.03
94.5	16,500		0.0000	1.0000	71.03
95.5	16,500		0.0000	1.0000	71.03
96.5	16,500		0.0000	1.0000	71.03
97.5	16,500	1,000	0.0606	0.9394	71.03
98.5	15,500		0.0000	1.0000	66.72
99.5	15,500		0.0000	1.0000	66.72
100.5	15,500		0.0000	1.0000	66.72
101.5	15,500		0.0000	1.0000	66.72
102.5	15,500		0.0000	1.0000	66.72
103.5	15,500		0.0000	1.0000	66.72
104.5	15,500		0.0000	1.0000	66.72
105.5					66.72

NEWFOUNDLAND POWER INC.
ACCOUNT 323.00 - CANALS, PENSTOCKS, SURGE TANKS, & TAILRACES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 323.00 - CANALS, PENSTOCKS, SURGE TANKS,& TAILRACES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2009

EXPERIENCE BAND 1948-2009

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	69,258,740		0.0000	1.0000	100.00
0.5	65,370,422	31,906	0.0005	0.9995	100.00
1.5	65,177,987	167,543	0.0026	0.9974	99.95
2.5	51,918,118	45,818	0.0009	0.9991	99.69
3.5	50,840,482		0.0000	1.0000	99.61
4.5	51,214,599	96,939	0.0019	0.9981	99.61
5.5	47,737,933	53,735	0.0011	0.9989	99.42
6.5	47,304,758	125,000	0.0026	0.9974	99.31
7.5	34,312,079	28,399	0.0008	0.9992	99.04
8.5	32,959,042		0.0000	1.0000	98.96
9.5	30,029,521		0.0000	1.0000	98.96
10.5	25,418,523	52,793	0.0021	0.9979	98.96
11.5	22,137,129	139,426	0.0063	0.9937	98.76
12.5	22,068,638		0.0000	1.0000	98.13
13.5	22,532,769	2,534	0.0001	0.9999	98.13
14.5	22,495,012	74,904	0.0033	0.9967	98.12
15.5	22,419,361	316,329	0.0141	0.9859	97.80
16.5	22,341,988		0.0000	1.0000	96.42
17.5	21,822,672	10,983	0.0005	0.9995	96.42
18.5	21,174,827	4,122	0.0002	0.9998	96.37
19.5	18,292,389		0.0000	1.0000	96.35
20.5	16,293,591	2,000	0.0001	0.9999	96.35
21.5	16,291,591		0.0000	1.0000	96.34
22.5	15,359,301	5,790	0.0004	0.9996	96.34
23.5	15,700,937		0.0000	1.0000	96.30
24.5	13,711,279		0.0000	1.0000	96.30
25.5	13,135,152	2,166	0.0002	0.9998	96.30
26.5	12,243,278	21,751	0.0018	0.9982	96.28
27.5	12,221,527	98,896	0.0081	0.9919	96.11
28.5	9,806,610	162,400	0.0166	0.9834	95.34
29.5	9,557,382		0.0000	1.0000	93.76
30.5	9,039,340	134,900	0.0149	0.9851	93.76
31.5	8,895,123		0.0000	1.0000	92.36
32.5	8,907,823	75,213	0.0084	0.9916	92.36
33.5	8,957,740	342,275	0.0382	0.9618	91.58
34.5	8,586,561		0.0000	1.0000	88.08
35.5	8,464,106	135	0.0000	1.0000	88.08
36.5	8,463,971	11,588	0.0014	0.9986	88.08
37.5	8,452,383		0.0000	1.0000	87.96
38.5	8,452,383	225,183	0.0266	0.9734	87.96

NEWFOUNDLAND POWER INC.

ACCOUNT 323.00 - CANALS, PENSTOCKS, SURGE TANKS,& TAILRACES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2009

EXPERIENCE BAND 1948-2009

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	8,226,258	472	0.0001	0.9999	85.61
40.5	8,225,786	5,832	0.0007	0.9993	85.61
41.5	8,238,354	1,834	0.0002	0.9998	85.55
42.5	8,252,691	84,060	0.0102	0.9898	85.53
43.5	8,168,631	251,039	0.0307	0.9693	84.66
44.5	7,232,823	336,074	0.0465	0.9535	82.06
45.5	6,895,172	411,103	0.0596	0.9404	78.24
46.5	5,990,929	864,201	0.1443	0.8557	73.58
47.5	5,124,728	768,679	0.1500	0.8500	62.96
48.5	4,392,643	123,646	0.0281	0.9719	53.52
49.5	4,268,090	219,900	0.0515	0.9485	52.01
50.5	3,163,317	19,078	0.0060	0.9940	49.33
51.5	3,009,528	13,350	0.0044	0.9956	49.04
52.5	3,005,254	4,000	0.0013	0.9987	48.82
53.5	2,654,966	500	0.0002	0.9998	48.75
54.5	2,802,921		0.0000	1.0000	48.74
55.5	1,939,605	1,910	0.0010	0.9990	48.74
56.5	1,887,196		0.0000	1.0000	48.70
57.5	1,979,674	1,600	0.0008	0.9992	48.70
58.5	1,388,737	68,137	0.0491	0.9509	48.66
59.5	1,311,710	100,283	0.0765	0.9235	46.27
60.5	1,211,427		0.0000	1.0000	42.73
61.5	1,028,604	500	0.0005	0.9995	42.73
62.5	1,029,647		0.0000	1.0000	42.71
63.5	943,447		0.0000	1.0000	42.71
64.5	938,682		0.0000	1.0000	42.71
65.5	938,682		0.0000	1.0000	42.71
66.5	656,439	7,518	0.0115	0.9885	42.71
67.5	559,831	157,270	0.2809	0.7191	42.22
68.5	299,675	5,000	0.0167	0.9833	30.36
69.5	294,675		0.0000	1.0000	29.85
70.5	294,675	1,475	0.0050	0.9950	29.85
71.5	293,200		0.0000	1.0000	29.71
72.5	292,816		0.0000	1.0000	29.71
73.5	297,816	1,345	0.0045	0.9955	29.71
74.5	281,129	19,208	0.0683	0.9317	29.57
75.5	248,467		0.0000	1.0000	27.55
76.5	247,197		0.0000	1.0000	27.55
77.5	240,693	9,000	0.0374	0.9626	27.55
78.5	142,673		0.0000	1.0000	26.52

NEWFOUNDLAND POWER INC.

ACCOUNT 323.00 - CANALS, PENSTOCKS, SURGE TANKS,& TAILRACES

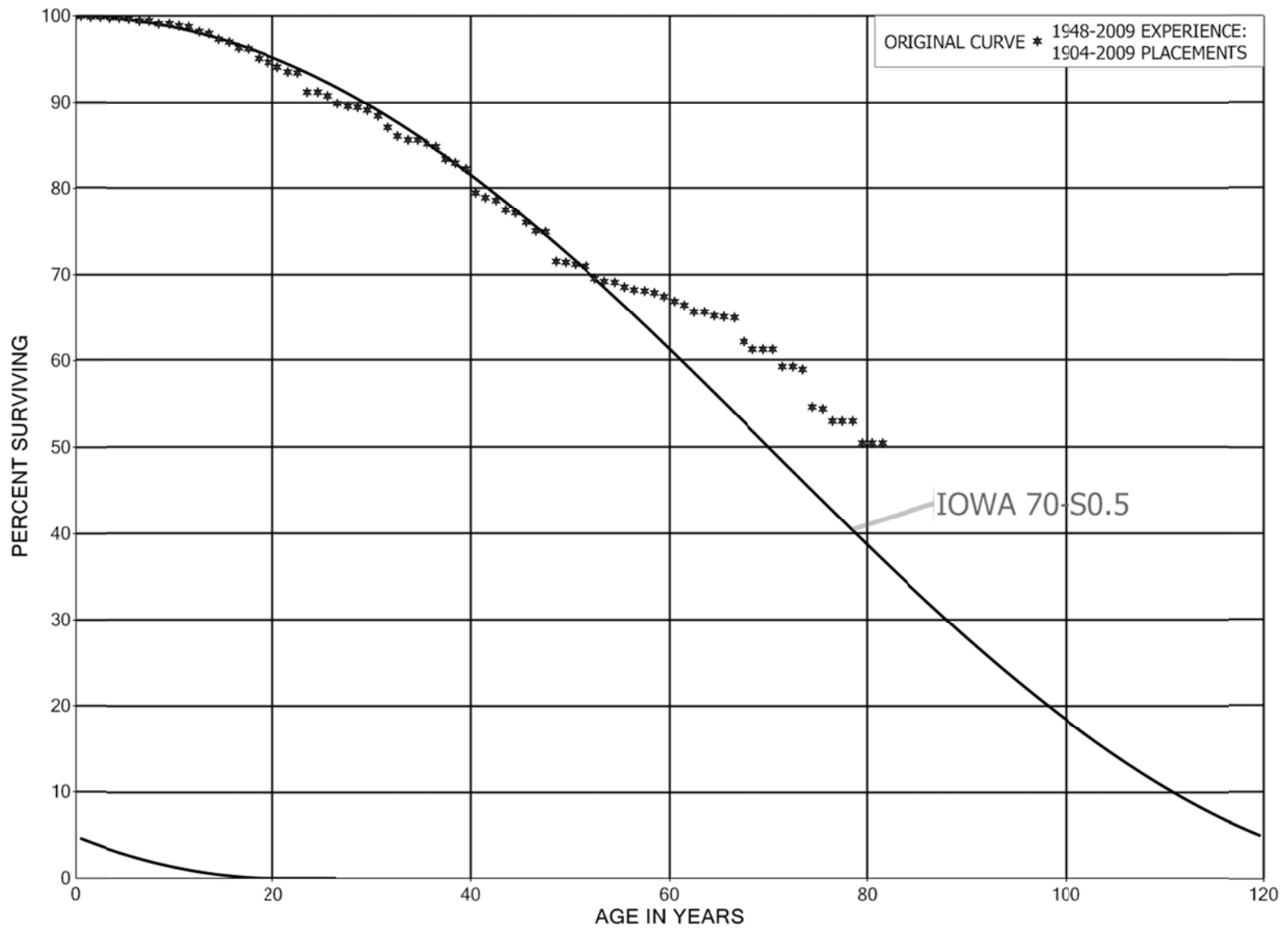
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2009

EXPERIENCE BAND 1948-2009

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	135,751		0.0000	1.0000	26.52
80.5	135,751		0.0000	1.0000	26.52
81.5	135,751		0.0000	1.0000	26.52
82.5	135,751		0.0000	1.0000	26.52
83.5	135,751		0.0000	1.0000	26.52
84.5	135,751		0.0000	1.0000	26.52
85.5	74,726	9,750	0.1305	0.8695	26.52
86.5	64,976		0.0000	1.0000	23.06
87.5	64,976		0.0000	1.0000	23.06
88.5	64,976		0.0000	1.0000	23.06
89.5	62,576		0.0000	1.0000	23.06
90.5	62,576		0.0000	1.0000	23.06
91.5	62,576		0.0000	1.0000	23.06
92.5	33,500		0.0000	1.0000	23.06
93.5	33,500		0.0000	1.0000	23.06
94.5	33,500		0.0000	1.0000	23.06
95.5	33,500		0.0000	1.0000	23.06
96.5					23.06

NEWFOUNDLAND POWER INC.
ACCOUNT 324.00 - DAMS AND RESERVOIRS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 324.00 - DAMS AND RESERVOIRS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2009

EXPERIENCE BAND 1948-2009

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	25,002,465		0.0000	1.0000	100.00
0.5	23,891,323	43,298	0.0018	0.9982	100.00
1.5	22,611,429	1,259	0.0001	0.9999	99.82
2.5	21,865,541	8,892	0.0004	0.9996	99.81
3.5	20,909,388		0.0000	1.0000	99.77
4.5	20,514,064	38,079	0.0019	0.9981	99.77
5.5	20,271,319	40,000	0.0020	0.9980	99.59
6.5	19,855,389		0.0000	1.0000	99.39
7.5	24,123,562	89,175	0.0037	0.9963	99.39
8.5	24,602,496		0.0000	1.0000	99.02
9.5	24,427,637	44,252	0.0018	0.9982	99.02
10.5	22,946,845	26,858	0.0012	0.9988	98.84
11.5	18,369,423	105,127	0.0057	0.9943	98.73
12.5	17,922,043	42,914	0.0024	0.9976	98.16
13.5	17,174,379	108,762	0.0063	0.9937	97.93
14.5	14,981,244	53,822	0.0036	0.9964	97.31
15.5	14,321,441	106,132	0.0074	0.9926	96.96
16.5	14,014,376	12,379	0.0009	0.9991	96.24
17.5	12,230,430	136,715	0.0112	0.9888	96.16
18.5	12,236,157	55,676	0.0046	0.9954	95.08
19.5	11,950,137	68,076	0.0057	0.9943	94.65
20.5	11,237,473	71,683	0.0064	0.9936	94.11
21.5	10,806,987	10,976	0.0010	0.9990	93.51
22.5	10,593,252	249,215	0.0235	0.9765	93.41
23.5	10,183,213	8,886	0.0009	0.9991	91.22
24.5	9,881,550	41,079	0.0042	0.9958	91.14
25.5	9,456,195	90,904	0.0096	0.9904	90.76
26.5	8,854,250	42,525	0.0048	0.9952	89.88
27.5	7,569,209	3,000	0.0004	0.9996	89.45
28.5	7,371,695	29,533	0.0040	0.9960	89.42
29.5	7,061,627	49,977	0.0071	0.9929	89.06
30.5	7,034,309	107,000	0.0152	0.9848	88.43
31.5	6,870,018	76,789	0.0112	0.9888	87.08
32.5	6,814,058	38,143	0.0056	0.9944	86.11
33.5	6,813,634	899	0.0001	0.9999	85.63
34.5	6,926,410	38,247	0.0055	0.9945	85.62
35.5	6,888,176	24,696	0.0036	0.9964	85.14
36.5	6,967,515	122,201	0.0175	0.9825	84.84
37.5	6,942,862	38,151	0.0055	0.9945	83.35
38.5	6,896,481	53,112	0.0077	0.9923	82.89

NEWFOUNDLAND POWER INC.

ACCOUNT 324.00 - DAMS AND RESERVOIRS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2009			EXPERIENCE BAND 1948-2009		
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	6,843,356	232,641	0.0340	0.9660	82.25
40.5	6,610,715	46,902	0.0071	0.9929	79.46
41.5	6,548,046	26,507	0.0040	0.9960	78.89
42.5	6,538,951	87,945	0.0134	0.9866	78.58
43.5	6,396,719	28,365	0.0044	0.9956	77.52
44.5	6,359,864	90,322	0.0142	0.9858	77.17
45.5	6,232,211	86,444	0.0139	0.9861	76.08
46.5	5,671,349	6,958	0.0012	0.9988	75.02
47.5	5,641,997	256,764	0.0455	0.9545	74.93
48.5	5,402,590	6,543	0.0012	0.9988	71.52
49.5	5,431,095	20,500	0.0038	0.9962	71.43
50.5	4,508,941	10,123	0.0022	0.9978	71.17
51.5	4,500,861	95,570	0.0212	0.9788	71.01
52.5	3,409,973	16,510	0.0048	0.9952	69.50
53.5	3,007,328	5,730	0.0019	0.9981	69.16
54.5	2,988,292	21,690	0.0073	0.9927	69.03
55.5	2,113,531	12,157	0.0058	0.9942	68.53
56.5	1,838,102	2,455	0.0013	0.9987	68.13
57.5	1,840,173	7,071	0.0038	0.9962	68.04
58.5	1,772,511	8,800	0.0050	0.9950	67.78
59.5	1,766,592	15,757	0.0089	0.9911	67.45
60.5	1,750,835	10,480	0.0060	0.9940	66.84
61.5	1,688,246	21,000	0.0124	0.9876	66.44
62.5	1,673,253		0.0000	1.0000	65.62
63.5	1,590,919	10,000	0.0063	0.9937	65.62
64.5	1,592,753	3,824	0.0024	0.9976	65.20
65.5	1,431,044	922	0.0006	0.9994	65.05
66.5	1,237,959	54,908	0.0444	0.9556	65.01
67.5	1,140,551	14,634	0.0128	0.9872	62.12
68.5	911,212	1,160	0.0013	0.9987	61.33
69.5	908,172		0.0000	1.0000	61.25
70.5	906,672	28,835	0.0318	0.9682	61.25
71.5	877,837		0.0000	1.0000	59.30
72.5	784,608	5,000	0.0064	0.9936	59.30
73.5	779,608	56,725	0.0728	0.9272	58.92
74.5	722,083	2,520	0.0035	0.9965	54.63
75.5	719,563	19,412	0.0270	0.9730	54.44
76.5	700,151	550	0.0008	0.9992	52.98
77.5	697,324		0.0000	1.0000	52.93
78.5	412,343	20,017	0.0485	0.9515	52.93

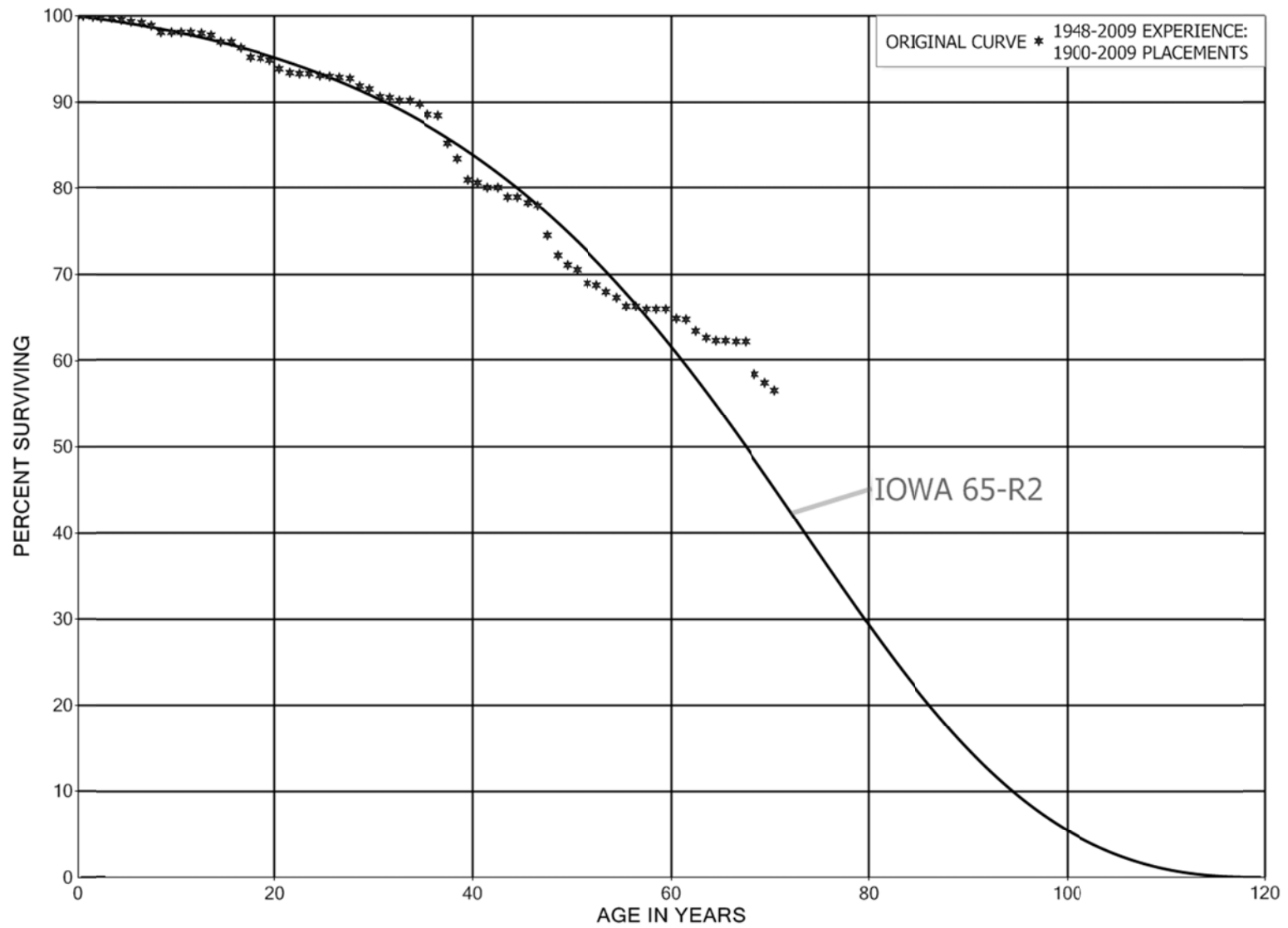
NEWFOUNDLAND POWER INC.

ACCOUNT 324.00 - DAMS AND RESERVOIRS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2009			EXPERIENCE BAND 1948-2009		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	392,326		0.0000	1.0000	50.36
80.5	306,979		0.0000	1.0000	50.36
81.5	242,769		0.0000	1.0000	50.36
82.5	242,769		0.0000	1.0000	50.36
83.5	242,769		0.0000	1.0000	50.36
84.5	242,769		0.0000	1.0000	50.36
85.5	86,579		0.0000	1.0000	50.36
86.5	86,579		0.0000	1.0000	50.36
87.5	86,579	922	0.0106	0.9894	50.36
88.5	60,218		0.0000	1.0000	49.83
89.5	46,670	17,314	0.3710	0.6290	49.83
90.5	29,356		0.0000	1.0000	31.34
91.5	29,356		0.0000	1.0000	31.34
92.5	22,000		0.0000	1.0000	31.34
93.5	22,000		0.0000	1.0000	31.34
94.5	22,000		0.0000	1.0000	31.34
95.5	22,000		0.0000	1.0000	31.34
96.5	22,000		0.0000	1.0000	31.34
97.5	22,000		0.0000	1.0000	31.34
98.5	22,000		0.0000	1.0000	31.34
99.5	22,000		0.0000	1.0000	31.34
100.5	22,000		0.0000	1.0000	31.34
101.5	22,000		0.0000	1.0000	31.34
102.5	22,000		0.0000	1.0000	31.34
103.5	22,000		0.0000	1.0000	31.34
104.5	22,000		0.0000	1.0000	31.34
105.5					31.34

NEWFOUNDLAND POWER INC.
ACCOUNT 325.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 325.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2009

EXPERIENCE BAND 1948-2009

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	31,713,923	34,600	0.0011	0.9989	100.00
0.5	28,942,888	19,417	0.0007	0.9993	99.89
1.5	27,293,640	32,026	0.0012	0.9988	99.82
2.5	23,737,328	4,306	0.0002	0.9998	99.71
3.5	22,167,510	39,741	0.0018	0.9982	99.69
4.5	21,464,004	52,446	0.0024	0.9976	99.51
5.5	19,617,155	18,140	0.0009	0.9991	99.27
6.5	18,823,873	66,192	0.0035	0.9965	99.18
7.5	21,196,930	159,880	0.0075	0.9925	98.83
8.5	20,354,419	200	0.0000	1.0000	98.08
9.5	20,041,669	11,150	0.0006	0.9994	98.08
10.5	19,119,743		0.0000	1.0000	98.03
11.5	15,869,281	20,228	0.0013	0.9987	98.03
12.5	14,878,951	20,000	0.0013	0.9987	97.90
13.5	13,977,705	108,824	0.0078	0.9922	97.77
14.5	13,683,630	2,717	0.0002	0.9998	97.01
15.5	13,378,787	95,296	0.0071	0.9929	96.99
16.5	13,286,405	157,559	0.0119	0.9881	96.30
17.5	13,008,950	15,309	0.0012	0.9988	95.16
18.5	12,823,022	24,661	0.0019	0.9981	95.04
19.5	12,138,662	128,821	0.0106	0.9894	94.86
20.5	11,955,998	62,075	0.0052	0.9948	93.85
21.5	11,693,038	13,952	0.0012	0.9988	93.37
22.5	11,393,377		0.0000	1.0000	93.26
23.5	9,467,862	14,525	0.0015	0.9985	93.26
24.5	8,958,496	19,070	0.0021	0.9979	93.11
25.5	7,762,683	6,000	0.0008	0.9992	92.91
26.5	5,159,492	7,500	0.0015	0.9985	92.84
27.5	5,060,832	49,000	0.0097	0.9903	92.71
28.5	5,035,713	15,141	0.0030	0.9970	91.81
29.5	4,667,224	48,882	0.0105	0.9895	91.53
30.5	4,541,275	1,500	0.0003	0.9997	90.58
31.5	4,536,419	16,500	0.0036	0.9964	90.55
32.5	4,467,469	1,500	0.0003	0.9997	90.22
33.5	4,572,818	23,597	0.0052	0.9948	90.19
34.5	4,536,439	60,930	0.0134	0.9866	89.72
35.5	4,508,580	5,872	0.0013	0.9987	88.52
36.5	4,502,695	161,580	0.0359	0.9641	88.40
37.5	4,410,382	93,635	0.0212	0.9788	85.23
38.5	4,307,983	125,150	0.0291	0.9709	83.42

NEWFOUNDLAND POWER INC.

ACCOUNT 325.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2009			EXPERIENCE BAND 1948-2009		
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	4,072,600	17,100	0.0042	0.9958	80.99
40.5	4,124,528	29,600	0.0072	0.9928	80.65
41.5	4,268,391	1,500	0.0004	0.9996	80.08
42.5	4,232,824	56,282	0.0133	0.9867	80.05
43.5	4,172,304	2,522	0.0006	0.9994	78.98
44.5	4,161,725	36,068	0.0087	0.9913	78.94
45.5	4,125,071	15,744	0.0038	0.9962	78.25
46.5	3,656,625	163,554	0.0447	0.9553	77.95
47.5	3,808,316	115,370	0.0303	0.9697	74.47
48.5	3,731,447	61,740	0.0165	0.9835	72.21
49.5	3,661,430	25,777	0.0070	0.9930	71.02
50.5	2,768,035	60,304	0.0218	0.9782	70.52
51.5	2,616,031	7,778	0.0030	0.9970	68.98
52.5	2,499,662	30,081	0.0120	0.9880	68.77
53.5	2,368,981	22,079	0.0093	0.9907	67.95
54.5	2,346,902	36,000	0.0153	0.9847	67.31
55.5	1,851,610		0.0000	1.0000	66.28
56.5	1,850,714	8,100	0.0044	0.9956	66.28
57.5	1,842,421		0.0000	1.0000	65.99
58.5	1,560,534	1,000	0.0006	0.9994	65.99
59.5	1,559,534	27,400	0.0176	0.9824	65.95
60.5	1,532,134	400	0.0003	0.9997	64.79
61.5	1,531,734	33,540	0.0219	0.9781	64.77
62.5	1,498,194	17,648	0.0118	0.9882	63.35
63.5	1,480,546	7,000	0.0047	0.9953	62.61
64.5	1,473,046		0.0000	1.0000	62.31
65.5	1,473,046	2,000	0.0014	0.9986	62.31
66.5	1,473,046		0.0000	1.0000	62.23
67.5	1,428,456	88,000	0.0616	0.9384	62.23
68.5	1,064,421	18,900	0.0178	0.9822	58.39
69.5	1,045,521	15,000	0.0143	0.9857	57.36
70.5	998,489		0.0000	1.0000	56.53
71.5	998,489	200	0.0002	0.9998	56.53
72.5	998,489	2,274	0.0023	0.9977	56.52
73.5	996,215		0.0000	1.0000	56.39
74.5	961,615		0.0000	1.0000	56.39
75.5	961,615	4,548	0.0047	0.9953	56.39
76.5	957,067		0.0000	1.0000	56.13
77.5	957,067		0.0000	1.0000	56.13
78.5	869,286	77,572	0.0892	0.9108	56.13

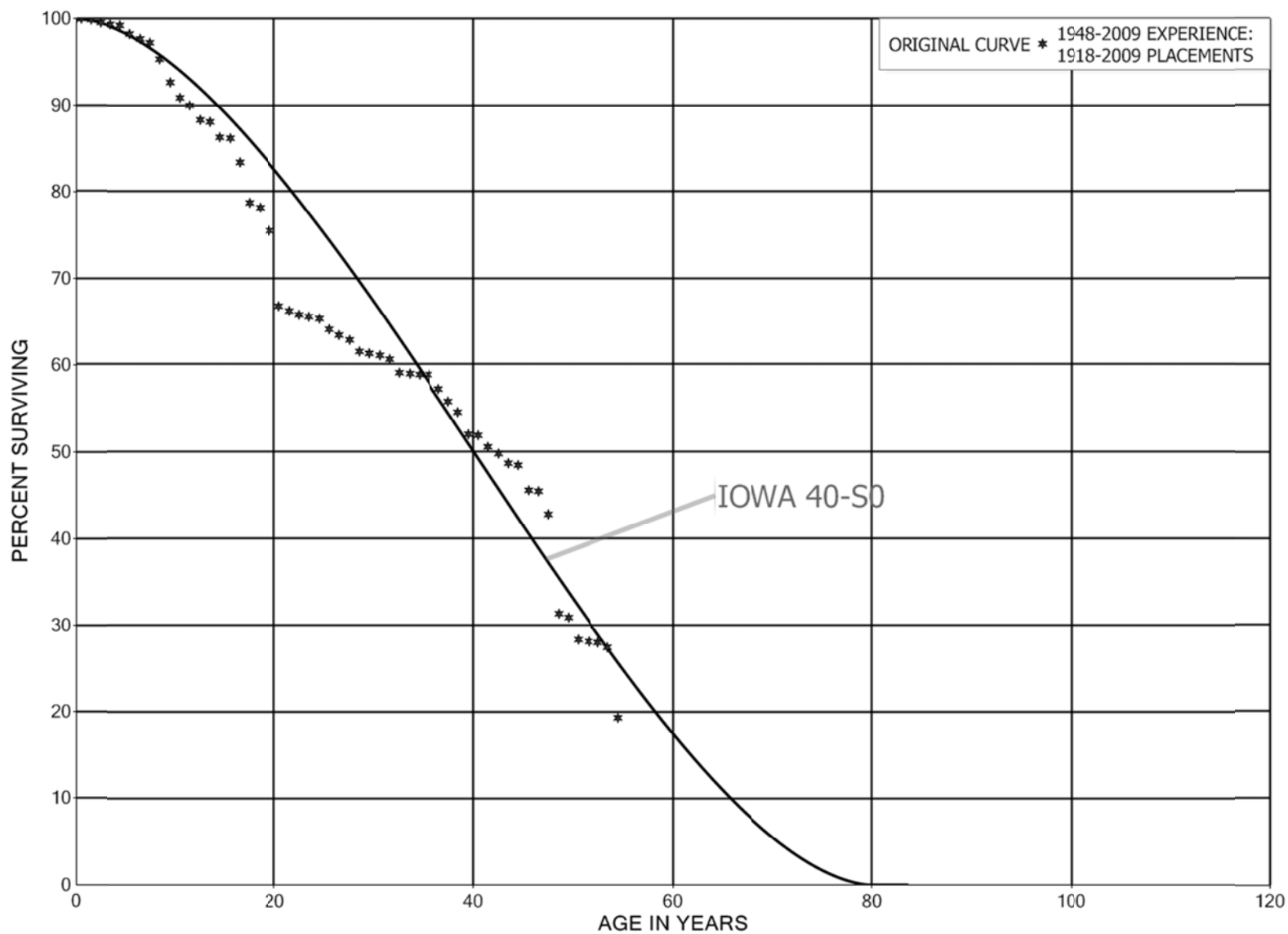
NEWFOUNDLAND POWER INC.

ACCOUNT 325.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2009			EXPERIENCE BAND 1948-2009		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	791,714		0.0000	1.0000	51.12
80.5	791,714		0.0000	1.0000	51.12
81.5	791,714		0.0000	1.0000	51.12
82.5	791,714		0.0000	1.0000	51.12
83.5	791,714		0.0000	1.0000	51.12
84.5	791,714	40,000	0.0505	0.9495	51.12
85.5	583,696		0.0000	1.0000	48.54
86.5	583,696		0.0000	1.0000	48.54
87.5	583,696		0.0000	1.0000	48.54
88.5	583,696		0.0000	1.0000	48.54
89.5	583,696		0.0000	1.0000	48.54
90.5	583,696	382	0.0007	0.9993	48.54
91.5	583,314		0.0000	1.0000	48.50
92.5	521,694	200	0.0004	0.9996	48.50
93.5	521,494		0.0000	1.0000	48.49
94.5	521,494		0.0000	1.0000	48.49
95.5	521,494		0.0000	1.0000	48.49
96.5	495,976		0.0000	1.0000	48.49
97.5	495,976		0.0000	1.0000	48.49
98.5	495,976		0.0000	1.0000	48.49
99.5	429,494		0.0000	1.0000	48.49
100.5	429,494		0.0000	1.0000	48.49
101.5	429,494		0.0000	1.0000	48.49
102.5	417,584		0.0000	1.0000	48.49
103.5	417,584		0.0000	1.0000	48.49
104.5	417,584		0.0000	1.0000	48.49
105.5	417,584		0.0000	1.0000	48.49
106.5					48.49

NEWFOUNDLAND POWER INC.
ACCOUNT 326.00 - SWITCHING, METERING AND CONTROL EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 326.00 - SWITCHING, METERING AND CONTROL EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1918-2009

EXPERIENCE BAND 1948-2009

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	14,628,836		0.0000	1.0000	100.00
0.5	12,555,692	14,928	0.0012	0.9988	100.00
1.5	12,205,837	43,792	0.0036	0.9964	99.88
2.5	11,100,508	23,525	0.0021	0.9979	99.52
3.5	9,581,350	16,711	0.0017	0.9983	99.31
4.5	8,983,056	91,402	0.0102	0.9898	99.14
5.5	7,216,132	38,155	0.0053	0.9947	98.13
6.5	6,675,476	31,328	0.0047	0.9953	97.61
7.5	6,343,559	123,635	0.0195	0.9805	97.15
8.5	5,914,708	161,569	0.0273	0.9727	95.26
9.5	5,702,082	112,335	0.0197	0.9803	92.66
10.5	5,320,623	52,150	0.0098	0.9902	90.83
11.5	5,276,290	98,543	0.0187	0.9813	89.94
12.5	5,118,376	14,137	0.0028	0.9972	88.26
13.5	5,070,629	97,647	0.0193	0.9807	88.02
14.5	4,873,545	7,838	0.0016	0.9984	86.32
15.5	4,790,855	157,972	0.0330	0.9670	86.18
16.5	4,613,929	256,617	0.0556	0.9444	83.34
17.5	4,123,790	28,751	0.0070	0.9930	78.71
18.5	3,812,374	127,696	0.0335	0.9665	78.16
19.5	3,688,106	430,271	0.1167	0.8833	75.54
20.5	3,020,652	27,282	0.0090	0.9910	66.73
21.5	3,219,902	19,500	0.0061	0.9939	66.12
22.5	2,859,787	8,112	0.0028	0.9972	65.72
23.5	2,543,505	8,065	0.0032	0.9968	65.54
24.5	2,495,095	50,286	0.0202	0.9798	65.33
25.5	1,934,196	17,329	0.0090	0.9910	64.01
26.5	1,551,295	13,863	0.0089	0.9911	63.44
27.5	1,523,412	33,585	0.0220	0.9780	62.87
28.5	1,373,962	4,578	0.0033	0.9967	61.49
29.5	1,232,626	4,657	0.0038	0.9962	61.28
30.5	1,218,626	8,465	0.0069	0.9931	61.05
31.5	1,101,601	28,555	0.0259	0.9741	60.63
32.5	881,530	1,516	0.0017	0.9983	59.05
33.5	890,681	1,149	0.0013	0.9987	58.95
34.5	885,794	400	0.0005	0.9995	58.88
35.5	891,358	24,977	0.0280	0.9720	58.85
36.5	858,205	22,715	0.0265	0.9735	57.20
37.5	717,722	14,850	0.0207	0.9793	55.69
38.5	700,771	32,545	0.0464	0.9536	54.54

NEWFOUNDLAND POWER INC.

ACCOUNT 326.00 - SWITCHING, METERING AND CONTROL EQUIPMENT

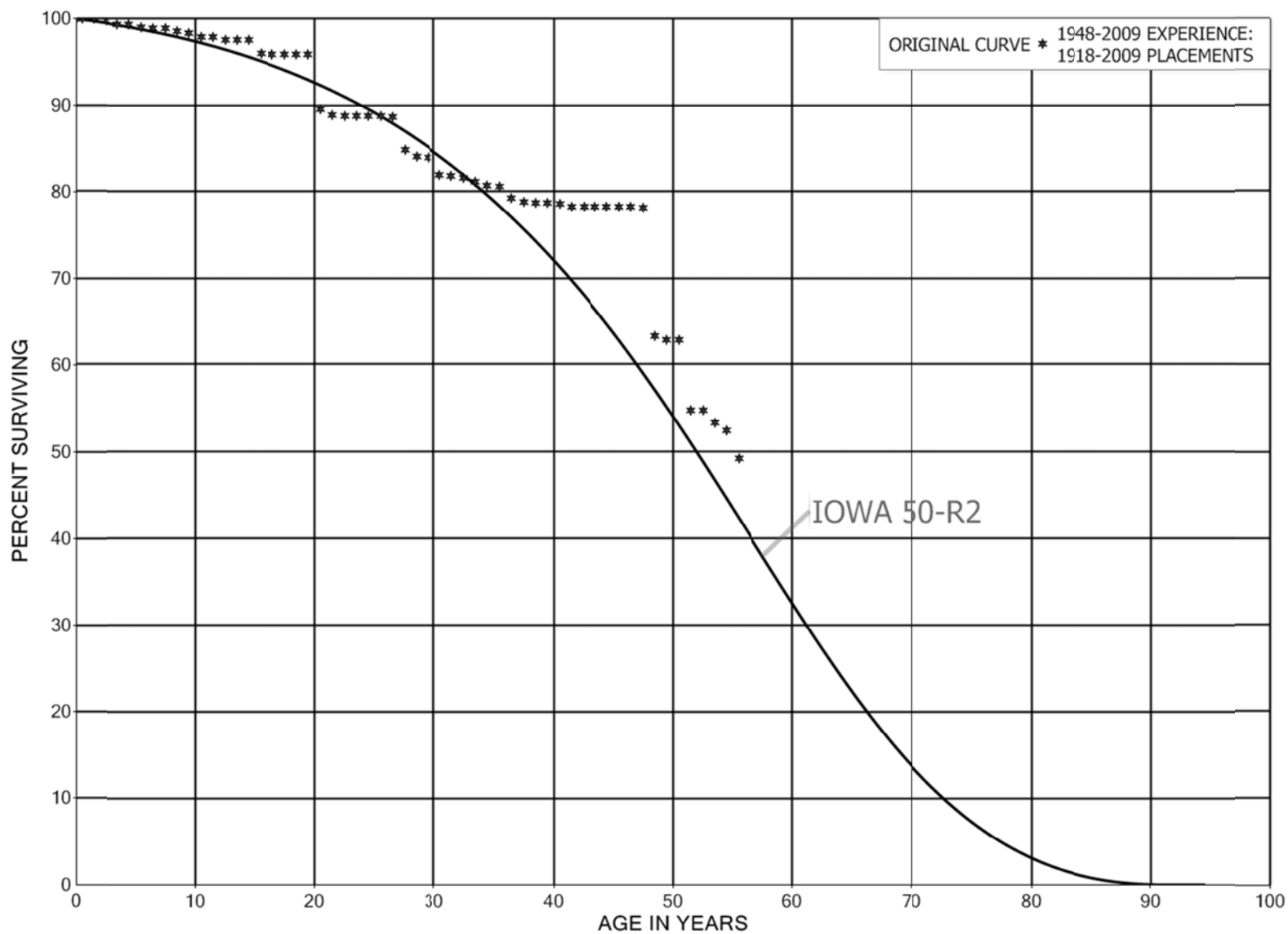
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2009

EXPERIENCE BAND 1948-2009

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	667,690	1,980	0.0030	0.9970	52.00
40.5	672,686	18,000	0.0268	0.9732	51.85
41.5	657,785	8,964	0.0136	0.9864	50.46
42.5	653,068	14,489	0.0222	0.9778	49.77
43.5	628,883	3,960	0.0063	0.9937	48.67
44.5	607,866	36,609	0.0602	0.9398	48.36
45.5	571,209	600	0.0011	0.9989	45.45
46.5	546,289	32,007	0.0586	0.9414	45.40
47.5	500,280	134,563	0.2690	0.7310	42.74
48.5	366,081	4,350	0.0119	0.9881	31.25
49.5	361,731	30,299	0.0838	0.9162	30.87
50.5	261,765	1,960	0.0075	0.9925	28.29
51.5	258,085	946	0.0037	0.9963	28.08
52.5	230,059	4,800	0.0209	0.9791	27.97
53.5	185,389	54,796	0.2956	0.7044	27.39
54.5	132,677	34,461	0.2597	0.7403	19.29
55.5	48,311		0.0000	1.0000	14.28
56.5	48,100		0.0000	1.0000	14.28
57.5	48,100		0.0000	1.0000	14.28
58.5	18,324		0.0000	1.0000	14.28
59.5	18,208		0.0000	1.0000	14.28
60.5	18,208		0.0000	1.0000	14.28
61.5	18,208		0.0000	1.0000	14.28
62.5	18,208		0.0000	1.0000	14.28
63.5	19,408	716	0.0369	0.9631	14.28
64.5	18,692		0.0000	1.0000	13.76
65.5	16,608		0.0000	1.0000	13.76
66.5	16,608		0.0000	1.0000	13.76
67.5	15,408	8,770	0.5692	0.4308	13.76
68.5	6,307		0.0000	1.0000	5.93
69.5	6,307		0.0000	1.0000	5.93
70.5	6,307		0.0000	1.0000	5.93
71.5	6,307		0.0000	1.0000	5.93
72.5	6,307		0.0000	1.0000	5.93
73.5	6,307		0.0000	1.0000	5.93
74.5	6,307		0.0000	1.0000	5.93
75.5	6,307		0.0000	1.0000	5.93
76.5	6,307		0.0000	1.0000	5.93
77.5	6,307	5,200	0.8245	0.1755	5.93
78.5					1.04

NEWFOUNDLAND POWER INC.
ACCOUNT 327.00 - MISCELLANEOUS POWER PLANT EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 327.00 - MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1918-2009

EXPERIENCE BAND 1948-2009

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	1,800,539	1,328	0.0007	0.9993	100.00
0.5	2,382,489	832	0.0003	0.9997	99.93
1.5	2,367,908	3,118	0.0013	0.9987	99.89
2.5	1,600,577	6,868	0.0043	0.9957	99.76
3.5	1,652,567	337	0.0002	0.9998	99.33
4.5	1,615,761	5,083	0.0031	0.9969	99.31
5.5	1,641,226	2,245	0.0014	0.9986	99.00
6.5	825,454	651	0.0008	0.9992	98.86
7.5	584,171	1,492	0.0026	0.9974	98.79
8.5	588,283	1,756	0.0030	0.9970	98.53
9.5	576,849	2,188	0.0038	0.9962	98.24
10.5	559,186		0.0000	1.0000	97.87
11.5	548,333	2,074	0.0038	0.9962	97.87
12.5	546,259	93	0.0002	0.9998	97.50
13.5	521,423		0.0000	1.0000	97.48
14.5	521,423	7,997	0.0153	0.9847	97.48
15.5	513,426	724	0.0014	0.9986	95.98
16.5	503,532	229	0.0005	0.9995	95.85
17.5	507,610		0.0000	1.0000	95.81
18.5	494,952	88	0.0002	0.9998	95.81
19.5	502,299	32,701	0.0651	0.9349	95.79
20.5	481,795	3,636	0.0075	0.9925	89.55
21.5	473,852	960	0.0020	0.9980	88.88
22.5	452,036		0.0000	1.0000	88.70
23.5	425,545		0.0000	1.0000	88.70
24.5	428,956		0.0000	1.0000	88.70
25.5	470,449	551	0.0012	0.9988	88.70
26.5	375,222	15,777	0.0420	0.9580	88.59
27.5	359,445	3,370	0.0094	0.9906	84.87
28.5	316,365	474	0.0015	0.9985	84.07
29.5	277,276	6,588	0.0238	0.9762	83.95
30.5	258,641	300	0.0012	0.9988	81.95
31.5	257,634	719	0.0028	0.9972	81.86
32.5	240,328	1,466	0.0061	0.9939	81.63
33.5	238,491	1,047	0.0044	0.9956	81.13
34.5	237,444	623	0.0026	0.9974	80.77
35.5	226,565	3,600	0.0159	0.9841	80.56
36.5	222,965	1,376	0.0062	0.9938	79.28
37.5	219,162	253	0.0012	0.9988	78.79
38.5	216,971		0.0000	1.0000	78.70

NEWFOUNDLAND POWER INC.

ACCOUNT 327.00 - MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2009			EXPERIENCE BAND 1948-2009		
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	215,726	171	0.0008	0.9992	78.70
40.5	213,131	1,074	0.0050	0.9950	78.64
41.5	214,178		0.0000	1.0000	78.24
42.5	219,333		0.0000	1.0000	78.24
43.5	215,303		0.0000	1.0000	78.24
44.5	214,349		0.0000	1.0000	78.24
45.5	213,873		0.0000	1.0000	78.24
46.5	197,224	93	0.0005	0.9995	78.24
47.5	175,178	33,306	0.1901	0.8099	78.21
48.5	140,677	1,159	0.0082	0.9918	63.34
49.5	106,714		0.0000	1.0000	62.82
50.5	69,075	8,883	0.1286	0.8714	62.82
51.5	56,999	59	0.0010	0.9990	54.74
52.5	48,855	1,200	0.0246	0.9754	54.68
53.5	44,313	750	0.0169	0.9831	53.34
54.5	42,826	2,683	0.0626	0.9374	52.43
55.5	19,789		0.0000	1.0000	49.15
56.5	19,275		0.0000	1.0000	49.15
57.5	22,275		0.0000	1.0000	49.15
58.5	22,275		0.0000	1.0000	49.15
59.5	21,379		0.0000	1.0000	49.15
60.5	16,979		0.0000	1.0000	49.15
61.5	7,290		0.0000	1.0000	49.15
62.5	7,290		0.0000	1.0000	49.15
63.5	6,120		0.0000	1.0000	49.15
64.5	4,920		0.0000	1.0000	49.15
65.5	4,920		0.0000	1.0000	49.15
66.5	4,920		0.0000	1.0000	49.15
67.5	4,920		0.0000	1.0000	49.15
68.5	4,920		0.0000	1.0000	49.15
69.5	4,920		0.0000	1.0000	49.15
70.5	4,920		0.0000	1.0000	49.15
71.5	4,920		0.0000	1.0000	49.15
72.5	4,920		0.0000	1.0000	49.15
73.5	4,920		0.0000	1.0000	49.15
74.5	2,200		0.0000	1.0000	49.15
75.5	2,200		0.0000	1.0000	49.15
76.5	2,200		0.0000	1.0000	49.15
77.5	2,200	2,000	0.9091	0.0909	49.15
78.5	200		0.0000	1.0000	4.47

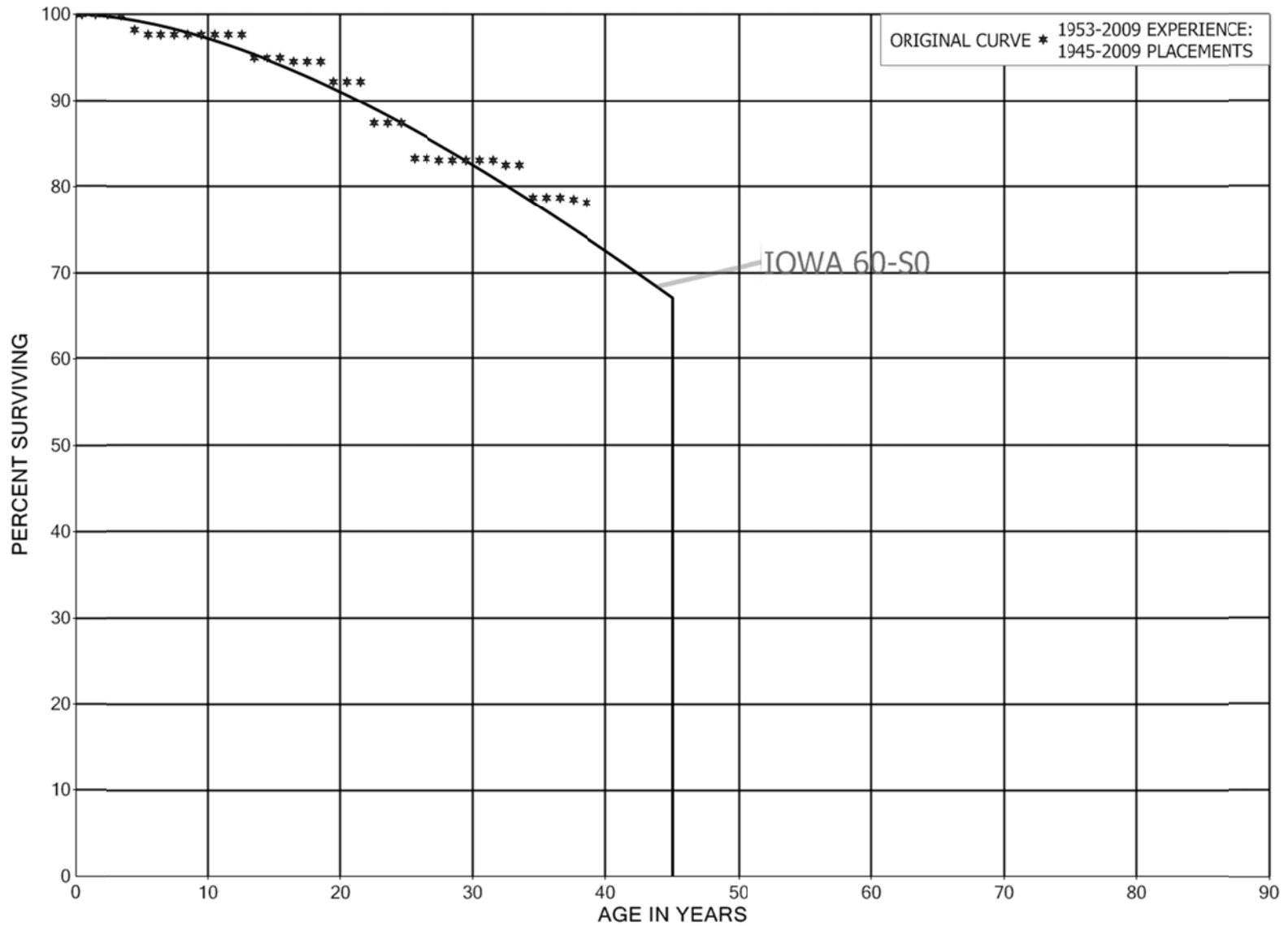
NEWFOUNDLAND POWER INC.

ACCOUNT 327.00 - MISCELLANEOUS POWER PLANT EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2009			EXPERIENCE BAND 1948-2009		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	200		0.0000	1.0000	4.47
80.5	200		0.0000	1.0000	4.47
81.5	200		0.0000	1.0000	4.47
82.5	200		0.0000	1.0000	4.47
83.5	200		0.0000	1.0000	4.47
84.5	200		0.0000	1.0000	4.47
85.5					4.47

NEWFOUNDLAND POWER INC.
ACCOUNT 331.00 - BUILDING AND STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 331.00 - BUILDING AND STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2009

EXPERIENCE BAND 1953-2009

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	1,454,631		0.0000	1.0000	100.00
0.5	1,363,549		0.0000	1.0000	100.00
1.5	1,443,879		0.0000	1.0000	100.00
2.5	1,500,892	2,795	0.0019	0.9981	100.00
3.5	1,584,417	25,142	0.0159	0.9841	99.81
4.5	1,556,879	10,022	0.0064	0.9936	98.23
5.5	1,530,724		0.0000	1.0000	97.60
6.5	1,530,724		0.0000	1.0000	97.60
7.5	1,476,520		0.0000	1.0000	97.60
8.5	1,476,520		0.0000	1.0000	97.60
9.5	1,159,044		0.0000	1.0000	97.60
10.5	1,144,821		0.0000	1.0000	97.60
11.5	1,116,222		0.0000	1.0000	97.60
12.5	1,116,222	30,000	0.0269	0.9731	97.60
13.5	1,086,222		0.0000	1.0000	94.97
14.5	987,938		0.0000	1.0000	94.97
15.5	857,826	3,758	0.0044	0.9956	94.97
16.5	857,115		0.0000	1.0000	94.56
17.5	857,115		0.0000	1.0000	94.56
18.5	846,416	20,945	0.0247	0.9753	94.56
19.5	851,381		0.0000	1.0000	92.22
20.5	807,079	340	0.0004	0.9996	92.22
21.5	785,888	40,935	0.0521	0.9479	92.18
22.5	744,953		0.0000	1.0000	87.38
23.5	740,204		0.0000	1.0000	87.38
24.5	740,204	34,569	0.0467	0.9533	87.38
25.5	704,460		0.0000	1.0000	83.30
26.5	674,313	2,000	0.0030	0.9970	83.30
27.5	659,726		0.0000	1.0000	83.05
28.5	659,726		0.0000	1.0000	83.05
29.5	659,726		0.0000	1.0000	83.05
30.5	686,726		0.0000	1.0000	83.05
31.5	686,726	4,136	0.0060	0.9940	83.05
32.5	682,590		0.0000	1.0000	82.55
33.5	682,590	31,864	0.0467	0.9533	82.55
34.5	465,192		0.0000	1.0000	78.70
35.5	456,071		0.0000	1.0000	78.70
36.5	454,929	1,178	0.0026	0.9974	78.70
37.5	351,761	1,500	0.0043	0.9957	78.49
38.5	284,587		0.0000	1.0000	78.16

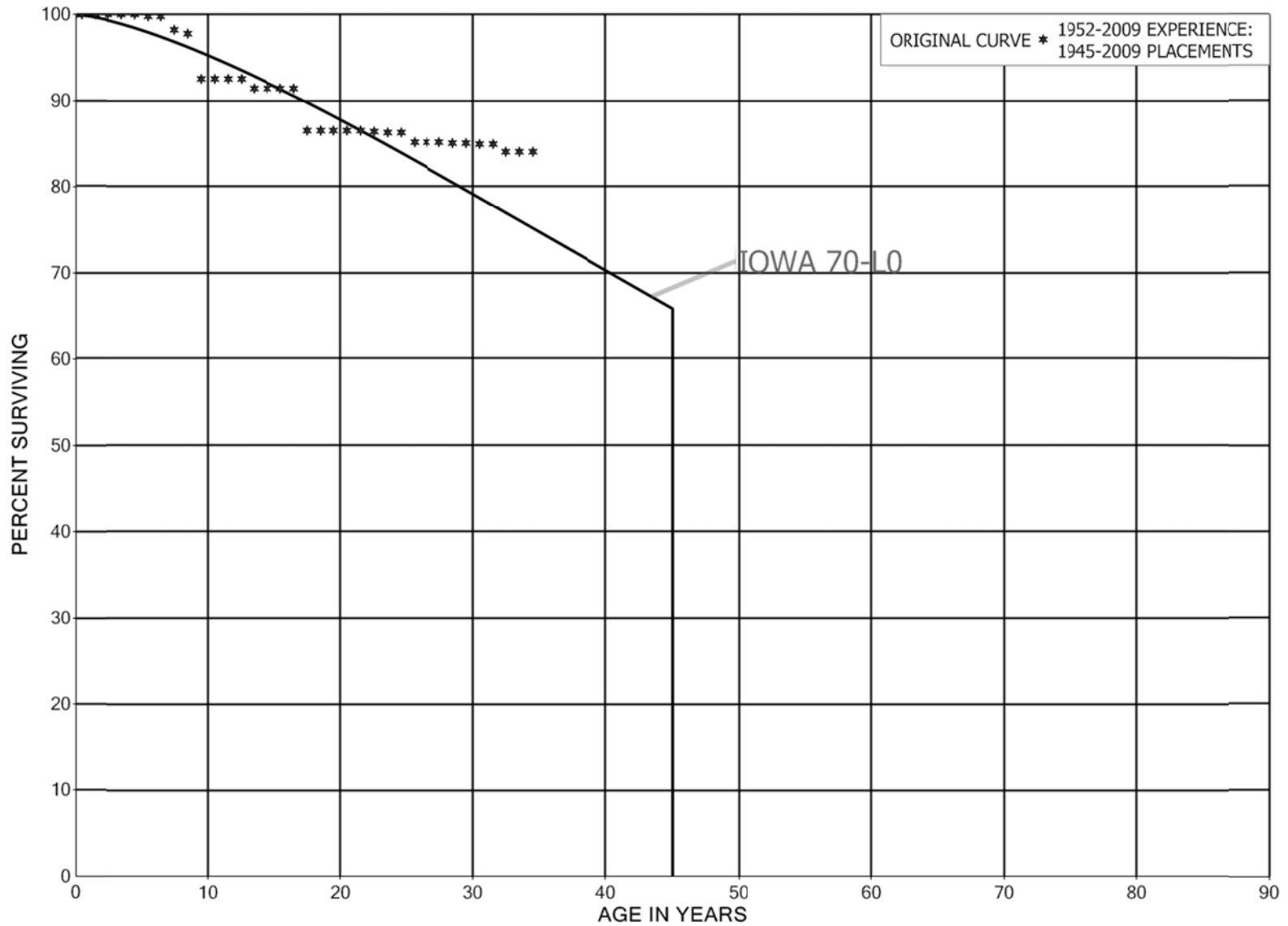
NEWFOUNDLAND POWER INC.

ACCOUNT 331.00 - BUILDING AND STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2009			EXPERIENCE BAND 1953-2009		
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	251,479		0.0000	1.0000	78.16
40.5	235,435		0.0000	1.0000	78.16
41.5	186,260	100	0.0005	0.9995	78.16
42.5	186,160		0.0000	1.0000	78.12
43.5	171,050		0.0000	1.0000	78.12
44.5	171,050		0.0000	1.0000	78.12
45.5	170,060		0.0000	1.0000	78.12
46.5	170,060		0.0000	1.0000	78.12
47.5	170,060		0.0000	1.0000	78.12
48.5	170,060	5,000	0.0294	0.9706	78.12
49.5	165,060		0.0000	1.0000	75.82
50.5	165,060		0.0000	1.0000	75.82
51.5	165,060	101,220	0.6132	0.3868	75.82
52.5	62,300		0.0000	1.0000	29.32
53.5	62,300		0.0000	1.0000	29.32
54.5	62,300		0.0000	1.0000	29.32
55.5	35,780	150	0.0042	0.9958	29.32
56.5	35,630		0.0000	1.0000	29.20
57.5	35,630		0.0000	1.0000	29.20
58.5	35,630		0.0000	1.0000	29.20
59.5	37,170		0.0000	1.0000	29.20
60.5	37,170		0.0000	1.0000	29.20
61.5	37,170		0.0000	1.0000	29.20
62.5	37,170		0.0000	1.0000	29.20
63.5	35,700		0.0000	1.0000	29.20
64.5					29.20

NEWFOUNDLAND POWER INC.
ACCOUNT 332.00 - ELECTRICAL PLANT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 332.00 - ELECTRICAL PLANT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1945-2009

EXPERIENCE BAND 1952-2009

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	3,656,589		0.0000	1.0000	100.00
0.5	2,447,615		0.0000	1.0000	100.00
1.5	2,454,931	1,060	0.0004	0.9996	100.00
2.5	2,486,488		0.0000	1.0000	99.96
3.5	2,505,413		0.0000	1.0000	99.96
4.5	2,495,571	5,200	0.0021	0.9979	99.96
5.5	1,032,857		0.0000	1.0000	99.75
6.5	887,981	14,376	0.0162	0.9838	99.75
7.5	812,434	2,959	0.0036	0.9964	98.13
8.5	471,797	25,352	0.0537	0.9463	97.78
9.5	461,016	200	0.0004	0.9996	92.52
10.5	439,682		0.0000	1.0000	92.48
11.5	434,267		0.0000	1.0000	92.48
12.5	401,048	4,700	0.0117	0.9883	92.48
13.5	380,536		0.0000	1.0000	91.40
14.5	380,536		0.0000	1.0000	91.40
15.5	380,536		0.0000	1.0000	91.40
16.5	350,934	18,669	0.0532	0.9468	91.40
17.5	259,881		0.0000	1.0000	86.54
18.5	247,860	161	0.0006	0.9994	86.54
19.5	258,669		0.0000	1.0000	86.48
20.5	260,679		0.0000	1.0000	86.48
21.5	260,679	170	0.0007	0.9993	86.48
22.5	247,622	440	0.0018	0.9982	86.42
23.5	242,205		0.0000	1.0000	86.27
24.5	242,205	3,029	0.0125	0.9875	86.27
25.5	239,176		0.0000	1.0000	85.19
26.5	239,176		0.0000	1.0000	85.19
27.5	235,247	479	0.0020	0.9980	85.19
28.5	234,768		0.0000	1.0000	85.02
29.5	234,768	200	0.0009	0.9991	85.02
30.5	234,568		0.0000	1.0000	84.95
31.5	234,568	2,540	0.0108	0.9892	84.95
32.5	232,028		0.0000	1.0000	84.03
33.5	232,028		0.0000	1.0000	84.03
34.5	191,473		0.0000	1.0000	84.03
35.5	151,537		0.0000	1.0000	84.03
36.5	130,234		0.0000	1.0000	84.03
37.5	130,234		0.0000	1.0000	84.03
38.5	129,167		0.0000	1.0000	84.03

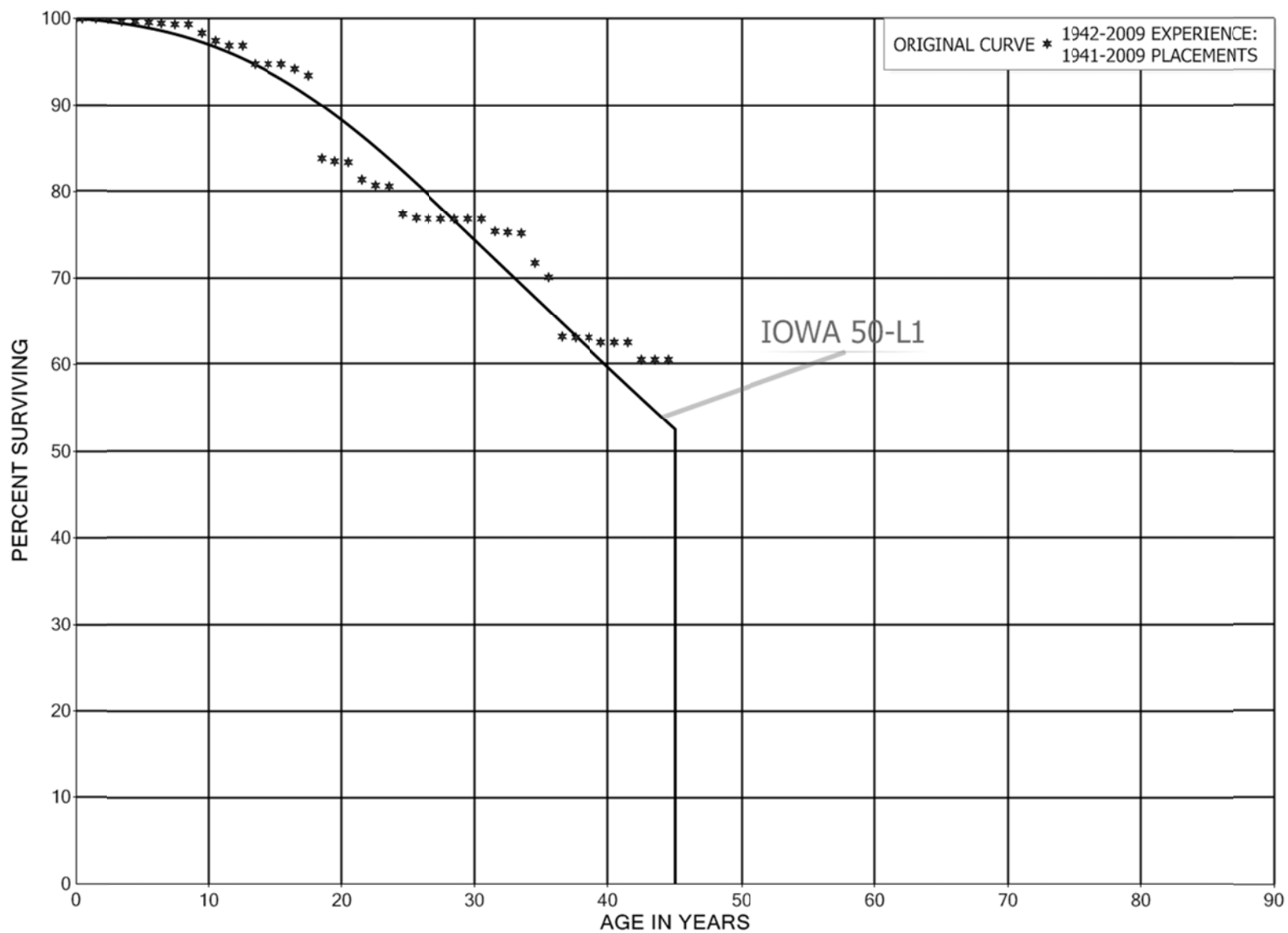
NEWFOUNDLAND POWER INC.

ACCOUNT 332.00 - ELECTRICAL PLANT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1945-2009			EXPERIENCE BAND 1952-2009		
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	127,157		0.0000	1.0000	84.03
40.5	108,203		0.0000	1.0000	84.03
41.5	108,203		0.0000	1.0000	84.03
42.5	108,203	242	0.0022	0.9978	84.03
43.5	106,254	500	0.0047	0.9953	83.84
44.5	103,834		0.0000	1.0000	83.44
45.5	99,594		0.0000	1.0000	83.44
46.5	48,569		0.0000	1.0000	83.44
47.5	43,550		0.0000	1.0000	83.44
48.5	43,550		0.0000	1.0000	83.44
49.5	43,550		0.0000	1.0000	83.44
50.5	29,750		0.0000	1.0000	83.44
51.5	29,750	15,785	0.5306	0.4694	83.44
52.5	13,965		0.0000	1.0000	39.17
53.5	13,965		0.0000	1.0000	39.17
54.5	13,965		0.0000	1.0000	39.17
55.5	11,370		0.0000	1.0000	39.17
56.5	11,370		0.0000	1.0000	39.17
57.5	11,370		0.0000	1.0000	39.17
58.5	11,370		0.0000	1.0000	39.17
59.5	11,370		0.0000	1.0000	39.17
60.5	11,370		0.0000	1.0000	39.17
61.5	11,370		0.0000	1.0000	39.17
62.5	9,670		0.0000	1.0000	39.17
63.5					39.17

NEWFOUNDLAND POWER INC.
ACCOUNT 333.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 333.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1941-2009

EXPERIENCE BAND 1942-2009

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	21,274,126	230	0.0000	1.0000	100.00
0.5	20,799,897	4,442	0.0002	0.9998	100.00
1.5	20,719,456	10,149	0.0005	0.9995	99.98
2.5	20,699,522	54,672	0.0026	0.9974	99.93
3.5	20,836,824	1,043	0.0001	0.9999	99.66
4.5	19,073,226	37,621	0.0020	0.9980	99.66
5.5	17,540,588	14,989	0.0009	0.9991	99.46
6.5	12,989,760	15,083	0.0012	0.9988	99.38
7.5	11,389,747	350	0.0000	1.0000	99.26
8.5	10,993,613	106,332	0.0097	0.9903	99.26
9.5	10,745,205	93,342	0.0087	0.9913	98.30
10.5	10,410,945	62,160	0.0060	0.9940	97.45
11.5	10,429,793	3,000	0.0003	0.9997	96.86
12.5	10,346,477	223,966	0.0216	0.9784	96.84
13.5	9,170,997	1,869	0.0002	0.9998	94.74
14.5	9,071,922		0.0000	1.0000	94.72
15.5	8,468,178	47,181	0.0056	0.9944	94.72
16.5	8,188,906	70,642	0.0086	0.9914	94.19
17.5	7,617,005	780,509	0.1025	0.8975	93.38
18.5	7,005,273	23,997	0.0034	0.9966	83.81
19.5	6,620,545	11,000	0.0017	0.9983	83.52
20.5	6,627,145	158,078	0.0239	0.9761	83.39
21.5	6,460,577	55,795	0.0086	0.9914	81.40
22.5	6,406,792	6,413	0.0010	0.9990	80.69
23.5	6,310,957	249,437	0.0395	0.9605	80.61
24.5	6,188,951	34,200	0.0055	0.9945	77.43
25.5	6,144,599	9,697	0.0016	0.9984	77.00
26.5	6,133,071	5,000	0.0008	0.9992	76.88
27.5	6,062,459		0.0000	1.0000	76.81
28.5	6,062,459	2,063	0.0003	0.9997	76.81
29.5	6,060,396	607	0.0001	0.9999	76.79
30.5	6,067,367	111,462	0.0184	0.9816	76.78
31.5	5,925,905	8,835	0.0015	0.9985	75.37
32.5	5,789,551	4,894	0.0008	0.9992	75.26
33.5	5,781,657	267,100	0.0462	0.9538	75.19
34.5	2,857,044	64,662	0.0226	0.9774	71.72
35.5	2,677,813	266,400	0.0995	0.9005	70.10
36.5	2,182,203	2,000	0.0009	0.9991	63.12
37.5	2,180,203		0.0000	1.0000	63.07
38.5	2,180,203	18,600	0.0085	0.9915	63.07

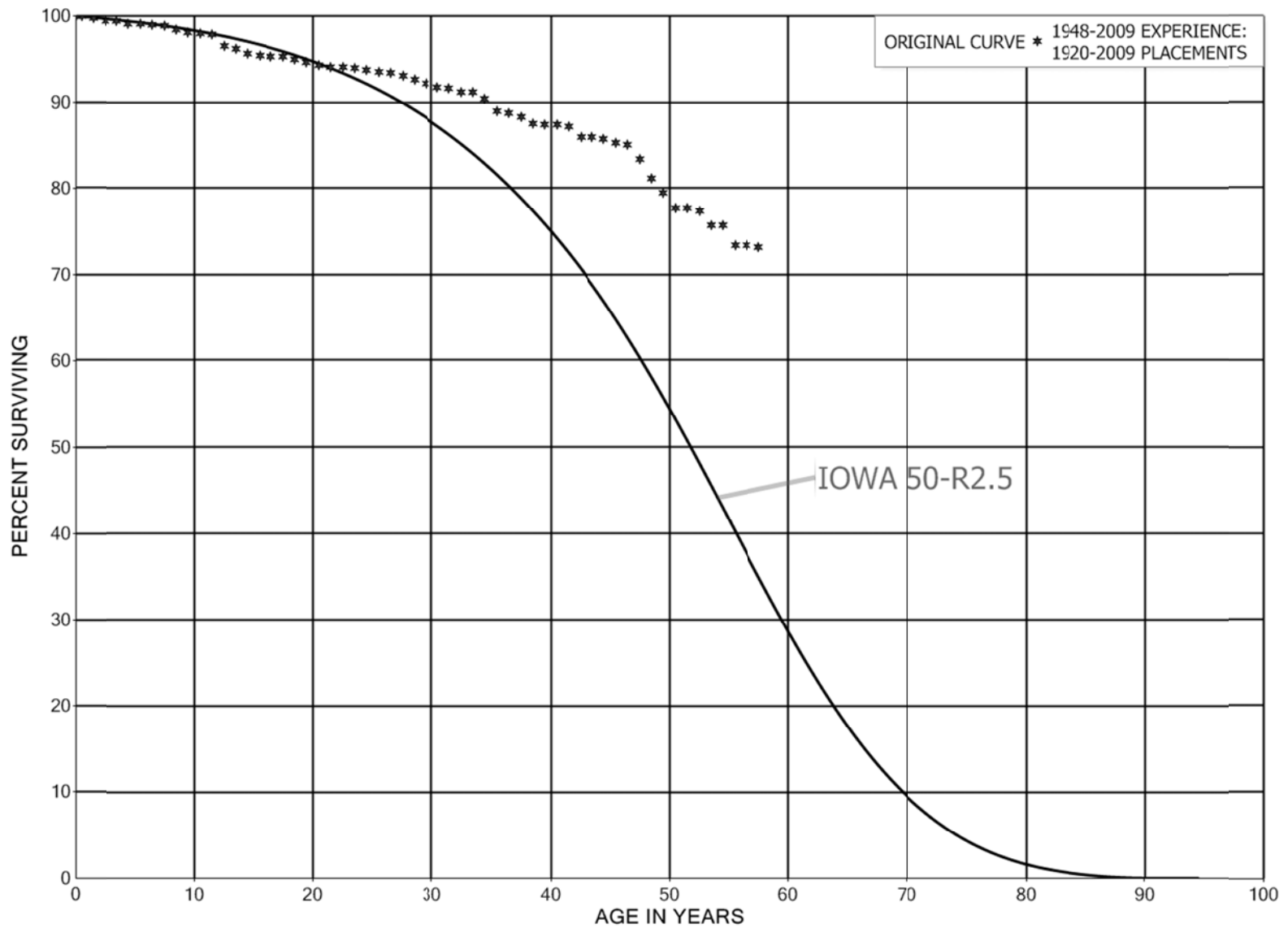
NEWFOUNDLAND POWER INC.

ACCOUNT 333.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1941-2009			EXPERIENCE BAND 1942-2009		
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	2,160,160		0.0000	1.0000	62.53
40.5	1,514,076		0.0000	1.0000	62.53
41.5	1,309,832	43,185	0.0330	0.9670	62.53
42.5	1,266,647		0.0000	1.0000	60.47
43.5	1,265,947		0.0000	1.0000	60.47
44.5	1,265,947	2,830	0.0022	0.9978	60.47
45.5	1,064,108	25,950	0.0244	0.9756	60.33
46.5	1,038,157	24,120	0.0232	0.9768	58.86
47.5	964,127		0.0000	1.0000	57.49
48.5	964,127	3,544	0.0037	0.9963	57.49
49.5	960,583		0.0000	1.0000	57.28
50.5	757,574	16,767	0.0221	0.9779	57.28
51.5	740,807	538,246	0.7266	0.2734	56.01
52.5	202,561		0.0000	1.0000	15.32
53.5	202,561		0.0000	1.0000	15.32
54.5	202,561	130	0.0006	0.9994	15.32
55.5	202,431		0.0000	1.0000	15.31
56.5	202,431		0.0000	1.0000	15.31
57.5					15.31

NEWFOUNDLAND POWER INC.
ACCOUNT 341.00 - SUBSTATION - BUILDINGS AND STRUCTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 341.00 - SUBSTATION - BUILDINGS AND STRUCTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1920-2009

EXPERIENCE BAND 1948-2009

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	7,036,536	388	0.0001	0.9999	100.00
0.5	6,390,355	18,472	0.0029	0.9971	99.99
1.5	7,081,136	18,386	0.0026	0.9974	99.71
2.5	7,558,003		0.0000	1.0000	99.45
3.5	7,827,206	27,661	0.0035	0.9965	99.45
4.5	7,329,236	3,268	0.0004	0.9996	99.10
5.5	7,005,544	8,821	0.0013	0.9987	99.05
6.5	6,625,779	6,918	0.0010	0.9990	98.93
7.5	6,655,935	27,991	0.0042	0.9958	98.82
8.5	5,860,214	22,701	0.0039	0.9961	98.41
9.5	4,785,262	5,899	0.0012	0.9988	98.03
10.5	4,741,405	5,725	0.0012	0.9988	97.91
11.5	4,556,630	60,635	0.0133	0.9867	97.79
12.5	4,459,096	15,705	0.0035	0.9965	96.49
13.5	4,297,750	22,676	0.0053	0.9947	96.15
14.5	4,167,604	12,973	0.0031	0.9969	95.64
15.5	3,959,043	3,475	0.0009	0.9991	95.34
16.5	3,962,005		0.0000	1.0000	95.26
17.5	3,922,679	12,571	0.0032	0.9968	95.26
18.5	3,789,384	12,087	0.0032	0.9968	94.95
19.5	3,262,557	11,080	0.0034	0.9966	94.65
20.5	3,147,219	7,205	0.0023	0.9977	94.33
21.5	2,743,720	1,250	0.0005	0.9995	94.11
22.5	2,682,573	3,010	0.0011	0.9989	94.07
23.5	2,644,170	5,779	0.0022	0.9978	93.96
24.5	2,583,061	5,945	0.0023	0.9977	93.76
25.5	2,477,510	3,899	0.0016	0.9984	93.54
26.5	2,169,351	7,167	0.0033	0.9967	93.40
27.5	2,038,622	10,216	0.0050	0.9950	93.09
28.5	2,075,616	11,050	0.0053	0.9947	92.62
29.5	2,120,966	8,716	0.0041	0.9959	92.13
30.5	2,139,886	2,421	0.0011	0.9989	91.75
31.5	1,246,182	6,002	0.0048	0.9952	91.64
32.5	1,291,831	393	0.0003	0.9997	91.20
33.5	986,856	8,324	0.0084	0.9916	91.18
34.5	764,001	12,598	0.0165	0.9835	90.41
35.5	739,763	1,240	0.0017	0.9983	88.92
36.5	711,942	3,923	0.0055	0.9945	88.77
37.5	561,800	5,049	0.0090	0.9910	88.28
38.5	545,045	800	0.0015	0.9985	87.48

NEWFOUNDLAND POWER INC.

ACCOUNT 341.00 - SUBSTATION - BUILDINGS AND STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1920-2009			EXPERIENCE BAND 1948-2009		
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	526,090		0.0000	1.0000	87.36
40.5	488,062	1,200	0.0025	0.9975	87.36
41.5	447,864	6,000	0.0134	0.9866	87.14
42.5	395,602		0.0000	1.0000	85.97
43.5	354,767	1,000	0.0028	0.9972	85.97
44.5	360,049	1,724	0.0048	0.9952	85.73
45.5	333,409	1,211	0.0036	0.9964	85.32
46.5	318,663	6,000	0.0188	0.9812	85.01
47.5	302,744	7,944	0.0262	0.9738	83.41
48.5	265,943	5,489	0.0206	0.9794	81.22
49.5	222,639	4,982	0.0224	0.9776	79.55
50.5	171,174		0.0000	1.0000	77.77
51.5	119,351	600	0.0050	0.9950	77.77
52.5	118,751	2,611	0.0220	0.9780	77.37
53.5	116,896		0.0000	1.0000	75.67
54.5	116,896	3,476	0.0297	0.9703	75.67
55.5	97,805		0.0000	1.0000	73.42
56.5	97,090	284	0.0029	0.9971	73.42
57.5	95,342		0.0000	1.0000	73.21
58.5	93,958		0.0000	1.0000	73.21
59.5	90,897		0.0000	1.0000	73.21
60.5	90,897		0.0000	1.0000	73.21
61.5	90,897		0.0000	1.0000	73.21
62.5	90,897		0.0000	1.0000	73.21
63.5	90,052		0.0000	1.0000	73.21
64.5	90,052		0.0000	1.0000	73.21
65.5	86,762		0.0000	1.0000	73.21
66.5	86,762		0.0000	1.0000	73.21
67.5	61,602		0.0000	1.0000	73.21
68.5	61,602		0.0000	1.0000	73.21
69.5	61,602		0.0000	1.0000	73.21
70.5	61,602		0.0000	1.0000	73.21
71.5	61,602		0.0000	1.0000	73.21
72.5	61,602		0.0000	1.0000	73.21
73.5	61,602		0.0000	1.0000	73.21
74.5	61,602	465	0.0075	0.9925	73.21
75.5	61,137		0.0000	1.0000	72.66
76.5	61,137		0.0000	1.0000	72.66
77.5	61,137		0.0000	1.0000	72.66
78.5	53,637		0.0000	1.0000	72.66

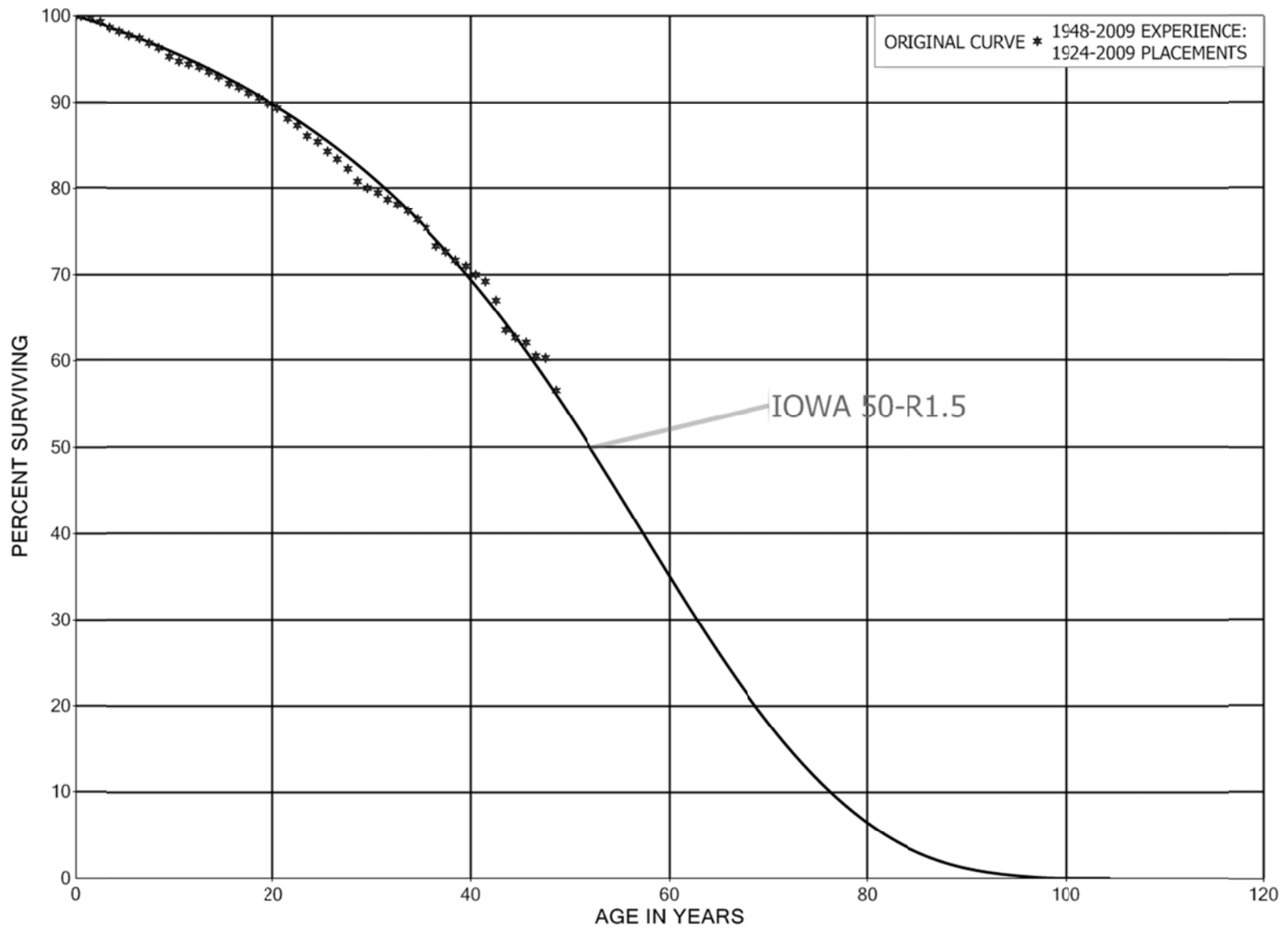
NEWFOUNDLAND POWER INC.

ACCOUNT 341.00 - SUBSTATION - BUILDINGS AND STRUCTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1920-2009			EXPERIENCE BAND 1948-2009		
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	50,634		0.0000	1.0000	72.66
80.5	50,634		0.0000	1.0000	72.66
81.5	885		0.0000	1.0000	72.66
82.5	885		0.0000	1.0000	72.66
83.5	885		0.0000	1.0000	72.66
84.5	885		0.0000	1.0000	72.66
85.5	885		0.0000	1.0000	72.66
86.5	885		0.0000	1.0000	72.66
87.5					72.66

NEWFOUNDLAND POWER INC.
ACCOUNT 342.00 - SUBSTATION - EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 342.00 - SUBSTATION - EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2009

EXPERIENCE BAND 1948-2009

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	154,900,318	76,322	0.0005	0.9995	100.00
0.5	146,155,036	342,206	0.0023	0.9977	99.95
1.5	137,854,185	535,868	0.0039	0.9961	99.72
2.5	131,710,464	942,967	0.0072	0.9928	99.33
3.5	125,338,909	547,444	0.0044	0.9956	98.62
4.5	121,412,672	554,539	0.0046	0.9954	98.19
5.5	115,476,543	426,169	0.0037	0.9963	97.74
6.5	107,802,454	604,704	0.0056	0.9944	97.38
7.5	102,363,314	612,264	0.0060	0.9940	96.83
8.5	97,957,713	944,332	0.0096	0.9904	96.25
9.5	93,543,846	618,396	0.0066	0.9934	95.32
10.5	89,523,328	315,567	0.0035	0.9965	94.69
11.5	86,666,702	289,212	0.0033	0.9967	94.36
12.5	84,111,575	525,590	0.0062	0.9938	94.05
13.5	81,859,804	450,794	0.0055	0.9945	93.46
14.5	79,918,254	683,594	0.0086	0.9914	92.94
15.5	78,521,262	342,066	0.0044	0.9956	92.15
16.5	75,422,288	599,821	0.0080	0.9920	91.75
17.5	71,127,660	375,068	0.0053	0.9947	91.02
18.5	66,548,452	522,078	0.0078	0.9922	90.54
19.5	58,283,733	378,619	0.0065	0.9935	89.83
20.5	54,499,913	713,407	0.0131	0.9869	89.24
21.5	51,410,337	464,519	0.0090	0.9910	88.08
22.5	48,941,043	668,170	0.0137	0.9863	87.28
23.5	47,264,937	403,811	0.0085	0.9915	86.09
24.5	45,501,456	569,568	0.0125	0.9875	85.35
25.5	43,907,913	465,922	0.0106	0.9894	84.28
26.5	41,744,850	574,505	0.0138	0.9862	83.39
27.5	39,160,243	677,088	0.0173	0.9827	82.24
28.5	36,830,201	330,314	0.0090	0.9910	80.82
29.5	34,526,565	269,617	0.0078	0.9922	80.10
30.5	32,755,734	316,504	0.0097	0.9903	79.47
31.5	31,811,589	228,171	0.0072	0.9928	78.70
32.5	26,075,788	258,670	0.0099	0.9901	78.14
33.5	16,745,611	218,128	0.0130	0.9870	77.36
34.5	12,546,329	158,046	0.0126	0.9874	76.35
35.5	10,560,161	300,980	0.0285	0.9715	75.39
36.5	8,968,261	81,539	0.0091	0.9909	73.24
37.5	7,726,136	99,181	0.0128	0.9872	72.58
38.5	6,569,477	68,286	0.0104	0.9896	71.65

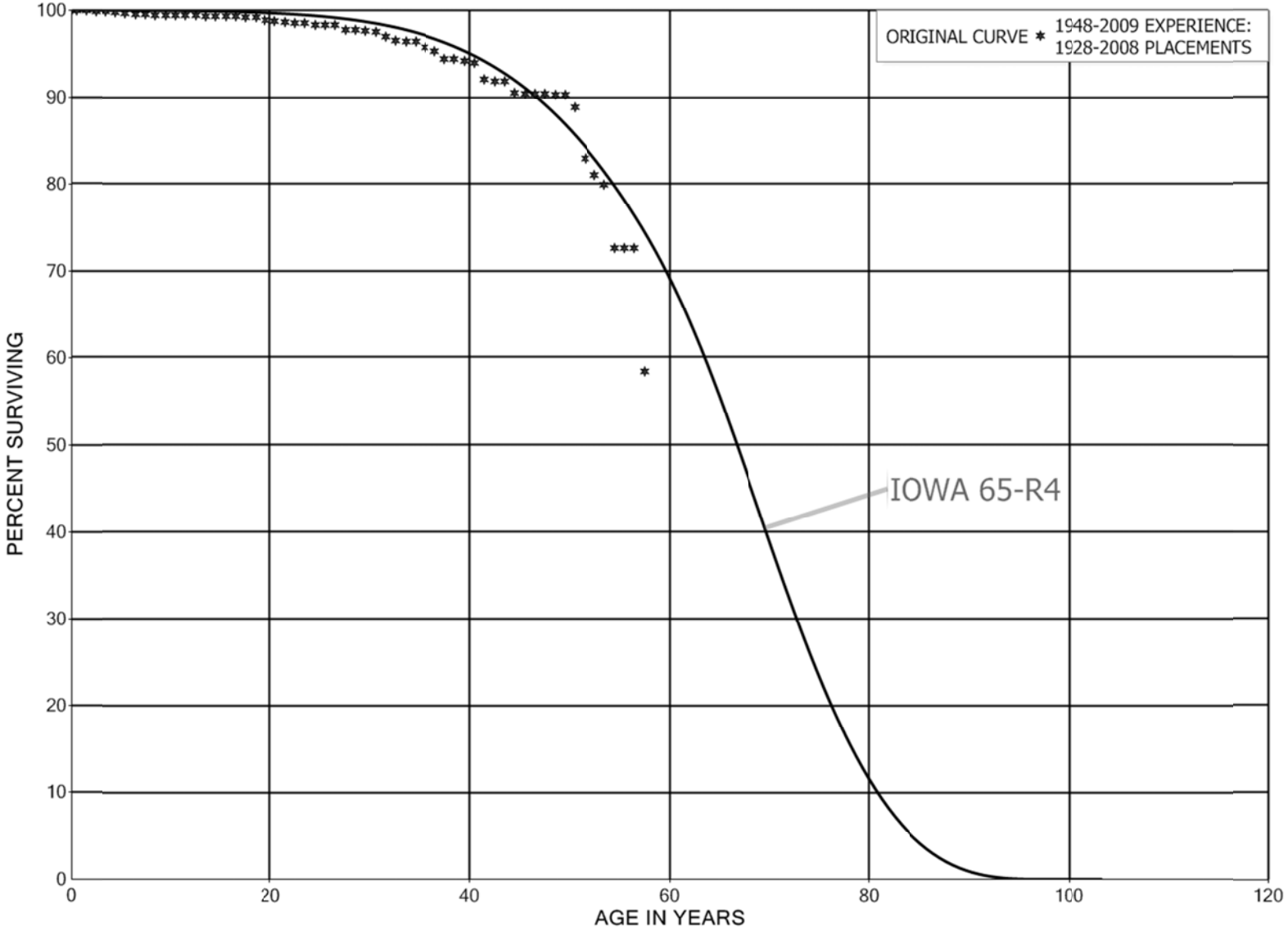
NEWFOUNDLAND POWER INC.

ACCOUNT 342.00 - SUBSTATION - EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2009			EXPERIENCE BAND 1948-2009		
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	6,301,615	88,692	0.0141	0.9859	70.90
40.5	5,039,912	56,209	0.0112	0.9888	69.90
41.5	4,665,372	147,860	0.0317	0.9683	69.12
42.5	3,892,579	197,535	0.0507	0.9493	66.93
43.5	2,958,685	45,073	0.0152	0.9848	63.54
44.5	2,686,692	23,852	0.0089	0.9911	62.57
45.5	2,581,077	61,099	0.0237	0.9763	62.01
46.5	2,063,271	9,429	0.0046	0.9954	60.55
47.5	1,902,520	118,683	0.0624	0.9376	60.27
48.5	1,361,833	25,492	0.0187	0.9813	56.51
49.5	1,179,625	69,085	0.0586	0.9414	55.45
50.5	837,107	18,658	0.0223	0.9777	52.20
51.5	602,449	6,435	0.0107	0.9893	51.04
52.5	596,014	8,949	0.0150	0.9850	50.49
53.5	411,819	12,998	0.0316	0.9684	49.74
54.5	393,765	59,393	0.1508	0.8492	48.17
55.5	183,879	415	0.0023	0.9977	40.90
56.5	187,578	31,106	0.1658	0.8342	40.81
57.5	146,971	2,251	0.0153	0.9847	34.04
58.5	104,975	14,256	0.1358	0.8642	33.52
59.5	90,719		0.0000	1.0000	28.97
60.5	90,296		0.0000	1.0000	28.97
61.5	90,791	1,278	0.0141	0.9859	28.97
62.5	89,513	1,890	0.0211	0.9789	28.56
63.5	76,279		0.0000	1.0000	27.96
64.5	70,362	3,855	0.0548	0.9452	27.96
65.5	66,507	1,414	0.0213	0.9787	26.43
66.5	55,928	3,388	0.0606	0.9394	25.86
67.5					24.30

NEWFOUNDLAND POWER INC.
ACCOUNT 350.00 - TRANSMISSION - LAND AND LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 350.00 - TRANSMISSION - LAND AND LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2008			EXPERIENCE BAND 1948-2009		
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	9,607,061		0.0000	1.0000	100.00
0.5	9,240,447	4,970	0.0005	0.9995	100.00
1.5	10,292,469	13,679	0.0013	0.9987	99.95
2.5	10,862,557	855	0.0001	0.9999	99.81
3.5	10,621,311	12,265	0.0012	0.9988	99.81
4.5	10,578,675	3,815	0.0004	0.9996	99.69
5.5	10,514,215	13,982	0.0013	0.9987	99.65
6.5	10,323,683		0.0000	1.0000	99.52
7.5	9,780,605	8,080	0.0008	0.9992	99.52
8.5	9,763,263	3,787	0.0004	0.9996	99.44
9.5	9,752,458		0.0000	1.0000	99.40
10.5	9,829,849	3,351	0.0003	0.9997	99.40
11.5	9,874,412	1,434	0.0001	0.9999	99.37
12.5	9,604,132	7,704	0.0008	0.9992	99.35
13.5	9,597,898		0.0000	1.0000	99.27
14.5	9,578,091	2,448	0.0003	0.9997	99.27
15.5	9,508,455	914	0.0001	0.9999	99.25
16.5	9,463,594	3,203	0.0003	0.9997	99.24
17.5	9,376,091		0.0000	1.0000	99.20
18.5	9,242,730	32,623	0.0035	0.9965	99.20
19.5	9,155,073	15,576	0.0017	0.9983	98.85
20.5	9,031,281	5,447	0.0006	0.9994	98.69
21.5	9,018,512	10,012	0.0011	0.9989	98.63
22.5	8,953,488	1,342	0.0001	0.9999	98.52
23.5	8,782,128	17,189	0.0020	0.9980	98.50
24.5	8,434,222		0.0000	1.0000	98.31
25.5	8,054,893		0.0000	1.0000	98.31
26.5	7,265,804	43,259	0.0060	0.9940	98.31
27.5	6,312,592	1,104	0.0002	0.9998	97.72
28.5	5,219,129	4,191	0.0008	0.9992	97.71
29.5	4,959,351	7,325	0.0015	0.9985	97.63
30.5	4,661,387	23,556	0.0051	0.9949	97.48
31.5	4,157,351	21,830	0.0053	0.9947	96.99
32.5	3,991,668	2,789	0.0007	0.9993	96.48
33.5	2,967,394		0.0000	1.0000	96.42
34.5	2,382,334	16,457	0.0069	0.9931	96.42
35.5	1,854,688	9,150	0.0049	0.9951	95.75
36.5	1,700,547	16,270	0.0096	0.9904	95.28
37.5	1,477,058		0.0000	1.0000	94.37
38.5	1,374,508	3,480	0.0025	0.9975	94.37

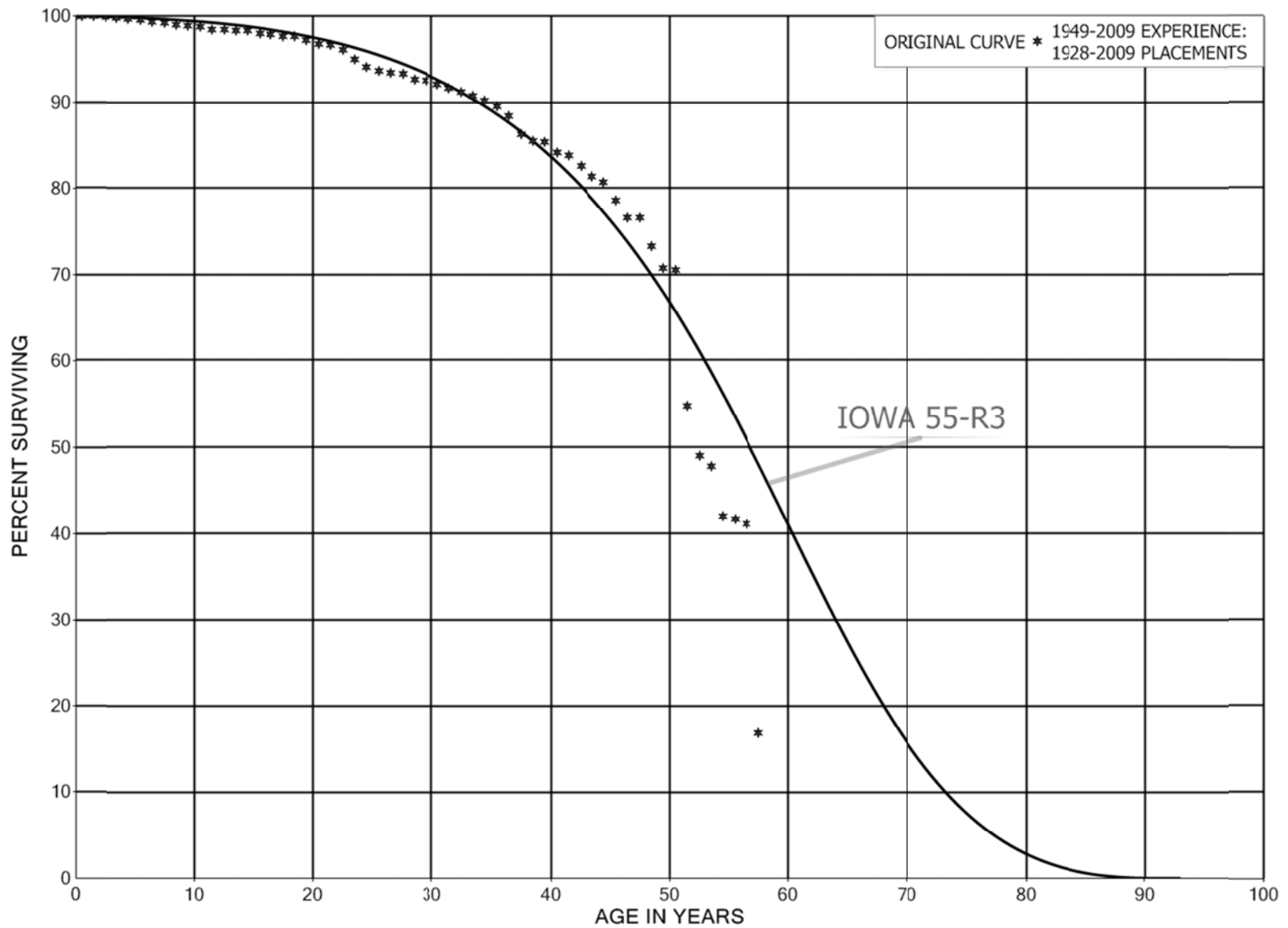
NEWFOUNDLAND POWER INC.

ACCOUNT 350.00 - TRANSMISSION - LAND AND LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2008			EXPERIENCE BAND 1948-2009		
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	1,251,974	3,041	0.0024	0.9976	94.13
40.5	1,086,674	21,099	0.0194	0.9806	93.90
41.5	978,689	2,122	0.0022	0.9978	92.07
42.5	940,845		0.0000	1.0000	91.87
43.5	832,516	12,638	0.0152	0.9848	91.87
44.5	607,713	890	0.0015	0.9985	90.48
45.5	599,332		0.0000	1.0000	90.35
46.5	538,803		0.0000	1.0000	90.35
47.5	483,372	500	0.0010	0.9990	90.35
48.5	451,798		0.0000	1.0000	90.25
49.5	512,229	8,220	0.0160	0.9840	90.25
50.5	339,591	22,448	0.0661	0.9339	88.81
51.5	218,834	4,940	0.0226	0.9774	82.94
52.5	197,857	2,743	0.0139	0.9861	81.06
53.5	178,809	16,282	0.0911	0.9089	79.94
54.5	150,001		0.0000	1.0000	72.66
55.5	143,831		0.0000	1.0000	72.66
56.5	143,831	28,280	0.1966	0.8034	72.66
57.5	107,793		0.0000	1.0000	58.37
58.5	107,791		0.0000	1.0000	58.37
59.5	107,791		0.0000	1.0000	58.37
60.5	107,791		0.0000	1.0000	58.37
61.5	100,575		0.0000	1.0000	58.37
62.5	81,520		0.0000	1.0000	58.37
63.5	24,357		0.0000	1.0000	58.37
64.5	24,357		0.0000	1.0000	58.37
65.5	24,357		0.0000	1.0000	58.37
66.5	24,357		0.0000	1.0000	58.37
67.5	24,357		0.0000	1.0000	58.37
68.5	24,357		0.0000	1.0000	58.37
69.5	24,357		0.0000	1.0000	58.37
70.5	24,357		0.0000	1.0000	58.37
71.5	24,357		0.0000	1.0000	58.37
72.5	24,357	4,450	0.1827	0.8173	58.37
73.5	19,907		0.0000	1.0000	47.71
74.5	19,907		0.0000	1.0000	47.71
75.5	19,907		0.0000	1.0000	47.71
76.5	19,907		0.0000	1.0000	47.71
77.5	19,907		0.0000	1.0000	47.71
78.5					47.71

NEWFOUNDLAND POWER INC.
ACCOUNT 353.10 - TRANSMISSION - OVERHEAD CONDUCTORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 353.10 - TRANSMISSION - OVERHEAD CONDUCTORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2009

EXPERIENCE BAND 1949-2009

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	19,648,571	40	0.0000	1.0000	100.00
0.5	20,070,445	1,781	0.0001	0.9999	100.00
1.5	20,196,570	26,029	0.0013	0.9987	99.99
2.5	20,623,920	23,881	0.0012	0.9988	99.86
3.5	19,967,499	20,108	0.0010	0.9990	99.75
4.5	19,427,167	19,767	0.0010	0.9990	99.65
5.5	19,123,235	46,754	0.0024	0.9976	99.54
6.5	18,227,032	29,675	0.0016	0.9984	99.30
7.5	18,035,215	34,753	0.0019	0.9981	99.14
8.5	17,550,969	13,269	0.0008	0.9992	98.95
9.5	17,500,273	25,978	0.0015	0.9985	98.87
10.5	17,386,431	50,134	0.0029	0.9971	98.73
11.5	17,169,007	10,568	0.0006	0.9994	98.44
12.5	16,812,589	11,543	0.0007	0.9993	98.38
13.5	16,391,176	6,698	0.0004	0.9996	98.31
14.5	16,156,029	53,812	0.0033	0.9967	98.27
15.5	15,819,352	21,477	0.0014	0.9986	97.95
16.5	15,394,227	31,878	0.0021	0.9979	97.81
17.5	14,837,439	6,611	0.0004	0.9996	97.61
18.5	14,429,878	51,732	0.0036	0.9964	97.57
19.5	13,892,182	68,769	0.0050	0.9950	97.22
20.5	13,430,542	19,955	0.0015	0.9985	96.74
21.5	13,178,913	67,997	0.0052	0.9948	96.59
22.5	13,040,998	151,541	0.0116	0.9884	96.09
23.5	12,468,796	116,139	0.0093	0.9907	94.98
24.5	11,918,406	57,680	0.0048	0.9952	94.09
25.5	11,541,907	29,738	0.0026	0.9974	93.64
26.5	10,789,515	7,857	0.0007	0.9993	93.40
27.5	10,120,952	81,248	0.0080	0.9920	93.33
28.5	8,336,303	5,294	0.0006	0.9994	92.58
29.5	8,046,737	36,668	0.0046	0.9954	92.52
30.5	8,222,698	40,136	0.0049	0.9951	92.10
31.5	6,902,140	31,699	0.0046	0.9954	91.65
32.5	6,513,569	33,573	0.0052	0.9948	91.23
33.5	4,514,182	30,485	0.0068	0.9932	90.76
34.5	3,604,511	24,574	0.0068	0.9932	90.15
35.5	3,048,660	39,184	0.0129	0.9871	89.53
36.5	2,896,572	67,017	0.0231	0.9769	88.38
37.5	2,573,968	26,315	0.0102	0.9898	86.34
38.5	2,115,170	921	0.0004	0.9996	85.45

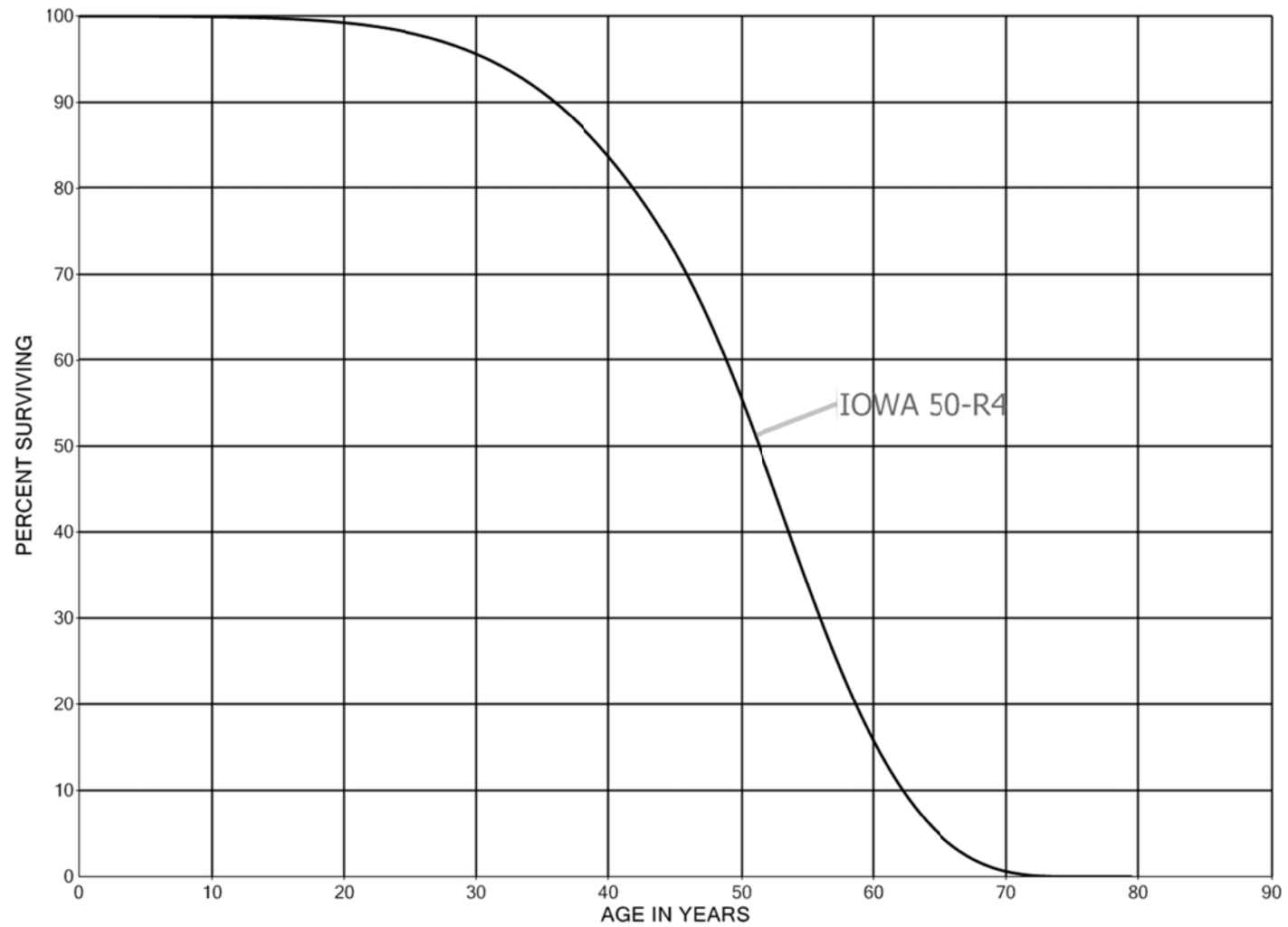
NEWFOUNDLAND POWER INC.

ACCOUNT 353.10 - TRANSMISSION - OVERHEAD CONDUCTORS

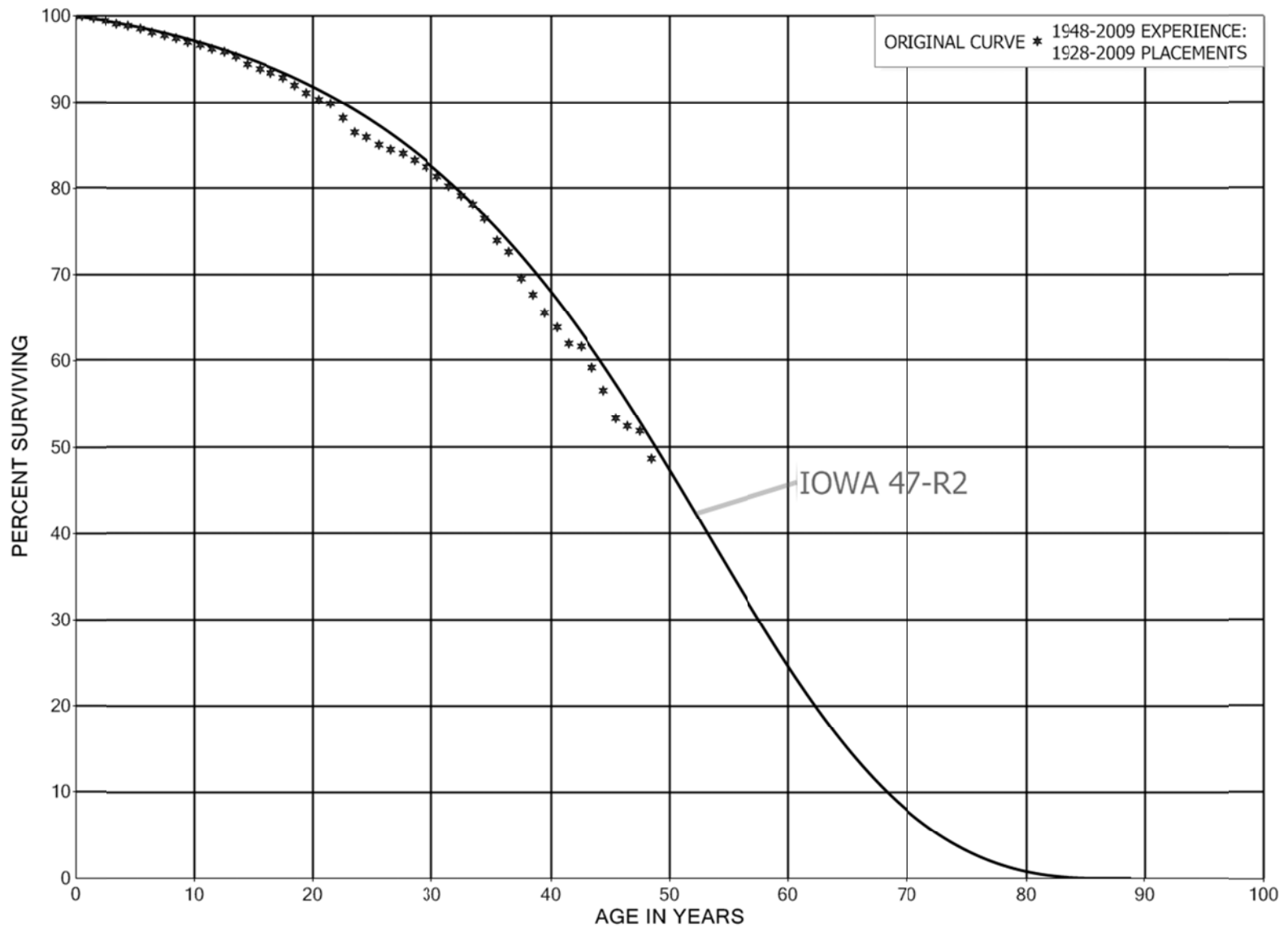
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2009			EXPERIENCE BAND 1949-2009		
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	2,263,967	32,876	0.0145	0.9855	85.42
40.5	2,153,656	7,660	0.0036	0.9964	84.17
41.5	1,778,311	25,748	0.0145	0.9855	83.88
42.5	1,650,747	25,343	0.0154	0.9846	82.66
43.5	1,563,810	11,829	0.0076	0.9924	81.39
44.5	987,069	26,037	0.0264	0.9736	80.78
45.5	904,691	23,819	0.0263	0.9737	78.65
46.5	711,640		0.0000	1.0000	76.58
47.5	638,304	27,265	0.0427	0.9573	76.58
48.5	586,904	20,453	0.0348	0.9652	73.30
49.5	754,965	3,189	0.0042	0.9958	70.75
50.5	623,730	139,407	0.2235	0.7765	70.45
51.5	393,861	41,400	0.1051	0.8949	54.70
52.5	328,970	8,346	0.0254	0.9746	48.95
53.5	267,585	32,337	0.1208	0.8792	47.71
54.5	236,187	1,909	0.0081	0.9919	41.95
55.5	217,231	2,790	0.0128	0.9872	41.61
56.5	210,981	124,770	0.5914	0.4086	41.07
57.5	66,062		0.0000	1.0000	16.78
58.5	70,132	4,473	0.0638	0.9362	16.78
59.5	65,659	4,110	0.0626	0.9374	15.71
60.5	40,124		0.0000	1.0000	14.73
61.5	39,625		0.0000	1.0000	14.73
62.5	39,625	10,247	0.2586	0.7414	14.73
63.5	39,625		0.0000	1.0000	10.92
64.5	39,625		0.0000	1.0000	10.92
65.5	39,625		0.0000	1.0000	10.92
66.5	39,625		0.0000	1.0000	10.92
67.5	39,625		0.0000	1.0000	10.92
68.5	39,625		0.0000	1.0000	10.92
69.5	39,625		0.0000	1.0000	10.92
70.5	39,625		0.0000	1.0000	10.92
71.5	39,625	2,750	0.0694	0.9306	10.92
72.5	36,875		0.0000	1.0000	10.16
73.5	36,875		0.0000	1.0000	10.16
74.5	36,875		0.0000	1.0000	10.16
75.5	26,628		0.0000	1.0000	10.16
76.5	26,344	500	0.0190	0.9810	10.16
77.5	25,844		0.0000	1.0000	9.97
78.5					9.97

NEWFOUNDLAND POWER INC.
ACCOUNT 353.20 - TRANSMISSION - UNDERGROUND CABLE (14L)
SMOOTH SURVIVOR CURVE



NEWFOUNDLAND POWER INC.
ACCOUNT 355.10 & 355.20 - TRANSMISSION - POLES AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 355.10 & 355.20 - TRANSMISSION - POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2009

EXPERIENCE BAND 1948-2009

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	59,817,674	15,731	0.0003	0.9997	100.00
0.5	57,112,175	126,558	0.0022	0.9978	99.97
1.5	51,006,278	194,247	0.0038	0.9962	99.75
2.5	47,204,257	129,895	0.0028	0.9972	99.37
3.5	44,516,619	133,196	0.0030	0.9970	99.10
4.5	42,190,517	103,847	0.0025	0.9975	98.80
5.5	41,454,863	229,154	0.0055	0.9945	98.56
6.5	38,962,395	104,911	0.0027	0.9973	98.01
7.5	37,491,372	141,714	0.0038	0.9962	97.75
8.5	36,120,439	139,704	0.0039	0.9961	97.38
9.5	35,668,961	150,423	0.0042	0.9958	97.00
10.5	34,443,653	138,550	0.0040	0.9960	96.60
11.5	33,347,113	130,614	0.0039	0.9961	96.21
12.5	32,342,414	174,019	0.0054	0.9946	95.83
13.5	31,702,555	292,422	0.0092	0.9908	95.31
14.5	31,028,726	203,419	0.0066	0.9934	94.44
15.5	29,908,932	133,069	0.0044	0.9956	93.82
16.5	29,020,467	190,203	0.0066	0.9934	93.40
17.5	27,516,777	261,032	0.0095	0.9905	92.79
18.5	26,305,297	230,687	0.0088	0.9912	91.91
19.5	24,619,607	218,947	0.0089	0.9911	91.10
20.5	23,474,636	107,154	0.0046	0.9954	90.29
21.5	22,550,366	422,225	0.0187	0.9813	89.88
22.5	21,206,880	401,342	0.0189	0.9811	88.20
23.5	20,181,913	147,950	0.0073	0.9927	86.53
24.5	19,162,579	175,563	0.0092	0.9908	85.89
25.5	18,005,870	126,854	0.0070	0.9930	85.10
26.5	16,240,410	89,246	0.0055	0.9945	84.51
27.5	15,073,667	134,174	0.0089	0.9911	84.04
28.5	12,198,248	110,672	0.0091	0.9909	83.29
29.5	11,358,289	160,069	0.0141	0.9859	82.54
30.5	11,029,216	148,341	0.0134	0.9866	81.37
31.5	10,029,741	136,477	0.0136	0.9864	80.28
32.5	9,628,218	122,790	0.0128	0.9872	79.19
33.5	6,166,786	129,909	0.0211	0.9789	78.18
34.5	4,546,363	151,611	0.0333	0.9667	76.53
35.5	3,716,334	69,169	0.0186	0.9814	73.98
36.5	3,344,618	143,622	0.0429	0.9571	72.60
37.5	2,795,145	73,928	0.0264	0.9736	69.48
38.5	2,278,673	71,990	0.0316	0.9684	67.65

NEWFOUNDLAND POWER INC.

ACCOUNT 355.10 & 355.20 - TRANSMISSION - POLES AND FIXTURES

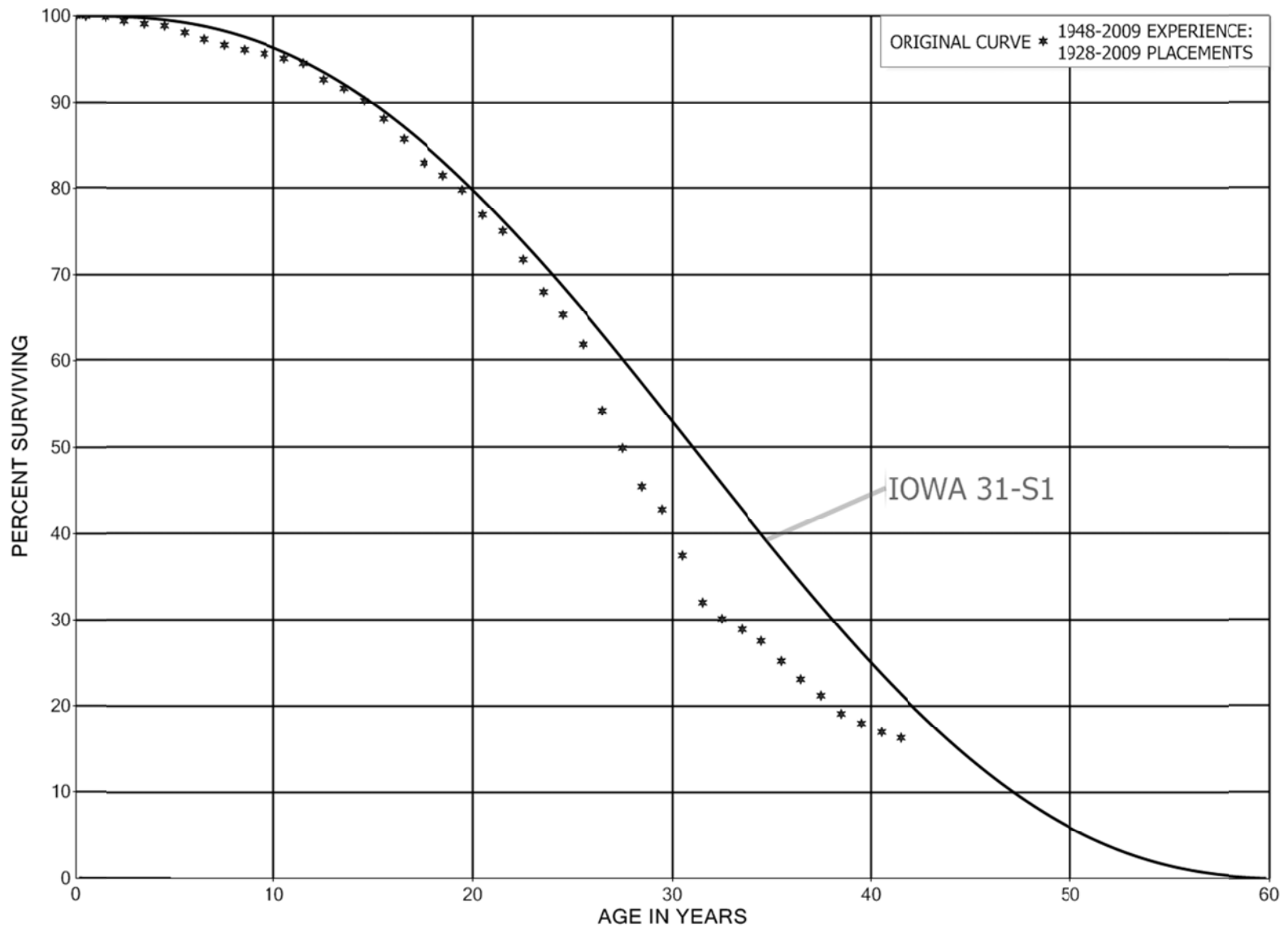
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2009

EXPERIENCE BAND 1948-2009

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	2,374,199	58,696	0.0247	0.9753	65.51
40.5	2,161,517	67,252	0.0311	0.9689	63.89
41.5	1,564,883	6,683	0.0043	0.9957	61.90
42.5	1,464,694	58,421	0.0399	0.9601	61.64
43.5	1,474,779	67,235	0.0456	0.9544	59.18
44.5	1,090,294	62,499	0.0573	0.9427	56.48
45.5	998,553	16,618	0.0166	0.9834	53.24
46.5	611,391	6,252	0.0102	0.9898	52.36
47.5	430,668	26,984	0.0627	0.9373	51.82
48.5	385,495	15,608	0.0405	0.9595	48.57
49.5	650,114	9,485	0.0146	0.9854	46.61
50.5	512,411	80,313	0.1567	0.8433	45.93
51.5	433,997	33,024	0.0761	0.9239	38.73
52.5	387,406	14,070	0.0363	0.9637	35.78
53.5	341,372	39,817	0.1166	0.8834	34.48
54.5	311,854	12,142	0.0389	0.9611	30.46
55.5	290,596	2,884	0.0099	0.9901	29.27
56.5	285,105	867	0.0030	0.9970	28.98
57.5	273,617	262	0.0010	0.9990	28.90
58.5	273,656	2,405	0.0088	0.9912	28.87
59.5	271,251	462	0.0017	0.9983	28.61
60.5	270,488	57	0.0002	0.9998	28.57
61.5	270,431	47	0.0002	0.9998	28.56
62.5	270,384	3,533	0.0131	0.9869	28.55
63.5	270,374	1,717	0.0064	0.9936	28.18
64.5	268,657		0.0000	1.0000	28.00
65.5	268,657		0.0000	1.0000	28.00
66.5	268,657		0.0000	1.0000	28.00
67.5	268,657	48	0.0002	0.9998	28.00
68.5	268,609	546	0.0020	0.9980	28.00
69.5	268,063		0.0000	1.0000	27.94
70.5	268,063	1,931	0.0072	0.9928	27.94
71.5	266,132	62	0.0002	0.9998	27.74
72.5	266,070		0.0000	1.0000	27.73
73.5	266,070		0.0000	1.0000	27.73
74.5	269,727	135	0.0005	0.9995	27.73
75.5	269,592		0.0000	1.0000	27.72
76.5	267,118	464	0.0017	0.9983	27.72
77.5	266,654	14	0.0001	0.9999	27.67
78.5	262,195		0.0000	1.0000	27.67
79.5					27.67

NEWFOUNDLAND POWER INC.
ACCOUNT 355.30 - TRANSMISSION - INSULATORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 355.30 - TRANSMISSION - INSULATORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2009

EXPERIENCE BAND 1948-2009

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	23,898,796	2,664	0.0001	0.9999	100.00
0.5	23,549,603	28,687	0.0012	0.9988	99.99
1.5	23,212,774	102,411	0.0044	0.9956	99.87
2.5	22,595,742	74,144	0.0033	0.9967	99.43
3.5	21,053,506	65,028	0.0031	0.9969	99.10
4.5	20,181,742	150,389	0.0075	0.9925	98.79
5.5	19,416,295	156,857	0.0081	0.9919	98.06
6.5	18,412,504	119,809	0.0065	0.9935	97.27
7.5	17,374,380	94,345	0.0054	0.9946	96.63
8.5	16,430,162	81,525	0.0050	0.9950	96.11
9.5	15,873,683	93,683	0.0059	0.9941	95.63
10.5	14,916,998	86,482	0.0058	0.9942	95.07
11.5	13,954,639	272,641	0.0195	0.9805	94.52
12.5	12,492,629	143,064	0.0115	0.9885	92.67
13.5	11,270,688	175,689	0.0156	0.9844	91.61
14.5	10,127,599	234,628	0.0232	0.9768	90.18
15.5	9,167,854	248,540	0.0271	0.9729	88.09
16.5	8,374,722	270,575	0.0323	0.9677	85.70
17.5	7,201,440	124,396	0.0173	0.9827	82.93
18.5	6,124,617	127,817	0.0209	0.9791	81.50
19.5	4,491,993	161,176	0.0359	0.9641	79.80
20.5	3,651,410	89,982	0.0246	0.9754	76.94
21.5	3,377,814	150,566	0.0446	0.9554	75.04
22.5	3,052,323	157,919	0.0517	0.9483	71.70
23.5	2,708,695	106,821	0.0394	0.9606	67.99
24.5	2,379,365	127,828	0.0537	0.9463	65.31
25.5	2,160,454	267,729	0.1239	0.8761	61.80
26.5	1,752,731	137,721	0.0786	0.9214	54.14
27.5	1,545,986	137,693	0.0891	0.9109	49.88
28.5	1,233,016	74,001	0.0600	0.9400	45.44
29.5	1,087,050	135,167	0.1243	0.8757	42.71
30.5	970,804	140,856	0.1451	0.8549	37.40
31.5	752,589	44,413	0.0590	0.9410	31.98
32.5	565,261	24,582	0.0435	0.9565	30.09
33.5	475,432	20,490	0.0431	0.9569	28.78
34.5	431,208	37,802	0.0877	0.9123	27.54
35.5	371,052	30,528	0.0823	0.9177	25.13
36.5	355,298	28,293	0.0796	0.9204	23.06
37.5	323,853	33,605	0.1038	0.8962	21.22
38.5	289,309	15,858	0.0548	0.9452	19.02

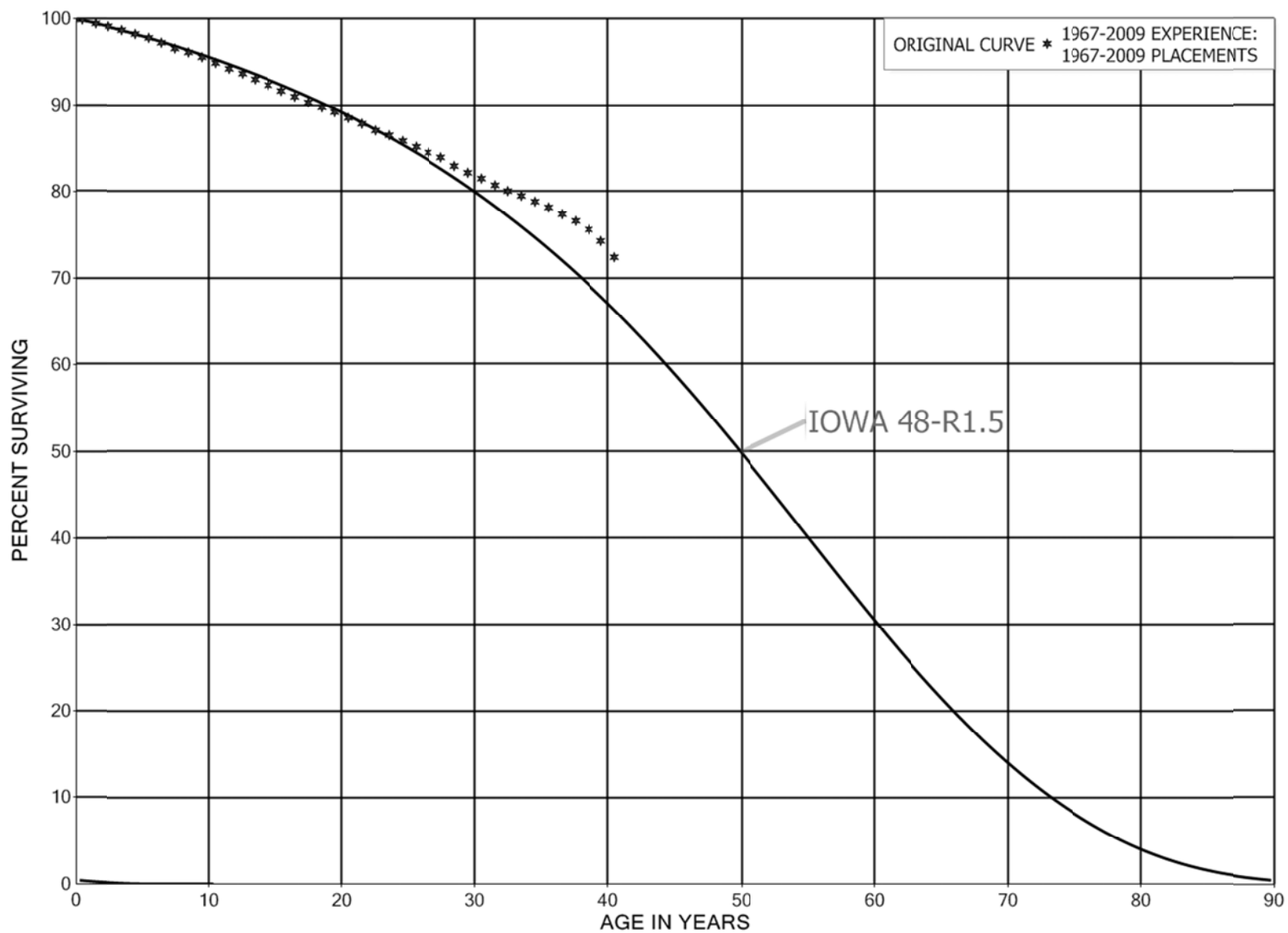
NEWFOUNDLAND POWER INC.

ACCOUNT 355.30 - TRANSMISSION - INSULATORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2009			EXPERIENCE BAND 1948-2009		
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	265,333	15,744	0.0593	0.9407	17.98
40.5	246,492	8,438	0.0342	0.9658	16.91
41.5	188,744	10,079	0.0534	0.9466	16.33
42.5	225,178	7,678	0.0341	0.9659	15.46
43.5	185,901	12,956	0.0697	0.9303	14.93
44.5	145,960	9,121	0.0625	0.9375	13.89
45.5	129,096	21,507	0.1666	0.8334	13.02
46.5	71,756	19,684	0.2743	0.7257	10.85
47.5	56,107	3,319	0.0591	0.9409	7.88
48.5	35,055	690	0.0197	0.9803	7.41
49.5	49,611	12,872	0.2595	0.7405	7.26
50.5	34,338	17,172	0.5001	0.4999	5.38
51.5	17,133	237	0.0138	0.9862	2.69
52.5	16,896	336	0.0199	0.9801	2.65
53.5	23,255	10,378	0.4462	0.5538	2.60
54.5	16,119	4,121	0.2557	0.7443	1.44
55.5	11,537		0.0000	1.0000	1.07
56.5	11,537	6,106	0.5293	0.4707	1.07
57.5	5,431	135	0.0249	0.9751	0.50
58.5	5,296	693	0.1309	0.8691	0.49
59.5	4,603	176	0.0382	0.9618	0.43
60.5	4,427	43	0.0097	0.9903	0.41
61.5	4,384	38	0.0087	0.9913	0.41
62.5	4,346	607	0.1397	0.8603	0.40
63.5	4,332	135	0.0312	0.9688	0.35
64.5	4,197		0.0000	1.0000	0.34
65.5	4,197		0.0000	1.0000	0.34
66.5	4,197		0.0000	1.0000	0.34
67.5	4,197	143	0.0341	0.9659	0.34
68.5	4,054	3,641	0.8981	0.1019	0.32
69.5	413		0.0000	1.0000	0.03
70.5	413	413	1.0000		0.03
71.5					
72.5					
73.5					
74.5	745	47	0.0631		
75.5	698		0.0000		
76.5	466	234	0.5031		
77.5	232	208	0.8981		
78.5					

NEWFOUNDLAND POWER INC.
ACCOUNT 361.10 - BARE COPPER & 362.1 / 362.2 - POLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 361.10 - BARE COPPER & 362.1 / 362.2 - POLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2009

EXPERIENCE BAND 1967-2009

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	364,373,114	731,198	0.0020	0.9980	100.00
0.5	349,300,839	1,289,379	0.0037	0.9963	99.80
1.5	336,239,077	1,281,014	0.0038	0.9962	99.43
2.5	324,243,477	1,298,258	0.0040	0.9960	99.05
3.5	309,277,588	1,444,009	0.0047	0.9953	98.66
4.5	299,316,220	1,325,645	0.0044	0.9956	98.19
5.5	290,599,757	1,783,975	0.0061	0.9939	97.76
6.5	281,710,887	1,787,208	0.0063	0.9937	97.16
7.5	272,721,425	1,474,862	0.0054	0.9946	96.54
8.5	262,679,774	1,413,325	0.0054	0.9946	96.02
9.5	252,783,721	1,719,242	0.0068	0.9932	95.50
10.5	244,689,727	1,634,783	0.0067	0.9933	94.86
11.5	235,872,834	1,628,726	0.0069	0.9931	94.22
12.5	226,507,590	1,503,275	0.0066	0.9934	93.57
13.5	214,817,585	1,454,746	0.0068	0.9932	92.95
14.5	200,985,193	1,474,095	0.0073	0.9927	92.32
15.5	187,332,101	1,383,231	0.0074	0.9926	91.64
16.5	172,836,938	1,227,225	0.0071	0.9929	90.97
17.5	158,064,126	991,628	0.0063	0.9937	90.32
18.5	143,520,666	955,944	0.0067	0.9933	89.75
19.5	127,370,491	918,366	0.0072	0.9928	89.16
20.5	114,572,928	940,738	0.0082	0.9918	88.51
21.5	103,575,364	831,399	0.0080	0.9920	87.79
22.5	92,487,252	670,571	0.0073	0.9927	87.08
23.5	82,720,464	609,230	0.0074	0.9926	86.45
24.5	74,172,757	514,855	0.0069	0.9931	85.81
25.5	65,362,218	543,330	0.0083	0.9917	85.22
26.5	58,109,902	425,276	0.0073	0.9927	84.51
27.5	51,577,083	598,124	0.0116	0.9884	83.89
28.5	44,719,926	381,542	0.0085	0.9915	82.92
29.5	37,756,542	337,028	0.0089	0.9911	82.21
30.5	32,434,046	289,647	0.0089	0.9911	81.48
31.5	27,403,989	234,595	0.0086	0.9914	80.75
32.5	22,696,143	171,385	0.0076	0.9924	80.06
33.5	18,443,195	150,525	0.0082	0.9918	79.45
34.5	13,806,050	117,588	0.0085	0.9915	78.81
35.5	10,782,389	95,438	0.0089	0.9911	78.13
36.5	8,387,466	87,948	0.0105	0.9895	77.44
37.5	6,730,340	87,366	0.0130	0.9870	76.63
38.5	4,765,081	82,985	0.0174	0.9826	75.64

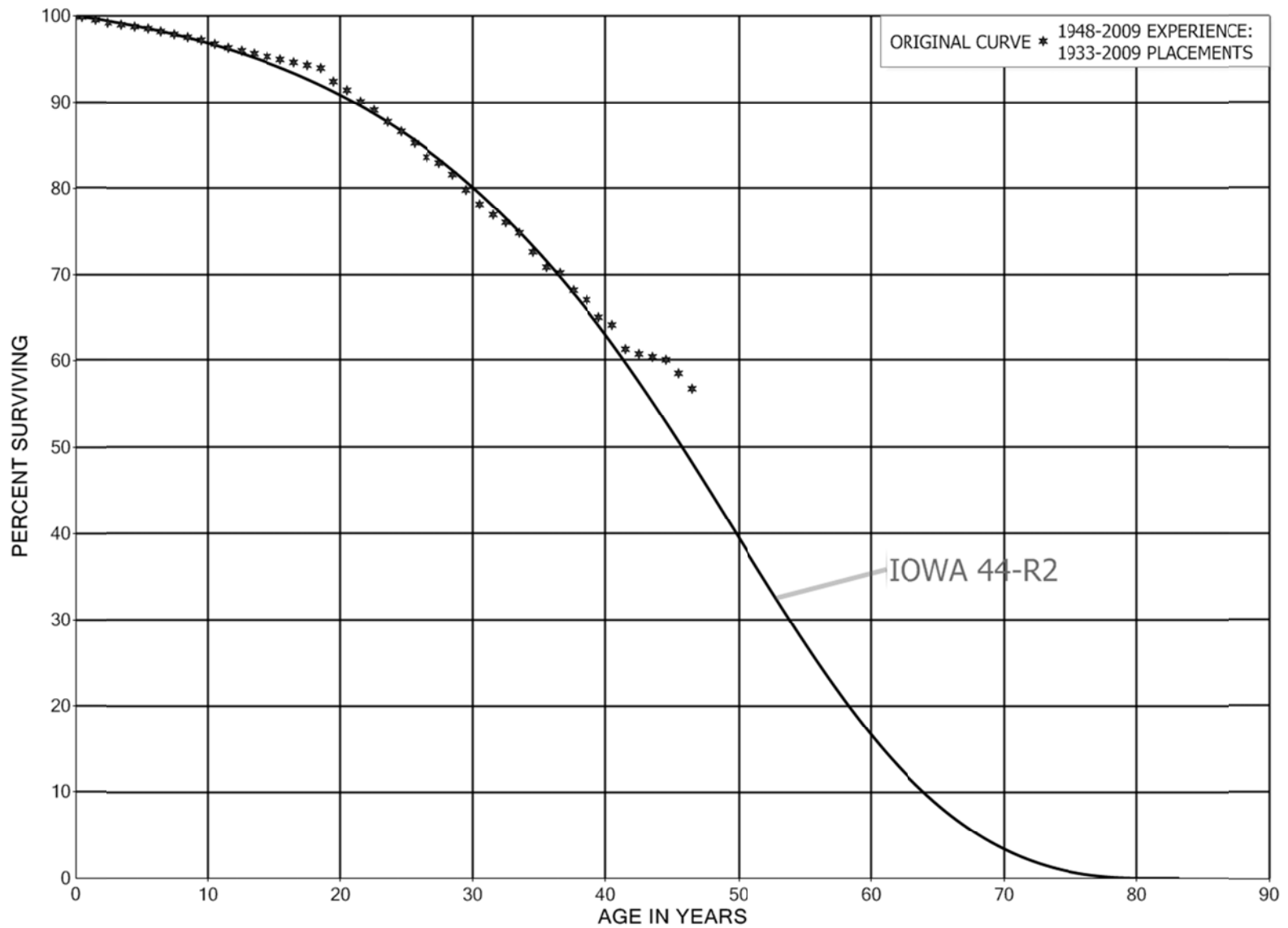
NEWFOUNDLAND POWER INC.

ACCOUNT 361.10 - BARE COPPER & 362.1 / 362.2 - POLES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1967-2009			EXPERIENCE BAND 1967-2009		
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	3,517,827	91,458	0.0260	0.9740	74.32
40.5	1,871,531	61,033	0.0326	0.9674	72.39
41.5	977,144	38,218	0.0391	0.9609	70.03
42.5					67.29

NEWFOUNDLAND POWER INC.
ACCOUNT 361.11-W/P COPPER & 361.15-DUPLEX & 365.1-SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 361.11-W/P COPPER & 361.15-DUPLEX & 365.1-SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1933-2009

EXPERIENCE BAND 1948-2009

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	83,931,596	174,286	0.0021	0.9979	100.00
0.5	79,716,991	237,454	0.0030	0.9970	99.79
1.5	76,241,998	207,050	0.0027	0.9973	99.50
2.5	73,660,866	174,076	0.0024	0.9976	99.22
3.5	71,246,419	184,606	0.0026	0.9974	98.99
4.5	68,865,531	188,383	0.0027	0.9973	98.73
5.5	66,825,539	206,372	0.0031	0.9969	98.46
6.5	65,065,147	232,055	0.0036	0.9964	98.16
7.5	63,040,581	222,035	0.0035	0.9965	97.81
8.5	61,157,759	195,968	0.0032	0.9968	97.47
9.5	59,578,483	277,079	0.0047	0.9953	97.15
10.5	57,817,479	230,362	0.0040	0.9960	96.70
11.5	56,166,178	215,547	0.0038	0.9962	96.32
12.5	54,409,292	182,755	0.0034	0.9966	95.95
13.5	52,688,498	189,332	0.0036	0.9964	95.62
14.5	50,550,172	179,026	0.0035	0.9965	95.28
15.5	48,019,944	153,741	0.0032	0.9968	94.94
16.5	45,141,367	162,407	0.0036	0.9964	94.64
17.5	41,979,702	142,548	0.0034	0.9966	94.30
18.5	38,767,723	631,570	0.0163	0.9837	93.98
19.5	35,240,355	389,935	0.0111	0.9889	92.45
20.5	31,843,323	468,023	0.0147	0.9853	91.42
21.5	28,679,406	309,134	0.0108	0.9892	90.08
22.5	25,920,598	396,379	0.0153	0.9847	89.11
23.5	23,304,167	301,250	0.0129	0.9871	87.75
24.5	20,824,066	331,160	0.0159	0.9841	86.61
25.5	18,035,753	333,558	0.0185	0.9815	85.24
26.5	15,922,436	139,533	0.0088	0.9912	83.66
27.5	14,191,571	216,832	0.0153	0.9847	82.93
28.5	12,330,914	279,374	0.0227	0.9773	81.66
29.5	10,672,370	219,322	0.0206	0.9794	79.81
30.5	9,153,330	148,041	0.0162	0.9838	78.17
31.5	7,982,615	92,045	0.0115	0.9885	76.90
32.5	6,944,758	110,224	0.0159	0.9841	76.02
33.5	5,864,771	169,233	0.0289	0.9711	74.81
34.5	4,777,824	116,541	0.0244	0.9756	72.65
35.5	3,962,979	41,738	0.0105	0.9895	70.88
36.5	3,350,531	91,962	0.0274	0.9726	70.13
37.5	2,912,376	47,947	0.0165	0.9835	68.21
38.5	2,496,199	78,786	0.0316	0.9684	67.09

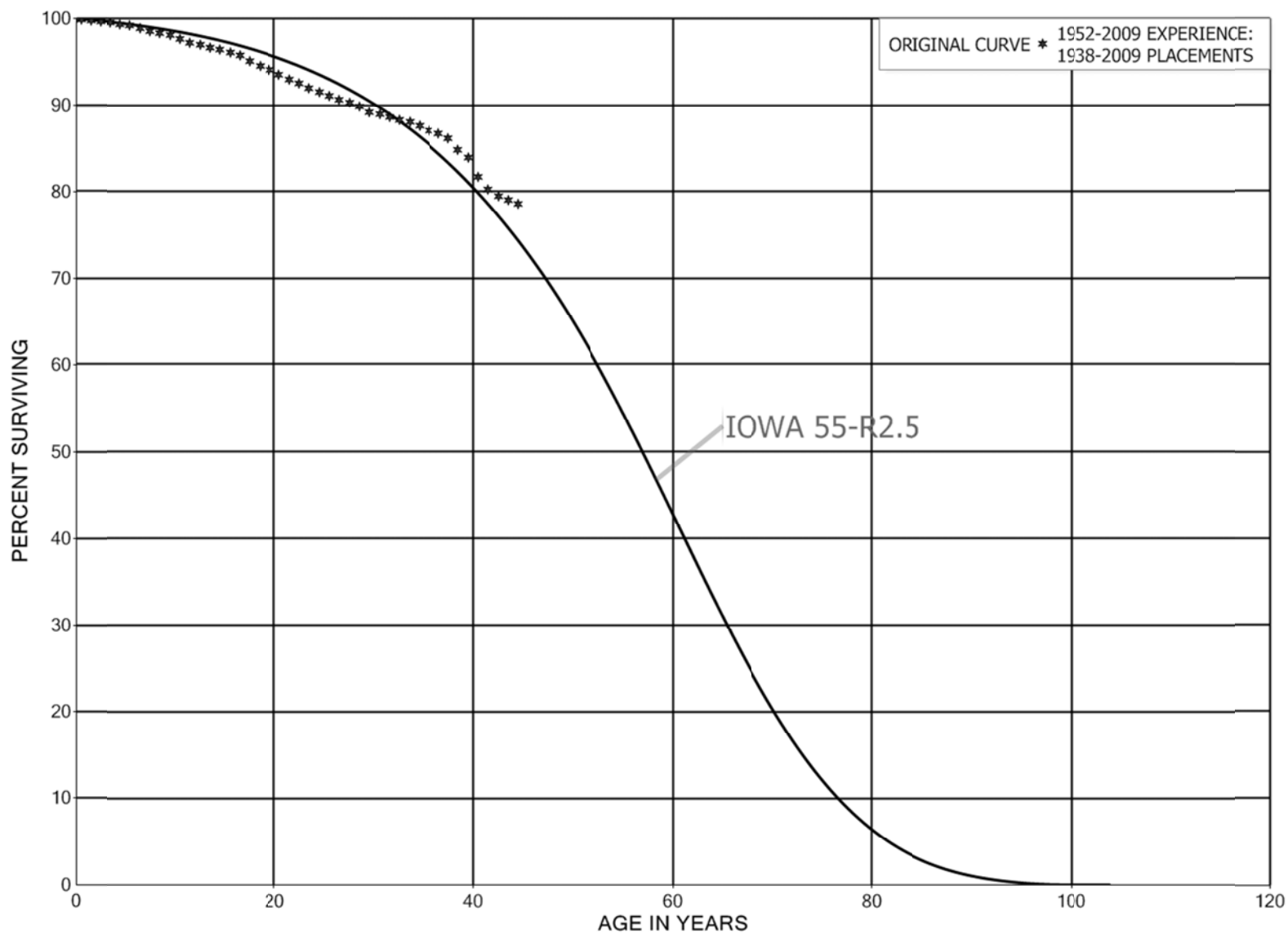
NEWFOUNDLAND POWER INC.

ACCOUNT 361.11-W/P COPPER & 361.15-DUPLEX & 365.1-SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1933-2009			EXPERIENCE BAND 1948-2009		
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	2,197,470	31,233	0.0142	0.9858	64.97
40.5	1,930,645	84,581	0.0438	0.9562	64.04
41.5	1,596,373	12,849	0.0080	0.9920	61.24
42.5	1,452,931	7,402	0.0051	0.9949	60.75
43.5	1,316,898	9,103	0.0069	0.9931	60.44
44.5	1,075,066	26,891	0.0250	0.9750	60.02
45.5	890,268	26,458	0.0297	0.9703	58.52
46.5	741,211	33,292	0.0449	0.9551	56.78
47.5	474,575	895	0.0019	0.9981	54.23
48.5	341,636	18,918	0.0554	0.9446	54.13
49.5	141,356	21,961	0.1554	0.8446	51.13
50.5					43.19

NEWFOUNDLAND POWER INC.
ACCOUNT 361.12 - OVERHEAD CONDUCTORS - BARE ALUMINUM
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 - OVERHEAD CONDUCTORS - BARE ALUMINUM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2009			EXPERIENCE BAND 1952-2009		
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	103,582,095	123,827	0.0012	0.9988	100.00
0.5	100,012,004	150,565	0.0015	0.9985	99.88
1.5	95,504,322	116,944	0.0012	0.9988	99.73
2.5	92,438,744	126,021	0.0014	0.9986	99.61
3.5	87,460,664	156,287	0.0018	0.9982	99.47
4.5	83,760,475	138,525	0.0017	0.9983	99.29
5.5	80,338,266	255,661	0.0032	0.9968	99.13
6.5	76,718,784	215,609	0.0028	0.9972	98.81
7.5	74,251,500	180,612	0.0024	0.9976	98.54
8.5	70,985,204	200,972	0.0028	0.9972	98.30
9.5	68,023,294	252,291	0.0037	0.9963	98.02
10.5	64,682,393	283,304	0.0044	0.9956	97.66
11.5	62,334,532	186,266	0.0030	0.9970	97.23
12.5	60,117,657	166,480	0.0028	0.9972	96.94
13.5	58,489,740	169,686	0.0029	0.9971	96.67
14.5	56,398,215	180,989	0.0032	0.9968	96.39
15.5	53,710,879	214,997	0.0040	0.9960	96.08
16.5	50,774,129	316,896	0.0062	0.9938	95.69
17.5	47,060,318	270,465	0.0057	0.9943	95.10
18.5	43,740,126	242,878	0.0056	0.9944	94.55
19.5	39,782,532	215,353	0.0054	0.9946	94.03
20.5	36,574,525	211,535	0.0058	0.9942	93.52
21.5	33,643,574	154,236	0.0046	0.9954	92.98
22.5	31,059,357	191,333	0.0062	0.9938	92.55
23.5	28,694,797	136,158	0.0047	0.9953	91.98
24.5	26,421,212	145,540	0.0055	0.9945	91.54
25.5	23,845,605	102,070	0.0043	0.9957	91.04
26.5	21,677,670	80,461	0.0037	0.9963	90.65
27.5	19,483,507	111,100	0.0057	0.9943	90.31
28.5	17,106,101	115,664	0.0068	0.9932	89.80
29.5	14,331,284	44,079	0.0031	0.9969	89.19
30.5	12,567,595	36,577	0.0029	0.9971	88.92
31.5	10,742,341	43,755	0.0041	0.9959	88.66
32.5	8,724,020	27,598	0.0032	0.9968	88.30
33.5	7,222,507	33,754	0.0047	0.9953	88.02
34.5	5,594,905	31,971	0.0057	0.9943	87.61
35.5	4,605,586	20,544	0.0045	0.9955	87.10
36.5	3,822,152	24,285	0.0064	0.9936	86.72
37.5	3,318,233	53,233	0.0160	0.9840	86.17
38.5	2,779,631	26,775	0.0096	0.9904	84.78

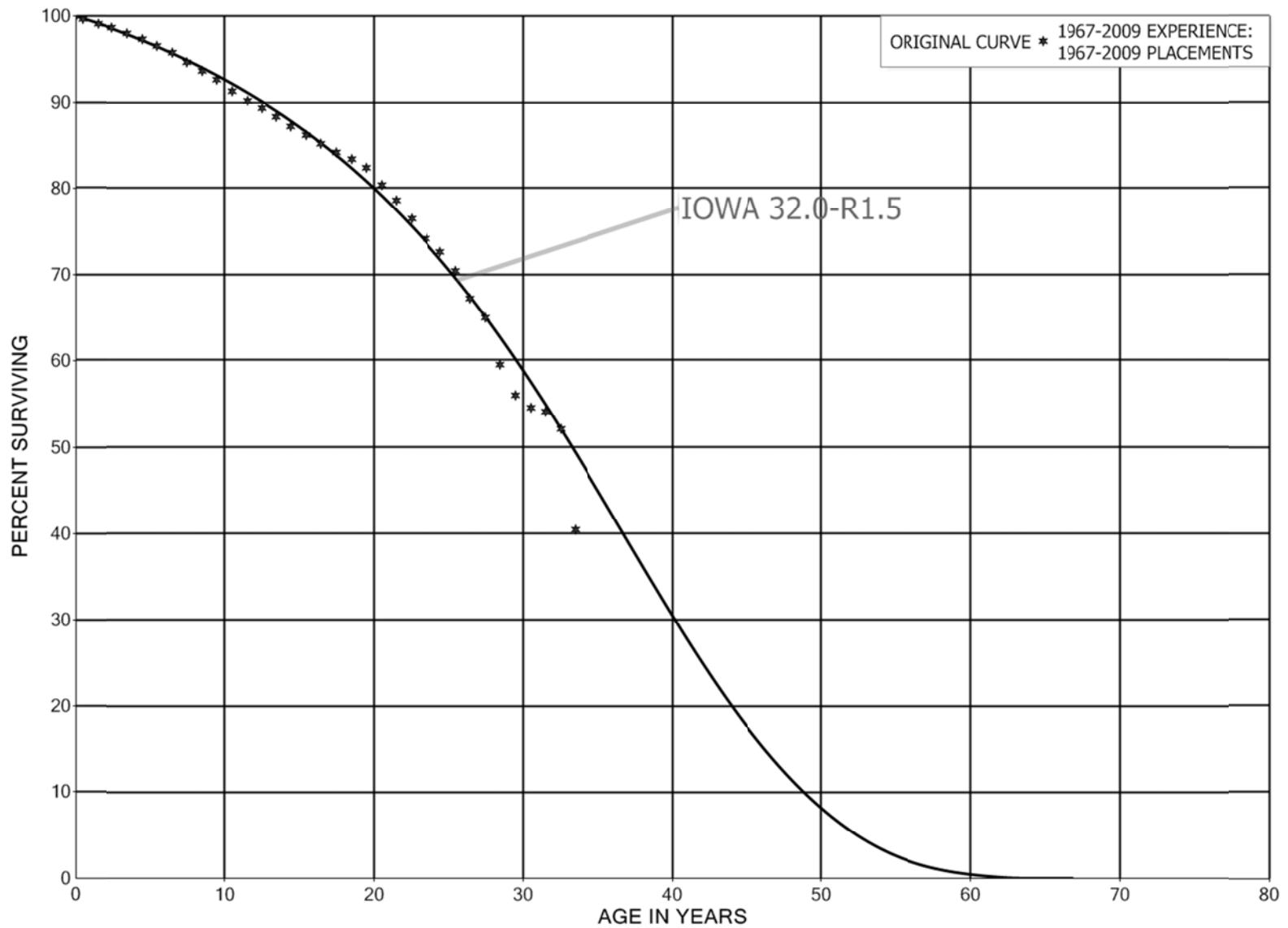
NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 - OVERHEAD CONDUCTORS - BARE ALUMINUM

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2009			EXPERIENCE BAND 1952-2009		
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	2,549,611	68,310	0.0268	0.9732	83.97
40.5	2,123,378	37,450	0.0176	0.9824	81.72
41.5	1,938,593	18,333	0.0095	0.9905	80.28
42.5	1,765,788	11,158	0.0063	0.9937	79.52
43.5	1,127,142	6,432	0.0057	0.9943	79.01
44.5	233,985	6,325	0.0270	0.9730	78.56
45.5	98,256	10,075	0.1025	0.8975	76.44
46.5					68.60

NEWFOUNDLAND POWER INC.
ACCOUNT 361.13 - OVERHEAD CONDUCTORS - W/P ALUMINUM
ORIGINAL AND SMOOTH SURVIVOR CURVES



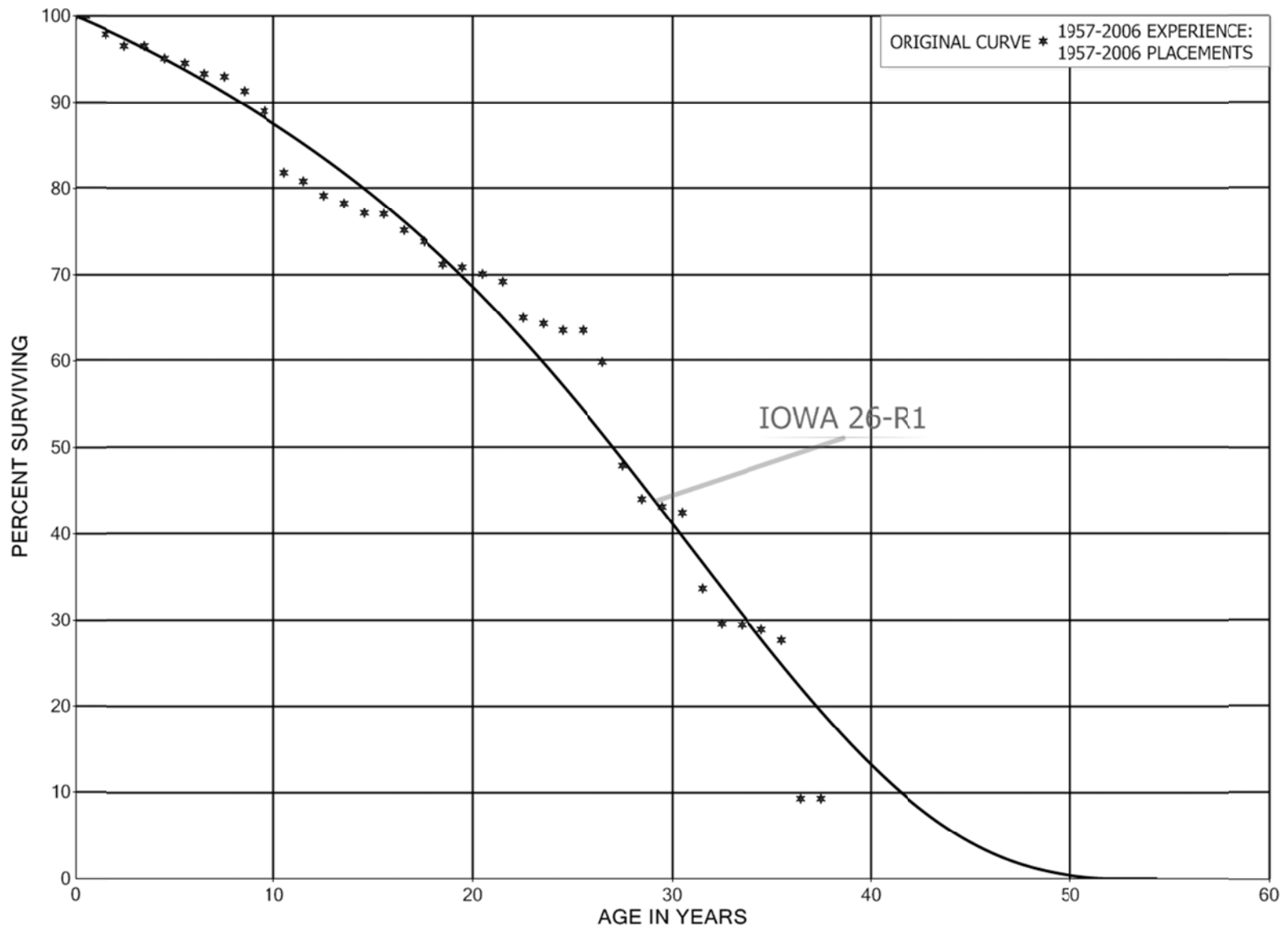
NEWFOUNDLAND POWER INC.

ACCOUNT 361.13 - OVERHEAD CONDUCTORS - W/P ALUMINUM

ORIGINAL LIFE TABLE

PLACEMENT BAND 1967-2009			EXPERIENCE BAND 1967-2009		
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	34,265,419	150,008	0.0044	0.9956	100.00
0.5	32,554,436	155,080	0.0048	0.9952	99.56
1.5	30,760,113	154,710	0.0050	0.9950	99.09
2.5	29,046,238	171,115	0.0059	0.9941	98.59
3.5	27,615,684	212,208	0.0077	0.9923	98.01
4.5	26,364,127	198,361	0.0075	0.9925	97.26
5.5	25,204,586	213,720	0.0085	0.9915	96.52
6.5	24,111,047	262,623	0.0109	0.9891	95.71
7.5	23,226,789	264,583	0.0114	0.9886	94.66
8.5	22,340,432	232,172	0.0104	0.9896	93.58
9.5	21,751,056	307,322	0.0141	0.9859	92.61
10.5	20,896,059	257,214	0.0123	0.9877	91.30
11.5	20,042,027	202,521	0.0101	0.9899	90.18
12.5	19,234,772	222,993	0.0116	0.9884	89.27
13.5	18,379,973	219,678	0.0120	0.9880	88.23
14.5	17,505,414	205,922	0.0118	0.9882	87.18
15.5	16,462,207	196,891	0.0120	0.9880	86.15
16.5	15,343,572	166,495	0.0109	0.9891	85.12
17.5	14,087,113	125,556	0.0089	0.9911	84.20
18.5	13,153,220	159,229	0.0121	0.9879	83.45
19.5	11,927,662	293,497	0.0246	0.9754	82.44
20.5	10,835,842	238,123	0.0220	0.9780	80.41
21.5	10,001,938	272,488	0.0272	0.9728	78.64
22.5	9,271,369	279,766	0.0302	0.9698	76.50
23.5	8,491,289	177,724	0.0209	0.9791	74.19
24.5	7,803,666	240,081	0.0308	0.9692	72.64
25.5	7,048,517	320,638	0.0455	0.9545	70.40
26.5	6,186,978	204,886	0.0331	0.9669	67.20
27.5	5,368,078	452,713	0.0843	0.9157	64.98
28.5	3,923,548	237,359	0.0605	0.9395	59.50
29.5	2,858,632	70,340	0.0246	0.9754	55.90
30.5	1,832,196	16,276	0.0089	0.9911	54.52
31.5	1,154,744	42,288	0.0366	0.9634	54.04
32.5	487,993	109,035	0.2234	0.7766	52.06
33.5					40.43

NEWFOUNDLAND POWER INC.
ACCOUNT 361.14 AERIAL CABLE/361.30 SPECIAL INSUL. COPPER
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 361.14 AERIAL CABLE/361.30 SPECIAL INSUL. COPPER

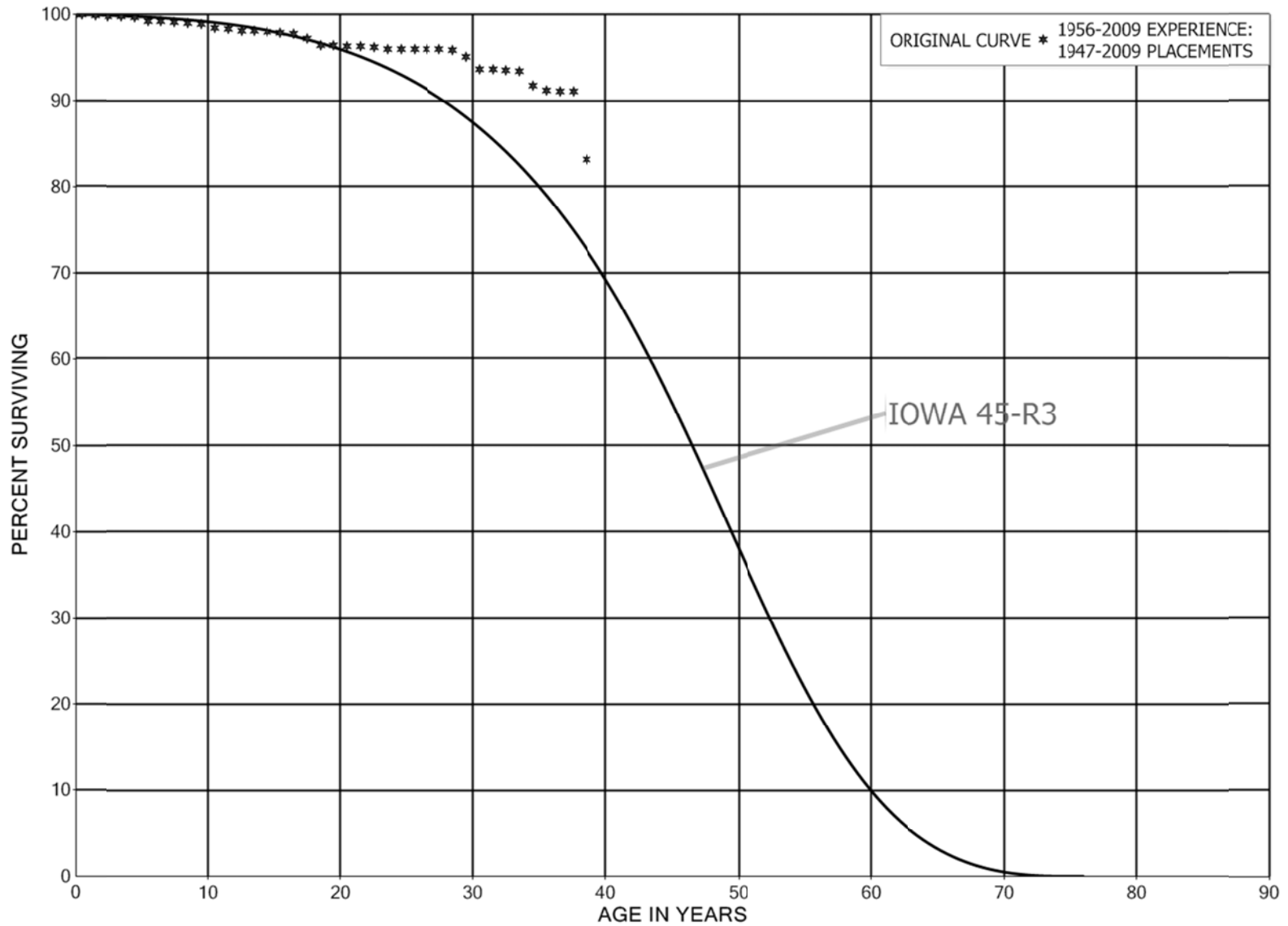
ORIGINAL LIFE TABLE

PLACEMENT BAND 1957-2006

EXPERIENCE BAND 1957-2006

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	1,325,025		0.0000	1.0000	100.00
0.5	1,314,787	29,118	0.0221	0.9779	100.00
1.5	1,279,493	17,104	0.0134	0.9866	97.79
2.5	1,277,937	345	0.0003	0.9997	96.48
3.5	1,277,592	18,404	0.0144	0.9856	96.45
4.5	1,264,645	8,067	0.0064	0.9936	95.06
5.5	1,256,578	15,425	0.0123	0.9877	94.46
6.5	1,185,930	3,678	0.0031	0.9969	93.30
7.5	1,092,932	20,600	0.0188	0.9812	93.01
8.5	1,068,710	27,042	0.0253	0.9747	91.25
9.5	1,041,668	83,188	0.0799	0.9201	88.95
10.5	958,947	11,778	0.0123	0.9877	81.84
11.5	903,786	17,995	0.0199	0.9801	80.84
12.5	862,866	10,123	0.0117	0.9883	79.23
13.5	852,743	12,538	0.0147	0.9853	78.30
14.5	853,952	784	0.0009	0.9991	77.15
15.5	829,548	20,505	0.0247	0.9753	77.08
16.5	824,866	14,483	0.0176	0.9824	75.17
17.5	686,685	24,477	0.0356	0.9644	73.85
18.5	665,673	3,283	0.0049	0.9951	71.22
19.5	485,852	5,265	0.0108	0.9892	70.87
20.5	481,174	6,286	0.0131	0.9869	70.10
21.5	468,565	28,837	0.0615	0.9385	69.18
22.5	443,831	4,324	0.0097	0.9903	64.93
23.5	349,336	4,170	0.0119	0.9881	64.29
24.5	293,718	147	0.0005	0.9995	63.53
25.5	278,674	16,154	0.0580	0.9420	63.49
26.5	262,520	52,776	0.2010	0.7990	59.81
27.5	209,479	16,997	0.0811	0.9189	47.79
28.5	173,998	3,447	0.0198	0.9802	43.91
29.5	135,301	2,073	0.0153	0.9847	43.04
30.5	103,194	21,243	0.2059	0.7941	42.38
31.5	93,321	11,581	0.1241	0.8759	33.66
32.5	80,977	170	0.0021	0.9979	29.48
33.5	75,647	1,362	0.0180	0.9820	29.42
34.5	72,789	3,256	0.0447	0.9553	28.89
35.5	59,278	39,235	0.6619	0.3381	27.60
36.5	19,988		0.0000	1.0000	9.33
37.5	4,263		0.0000	1.0000	9.33
38.5	4,263		0.0000	1.0000	9.33
39.5					9.33

NEWFOUNDLAND POWER INC.
ACCOUNT 361.20 & 367.20 - UNDERGROUND CABLE AND SWITCHES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 361.20 & 367.20 - UNDERGROUND CABLE AND SWITCHES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1947-2009

EXPERIENCE BAND 1956-2009

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	22,210,246	4,141	0.0002	0.9998	100.00
0.5	21,111,019	25,314	0.0012	0.9988	99.98
1.5	20,861,722	21,695	0.0010	0.9990	99.86
2.5	20,381,333	15,972	0.0008	0.9992	99.76
3.5	19,962,939	8,761	0.0004	0.9996	99.68
4.5	19,211,800	80,304	0.0042	0.9958	99.64
5.5	18,392,800	13,666	0.0007	0.9993	99.22
6.5	17,338,367	14,128	0.0008	0.9992	99.15
7.5	16,696,760	25,787	0.0015	0.9985	99.06
8.5	16,063,865	8,693	0.0005	0.9995	98.91
9.5	15,591,055	73,688	0.0047	0.9953	98.86
10.5	15,119,887	22,567	0.0015	0.9985	98.39
11.5	14,784,010	21,438	0.0015	0.9985	98.24
12.5	14,470,757	10,026	0.0007	0.9993	98.10
13.5	14,140,656	7,424	0.0005	0.9995	98.03
14.5	13,631,935	22,114	0.0016	0.9984	97.98
15.5	13,194,518	11,640	0.0009	0.9991	97.82
16.5	12,598,923	75,458	0.0060	0.9940	97.74
17.5	11,575,169	93,487	0.0081	0.9919	97.15
18.5	10,324,905	2,504	0.0002	0.9998	96.37
19.5	9,556,298	6,324	0.0007	0.9993	96.34
20.5	8,807,236	3,682	0.0004	0.9996	96.28
21.5	7,918,690	2,551	0.0003	0.9997	96.24
22.5	6,939,978	18,833	0.0027	0.9973	96.21
23.5	5,585,216	1,876	0.0003	0.9997	95.95
24.5	5,171,875	692	0.0001	0.9999	95.92
25.5	4,722,781		0.0000	1.0000	95.90
26.5	4,475,793	48	0.0000	1.0000	95.90
27.5	4,172,443	3,424	0.0008	0.9992	95.90
28.5	3,693,855	27,562	0.0075	0.9925	95.82
29.5	3,055,838	47,942	0.0157	0.9843	95.11
30.5	2,900,493		0.0000	1.0000	93.62
31.5	2,400,138	2,408	0.0010	0.9990	93.62
32.5	2,193,014	1,940	0.0009	0.9991	93.52
33.5	1,932,547	36,203	0.0187	0.9813	93.44
34.5	1,619,868	9,261	0.0057	0.9943	91.69
35.5	1,345,827	1,198	0.0009	0.9991	91.16
36.5	1,241,728	777	0.0006	0.9994	91.08
37.5	1,079,238	92,490	0.0857	0.9143	91.03
38.5	880,085		0.0000	1.0000	83.23

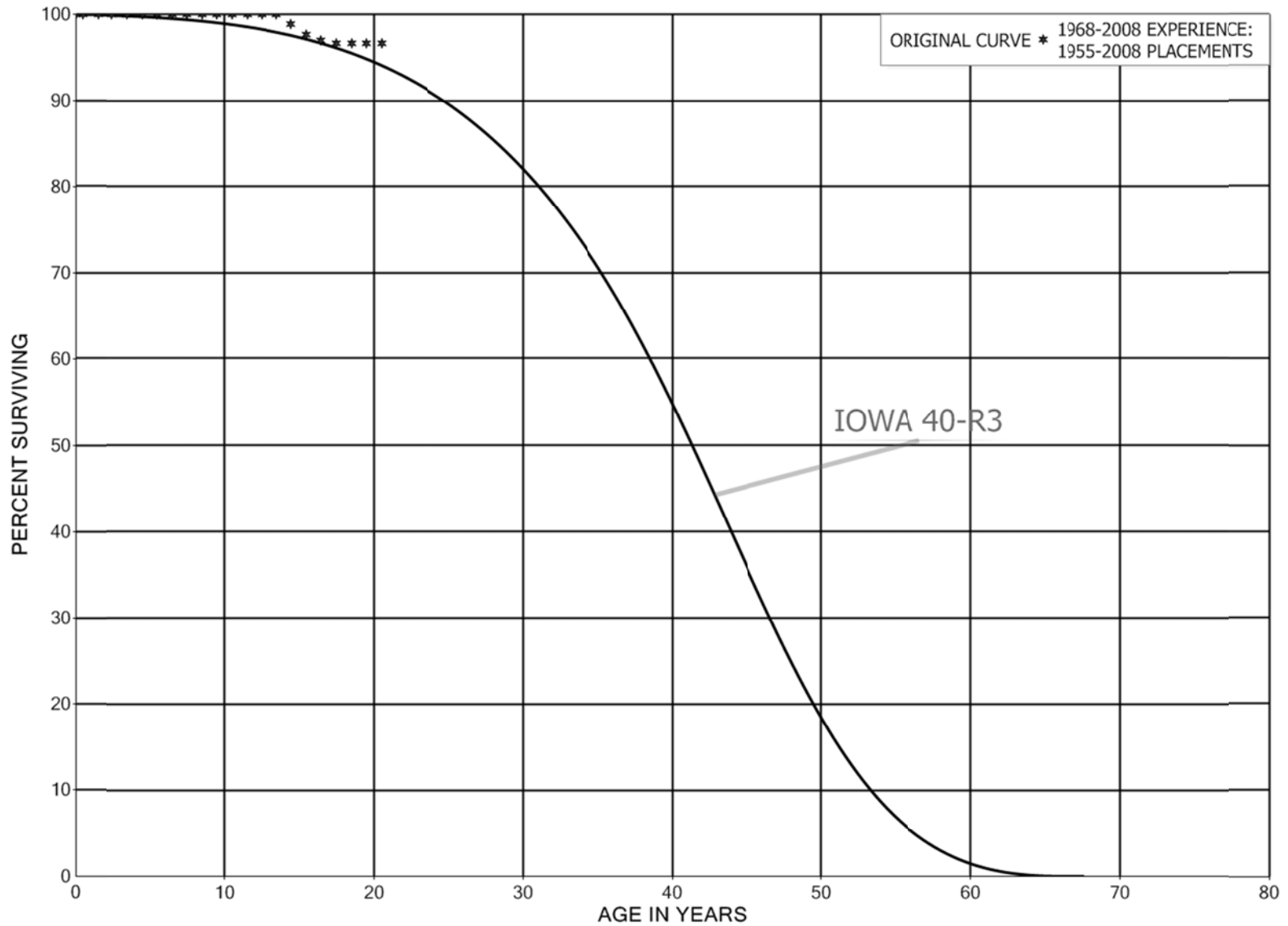
NEWFOUNDLAND POWER INC.

ACCOUNT 361.20 & 367.20 - UNDERGROUND CABLE AND SWITCHES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1947-2009			EXPERIENCE BAND 1956-2009		
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	761,645	1,097	0.0000	1.0000	83.23
40.5	631,777		0.0017	0.9983	83.23
41.5	498,436		0.0000	1.0000	83.08
42.5	160,780		0.0000	1.0000	83.08
43.5	10,818		0.0000	1.0000	83.08
44.5	10,818		0.0000	1.0000	83.08
45.5	10,818		0.0000	1.0000	83.08
46.5	10,818		0.0000	1.0000	83.08
47.5	10,818		0.0000	1.0000	83.08
48.5	10,818		0.0000	1.0000	83.08
49.5	825		0.0000	1.0000	83.08
50.5	825		0.0000	1.0000	83.08
51.5	825		0.0000	1.0000	83.08
52.5	825		0.0000	1.0000	83.08
53.5					83.08

NEWFOUNDLAND POWER INC.
ACCOUNT 361.40 - DISTRIBUTION - UNDERWATER CONDUCTORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 361.40 - DISTRIBUTION - UNDERWATER CONDUCTORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1955-2008			EXPERIENCE BAND 1968-2008		
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	3,499,831		0.0000	1.0000	100.00
0.5	3,423,982		0.0000	1.0000	100.00
1.5	3,423,982		0.0000	1.0000	100.00
2.5	3,426,222		0.0000	1.0000	100.00
3.5	3,468,963		0.0000	1.0000	100.00
4.5	3,511,898		0.0000	1.0000	100.00
5.5	3,535,183		0.0000	1.0000	100.00
6.5	3,566,889		0.0000	1.0000	100.00
7.5	3,566,889		0.0000	1.0000	100.00
8.5	3,566,889		0.0000	1.0000	100.00
9.5	3,566,889		0.0000	1.0000	100.00
10.5	3,566,889		0.0000	1.0000	100.00
11.5	3,566,889		0.0000	1.0000	100.00
12.5	3,566,889		0.0000	1.0000	100.00
13.5	3,566,889	42,742	0.0120	0.9880	100.00
14.5	3,524,147	42,935	0.0122	0.9878	98.80
15.5	3,483,583	23,285	0.0067	0.9933	97.60
16.5	3,460,298	10,296	0.0030	0.9970	96.95
17.5	3,450,002		0.0000	1.0000	96.66
18.5	1,977,919		0.0000	1.0000	96.66
19.5	1,977,919		0.0000	1.0000	96.66
20.5	26,021		0.0000	1.0000	96.66
21.5	29,055		0.0000	1.0000	96.66
22.5	29,055		0.0000	1.0000	96.66
23.5	29,055		0.0000	1.0000	96.66
24.5	29,055		0.0000	1.0000	96.66
25.5	29,055	2,371	0.0816	0.9184	96.66
26.5	29,549		0.0000	1.0000	88.77
27.5	29,549		0.0000	1.0000	88.77
28.5	29,549		0.0000	1.0000	88.77
29.5	29,549		0.0000	1.0000	88.77
30.5	31,363		0.0000	1.0000	88.77
31.5	31,363	3,034	0.0967	0.9033	88.77
32.5	28,329		0.0000	1.0000	80.18
33.5	31,066		0.0000	1.0000	80.18
34.5	46,818		0.0000	1.0000	80.18
35.5	336,723		0.0000	1.0000	80.18
36.5	336,723		0.0000	1.0000	80.18
37.5	336,723	2,865	0.0085	0.9915	80.18
38.5	333,858		0.0000	1.0000	79.50

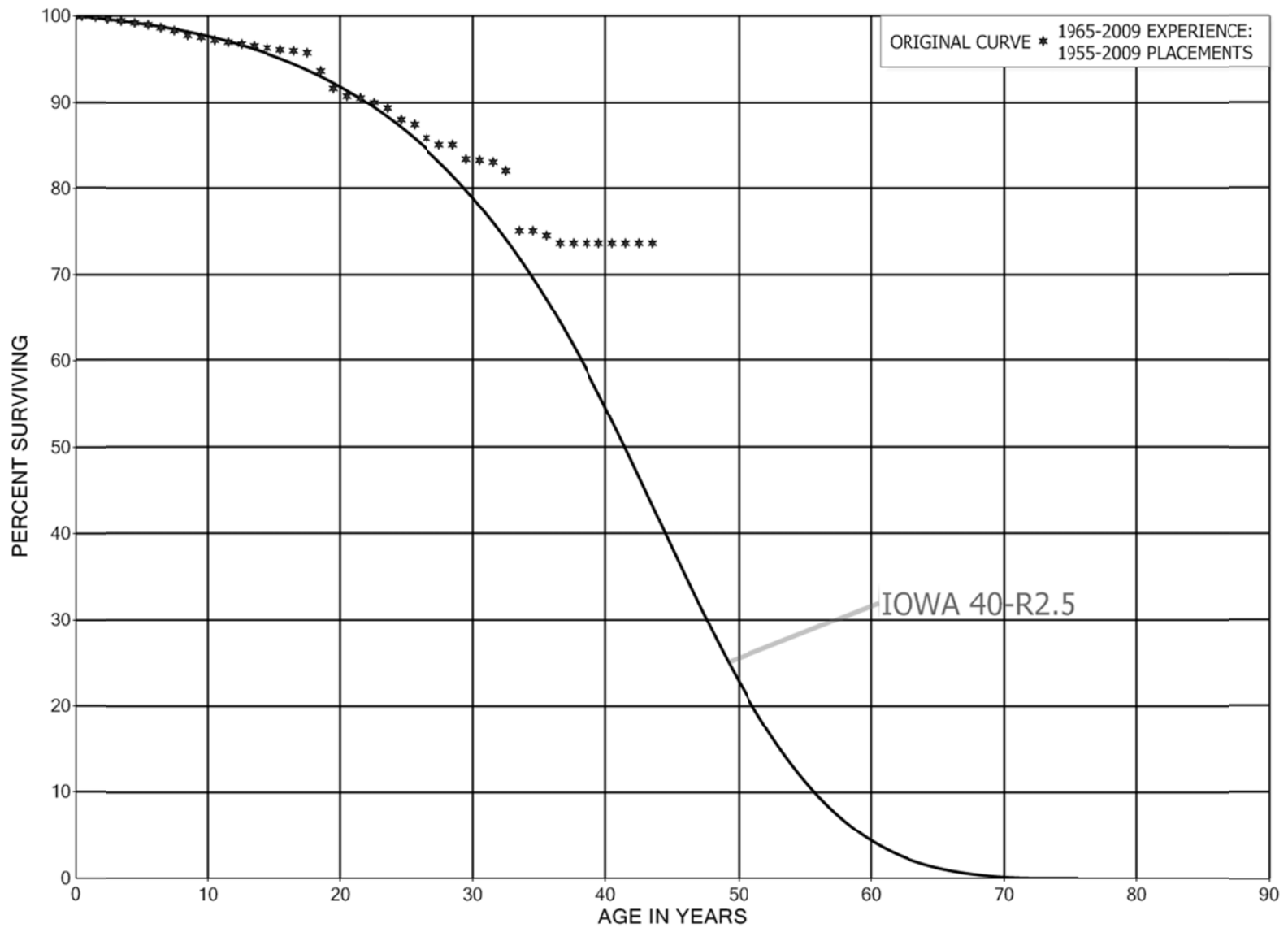
NEWFOUNDLAND POWER INC.

ACCOUNT 361.40 - DISTRIBUTION - UNDERWATER CONDUCTORS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1955-2008			EXPERIENCE BAND 1968-2008		
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	333,858		0.0000	1.0000	79.50
40.5	333,858		0.0000	1.0000	79.50
41.5	333,858	1,814	0.0054	0.9946	79.50
42.5	332,044		0.0000	1.0000	79.07
43.5	308,394		0.0000	1.0000	79.07
44.5	308,394	2,737	0.0089	0.9911	79.07
45.5	305,657	15,752	0.0515	0.9485	78.37
46.5	289,905	289,905	1.0000		74.33
47.5					

NEWFOUNDLAND POWER INC.
ACCOUNT 362.30 - DISTRIBUTION - POLES (CONCRETE & STEEL)
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 362.30 - DISTRIBUTION - POLES (CONCRETE & STEEL)

ORIGINAL LIFE TABLE

PLACEMENT BAND 1955-2009

EXPERIENCE BAND 1965-2009

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	7,447,639	1,484	0.0002	0.9998	100.00
0.5	7,104,552	9,439	0.0013	0.9987	99.98
1.5	6,787,655	13,718	0.0020	0.9980	99.85
2.5	6,546,811	17,162	0.0026	0.9974	99.65
3.5	6,365,568	10,914	0.0017	0.9983	99.38
4.5	6,100,759	17,004	0.0028	0.9972	99.21
5.5	5,760,223	19,794	0.0034	0.9966	98.94
6.5	5,602,896	16,665	0.0030	0.9970	98.60
7.5	5,449,282	33,038	0.0061	0.9939	98.30
8.5	5,343,675	13,409	0.0025	0.9975	97.71
9.5	5,239,299	18,198	0.0035	0.9965	97.46
10.5	5,132,195	8,480	0.0017	0.9983	97.12
11.5	5,012,218	13,339	0.0027	0.9973	96.96
12.5	4,846,569	10,556	0.0022	0.9978	96.71
13.5	4,627,050	10,322	0.0022	0.9978	96.50
14.5	4,430,500	8,748	0.0020	0.9980	96.28
15.5	4,176,554	5,646	0.0014	0.9986	96.09
16.5	3,849,501	9,164	0.0024	0.9976	95.96
17.5	3,543,536	78,531	0.0222	0.9778	95.73
18.5	3,247,179	67,510	0.0208	0.9792	93.61
19.5	2,954,732	29,587	0.0100	0.9900	91.66
20.5	2,591,309	7,291	0.0028	0.9972	90.75
21.5	2,329,770	13,951	0.0060	0.9940	90.49
22.5	2,109,047	16,111	0.0076	0.9924	89.95
23.5	1,782,406	26,634	0.0149	0.9851	89.26
24.5	1,550,013	9,467	0.0061	0.9939	87.93
25.5	1,381,436	23,946	0.0173	0.9827	87.39
26.5	1,334,383	11,986	0.0090	0.9910	85.88
27.5	1,199,056	186	0.0002	0.9998	85.10
28.5	974,650	19,648	0.0202	0.9798	85.09
29.5	820,256	896	0.0011	0.9989	83.38
30.5	744,504	1,673	0.0022	0.9978	83.28
31.5	663,753	8,003	0.0121	0.9879	83.10
32.5	575,831	49,255	0.0855	0.9145	82.10
33.5	420,111		0.0000	1.0000	75.07
34.5	283,962	2,141	0.0075	0.9925	75.07
35.5	221,932	2,804	0.0126	0.9874	74.51
36.5	145,226		0.0000	1.0000	73.57
37.5	87,328		0.0000	1.0000	73.57
38.5	38,837		0.0000	1.0000	73.57

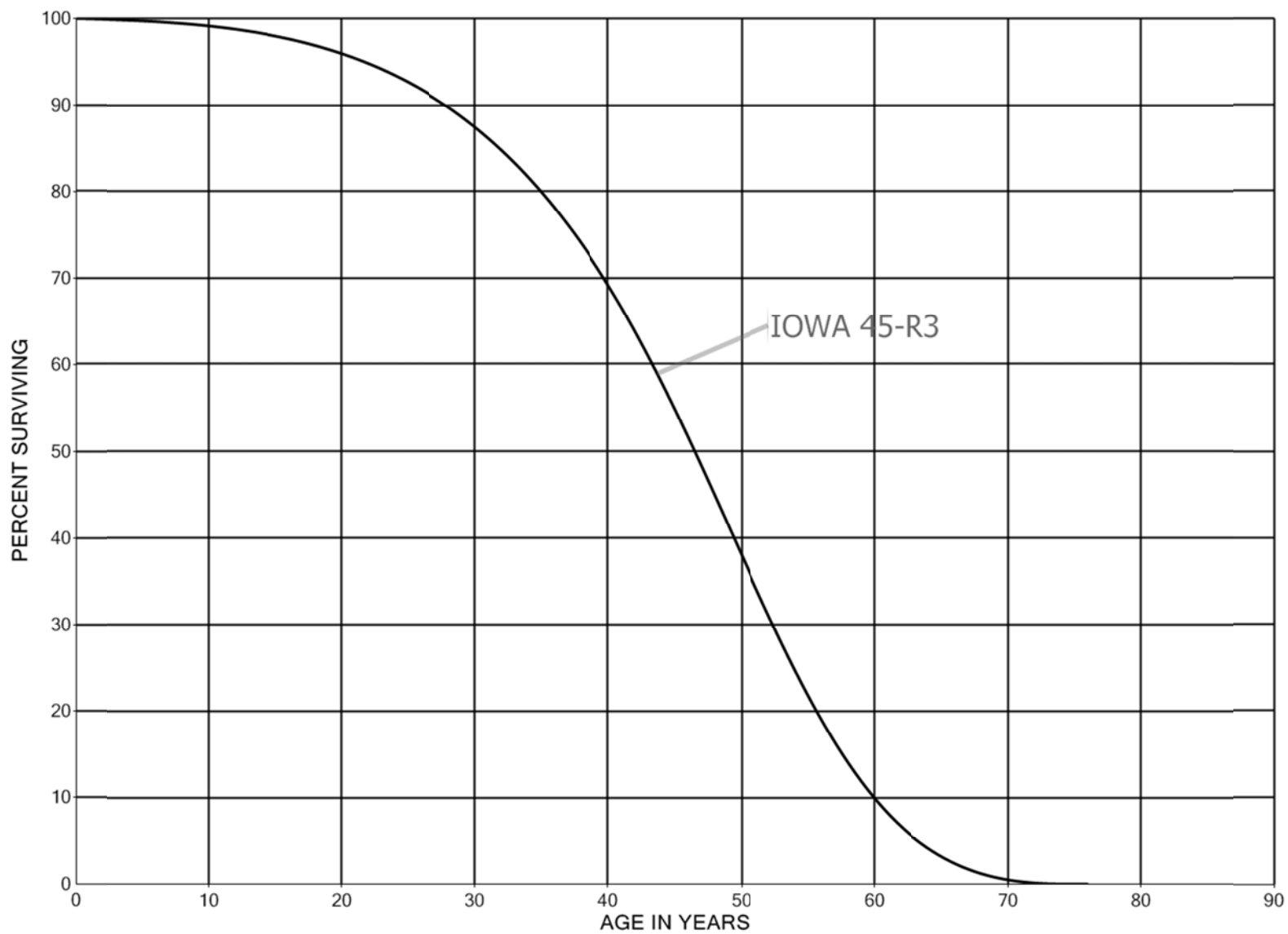
NEWFOUNDLAND POWER INC.

ACCOUNT 362.30 - DISTRIBUTION - POLES (CONCRETE & STEEL)

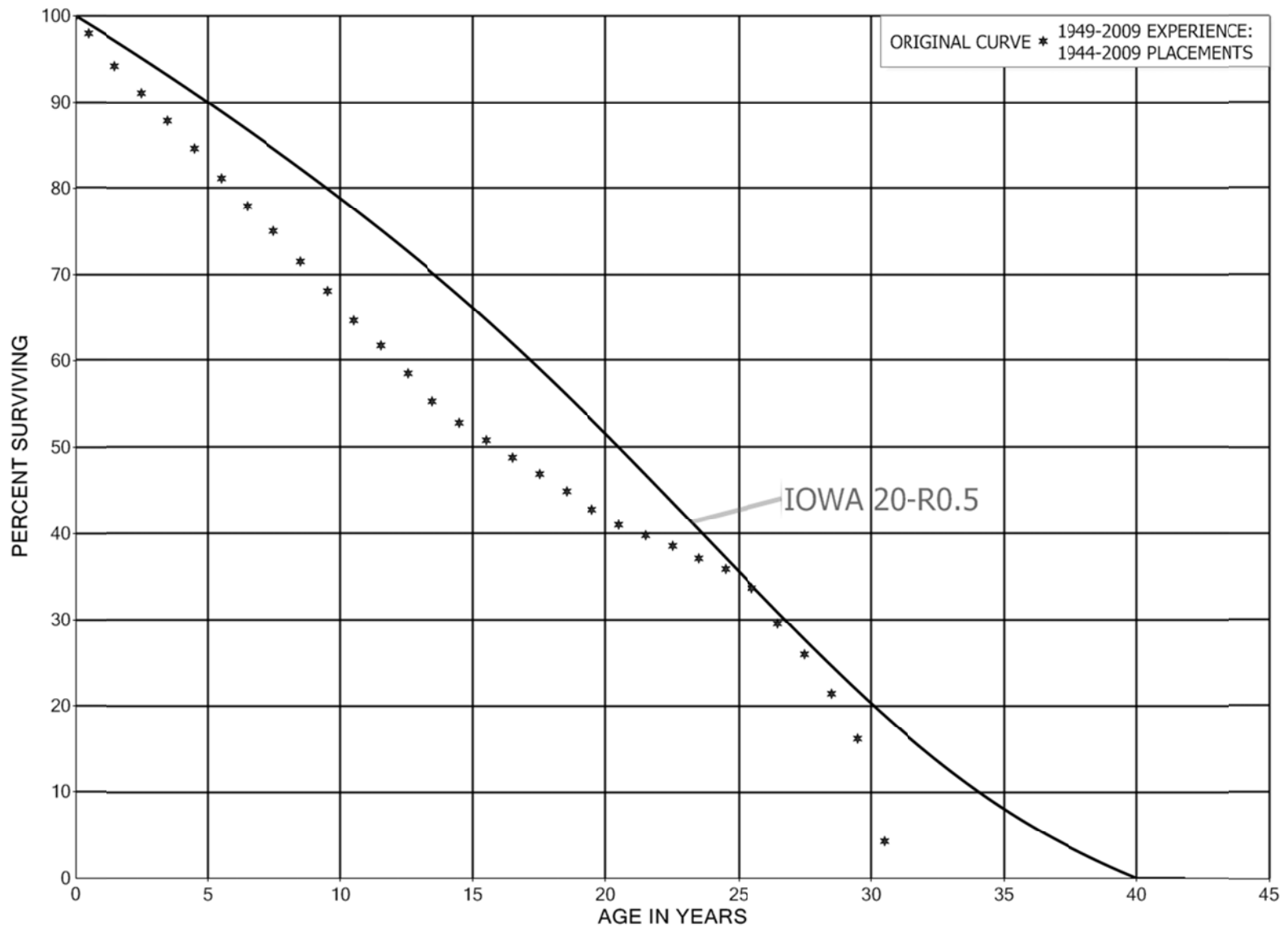
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1955-2009			EXPERIENCE BAND 1965-2009		
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	14,887		0.0000	1.0000	73.57
40.5	14,887		0.0000	1.0000	73.57
41.5	14,887		0.0000	1.0000	73.57
42.5	14,635		0.0000	1.0000	73.57
43.5					73.57

NEWFOUNDLAND POWER INC.
ACCOUNT 362.40 - DISTRIBUTION - STEEL TOWERS
SMOOTH SURVIVOR CURVE



NEWFOUNDLAND POWER INC.
ACCOUNT 363.00 - DISTRIBUTION - STREET LIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 363.00 - DISTRIBUTION - STREET LIGHTS

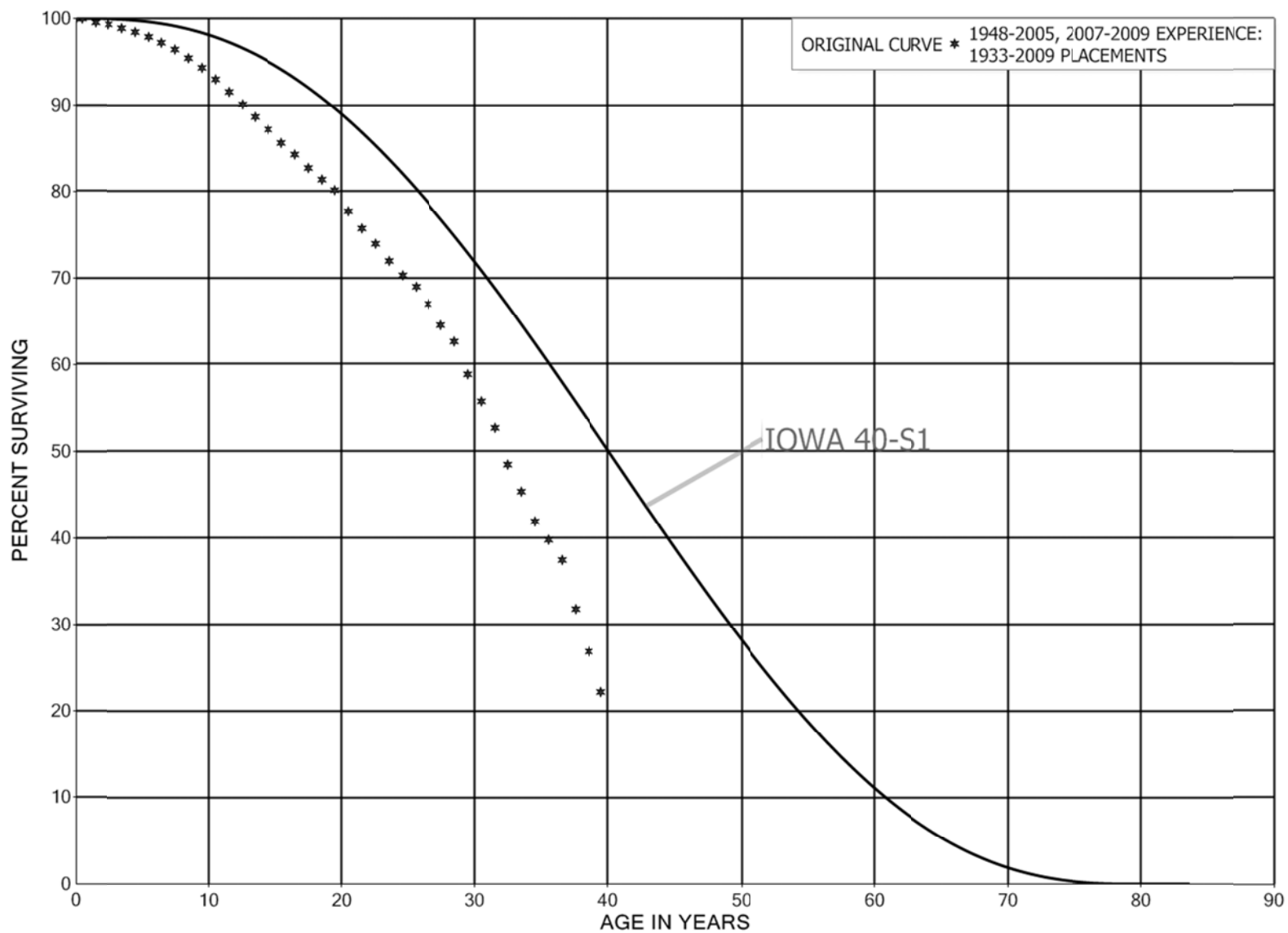
ORIGINAL LIFE TABLE

PLACEMENT BAND 1944-2009

EXPERIENCE BAND 1949-2009

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	40,037,015	825,205	0.0206	0.9794	100.00
0.5	37,620,846	1,429,403	0.0380	0.9620	97.94
1.5	35,152,733	1,185,418	0.0337	0.9663	94.22
2.5	32,875,480	1,175,576	0.0358	0.9642	91.04
3.5	30,965,688	1,131,855	0.0366	0.9634	87.79
4.5	29,078,632	1,163,771	0.0400	0.9600	84.58
5.5	27,467,173	1,085,925	0.0395	0.9605	81.19
6.5	26,323,023	997,205	0.0379	0.9621	77.98
7.5	24,911,596	1,182,807	0.0475	0.9525	75.03
8.5	23,348,334	1,113,727	0.0477	0.9523	71.47
9.5	22,015,316	1,129,995	0.0513	0.9487	68.06
10.5	20,763,057	915,573	0.0441	0.9559	64.56
11.5	19,587,092	1,006,981	0.0514	0.9486	61.72
12.5	17,913,170	1,003,972	0.0560	0.9440	58.54
13.5	15,795,742	714,551	0.0452	0.9548	55.26
14.5	14,712,248	559,750	0.0380	0.9620	52.76
15.5	13,596,882	550,380	0.0405	0.9595	50.75
16.5	12,264,673	482,150	0.0393	0.9607	48.70
17.5	11,032,476	467,970	0.0424	0.9576	46.79
18.5	9,680,246	457,556	0.0473	0.9527	44.80
19.5	8,599,130	349,383	0.0406	0.9594	42.68
20.5	7,685,468	224,353	0.0292	0.9708	40.95
21.5	7,019,815	224,732	0.0320	0.9680	39.75
22.5	6,001,088	215,914	0.0360	0.9640	38.48
23.5	4,738,038	162,666	0.0343	0.9657	37.10
24.5	3,857,441	242,571	0.0629	0.9371	35.82
25.5	3,179,991	385,472	0.1212	0.8788	33.57
26.5	2,664,998	319,709	0.1200	0.8800	29.50
27.5	2,070,434	367,039	0.1773	0.8227	25.96
28.5	1,356,385	330,609	0.2437	0.7563	21.36
29.5	748,981	550,153	0.7345	0.2655	16.15
30.5	114,273	3,946	0.0345	0.9655	4.29
31.5	7,103	1,235	0.1739	0.8261	4.14
32.5	4,854	930	0.1915	0.8085	3.42
33.5	4,854		0.0000	1.0000	2.77
34.5					2.77

NEWFOUNDLAND POWER INC.
ACCOUNT 364.10, 364.11, 364.2, 364.3, 364.4 - LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 364.10,364.11,364.2,364.3,364.4 - LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1933-2009			EXPERIENCE BAND 1948-2005, 2007-2009		
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	124,109,014	132,649	0.0011	0.9989	100.00
0.5	116,991,840	400,209	0.0034	0.9966	99.89
1.5	107,780,428	334,254	0.0031	0.9969	99.55
2.5	100,389,235	372,722	0.0037	0.9963	99.24
3.5	94,667,316	464,012	0.0049	0.9951	98.87
4.5	89,195,964	502,932	0.0056	0.9944	98.39
5.5	82,980,140	551,011	0.0066	0.9934	97.83
6.5	78,412,421	607,529	0.0077	0.9923	97.19
7.5	72,025,954	757,239	0.0105	0.9895	96.43
8.5	68,236,944	814,287	0.0119	0.9881	95.42
9.5	63,080,524	859,831	0.0136	0.9864	94.28
10.5	58,510,108	926,201	0.0158	0.9842	92.99
11.5	54,170,573	834,428	0.0154	0.9846	91.52
12.5	51,439,420	844,714	0.0164	0.9836	90.11
13.5	49,104,347	832,846	0.0170	0.9830	88.63
14.5	45,441,664	808,767	0.0178	0.9822	87.13
15.5	42,077,194	655,957	0.0156	0.9844	85.58
16.5	41,073,867	747,392	0.0182	0.9818	84.24
17.5	39,647,840	645,432	0.0163	0.9837	82.71
18.5	36,120,540	530,568	0.0147	0.9853	81.37
19.5	31,989,966	988,725	0.0309	0.9691	80.17
20.5	29,353,645	753,747	0.0257	0.9743	77.69
21.5	26,397,063	612,237	0.0232	0.9768	75.70
22.5	24,261,851	668,167	0.0275	0.9725	73.94
23.5	21,083,069	471,665	0.0224	0.9776	71.91
24.5	20,228,995	400,956	0.0198	0.9802	70.30
25.5	18,511,732	515,900	0.0279	0.9721	68.90
26.5	18,113,517	657,039	0.0363	0.9637	66.98
27.5	15,828,271	484,650	0.0306	0.9694	64.55
28.5	14,128,196	839,567	0.0594	0.9406	62.58
29.5	10,981,956	579,661	0.0528	0.9472	58.86
30.5	9,202,740	514,236	0.0559	0.9441	55.75
31.5	8,977,694	730,003	0.0813	0.9187	52.64
32.5	7,538,152	473,805	0.0629	0.9371	48.36
33.5	5,741,894	447,956	0.0780	0.9220	45.32
34.5	4,167,522	209,157	0.0502	0.9498	41.78
35.5	3,553,668	209,374	0.0589	0.9411	39.68
36.5	2,846,087	431,837	0.1517	0.8483	37.35
37.5	2,031,446	308,687	0.1520	0.8480	31.68
38.5	1,393,209	245,164	0.1760	0.8240	26.87

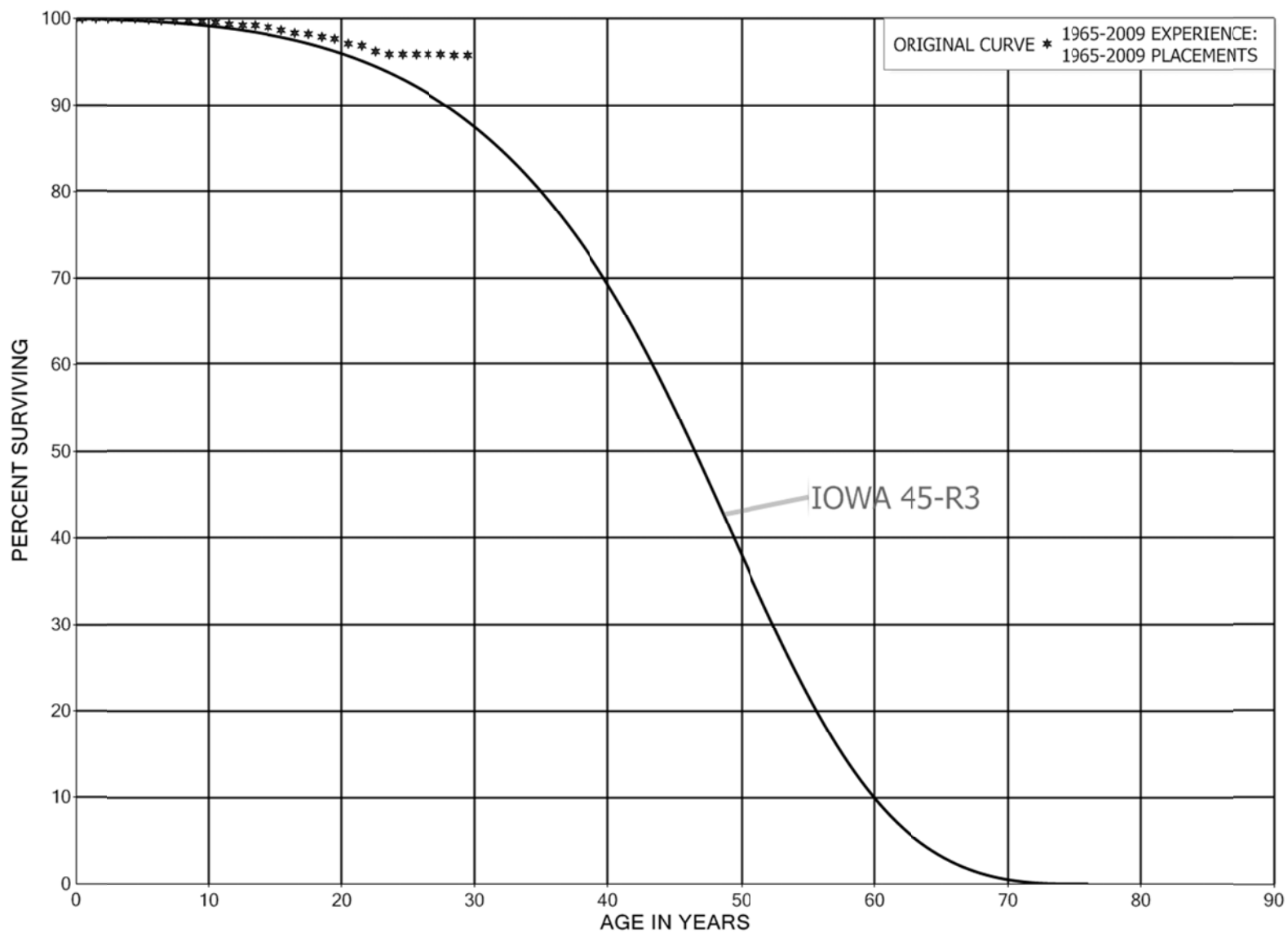
NEWFOUNDLAND POWER INC.

ACCOUNT 364.10,364.11,364.2,364.3,364.4 - LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1933-2009			EXPERIENCE BAND 1948-2005, 2007-2009		
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	1,040,116	77,854	0.0749	0.9251	22.14
40.5	485,909	34,004	0.0700	0.9300	20.48
41.5	387,864	36,109	0.0931	0.9069	19.05
42.5	204,696	31,473	0.1538	0.8462	17.27
43.5	176,622	40,110	0.2271	0.7729	14.62
44.5	19,648	2,201	0.1120	0.8880	11.30
45.5	18,662		0.0000	1.0000	10.03
46.5	12,943		0.0000	1.0000	10.03
47.5	26,801	2,848	0.1063	0.8937	10.03
48.5	14,599	600	0.0411	0.9589	8.97
49.5	8,739		0.0000	1.0000	8.60
50.5	4,560		0.0000	1.0000	8.60
51.5	3,400		0.0000	1.0000	8.60
52.5	3,400		0.0000	1.0000	8.60
53.5					8.60

NEWFOUNDLAND POWER INC.
ACCOUNT 365.20 - DISTRIBUTION - SERVICES UNDERGROUND
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 365.20 - DISTRIBUTION - SERVICES UNDERGROUND

ORIGINAL LIFE TABLE

PLACEMENT BAND 1965-2009			EXPERIENCE BAND 1965-2009		
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	6,474,228	3,167	0.0005	0.9995	100.00
0.5	6,136,064		0.0000	1.0000	99.95
1.5	5,770,294		0.0000	1.0000	99.95
2.5	5,457,324	1,312	0.0002	0.9998	99.95
3.5	5,303,355		0.0000	1.0000	99.93
4.5	5,122,725	3,107	0.0006	0.9994	99.93
5.5	4,868,048	7,543	0.0015	0.9985	99.87
6.5	4,549,868		0.0000	1.0000	99.71
7.5	4,411,454	1,137	0.0003	0.9997	99.71
8.5	4,337,659	4,565	0.0011	0.9989	99.69
9.5	4,158,148	4,815	0.0012	0.9988	99.58
10.5	4,214,029	8,160	0.0019	0.9981	99.47
11.5	4,191,720	2,838	0.0007	0.9993	99.27
12.5	3,919,269	284	0.0001	0.9999	99.21
13.5	3,555,340	7,128	0.0020	0.9980	99.20
14.5	3,298,177	13,989	0.0042	0.9958	99.00
15.5	3,047,740	10,243	0.0034	0.9966	98.58
16.5	2,854,591	3,490	0.0012	0.9988	98.25
17.5	2,691,928	8,266	0.0031	0.9969	98.13
18.5	2,517,494	4,360	0.0017	0.9983	97.83
19.5	2,251,607	12,656	0.0056	0.9944	97.66
20.5	1,948,277	4,975	0.0026	0.9974	97.11
21.5	1,732,909	11,324	0.0065	0.9935	96.86
22.5	1,596,389	6,459	0.0040	0.9960	96.23
23.5	1,525,339		0.0000	1.0000	95.84
24.5	1,386,882		0.0000	1.0000	95.84
25.5	1,251,737		0.0000	1.0000	95.84
26.5	1,182,373	458	0.0004	0.9996	95.84
27.5	1,002,773	229	0.0002	0.9998	95.80
28.5	918,793	915	0.0010	0.9990	95.78
29.5	783,821	229	0.0003	0.9997	95.68
30.5	730,602		0.0000	1.0000	95.66
31.5	696,026		0.0000	1.0000	95.66
32.5	586,365	49	0.0001	0.9999	95.66
33.5	467,176		0.0000	1.0000	95.65
34.5	182,509		0.0000	1.0000	95.65
35.5	107,506		0.0000	1.0000	95.65
36.5	107,506		0.0000	1.0000	95.65
37.5	107,506		0.0000	1.0000	95.65
38.5	107,506		0.0000	1.0000	95.65

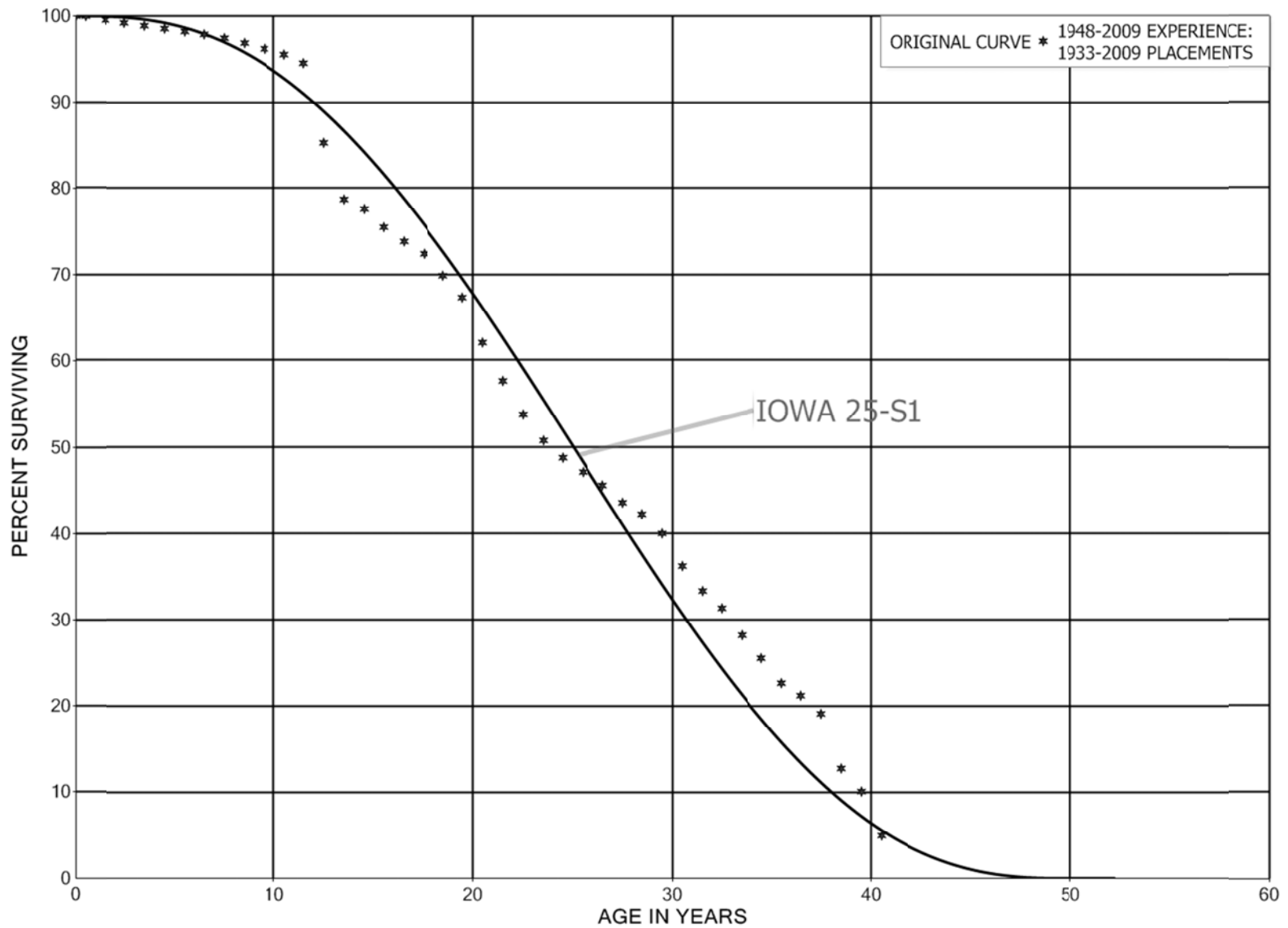
NEWFOUNDLAND POWER INC.

ACCOUNT 365.20 - DISTRIBUTION - SERVICES UNDERGROUND

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1965-2009			EXPERIENCE BAND 1965-2009		
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	93,561		0.0000	1.0000	95.65
40.5	80,001		0.0000	1.0000	95.65
41.5	60,374		0.0000	1.0000	95.65
42.5	15,968		0.0000	1.0000	95.65
43.5	5,690		0.0000	1.0000	95.65
44.5					95.65

NEWFOUNDLAND POWER INC.
ACCOUNT 366.10 - DISTRIBUTION - WATT-HOUR METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 366.10 - DISTRIBUTION - WATT-HOUR METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1933-2009

EXPERIENCE BAND 1948-2009

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	21,797,345	21,668	0.0010	0.9990	100.00
0.5	20,366,913	78,105	0.0038	0.9962	99.90
1.5	19,308,173	63,617	0.0033	0.9967	99.52
2.5	18,793,587	61,680	0.0033	0.9967	99.19
3.5	17,783,183	61,868	0.0035	0.9965	98.86
4.5	16,831,003	55,116	0.0033	0.9967	98.52
5.5	15,942,950	61,366	0.0038	0.9962	98.20
6.5	15,558,276	65,040	0.0042	0.9958	97.82
7.5	15,130,798	87,612	0.0058	0.9942	97.41
8.5	14,998,812	98,425	0.0066	0.9934	96.85
9.5	14,616,138	112,160	0.0077	0.9923	96.21
10.5	14,153,715	141,684	0.0100	0.9900	95.47
11.5	13,838,018	1,354,869	0.0979	0.9021	94.52
12.5	12,499,616	952,834	0.0762	0.9238	85.26
13.5	11,594,470	173,619	0.0150	0.9850	78.76
14.5	11,330,507	300,296	0.0265	0.9735	77.58
15.5	11,067,538	251,986	0.0228	0.9772	75.53
16.5	10,863,167	203,213	0.0187	0.9813	73.81
17.5	10,555,568	380,190	0.0360	0.9640	72.43
18.5	9,823,910	360,623	0.0367	0.9633	69.82
19.5	8,988,042	698,671	0.0777	0.9223	67.26
20.5	8,124,333	582,660	0.0717	0.9283	62.03
21.5	7,221,112	483,015	0.0669	0.9331	57.58
22.5	6,683,506	376,365	0.0563	0.9437	53.73
23.5	6,125,501	241,994	0.0395	0.9605	50.70
24.5	5,531,937	187,142	0.0338	0.9662	48.70
25.5	5,035,287	167,381	0.0332	0.9668	47.05
26.5	4,495,323	192,901	0.0429	0.9571	45.49
27.5	4,288,084	137,978	0.0322	0.9678	43.54
28.5	3,815,756	194,070	0.0509	0.9491	42.13
29.5	3,440,381	323,790	0.0941	0.9059	39.99
30.5	2,993,791	244,163	0.0816	0.9184	36.23
31.5	2,612,049	155,540	0.0595	0.9405	33.27
32.5	2,197,648	218,821	0.0996	0.9004	31.29
33.5	1,753,495	163,286	0.0931	0.9069	28.18
34.5	1,484,443	173,415	0.1168	0.8832	25.55
35.5	1,088,698	69,799	0.0641	0.9359	22.57
36.5	891,384	88,875	0.0997	0.9003	21.12
37.5	722,571	240,227	0.3325	0.6675	19.01
38.5	435,921	91,694	0.2103	0.7897	12.69

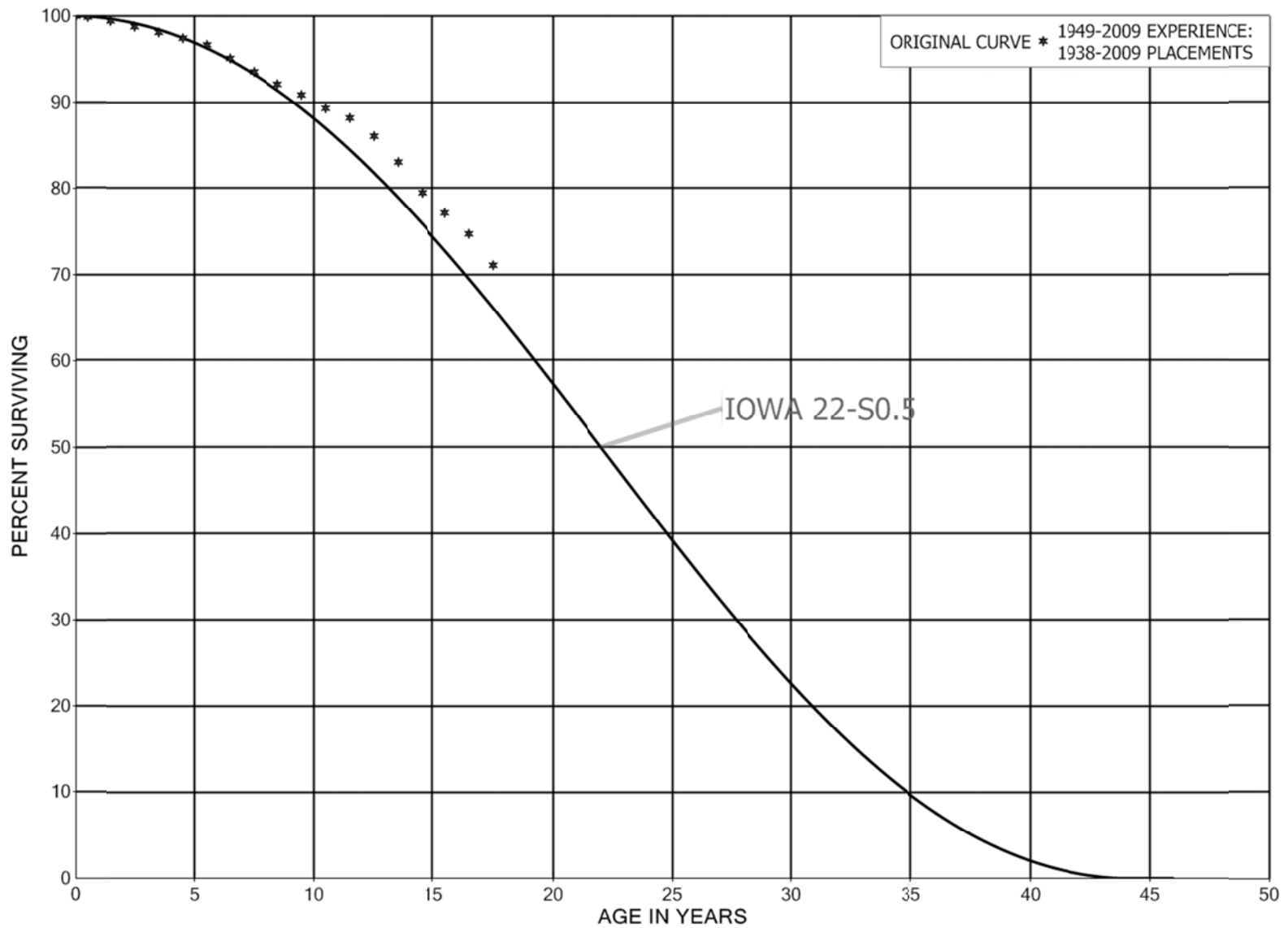
NEWFOUNDLAND POWER INC.

ACCOUNT 366.10 - DISTRIBUTION - WATT-HOUR METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1933-2009			EXPERIENCE BAND 1948-2009		
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	377,762	189,834	0.5025	0.4975	10.02
40.5	215,418	198,811	0.9229	0.0771	4.99
41.5	16,613	16,613	1.0000		0.38
42.5					

NEWFOUNDLAND POWER INC.
ACCOUNT 366.20 - DISTRIBUTION - DEMAND METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



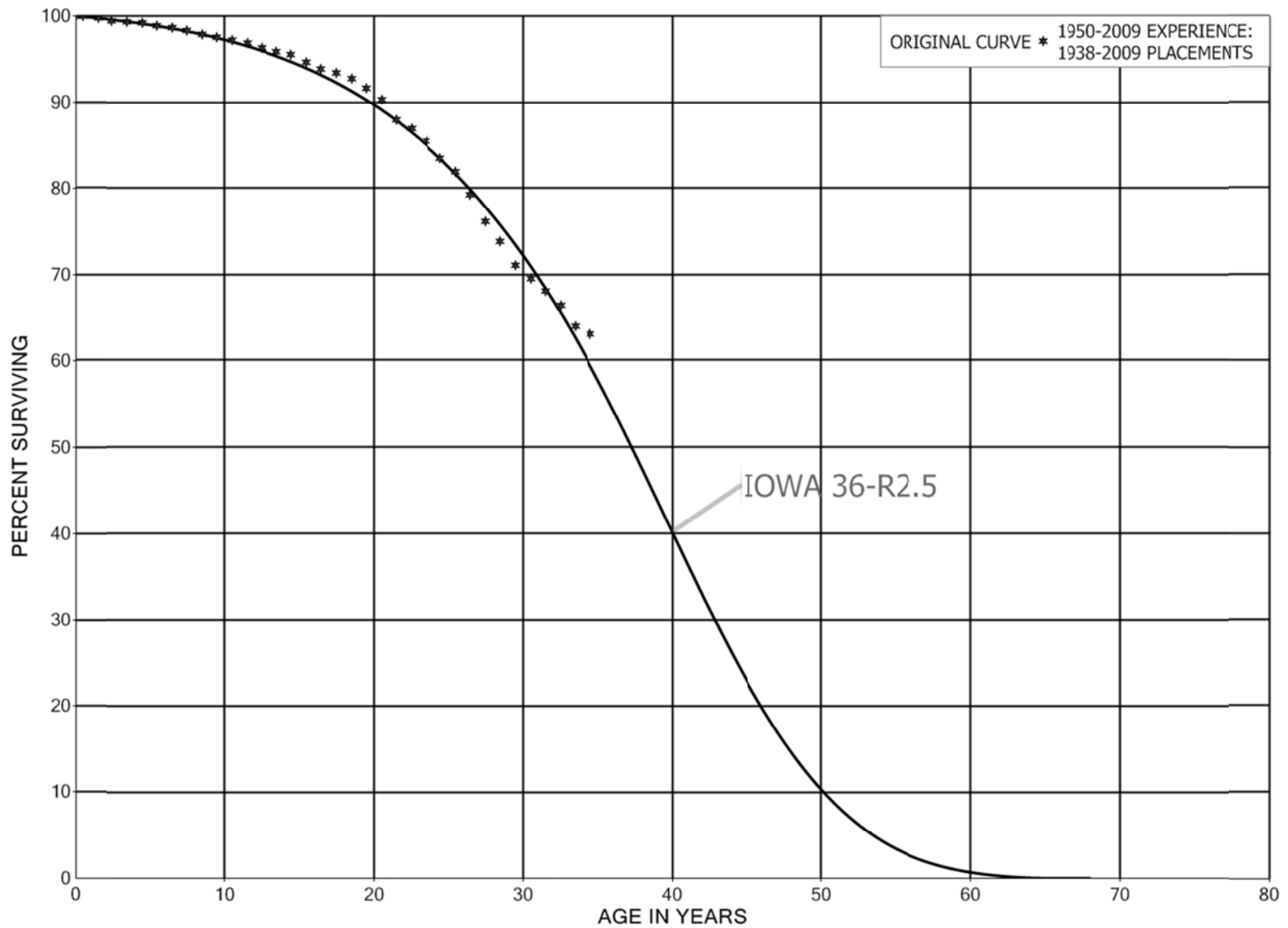
NEWFOUNDLAND POWER INC.

ACCOUNT 366.20 - DISTRIBUTION - DEMAND METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2009			EXPERIENCE BAND 1949-2009		
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	8,387,529	11,571	0.0014	0.9986	100.00
0.5	7,937,242	40,842	0.0051	0.9949	99.86
1.5	7,663,859	44,495	0.0058	0.9942	99.35
2.5	7,170,876	51,915	0.0072	0.9928	98.77
3.5	6,793,519	45,074	0.0066	0.9934	98.06
4.5	6,471,350	56,130	0.0087	0.9913	97.41
5.5	6,123,660	92,749	0.0151	0.9849	96.56
6.5	5,587,175	95,558	0.0171	0.9829	95.10
7.5	5,331,251	80,647	0.0151	0.9849	93.47
8.5	5,028,000	65,117	0.0130	0.9870	92.06
9.5	4,809,886	81,863	0.0170	0.9830	90.87
10.5	4,631,786	57,869	0.0125	0.9875	89.32
11.5	4,511,114	107,311	0.0238	0.9762	88.20
12.5	4,344,848	154,894	0.0357	0.9643	86.11
13.5	4,172,289	175,177	0.0420	0.9580	83.04
14.5	3,908,964	116,289	0.0297	0.9703	79.55
15.5	3,729,003	118,649	0.0318	0.9682	77.18
16.5	3,537,277	174,622	0.0494	0.9506	74.73
17.5	3,299,584	171,123	0.0519	0.9481	71.04
18.5	3,121,272	204,688	0.0656	0.9344	67.35
19.5	2,884,427	172,613	0.0598	0.9402	62.94
20.5	2,693,315	106,051	0.0394	0.9606	59.17
21.5	2,470,087	79,118	0.0320	0.9680	56.84
22.5	2,073,746	67,543	0.0326	0.9674	55.02
23.5	1,826,346	54,007	0.0296	0.9704	53.23
24.5	1,722,920	75,939	0.0441	0.9559	51.65
25.5	1,593,102	71,024	0.0446	0.9554	49.38
26.5	1,378,622	60,148	0.0436	0.9564	47.18
27.5	1,255,689	58,101	0.0463	0.9537	45.12
28.5	975,687	57,767	0.0592	0.9408	43.03
29.5	770,798	61,663	0.0800	0.9200	40.48
30.5	610,075	53,466	0.0876	0.9124	37.24
31.5	449,667	58,588	0.1303	0.8697	33.98
32.5	311,804	47,876	0.1535	0.8465	29.55
33.5	140,764	29,943	0.2127	0.7873	25.01
34.5	72,539	19,892	0.2742	0.7258	19.69
35.5	22,249	22,248	1.0000	0.0000	14.29
36.5	1		0.0000	1.0000	0.00
37.5	0		0.0000	1.0000	0.00
38.5	0		0.0000	1.0000	0.00
39.5					0.00

NEWFOUNDLAND POWER INC.
ACCOUNT 366.30 - INSTRU. TRANSF. & 366.40 - METERING TANKS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 366.30 - INSTRU. TRANSF. & 366.40 - METERING TANKS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2009

EXPERIENCE BAND 1950-2009

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	4,098,772	3,419	0.0008	0.9992	100.00
0.5	4,000,844	8,515	0.0021	0.9979	99.92
1.5	3,898,725	12,851	0.0033	0.9967	99.70
2.5	3,797,885	1,576	0.0004	0.9996	99.38
3.5	3,740,015	7,644	0.0020	0.9980	99.33
4.5	3,626,959	11,839	0.0033	0.9967	99.13
5.5	3,537,662	7,914	0.0022	0.9978	98.81
6.5	3,315,440	9,453	0.0029	0.9971	98.59
7.5	3,224,325	17,099	0.0053	0.9947	98.31
8.5	3,139,879	7,951	0.0025	0.9975	97.78
9.5	3,103,951	11,259	0.0036	0.9964	97.54
10.5	3,074,902	10,793	0.0035	0.9965	97.18
11.5	3,042,914	17,811	0.0059	0.9941	96.84
12.5	3,005,801	13,449	0.0045	0.9955	96.27
13.5	2,962,323	12,103	0.0041	0.9959	95.84
14.5	2,925,283	26,296	0.0090	0.9910	95.45
15.5	2,826,975	21,790	0.0077	0.9923	94.59
16.5	2,803,006	14,640	0.0052	0.9948	93.87
17.5	2,587,004	18,426	0.0071	0.9929	93.37
18.5	2,475,551	29,044	0.0117	0.9883	92.71
19.5	2,258,098	32,733	0.0145	0.9855	91.62
20.5	2,122,644	54,173	0.0255	0.9745	90.29
21.5	1,942,440	22,286	0.0115	0.9885	87.99
22.5	1,823,996	30,645	0.0168	0.9832	86.98
23.5	1,715,723	41,390	0.0241	0.9759	85.52
24.5	1,596,927	27,803	0.0174	0.9826	83.46
25.5	1,391,166	46,791	0.0336	0.9664	82.00
26.5	1,276,214	48,826	0.0383	0.9617	79.24
27.5	1,213,764	37,578	0.0310	0.9690	76.21
28.5	1,101,204	41,087	0.0373	0.9627	73.85
29.5	985,575	22,508	0.0228	0.9772	71.10
30.5	832,922	16,463	0.0198	0.9802	69.47
31.5	740,020	18,897	0.0255	0.9745	68.10
32.5	604,996	21,623	0.0357	0.9643	66.36
33.5	489,468	7,203	0.0147	0.9853	63.99
34.5	352,556	9,511	0.0270	0.9730	63.05
35.5	303,121	6,485	0.0214	0.9786	61.35
36.5	262,507	5,926	0.0226	0.9774	60.03
37.5	213,045	4,111	0.0193	0.9807	58.68
38.5	191,062	1,141	0.0060	0.9940	57.55

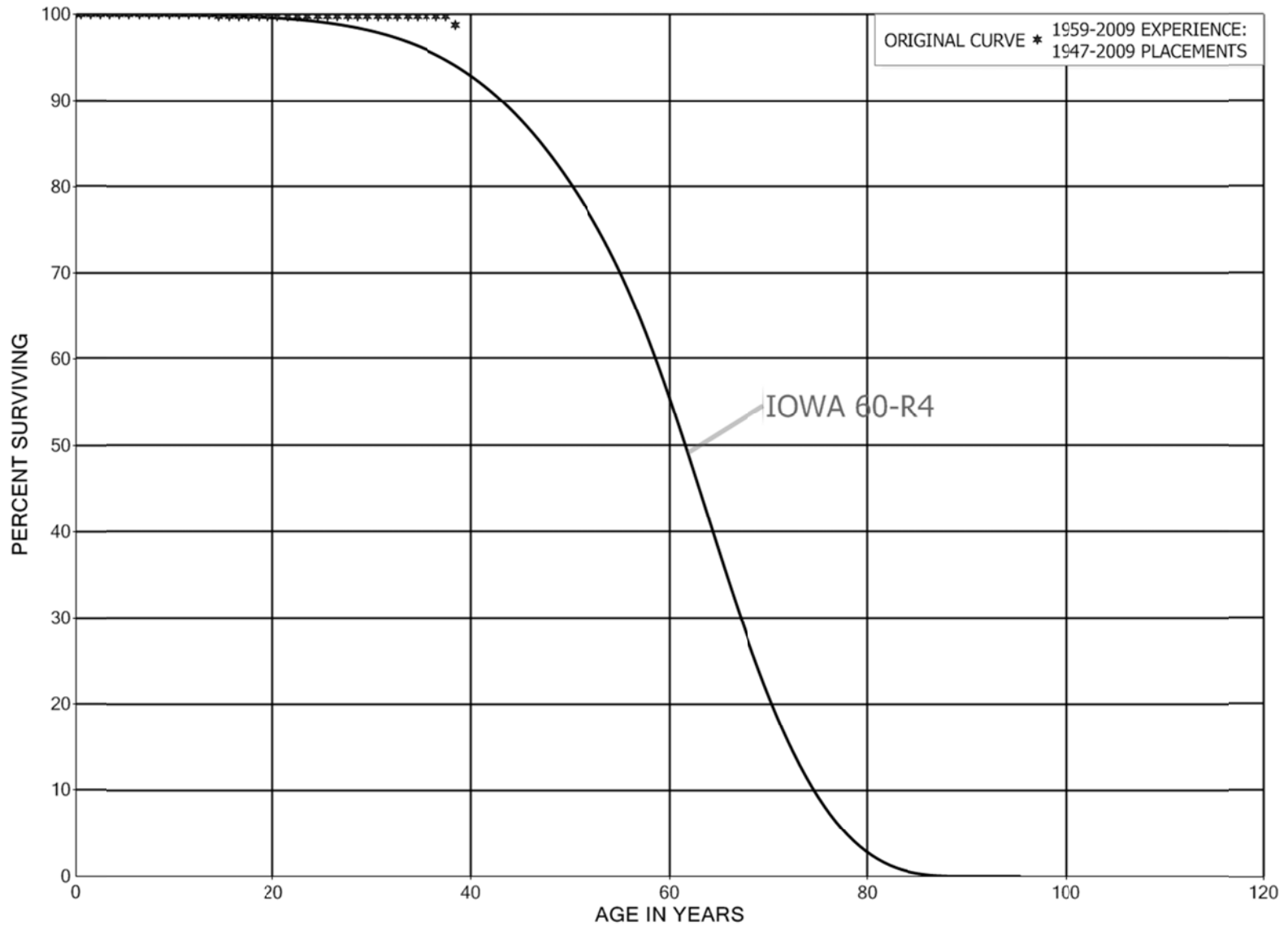
NEWFOUNDLAND POWER INC.

ACCOUNT 366.30 - INSTRU. TRANSF. & 366.40 - METERING TANKS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2009			EXPERIENCE BAND 1950-2009		
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	157,030	2,524	0.0161	0.9839	57.20
40.5	143,039	690	0.0048	0.9952	56.28
41.5	119,935	2,721	0.0227	0.9773	56.01
42.5	104,029	5,272	0.0507	0.9493	54.74
43.5	64,455	3,956	0.0614	0.9386	51.97
44.5	45,624	1,899	0.0416	0.9584	48.78
45.5	32,201	653	0.0203	0.9797	46.75
46.5	21,406	368	0.0172	0.9828	45.80
47.5	15,488	42	0.0027	0.9973	45.01
48.5	13,215	254	0.0192	0.9808	44.89
49.5	7,898	1,082	0.1370	0.8630	44.03
50.5	3		0.0000	1.0000	38.00
51.5					38.00

NEWFOUNDLAND POWER INC.
ACCOUNT 367.10 - DISTRIBUTION - UNDERGROUND DUCT & MANHOLES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 367.10 - DISTRIBUTION - UNDERGROUND DUCT & MANHOLES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1947-2009

EXPERIENCE BAND 1959-2009

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	5,013,426		0.0000	1.0000	100.00
0.5	4,961,565		0.0000	1.0000	100.00
1.5	4,874,988	1,547	0.0003	0.9997	100.00
2.5	4,723,005		0.0000	1.0000	99.97
3.5	4,674,920		0.0000	1.0000	99.97
4.5	4,604,573		0.0000	1.0000	99.97
5.5	4,510,020		0.0000	1.0000	99.97
6.5	4,436,096		0.0000	1.0000	99.97
7.5	4,242,280		0.0000	1.0000	99.97
8.5	4,195,113		0.0000	1.0000	99.97
9.5	4,111,799	2,079	0.0005	0.9995	99.97
10.5	4,109,720		0.0000	1.0000	99.92
11.5	4,109,720		0.0000	1.0000	99.92
12.5	4,109,720		0.0000	1.0000	99.92
13.5	4,085,086	9,712	0.0024	0.9976	99.92
14.5	4,075,374	219	0.0001	0.9999	99.68
15.5	4,057,584		0.0000	1.0000	99.67
16.5	4,022,689		0.0000	1.0000	99.67
17.5	3,761,688		0.0000	1.0000	99.67
18.5	3,160,654		0.0000	1.0000	99.67
19.5	3,117,363		0.0000	1.0000	99.67
20.5	3,156,058		0.0000	1.0000	99.67
21.5	3,156,058		0.0000	1.0000	99.67
22.5	3,101,598		0.0000	1.0000	99.67
23.5	2,669,334		0.0000	1.0000	99.67
24.5	2,634,219		0.0000	1.0000	99.67
25.5	2,622,232		0.0000	1.0000	99.67
26.5	2,582,137		0.0000	1.0000	99.67
27.5	2,497,025		0.0000	1.0000	99.67
28.5	2,259,241		0.0000	1.0000	99.67
29.5	1,643,930		0.0000	1.0000	99.67
30.5	1,556,436		0.0000	1.0000	99.67
31.5	1,513,291		0.0000	1.0000	99.67
32.5	1,087,891		0.0000	1.0000	99.67
33.5	942,576		0.0000	1.0000	99.67
34.5	833,472		0.0000	1.0000	99.67
35.5	574,287		0.0000	1.0000	99.67
36.5	573,438		0.0000	1.0000	99.67
37.5	569,109	5,340	0.0094	0.9906	99.67
38.5	555,818		0.0000	1.0000	98.74

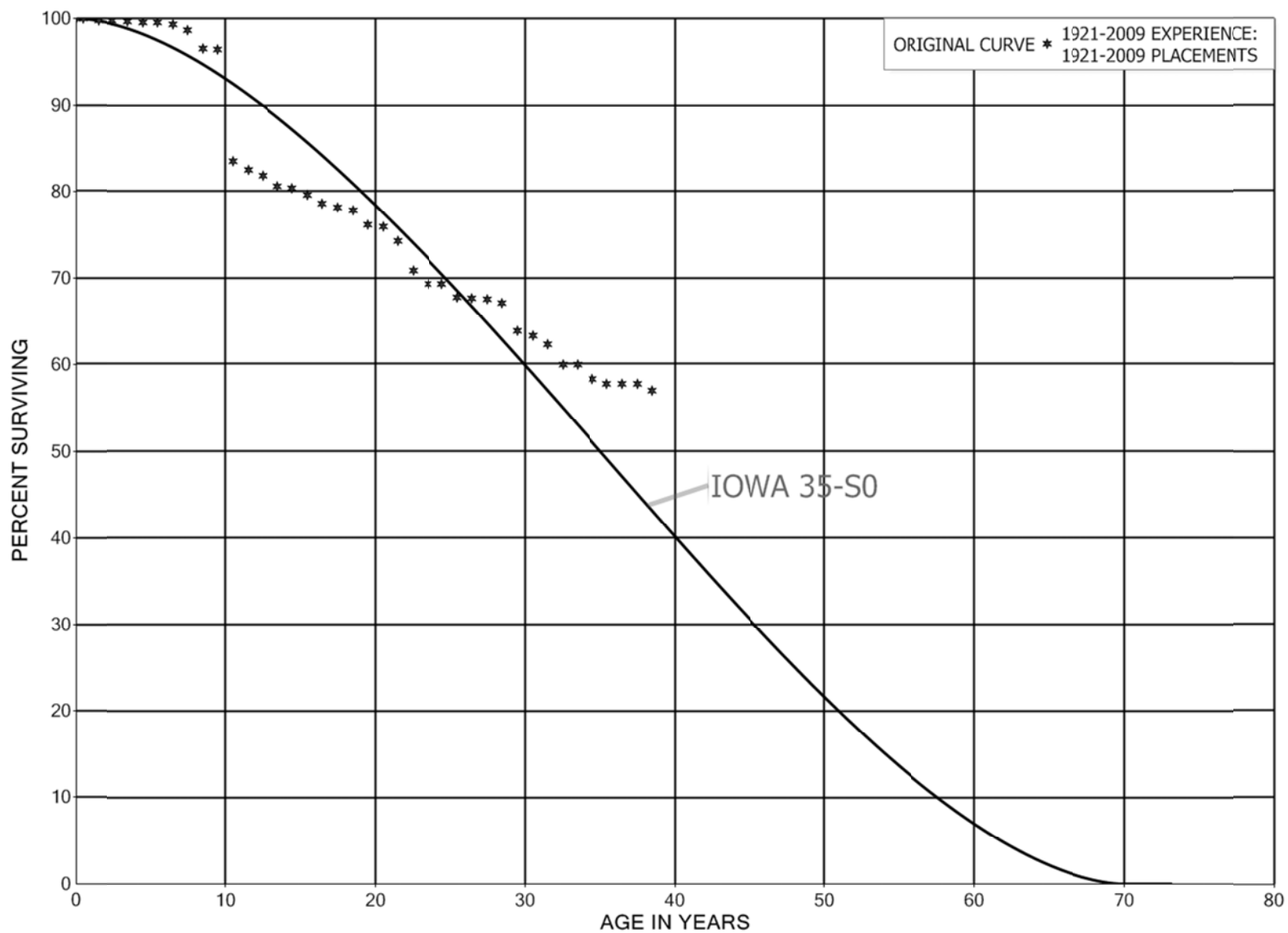
NEWFOUNDLAND POWER INC.

ACCOUNT 367.10 - DISTRIBUTION - UNDERGROUND DUCT & MANHOLES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1947-2009			EXPERIENCE BAND 1959-2009		
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	552,226		0.0000	1.0000	98.74
40.5	552,226		0.0000	1.0000	98.74
41.5	552,226		0.0000	1.0000	98.74
42.5	467,414		0.0000	1.0000	98.74
43.5	206,796		0.0000	1.0000	98.74
44.5	176,477	2,304	0.0131	0.9869	98.74
45.5	174,173		0.0000	1.0000	97.45
46.5	174,173		0.0000	1.0000	97.45
47.5	174,173		0.0000	1.0000	97.45
48.5	174,173	538	0.0031	0.9969	97.45
49.5	173,635		0.0000	1.0000	97.15
50.5	167,477		0.0000	1.0000	97.15
51.5	167,477		0.0000	1.0000	97.15
52.5	167,477		0.0000	1.0000	97.15
53.5	99,263		0.0000	1.0000	97.15
54.5	99,263		0.0000	1.0000	97.15
55.5	99,263		0.0000	1.0000	97.15
56.5	99,263		0.0000	1.0000	97.15
57.5	99,263		0.0000	1.0000	97.15
58.5	99,263		0.0000	1.0000	97.15
59.5	99,263		0.0000	1.0000	97.15
60.5	99,263		0.0000	1.0000	97.15
61.5	99,263		0.0000	1.0000	97.15
62.5					97.15

NEWFOUNDLAND POWER INC.
ACCOUNT 371.10 - BUILDINGS AND STRUCTURES - SMALL
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 371.10 - BUILDINGS AND STRUCTURES - SMALL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1921-2009			EXPERIENCE BAND 1921-2009		
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	2,159,047	200	0.0001	0.9999	100.00
0.5	2,153,861	6,000	0.0028	0.9972	99.99
1.5	1,986,272		0.0000	1.0000	99.71
2.5	1,810,427	1,100	0.0006	0.9994	99.71
3.5	1,836,541	2,470	0.0013	0.9987	99.65
4.5	1,857,236	873	0.0005	0.9995	99.52
5.5	1,847,468	2,617	0.0014	0.9986	99.47
6.5	1,867,408	13,211	0.0071	0.9929	99.33
7.5	2,041,062	43,530	0.0213	0.9787	98.63
8.5	1,992,873	2,218	0.0011	0.9989	96.52
9.5	2,295,810	308,532	0.1344	0.8656	96.42
10.5	1,966,497	22,743	0.0116	0.9884	83.46
11.5	1,922,230	14,082	0.0073	0.9927	82.49
12.5	1,873,011	29,534	0.0158	0.9842	81.89
13.5	1,837,613	4,884	0.0027	0.9973	80.60
14.5	1,863,809	17,460	0.0094	0.9906	80.38
15.5	1,850,701	23,659	0.0128	0.9872	79.63
16.5	1,841,735	9,047	0.0049	0.9951	78.61
17.5	1,835,991	8,980	0.0049	0.9951	78.23
18.5	1,766,494	37,559	0.0213	0.9787	77.84
19.5	1,702,726	6,319	0.0037	0.9963	76.19
20.5	1,725,220	37,918	0.0220	0.9780	75.91
21.5	1,591,925	74,088	0.0465	0.9535	74.24
22.5	1,458,160	31,505	0.0216	0.9784	70.78
23.5	1,370,529	423	0.0003	0.9997	69.25
24.5	1,181,613	25,930	0.0219	0.9781	69.23
25.5	1,085,731	961	0.0009	0.9991	67.71
26.5	930,729	2,483	0.0027	0.9973	67.65
27.5	879,360	4,981	0.0057	0.9943	67.47
28.5	650,324	31,999	0.0492	0.9508	67.09
29.5	614,064	5,100	0.0083	0.9917	63.79
30.5	590,267	8,717	0.0148	0.9852	63.26
31.5	517,648	20,057	0.0387	0.9613	62.33
32.5	452,369		0.0000	1.0000	59.91
33.5	419,035	11,631	0.0278	0.9722	59.91
34.5	392,191	3,867	0.0099	0.9901	58.25
35.5	304,897		0.0000	1.0000	57.67
36.5	276,143		0.0000	1.0000	57.67
37.5	236,516	2,821	0.0119	0.9881	57.67
38.5	279,746		0.0000	1.0000	56.99

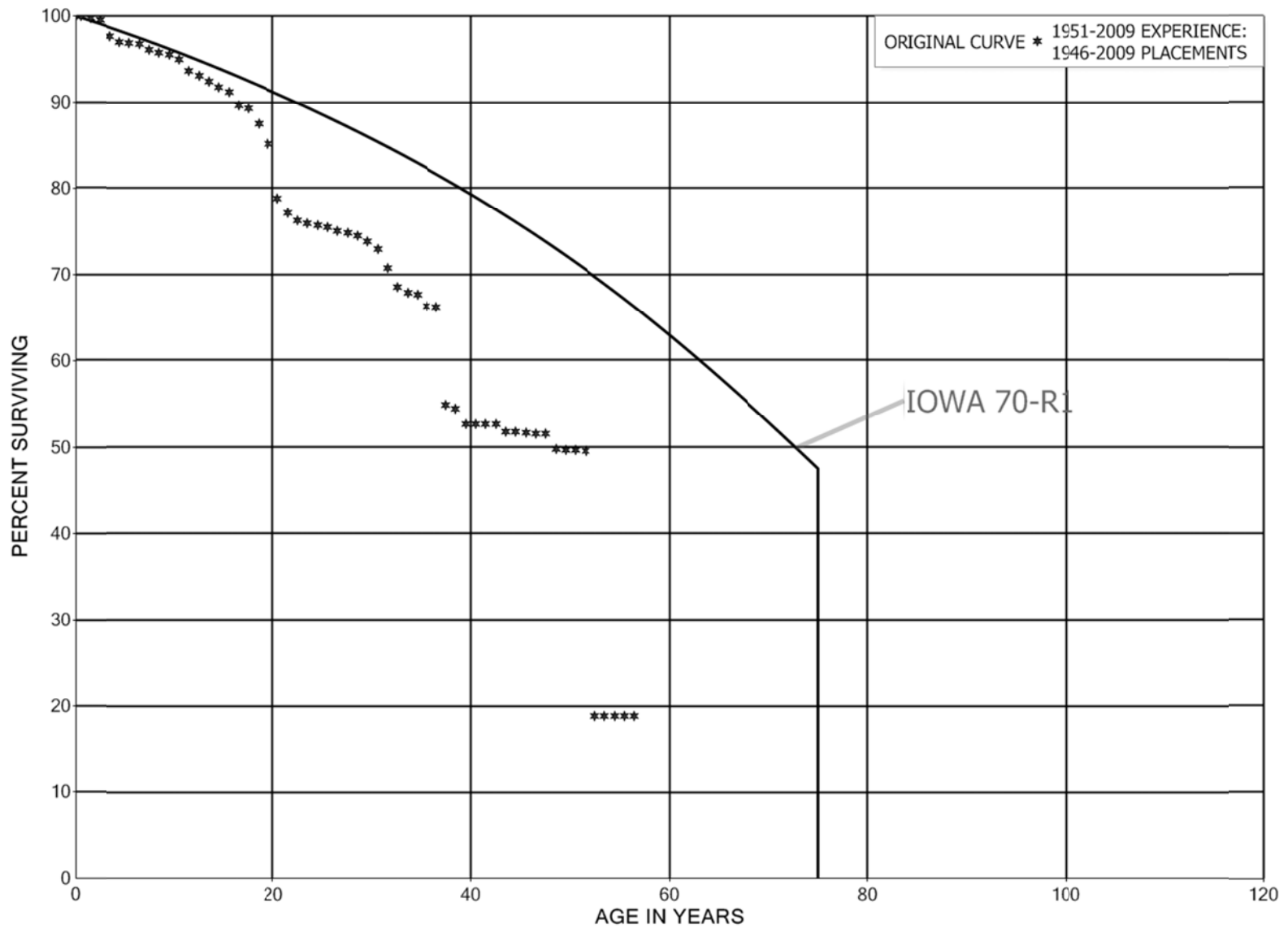
NEWFOUNDLAND POWER INC.

ACCOUNT 371.10 - BUILDINGS AND STRUCTURES - SMALL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1921-2009			EXPERIENCE BAND 1921-2009		
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	275,127		0.0000	1.0000	56.99
40.5	252,039		0.0000	1.0000	56.99
41.5	276,646	6,654	0.0241	0.9759	56.99
42.5	260,403	1,750	0.0067	0.9933	55.61
43.5	243,124		0.0000	1.0000	55.24
44.5	241,319	12,815	0.0531	0.9469	55.24
45.5	159,801		0.0000	1.0000	52.31
46.5	65,674		0.0000	1.0000	52.31
47.5	62,845		0.0000	1.0000	52.31
48.5	53,894		0.0000	1.0000	52.31
49.5	53,894		0.0000	1.0000	52.31
50.5	17,629		0.0000	1.0000	52.31
51.5	15,300		0.0000	1.0000	52.31
52.5	15,300		0.0000	1.0000	52.31
53.5	15,300		0.0000	1.0000	52.31
54.5	15,300		0.0000	1.0000	52.31
55.5	15,300		0.0000	1.0000	52.31
56.5	15,300	15,300	1.0000		52.31
57.5					

NEWFOUNDLAND POWER INC.
ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

ORIGINAL LIFE TABLE

PLACEMENT BAND 1946-2009

EXPERIENCE BAND 1951-2009

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	41,604,047		0.0000	1.0000	100.00
0.5	41,427,340	93,588	0.0023	0.9977	100.00
1.5	40,313,733	106,158	0.0026	0.9974	99.77
2.5	37,377,492	700,931	0.0188	0.9812	99.51
3.5	35,141,476	234,766	0.0067	0.9933	97.65
4.5	34,338,807	53,692	0.0016	0.9984	96.99
5.5	33,917,551	25,635	0.0008	0.9992	96.84
6.5	33,646,694	233,837	0.0069	0.9931	96.77
7.5	33,076,171	119,610	0.0036	0.9964	96.10
8.5	32,475,164	87,814	0.0027	0.9973	95.75
9.5	31,552,395	187,568	0.0059	0.9941	95.49
10.5	30,067,490	407,484	0.0136	0.9864	94.92
11.5	29,105,744	164,241	0.0056	0.9944	93.64
12.5	28,117,925	206,953	0.0074	0.9926	93.11
13.5	27,822,487	197,680	0.0071	0.9929	92.42
14.5	27,454,587	170,617	0.0062	0.9938	91.76
15.5	27,067,174	467,175	0.0173	0.9827	91.19
16.5	26,295,847	109,507	0.0042	0.9958	89.62
17.5	25,412,554	503,951	0.0198	0.9802	89.25
18.5	24,500,016	635,325	0.0259	0.9741	87.48
19.5	12,289,952	920,905	0.0749	0.9251	85.21
20.5	10,426,772	217,775	0.0209	0.9791	78.82
21.5	8,888,255	105,329	0.0119	0.9881	77.18
22.5	7,558,516	30,966	0.0041	0.9959	76.26
23.5	7,191,097	17,829	0.0025	0.9975	75.95
24.5	7,142,000	19,219	0.0027	0.9973	75.76
25.5	7,051,529	48,748	0.0069	0.9931	75.56
26.5	6,835,346	23,235	0.0034	0.9966	75.04
27.5	6,445,129	21,663	0.0034	0.9966	74.78
28.5	6,386,381	58,525	0.0092	0.9908	74.53
29.5	3,717,644	47,891	0.0129	0.9871	73.85
30.5	3,175,836	96,584	0.0304	0.9696	72.90
31.5	2,680,595	83,705	0.0312	0.9688	70.68
32.5	2,235,080	20,458	0.0092	0.9908	68.47
33.5	2,147,132	7,812	0.0036	0.9964	67.84
34.5	1,876,261	37,022	0.0197	0.9803	67.60
35.5	1,658,423	2,912	0.0018	0.9982	66.26
36.5	1,626,486	279,188	0.1717	0.8283	66.15
37.5	1,323,501	8,494	0.0064	0.9936	54.79
38.5	1,310,922	43,739	0.0334	0.9666	54.44

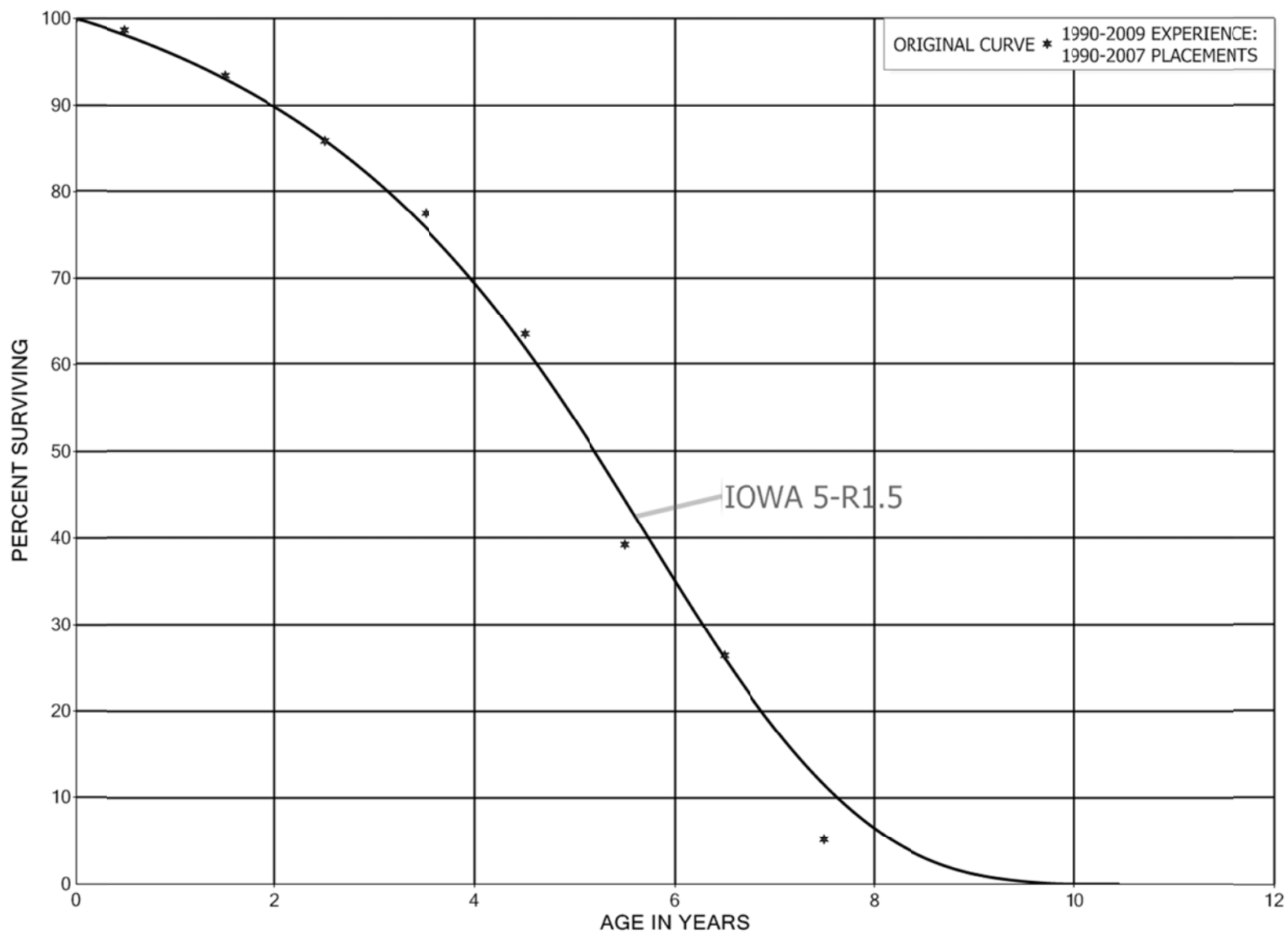
NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1946-2009			EXPERIENCE BAND 1951-2009		
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	1,257,386	600	0.0005	0.9995	52.63
40.5	495,118	94	0.0002	0.9998	52.60
41.5	487,663		0.0000	1.0000	52.59
42.5	485,869	7,985	0.0164	0.9836	52.59
43.5	367,924		0.0000	1.0000	51.73
44.5	364,336	425	0.0012	0.9988	51.73
45.5	363,911	1,005	0.0028	0.9972	51.67
46.5	350,076		0.0000	1.0000	51.52
47.5	346,733	11,899	0.0343	0.9657	51.52
48.5	331,334	972	0.0029	0.9971	49.75
49.5	329,326		0.0000	1.0000	49.61
50.5	327,279	500	0.0015	0.9985	49.61
51.5	189,341	117,499	0.6206	0.3794	49.53
52.5	2,100		0.0000	1.0000	18.79
53.5	2,100		0.0000	1.0000	18.79
54.5	2,100		0.0000	1.0000	18.79
55.5	2,100		0.0000	1.0000	18.79
56.5					18.79

NEWFOUNDLAND POWER INC.
ACCOUNT 378.10 - TRANSPORTATION - SEDANS & STATION WAGONS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 378.10 - TRANSPORTATION - SEDANS & STATION WAGONS

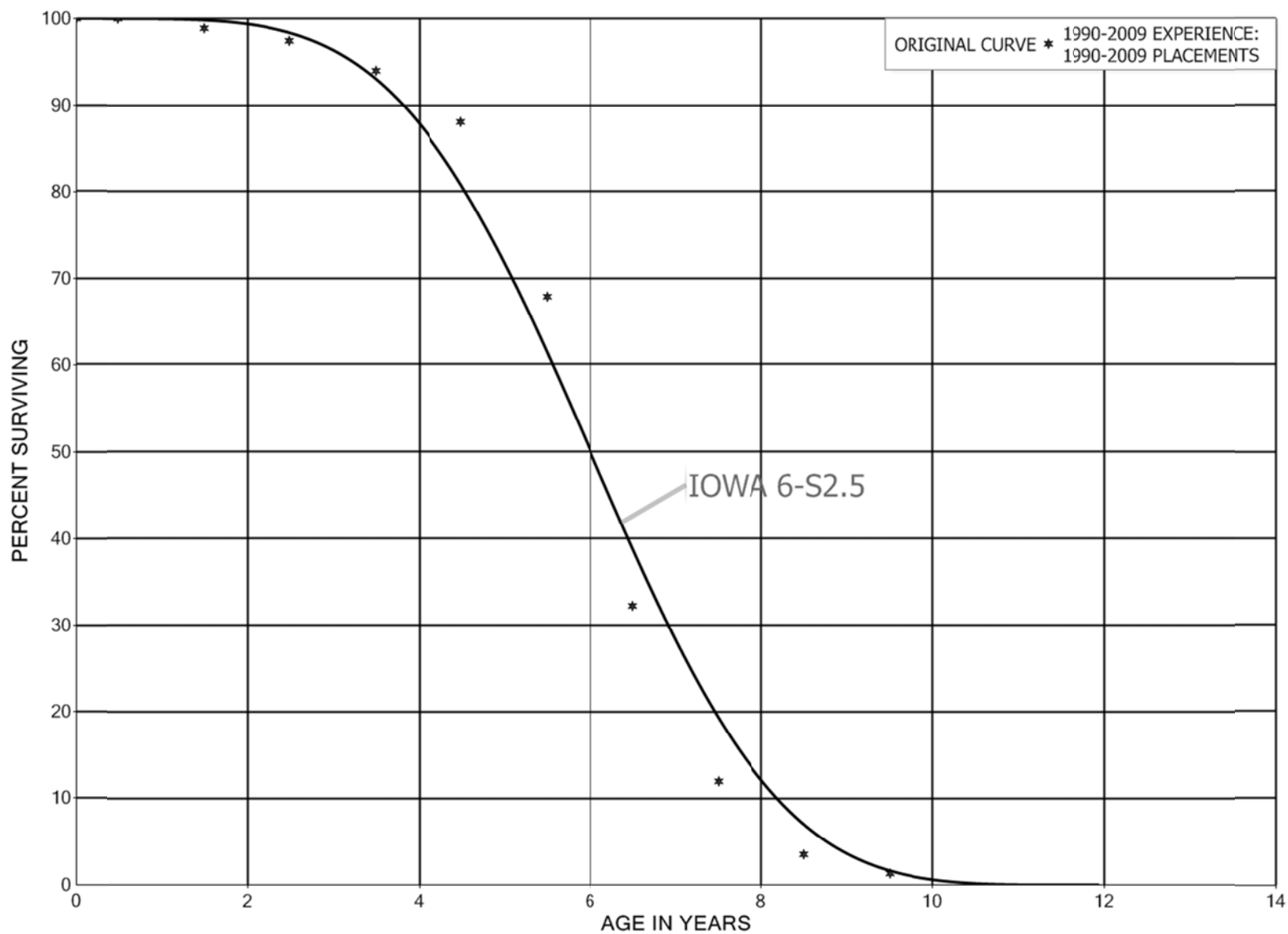
ORIGINAL LIFE TABLE

PLACEMENT BAND 1990-2007

EXPERIENCE BAND 1990-2009

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	2,491,007	35,297	0.0142	0.9858	100.00
0.5	2,149,414	112,518	0.0523	0.9477	98.58
1.5	1,782,636	144,733	0.0812	0.9188	93.42
2.5	1,495,398	145,705	0.0974	0.9026	85.84
3.5	1,249,644	225,488	0.1804	0.8196	77.47
4.5	852,353	326,458	0.3830	0.6170	63.49
5.5	542,990	176,872	0.3257	0.6743	39.18
6.5	382,535	307,695	0.8044	0.1956	26.41
7.5	74,840	35,087	0.4688	0.5312	5.17
8.5	39,753	22,657	0.5699	0.4301	2.74
9.5	17,096		0.0000	1.0000	1.18
10.5	17,096		0.0000	1.0000	1.18
11.5					1.18

NEWFOUNDLAND POWER INC.
ACCOUNT 378.20 - TRANSPORTATION - PICK-UPS, JEEPS
ORIGINAL AND SMOOTH SURVIVOR CURVES



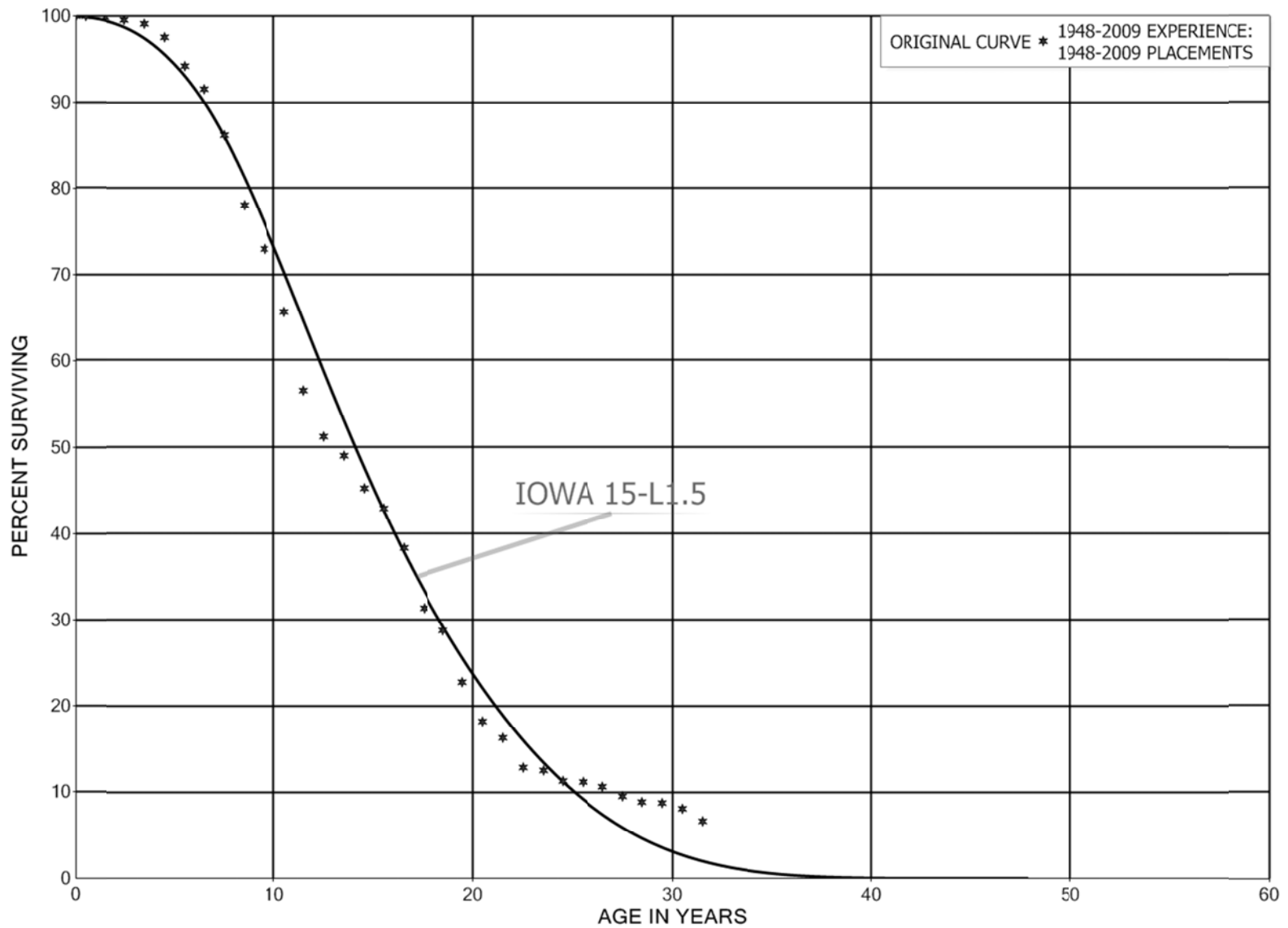
NEWFOUNDLAND POWER INC.

ACCOUNT 378.20 - TRANSPORTATION - PICK-UPS, JEEPS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1990-2009			EXPERIENCE BAND 1990-2009		
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	15,967,405		0.0000	1.0000	100.00
0.5	15,181,442	174,605	0.0115	0.9885	100.00
1.5	13,845,664	204,209	0.0147	0.9853	98.85
2.5	12,931,284	459,536	0.0355	0.9645	97.39
3.5	11,641,287	731,379	0.0628	0.9372	93.93
4.5	9,664,949	2,215,328	0.2292	0.7708	88.03
5.5	7,251,231	3,810,098	0.5254	0.4746	67.85
6.5	3,360,916	2,117,522	0.6300	0.3700	32.20
7.5	1,191,242	835,739	0.7016	0.2984	11.91
8.5	353,832	222,231	0.6281	0.3719	3.56
9.5	19,546	19,546	1.0000	0.0000	1.32
10.5	0		0.0000	1.0000	0.00
11.5	0		0.0000	1.0000	0.00
12.5					0.00

NEWFOUNDLAND POWER INC.
ACCOUNT 378.50 - TRANSPORTATION - MISCELLANEOUS
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 378.50 - TRANSPORTATION - MISCELLANEOUS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2009			EXPERIENCE BAND 1948-2009		
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	4,180,940		0.0000	1.0000	100.00
0.5	4,072,703	8,107	0.0020	0.9980	100.00
1.5	3,804,712	11,896	0.0031	0.9969	99.80
2.5	3,785,481	17,907	0.0047	0.9953	99.49
3.5	3,640,397	56,163	0.0154	0.9846	99.02
4.5	3,448,742	116,159	0.0337	0.9663	97.49
5.5	3,132,117	89,189	0.0285	0.9715	94.21
6.5	3,021,830	175,044	0.0579	0.9421	91.52
7.5	2,790,241	263,237	0.0943	0.9057	86.22
8.5	2,494,651	165,536	0.0664	0.9336	78.09
9.5	2,277,025	229,121	0.1006	0.8994	72.91
10.5	2,027,346	281,490	0.1388	0.8612	65.57
11.5	1,718,188	160,210	0.0932	0.9068	56.47
12.5	1,524,775	68,749	0.0451	0.9549	51.20
13.5	1,423,566	107,619	0.0756	0.9244	48.89
14.5	1,318,933	67,670	0.0513	0.9487	45.20
15.5	1,178,450	127,420	0.1081	0.8919	42.88
16.5	1,053,246	191,075	0.1814	0.8186	38.24
17.5	858,771	71,470	0.0832	0.9168	31.30
18.5	765,202	159,411	0.2083	0.7917	28.70
19.5	603,726	120,124	0.1990	0.8010	22.72
20.5	434,130	46,304	0.1067	0.8933	18.20
21.5	384,269	82,162	0.2138	0.7862	16.26
22.5	296,980	5,250	0.0177	0.9823	12.78
23.5	268,590	28,226	0.1051	0.8949	12.56
24.5	240,364	874	0.0036	0.9964	11.24
25.5	239,490	11,503	0.0480	0.9520	11.20
26.5	227,987	25,463	0.1117	0.8883	10.66
27.5	201,924	13,020	0.0645	0.9355	9.47
28.5	188,904	3,545	0.0188	0.9812	8.86
29.5	185,359	12,233	0.0660	0.9340	8.69
30.5	113,452	21,507	0.1896	0.8104	8.12
31.5	91,945		0.0000	1.0000	6.58
32.5	91,945	332	0.0036	0.9964	6.58
33.5	91,363	2,077	0.0227	0.9773	6.55
34.5	63,255		0.0000	1.0000	6.41
35.5	48,102		0.0000	1.0000	6.41
36.5	48,102	4,181	0.0869	0.9131	6.41
37.5	43,921		0.0000	1.0000	5.85
38.5	43,921		0.0000	1.0000	5.85

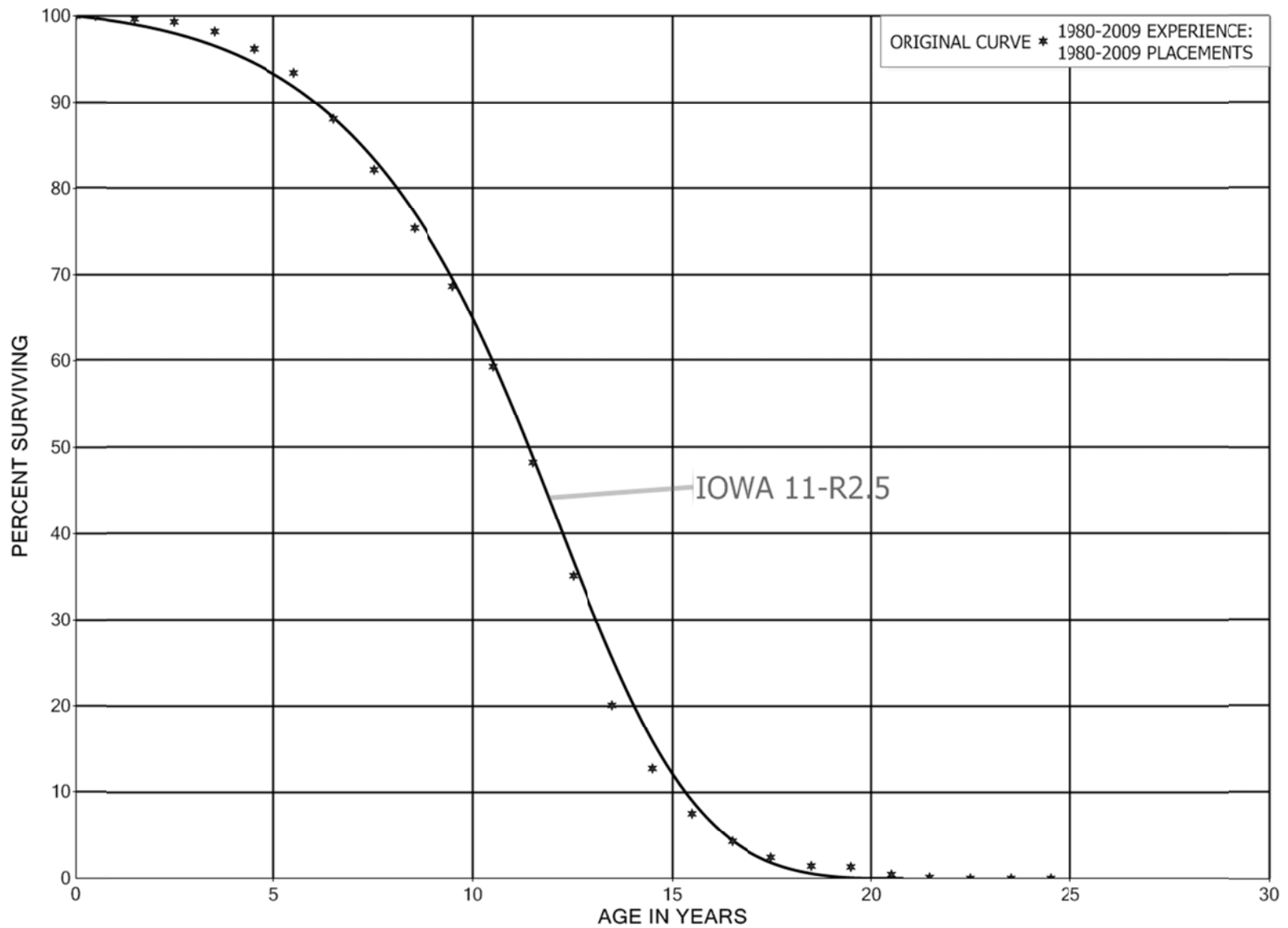
NEWFOUNDLAND POWER INC.

ACCOUNT 378.50 - TRANSPORTATION - MISCELLANEOUS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2009			EXPERIENCE BAND 1948-2009		
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	43,921		0.0000	1.0000	5.85
40.5	43,921		0.0000	1.0000	5.85
41.5	4,182		0.0000	1.0000	5.85
42.5	4,182		0.0000	1.0000	5.85
43.5					5.85

NEWFOUNDLAND POWER INC.
ACCOUNT 378.3 & 378.4-CAB & CHASSIS/TRUCKS W/ STAKE BODIES
ORIGINAL AND SMOOTH SURVIVOR CURVES



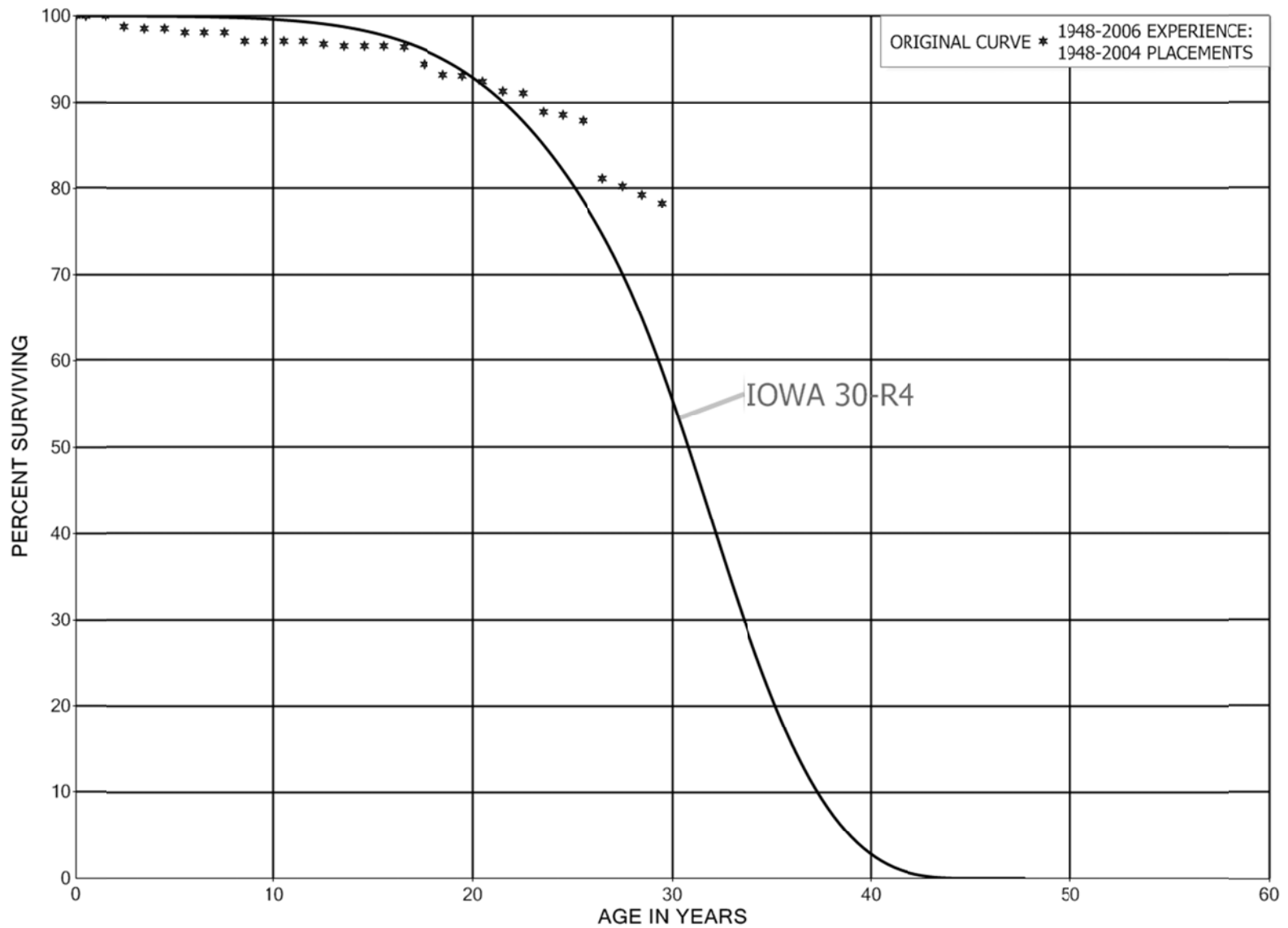
NEWFOUNDLAND POWER INC.

ACCOUNT 378.3 & 378.4-CAB & CHASSIS/TRUCKS W/ STAKE BODIES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1980-2009			EXPERIENCE BAND 1980-2009		
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	35,782,419		0.0000	1.0000	100.00
0.5	34,827,422	118,779	0.0034	0.9966	100.00
1.5	34,587,940	141,377	0.0041	0.9959	99.66
2.5	32,201,553	357,566	0.0111	0.9889	99.25
3.5	29,964,789	613,088	0.0205	0.9795	98.15
4.5	27,999,968	815,349	0.0291	0.9709	96.14
5.5	25,129,376	1,429,793	0.0569	0.9431	93.34
6.5	20,573,774	1,379,573	0.0671	0.9329	88.03
7.5	18,912,327	1,540,516	0.0815	0.9185	82.13
8.5	16,415,908	1,491,493	0.0909	0.9091	75.44
9.5	13,516,661	1,830,834	0.1355	0.8645	68.58
10.5	10,991,255	2,051,638	0.1867	0.8133	59.29
11.5	8,631,272	2,351,941	0.2725	0.7275	48.23
12.5	6,219,764	2,665,149	0.4285	0.5715	35.09
13.5	3,534,877	1,282,167	0.3627	0.6373	20.05
14.5	2,252,708	925,791	0.4110	0.5890	12.78
15.5	1,333,152	570,272	0.4278	0.5722	7.53
16.5	664,617	297,204	0.4472	0.5528	4.31
17.5	325,415	134,850	0.4144	0.5856	2.38
18.5	207,183	23,975	0.1157	0.8843	1.39
19.5	183,208	124,571	0.6799	0.3201	1.23
20.5	58,638	53,688	0.9156	0.0844	0.39
21.5	36,568	30,330	0.8294	0.1706	0.03
22.5	6,238		0.0000	1.0000	0.01
23.5	6,238		0.0000	1.0000	0.01
24.5					0.01

NEWFOUNDLAND POWER INC.
ACCOUNT 382.00 - RADIO SITES
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 382.00 - RADIO SITES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1948-2004			EXPERIENCE BAND 1948-2006		
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	578,768		0.0000	1.0000	100.00
0.5	578,546		0.0000	1.0000	100.00
1.5	578,546	7,217	0.0125	0.9875	100.00
2.5	569,614	1,239	0.0022	0.9978	98.75
3.5	575,500		0.0000	1.0000	98.54
4.5	591,620	2,815	0.0048	0.9952	98.54
5.5	586,936		0.0000	1.0000	98.07
6.5	571,781		0.0000	1.0000	98.07
7.5	597,841	6,302	0.0105	0.9895	98.07
8.5	592,431	93	0.0002	0.9998	97.04
9.5	596,010		0.0000	1.0000	97.02
10.5	596,220		0.0000	1.0000	97.02
11.5	596,220	1,612	0.0027	0.9973	97.02
12.5	594,608	1,250	0.0021	0.9979	96.76
13.5	601,715		0.0000	1.0000	96.55
14.5	600,750	91	0.0002	0.9998	96.55
15.5	602,037	1,000	0.0017	0.9983	96.54
16.5	601,037	12,627	0.0210	0.9790	96.38
17.5	588,410	7,349	0.0125	0.9875	94.35
18.5	565,095	352	0.0006	0.9994	93.18
19.5	564,743	4,564	0.0081	0.9919	93.12
20.5	486,655	5,804	0.0119	0.9881	92.37
21.5	340,667	612	0.0018	0.9982	91.26
22.5	279,253	7,087	0.0254	0.9746	91.10
23.5	152,675	500	0.0033	0.9967	88.79
24.5	148,475	1,098	0.0074	0.9926	88.50
25.5	147,377	11,276	0.0765	0.9235	87.84
26.5	136,101	1,469	0.0108	0.9892	81.12
27.5	134,632	1,625	0.0121	0.9879	80.25
28.5	133,007	1,648	0.0124	0.9876	79.28
29.5	83,428	8,941	0.1072	0.8928	78.30
30.5	74,487	25,146	0.3376	0.6624	69.90
31.5	43,205	1,341	0.0310	0.9690	46.31
32.5	41,864	10,797	0.2579	0.7421	44.87
33.5	31,067	4,536	0.1460	0.8540	33.30
34.5	26,531		0.0000	1.0000	28.43
35.5	26,531	11,592	0.4369	0.5631	28.43
36.5	14,939	4,840	0.3240	0.6760	16.01
37.5	10,099		0.0000	1.0000	10.82
38.5	10,099	1,183	0.1171	0.8829	10.82

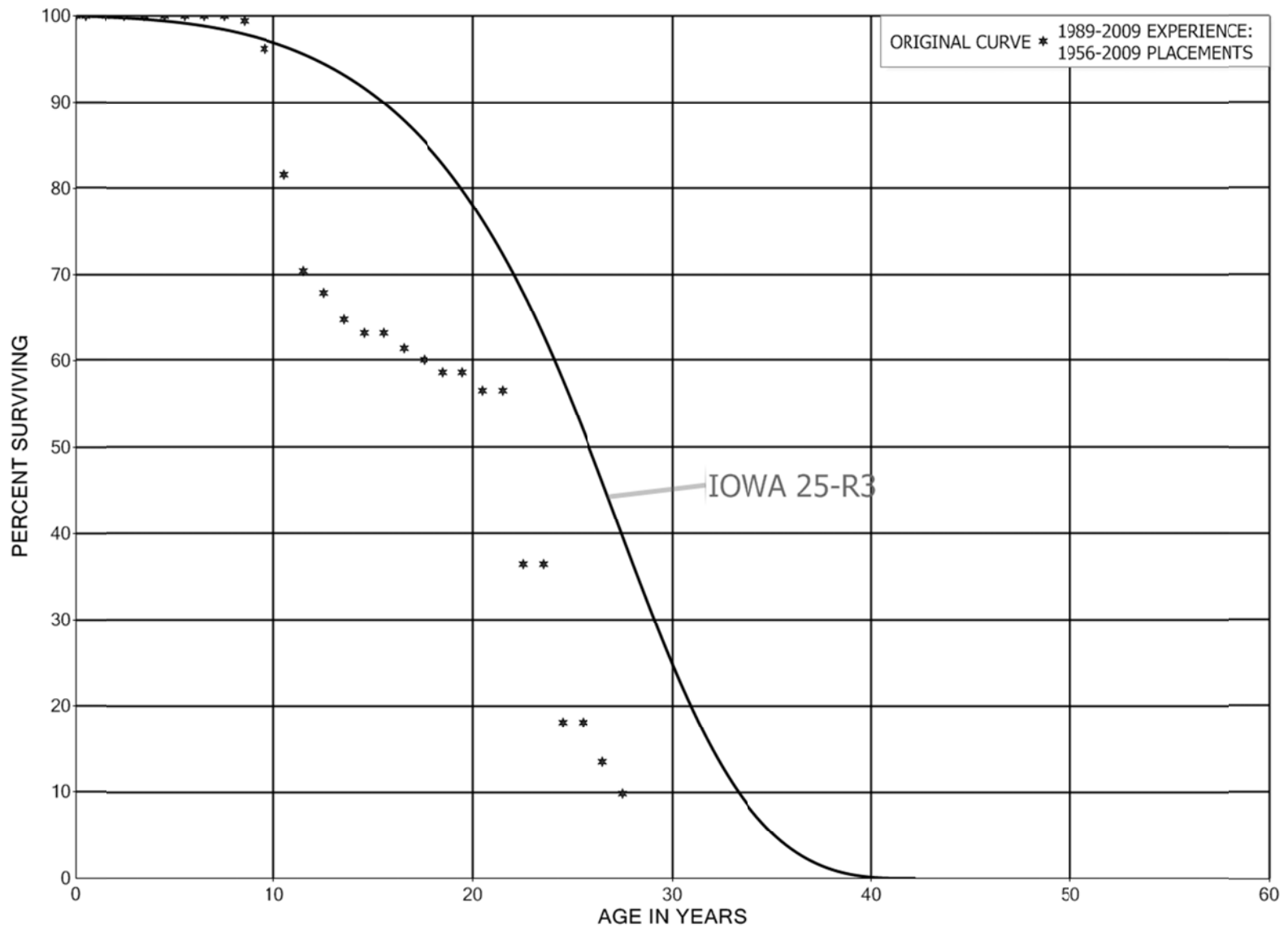
NEWFOUNDLAND POWER INC.

ACCOUNT 382.00 - RADIO SITES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1948-2004			EXPERIENCE BAND 1948-2006		
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	4,954	210	0.0424	0.9576	9.56
40.5	1,647		0.0000	1.0000	9.15
41.5	1,647		0.0000	1.0000	9.15
42.5	1,647	1,452	0.8816	0.1184	9.15
43.5	195		0.0000	1.0000	1.08
44.5	195	195	1.0000		1.08
45.5					

NEWFOUNDLAND POWER INC.
ACCOUNT 384.00 - COMMUNICATIONS - CABLES AND PROTECTION
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 384.00 - COMMUNICATIONS - CABLES AND PROTECTION

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2009

EXPERIENCE BAND 1989-2009

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	3,287,560		0.0000	1.0000	100.00
0.5	2,958,455		0.0000	1.0000	100.00
1.5	2,815,694		0.0000	1.0000	100.00
2.5	2,791,963	775	0.0003	0.9997	100.00
3.5	2,911,651		0.0000	1.0000	99.97
4.5	2,819,506		0.0000	1.0000	99.97
5.5	2,773,148		0.0000	1.0000	99.97
6.5	2,565,464		0.0000	1.0000	99.97
7.5	2,657,669	16,593	0.0062	0.9938	99.97
8.5	2,408,453	75,717	0.0314	0.9686	99.35
9.5	2,219,537	337,698	0.1521	0.8479	96.22
10.5	1,857,610	254,491	0.1370	0.8630	81.58
11.5	1,398,997	50,329	0.0360	0.9640	70.41
12.5	1,348,668	63,643	0.0472	0.9528	67.87
13.5	1,248,790	29,546	0.0237	0.9763	64.67
14.5	1,219,244		0.0000	1.0000	63.14
15.5	1,208,277	33,889	0.0280	0.9720	63.14
16.5	1,180,862	25,283	0.0214	0.9786	61.37
17.5	1,206,691	29,417	0.0244	0.9756	60.06
18.5	684,653		0.0000	1.0000	58.59
19.5	465,719	16,915	0.0363	0.9637	58.59
20.5	452,763		0.0000	1.0000	56.46
21.5	448,240	158,975	0.3547	0.6453	56.46
22.5	289,303		0.0000	1.0000	36.44
23.5	300,737	151,259	0.5030	0.4970	36.44
24.5	126,720		0.0000	1.0000	18.11
25.5	133,931	33,788	0.2523	0.7477	18.11
26.5	100,143	27,149	0.2711	0.7289	13.54
27.5	36,133		0.0000	1.0000	9.87
28.5	36,133	17,450	0.4829	0.5171	9.87
29.5	19,532		0.0000	1.0000	5.10
30.5	19,532	38	0.0019	0.9981	5.10
31.5	19,494	11,434	0.5865	0.4135	5.09
32.5	16,793	379	0.0226	0.9774	2.11
33.5	16,939	7,211	0.4257	0.5743	2.06
34.5	9,728		0.0000	1.0000	1.18
35.5	9,728		0.0000	1.0000	1.18
36.5	9,728		0.0000	1.0000	1.18
37.5	9,728	849	0.0873	0.9127	1.18
38.5	8,879		0.0000	1.0000	1.08

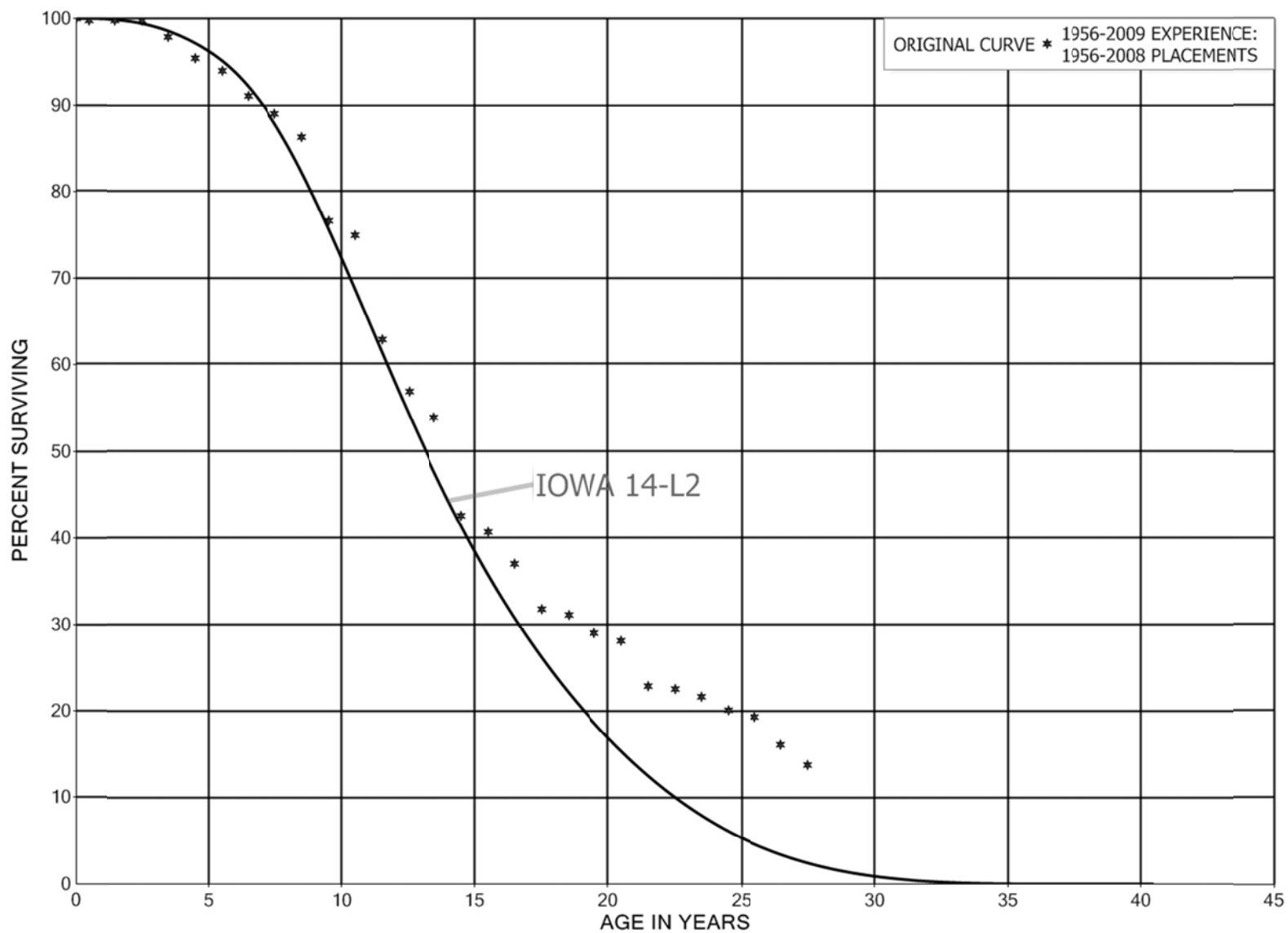
NEWFOUNDLAND POWER INC.

ACCOUNT 384.00 - COMMUNICATIONS - CABLES AND PROTECTION

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2009			EXPERIENCE BAND 1989-2009			
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	8,879		0.0000	1.0000	1.08	
40.5	8,879	7,262	0.8179	0.1821	1.08	
41.5	1,617	525	0.3247	0.6753	0.20	
42.5	1,092		0.0000	1.0000	0.13	
43.5	1,092		0.0000	1.0000	0.13	
44.5	1,092	1,092	1.0000		0.13	
45.5						

NEWFOUNDLAND POWER INC.
ACCOUNT 386.00 - COMMUNICATIONS - SCADA EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



NEWFOUNDLAND POWER INC.

ACCOUNT 386.00 - COMMUNICATIONS - SCADA EQUIPMENT

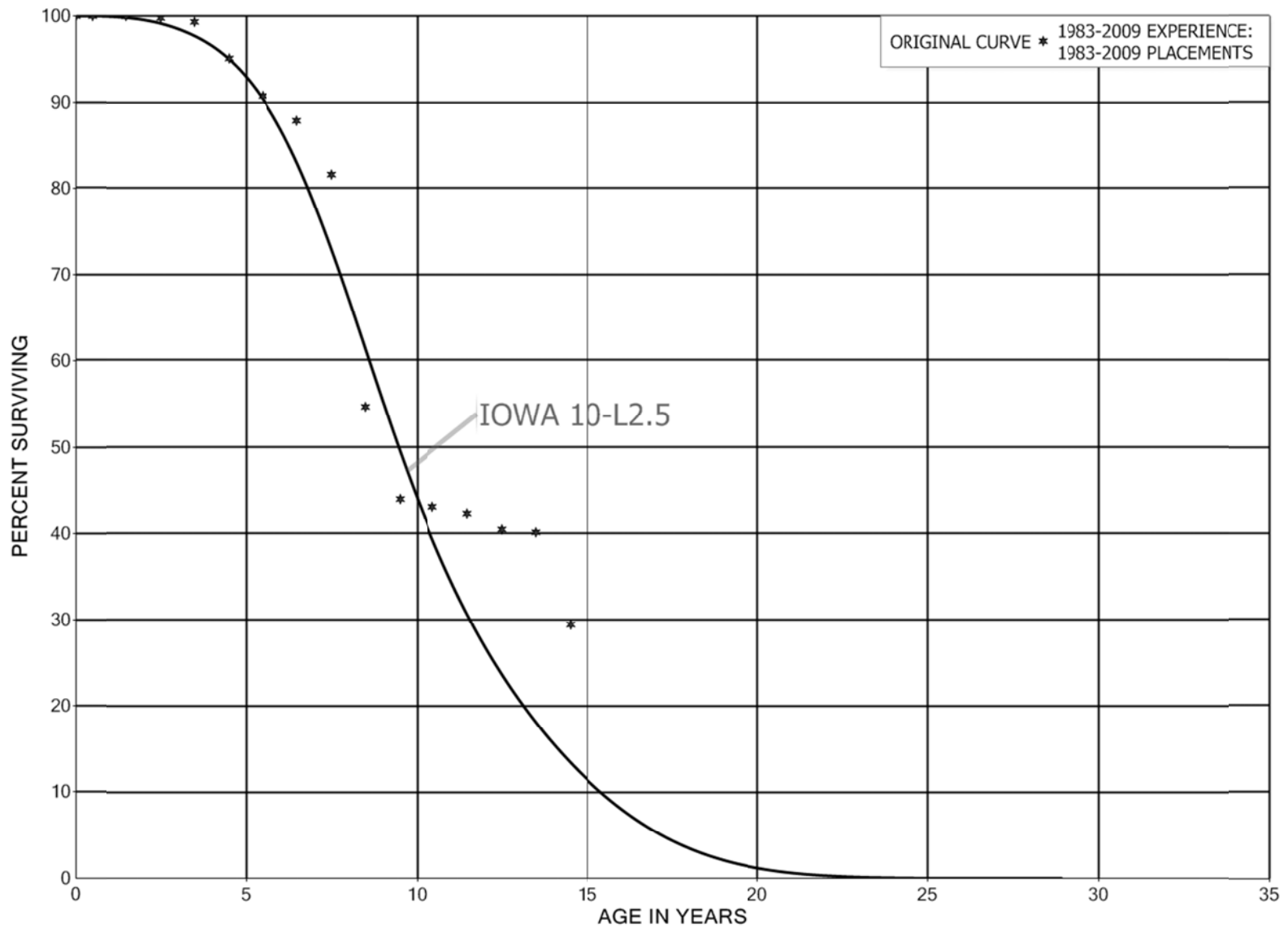
ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2008

EXPERIENCE BAND 1956-2009

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	15,099,556	43,026	0.0028	0.9972	100.00
0.5	14,700,074	827	0.0001	0.9999	99.72
1.5	14,325,230	3,438	0.0002	0.9998	99.71
2.5	14,178,609	266,606	0.0188	0.9812	99.69
3.5	14,502,374	352,648	0.0243	0.9757	97.81
4.5	14,258,422	228,762	0.0160	0.9840	95.43
5.5	13,715,038	408,623	0.0298	0.9702	93.90
6.5	12,910,665	303,656	0.0235	0.9765	91.10
7.5	12,124,107	369,459	0.0305	0.9695	88.96
8.5	10,918,802	1,214,511	0.1112	0.8888	86.25
9.5	8,389,469	188,550	0.0225	0.9775	76.66
10.5	8,361,690	1,348,789	0.1613	0.8387	74.93
11.5	7,070,348	675,863	0.0956	0.9044	62.85
12.5	6,393,519	337,140	0.0527	0.9473	56.84
13.5	5,897,927	1,244,305	0.2110	0.7890	53.84
14.5	4,633,218	206,931	0.0447	0.9553	42.48
15.5	4,493,965	397,422	0.0884	0.9116	40.59
16.5	3,646,640	523,773	0.1436	0.8564	37.00
17.5	3,025,882	59,123	0.0195	0.9805	31.68
18.5	3,088,497	213,387	0.0691	0.9309	31.06
19.5	2,537,920	74,486	0.0293	0.9707	28.92
20.5	1,977,536	369,087	0.1866	0.8134	28.07
21.5	1,441,824	19,377	0.0134	0.9866	22.83
22.5	1,330,589	53,658	0.0403	0.9597	22.52
23.5	1,129,815	79,311	0.0702	0.9298	21.61
24.5	1,022,028	41,846	0.0409	0.9591	20.10
25.5	773,382	130,181	0.1683	0.8317	19.27
26.5	282,921	40,288	0.1424	0.8576	16.03
27.5	41,765	1,993	0.0477	0.9523	13.75
28.5	39,772	7,104	0.1786	0.8214	13.09
29.5	26,201		0.0000	1.0000	10.75
30.5	26,201		0.0000	1.0000	10.75
31.5	26,201	7,382	0.2817	0.7183	10.75
32.5	9,462		0.0000	1.0000	7.72
33.5	8,937		0.0000	1.0000	7.72
34.5	8,937	2,335	0.2613	0.7387	7.72
35.5	6,602		0.0000	1.0000	5.71
36.5	6,602	624	0.0945	0.9055	5.71
37.5	5,978	514	0.0860	0.9140	5.17
38.5	5,464		0.0000	1.0000	4.72
39.5					4.72

NEWFOUNDLAND POWER INC.
ACCOUNT 389.10 - TELEPHONE EQUIPMENT - TELE. & DATA EQUIP.
ORIGINAL AND SMOOTH SURVIVOR CURVES



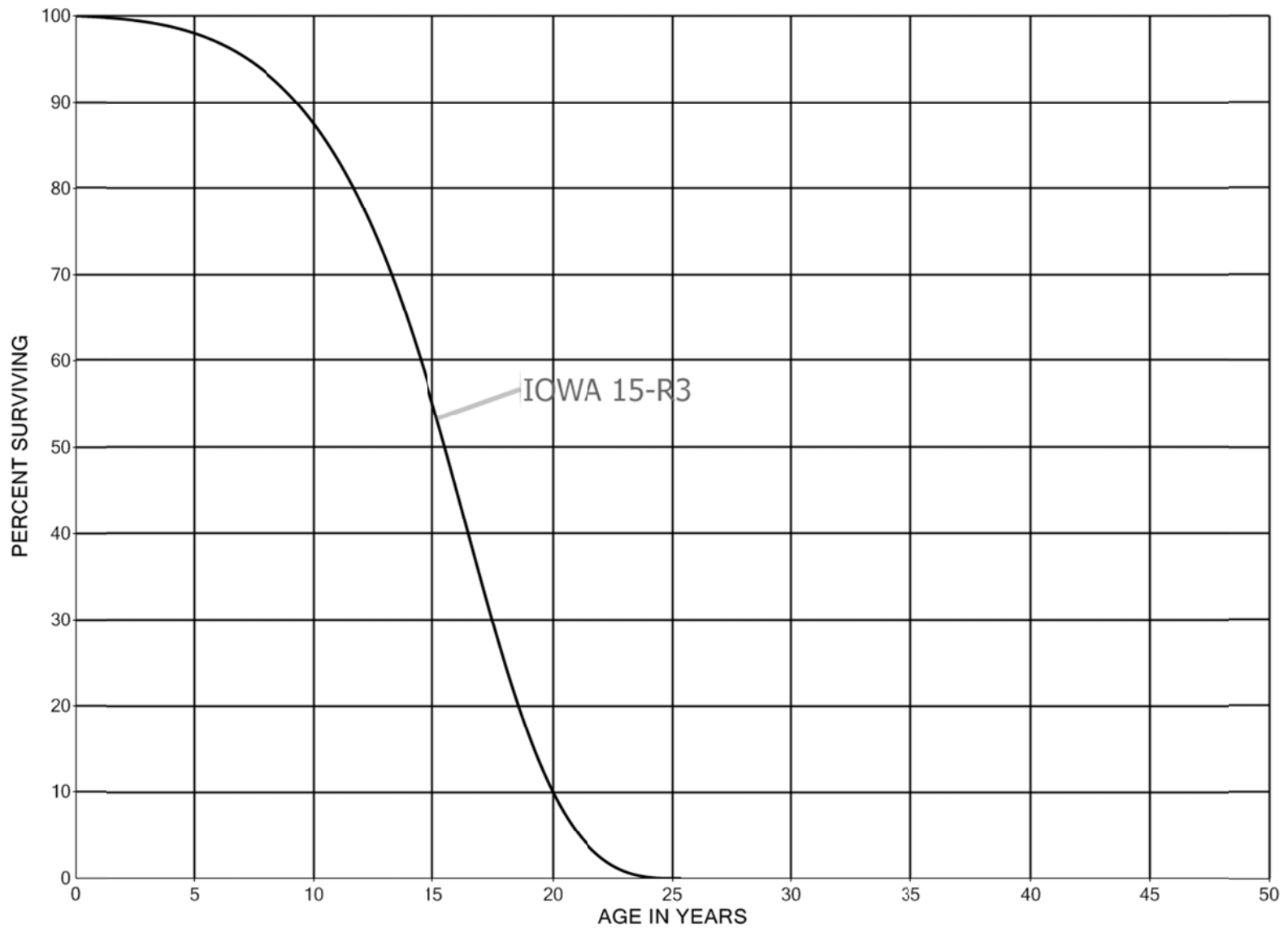
NEWFOUNDLAND POWER INC.

ACCOUNT 389.10 - TELEPHONE EQUIPMENT - TELE. & DATA EQUIP.

ORIGINAL LIFE TABLE

PLACEMENT BAND 1983-2009			EXPERIENCE BAND 1983-2009		
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	2,445,462		0.0000	1.0000	100.00
0.5	2,443,203		0.0000	1.0000	100.00
1.5	2,950,377	7,202	0.0024	0.9976	100.00
2.5	2,984,223	13,912	0.0047	0.9953	99.76
3.5	2,902,655	122,064	0.0421	0.9579	99.29
4.5	2,764,284	126,640	0.0458	0.9542	95.12
5.5	2,641,906	84,353	0.0319	0.9681	90.76
6.5	2,557,553	181,941	0.0711	0.9289	87.86
7.5	2,203,667	729,893	0.3312	0.6688	81.61
8.5	1,473,774	288,069	0.1955	0.8045	54.58
9.5	1,162,282	22,828	0.0196	0.9804	43.91
10.5	1,167,911	19,866	0.0170	0.9830	43.05
11.5	356,055	16,086	0.0452	0.9548	42.32
12.5	312,327	2,741	0.0088	0.9912	40.40
13.5	185,906	49,533	0.2664	0.7336	40.05
14.5	77,158	12,528	0.1624	0.8376	29.38
15.5	59,889	28,039	0.4682	0.5318	24.61
16.5	29,435		0.0000	1.0000	13.09
17.5	14,431		0.0000	1.0000	13.09
18.5	14,431	2,843	0.1970	0.8030	13.09
19.5					10.51

NEWFOUNDLAND POWER INC.
ACCOUNT 391.00 - COMMUNICATIONS - TEST EQUIPMENT
SMOOTH SURVIVOR CURVE



APPENDIX B — NET SALVAGE STATISTICS

NEWFOUNDLAND POWER INC.

HYDRO PRODUCTION PLANT - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	13,026	4,263	33		0		0	4,263-	33-
1977	93,651	5,340	6		0	6,172	7	832	1
1978	153,825	11,880	8		0	1,383	1	10,497-	7-
1979	216,689	42,834	20		0		0	42,834-	20-
1980	58,096	7,434	13		0		0	7,434-	13-
1981	176,662	15,829	9		0	5,000	3	10,829-	6-
1982	112,902	13,606	12		0	291	0	13,315-	12-
1983	622,353	62,201	10		0	706	0	61,495-	10-
1984	214,685	7,248	3		0	2,448	1	4,800-	2-
1985	326,146	40,098	12		0	19,936	6	20,162-	6-
1986	213,292	40,731	19		0	37,679	18	3,052-	1-
1987	418,535	84,545	20		0	229	0	84,316-	20-
1988	122,353	25,334	21		0	83,754	68	58,420	48
1989	374,685	43,992	12		0	8-	0	44,000-	12-
1990	458,300	68,601	15		0	525	0	68,076-	15-
1991	191,896	50,886	27		0		0	50,886-	27-
1992	245,358	14,431	6		0	54,166	22	39,735	16
1993	72,070	19,768	27	3,863-	5-		0	23,631-	33-
1994	181,301	41,612	23		0	182,450	101	140,838	78
1995	445,220	70,341	16		0		0	70,341-	16-
1996	180,927	37,327	21		0		0	37,327-	21-
1997	556,891	27,502	5		0		0	27,502-	5-
1998	275,574	84,467	31		0		0	84,467-	31-
1999	787,325	270,332	34		0		0	270,332-	34-
2000	840,111	325,162	39		0		0	325,162-	39-
2001	518,992	278,683	54		0		0	278,683-	54-
2002	802,570	174,472	22		0	2,058	0	172,414-	21-
2003	443,979	80,275	18		0		0	80,275-	18-
2004	1,219,396	239,492	20		0		0	239,492-	20-
2005	282,005	107,792	38		0		0	107,792-	38-
2006	742,973	308,439	42		0		0	308,439-	42-
2007	1,280,921	605,551	47		0		0	605,551-	47-
2008	711,803	281,060	39		0		0	281,060-	39-
2009	836,483	518,819	62		0		0	518,819-	62-
TOTAL	14,190,995	4,010,347	28	3,863-	0	396,789	3	3,617,421-	25-

THREE-YEAR MOVING AVERAGES

76-78	86,834	7,161	8		0	2,518	3	4,643-	5-
77-79	154,722	20,018	13		0	2,518	2	17,500-	11-
78-80	142,870	20,716	14		0	461	0	20,255-	14-

NEWFOUNDLAND POWER INC.

HYDRO PRODUCTION PLANT - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	150,482	22,032	15		0	1,667	1	20,366-	14-
80-82	115,887	12,290	11		0	1,764	2	10,526-	9-
81-83	303,972	30,545	10		0	1,999	1	28,546-	9-
82-84	316,647	27,685	9		0	1,148	0	26,537-	8-
83-85	387,728	36,516	9		0	7,697	2	28,819-	7-
84-86	251,374	29,359	12		0	20,021	8	9,338-	4-
85-87	319,324	55,125	17		0	19,281	6	35,843-	11-
86-88	251,393	50,203	20		0	40,554	16	9,649-	4-
87-89	305,191	51,290	17		0	27,992	9	23,299-	8-
88-90	318,446	45,976	14		0	28,090	9	17,885-	6-
89-91	341,627	54,493	16		0	172	0	54,321-	16-
90-92	298,518	44,639	15		0	18,230	6	26,409-	9-
91-93	169,775	28,362	17	1,288-	1-	18,055	11	11,594-	7-
92-94	166,243	25,270	15	1,288-	1-	78,872	47	52,314	31
93-95	232,864	43,907	19	1,288-	1-	60,817	26	15,622	7
94-96	269,149	49,760	18		0	60,817	23	11,057	4
95-97	394,346	45,057	11		0		0	45,057-	11-
96-98	337,797	49,765	15		0		0	49,765-	15-
97-99	539,930	127,434	24		0		0	127,434-	24-
98-00	634,337	226,654	36		0		0	226,654-	36-
99-01	715,476	291,392	41		0		0	291,392-	41-
00-02	720,558	259,439	36		0	686	0	258,753-	36-
01-03	588,514	177,810	30		0	686	0	177,124-	30-
02-04	821,982	164,746	20		0	686	0	164,060-	20-
03-05	648,460	142,520	22		0		0	142,520-	22-
04-06	748,125	218,574	29		0		0	218,574-	29-
05-07	768,633	340,594	44		0		0	340,594-	44-
06-08	911,899	398,350	44		0		0	398,350-	44-
07-09	943,069	468,477	50		0		0	468,477-	50-
FIVE-YEAR AVERAGE									
05-09	770,837	364,332	47		0		0	364,332-	47-

NEWFOUNDLAND POWER INC.

OTHER PRODUCTION PLANT - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1977	14,090		0		0	1,545	11	1,545	11
1978	150		0		0		0		0
1979	333		0		0		0		0
1980									
1981									
1982	38,426	249	1		0		0	249-	1-
1983	27,838	871	3		0	1	0	870-	3-
1984	24,089	500	2		0	338	1	162-	1-
1985	13,345	426	3		0	324	2	102-	1-
1986	10,885	4,510	41		0		0	4,510-	41-
1987	136,510	21,638	16		0		0	21,638-	16-
1988	30,100	7,105	24		0		0	7,105-	24-
1989	3,747	108	3		0		0	108-	3-
1990	28,400	3,657	13		0		0	3,657-	13-
1991	40,689	601	1		0		0	601-	1-
1992	4,000		0		0		0		0
1993	93,144	29,147	31		0		0	29,147-	31-
1994	167,629	15,108	9		0		0	15,108-	9-
1995	44,946	54,018	120		0		0	54,018-	120-
1996	138,078	30,328	22		0		0	30,328-	22-
1997	45,630	12,706	28		0		0	12,706-	28-
1998	1,699,761	116,979	7	394	0		0	116,585-	7-
1999	185,402	275,360	149		0	18,400	10	256,960-	139-
2000	533,728	56,747	11		0		0	56,747-	11-
2001	18,145	20,026	110		0		0	20,026-	110-
2002	261,391	118,715	45		0		0	118,715-	45-
2003	783,624	70,120	9		0	83,609-	11-	153,729-	20-
2004	118,794	21,602	18		0	13,996	12	7,606-	6-
2005	1,663,002	130,859	8		0	423,735	25	292,876	18
2006	26,302	6,858	26		0		0	6,858-	26-
2007	5,636	2,429	43		0		0	2,429-	43-
2008	1,500	3,769	251		0		0	3,769-	251-
2009	42,385	11,377	27		0		0	11,377-	27-
TOTAL	6,201,699	1,015,813	16	394	0	374,730	6	640,689-	10-

THREE-YEAR MOVING AVERAGES

77-79	4,858		0		0	515	11	515	11
78-80	161		0		0		0		0
79-81	111		0		0		0		0
80-82	12,809	83	1		0		0	83-	1-

NEWFOUNDLAND POWER INC.

OTHER PRODUCTION PLANT - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
81-83	22,088	373	2		0		0	373-	2-
82-84	30,118	540	2		0	113	0	427-	1-
83-85	21,757	599	3		0	221	1	378-	2-
84-86	16,106	1,812	11		0	221	1	1,591-	10-
85-87	53,580	8,858	17		0	108	0	8,750-	16-
86-88	59,165	11,084	19		0		0	11,084-	19-
87-89	56,786	9,617	17		0		0	9,617-	17-
88-90	20,749	3,623	17		0		0	3,623-	17-
89-91	24,279	1,455	6		0		0	1,455-	6-
90-92	24,363	1,419	6		0		0	1,419-	6-
91-93	45,944	9,916	22		0		0	9,916-	22-
92-94	88,258	14,752	17		0		0	14,752-	17-
93-95	101,906	32,758	32		0		0	32,758-	32-
94-96	116,884	33,151	28		0		0	33,151-	28-
95-97	76,218	32,351	42		0		0	32,351-	42-
96-98	627,823	53,338	8	131	0		0	53,206-	8-
97-99	643,598	135,015	21	131	0	6,133	1	128,750-	20-
98-00	806,297	149,695	19	131	0	6,133	1	143,431-	18-
99-01	245,758	117,378	48		0	6,133	2	111,244-	45-
00-02	271,088	65,163	24		0		0	65,163-	24-
01-03	354,387	69,620	20		0	27,870-	8-	97,490-	28-
02-04	387,936	70,146	18		0	23,204-	6-	93,350-	24-
03-05	855,140	74,194	9		0	118,041	14	43,847	5
04-06	602,699	53,106	9		0	145,910	24	92,804	15
05-07	564,980	46,715	8		0	141,245	25	94,530	17
06-08	11,146	4,352	39		0		0	4,352-	39-
07-09	16,507	5,858	35		0		0	5,858-	35-
FIVE-YEAR AVERAGE									
05-09	347,765	31,058	9		0	84,747	24	53,689	15

NEWFOUNDLAND POWER INC.

SUBSTATIONS - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1976	209,702	4,114	2		0	6,253	3	2,139	1
1977	715,030	12,172	2		0	24,614	3	12,442	2
1978	324,510	21,609	7		0	84,012	26	62,403	19
1979	122,514	10,227	8		0	17,454	14	7,227	6
1980	108,065	2,436	2		0	45,517	42	43,081	40
1981	238,697	147,479	62		0	61,857	26	85,622-	36-
1982	129,423	3,099	2		0	7,165	6	4,066	3
1983	122,630	11,041	9		0	15,891	13	4,850	4
1984	175,717	13,590	8		0	13,396	8	194-	0
1985	406,932	18,807	5		0	8,078	2	10,729-	3-
1986	192,045	12,595	7		0	6,350	3	6,245-	3-
1987	321,499	27,183	8		0	7,263	2	19,920-	6-
1988	293,006	44,292	15		0	34,462	12	9,830-	3-
1989	171,633	51,567	30		0	7,769-	5-	59,336-	35-
1990	439,514	61,127	14		0	25,181	6	35,946-	8-
1991	256,468	39,146	15	23,514	9		0	15,632-	6-
1992	490,044	36,153	7	2,086	0		0	34,067-	7-
1993	124,896	37,515	30	3,426	3		0	34,089-	27-
1994	457,823	83,034	18		0	101,855	22	18,821	4
1995	220,360	47,975	22	101,135	46		0	53,160	24
1996	408,816	63,917	16	10,702	3		0	53,215-	13-
1997	462,017	73,776	16	18,898	4		0	54,878-	12-
1998	453,867	57,107	13		0	17,258	4	39,849-	9-
1999	1,100,914	253,110	23	13,300	1		0	239,810-	22-
2000	491,183	186,825	38	25,556	5		0	161,269-	33-
2001	646,050	110,079	17	754	0		0	109,325-	17-
2002	1,921,197	88,133	5		0	2,773	0	85,360-	4-
2003	523,765	113,166	22		0	515,590	98	402,424	77
2004	806,466	434,013	54		0		0	434,013-	54-
2005	1,188,785	386,434	33		0	1,270	0	385,164-	32-
2006	1,167,025	459,498	39		0	65,682	6	393,816-	34-
2007	420,429	749,064	178		0	44,634	11	704,430-	168-
2008	1,035,685	656,368	63		0	2,932	0	653,436-	63-
2009	1,318,923	926,102	70		0		0	926,102-	70-
TOTAL	17,465,630	5,242,753	30	199,371	1	1,101,718	6	3,941,664-	23-

THREE-YEAR MOVING AVERAGES

76-78	416,414	12,632	3		0	38,293	9	25,661	6
77-79	387,351	14,669	4		0	42,027	11	27,357	7
78-80	185,030	11,424	6		0	48,994	26	37,570	20

NEWFOUNDLAND POWER INC.

SUBSTATIONS - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		FINAL		NET SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	156,425	53,381	34		0	41,609	27	11,771-	8-
80-82	158,728	51,005	32		0	38,180	24	12,825-	8-
81-83	163,583	53,873	33		0	28,304	17	25,569-	16-
82-84	142,590	9,243	6		0	12,151	9	2,907	2
83-85	235,093	14,479	6		0	12,455	5	2,024-	1-
84-86	258,231	14,997	6		0	9,275	4	5,723-	2-
85-87	306,825	19,528	6		0	7,230	2	12,298-	4-
86-88	268,850	28,023	10		0	16,025	6	11,998-	4-
87-89	262,046	41,014	16		0	11,319	4	29,695-	11-
88-90	301,384	52,329	17		0	17,291	6	35,037-	12-
89-91	289,205	50,613	18	7,838	3	5,804	2	36,971-	13-
90-92	395,342	45,475	12	8,533	2	8,394	2	28,548-	7-
91-93	290,469	37,605	13	9,675	3		0	27,929-	10-
92-94	357,588	52,234	15	1,837	1	33,952	9	16,445-	5-
93-95	267,693	56,175	21	34,854	13	33,952	13	12,631	5
94-96	362,333	64,975	18	37,279	10	33,952	9	6,255	2
95-97	363,731	61,889	17	43,578	12		0	18,311-	5-
96-98	441,567	64,933	15	9,867	2	5,753	1	49,314-	11-
97-99	672,266	127,998	19	10,733	2	5,753	1	111,512-	17-
98-00	681,988	165,681	24	12,952	2	5,753	1	146,976-	22-
99-01	746,049	183,338	25	13,203	2		0	170,135-	23-
00-02	1,019,477	128,346	13	8,770	1	924	0	118,651-	12-
01-03	1,030,337	103,793	10	251	0	172,788	17	69,246	7
02-04	1,083,809	211,771	20		0	172,788	16	38,983-	4-
03-05	839,672	311,204	37		0	172,287	21	138,918-	17-
04-06	1,054,092	426,648	40		0	22,317	2	404,331-	38-
05-07	925,413	531,665	57		0	37,195	4	494,470-	53-
06-08	874,380	621,643	71		0	37,749	4	583,894-	67-
07-09	925,012	777,178	84		0	15,855	2	761,323-	82-
FIVE-YEAR AVERAGE									
05-09	1,026,169	635,493	62		0	22,904	2	612,590-	60-

NEWFOUNDLAND POWER INC.

TRANSMISSION - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	74,518	27,005	36		0	22,953	31	4,052-	5-
1977	170,467	89,070	52		0	103,137	61	14,067	8
1978	166,933	20,255	12		0	26,050	16	5,795	3
1979	53,320	9,423	18		0	27,253	51	17,830	33
1980	192,641	14,937	8		0	29,762	15	14,825	8
1981	439,424	18,798	4		0	16,820	4	1,978-	0
1982	533,077	23,296	4		0	68,325	13	45,029	8
1983	26,333	8,388	32		0	8,175	31	213-	1-
1984	152,266	24,524	16		0	8,112	5	16,412-	11-
1985	780,922	16,683	2		0	15,442	2	1,241-	0
1986	68,915	19,596	28		0	19,343	28	253-	0
1987	393,705	43,333	11		0	18,684	5	24,649-	6-
1988	108,574	145,293	134		0	235,666	217	90,373	83
1989	215,507	112,599	52		0	48,771	23	63,828-	30-
1990	271,586	145,621	54		0	11,387	4	134,234-	49-
1991	347,937	103,835	30	16,558	5		0	87,277-	25-
1992	531,746	192,372	36	91,746	17		0	100,626-	19-
1993	245,837	77,899	32	51,560	21		0	26,339-	11-
1994	189,108	210,310	111	140,666	74		0	69,644-	37-
1995	243,439	126,204	52	72,160	30		0	54,044-	22-
1996	217,259	140,234	65	23,602	11		0	116,632-	54-
1997	189,948	152,957	81	4,219	2		0	148,738-	78-
1998	550,439	191,336	35	21,566	4		0	169,770-	31-
1999	319,663	163,447	51	16,998	5	107	0	146,342-	46-
2000	168,248	135,200	80	27,175	16		0	108,025-	64-
2001	353,001	361,072	102		0	2,224	1	358,848-	102-
2002	501,426	274,226	55		0	52,038	10	222,188-	44-
2003	1,674,595	286,028	17	94,658	6		0	191,370-	11-
2004	646,550	257,876	40		0		0	257,876-	40-
2005	495,890	312,005	63		0		0	312,005-	63-
2006	840,891	686,175	82		0	31,240	4	654,935-	78-
2007	1,021,564	586,391	57		0	35,423	3	550,968-	54-
2008	1,232,637	825,047	67		0	17,044	1	808,003-	66-
2009	620,333	793,743	128		0	300	0	793,443-	128-
TOTAL	14,038,699	6,595,178	47	560,908	4	798,256	6	5,236,014-	37-

THREE-YEAR MOVING AVERAGES

76-78	137,306	45,443	33		0	50,713	37	5,270	4
77-79	130,240	39,583	30		0	52,147	40	12,564	10
78-80	137,631	14,872	11		0	27,688	20	12,817	9

NEWFOUNDLAND POWER INC.

TRANSMISSION - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	228,462	14,386	6		0	24,612	11	10,226	4
80-82	388,381	19,010	5		0	38,302	10	19,292	5
81-83	332,945	16,827	5		0	31,107	9	14,279	4
82-84	237,225	18,736	8		0	28,204	12	9,468	4
83-85	319,840	16,532	5		0	10,576	3	5,955-	2-
84-86	334,034	20,268	6		0	14,299	4	5,969-	2-
85-87	414,514	26,537	6		0	17,823	4	8,714-	2-
86-88	190,398	69,407	36		0	91,231	48	21,824	11
87-89	239,262	100,408	42		0	101,040	42	632	0
88-90	198,556	134,504	68		0	98,608	50	35,896-	18-
89-91	278,343	120,685	43	5,519	2	20,053	7	95,113-	34-
90-92	383,756	147,276	38	36,101	9	3,796	1	107,379-	28-
91-93	375,173	124,702	33	53,288	14		0	71,414-	19-
92-94	322,230	160,194	50	94,657	29		0	65,536-	20-
93-95	226,128	138,138	61	88,129	39		0	50,009-	22-
94-96	216,602	158,916	73	78,809	36		0	80,107-	37-
95-97	216,882	139,798	64	33,327	15		0	106,471-	49-
96-98	319,215	161,509	51	16,462	5		0	145,047-	45-
97-99	353,350	169,247	48	14,261	4	36	0	154,950-	44-
98-00	346,117	163,328	47	21,913	6	36	0	141,379-	41-
99-01	280,304	219,906	78	14,724	5	777	0	204,405-	73-
00-02	340,892	256,833	75	9,058	3	18,087	5	229,687-	67-
01-03	843,007	307,109	36	31,553	4	18,087	2	257,469-	31-
02-04	940,857	272,710	29	31,553	3	17,346	2	223,811-	24-
03-05	939,012	285,303	30	31,553	3		0	253,750-	27-
04-06	661,110	418,685	63		0	10,413	2	408,272-	62-
05-07	786,115	528,190	67		0	22,221	3	505,969-	64-
06-08	1,031,697	699,204	68		0	27,902	3	671,302-	65-
07-09	958,178	735,060	77		0	17,589	2	717,471-	75-
FIVE-YEAR AVERAGE									
05-09	842,263	640,672	76		0	16,801	2	623,871-	74-

NEWFOUNDLAND POWER INC.

ACCOUNT 361.10/361.11/361.14/361.30 - O/H CONDUCTOR - COPPER

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	132,517	41,769	32		0	79,253	60	37,484	28
1977	95,956	40,152	42		0	46,300	48	6,148	6
1978	173,991	39,827	23		0	88,533	51	48,706	28
1979	123,830	36,705	30		0	79,504	64	42,799	35
1980	109,738	28,428	26		0	80,899	74	52,471	48
1981	126,244	41,099	33		0	85,428	68	44,329	35
1982	71,496	58,670	82		0	43,990	62	14,680-	21-
1983	58,006	29,082	50		0	50,786	88	21,704	37
1984	91,364	75,982	83		0	41,804	46	34,178-	37-
1985	146,796	80,316	55		0	74,289	51	6,027-	4-
1986	52,591	17,995	34		0	27,795	53	9,800	19
1987	45,990	46,400	101		0	24,076	52	22,324-	49-
1988	77,981	33,166	43		0	23,741	30	9,425-	12-
1989	75,814	44,423	59		0	52,127	69	7,704	10
1990	115,821	47,204	41		0	17,431-	15-	64,635-	56-
1991	114,894	48,610	42	54,402-	47-		0	103,012-	90-
1992	48,525	47,798	99	13,431-	28-		0	61,229-	126-
1993	54,537	42,373	78	59,488-	109-		0	101,861-	187-
1994	45,980	12,785	28	18,934-	41-		0	31,719-	69-
1995	38,539	35,154	91		0	8,124	21	27,030-	70-
1996	66,072	53,514	81	1,423	2	39,457	60	12,634-	19-
1997	37,599	41,250	110	1,021	3	28,171	75	12,058-	32-
1998	23,966	23,437	98	3,246	14	31,903	133	11,712	49
1999	481,168	129,222	27	293	0	28,056	6	100,873-	21-
2000	120,936	48,795	40		0	44,605	37	4,190-	3-
2001	145,784	43,823	30		0	20,761	14	23,062-	16-
2002	351,591	54,677	16		0	52,793	15	1,884-	1-
2003	211,296	109,607	52		0	38,175	18	71,432-	34-
2004	190,156	180,276	95		0	47,795	25	132,481-	70-
2005	232,783	171,438	74		0	69,537	30	101,901-	44-
2006	141,697	148,556	105		0	121,925	86	26,631-	19-
2007	20,977	29,594	141		0	32,212	154	2,618	12
2008	51,812	70,486	136		0	28,917	56	41,569-	80-
2009	136,118	137,351	101		0	72,261	53	65,090-	48-
TOTAL	4,012,565	2,089,964	52	140,272-	3-	1,445,786	36	784,450-	20-

THREE-YEAR MOVING AVERAGES

76-78	134,155	40,583	30		0	71,362	53	30,779	23
77-79	131,259	38,895	30		0	71,446	54	32,551	25
78-80	135,853	34,987	26		0	82,979	61	47,992	35

NEWFOUNDLAND POWER INC.

ACCOUNT 361.10/361.11/361.14/361.30 - O/H CONDUCTOR - COPPER

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	119,937	35,411	30		0	81,944	68	46,533	39
80-82	102,493	42,732	42		0	70,106	68	27,373	27
81-83	85,249	42,950	50		0	60,068	70	17,118	20
82-84	73,622	54,578	74		0	45,527	62	9,051-	12-
83-85	98,722	61,793	63		0	55,626	56	6,167-	6-
84-86	96,917	58,098	60		0	47,963	49	10,135-	10-
85-87	81,792	48,237	59		0	42,053	51	6,184-	8-
86-88	58,854	32,520	55		0	25,204	43	7,316-	12-
87-89	66,595	41,330	62		0	33,315	50	8,015-	12-
88-90	89,872	41,598	46		0	19,479	22	22,119-	25-
89-91	102,176	46,746	46	18,134-	18-	11,565	11	53,314-	52-
90-92	93,080	47,871	51	22,611-	24-	5,810-	6-	76,292-	82-
91-93	72,652	46,260	64	42,440-	58-		0	88,701-	122-
92-94	49,681	34,319	69	30,618-	62-		0	64,936-	131-
93-95	46,352	30,104	65	26,141-	56-	2,708	6	53,537-	116-
94-96	50,197	33,818	67	5,837-	12-	15,860	32	23,794-	47-
95-97	47,403	43,306	91	815	2	25,251	53	17,241-	36-
96-98	42,546	39,400	93	1,897	4	33,177	78	4,327-	10-
97-99	180,911	64,636	36	1,520	1	29,377	16	33,740-	19-
98-00	208,690	67,151	32	1,180	1	34,855	17	31,117-	15-
99-01	249,296	73,947	30	98	0	31,141	12	42,708-	17-
00-02	206,104	49,098	24		0	39,386	19	9,712-	5-
01-03	236,224	69,369	29		0	37,243	16	32,126-	14-
02-04	251,014	114,853	46		0	46,254	18	68,599-	27-
03-05	211,412	153,774	73		0	51,836	25	101,938-	48-
04-06	188,212	166,757	89		0	79,752	42	87,004-	46-
05-07	131,819	116,529	88		0	74,558	57	41,971-	32-
06-08	71,495	82,879	116		0	61,018	85	21,861-	31-
07-09	69,636	79,144	114		0	44,463	64	34,680-	50-
FIVE-YEAR AVERAGE									
05-09	116,677	111,485	96		0	64,970	56	46,515-	40-

NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 & 361.13 & 361.15 - O/H CONDUCTOR - ALUMINUM

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	114,352	32,493	28		0	10,057	9	22,436-	20-
1977	108,780	41,355	38		0	4,782	4	36,573-	34-
1978	140,791	33,261	24		0	37,806	27	4,545	3
1979	154,624	37,692	24		0	36,061	23	1,631-	1-
1980	164,657	34,710	21		0	42,215	26	7,505	5
1981	174,862	37,541	21		0	32,471	19	5,070-	3-
1982	218,786	112,179	51		0	56,834	26	55,345-	25-
1983	160,455	49,844	31		0	43,408	27	6,436-	4-
1984	153,914	66,712	43		0	35,513	23	31,199-	20-
1985	249,623	113,757	46		0	34,204	14	79,553-	32-
1986	186,915	108,955	58		0	24,317	13	84,638-	45-
1987	198,281	73,590	37		0	26,558	13	47,032-	24-
1988	217,376	139,050	64		0	32,336	15	106,714-	49-
1989	317,420	217,138	68		0	75,674	24	141,464-	45-
1990	332,374	103,431	31	1,217	0	33,020	10	69,194-	21-
1991	325,342	106,513	33	2,489	1	67,513	21	36,511-	11-
1992	232,436	104,733	45	2,467	1	66,917	29	35,349-	15-
1993	253,834	92,848	37	898	0	24,371	10	67,579-	27-
1994	254,897	28,014	11	1,230	0	33,360	13	6,576	3
1995	318,265	124,635	39	2,410	1	65,365	21	56,860-	18-
1996	186,416	73,900	40	1,072	1	29,601	16	43,227-	23-
1997	169,004	87,657	52	1,738	1	33,161	20	52,758-	31-
1998	197,011	77,707	39	2,765	1	26,431	13	48,511-	25-
1999	545,297	204,262	37	247	0	24,536	4	179,479-	33-
2000	799,899	195,815	24		0	95,580	12	100,235-	13-
2001	409,966	397,785	97	10,895	3	36,357	9	350,533-	86-
2002	1,612,240	334,441	21		0	57,755	4	276,686-	17-
2003	1,164,739	261,955	22		0	43,582	4	218,373-	19-
2004	973,070	530,818	55		0	24,888	3	505,930-	52-
2005	450,036	528,030	117		0	30,930	7	497,100-	110-
2006	385,721	788,369	204		0	41,339	11	747,030-	194-
2007	887,464	469,180	53		0	32,094	4	437,086-	49-
2008	381,307	647,537	170		0	24,787	7	622,750-	163-
2009	605,754	726,996	120		0	28,894	5	698,102-	115-
TOTAL	13,045,909	6,982,903	54	27,428	0	1,312,717	10	5,642,758-	43-

THREE-YEAR MOVING AVERAGES

76-78	121,308	35,703	29		0	17,548	14	18,155-	15-
77-79	134,732	37,436	28		0	26,216	19	11,220-	8-
78-80	153,357	35,221	23		0	38,694	25	3,473	2

NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 & 361.13 & 361.15 - O/H CONDUCTOR - ALUMINUM

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E FINAL PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
79-81	164,714	36,648	22		0	36,916	22
80-82	186,102	61,477	33		0	43,840	24
81-83	184,701	66,521	36		0	44,238	24
82-84	177,718	76,245	43		0	45,252	25
83-85	187,997	76,771	41		0	37,708	20
84-86	196,817	96,475	49		0	31,345	16
85-87	211,606	98,767	47		0	28,360	13
86-88	200,857	107,198	53		0	27,737	14
87-89	244,359	143,259	59		0	44,856	18
88-90	289,057	153,206	53	406	0	47,010	16
89-91	325,045	142,361	44	1,235	0	58,736	18
90-92	296,717	104,892	35	2,058	1	55,817	19
91-93	270,537	101,365	37	1,951	1	52,934	20
92-94	247,056	75,198	30	1,532	1	41,549	17
93-95	275,665	81,832	30	1,513	1	41,032	15
94-96	253,193	75,516	30	1,571	1	42,775	17
95-97	224,562	95,397	42	1,740	1	42,709	19
96-98	184,144	79,755	43	1,858	1	29,731	16
97-99	303,771	123,209	41	1,583	1	28,043	9
98-00	514,069	159,261	31	1,004	0	48,849	10
99-01	585,054	265,954	45	3,714	1	52,158	9
00-02	940,702	309,347	33	3,632	0	63,231	7
01-03	1,062,315	331,394	31	3,632	0	45,898	4
02-04	1,250,017	375,738	30		0	42,075	3
03-05	862,615	440,268	51		0	33,133	4
04-06	602,942	615,739	102		0	32,386	5
05-07	574,407	595,193	104		0	34,788	6
06-08	551,497	635,029	115		0	32,740	6
07-09	624,842	614,571	98		0	28,592	5
FIVE-YEAR AVERAGE							
05-09	542,056	632,022	117		0	31,609	6

NEWFOUNDLAND POWER INC.

ACCOUNT 361.20 & 361.40 - DISTRIBUTION - UNDERGROUND CABLES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	15,435	5,850	38		0	2,499	16	3,351-	22-
1977	29,672	6,820	23		0	1,945	7	4,875-	16-
1978	10,173	3,903	38		0	7,184	71	3,281	32
1979	18,146	5,758	32		0	5,122	28	636-	4-
1980	7,019	1,035	15		0	413	6	622-	9-
1981	18,462		0		0		0		0
1982	13,029		0		0		0		0
1983	5,425		0		0		0		0
1984	9,668		0		0		0		0
1985	136,329		0		0		0		0
1986	42,361		0		0		0		0
1987	27,747		0		0		0		0
1988	27,914		0		0		0		0
1989	33,138		0		0		0		0
1990	63,650		0		0	80,445	126	80,445	126
1991	62,058		0	6,110	10		0	6,110	10
1992	12,570		0	1,212-	10-		0	1,212-	10-
1993	21,230		0		0		0		0
1994	61,710		0	333-	1-		0	333-	1-
1995	28,002		0		0	494	2	494	2
1996	50,538	2,165	4	98	0	9,684	19	7,617	15
1997	2,251		0	2,807-	125-		0	2,807-	125-
1998	4,980	37	1		0	950	19	913	18
1999									
2000		8,179				1,786		6,393-	
2001	1,886	1,867	99		0		0	1,867-	99-
2002	437,736		0		0		0		0
2003		44,602						44,602-	
2004		48,977						48,977-	
2005									
2006		15,391						15,391-	
2007		17,422						17,422-	
2008		1,951						1,951-	
2009		40,163						40,163-	
TOTAL	1,141,129	204,120	18	1,856	0	110,522	10	91,742-	8-

THREE-YEAR MOVING AVERAGES

76-78	18,427	5,524	30		0	3,876	21	1,648-	9-
77-79	19,330	5,494	28		0	4,750	25	743-	4-
78-80	11,779	3,565	30		0	4,240	36	674	6

NEWFOUNDLAND POWER INC.

ACCOUNT 361.20 & 361.40 - DISTRIBUTION - UNDERGROUND CABLES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	14,542	2,264	16		0	1,845	13	419-	3-
80-82	12,837	345	3		0	138	1	207-	2-
81-83	12,305		0		0		0		0
82-84	9,374		0		0		0		0
83-85	50,474		0		0		0		0
84-86	62,786		0		0		0		0
85-87	68,812		0		0		0		0
86-88	32,674		0		0		0		0
87-89	29,600		0		0		0		0
88-90	41,567		0		0	26,815	65	26,815	65
89-91	52,949		0	2,037	4	26,815	51	28,852	54
90-92	46,093		0	1,633	4	26,815	58	28,448	62
91-93	31,953		0	1,633	5		0	1,633	5
92-94	31,837		0	515-	2-		0	515-	2-
93-95	36,981		0	111-	0	165	0	54	0
94-96	46,750	722	2	78-	0	3,393	7	2,593	6
95-97	26,930	722	3	903-	3-	3,393	13	1,768	7
96-98	19,256	734	4	903-	5-	3,545	18	1,908	10
97-99	2,410	12	1	936-	39-	317	13	631-	26-
98-00	1,660	2,739	165		0	912	55	1,827-	110-
99-01	629	3,349	533		0	595	95	2,753-	438-
00-02	146,541	3,349	2		0	595	0	2,753-	2-
01-03	146,541	15,490	11		0		0	15,490-	11-
02-04	145,912	31,193	21		0		0	31,193-	21-
03-05		31,193						31,193-	
04-06		21,456						21,456-	
05-07		10,938						10,938-	
06-08		11,588						11,588-	
07-09		19,845						19,845-	
FIVE-YEAR AVERAGE									
05-09		14,985						14,985-	

NEWFOUNDLAND POWER INC.

ACCOUNT 361.40 - DISTRIBUTION - SUBMARINE CABLE

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2008		17,903						17,903-	
2009		4,310						4,310-	
TOTAL		22,213						22,213-	

NEWFOUNDLAND POWER INC.

ACCOUNT 362.1 & 362.2 - DIST. - POLES AND FIXTURES - WOOD

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	1,527,165	587,498	38	90,426	6		0	497,072-	33-
2001	2,817,699	534,374	19	136,453	5		0	397,921-	14-
2002	2,048,803	727,652	36		0	55,979	3	671,673-	33-
2003	848,567	474,873	56		0	238	0	474,635-	56-
2004	837,695	479,745	57		0		0	479,745-	57-
2005	1,251,337	503,125	40		0	32,119	3	471,006-	38-
2006	1,401,597	734,953	52		0	5,042	0	729,911-	52-
2007	2,055,461	805,702	39		0		0	805,702-	39-
2008	1,517,900	1,000,432	66		0		0	1,000,432-	66-
2009	1,158,627	571,716	49		0		0	571,716-	49-
TOTAL	15,464,852	6,420,070	42	226,879	1	93,378	1	6,099,813-	39-

THREE-YEAR MOVING AVERAGES

00-02	2,131,222	616,508	29	75,626	4	18,660	1	522,222-	25-
01-03	1,905,023	578,966	30	45,484	2	18,739	1	514,743-	27-
02-04	1,245,022	560,757	45		0	18,739	2	542,018-	44-
03-05	979,200	485,914	50		0	10,786	1	475,129-	49-
04-06	1,163,543	572,608	49		0	12,387	1	560,221-	48-
05-07	1,569,465	681,260	43		0	12,387	1	668,873-	43-
06-08	1,658,319	847,029	51		0	1,681	0	845,348-	51-
07-09	1,577,329	792,617	50		0		0	792,617-	50-

FIVE-YEAR AVERAGE

05-09	1,476,984	723,186	49		0	7,432	1	715,753-	48-

NEWFOUNDLAND POWER INC.

ACCOUNT 362.30 - DIST. - POLES AND FIXTURES - CONCRETE/STEEL

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
2001	4,945	2,358	48		0		0	2,358-	48-
2002	240,169		0		0		0		0
2003									
2004									
2005									
2006									
2007									
2008									
2009									
TOTAL	245,114	2,358	1		0		0	2,358-	1-

THREE-YEAR MOVING AVERAGES

01-03	81,705	786	1		0		0	786-	1-
02-04	80,056		0		0		0		0
03-05									
04-06									
05-07									
06-08									
07-09									

FIVE-YEAR AVERAGE

05-09

NEWFOUNDLAND POWER INC.

ACCOUNT 362.40 - DISTRIBUTION - STEEL TOWERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	38,068		0		0		0		0
1978									
1979									
1980									
1981									
1982									
1983									
1984									
1985									
1986									
1987									
1988									
1989									
1990									
1991									
1992									
1993									
1994									
1995									
1996									
1997									
1998									
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
TOTAL	38,068		0		0		0		0

THREE-YEAR MOVING AVERAGES

77-79	12,689		0		0		0		0
78-80									
79-81									
80-82									

NEWFOUNDLAND POWER INC.

ACCOUNT 362.40 - DISTRIBUTION - STEEL TOWERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR	COST OF		G R O S S S A L V A G E				NET	
	RETIREMENTS	REMOVAL	PCT	REUSE	PCT	FINAL	PCT	SALVAGE	PCT
	AMOUNT	AMOUNT		AMOUNT		AMOUNT		AMOUNT	
THREE-YEAR MOVING AVERAGES									
81-83									
82-84									
83-85									
84-86									
85-87									
86-88									
87-89									
88-90									
89-91									
90-92									
91-93									
92-94									
93-95									
94-96									
95-97									
96-98									
97-99									
98-00									
99-01									
00-02									
01-03									
02-04									
03-05									
04-06									
05-07									
06-08									
07-09									

FIVE-YEAR AVERAGE

05-09

NEWFOUNDLAND POWER INC.

ACCOUNT 363.00 - DISTRIBUTION - STREET LIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	339,322	22,029	6		0	125,561	37	103,532	31
1977	292,908	28,558	10		0	118,441	40	89,883	31
1978	320,116	22,212	7		0	45,087	14	22,875	7
1979	276,629	28,957	10		0	50,176	18	21,219	8
1980	652,796	24,086	4		0	57,568	9	33,482	5
1981	287,170	22,230	8		0	58,125	20	35,895	12
1982	386,991	25,909	7		0	64,306	17	38,397	10
1983	266,347	20,962	8		0	60,854	23	39,892	15
1984	324,804	26,377	8		0	66,612	21	40,235	12
1985	298,090	30,373	10		0	74,415	25	44,042	15
1986	320,832	39,069	12		0	102,154	32	63,085	20
1987	353,116	63,166	18		0	86,793	25	23,627	7
1988	320,397	60,541	19		0	85,322	27	24,781	8
1989	440,693	62,442	14		0	105,334	24	42,892	10
1990	434,043	93,205	21		0	131,171	30	37,966	9
1991	570,055	94,194	17	119,048	21		0	24,854	4
1992	553,001	75,827	14	139,543	25		0	63,716	12
1993	539,127	67,992	13	138,012	26		0	70,020	13
1994	624,544	94,884	15	151,019	24		0	56,135	9
1995	651,946	78,266	12	137,761	21	2,493	0	61,988	10
1996	821,347	91,578	11	104,264	13	85,107	10	97,793	12
1997	473,302	78,014	16	73,658	16	83,379	18	79,023	17
1998	286,015	67,032	23	64,895	23	62,611	22	60,474	21
1999	755,062	54,548	7	32,768	4	27,155	4	5,375	1
2000	790,310	71,692	9	59,204	7	2,619	0	9,869-	1-
2001	848,141	80,975	10	48,197	6	5,576	1	27,202-	3-
2002	2,029,708	59,282	3		0	24,392	1	34,890-	2-
2003	808,150	81,887	10		0	5,824	1	76,063-	9-
2004	792,759	87,414	11		0	3,850	0	83,564-	11-
2005	868,981	107,588	12		0	9,024	1	98,564-	11-
2006	1,003,349	97,400	10		0	5,399	1	92,001-	9-
2007	1,018,473	151,112	15		0	6,546	1	144,566-	14-
2008	1,005,172	195,116	19		0	5,043	1	190,073-	19-
2009	960,513	207,752	22		0	620	0	207,132-	22-
TOTAL	20,714,208	2,412,669	12	1,068,369	5	1,561,557	8	217,257	1

THREE-YEAR MOVING AVERAGES

76-78	317,449	24,266	8		0	96,363	30	72,097	23
77-79	296,551	26,576	9		0	71,235	24	44,659	15
78-80	416,514	25,085	6		0	50,944	12	25,859	6

NEWFOUNDLAND POWER INC.

ACCOUNT 363.00 - DISTRIBUTION - STREET LIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	405,532	25,091	6		0	55,290	14	30,199	7
80-82	442,319	24,075	5		0	60,000	14	35,925	8
81-83	313,503	23,034	7		0	61,095	19	38,061	12
82-84	326,047	24,416	7		0	63,924	20	39,508	12
83-85	296,414	25,904	9		0	67,294	23	41,390	14
84-86	314,575	31,940	10		0	81,060	26	49,121	16
85-87	324,013	44,203	14		0	87,787	27	43,585	13
86-88	331,448	54,259	16		0	91,423	28	37,164	11
87-89	371,402	62,050	17		0	92,483	25	30,433	8
88-90	398,378	72,063	18		0	107,276	27	35,213	9
89-91	481,597	83,280	17	39,683	8	78,835	16	35,237	7
90-92	519,033	87,742	17	86,197	17	43,724	8	42,179	8
91-93	554,061	79,338	14	132,201	24		0	52,863	10
92-94	572,224	79,568	14	142,858	25		0	63,290	11
93-95	605,206	80,381	13	142,264	24	831	0	62,714	10
94-96	699,279	88,243	13	131,015	19	29,200	4	71,972	10
95-97	648,865	82,619	13	105,228	16	56,993	9	79,601	12
96-98	526,888	78,875	15	80,939	15	77,032	15	79,097	15
97-99	504,793	66,531	13	57,107	11	57,715	11	48,291	10
98-00	610,462	64,424	11	52,289	9	30,795	5	18,660	3
99-01	797,838	69,072	9	46,723	6	11,783	1	10,565-	1-
00-02	1,222,720	70,650	6	35,800	3	10,862	1	23,987-	2-
01-03	1,228,666	74,048	6	16,066	1	11,931	1	46,052-	4-
02-04	1,210,206	76,194	6		0	11,355	1	64,839-	5-
03-05	823,297	92,296	11		0	6,233	1	86,064-	10-
04-06	888,363	97,467	11		0	6,091	1	91,376-	10-
05-07	963,601	118,700	12		0	6,990	1	111,710-	12-
06-08	1,008,998	147,876	15		0	5,663	1	142,213-	14-
07-09	994,719	184,660	19		0	4,070	0	180,590-	18-
FIVE-YEAR AVERAGE									
05-09	971,298	151,794	16		0	5,326	1	146,467-	15-

NEWFOUNDLAND POWER INC.

ACCOUNT 364.00 - DISTRIBUTION - TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	209,142		0		0	20,950	10	20,950	10
1977	301,115		0		0	11,869	4	11,869	4
1978	370,766		0		0	30,646	8	30,646	8
1979	324,223	277	0		0	22,112	7	21,835	7
1980	243,756	352	0		0	45,495	19	45,143	19
1981	343,984	2,209	1		0	9,958	3	7,749	2
1982	300,512		0		0	9,111	3	9,111	3
1983	345,070	203	0		0	30,557	9	30,354	9
1984	429,292	585	0		0	18,444	4	17,859	4
1985	202,997	294	0		0	5,596	3	5,302	3
1986	259,030	892	0		0	11,023	4	10,131	4
1987	235,686	601	0		0	6,422	3	5,821	2
1988	330,575	1,658	1		0	29,257	9	27,599	8
1989	371,252	5,113	1		0	14,079	4	8,966	2
1990	470,448	4,905	1		0	16,675	4	11,770	3
1991	339,804	4,659	1	26,611	8		0	21,952	6
1992	191,717	5,687	3	19,686	10		0	13,999	7
1993	230,692	7,268	3	28,350	12		0	21,082	9
1994	197,274	2,670	1	10,681	5		0	8,011	4
1995	227,683	211,488	93	30,731	13	27,410	12	153,347-	67-
1996	155,826	10,408	7	19,440	12	13,940	9	22,972	15
1997	845,887	4,487	1	640-	0	7,000	1	1,873	0
1998	1,789,961	88,001	5	269,189	15	95,274	5	276,462	15
1999	1,419,119	78,045	5	414,515	29	14,427	1	350,897	25
2000	1,226,597	80,581	7	325,960	27	13,712	1	259,091	21
2001	912,446	80,007	9	118,967	13	3,950	0	42,910	5
2002	1,483,362	36,016	2		0	2,340	0	33,676-	2-
2003	1,242,319	326,589	26		0	387,620	31	61,031	5
2004	752,442	85,395	11		0		0	85,395-	11-
2005	1,600,527	346,248	22		0	68,693	4	277,555-	17-
2006	5,835,609	253,498	4		0	161,989	3	91,509-	2-
2007	2,836,750	345,826	12		0	90,402	3	255,424-	9-
2008	1,088,626	384,841	35		0	90,343	8	294,498-	27-
2009	1,234,999	375,460	30		0	75,444	6	300,016-	24-
TOTAL	28,349,488	2,744,263	10	1,263,490	4	1,334,738	5	146,035-	1-

THREE-YEAR MOVING AVERAGES

76-78	293,674		0		0	21,155	7	21,155	7
77-79	332,035	92	0		0	21,542	6	21,450	6
78-80	312,915	210	0		0	32,751	10	32,541	10

NEWFOUNDLAND POWER INC.

ACCOUNT 364.00 - DISTRIBUTION - TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	303,988	946	0		0	25,855	9	24,909	8
80-82	296,084	854	0		0	21,521	7	20,668	7
81-83	329,855	804	0		0	16,542	5	15,738	5
82-84	358,291	263	0		0	19,371	5	19,108	5
83-85	325,786	361	0		0	18,199	6	17,838	5
84-86	297,106	590	0		0	11,688	4	11,097	4
85-87	232,571	596	0		0	7,680	3	7,085	3
86-88	275,097	1,050	0		0	15,567	6	14,517	5
87-89	312,504	2,457	1		0	16,586	5	14,129	5
88-90	390,758	3,892	1		0	20,004	5	16,112	4
89-91	393,835	4,892	1	8,870	2	10,251	3	14,229	4
90-92	333,990	5,084	2	15,432	5	5,558	2	15,907	5
91-93	254,071	5,871	2	24,882	10		0	19,011	7
92-94	206,561	5,208	3	19,572	9		0	14,364	7
93-95	218,550	73,809	34	23,254	11	9,137	4	41,418-	19-
94-96	193,594	74,855	39	20,284	10	13,783	7	40,788-	21-
95-97	409,799	75,461	18	16,510	4	16,117	4	42,834-	10-
96-98	930,558	34,299	4	95,996	10	38,738	4	100,436	11
97-99	1,351,656	56,844	4	227,688	17	38,900	3	209,744	16
98-00	1,478,559	82,209	6	336,555	23	41,138	3	295,483	20
99-01	1,186,054	79,544	7	286,481	24	10,696	1	217,633	18
00-02	1,207,468	65,535	5	148,309	12	6,667	1	89,442	7
01-03	1,212,709	147,537	12	39,656	3	131,303	11	23,422	2
02-04	1,159,374	149,333	13		0	129,987	11	19,347-	2-
03-05	1,198,429	252,744	21		0	152,104	13	100,640-	8-
04-06	2,729,526	228,380	8		0	76,894	3	151,486-	6-
05-07	3,424,295	315,191	9		0	107,028	3	208,163-	6-
06-08	3,253,662	328,055	10		0	114,245	4	213,810-	7-
07-09	1,720,125	368,709	21		0	85,396	5	283,313-	16-
FIVE-YEAR AVERAGE									
05-09	2,519,302	341,175	14		0	97,374	4	243,800-	10-

NEWFOUNDLAND POWER INC.

ACCOUNT 365.00 - DISTRIBUTION - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	116,831	47,923	41		0	4,701	4	43,222-	37-
1977	123,300	58,412	47		0	6,263	5	52,149-	42-
1978	126,631	60,500	48		0	15,116	12	45,384-	36-
1979	138,960	63,186	45		0	17,372	13	45,814-	33-
1980	118,572	62,500	53		0	10,391	9	52,109-	44-
1981	146,271	76,388	52		0	14,830	10	61,558-	42-
1982	161,068	72,978	45		0	11,232	7	61,746-	38-
1983	165,847	81,841	49		0	15,508	9	66,333-	40-
1984	227,839	83,655	37		0	15,558	7	68,097-	30-
1985	166,496	86,937	52		0	18,404	11	68,533-	41-
1986	143,362	93,190	65		0	19,515	14	73,675-	51-
1987	121,573	113,175	93		0	13,435	11	99,740-	82-
1988	150,491	102,958	68		0	53,716	36	49,242-	33-
1989	166,620	130,934	79		0	24,406	15	106,528-	64-
1990	182,441	163,221	89		0	69,679	38	93,542-	51-
1991	149,716	161,073	108	63,727	43		0	97,346-	65-
1992	164,570	150,230	91	43,847	27		0	106,383-	65-
1993	158,154	121,755	77	40,719	26		0	81,036-	51-
1994	104,640	115,175	110	42,048	40		0	73,127-	70-
1995	87,789	104,798	119	35,449	40		0	69,349-	79-
1996	94,690	99,313	105	300	0	20,917	22	78,096-	82-
1997	61,501	91,488	149		0	16,317	27	75,171-	122-
1998	27,057	73,289	271		0	14,685	54	58,604-	217-
1999	176,631	108,307	61		0	21,903	12	86,404-	49-
2000	188,122	127,528	68		0		0	127,528-	68-
2001	226,430	149,407	66		0	26,471	12	122,936-	54-
2002	209,907	174,746	83		0	33,015	16	141,731-	68-
2003	503,249	174,526	35		0	27,862	6	146,664-	29-
2004	449,745	158,542	35		0	19,516	4	139,026-	31-
2005	253,823	191,208	75		0	24,450	10	166,758-	66-
2006	291,904	177,395	61		0	23,250	8	154,145-	53-
2007	289,498	159,345	55		0	18,364	6	140,981-	49-
2008	267,118	227,578	85		0	14,156	5	213,422-	80-
2009	209,258	238,443	114		0	13,683	7	224,760-	107-
TOTAL	6,170,104	4,101,944	66	226,090	4	584,715	9	3,291,139-	53-

THREE-YEAR MOVING AVERAGES

76-78	122,254	55,612	45		0	8,693	7	46,918-	38-
77-79	129,630	60,699	47		0	12,917	10	47,782-	37-
78-80	128,054	62,062	48		0	14,293	11	47,769-	37-

NEWFOUNDLAND POWER INC.

ACCOUNT 365.00 - DISTRIBUTION - SERVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	134,601	67,358	50		0	14,198	11	53,160-	39-
80-82	141,970	70,622	50		0	12,151	9	58,471-	41-
81-83	157,729	77,069	49		0	13,857	9	63,212-	40-
82-84	184,918	79,491	43		0	14,099	8	65,392-	35-
83-85	186,727	84,144	45		0	16,490	9	67,654-	36-
84-86	179,232	87,927	49		0	17,826	10	70,102-	39-
85-87	143,810	97,767	68		0	17,118	12	80,649-	56-
86-88	138,475	103,108	74		0	28,889	21	74,219-	54-
87-89	146,228	115,689	79		0	30,519	21	85,170-	58-
88-90	166,517	132,371	79		0	49,267	30	83,104-	50-
89-91	166,259	151,743	91	21,242	13	31,362	19	99,139-	60-
90-92	165,576	158,175	96	35,858	22	23,226	14	99,090-	60-
91-93	157,480	144,353	92	49,431	31		0	94,922-	60-
92-94	142,455	129,053	91	42,205	30		0	86,849-	61-
93-95	116,861	113,909	97	39,405	34		0	74,504-	64-
94-96	95,706	106,429	111	25,932	27	6,972	7	73,524-	77-
95-97	81,327	98,533	121	11,916	15	12,411	15	74,205-	91-
96-98	61,083	88,030	144	100	0	17,306	28	70,624-	116-
97-99	88,396	91,028	103		0	17,635	20	73,393-	83-
98-00	130,603	103,041	79		0	12,196	9	90,845-	70-
99-01	197,061	128,414	65		0	16,125	8	112,289-	57-
00-02	208,153	150,560	72		0	19,829	10	130,732-	63-
01-03	313,195	166,226	53		0	29,116	9	137,110-	44-
02-04	387,634	169,271	44		0	26,798	7	142,474-	37-
03-05	402,272	174,759	43		0	23,943	6	150,816-	37-
04-06	331,824	175,715	53		0	22,405	7	153,310-	46-
05-07	278,408	175,983	63		0	22,021	8	153,961-	55-
06-08	282,840	188,106	67		0	18,590	7	169,516-	60-
07-09	255,291	208,455	82		0	15,401	6	193,054-	76-
FIVE-YEAR AVERAGE									
05-09	262,320	198,794	76		0	18,781	7	180,013-	69-

NEWFOUNDLAND POWER INC.

ACCOUNT 366.00 - DISTRIBUTION - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	267,479		0		0		0		0
1977	230,387		0		0		0		0
1978	118,924	44	0		0	38	0	6-	0
1979	119,222	27	0		0	2,599	2	2,572	2
1980	132,578		0		0	893	1	893	1
1981	157,254		0		0	303	0	303	0
1982	153,822		0		0	236	0	236	0
1983	139,459		0		0	503	0	503	0
1984	129,968		0		0		0		0
1985	107,970		0		0		0		0
1986	137,434	52	0		0		0	52-	0
1987	173,229		0		0		0		0
1988	178,275		0		0		0		0
1989	140,116		0		0	750	1	750	1
1990	123,401		0		0		0		0
1991	259,750		0		0		0		0
1992	148,500	211	0		0		0	211-	0
1993	240,308	130	0	337-	0		0	467-	0
1994	293,024		0	30	0		0	30	0
1995	267,494		0		0		0		0
1996	270,217		0		0		0		0
1997	258,728		0		0		0		0
1998	188,284		0		0		0		0
1999	463,615	10,421	2		0		0	10,421-	2-
2000	491,727	5,578	1		0		0	5,578-	1-
2001	348,826	9,202	3		0		0	9,202-	3-
2002	367,726	8,903	2		0	88	0	8,815-	2-
2003	384,661	8,840	2		0	928	0	7,912-	2-
2004	587,863	48,439	8		0	1,082	0	47,357-	8-
2005	1,562,397	67,588	4		0	2,041	0	65,547-	4-
2006	611,499	70,404	12		0	3,931	1	66,473-	11-
2007	1,244,564	55,815	4		0	4,882	0	50,933-	4-
2008	1,395,748	112,233	8		0	1,355	0	110,878-	8-
2009	1,433,262	161,882	11		0		0	161,882-	11-
TOTAL	13,127,710	559,769	4	307-	0	19,629	0	540,447-	4-

THREE-YEAR MOVING AVERAGES

76-78	205,597	15	0		0	13	0	2-	0
77-79	156,178	24	0		0	879	1	855	1
78-80	123,575	24	0		0	1,177	1	1,153	1

NEWFOUNDLAND POWER INC.

ACCOUNT 366.00 - DISTRIBUTION - METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	136,351	9	0		0	1,265	1	1,256	1
80-82	147,885		0		0	477	0	477	0
81-83	150,178		0		0	347	0	347	0
82-84	141,083		0		0	246	0	246	0
83-85	125,799		0		0	168	0	168	0
84-86	125,124	17	0		0		0	17-	0
85-87	139,544	17	0		0		0	17-	0
86-88	162,979	17	0		0		0	17-	0
87-89	163,873		0		0	250	0	250	0
88-90	147,264		0		0	250	0	250	0
89-91	174,422		0		0	250	0	250	0
90-92	177,217	70	0		0		0	70-	0
91-93	216,186	114	0	112-	0		0	226-	0
92-94	227,277	114	0	102-	0		0	216-	0
93-95	266,942	43	0	102-	0		0	146-	0
94-96	276,912		0	10	0		0	10	0
95-97	265,480		0		0		0		0
96-98	239,076		0		0		0		0
97-99	303,542	3,474	1		0		0	3,474-	1-
98-00	381,209	5,333	1		0		0	5,333-	1-
99-01	434,723	8,400	2		0		0	8,400-	2-
00-02	402,760	7,894	2		0	29	0	7,865-	2-
01-03	367,071	8,982	2		0	339	0	8,643-	2-
02-04	446,750	22,061	5		0	699	0	21,361-	5-
03-05	844,974	41,622	5		0	1,350	0	40,272-	5-
04-06	920,586	62,144	7		0	2,351	0	59,792-	6-
05-07	1,139,487	64,602	6		0	3,618	0	60,984-	5-
06-08	1,083,937	79,484	7		0	3,389	0	76,095-	7-
07-09	1,357,858	109,977	8		0	2,079	0	107,898-	8-
FIVE-YEAR AVERAGE									
05-09	1,249,494	93,584	7		0	2,442	0	91,143-	7-

NEWFOUNDLAND POWER INC.

ACCOUNT 367.00 - DISTRIBUTION - UNDERGROUND

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	18,627		0		0		0		0
1978	1,527		0		0		0		0
1979									
1980	20		0		0		0		0
1981									
1982									
1983									
1984									
1985	37,480		0		0		0		0
1986									
1987									
1988									
1989									
1990									
1991	9,931		0		0		0		0
1992	254		0		0		0		0
1993									
1994									
1995									
1996	538		0		0		0		0
1997				1,688-				1,688-	
1998									
1999									
2000									
2001	2,050	21,665			0		0	21,665-	
2002		59,701				1,037		58,664-	
2003		101,237				354		100,883-	
2004		36,433						36,433-	
2005									
2006									
2007									
2008									
2009									
TOTAL	70,427	219,036	311	1,688-	2-	1,391	2	219,333-	311-

THREE-YEAR MOVING AVERAGES

77-79	6,718		0		0		0		0
78-80	516		0		0		0		0
79-81	7		0		0		0		0
80-82	7		0		0		0		0

NEWFOUNDLAND POWER INC.

ACCOUNT 367.00 - DISTRIBUTION - UNDERGROUND

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
81-83									
82-84									
83-85	12,493		0		0		0		0
84-86	12,493		0		0		0		0
85-87	12,493		0		0		0		0
86-88									
87-89									
88-90									
89-91	3,310		0		0		0		0
90-92	3,395		0		0		0		0
91-93	3,395		0		0		0		0
92-94	85		0		0		0		0
93-95									
94-96	179		0		0		0		0
95-97	179		0	563-	314-		0	563-	314-
96-98	179		0	563-	314-		0	563-	314-
97-99				563-				563-	
98-00									
99-01	683	7,222			0		0	7,222-	
00-02	683	27,122			0	346	51	26,776-	
01-03	683	60,868			0	464	68	60,404-	
02-04		65,790				464		65,327-	
03-05		45,890				118		45,772-	
04-06		12,144						12,144-	
05-07									
06-08									
07-09									

FIVE-YEAR AVERAGE

05-09

NEWFOUNDLAND POWER INC.

ACCOUNT 371.00 - GENERAL - BUILDINGS AND STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	4,843	163	3		0	8,659	179	8,496	175
1977	300		0		0	1,650	550	1,650	550
1978	79,242	637	1		0	11,980	15	11,343	14
1979	5,552	520	9		0	26,283	473	25,763	464
1980	57,403	6,451	11		0	18,648	32	12,197	21
1981	35,733	1,746	5		0	25,401	71	23,655	66
1982	43,455	10,346	24		0	375	1	9,971-	23-
1983	160,675	5,884	4		0	1,228	1	4,656-	3-
1984	37,007	516	1		0	48,478	131	47,962	130
1985	78,642	939	1		0	1,837	2	898	1
1986	50,404	1,886	4		0	2,879	6	993	2
1987	39,555	7,433	19		0	700	2	6,733-	17-
1988	68,927	39,213	57		0	45,121	65	5,908	9
1989	248,470	48,248	19		0	12,616	5	35,632-	14-
1990	16,329	2,622	16		0		0	2,622-	16-
1991	23,928	9,157	38		0	12,049	50	2,892	12
1992	859,831	11,658	1		0	86,852	10	75,194	9
1993	29,875	7,811	26		0		0	7,811-	26-
1994	235,688	47,807	20		0	50,341	21	2,534	1
1995	84,430	26,455	31		0		0	26,455-	31-
1996	23,201	5,802	25		0		0	5,802-	25-
1997	404,294	38,948	10		0	9,826	2	29,122-	7-
1998	190,691	37,368	20		0		0	37,368-	20-
1999	176,260	11,040	6		0		0	11,040-	6-
2000	26,000	12,896	50		0	5,245	20	7,651-	29-
2001	22,301	13,475	60		0		0	13,475-	60-
2002	753,173	42,714	6		0	3,218	0	39,496-	5-
2003	5,000	7,180	144		0	3,896	78	3,284-	66-
2004	548,906	22,445	4		0		0	22,445-	4-
2005	442,464	8,384	2		0	10,028	2	1,644	0
2006	604,572	58,326	10		0		0	58,326-	10-
2007	168,484	57,130	34		0		0	57,130-	34-
2008	60,600	65,497	108		0		0	65,497-	108-
2009	207,927	17,374	8		0		0	17,374-	8-
TOTAL	5,794,162	628,071	11		0	387,310	7	240,761-	4-

THREE-YEAR MOVING AVERAGES

76-78	28,128	267	1		0	7,430	26	7,163	25
77-79	28,365	386	1		0	13,304	47	12,919	46
78-80	47,399	2,536	5		0	18,970	40	16,434	35

NEWFOUNDLAND POWER INC.

ACCOUNT 371.00 - GENERAL - BUILDINGS AND STRUCTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	32,896	2,906	9	0		23,444	71	20,538	62
80-82	45,530	6,181	14	0		14,808	33	8,627	19
81-83	79,954	5,992	7	0		9,001	11	3,009	4
82-84	80,379	5,582	7	0		16,694	21	11,112	14
83-85	92,108	2,446	3	0		17,181	19	14,735	16
84-86	55,351	1,114	2	0		17,731	32	16,618	30
85-87	56,200	3,419	6	0		1,805	3	1,614-	3-
86-88	52,962	16,177	31	0		16,233	31	56	0
87-89	118,984	31,631	27	0		19,479	16	12,152-	10-
88-90	111,242	30,028	27	0		19,246	17	10,782-	10-
89-91	96,242	20,009	21	0		8,222	9	11,787-	12-
90-92	300,029	7,812	3	0		32,967	11	25,155	8
91-93	304,545	9,542	3	0		32,967	11	23,425	8
92-94	375,131	22,425	6	0		45,731	12	23,306	6
93-95	116,664	27,358	23	0		16,780	14	10,577-	9-
94-96	114,440	26,688	23	0		16,780	15	9,908-	9-
95-97	170,642	23,735	14	0		3,275	2	20,460-	12-
96-98	206,062	27,373	13	0		3,275	2	24,097-	12-
97-99	257,082	29,119	11	0		3,275	1	25,843-	10-
98-00	130,984	20,435	16	0		1,748	1	18,686-	14-
99-01	74,854	12,470	17	0		1,748	2	10,722-	14-
00-02	267,158	23,028	9	0		2,821	1	20,207-	8-
01-03	260,158	21,123	8	0		2,371	1	18,752-	7-
02-04	435,693	24,113	6	0		2,371	1	21,742-	5-
03-05	332,123	12,670	4	0		4,641	1	8,028-	2-
04-06	531,981	29,718	6	0		3,343	1	26,376-	5-
05-07	405,173	41,280	10	0		3,343	1	37,937-	9-
06-08	277,885	60,318	22	0			0	60,318-	22-
07-09	145,670	46,667	32	0			0	46,667-	32-
FIVE-YEAR AVERAGE									
05-09	296,809	41,342	14	0		2,006	1	39,337-	13-

NEWFOUNDLAND POWER INC.

ACCOUNT 378.10 - TRANSPORTATION - SEDANS & STATION WAGONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	124,348		0		0	23,462	19	23,462	19
1977	110,821		0		0	13,341	12	13,341	12
1978	81,553		0		0	10,705	13	10,705	13
1979	81,046		0		0	12,560	15	12,560	15
1980	127,272		0		0	22,561	18	22,561	18
1981	186,427	85	0		0	25,364	14	25,279	14
1982	143,030	413	0		0	29,964	21	29,551	21
1983	92,917	179	0		0	11,477	12	11,298	12
1984	176,318	334	0		0	28,009	16	27,675	16
1985	236,329	409	0		0	29,849	13	29,440	12
1986	278,509		0		0	43,119	15	43,119	15
1987	264,368		0		0	38,802	15	38,802	15
1988	131,896		0		0	25,453	19	25,453	19
1989	132,471		0		0	26,845	20	26,845	20
1990	258,032		0		0	58,540	23	58,540	23
1991	138,611		0		0	18,505	13	18,505	13
1992	237,337		0		0	38,718	16	38,718	16
1993	209,555		0		0	43,080	21	43,080	21
1994	186,032		0		0	25,416	14	25,416	14
1995	134,171		0		0	35,456	26	35,456	26
1996	79,572		0		0	37,371	47	37,371	47
1997	331,874		0		0	48,576	15	48,576	15
1998	115,250		0		0	2,784	2	2,784	2
1999	233,791		0		0	27,162	12	27,162	12
2000	173,104		0		0	23,236	13	23,236	13
2001	110,313		0		0	18,771	17	18,771	17
2002	142,814		0		0	25,124	18	25,124	18
2003	22,785		0		0	2,556	11	2,556	11
2004	22,230		0		0	2,187	10	2,187	10
2005	21,466		0		0	2,187	10	2,187	10
2006	110,270		0		0	9,510	9	9,510	9
2007	55,111		0		0	31,350	57	31,350	57
2008	42,536		0		0	22,908	54	22,908	54
2009									

TOTAL	4,792,159	1,420	0		0	814,948	17	813,528	17

THREE-YEAR MOVING AVERAGES

76-78	105,574		0		0	15,836	15	15,836	15
77-79	91,140		0		0	12,202	13	12,202	13
78-80	96,624		0		0	15,275	16	15,275	16

NEWFOUNDLAND POWER INC.

ACCOUNT 378.10 - TRANSPORTATION - SEDANS & STATION WAGONS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	131,582	28	0		0	20,162	15	20,133	15
80-82	152,243	166	0		0	25,963	17	25,797	17
81-83	140,791	226	0		0	22,268	16	22,043	16
82-84	137,422	309	0		0	23,150	17	22,841	17
83-85	168,521	307	0		0	23,112	14	22,804	14
84-86	230,385	248	0		0	33,659	15	33,411	15
85-87	259,735	136	0		0	37,257	14	37,120	14
86-88	224,924		0		0	35,791	16	35,791	16
87-89	176,245		0		0	30,367	17	30,367	17
88-90	174,133		0		0	36,946	21	36,946	21
89-91	176,371		0		0	34,630	20	34,630	20
90-92	211,327		0		0	38,588	18	38,588	18
91-93	195,168		0		0	33,434	17	33,434	17
92-94	210,975		0		0	35,738	17	35,738	17
93-95	176,586		0		0	34,651	20	34,651	20
94-96	133,258		0		0	32,748	25	32,748	25
95-97	181,872		0		0	40,468	22	40,468	22
96-98	175,565		0		0	29,577	17	29,577	17
97-99	226,972		0		0	26,174	12	26,174	12
98-00	174,048		0		0	17,727	10	17,727	10
99-01	172,403		0		0	23,056	13	23,056	13
00-02	142,077		0		0	22,377	16	22,377	16
01-03	91,971		0		0	15,484	17	15,484	17
02-04	62,610		0		0	9,956	16	9,956	16
03-05	22,160		0		0	2,310	10	2,310	10
04-06	51,322		0		0	4,628	9	4,628	9
05-07	62,282		0		0	14,349	23	14,349	23
06-08	69,306		0		0	21,256	31	21,256	31
07-09	32,549		0		0	18,086	56	18,086	56
FIVE-YEAR AVERAGE									
05-09	45,877		0		0	13,191	29	13,191	29

NEWFOUNDLAND POWER INC.

ACCOUNT 378.20 - TRANSPORTATION-PICK-UP TRUCKS, WINDOW VANS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	76,935		0		0	14,419	19	14,419	19
1977	194,411		0		0	27,272	14	27,272	14
1978	117,670		0		0	20,360	17	20,360	17
1979	140,956		0		0	30,262	21	30,262	21
1980	189,104		0		0	37,925	20	37,925	20
1981	234,687	167	0		0	48,049	20	47,882	20
1982	192,122	446	0		0	34,468	18	34,022	18
1983	152,371	420	0		0	23,322	15	22,902	15
1984	253,637	559	0		0	46,893	18	46,334	18
1985	296,407	1,825	1		0	41,565	14	39,740	13
1986	411,189		0		0	53,406	13	53,406	13
1987	291,609		0		0	44,965	15	44,965	15
1988	485,410		0		0	91,137	19	91,137	19
1989	350,708		0		0	81,021	23	81,021	23
1990	225,867		0		0	37,234	16	37,234	16
1991	505,246		0		0	65,950	13	65,950	13
1992	455,597	61	0		0	65,336	14	65,275	14
1993	496,798	52	0		0	81,279	16	81,227	16
1994	592,278	141	0		0	75,541	13	75,400	13
1995	645,586	242	0		0	99,820	15	99,578	15
1996	342,615		0		0	54,438	16	54,438	16
1997	810,668	3,015	0		0	126,979	16	123,964	15
1998	399,694		0		0	61,392	15	61,392	15
1999	745,007		0		0	147,720	20	147,720	20
2000	655,463	336	0		0	104,561	16	104,225	16
2001	456,416		0		0	67,984	15	67,984	15
2002	1,042,188		0		0	143,096	14	143,096	14
2003	707,749		0		0	244,822	35	244,822	35
2004	558,682		0		0	112,179	20	112,179	20
2005	1,315,354		0		0	175,840	13	175,840	13
2006	723,512		0		0	67,772	9	67,772	9
2007	842,147		0		0	116,614	14	116,614	14
2008	1,131,192		0		0	141,281	12	141,281	12
2009	858,160		0		0	122,252	14	122,252	14
TOTAL	16,897,435	7,264	0		0	2,707,154	16	2,699,890	16

THREE-YEAR MOVING AVERAGES

76-78	129,672		0		0	20,684	16	20,684	16
77-79	151,012		0		0	25,965	17	25,965	17
78-80	149,243		0		0	29,516	20	29,516	20

NEWFOUNDLAND POWER INC.

ACCOUNT 378.20 - TRANSPORTATION-PICK-UP TRUCKS, WINDOW VANS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	188,249	56	0		0	38,745	21	38,690	21
80-82	205,304	204	0		0	40,147	20	39,943	19
81-83	193,060	344	0		0	35,280	18	34,935	18
82-84	199,377	475	0		0	34,894	18	34,419	17
83-85	234,138	935	0		0	37,260	16	36,325	16
84-86	320,411	795	0		0	47,288	15	46,493	15
85-87	333,068	608	0		0	46,645	14	46,037	14
86-88	396,069		0		0	63,169	16	63,169	16
87-89	375,909		0		0	72,374	19	72,374	19
88-90	353,995		0		0	69,797	20	69,797	20
89-91	360,607		0		0	61,402	17	61,402	17
90-92	395,570	20	0		0	56,173	14	56,153	14
91-93	485,880	38	0		0	70,855	15	70,817	15
92-94	514,891	85	0		0	74,052	14	73,967	14
93-95	578,221	145	0		0	85,547	15	85,402	15
94-96	526,826	128	0		0	76,600	15	76,472	15
95-97	599,623	1,086	0		0	93,746	16	92,660	15
96-98	517,659	1,005	0		0	80,936	16	79,931	15
97-99	651,790	1,005	0		0	112,030	17	111,025	17
98-00	600,055	112	0		0	104,558	17	104,446	17
99-01	618,962	112	0		0	106,755	17	106,643	17
00-02	718,022	112	0		0	105,214	15	105,102	15
01-03	735,451		0		0	151,967	21	151,967	21
02-04	769,540		0		0	166,699	22	166,699	22
03-05	860,595		0		0	177,614	21	177,614	21
04-06	865,849		0		0	118,597	14	118,597	14
05-07	960,338		0		0	120,075	13	120,075	13
06-08	898,950		0		0	108,556	12	108,556	12
07-09	943,833		0		0	126,716	13	126,716	13
FIVE-YEAR AVERAGE									
05-09	974,073		0		0	124,752	13	124,752	13

NEWFOUNDLAND POWER INC.

ACCOUNT 378.30 & 378.4-CAB & CHASSIS/TRUCKS W/ STAKE BODIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	149,595		0		0	29,724	20	29,724	20
1977	138,522		0		0	14,801	11	14,801	11
1978	111,020		0		0	19,504	18	19,504	18
1979	164,939		0		0	39,929	24	39,929	24
1980	213,407		0		0	35,616	17	35,616	17
1981	287,923	118	0		0	46,910	16	46,792	16
1982	199,377	418	0		0	32,547	16	32,129	16
1983	182,861	394	0		0	23,481	13	23,087	13
1984	266,256	416	0		0	34,328	13	33,912	13
1985	397,684	1,691	0		0	48,376	12	46,685	12
1986	431,677		0		0	83,827	19	83,827	19
1987	234,342		0		0	34,245	15	34,245	15
1988	543,153		0		0	60,253	11	60,253	11
1989	353,947	702	0		0	72,535	20	71,833	20
1990	119,715	390	0		0	23,040	19	22,650	19
1991	567,478	12,953	2		0	70,266	12	57,313	10
1992	491,105		0		0	30,464	6	30,464	6
1993	709,026		0		0	45,489	6	45,489	6
1994	413,730		0		0	50,740	12	50,740	12
1995	493,263		0		0	32,606	7	32,606	7
1996	644,052	2,362	0		0	40,408	6	38,046	6
1997	325,291		0		0	31,975	10	31,975	10
1998	393,101		0		0	21,756	6	21,756	6
1999	189,634		0		0	18,191	10	18,191	10
2000	654,990		0		0	99,432	15	99,432	15
2001	461,474		0		0	81,224	18	81,224	18
2002	628,947		0		0	23,987	4	23,987	4
2003	597,049	2,457	0		0	60,899	10	58,442	10
2004	714,182		0		0	31,072	4	31,072	4
2005	818,852		0		0	35,748	4	35,748	4
2006	913,874		0		0	2,594	0	2,594	0
2007	342,583		0		0	8,654	3	8,654	3
2008	426,360		0		0	5,569	1	5,569	1
2009	938,144	137	0		0	15,764	2	15,627	2
TOTAL	14,517,552	22,038	0		0	1,305,954	9	1,283,916	9

THREE-YEAR MOVING AVERAGES

76-78	133,046		0		0	21,343	16	21,343	16
77-79	138,160		0		0	24,745	18	24,745	18
78-80	163,122		0		0	31,683	19	31,683	19

NEWFOUNDLAND POWER INC.

ACCOUNT 378.30 & 378.4-CAB & CHASSIS/TRUCKS W/ STAKE BODIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	222,090	39	0		0	40,818	18	40,779	18
80-82	233,569	179	0		0	38,358	16	38,179	16
81-83	223,387	310	0		0	34,313	15	34,003	15
82-84	216,165	409	0		0	30,119	14	29,709	14
83-85	282,267	834	0		0	35,395	13	34,561	12
84-86	365,206	702	0		0	55,510	15	54,808	15
85-87	354,568	564	0		0	55,483	16	54,919	15
86-88	403,057		0		0	59,442	15	59,442	15
87-89	377,147	234	0		0	55,678	15	55,444	15
88-90	338,938	364	0		0	51,943	15	51,579	15
89-91	347,047	4,682	1		0	55,280	16	50,599	15
90-92	392,766	4,448	1		0	41,257	11	36,809	9
91-93	589,203	4,318	1		0	48,740	8	44,422	8
92-94	537,954		0		0	42,231	8	42,231	8
93-95	538,673		0		0	42,945	8	42,945	8
94-96	517,015	787	0		0	41,251	8	40,464	8
95-97	487,535	787	0		0	34,996	7	34,209	7
96-98	454,148	787	0		0	31,380	7	30,592	7
97-99	302,675		0		0	23,974	8	23,974	8
98-00	412,575		0		0	46,460	11	46,460	11
99-01	435,366		0		0	66,282	15	66,282	15
00-02	581,804		0		0	68,214	12	68,214	12
01-03	562,490	819	0		0	55,370	10	54,551	10
02-04	646,726	819	0		0	38,653	6	37,834	6
03-05	710,028	819	0		0	42,573	6	41,754	6
04-06	815,636		0		0	23,138	3	23,138	3
05-07	691,769		0		0	15,665	2	15,665	2
06-08	560,939		0		0	5,606	1	5,606	1
07-09	569,029	46	0		0	9,996	2	9,950	2
FIVE-YEAR AVERAGE									
05-09	687,962	27	0		0	13,666	2	13,638	2

NEWFOUNDLAND POWER INC.

ACCOUNT 378.32 - TRUCKS W/ DERRICKS - EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	33,168		0		0		0		0
1977	12,009		0		0		0		0
1978	8,236		0		0		0		0
1979	41,097		0		0		0		0
1980	26,170		0		0		0		0
1981	95,027		0		0		0		0
1982	56,413		0		0		0		0
1983	23,078		0		0		0		0
1984	30,733		0		0		0		0
1985	151,015		0		0		0		0
1986	186,209		0		0		0		0
1987	100,468		0		0		0		0
1988	64,374		0		0		0		0
1989	149,461		0		0		0		0
1990	58,037		0		0		0		0
1991	186,521		0		0		0		0
1992	175,061		0		0		0		0
1993	178,066		0		0		0		0
1994	354,672		0		0		0		0
1995	201,836		0		0	12,830	6	12,830	6
1996	405,228		0		0	28,623	7	28,623	7
1997	259,544		0		0	12,849	5	12,849	5
1998	44,746		0		0		0		0
1999	122,558		0		0	12,773	10	12,773	10
2000	823,174		0		0	72,175	9	72,175	9
2001	725,737		0		0	25,704	4	25,704	4
2002	931,827		0		0	31,703	3	31,703	3
2003	822,169		0		0	56,743	7	56,743	7
2004	824,566		0		0	33,263	4	33,263	4
2005	1,357,316		0		0	46,704	3	46,704	3
2006									
2007									
2008									
2009									
TOTAL	8,448,516		0		0	333,367	4	333,367	4

THREE-YEAR MOVING AVERAGES

76-78	17,804		0		0		0		0
77-79	20,447		0		0		0		0
78-80	25,168		0		0		0		0

NEWFOUNDLAND POWER INC.

ACCOUNT 378.32 - TRUCKS W/ DERRICKS - EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	54,098		0		0		0		0
80-82	59,203		0		0		0		0
81-83	58,173		0		0		0		0
82-84	36,741		0		0		0		0
83-85	68,275		0		0		0		0
84-86	122,652		0		0		0		0
85-87	145,897		0		0		0		0
86-88	117,017		0		0		0		0
87-89	104,768		0		0		0		0
88-90	90,624		0		0		0		0
89-91	131,340		0		0		0		0
90-92	139,873		0		0		0		0
91-93	179,883		0		0		0		0
92-94	235,933		0		0		0		0
93-95	244,858		0		0	4,277	2	4,277	2
94-96	320,579		0		0	13,818	4	13,818	4
95-97	288,869		0		0	18,101	6	18,101	6
96-98	236,506		0		0	13,824	6	13,824	6
97-99	142,283		0		0	8,541	6	8,541	6
98-00	330,159		0		0	28,316	9	28,316	9
99-01	557,156		0		0	36,884	7	36,884	7
00-02	826,913		0		0	43,194	5	43,194	5
01-03	826,578		0		0	38,050	5	38,050	5
02-04	859,521		0		0	40,570	5	40,570	5
03-05	1,001,350		0		0	45,570	5	45,570	5
04-06	727,294		0		0	26,656	4	26,656	4
05-07	452,439		0		0	15,568	3	15,568	3
06-08									
07-09									
FIVE-YEAR AVERAGE									
05-09	271,463		0		0	9,341	3	9,341	3

NEWFOUNDLAND POWER INC.

ACCOUNT 378.40 - TRUCKS W/ LINE AND STAKE BODIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
2006						35,674		35,674	
2007	610,538		0		0	41,834	7	41,834	7
2008	321,254		0		0	16,408	5	16,408	5
2009	59,400		0		0	4,155	7	4,155	7
TOTAL	991,192		0		0	98,071	10	98,071	10
THREE-YEAR MOVING AVERAGES									
06-08	310,597		0		0	31,305	10	31,305	10
07-09	330,397		0		0	20,799	6	20,799	6

NEWFOUNDLAND POWER INC.

ACCOUNT 378.50 - TRANSPORTATION - MISCELLANEOUS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1976	6,055		0		0	4,743	78	4,743	78
1977	7,555		0		0	652	9	652	9
1978	10,730		0		0		0		0
1979	5,596		0		0	1,670	30	1,670	30
1980	9,742		0		0	3,364	35	3,364	35
1981	10,912	18	0		0	1,851	17	1,833	17
1982	20,328	80	0		0	6,505	32	6,425	32
1983	5,165	35	1		0	2,240	43	2,205	43
1984	34,387	1,180	3		0	10,802	31	9,622	28
1985	12,169	62	1		0	3,184	26	3,122	26
1986	40,742		0		0	6,576	16	6,576	16
1987	51,976		0		0	8,499	16	8,499	16
1988	47,006		0		0	4,375	9	4,375	9
1989	127,685		0		0	16,403	13	16,403	13
1990	37,743		0		0	9,560	25	9,560	25
1991						584		584	
1992	109,454		0		0	9,069	8	9,069	8
1993	21,690		0		0	4,557	21	4,557	21
1994	117,038		0		0	26,435	23	26,435	23
1995	47,593	48	0		0	4,513	9	4,465	9
1996	114,131		0		0	9,103	8	9,103	8
1997	150,730		0		0	20,605	14	20,605	14
1998	123,183		0		0	51,349	42	51,349	42
1999	45,848		0		0	21,811	48	21,811	48
2000	313,095		0		0	37,477	12	37,477	12
2001	63,382		0		0	10,698	17	10,698	17
2002	97,728		0		0	6,939	7	6,939	7
2003	223,072		0		0	53,327	24	53,327	24
2004	59,431		0		0	10,228	17	10,228	17
2005	192,846		0		0	46,314	24	46,314	24
2006	366,663		0		0	21,041	6	21,041	6
2007	10,430-		0		0	4,422	42-	4,422	42-
2008	135,566		0		0	8,670	6	8,670	6
2009	69,318		0		0	11,457	17	11,457	17
TOTAL	2,668,129	1,423	0		0	439,023	16	437,600	16

THREE-YEAR MOVING AVERAGES

76-78	8,113		0		0	1,798	22	1,798	22
77-79	7,960		0		0	774	10	774	10
78-80	8,689		0		0	1,678	19	1,678	19

NEWFOUNDLAND POWER INC.

ACCOUNT 378.50 - TRANSPORTATION - MISCELLANEOUS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	8,750	6	0		0	2,295	26	2,289	26
80-82	13,661	33	0		0	3,907	29	3,874	28
81-83	12,135	44	0		0	3,532	29	3,488	29
82-84	19,960	432	2		0	6,516	33	6,084	30
83-85	17,240	426	2		0	5,409	31	4,983	29
84-86	29,099	414	1		0	6,854	24	6,440	22
85-87	34,962	21	0		0	6,086	17	6,066	17
86-88	46,575		0		0	6,483	14	6,483	14
87-89	75,556		0		0	9,759	13	9,759	13
88-90	70,811		0		0	10,113	14	10,113	14
89-91	55,143		0		0	8,849	16	8,849	16
90-92	49,066		0		0	6,404	13	6,404	13
91-93	43,715		0		0	4,737	11	4,737	11
92-94	82,727		0		0	13,354	16	13,354	16
93-95	62,107	16	0		0	11,835	19	11,819	19
94-96	92,921	16	0		0	13,350	14	13,334	14
95-97	104,151	16	0		0	11,407	11	11,391	11
96-98	129,348		0		0	27,019	21	27,019	21
97-99	106,587		0		0	31,255	29	31,255	29
98-00	160,709		0		0	36,879	23	36,879	23
99-01	140,775		0		0	23,329	17	23,329	17
00-02	158,068		0		0	18,371	12	18,371	12
01-03	128,061		0		0	23,655	18	23,655	18
02-04	126,744		0		0	23,498	19	23,498	19
03-05	158,450		0		0	36,623	23	36,623	23
04-06	206,313		0		0	25,861	13	25,861	13
05-07	183,027		0		0	23,926	13	23,926	13
06-08	163,933		0		0	11,378	7	11,378	7
07-09	64,818		0		0	8,183	13	8,183	13
FIVE-YEAR AVERAGE									
05-09	150,793		0		0	18,381	12	18,381	12

NEWFOUNDLAND POWER INC.

ACCOUNT 382.00 - RADIO SITES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1977	4,562		0		0		0		0
1978									
1979									
1980									
1981									
1982									
1983									
1984	53,582		0		0		0		0
1985									
1986		916						916-	
1987		2,761				2,712		49-	
1988									
1989	42,807		0		0	232	1	232	1
1990									
1991									
1992		2,520		1,850				670-	
1993		445				634		189	
1994									
1995	8,982		0		0		0		0
1996									
1997									
1998									
1999									
2000		222						222-	
2001	4,699		0		0		0		0
2002	10,286		0		0		0		0
2003									
2004									
2005									
2006									
2007									
2008									
2009									
TOTAL	124,918	6,864	5	1,850	1	3,578	3	1,436-	1-

THREE-YEAR MOVING AVERAGES

77-79	1,521		0		0		0		0
78-80									
79-81									
80-82									

NEWFOUNDLAND POWER INC.

ACCOUNT 382.00 - RADIO SITES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
81-83									
82-84	17,861		0		0		0		0
83-85	17,861		0		0		0		0
84-86	17,861	305	2		0		0	305-	2-
85-87		1,226				904		322-	
86-88		1,226				904		322-	
87-89	14,269	920	6		0	981	7	61	0
88-90	14,269		0		0	77	1	77	1
89-91	14,269		0		0	77	1	77	1
90-92		840		617				223-	
91-93		988		617		211		160-	
92-94		988		617		211		160-	
93-95	2,994	148	5		0	211	7	63	2
94-96	2,994		0		0		0		0
95-97	2,994		0		0		0		0
96-98									
97-99									
98-00		74						74-	
99-01	1,566	74	5		0		0	74-	5-
00-02	4,995	74	1		0		0	74-	1-
01-03	4,995		0		0		0		0
02-04	3,429		0		0		0		0
03-05									
04-06									
05-07									
06-08									
07-09									

FIVE-YEAR AVERAGE

05-09

NEWFOUNDLAND POWER INC.

ACCOUNT 384.00 - COMMUNICATION CABLES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1990	379		0		0		0		0
1991									
1992									
1993									
1994									
1995		629						629-	
1996		5,398		220				5,178-	
1997									
1998	95,974		0		0		0		0
1999	24,573	11,599	47		0		0	11,599-	47-
2000									
2001									
2002	398,614	42,493	11		0		0	42,493-	11-
2003	336,135		0		0		0		0
2004	13,313	184	1		0		0	184-	1-
2005	5,964		0		0		0		0
2006	201,741	8,790	4		0		0	8,790-	4-
2007	86,139	2,305	3		0		0	2,305-	3-
2008	29,559	9,632	33		0		0	9,632-	33-
2009	159,316	583	0		0		0	583-	0
TOTAL	1,351,707	81,613	6	220	0		0	81,393-	6-

THREE-YEAR MOVING AVERAGES

90-92	126		0		0		0		0
91-93									
92-94									
93-95		210						210-	
94-96		2,009		73				1,936-	
95-97		2,009		73				1,936-	
96-98	31,991	1,799	6	73	0		0	1,726-	5-
97-99	40,182	3,866	10		0		0	3,866-	10-
98-00	40,182	3,866	10		0		0	3,866-	10-
99-01	8,191	3,866	47		0		0	3,866-	47-
00-02	132,871	14,164	11		0		0	14,164-	11-
01-03	244,916	14,164	6		0		0	14,164-	6-
02-04	249,354	14,226	6		0		0	14,226-	6-
03-05	118,471	61	0		0		0	61-	0
04-06	73,673	2,991	4		0		0	2,991-	4-
05-07	97,948	3,698	4		0		0	3,698-	4-

NEWFOUNDLAND POWER INC.

ACCOUNT 384.00 - COMMUNICATION CABLES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E REUSE		F I N A L AMOUNT		N E T SALVAGE	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
06-08	105,813	6,909	7		0		0	6,909-	7-
07-09	91,671	4,173	5		0		0	4,173-	5-
FIVE-YEAR AVERAGE									
05-09	96,544	4,262	4		0		0	4,262-	4-

NEWFOUNDLAND POWER INC.

ACCOUNT 386.00 - SCADA EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1994	168,116	5,156	3		0		0	5,156-	3-
1995	131,945		0		0		0		0
1996	624		0		0		0		0
1997	1,858,202		0		0		0		0
1998	41,691		0		0		0		0
1999	390,626	15,843	4		0		0	15,843-	4-
2000	3,852,189	35,852	1		0		0	35,852-	1-
2001		7,580						7,580-	
2002	693,798	403	0		0		0	403-	0
2003									
2004	53,493		0		0		0		0
2005	2,681		0		0		0		0
2006	413,312		0		0		0		0
2007	116,066		0		0		0		0
2008									
2009	74,712		0		0		0		0
TOTAL	7,797,455	64,834	1		0		0	64,834-	1-

THREE-YEAR MOVING AVERAGES

94-96	100,228	1,719	2		0		0	1,719-	2-
95-97	663,590		0		0		0		0
96-98	633,506		0		0		0		0
97-99	763,506	5,281	1		0		0	5,281-	1-
98-00	1,428,169	17,232	1		0		0	17,232-	1-
99-01	1,414,272	19,758	1		0		0	19,758-	1-
00-02	1,515,329	14,612	1		0		0	14,612-	1-
01-03	231,266	2,661	1		0		0	2,661-	1-
02-04	249,097	134	0		0		0	134-	0
03-05	18,725		0		0		0		0
04-06	156,495		0		0		0		0
05-07	177,353		0		0		0		0
06-08	176,459		0		0		0		0
07-09	63,593		0		0		0		0

FIVE-YEAR AVERAGE

05-09	121,354		0		0		0		0

NEWFOUNDLAND POWER INC.

ACCOUNT 389.10 - TELEPHONE AND DATA COLLECTION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1998	124,292	3,520	3		0		0	3,520-	3-
1999		137						137-	
2000	533,547	12,538	2		0	23,402	4	10,864	2
2001	12,511	138	1		0		0	138-	1-
2002	48,074		0		0		0		0
2003									
2004	593,526		0		0		0		0
2005	93,477	22,263	24		0		0	22,263-	24-
2006	303,110		0		0		0		0
2007									
2008									
2009									
TOTAL	1,708,538	38,596	2		0	23,402	1	15,194-	1-

THREE-YEAR MOVING AVERAGES

98-00	219,280	5,398	2		0	7,801	4	2,402	1
99-01	182,019	4,271	2		0	7,801	4	3,530	2
00-02	198,044	4,225	2		0	7,801	4	3,575	2
01-03	20,195	46	0		0		0	46-	0
02-04	213,867		0		0		0		0
03-05	229,001	7,421	3		0		0	7,421-	3-
04-06	330,038	7,421	2		0		0	7,421-	2-
05-07	132,196	7,421	6		0		0	7,421-	6-
06-08	101,037		0		0		0		0
07-09									

FIVE-YEAR AVERAGE

05-09	79,317	4,453	6		0		0	4,453-	6-

NEWFOUNDLAND POWER INC.

ACCOUNT 389.30 - TELEPHONE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1998	34,953		0		0		0		0
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
TOTAL	34,953		0		0		0		0

THREE-YEAR MOVING AVERAGES

98-00	11,651		0		0		0		0
99-01									
00-02									
01-03									
02-04									
03-05									
04-06									
05-07									
06-08									
07-09									

FIVE-YEAR AVERAGE

05-09

NEWFOUNDLAND POWER INC.

ACCOUNT 390.00 - COMMUNICATIONS - POWER LINE CARRIER

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
2001	124,789		0		0		0		0
2002	7,414		0		0		0		0
2003									
2004	39,695		0		0		0		0
2005									
2006	21,848		0		0		0		0
2007									
2008									
2009									
TOTAL	193,746		0		0		0		0

THREE-YEAR MOVING AVERAGES

01-03	44,068		0		0		0		0
02-04	15,703		0		0		0		0
03-05	13,232		0		0		0		0
04-06	20,514		0		0		0		0
05-07	7,283		0		0		0		0
06-08	7,283		0		0		0		0
07-09									

FIVE-YEAR AVERAGE

05-09	4,370		0		0		0		0

NEWFOUNDLAND POWER INC.

ACCOUNT 391.00 - COMMUNICATIONS - TEST EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S S A L V A G E				NET SALVAGE	
		AMOUNT	PCT	REUSE AMOUNT	PCT	FINAL AMOUNT	PCT	AMOUNT	PCT
1995	8,355		0		0		0		0
1996	1,625		0		0		0		0
1997									
1998	36,301		0		0		0		0
1999									
2000									
2001									
2002	9,826		0		0		0		0
2003									
2004									
2005									
2006	84,890		0		0		0		0
2007									
2008									
2009									
TOTAL	140,997		0		0		0		0

THREE-YEAR MOVING AVERAGES

95-97	3,327		0		0		0		0
96-98	12,642		0		0		0		0
97-99	12,100		0		0		0		0
98-00	12,100		0		0		0		0
99-01									
00-02	3,275		0		0		0		0
01-03	3,275		0		0		0		0
02-04	3,275		0		0		0		0
03-05									
04-06	28,297		0		0		0		0
05-07	28,297		0		0		0		0
06-08	28,297		0		0		0		0
07-09									

FIVE-YEAR AVERAGE

05-09	16,978		0		0		0		0

NET SALVAGE STATISTICS - ADJUSTED

NEWFOUNDLAND POWER INC.

SUBSTATIONS - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1976	209,702	4,114	2		0	6,253	3	2,139	1
1977	715,030	12,172	2		0	24,614	3	12,442	2
1978	324,510	21,609	7		0	84,012	26	62,403	19
1979	122,514	10,227	8		0	17,454	14	7,227	6
1980	108,065	2,436	2		0	45,517	42	43,081	40
1981	238,697	147,479	62		0	61,857	26	85,622-	36-
1982	129,423	3,099	2		0	7,165	6	4,066	3
1983	122,630	11,041	9		0	15,891	13	4,850	4
1984	175,717	13,590	8		0	13,396	8	194-	0
1985	406,932	18,807	5		0	8,078	2	10,729-	3-
1986	192,045	12,595	7		0	6,350	3	6,245-	3-
1987	321,499	27,183	8		0	7,263	2	19,920-	6-
1988	293,006	44,292	15		0	34,462	12	9,830-	3-
1989	171,633	51,567	30		0	7,769-	5-	59,336-	35-
1990	439,514	61,127	14		0	25,181	6	35,946-	8-
1991	256,468	39,146	15	23,514	9		0	15,632-	6-
1992	490,044	36,153	7	2,086	0		0	34,067-	7-
1993	124,896	37,515	30	3,426	3		0	34,089-	27-
1994	457,823	83,034	18		0	101,855	22	18,821	4
1995	220,360	47,975	22	101,135	46		0	53,160	24
1996	408,816	63,917	16	10,702	3		0	53,215-	13-
1997	462,017	73,776	16	18,898	4		0	54,878-	12-
1998	453,867	57,107	13		0	17,258	4	39,849-	9-
1999	1,100,914	253,110	23	13,300	1		0	239,810-	22-
2000	491,183	186,825	38	25,556	5		0	161,269-	33-
2001	646,050	110,079	17	754	0		0	109,325-	17-
2002	1,921,197	88,133	5		0	2,773	0	85,360-	4-
2003	523,765	113,166	22		0	515,590	98	402,424	77
2004	806,466	434,013	54		0		0	434,013-	54-
2005	1,188,785	360,286	30		0	1,270	0	359,016-	30-
2006	1,167,025	426,925	37		0	65,682	6	361,243-	31-
2007	420,429	697,365	166		0	44,634	11	652,731-	155-
2008	1,035,685	610,079	59		0	2,932	0	607,147-	59-
2009	1,318,923	865,770	66		0		0	865,770-	66-
TOTAL	17,465,630	5,025,712	29	199,371	1	1,101,718	6	3,724,623-	21-

THREE-YEAR MOVING AVERAGES

76-78	416,414	12,632	3		0	38,293	9	25,661	6
77-79	387,351	14,669	4		0	42,027	11	27,357	7
78-80	185,030	11,424	6		0	48,994	26	37,570	20

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

SUBSTATIONS - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S PCT	S A L V A G E FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	156,425	53,381	34		0	41,609	27	11,771-	8-
80-82	158,728	51,005	32		0	38,180	24	12,825-	8-
81-83	163,583	53,873	33		0	28,304	17	25,569-	16-
82-84	142,590	9,243	6		0	12,151	9	2,907	2
83-85	235,093	14,479	6		0	12,455	5	2,024-	1-
84-86	258,231	14,997	6		0	9,275	4	5,723-	2-
85-87	306,825	19,528	6		0	7,230	2	12,298-	4-
86-88	268,850	28,023	10		0	16,025	6	11,998-	4-
87-89	262,046	41,014	16		0	11,319	4	29,695-	11-
88-90	301,384	52,329	17		0	17,291	6	35,037-	12-
89-91	289,205	50,613	18	7,838	3	5,804	2	36,971-	13-
90-92	395,342	45,475	12	8,533	2	8,394	2	28,548-	7-
91-93	290,469	37,605	13	9,675	3		0	27,929-	10-
92-94	357,588	52,234	15	1,837	1	33,952	9	16,445-	5-
93-95	267,693	56,175	21	34,854	13	33,952	13	12,631	5
94-96	362,333	64,975	18	37,279	10	33,952	9	6,255	2
95-97	363,731	61,889	17	43,578	12		0	18,311-	5-
96-98	441,567	64,933	15	9,867	2	5,753	1	49,314-	11-
97-99	672,266	127,998	19	10,733	2	5,753	1	111,512-	17-
98-00	681,988	165,681	24	12,952	2	5,753	1	146,976-	22-
99-01	746,049	183,338	25	13,203	2		0	170,135-	23-
00-02	1,019,477	128,346	13	8,770	1	924	0	118,651-	12-
01-03	1,030,337	103,793	10	251	0	172,788	17	69,246	7
02-04	1,083,809	211,771	20		0	172,788	16	38,983-	4-
03-05	839,672	302,488	36		0	172,287	21	130,202-	16-
04-06	1,054,092	407,075	39		0	22,317	2	384,757-	37-
05-07	925,413	494,859	53		0	37,195	4	457,663-	49-
06-08	874,380	578,123	66		0	37,749	4	540,374-	62-
07-09	925,012	724,405	78		0	15,855	2	708,549-	77-
FIVE-YEAR AVERAGE									
05-09	1,026,169	592,085	58		0	22,904	2	569,181-	55-

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

TRANSMISSION - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1976	74,518	27,005	36		0	22,953	31	4,052-	5-
1977	170,467	89,070	52		0	103,137	61	14,067	8
1978	166,933	20,255	12		0	26,050	16	5,795	3
1979	53,320	9,423	18		0	27,253	51	17,830	33
1980	192,641	14,937	8		0	29,762	15	14,825	8
1981	439,424	18,798	4		0	16,820	4	1,978-	0
1982	533,077	23,296	4		0	68,325	13	45,029	8
1983	26,333	8,388	32		0	8,175	31	213-	1-
1984	152,266	24,524	16		0	8,112	5	16,412-	11-
1985	780,922	16,683	2		0	15,442	2	1,241-	0
1986	68,915	19,596	28		0	19,343	28	253-	0
1987	393,705	43,333	11		0	18,684	5	24,649-	6-
1988	108,574	145,293	134		0	235,666	217	90,373	83
1989	215,507	112,599	52		0	48,771	23	63,828-	30-
1990	271,586	145,621	54		0	11,387	4	134,234-	49-
1991	347,937	103,835	30	16,558	5		0	87,277-	25-
1992	531,746	192,372	36	91,746	17		0	100,626-	19-
1993	245,837	77,899	32	51,560	21		0	26,339-	11-
1994	189,108	210,310	111	140,666	74		0	69,644-	37-
1995	243,439	126,204	52	72,160	30		0	54,044-	22-
1996	217,259	140,234	65	23,602	11		0	116,632-	54-
1997	189,948	152,957	81	4,219	2		0	148,738-	78-
1998	550,439	191,336	35	21,566	4		0	169,770-	31-
1999	319,663	163,447	51	16,998	5	107	0	146,342-	46-
2000	168,248	135,200	80	27,175	16		0	108,025-	64-
2001	353,001	361,072	102		0	2,224	1	358,848-	102-
2002	501,426	274,226	55		0	52,038	10	222,188-	44-
2003	1,674,595	286,028	17	94,658	6		0	191,370-	11-
2004	646,550	257,876	40		0		0	257,876-	40-
2005	495,890	289,917	58		0		0	289,917-	58-
2006	840,891	646,584	77		0	31,240	4	615,344-	73-
2007	1,021,564	548,664	54		0	35,423	3	513,241-	50-
2008	1,232,637	766,438	62		0	17,044	1	749,394-	61-
2009	620,333	747,788	121		0	300	0	747,488-	120-
TOTAL	14,038,699	6,391,208	46	560,908	4	798,256	6	5,032,044-	36-

THREE-YEAR MOVING AVERAGES

76-78	137,306	45,443	33	0	50,713	37	5,270	4
77-79	130,240	39,583	30	0	52,147	40	12,564	10
78-80	137,631	14,872	11	0	27,688	20	12,817	9

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

TRANSMISSION - ALL ACCOUNTS

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E FINAL PCT	AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	228,462	14,386	6		0	24,612	11	10,226	4
80-82	388,381	19,010	5		0	38,302	10	19,292	5
81-83	332,945	16,827	5		0	31,107	9	14,279	4
82-84	237,225	18,736	8		0	28,204	12	9,468	4
83-85	319,840	16,532	5		0	10,576	3	5,955-	2-
84-86	334,034	20,268	6		0	14,299	4	5,969-	2-
85-87	414,514	26,537	6		0	17,823	4	8,714-	2-
86-88	190,398	69,407	36		0	91,231	48	21,824	11
87-89	239,262	100,408	42		0	101,040	42	632	0
88-90	198,556	134,504	68		0	98,608	50	35,896-	18-
89-91	278,343	120,685	43	5,519	2	20,053	7	95,113-	34-
90-92	383,756	147,276	38	36,101	9	3,796	1	107,379-	28-
91-93	375,173	124,702	33	53,288	14		0	71,414-	19-
92-94	322,230	160,194	50	94,657	29		0	65,536-	20-
93-95	226,128	138,138	61	88,129	39		0	50,009-	22-
94-96	216,602	158,916	73	78,809	36		0	80,107-	37-
95-97	216,882	139,798	64	33,327	15		0	106,471-	49-
96-98	319,215	161,509	51	16,462	5		0	145,047-	45-
97-99	353,350	169,247	48	14,261	4	36	0	154,950-	44-
98-00	346,117	163,328	47	21,913	6	36	0	141,379-	41-
99-01	280,304	219,906	78	14,724	5	777	0	204,405-	73-
00-02	340,892	256,833	75	9,058	3	18,087	5	229,687-	67-
01-03	843,007	307,109	36	31,553	4	18,087	2	257,469-	31-
02-04	940,857	272,710	29	31,553	3	17,346	2	223,811-	24-
03-05	939,012	277,940	30	31,553	3		0	246,388-	26-
04-06	661,110	398,126	60		0	10,413	2	387,712-	59-
05-07	786,115	495,055	63		0	22,221	3	472,834-	60-
06-08	1,031,697	653,896	63		0	27,902	3	625,993-	61-
07-09	958,178	687,630	72		0	17,589	2	670,041-	70-
FIVE-YEAR AVERAGE									
05-09	842,263	599,878	71		0	16,801	2	583,077-	69-

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 & 361.13 & 361.15 - O/H CONDUCTOR - ALUMINUM

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1976	114,352	32,493	28		0	10,057	9	22,436-	20-
1977	108,780	41,355	38		0	4,782	4	36,573-	34-
1978	140,791	33,261	24		0	37,806	27	4,545	3
1979	154,624	37,692	24		0	36,061	23	1,631-	1-
1980	164,657	34,710	21		0	42,215	26	7,505	5
1981	174,862	37,541	21		0	32,471	19	5,070-	3-
1982	218,786	112,179	51		0	56,834	26	55,345-	25-
1983	160,455	49,844	31		0	43,408	27	6,436-	4-
1984	153,914	66,712	43		0	35,513	23	31,199-	20-
1985	249,623	113,757	46		0	34,204	14	79,553-	32-
1986	186,915	108,955	58		0	24,317	13	84,638-	45-
1987	198,281	73,590	37		0	26,558	13	47,032-	24-
1988	217,376	139,050	64		0	32,336	15	106,714-	49-
1989	317,420	217,138	68		0	75,674	24	141,464-	45-
1990	332,374	103,431	31	1,217	0	33,020	10	69,194-	21-
1991	325,342	106,513	33	2,489	1	67,513	21	36,511-	11-
1992	232,436	104,733	45	2,467	1	66,917	29	35,349-	15-
1993	253,834	92,848	37	898	0	24,371	10	67,579-	27-
1994	254,897	28,014	11	1,230	0	33,360	13	6,576	3
1995	318,265	124,635	39	2,410	1	65,365	21	56,860-	18-
1996	186,416	73,900	40	1,072	1	29,601	16	43,227-	23-
1997	169,004	87,657	52	1,738	1	33,161	20	52,758-	31-
1998	197,011	77,707	39	2,765	1	26,431	13	48,511-	25-
1999	545,297	204,262	37	247	0	24,536	4	179,479-	33-
2000	799,899	195,815	24		0	95,580	12	100,235-	13-
2001	409,966	397,785	97	10,895	3	36,357	9	350,533-	86-
2002	1,612,240	334,441	21		0	57,755	4	276,686-	17-
2003	1,164,739	261,955	22		0	43,582	4	218,373-	19-
2004	973,070	530,818	55		0	24,888	3	505,930-	52-
2005	450,036	373,623	83		0	30,930	7	342,693-	76-
2006	385,721	557,828	145		0	41,339	11	516,489-	134-
2007	887,464	332,029	37		0	32,094	4	299,935-	34-
2008	381,307	458,138	120		0	24,787	7	433,351-	114-
2009	605,754	636,458	105		0	28,894	5	607,564-	100-
TOTAL	13,045,909	6,180,868	47	27,428	0	1,312,717	10	4,840,723-	37-

THREE-YEAR MOVING AVERAGES

76-78	121,308	35,703	29		0	17,548	14	18,155-	15-
77-79	134,732	37,436	28		0	26,216	19	11,220-	8-
78-80	153,357	35,221	23		0	38,694	25	3,473	2

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 & 361.13 & 361.15 - O/H CONDUCTOR - ALUMINUM

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S S A L V A G E PCT	FINAL AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES									
79-81	164,714	36,648	22		0	36,916	22	268	0
80-82	186,102	61,477	33		0	43,840	24	17,637-	9-
81-83	184,701	66,521	36		0	44,238	24	22,284-	12-
82-84	177,718	76,245	43		0	45,252	25	30,993-	17-
83-85	187,997	76,771	41		0	37,708	20	39,063-	21-
84-86	196,817	96,475	49		0	31,345	16	65,130-	33-
85-87	211,606	98,767	47		0	28,360	13	70,408-	33-
86-88	200,857	107,198	53		0	27,737	14	79,461-	40-
87-89	244,359	143,259	59		0	44,856	18	98,403-	40-
88-90	289,057	153,206	53	406	0	47,010	16	105,791-	37-
89-91	325,045	142,361	44	1,235	0	58,736	18	82,390-	25-
90-92	296,717	104,892	35	2,058	1	55,817	19	47,018-	16-
91-93	270,537	101,365	37	1,951	1	52,934	20	46,480-	17-
92-94	247,056	75,198	30	1,532	1	41,549	17	32,117-	13-
93-95	275,665	81,832	30	1,513	1	41,032	15	39,288-	14-
94-96	253,193	75,516	30	1,571	1	42,775	17	31,170-	12-
95-97	224,562	95,397	42	1,740	1	42,709	19	50,948-	23-
96-98	184,144	79,755	43	1,858	1	29,731	16	48,165-	26-
97-99	303,771	123,209	41	1,583	1	28,043	9	93,583-	31-
98-00	514,069	159,261	31	1,004	0	48,849	10	109,408-	21-
99-01	585,054	265,954	45	3,714	1	52,158	9	210,082-	36-
00-02	940,702	309,347	33	3,632	0	63,231	7	242,485-	26-
01-03	1,062,315	331,394	31	3,632	0	45,898	4	281,864-	27-
02-04	1,250,017	375,738	30		0	42,075	3	333,663-	27-
03-05	862,615	388,799	45		0	33,133	4	355,665-	41-
04-06	602,942	487,423	81		0	32,386	5	455,038-	75-
05-07	574,407	421,160	73		0	34,788	6	386,373-	67-
06-08	551,497	449,332	81		0	32,740	6	416,592-	76-
07-09	624,842	475,542	76		0	28,592	5	446,950-	72-
FIVE-YEAR AVERAGE									
05-09	542,056	471,615	87		0	31,609	6	440,007-	81-

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

ACCOUNT 362.1 & 362.2 - DIST. - POLES AND FIXTURES - WOOD

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
2000	1,527,165	587,498	38	90,426	6		0	497,072-	33-
2001	2,817,699	534,374	19	136,453	5		0	397,921-	14-
2002	2,048,803	727,652	36		0	55,979	3	671,673-	33-
2003	848,567	474,873	56		0	238	0	474,635-	56-
2004	837,695	479,745	57		0		0	479,745-	57-
2005	1,251,337	386,994	31		0	32,119	3	354,875-	28-
2006	1,401,597	565,256	40		0	5,042	0	560,214-	40-
2007	2,055,461	619,670	30		0		0	619,670-	30-
2008	1,517,900	769,431	51		0		0	769,431-	51-
2009	1,158,627	325,141	28		0		0	325,141-	28-
TOTAL	15,464,852	5,470,634	35	226,879	1	93,378	1	5,150,377-	33-

THREE-YEAR MOVING AVERAGES

00-02	2,131,222	616,508	29	75,626	4	18,660	1	522,222-	25-
01-03	1,905,023	578,966	30	45,484	2	18,739	1	514,743-	27-
02-04	1,245,022	560,757	45		0	18,739	2	542,018-	44-
03-05	979,200	447,204	46		0	10,786	1	436,418-	45-
04-06	1,163,543	477,332	41		0	12,387	1	464,945-	40-
05-07	1,569,465	523,973	33		0	12,387	1	511,586-	33-
06-08	1,658,319	651,452	39		0	1,681	0	649,771-	39-
07-09	1,577,329	571,414	36		0		0	571,414-	36-

FIVE-YEAR AVERAGE

05-09	1,476,984	533,298	36		0	7,432	1	525,866-	36-

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

ACCOUNT 364.00 - DISTRIBUTION - TRANSFORMERS

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL		G R O S S R E U S E		S A L V A G E F I N A L		N E T S A L V A G E	
		AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT	AMOUNT	PCT
1976	209,142		0		0	20,950	10	20,950	10
1977	301,115		0		0	11,869	4	11,869	4
1978	370,766		0		0	30,646	8	30,646	8
1979	324,223	277	0		0	22,112	7	21,835	7
1980	243,756	352	0		0	45,495	19	45,143	19
1981	343,984	2,209	1		0	9,958	3	7,749	2
1982	300,512		0		0	9,111	3	9,111	3
1983	345,070	203	0		0	30,557	9	30,354	9
1984	429,292	585	0		0	18,444	4	17,859	4
1985	202,997	294	0		0	5,596	3	5,302	3
1986	259,030	892	0		0	11,023	4	10,131	4
1987	235,686	601	0		0	6,422	3	5,821	2
1988	330,575	1,658	1		0	29,257	9	27,599	8
1989	371,252	5,113	1		0	14,079	4	8,966	2
1990	470,448	4,905	1		0	16,675	4	11,770	3
1991	339,804	4,659	1	26,611	8		0	21,952	6
1992	191,717	5,687	3	19,686	10		0	13,999	7
1993	230,692	7,268	3	28,350	12		0	21,082	9
1994	197,274	2,670	1	10,681	5		0	8,011	4
1995	227,683	211,488	93	30,731	13	27,410	12	153,347-	67-
1996	155,826	10,408	7	19,440	12	13,940	9	22,972	15
1997	845,887	4,487	1	640-	0	7,000	1	1,873	0
1998	1,789,961	88,001	5	269,189	15	95,274	5	276,462	15
1999	1,419,119	78,045	5	414,515	29	14,427	1	350,897	25
2000	1,226,597	80,581	7	325,960	27	13,712	1	259,091	21
2001	912,446	80,007	9	118,967	13	3,950	0	42,910	5
2002	1,483,362	36,016	2		0	2,340	0	33,676-	2-
2003	1,242,319	326,589	26		0	387,620	31	61,031	5
2004	752,442	85,395	11		0		0	85,395-	11-
2005	1,600,527	291,062	18		0	68,693	4	222,369-	14-
2006	5,835,609	220,804	4		0	161,989	3	58,815-	1-
2007	2,836,750	287,746	10		0	90,402	3	197,344-	7-
2008	1,088,626	314,263	29		0	90,343	8	223,920-	21-
2009	1,234,999	301,660	24		0	75,444	6	226,216-	18-
TOTAL	28,349,488	2,453,925	9	1,263,490	4	1,334,738	5	144,303	1

THREE-YEAR MOVING AVERAGES

76-78	293,674		0		0	21,155	7	21,155	7
77-79	332,035	92	0		0	21,542	6	21,450	6
78-80	312,915	210	0		0	32,751	10	32,541	10

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

NEWFOUNDLAND POWER INC.

ACCOUNT 364.00 - DISTRIBUTION - TRANSFORMERS

SUMMARY OF BOOK SALVAGE - ADJUSTED*

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	G R O S S REUSE AMOUNT	S A L V A G E FINAL PCT	NET SALVAGE AMOUNT	PCT
THREE-YEAR MOVING AVERAGES							
79-81	303,988	946	0	0	25,855	9	24,909
80-82	296,084	854	0	0	21,521	7	20,668
81-83	329,855	804	0	0	16,542	5	15,738
82-84	358,291	263	0	0	19,371	5	19,108
83-85	325,786	361	0	0	18,199	6	17,838
84-86	297,106	590	0	0	11,688	4	11,097
85-87	232,571	596	0	0	7,680	3	7,085
86-88	275,097	1,050	0	0	15,567	6	14,517
87-89	312,504	2,457	1	0	16,586	5	14,129
88-90	390,758	3,892	1	0	20,004	5	16,112
89-91	393,835	4,892	1	8,870	10,251	3	14,229
90-92	333,990	5,084	2	15,432	5,558	2	15,907
91-93	254,071	5,871	2	24,882	10	0	19,011
92-94	206,561	5,208	3	19,572	9	0	14,364
93-95	218,550	73,809	34	23,254	11	9,137	41,418-
94-96	193,594	74,855	39	20,284	10	13,783	7 40,788-
95-97	409,799	75,461	18	16,510	4	16,117	4 42,834-
96-98	930,558	34,299	4	95,996	10	38,738	4 100,436
97-99	1,351,656	56,844	4	227,688	17	38,900	3 209,744
98-00	1,478,559	82,209	6	336,555	23	41,138	3 295,483
99-01	1,186,054	79,544	7	286,481	24	10,696	1 217,633
00-02	1,207,468	65,535	5	148,309	12	6,667	1 89,442
01-03	1,212,709	147,537	12	39,656	3	131,303	11 23,422
02-04	1,159,374	149,333	13	0	0	129,987	11 19,347-
03-05	1,198,429	234,349	20	0	0	152,104	13 82,244-
04-06	2,729,526	199,087	7	0	0	76,894	3 122,193-
05-07	3,424,295	266,537	8	0	0	107,028	3 159,509-
06-08	3,253,662	274,271	8	0	0	114,245	4 160,026-
07-09	1,720,125	301,223	18	0	0	85,396	5 215,826-
FIVE-YEAR AVERAGE							
05-09	2,519,302	283,107	11	0	97,374	4	185,733-

*2005-2009 COR amounts were adjusted to be consistent with new 2011 company guidelines regarding the allocation of cost for capital projects.

APPENDIX C — DETAILED DEPRECIATION CALCULATIONS

NEWFOUNDLAND POWER INC.

ACCOUNT 320.00 - LAND AND LAND CLEARING

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 75-R2.5					
NET SALVAGE PERCENT.. 0					
1924	12,170.00	1.01	122.92	0.8736	10,632
1928	154.00	1.04	1.60	0.8580	132
1930	250.00	1.05	2.62	0.8452	211
1931	1,087.00	1.06	11.52	0.8427	916
1932	3,626.00	1.07	38.80	0.8400	3,046
1941	15,399.00	1.13	174.01	0.7854	12,094
1943	9,075.00	1.15	104.36	0.7762	7,044
1944	201.00	1.15	2.31	0.7648	154
1946	140.00	1.17	1.64	0.7546	106
1949	3,200.00	1.19	38.08	0.7318	2,342
1951	11,452.00	1.20	137.42	0.7140	8,177
1952	378.00	1.21	4.57	0.7078	268
1953	70.00	1.22	0.85	0.7015	49
1954	55,986.00	1.22	683.03	0.6893	38,591
1955	1,000.00	1.23	12.30	0.6826	683
1956	2,920.00	1.24	36.21	0.6758	1,973
1957	3,055.00	1.24	37.88	0.6634	2,027
1959	21,557.00	1.26	271.62	0.6489	13,988
1960	400.00	1.26	5.04	0.6363	255
1963	74,052.00	1.28	947.87	0.6080	45,024
1981	142.00	1.40	1.99	0.4130	59
1982	3,200.00	1.41	45.12	0.4018	1,286
1983	112,607.00	1.42	1,599.02	0.3905	43,973
1984	132,423.00	1.42	1,880.41	0.3763	49,831
1985	66,452.00	1.43	950.26	0.3646	24,228
1986	49,101.00	1.44	707.05	0.3528	17,323
1987	4,580.00	1.44	65.95	0.3384	1,550
1997	217,657.62	1.52	3,308.40	0.2052	44,663
1999	109,120.00	1.54	1,680.45	0.1771	19,325
2001	6,436.42	1.56	100.41	0.1482	954
2002	4,806.01	1.57	75.45	0.1334	641
2003	34,601.78	1.59	550.17	0.1192	4,125
2007	1,815.00	1.65	29.95	0.0578	105
2008	13,970.71	1.68	234.71	0.0420	587
	973,084.54		13,863.99		356,362

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.42

NEWFOUNDLAND POWER INC.

ACCOUNT 321.00 - ROADS, TRAILS, AND BRIDGES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
SURVIVOR CURVE.. IOWA 55-R3					
NET SALVAGE PERCENT.. -10					
1924	4,370.00	1.14	54.80	0.9861	4,740
1928	18,327.00	1.18	237.88	0.9735	19,625
1931	33,287.00	1.21	443.05	0.9620	35,224
1935	2,300.00	1.26	31.88	0.9513	2,407
1941	27,250.00	1.33	398.67	0.9244	27,709
1942	10,431.00	1.34	153.75	0.9179	10,532
1943	40,620.00	1.36	607.68	0.9180	41,018
1946	20,310.00	1.40	312.77	0.9030	20,174
1948	7,587.00	1.43	119.34	0.8938	7,459
1951	6,542.00	1.47	105.78	0.8746	6,294
1952	33,656.00	1.48	547.92	0.8658	32,053
1953	35,883.00	1.50	592.07	0.8625	34,044
1954	111,427.00	1.51	1,850.80	0.8532	104,576
1955	33,328.00	1.52	557.24	0.8436	30,927
1956	20,400.00	1.54	345.58	0.8393	18,834
1957	11,282.00	1.55	192.36	0.8292	10,291
1958	40,980.00	1.57	707.72	0.8242	37,153
1959	89,346.00	1.58	1,552.83	0.8137	79,971
1960	1,647.00	1.59	28.81	0.8030	1,455
1963	86,012.08	1.63	1,542.20	0.7742	73,250
1964	2,611.00	1.64	47.10	0.7626	2,190
1966	741.00	1.67	13.61	0.7432	606
1971	1,905.00	1.73	36.25	0.6834	1,432
1973	56,816.00	1.75	1,093.71	0.6562	41,011
1980	12,075.00	1.83	243.07	0.5582	7,414
1982	3,208.00	1.85	65.28	0.5272	1,860
1983	77,923.00	1.86	1,594.30	0.5115	43,843
1985	5,610.00	1.88	116.01	0.4794	2,958
1986	16,513.00	1.89	343.31	0.4630	8,410
1987	49,831.00	1.90	1,041.47	0.4465	24,474
1989	42,002.00	1.92	887.08	0.4128	19,072
1991	3,865.00	1.94	82.48	0.3783	1,608
1992	264,500.00	1.95	5,673.52	0.3608	104,975
1993	11,715.00	1.95	251.29	0.3412	4,397
1994	68,471.14	1.96	1,476.24	0.3234	24,358
1997	500,242.38	1.99	10,950.31	0.2686	147,802
1998	804,952.24	2.00	17,708.95	0.2500	221,362
2000	51,766.00	2.01	1,144.55	0.2110	12,015
2002	31,053.63	2.03	693.43	0.1726	5,896
2003	192,895.38	2.04	4,328.57	0.1530	32,464
2004	45,419.90	2.05	1,024.22	0.1332	6,655
2005	40,659.00	2.06	921.33	0.1133	5,067
2007	103,836.68	2.08	2,375.78	0.0728	8,315

NEWFOUNDLAND POWER INC.

ACCOUNT 321.00 - ROADS, TRAILS, AND BRIDGES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 55-R3					
NET SALVAGE PERCENT.. -10					
2008	51,685.55	2.09	1,188.25	0.0522	2,968
2009	327,892.04	2.11	7,610.37	0.0316	11,398
2010	185,948.19	2.15	4,397.67	0.0108	2,209
	3,589,122.21		75,691.28		1,342,495
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.11					

NEWFOUNDLAND POWER INC.

ACCOUNT 322.00 - BUILDINGS AND STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 75-R2.5					
NET SALVAGE PERCENT.. -25					
1904	15,500.00	0.88	170.50	0.9372	18,158
1917	18,139.00	0.96	217.67	0.8976	20,352
1921	6,011.00	0.99	74.39	0.8860	6,657
1923	44,920.00	1.00	561.50	0.8750	49,131
1924	186,313.00	1.01	2,352.20	0.8736	203,454
1929	16,500.00	1.05	216.56	0.8558	17,651
1931	77,422.00	1.06	1,025.84	0.8427	81,554
1932	14,220.00	1.07	190.19	0.8400	14,931
1937	666.00	1.11	9.24	0.8158	679
1941	177,962.00	1.13	2,513.71	0.7854	174,714
1942	10,250.00	1.14	146.06	0.7809	10,005
1943	11,700.00	1.15	168.19	0.7762	11,352
1945	414.00	1.16	6.00	0.7598	393
1946	58,310.00	1.17	852.78	0.7546	55,001
1951	99,332.00	1.20	1,489.98	0.7140	88,654
1954	302,232.00	1.22	4,609.04	0.6893	260,411
1956	89,200.00	1.24	1,382.60	0.6758	75,352
1957	144,023.00	1.24	2,232.36	0.6634	119,431
1958	86,398.00	1.25	1,349.97	0.6562	70,868
1959	480,066.00	1.26	7,561.04	0.6489	389,394
1960	2,430.00	1.26	38.27	0.6363	1,933
1961	432.00	1.27	6.86	0.6286	339
1962	1,420.79	1.28	22.73	0.6208	1,103
1963	114,221.00	1.28	1,827.54	0.6080	86,808
1964	59,451.00	1.29	958.65	0.5998	44,573
1965	2,841.00	1.30	46.17	0.5915	2,101
1966	125.00	1.30	2.03	0.5785	90
1968	591.00	1.32	9.75	0.5610	414
1970	895.00	1.33	14.88	0.5386	603
1972	3,248.00	1.34	54.40	0.5159	2,095
1973	0.47	1.35	0.01	0.5062	0
1974	3,529.00	1.36	59.99	0.4964	2,190
1975	7,490.00	1.36	127.33	0.4828	4,520
1976	2,591.00	1.37	44.37	0.4726	1,531
1977	26,775.00	1.38	461.87	0.4623	15,473
1978	35,786.00	1.38	617.31	0.4485	20,063
1979	31,324.00	1.39	544.25	0.4378	17,142
1980	252,298.72	1.40	4,415.23	0.4270	134,664
1981	93,426.00	1.40	1,634.96	0.4130	48,231
1982	24,102.00	1.41	424.80	0.4018	12,105
1983	698,015.00	1.42	12,389.77	0.3905	340,719
1984	234,186.42	1.42	4,156.81	0.3763	110,155
1985	48,285.00	1.43	863.09	0.3646	22,006

NEWFOUNDLAND POWER INC.

ACCOUNT 322.00 - BUILDINGS AND STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 75-R2.5					
NET SALVAGE PERCENT.. -25					
1986	58,401.00	1.44	1,051.22	0.3528	25,755
1987	35,305.82	1.44	635.50	0.3384	14,934
1988	374,461.80	1.45	6,787.12	0.3262	152,687
1989	16,476.00	1.46	300.69	0.3139	6,465
1990	28,900.00	1.47	531.04	0.3014	10,888
1991	51,943.00	1.47	954.45	0.2866	18,609
1992	77,307.00	1.48	1,430.18	0.2738	26,458
1993	6,224.00	1.49	115.92	0.2608	2,029
1994	36,766.00	1.50	689.36	0.2475	11,374
1995	43,836.00	1.51	827.40	0.2340	12,822
1996	77,128.00	1.51	1,455.79	0.2190	21,114
1998	1,725,266.83	1.53	32,995.73	0.1912	412,339
1999	74,193.00	1.54	1,428.22	0.1771	16,424
2000	384,966.90	1.55	7,458.73	0.1628	78,341
2001	153,269.13	1.56	2,988.75	0.1482	28,393
2002	179,495.26	1.57	3,522.59	0.1334	29,931
2003	285,670.79	1.59	5,677.71	0.1192	42,565
2004	133,653.85	1.60	2,673.08	0.1040	17,375
2005	86,176.85	1.61	1,734.31	0.0886	9,544
2006	245,216.48	1.63	4,996.29	0.0734	22,499
2007	399,351.19	1.65	8,236.62	0.0578	28,853
2008	333,115.04	1.68	6,995.42	0.0420	17,489
2009	252,541.65	1.72	5,429.65	0.0258	8,144
2010	520,886.57	1.82	11,850.17	0.0091	5,925
	9,063,593.56		166,616.83		3,557,957

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.84

NEWFOUNDLAND POWER INC.

ACCOUNT 323.00 - CANALS, PENSTOCKS, SURGE TANKS,& TAILRACES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 60-L2.5					
NET SALVAGE PERCENT.. -25					
1913	33,500.00	0.92	385.25	0.8970	37,562
1917	29,076.00	0.95	345.28	0.8882	32,282
1920	2,400.00	0.97	29.10	0.8778	2,633
1924	60,525.00	1.00	756.56	0.8650	65,443
1930	6,922.00	1.05	90.85	0.8452	7,313
1931	89,020.00	1.06	1,179.52	0.8427	93,771
1932	6,504.00	1.07	86.99	0.8400	6,829
1933	1,270.00	1.08	17.14	0.8370	1,329
1934	13,454.00	1.09	183.31	0.8338	14,022
1937	384.00	1.12	5.38	0.8232	395
1941	102,886.50	1.16	1,491.85	0.8062	103,684
1942	89,090.00	1.17	1,302.94	0.8014	89,246
1943	282,243.00	1.19	4,198.36	0.8032	283,372
1946	86,200.00	1.22	1,314.55	0.7869	84,788
1948	182,823.00	1.25	2,856.61	0.7812	178,527
1950	13,840.00	1.28	221.44	0.7744	13,397
1951	440,882.00	1.29	7,109.22	0.7676	423,026
1952	55,977.00	1.31	916.62	0.7664	53,626
1953	50,499.00	1.33	839.55	0.7648	48,277
1954	858,366.00	1.34	14,377.63	0.7571	812,336
1956	367,851.00	1.37	6,299.45	0.7466	343,297
1957	6,861.00	1.39	119.21	0.7436	6,377
1958	143,625.00	1.41	2,531.39	0.7402	132,889
1959	884,873.00	1.43	15,817.10	0.7364	814,526
1960	907.00	1.44	16.33	0.7272	824
1961	500.00	1.46	9.12	0.7227	452
1963	502,890.00	1.49	9,366.33	0.7078	444,932
1964	3,977.00	1.51	75.07	0.7022	3,491
1965	685,769.00	1.53	13,115.33	0.6962	596,790
1970	942.00	1.62	19.08	0.6561	773
1978	9,317.00	1.74	202.64	0.5655	6,586
1979	518,042.00	1.75	11,332.17	0.5512	356,931
1980	107,100.00	1.77	2,369.59	0.5398	72,266
1981	2,316,405.15	1.78	51,540.01	0.5251	1,520,430
1983	889,708.00	1.80	20,018.43	0.4950	550,507
1984	576,127.00	1.82	13,106.89	0.4823	347,333
1985	1,989,658.00	1.83	45,513.43	0.4666	1,160,468
1986	93,462.00	1.84	2,149.63	0.4508	52,666
1987	934,890.00	1.85	21,619.33	0.4348	508,113
1989	1,841,429.00	1.87	43,043.40	0.4020	925,318
1990	3,109,126.00	1.88	73,064.46	0.3854	1,497,821
1991	636,862.00	1.89	15,045.86	0.3686	293,434
1992	410,297.00	1.90	9,744.55	0.3515	180,274

NEWFOUNDLAND POWER INC.

ACCOUNT 323.00 - CANALS, PENSTOCKS, SURGE TANKS, & TAILRACES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 60-L2.5					
NET SALVAGE PERCENT.. -25					
1993	286,917.86	1.91	6,850.16	0.3342	119,860
1995	60,173.00	1.92	1,444.15	0.2976	22,384
1996	202,472.62	1.93	4,884.65	0.2798	70,815
1997	28,379.00	1.94	688.19	0.2619	9,291
1998	3,229,444.81	1.95	78,717.72	0.2438	984,173
1999	4,610,997.73	1.95	112,393.07	0.2242	1,292,232
2000	3,395,024.39	1.96	83,178.10	0.2058	873,370
2001	1,652,328.79	1.97	40,688.60	0.1872	386,645
2002	2,598,135.75	1.97	63,979.09	0.1674	543,660
2003	1,534,989.18	1.98	37,990.98	0.1485	284,932
2004	2,463,678.09	1.98	60,976.03	0.1287	396,344
2005	84,380.97	1.99	2,098.98	0.1094	11,539
2006	844,772.79	1.99	21,013.72	0.0896	94,615
2007	13,629,599.00	1.99	339,036.28	0.0696	1,185,775
2008	168,461.46	1.99	4,190.48	0.0498	10,487
2009	3,398,598.68	2.00	84,964.97	0.0300	127,447
2010	539,161.87	2.00	13,479.05	0.0100	6,740
57,163,995.64		1,350,401.17		18,588,665	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.36					

NEWFOUNDLAND POWER INC.

ACCOUNT 324.00 - DAMS AND RESERVOIRS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 70-S0.5					
NET SALVAGE PERCENT.. -25					
1904	22,000.00	0.85	233.75	0.9052	24,893
1917	7,356.00	0.92	84.59	0.8602	7,910
1920	13,548.00	0.94	159.19	0.8507	14,407
1921	22,734.00	0.95	269.97	0.8502	24,161
1924	156,190.00	0.97	1,893.80	0.8390	163,804
1928	65,645.00	0.99	812.36	0.8168	67,024
1929	85,347.00	1.00	1,066.84	0.8150	86,947
1931	284,981.00	1.01	3,597.89	0.8030	286,050
1932	1,806.00	1.02	23.03	0.8007	1,808
1937	78,579.00	1.06	1,041.17	0.7791	76,526
1939	1,500.00	1.07	20.06	0.7650	1,434
1940	1,880.00	1.08	25.38	0.7614	1,789
1941	214,705.01	1.09	2,925.36	0.7576	203,326
1942	42,500.00	1.09	579.06	0.7466	39,663
1943	193,663.00	1.10	2,662.87	0.7425	179,743
1944	156,700.00	1.11	2,174.21	0.7382	144,595
1946	70,500.00	1.13	995.81	0.7288	64,226
1948	52,109.00	1.15	749.07	0.7188	46,820
1950	919.00	1.16	13.33	0.7018	806
1951	87,591.00	1.17	1,281.02	0.6962	76,226
1952	47,583.00	1.18	701.85	0.6903	41,058
1953	263,272.00	1.19	3,916.17	0.6842	225,163
1954	799,962.08	1.20	11,999.43	0.6780	677,968
1955	7,906.00	1.21	119.58	0.6716	6,637
1956	397,412.00	1.22	6,060.53	0.6649	330,299
1957	986,230.00	1.23	15,163.29	0.6580	811,174
1959	884,277.00	1.25	13,816.83	0.6438	711,622
1960	2,603.00	1.26	41.00	0.6363	2,070
1961	4,120.00	1.27	65.40	0.6286	3,237
1962	74,666.00	1.28	1,194.66	0.6208	57,941
1963	488,682.00	1.29	7,880.00	0.6128	374,330
1964	50,801.00	1.30	825.52	0.6045	38,387
1965	34,970.09	1.31	572.64	0.5960	26,053
1966	591.00	1.32	9.75	0.5874	434
1970	13.00	1.37	0.22	0.5548	9
1971	8,230.00	1.38	141.97	0.5451	5,608
1972	15,832.00	1.40	277.06	0.5390	10,667
1973	8,965.00	1.41	158.01	0.5288	5,926
1975	4,625.00	1.43	82.67	0.5076	2,935
1978	123,887.00	1.47	2,276.42	0.4778	73,992
1979	84,308.00	1.49	1,570.24	0.4694	49,468
1980	280,280.00	1.50	5,255.25	0.4575	160,285
1981	277,514.00	1.51	5,238.08	0.4454	154,506

NEWFOUNDLAND POWER INC.

ACCOUNT 324.00 - DAMS AND RESERVOIRS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 70-S0.5					
NET SALVAGE PERCENT.. -25					
1982	1,239,138.83	1.53	23,698.53	0.4360	675,331
1983	606,916.49	1.54	11,683.14	0.4235	321,286
1984	413,469.00	1.56	8,062.65	0.4134	213,660
1985	390,033.62	1.57	7,654.41	0.4004	195,212
1986	513,628.00	1.59	10,208.36	0.3896	250,137
1987	536,303.00	1.60	10,726.06	0.3760	252,062
1988	581,493.97	1.62	11,775.25	0.3645	264,943
1989	666,448.00	1.63	13,578.88	0.3504	291,904
1990	457,337.43	1.65	9,432.58	0.3382	193,339
1991	44,657.00	1.67	932.21	0.3256	18,175
1992	1,785,965.04	1.68	37,505.27	0.3108	693,847
1993	605,943.00	1.70	12,876.29	0.2975	225,335
1994	593,360.52	1.72	12,757.25	0.2838	210,495
1995	1,478,542.00	1.73	31,973.47	0.2682	495,681
1996	583,127.38	1.75	12,755.91	0.2538	184,997
1997	332,675.00	1.77	7,360.43	0.2390	99,387
1998	4,537,056.77	1.79	101,516.65	0.2238	1,269,242
1999	1,436,740.00	1.81	32,506.24	0.2082	373,912
2000	618,707.87	1.83	14,152.94	0.1922	148,645
2001	417,754.00	1.85	9,660.56	0.1758	91,801
2002	122,280.50	1.87	2,858.31	0.1590	24,303
2003	522,921.64	1.89	12,354.02	0.1418	92,688
2004	279,006.38	1.91	6,661.28	0.1242	43,316
2005	784,131.35	1.93	18,917.17	0.1062	104,093
2006	1,084,825.72	1.96	26,578.23	0.0882	119,602
2007	448,706.99	1.98	11,105.50	0.0693	38,869
2008	1,303,389.13	2.01	32,747.65	0.0502	81,788
2009	1,385,818.25	2.04	35,338.37	0.0306	53,008
2010	1,273,135.79	2.08	33,101.53	0.0104	16,551
31,450,494.85		658,454.47		12,325,536	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.09

NEWFOUNDLAND POWER INC.

ACCOUNT 325.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R2					
NET SALVAGE PERCENT.. -25					
1907	11,910.00	0.93	138.45	0.9626	14,331
1910	61,482.00	0.94	722.41	0.9447	72,603
1913	25,518.00	0.96	306.22	0.9360	29,856
1917	61,620.00	0.99	762.55	0.9256	71,294
1924	151,518.00	1.05	1,988.67	0.9082	172,011
1931	87,781.00	1.10	1,206.99	0.8745	95,956
1939	32,032.00	1.17	468.47	0.8366	33,497
1941	276,035.00	1.19	4,106.02	0.8270	285,351
1942	43,090.00	1.20	646.35	0.8220	44,275
1951	281,887.00	1.28	4,510.19	0.7616	268,356
1952	193.00	1.29	3.11	0.7546	182
1954	450,218.00	1.31	7,372.32	0.7402	416,564
1956	100,600.00	1.33	1,672.48	0.7248	91,144
1957	147,591.00	1.33	2,453.70	0.7116	131,282
1958	88,685.00	1.34	1,485.47	0.7035	77,987
1959	867,618.00	1.35	14,641.05	0.6952	753,960
1960	8,277.06	1.36	140.71	0.6868	7,106
1961	3,145.00	1.37	53.86	0.6782	2,666
1962	100,421.98	1.38	1,732.28	0.6693	84,016
1963	452,702.00	1.39	7,865.70	0.6602	373,592
1964	1,376.00	1.40	24.08	0.6510	1,120
1965	8,057.47	1.41	142.01	0.6416	6,462
1966	74.00	1.42	1.31	0.6319	58
1967	33,468.00	1.43	598.24	0.6220	26,021
1968	118.00	1.44	2.12	0.6120	90
1969	20,454.00	1.45	370.73	0.6018	15,387
1970	110,233.00	1.46	2,011.75	0.5913	81,476
1971	8,764.00	1.47	161.04	0.5806	6,360
1972	20,215.00	1.48	373.98	0.5698	14,398
1976	3,510.00	1.52	66.69	0.5244	2,301
1977	30,571.00	1.53	584.67	0.5126	19,588
1978	4,856.00	1.54	93.48	0.5005	3,038
1979	77,067.48	1.55	1,493.18	0.4882	47,030
1980	284,993.67	1.56	5,557.38	0.4758	169,500
1982	96,016.00	1.58	1,896.32	0.4503	54,045
1983	2,598,969.00	1.59	51,654.51	0.4372	1,420,337
1984	1,166,298.05	1.61	23,471.75	0.4266	621,928
1985	485,416.94	1.62	9,829.69	0.4131	250,657
1986	2,067,136.00	1.63	42,117.90	0.3994	1,032,018
1987	325,351.00	1.64	6,669.70	0.3854	156,738
1988	160,077.00	1.65	3,301.59	0.3712	74,276
1989	24,329.00	1.66	504.83	0.3569	10,854
1990	842,107.00	1.68	17,684.25	0.3444	362,527

NEWFOUNDLAND POWER INC.

ACCOUNT 325.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R2					
NET SALVAGE PERCENT.. -25					
1991	170,619.00	1.69	3,604.33	0.3296	70,295
1992	195,803.00	1.70	4,160.81	0.3145	76,975
1993	127,699.00	1.72	2,745.53	0.3010	48,047
1994	719,710.00	1.73	15,563.73	0.2854	256,757
1995	179,089.00	1.75	3,917.57	0.2712	60,711
1996	861,636.29	1.76	18,956.00	0.2552	274,862
1997	902,037.83	1.78	20,070.34	0.2403	270,950
1998	3,211,509.23	1.79	71,857.52	0.2238	898,420
1999	918,287.04	1.81	20,776.24	0.2082	238,984
2000	434,045.46	1.83	9,928.79	0.1922	104,279
2001	1,001,016.67	1.85	23,148.51	0.1758	219,973
2002	890,619.47	1.87	20,818.23	0.1590	177,011
2003	1,540,355.82	1.89	36,390.91	0.1418	273,028
2004	1,688,326.17	1.92	40,519.83	0.1248	263,379
2005	1,103,155.74	1.95	26,889.42	0.1072	147,823
2006	797,669.29	1.98	19,742.31	0.0891	88,840
2007	2,140,568.60	2.02	54,049.36	0.0707	189,173
2008	1,222,774.79	2.08	31,792.14	0.0520	79,480
2009	2,507,142.65	2.16	67,692.85	0.0324	101,539
2010	1,487,499.76	2.35	43,695.31	0.0118	21,941
33,721,346.46		757,207.93		11,264,705	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.25					

NEWFOUNDLAND POWER INC.

ACCOUNT 326.00 - SWITCHING, METERING AND CONTROL EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S0					
NET SALVAGE PERCENT.. -25					
1931	1,107.00			1.0000	1,384
1941	331.00	1.36	5.63	0.9452	391
1942	1,200.00	1.38	20.70	0.9453	1,418
1950	116.00	1.48	2.15	0.8954	130
1951	29,776.00	1.50	558.30	0.8925	33,219
1953	211.00	1.53	4.04	0.8798	232
1954	49,904.63	1.54	960.66	0.8701	54,278
1956	39,870.00	1.57	782.45	0.8556	42,641
1957	26,079.84	1.59	518.34	0.8506	27,729
1958	723.00	1.60	14.46	0.8400	759
1959	69,667.29	1.62	1,410.76	0.8343	72,654
1962	21,240.00	1.67	443.38	0.8100	21,506
1963	65,090.00	1.69	1,375.03	0.8028	65,318
1964	2,984.00	1.71	63.78	0.7952	2,966
1965	15,937.00	1.73	344.64	0.7872	15,682
1966	385.00	1.75	8.42	0.7788	375
1970	920.55	1.84	21.17	0.7452	857
1971	1,737.00	1.86	40.39	0.7347	1,595
1972	118,761.00	1.88	2,790.88	0.7238	107,449
1973	8,143.00	1.91	194.41	0.7162	7,290
1975	2,711.53	1.96	66.43	0.6958	2,358
1977	192,340.14	2.01	4,832.55	0.6734	161,902
1978	135,834.00	2.04	3,463.77	0.6630	112,572
1979	9,343.00	2.07	241.75	0.6520	7,615
1980	89,882.22	2.09	2,348.17	0.6374	71,614
1981	10,192.00	2.12	270.09	0.6254	7,968
1982	4,596.93	2.16	124.12	0.6156	3,537
1983	320,675.00	2.19	8,778.48	0.6022	241,388
1984	255,345.40	2.22	7,085.83	0.5883	187,775
1985	28,657.69	2.26	809.58	0.5763	20,644
1986	62,308.51	2.29	1,783.58	0.5610	43,694
1987	322,504.15	2.33	9,392.93	0.5476	220,754
1988	4,631.64	2.37	137.21	0.5332	3,087
1989	243,763.27	2.41	7,343.37	0.5182	157,898
1991	215,608.78	2.49	6,710.82	0.4856	130,875
1992	229,541.32	2.54	7,287.94	0.4699	134,827
1993	51,708.00	2.58	1,667.58	0.4515	29,183
1994	43,684.83	2.63	1,436.14	0.4340	23,699
1995	99,437.00	2.68	3,331.14	0.4154	51,633
1996	38,986.00	2.74	1,335.27	0.3973	19,361
1997	59,571.00	2.79	2,077.54	0.3766	28,043
1998	45,867.39	2.85	1,634.03	0.3562	20,422
1999	221,165.59	2.91	8,044.90	0.3346	92,503

NEWFOUNDLAND POWER INC.

ACCOUNT 326.00 - SWITCHING, METERING AND CONTROL EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S0					
NET SALVAGE PERCENT.. -25					
2000	90,311.35	2.98	3,364.10	0.3129	35,323
2001	369,202.89	3.05	14,075.86	0.2898	133,744
2002	488,988.79	3.12	19,070.56	0.2652	162,100
2003	634,458.95	3.20	25,378.36	0.2400	190,338
2004	1,842,320.21	3.28	75,535.13	0.2132	490,978
2005	623,819.44	3.37	26,278.39	0.1854	144,570
2006	2,380,234.59	3.47	103,242.68	0.1562	464,741
2007	1,855,662.15	3.58	83,040.88	0.1253	290,643
2008	688,519.47	3.71	31,930.09	0.0928	79,868
2009	1,293,690.69	3.85	62,258.86	0.0578	93,469
2010	1,636,206.59	4.03	82,423.91	0.0202	41,314
15,045,953.82		616,361.63		4,358,313	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.10

NEWFOUNDLAND POWER INC.

ACCOUNT 327.00 - MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R2					
NET SALVAGE PERCENT.. -25					
1924	200.00	1.14	2.85	0.9861	247
1946	1,040.00	1.39	18.07	0.8966	1,166
1948	9,689.00	1.41	170.77	0.8812	10,672
1950	896.00	1.44	16.13	0.8712	976
1953	514.00	1.49	9.57	0.8568	550
1954	21,250.14	1.50	398.44	0.8475	22,512
1955	736.60	1.51	13.90	0.8380	772
1957	1,766.47	1.54	34.00	0.8239	1,819
1958	2,350.00	1.56	45.82	0.8190	2,406
1959	37,624.00	1.57	738.37	0.8086	38,028
1960	3,035.00	1.59	60.32	0.8030	3,046
1961	299.05	1.61	6.02	0.7970	298
1962	2,687.00	1.62	54.41	0.7857	2,639
1963	17,776.23	1.64	364.41	0.7790	17,310
1964	476.00	1.65	9.82	0.7672	456
1965	1,134.00	1.67	23.67	0.7598	1,077
1969	2,039.00	1.73	44.09	0.7180	1,830
1970	1,245.00	1.75	27.23	0.7088	1,103
1971	1,938.00	1.76	42.64	0.6952	1,684
1972	2,427.00	1.78	54.00	0.6853	2,079
1974	11,456.00	1.81	259.19	0.6606	9,460
1976	5,518.00	1.84	126.91	0.6348	4,379
1977	15,741.00	1.86	365.98	0.6231	12,260
1978	707.00	1.87	16.53	0.6078	537
1979	12,047.00	1.89	284.61	0.5954	8,966
1980	38,068.46	1.91	908.88	0.5826	27,723
1981	47,984.00	1.92	1,151.62	0.5664	33,973
1983	95,375.83	1.96	2,336.71	0.5390	64,259
1985	12,197.00	1.99	303.40	0.5074	7,736
1986	7,431.77	2.01	186.72	0.4924	4,574
1987	24,481.00	2.03	621.21	0.4770	14,597
1988	4,307.00	2.05	110.37	0.4612	2,483
1990	5,655.00	2.09	147.74	0.4284	3,028
1996	24,743.00	2.21	683.53	0.3204	9,910
1998	10,853.00	2.26	306.60	0.2825	3,832
1999	12,897.23	2.28	367.57	0.2622	4,227
2000	9,677.46	2.31	279.44	0.2426	2,935
2001	19,565.00	2.33	569.83	0.2214	5,415
2003	158,350.00	2.40	4,750.50	0.1800	35,629
2004	16,727.75	2.43	508.11	0.1580	3,304
2006	723.00	2.52	22.77	0.1134	102
2007	318,998.00	2.57	10,247.81	0.0900	35,887
2008	1,925.09	2.65	63.77	0.0662	159

NEWFOUNDLAND POWER INC.

ACCOUNT 327.00 - MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R2					
NET SALVAGE PERCENT.. -25					
2009	63,153.77	2.75	2,170.91	0.0412	3,252
2010	429.38	3.01	16.16	0.0150	8
	1,028,134.23		28,941.40		409,305
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.81					

NEWFOUNDLAND POWER INC.

ACCOUNT 331.00 - BUILDING AND STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
PORT AUX BASQUES DIESEL					
INTERIM SURVIVOR CURVE.. IOWA 60-S0					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. -20					
1945	35,700.00	1.42	608.33	0.9301	39,845
1946	1,470.00	1.44	25.40	0.9288	1,638
1954	26,520.00	1.62	515.55	0.9153	29,129
1964	990.00	1.93	22.93	0.8974	1,066
1966	15,110.00	2.01	364.45	0.8944	16,217
1968	2,842.00	2.09	71.28	0.8882	3,029
1969	16,044.00	2.14	412.01	0.8881	17,098
1982	12,587.00	2.96	447.09	0.8436	12,742
1983	12,428.00	3.05	454.86	0.8388	12,510
1984	1,175.00	3.14	44.27	0.8321	1,173
1986	4,549.00	3.35	182.87	0.8208	4,481
1988	18,412.00	3.59	793.19	0.8078	17,848
1994	24,685.00	4.57	1,353.73	0.7540	22,335
1995	48,455.00	4.79	2,785.19	0.7424	43,168
2002	1,476.00	7.20	127.53	0.6120	1,084
2004	7,393.15	8.40	745.23	0.5460	4,844
2009	36,897.07	14.43	6,389.10	0.2164	9,581
	266,733.22		15,343.01		237,788

GREEN HILL GAS TURBINE
INTERIM SURVIVOR CURVE.. IOWA 60-S0
PROBABLE RETIREMENT YEAR.. 6-2021
NET SALVAGE PERCENT.. -3

1975	183,252.38	2.22	4,190.25	0.7881	148,754
1983	17,719.00	2.68	489.12	0.7370	13,451
1998	56,659.00	4.45	2,596.97	0.5562	32,459
1999	14,223.00	4.65	681.21	0.5348	7,835
2000	6,275.00	4.88	315.41	0.5124	3,312
2002	52,728.00	5.40	2,932.73	0.4590	24,928
2004	4,770.15	6.04	296.76	0.3926	1,929
2007	15,387.36	7.36	1,166.48	0.2576	4,083
2009	7,595.65	8.62	674.39	0.1293	1,012
2010	103,008.43	9.43	10,005.11	0.0472	5,008
	461,617.97		23,348.43		242,771

NEWFOUNDLAND POWER INC.

ACCOUNT 331.00 - BUILDING AND STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
WESLEYVILLE					
INTERIM SURVIVOR CURVE.. IOWA 60-S0					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1994	66,463.00	3.79	2,594.52	0.6254	42,813
2000	3,292.00	4.88	165.47	0.5124	1,737
2004	3,970.00	6.04	246.98	0.3926	1,605
	73,725.00		3,006.97		46,155
	802,076.19		41,698.41		526,714
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.20					

NEWFOUNDLAND POWER INC.

ACCOUNT 332.00 - ELECTRICAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
PORT UNION DIESEL					
INTERIM SURVIVOR CURVE.. IOWA 70-L0					
PROBABLE RETIREMENT YEAR.. 12-2010					
NET SALVAGE PERCENT.. -65					
1962	5,019.00	2.06	170.60	0.9991	8,274
1966	160.00	2.24	5.91	0.9968	263
1999	4,968.00	8.69	712.34	0.9994	8,192
	10,147.00		888.85		16,729
PORT AUX BASQUES DIESEL					
INTERIM SURVIVOR CURVE.. IOWA 70-L0					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. -20					
1946	9,670.00	1.43	165.94	0.9224	10,704
1947	1,700.00	1.45	29.58	0.9208	1,878
1954	2,595.00	1.62	50.45	0.9153	2,850
1959	13,800.00	1.76	291.46	0.9064	15,010
1964	4,240.00	1.93	98.20	0.8974	4,566
1965	1,920.00	1.97	45.39	0.8964	2,065
1966	1,547.00	2.01	37.31	0.8944	1,660
1969	18,954.00	2.14	486.74	0.8881	20,200
1971	1,067.00	2.23	28.55	0.8808	1,128
1973	248.00	2.34	6.96	0.8775	261
1982	3,929.00	2.96	139.56	0.8436	3,977
1991	13,891.00	4.03	671.77	0.7858	13,099
1992	23,555.00	4.20	1,187.17	0.7770	21,963
1999	13,705.00	5.93	975.25	0.6820	11,216
	110,821.00		4,214.33		110,577
GREEN HILL GAS TURBINE					
INTERIM SURVIVOR CURVE.. IOWA 70-L0					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1975	25,560.00	2.21	581.82	0.7846	20,656
1986	4,977.00	2.92	149.69	0.7154	3,667
1987	6,870.00	3.00	212.28	0.7050	4,989
1992	65,629.00	3.53	2,386.20	0.6530	44,141
1996	20,512.00	4.11	868.33	0.5960	12,592
1997	31,835.00	4.28	1,403.41	0.5778	18,946
2001	281,644.00	5.16	14,968.82	0.4902	142,204
2002	32,632.00	5.44	1,828.44	0.4624	15,542

NEWFOUNDLAND POWER INC.

ACCOUNT 332.00 - ELECTRICAL PLANT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
GREEN HILL GAS TURBINE					
INTERIM SURVIVOR CURVE.. IOWA 70-L0					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
2003	158,676.00	5.76	9,413.93	0.4320	70,604
2004	4,158.00	6.11	261.68	0.3972	1,701
	632,493.00		32,074.60		335,042
WESLEYVILLE					
INTERIM SURVIVOR CURVE.. IOWA 70-L0					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1993	29,602.00	3.66	1,115.94	0.6405	19,529
1998	8,010.00	4.47	368.79	0.5588	4,610
1999	2,461.00	4.68	118.63	0.5382	1,364
2001	48,225.00	5.16	2,563.06	0.4902	24,349
2002	28,540.00	5.44	1,599.15	0.4624	13,593
2004	106,377.56	6.11	6,694.66	0.3972	43,521
	223,215.56		12,460.23		106,966
MOBILE DIESEL #3					
INTERIM SURVIVOR CURVE.. IOWA 70-L0					
PROBABLE RETIREMENT YEAR.. 6-2036					
NET SALVAGE PERCENT.. 0					
2004	1,349,488.17	3.69	49,796.11	0.2398	323,607
2010	2,676.74	5.12	137.05	0.0256	69
	1,352,164.91		49,933.16		323,676
	2,328,841.47		99,571.17		892,990
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.28					

NEWFOUNDLAND POWER INC.

ACCOUNT 333.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
PORT UNION DIESEL					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 12-2010					
NET SALVAGE PERCENT.. -65					
1962	49,910.00	2.05	1,688.21	0.9942	81,874
1966	700.00	2.24	25.87	0.9968	1,151
1998	1,984.00	7.99	261.56	0.9988	3,270
	52,594.00		1,975.64		86,295
PORT AUX BASQUES DIESEL					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. -20					
1969	295,188.00	2.15	7,615.85	0.8922	316,040
2000	64,192.00	6.31	4,860.62	0.6626	51,040
2001	94,319.00	6.73	7,617.20	0.6394	72,369
2004	2,276.00	8.40	229.42	0.5460	1,491
	455,975.00		20,323.09		440,940
PORTABLE GAS TURBINE					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. 0					
1974	54,937.00	2.40	1,318.49	0.8760	48,125
1986	89,421.78	3.37	3,013.51	0.8256	73,827
1990	591,361.36	3.89	23,003.96	0.7974	471,552
1991	219,982.13-	4.04	8,887.28-	0.7878	173,302-
1992	168,777.39-	4.21	7,105.53-	0.7788	131,444-
1994	23,650.00	4.59	1,085.54	0.7574	17,913
1995	40,004.00	4.81	1,924.19	0.7456	29,827
1998	2,279.00	5.61	127.85	0.7012	1,598
1999	383.00	5.94	22.75	0.6831	262
2000	88,772.00	6.31	5,601.51	0.6626	58,820
2001	28,300.00	6.73	1,904.59	0.6394	18,095
2002	32,823.00	7.20	2,363.26	0.6120	20,088
2003	1,496,428.19	7.76	116,122.83	0.5820	870,921
2004	296,595.92	8.40	24,914.06	0.5460	161,941
2005	41,993.62-	9.17	3,850.81-	0.5044	21,182-
2007	16,143.00	11.21	1,809.63	0.3924	6,335
2008	10,340.63	12.62	1,304.99	0.3155	3,262

NEWFOUNDLAND POWER INC.

ACCOUNT 333.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
PORTABLE GAS TURBINE					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. 0					
2009	12,507.88	14.44	1,806.14	0.2166	2,709
2010	90,538.62	16.94	15,337.24	0.0847	7,669
	2,443,732.24		181,816.92		1,467,016

GREEN HILL GAS TURBINE					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1975	2,653,268.00	2.24	61,216.20	0.7952	2,173,175
1983	1,832.00	2.72	51.33	0.7480	1,411
1984	4,087.00	2.80	117.87	0.7420	3,124
1988	83,490.00	3.14	2,700.23	0.7065	60,755
1990	2,192.00	3.34	75.41	0.6847	1,546
1992	670,037.00	3.57	24,637.93	0.6604	455,767
1994	56,775.00	3.83	2,239.72	0.6320	36,958
1995	21,882.00	3.98	897.03	0.6169	13,904
1996	943,936.00	4.14	40,251.32	0.6003	583,644
1997	59,496.00	4.31	2,641.21	0.5818	35,653
1999	225,943.00	4.70	10,937.90	0.5405	125,786
2000	14,117.00	4.92	715.39	0.5166	7,512
2001	267,129.00	5.16	14,197.37	0.4902	134,875
2002	360,414.00	5.43	20,157.59	0.4616	171,358
2003	458,780.27	5.73	27,076.75	0.4298	203,099
2005	35,481.00	6.44	2,353.53	0.3542	12,944
2006	10,215.00	6.87	722.82	0.3092	3,253
2008	1,446.87	7.94	118.33	0.1985	296
2009	23,723.26	8.63	2,108.74	0.1294	3,162
	5,894,244.40		213,216.67		4,028,222

WESLEYVILLE					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1969	350,896.00	1.98	7,156.17	0.8217	296,981
1970	1,443.00	2.02	30.02	0.8181	1,216
1982	65,612.00	2.65	1,790.88	0.7552	51,037
1994	611,471.00	3.83	24,121.92	0.6320	398,043

NEWFOUNDLAND POWER INC.

ACCOUNT 333.00 - PRIME MOVERS, GENERATORS AND AUXILIARIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
WESLEYVILLE					
INTERIM SURVIVOR CURVE.. IOWA 50-L1					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1997	39,940.00	4.31	1,773.06	0.5818	23,934
1998	42,606.00	4.49	1,970.40	0.5612	24,628
1999	16,392.00	4.70	793.54	0.5405	9,126
2002	1,241,553.00	5.43	69,438.82	0.4616	590,294
2003	2,591,284.68	5.73	152,935.03	0.4298	1,147,146
2004	594,443.67	6.07	37,165.21	0.3946	241,604
2005	1,732,347.00	6.44	114,910.04	0.3542	632,005
2006	70,619.69	6.87	4,997.12	0.3092	22,491
2008	297,676.84	7.94	24,344.61	0.1985	60,862
2009	117,077.43	8.63	10,406.90	0.1294	15,604
	7,773,362.31		451,833.72		3,514,971

MOBILE DIESEL #3
INTERIM SURVIVOR CURVE.. IOWA 50-L1
PROBABLE RETIREMENT YEAR.. 6-2036
NET SALVAGE PERCENT.. 0

1997	5,000.00	3.06	153.00	0.4131	2,066
1998	7,000.00	3.14	219.80	0.3925	2,748
2004	602,294.87	3.71	22,345.14	0.2412	145,274
2005	36,721.05	3.83	1,406.42	0.2106	7,733
2006	13,311.31	3.95	525.80	0.1778	2,367
2007	2,332.64	4.09	95.40	0.1432	334
	666,659.87		24,745.56		160,522
	17,286,567.82		893,911.60		9,697,966

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.17

NEWFOUNDLAND POWER INC.

ACCOUNT 334.00 - FUEL HOLDERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
PORT UNION DIESEL					
INTERIM SURVIVOR CURVE.. SQUARE					
PROBABLE RETIREMENT YEAR.. 12-2010					
NET SALVAGE PERCENT.. -65					
1993	17,545.00			1.0000	28,949
	17,545.00				28,949
PORT AUX BASQUES DIESEL					
INTERIM SURVIVOR CURVE.. SQUARE					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. -20					
2000	1,211.00	6.25	90.82	0.6563	954
2006	94,145.79	10.00	11,297.49	0.4500	50,839
	95,356.79		11,388.31		51,793
GREEN HILL GAS TURBINE					
INTERIM SURVIVOR CURVE.. SQUARE					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1975	36,755.00	2.17	821.51	0.7717	29,216
1994	85,285.00	3.70	3,250.21	0.6111	53,682
1998	8,444.00	4.35	378.33	0.5435	4,727
1999	47,951.00	4.55	2,247.22	0.5227	25,817
2000	65,210.00	4.76	3,197.12	0.5000	33,583
2002	198,000.00	5.26	10,727.24	0.4474	91,237
2006	66,769.21	6.67	4,587.11	0.3000	20,632
2007	9,454.64	7.14	695.31	0.2500	2,435
2009	12,856.79	8.33	1,103.10	0.1250	1,655
2010	8,659.53	9.09	810.77	0.0455	405
	539,385.17		27,817.92		263,389
WESLEYVILLE					
INTERIM SURVIVOR CURVE.. SQUARE					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
1986	19,774.00	2.86	582.50	0.7000	14,257

NEWFOUNDLAND POWER INC.

ACCOUNT 334.00 - FUEL HOLDERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
WESLEYVILLE					
INTERIM SURVIVOR CURVE.. SQUARE					
PROBABLE RETIREMENT YEAR.. 6-2021					
NET SALVAGE PERCENT.. -3					
2000	143,088.00	4.76	7,015.32	0.5000	73,690
2004	38,548.00	5.88	2,334.62	0.3824	15,181
	201,410.00		9,932.44		103,128
	853,696.96		49,138.67		447,259
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.76					

NEWFOUNDLAND POWER INC.

ACCOUNT 335.00 - MISCELLANEOUS POWER PLANT EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
PORT AUX BASQUES DIESEL					
INTERIM SURVIVOR CURVE.. SQUARE					
PROBABLE RETIREMENT YEAR.. 6-2016					
NET SALVAGE PERCENT.. -20					
1946	1,570.00	1.43	26.94	0.9214	1,736
1952	495.00	1.56	9.27	0.9141	543
1955	1,910.00	1.64	37.59	0.9098	2,085
1956	910.00	1.67	18.24	0.9083	992
1958	280.00	1.72	5.78	0.9052	304
1962	410.00	1.85	9.10	0.8982	442
1965	130.00	1.96	3.06	0.8922	139
1974	1,193.00	2.38	34.07	0.8691	1,244
	6,898.00		144.05		7,485
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.09					

NEWFOUNDLAND POWER INC.

ACCOUNT 341.00 - SUBSTATION - BUILDINGS AND STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R2.5					
NET SALVAGE PERCENT.. -15					
1928	49,749.00	1.17	669.37	0.9652	55,220
1931	7,500.00	1.21	104.36	0.9620	8,297
1942	24,410.00	1.35	378.97	0.9248	25,961
1944	883.00	1.38	14.01	0.9177	932
1950	3,061.00	1.47	51.75	0.8894	3,131
1951	1,100.00	1.49	18.85	0.8866	1,122
1952	1,464.00	1.50	25.25	0.8775	1,477
1954	15,615.47	1.54	276.55	0.8701	15,625
1956	1,371.00	1.57	24.75	0.8556	1,349
1958	53,194.00	1.60	978.77	0.8400	51,385
1959	35,340.07	1.62	658.39	0.8343	33,907
1960	21,151.53	1.63	396.49	0.8232	20,024
1961	26,158.00	1.65	496.35	0.8168	24,571
1962	11,346.00	1.67	217.90	0.8100	10,569
1963	31,548.02	1.68	609.51	0.7980	28,952
1964	26,518.34	1.70	518.43	0.7905	24,107
1965	10,244.00	1.71	201.45	0.7780	9,165
1966	41,084.00	1.73	817.37	0.7698	36,370
1967	51,562.44	1.75	1,037.69	0.7612	45,137
1968	39,233.34	1.76	794.08	0.7480	33,749
1969	72,891.58	1.78	1,492.09	0.7387	61,922
1970	7,720.78	1.79	158.93	0.7250	6,437
1971	29,963.23	1.81	623.68	0.7150	24,637
1972	141,505.00	1.82	2,961.70	0.7007	114,025
1973	50,216.93	1.84	1,062.59	0.6900	39,847
1974	49,615.89	1.85	1,055.58	0.6752	38,526
1975	205,977.61	1.87	4,429.55	0.6638	157,237
1976	301,902.00	1.88	6,527.12	0.6486	225,186
1977	140,556.14	1.90	3,071.15	0.6365	102,884
1978	113,959.55	1.91	2,503.12	0.6208	81,358
1979	109,813.62	1.93	2,437.31	0.6080	76,782
1980	53,027.00	1.94	1,183.03	0.5917	36,082
1981	68,654.29	1.96	1,547.47	0.5782	45,650
1982	149,536.00	1.97	3,387.74	0.5614	96,542
1983	130,200.36	1.99	2,979.64	0.5472	81,932
1984	58,636.00	2.00	1,348.63	0.5300	35,739
1985	91,745.00	2.02	2,131.24	0.5151	54,347
1986	52,862.00	2.03	1,234.06	0.4974	30,238
1987	68,331.00	2.05	1,610.90	0.4818	37,860
1988	308,069.00	2.06	7,298.15	0.4635	164,208
1989	157,928.00	2.08	3,777.64	0.4472	81,219
1990	152,448.07	2.09	3,664.09	0.4284	75,105
1991	29,354.00	2.11	712.27	0.4114	13,888

NEWFOUNDLAND POWER INC.

ACCOUNT 341.00 - SUBSTATION - BUILDINGS AND STRUCTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R2.5					
NET SALVAGE PERCENT.. -15					
1992	48,819.00	2.12	1,190.21	0.3922	22,019
1993	7,014.00	2.14	172.61	0.3745	3,021
1994	202,504.00	2.15	5,006.91	0.3548	82,626
1995	122,420.00	2.17	3,054.99	0.3364	47,359
1996	72,282.00	2.19	1,820.42	0.3176	26,400
1997	94,655.00	2.20	2,394.77	0.2970	32,329
1998	172,384.00	2.22	4,400.96	0.2775	55,012
1999	51,611.00	2.24	1,329.50	0.2576	15,289
2000	586,509.75	2.26	15,243.39	0.2373	160,056
2001	197,498.13	2.27	5,155.69	0.2156	48,968
2002	95,042.07	2.29	2,502.93	0.1946	21,269
2003	275,085.86	2.32	7,339.29	0.1740	55,045
2004	280,578.73	2.34	7,550.37	0.1521	49,077
2005	446,697.19	2.36	12,123.36	0.1298	66,678
2006	214,565.00	2.39	5,897.32	0.1076	26,550
2007	454,812.80	2.43	12,709.74	0.0850	44,458
2008	443,427.17	2.47	12,595.55	0.0618	31,514
2009	1,142,100.92	2.54	33,360.77	0.0381	50,041
2010	636,650.87	2.69	19,694.79	0.0134	9,811
8,542,103.75		219,031.54		2,960,223	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.56

NEWFOUNDLAND POWER INC.

ACCOUNT 342.00 - SUBSTATION - EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R1.5					
NET SALVAGE PERCENT.. -15					
1942	36,640.00	1.30	547.77	0.8905	37,522
1943	9,165.00	1.31	138.07	0.8842	9,319
1946	495.00	1.35	7.68	0.8708	496
1949	423.00	1.39	6.76	0.8548	416
1951	39,262.19	1.42	641.15	0.8449	38,149
1952	9,500.36	1.43	156.23	0.8366	9,140
1954	148,637.68	1.46	2,495.63	0.8249	141,003
1956	146,022.13	1.49	2,502.09	0.8120	136,355
1958	215,788.19	1.52	3,771.98	0.7980	198,029
1959	271,299.09	1.53	4,773.51	0.7880	245,851
1960	106,533.41	1.54	1,886.71	0.7777	95,279
1961	276,152.00	1.56	4,954.17	0.7722	245,231
1962	222,955.11	1.57	4,025.45	0.7614	195,222
1963	361,291.91	1.59	6,606.22	0.7552	313,775
1964	27,796.92	1.60	511.46	0.7440	23,783
1965	112,209.00	1.62	2,090.45	0.7371	95,116
1966	661,893.21	1.63	12,407.19	0.7254	552,158
1967	537,642.06	1.65	10,201.76	0.7178	443,807
1968	547,864.16	1.67	10,521.73	0.7098	447,205
1969	925,974.47	1.68	17,889.83	0.6972	742,428
1970	370,580.50	1.70	7,244.85	0.6885	293,416
1971	1,009,685.02	1.71	19,855.46	0.6754	784,232
1972	1,166,824.47	1.73	23,213.97	0.6660	893,671
1973	1,199,611.49	1.75	24,142.18	0.6562	905,263
1974	1,553,698.10	1.76	31,446.85	0.6424	1,147,810
1975	4,103,781.15	1.78	84,004.40	0.6319	2,982,156
1976	8,984,754.11	1.80	185,984.41	0.6210	6,416,462
1977	4,853,909.59	1.81	101,034.13	0.6064	3,384,922
1978	2,059,167.49	1.83	43,335.18	0.5948	1,408,512
1979	1,399,471.93	1.85	29,773.77	0.5828	937,954
1980	972,364.93	1.87	20,910.71	0.5704	637,832
1981	1,561,232.23	1.88	33,753.84	0.5546	995,738
1982	2,517,560.77	1.90	55,008.70	0.5415	1,567,748
1983	2,375,407.30	1.92	52,448.99	0.5280	1,442,347
1984	1,294,052.56	1.94	28,870.31	0.5141	765,063
1985	1,394,740.46	1.96	31,437.45	0.4998	801,655
1986	961,340.22	1.98	21,889.72	0.4851	536,298
1987	1,784,587.11	2.00	41,045.50	0.4700	964,569
1988	2,419,826.81	2.02	56,212.58	0.4545	1,264,783
1989	3,154,530.41	2.04	74,005.28	0.4386	1,591,114
1990	7,817,472.41	2.06	185,195.92	0.4223	3,796,516
1991	4,273,174.06	2.09	102,705.74	0.4076	2,003,008
1992	3,674,445.50	2.11	89,160.42	0.3904	1,649,679

NEWFOUNDLAND POWER INC.

ACCOUNT 342.00 - SUBSTATION - EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R1.5					
NET SALVAGE PERCENT.. -15					
1993	2,746,087.40	2.14	67,581.21	0.3745	1,182,671
1994	1,052,474.95	2.16	26,143.48	0.3564	431,367
1995	1,652,855.94	2.19	41,627.18	0.3394	645,126
1996	1,664,791.74	2.22	42,502.13	0.3219	616,281
1997	2,122,060.79	2.25	54,908.32	0.3038	741,384
1998	2,569,245.37	2.28	67,365.61	0.2850	842,070
1999	3,493,443.53	2.31	92,803.33	0.2656	1,067,037
2000	3,885,384.49	2.35	105,002.52	0.2468	1,102,750
2001	4,428,476.55	2.39	121,716.68	0.2270	1,156,054
2002	4,983,927.22	2.44	139,849.00	0.2074	1,188,716
2003	7,740,084.75	2.49	221,637.33	0.1868	1,662,725
2004	5,749,303.28	2.54	167,937.15	0.1651	1,091,591
2005	3,817,511.84	2.60	114,143.60	0.1430	627,790
2006	4,221,154.35	2.68	130,095.98	0.1206	585,432
2007	4,862,155.35	2.77	154,883.96	0.0970	542,373
2008	6,167,837.58	2.90	205,697.38	0.0725	514,243
2009	8,322,954.20	3.09	295,756.18	0.0464	444,113
2010	9,698,112.17	3.56	397,040.71	0.0178	198,520
144,737,625.01		3,875,507.95		55,781,275	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.68

NEWFOUNDLAND POWER INC.

ACCOUNT 350.01 - TRANS - ROW - CLEARING/EASEMENT SURVEY

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R4					
NET SALVAGE PERCENT.. 0					
1946	14,952.00	1.36	203.35	0.8772	13,116
1952	1,856.26	1.41	26.17	0.8248	1,531
1954	5,247.42	1.43	75.04	0.8080	4,240
1955	40.00	1.44	0.58	0.7992	32
1956	11,977.84	1.45	173.68	0.7902	9,465
1958	30.00	1.46	0.44	0.7665	23
1959	51,092.35	1.47	751.06	0.7570	38,677
1960	5,182.05	1.48	76.69	0.7474	3,873
1961	5,310.40	1.49	79.12	0.7376	3,917
1962	1,707.00	1.49	25.43	0.7226	1,233
1963	43,577.69	1.50	653.67	0.7125	31,049
1965	184,805.04	1.51	2,790.56	0.6870	126,961
1966	72,215.26	1.52	1,097.67	0.6764	48,846
1967	4,064.61	1.53	62.19	0.6656	2,705
1968	84,080.65	1.53	1,286.43	0.6502	54,669
1969	94,118.29	1.54	1,449.42	0.6391	60,151
1970	35,904.99	1.54	552.94	0.6237	22,394
1971	59,662.14	1.55	924.76	0.6122	36,525
1972	136,986.57	1.56	2,136.99	0.6006	82,274
1973	87,317.43	1.56	1,362.15	0.5850	51,081
1974	193,705.28	1.57	3,041.17	0.5730	110,993
1975	423,258.82	1.57	6,645.16	0.5574	235,924
1976	802,654.90	1.58	12,681.95	0.5451	437,527
1977	181,992.87	1.58	2,875.49	0.5293	96,329
1978	204,648.37	1.58	3,233.44	0.5135	105,087
1979	147,122.65	1.59	2,339.25	0.5008	73,679
1980	187,534.62	1.59	2,981.80	0.4850	90,954
1981	605,017.09	1.59	9,619.77	0.4690	283,753
1982	630,732.37	1.60	10,091.72	0.4560	287,614
1983	388,187.78	1.60	6,211.00	0.4400	170,803
1984	56,912.46	1.60	910.60	0.4240	24,131
1985	165,516.52	1.61	2,664.82	0.4106	67,961
1986	37,708.73	1.61	607.11	0.3944	14,872
1987	36,552.13	1.61	588.49	0.3784	13,831
1988	81,736.16	1.61	1,315.95	0.3622	29,605
1989	64,425.92	1.62	1,043.70	0.3483	22,440
1990	63,138.82	1.62	1,022.85	0.3321	20,968
1991	75,636.83	1.62	1,225.32	0.3159	23,894
1992	59,244.49	1.62	959.76	0.2997	17,756
1993	13,292.03	1.62	215.33	0.2835	3,768
1994	8,027.36	1.62	130.04	0.2673	2,146
1995	31,379.62	1.62	508.35	0.2511	7,879
1996	10,933.23	1.63	178.21	0.2364	2,585

NEWFOUNDLAND POWER INC.

ACCOUNT 350.01 - TRANS - ROW - CLEARING/EASEMENT SURVEY

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R4					
NET SALVAGE PERCENT.. 0					
1997	161,489.36	1.63	2,632.28	0.2200	35,528
1999	10,727.12	1.63	174.85	0.1874	2,010
2001	28,836.50	1.63	470.03	0.1548	4,464
2002	124,650.71	1.63	2,031.81	0.1386	17,277
2003	220,877.79	1.63	3,600.31	0.1222	26,991
2004	93,206.99	1.63	1,519.27	0.1060	9,880
2005	34,054.74	1.63	555.09	0.0896	3,051
2006	209,183.94	1.63	3,409.70	0.0734	15,354
2007	215,195.19	1.63	3,507.68	0.0570	12,266
2008	122,872.82	1.64	2,015.11	0.0410	5,038
2009	185,545.67	1.64	3,042.95	0.0246	4,564
2010	87,875.98	1.64	1,441.17	0.0082	721
	6,864,003.85		109,219.87		2,874,405
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.59					

NEWFOUNDLAND POWER INC.

ACCOUNT 350.02 - TRANS - ROW - ROADS/TRAILS/BRIDGES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 65-R4					
NET SALVAGE PERCENT.. 0					
1931	544.87	1.19	6.48	0.9460	515
1959	700.60	1.47	10.30	0.7570	530
1962	3,050.41	1.49	45.45	0.7226	2,204
1963	1,937.34	1.50	29.06	0.7125	1,380
1982	44,901.44	1.60	718.42	0.4560	20,475
1985	4,858.24	1.61	78.22	0.4106	1,995
1993	7,643.80	1.62	123.83	0.2835	2,167
2004	12,563.42	1.63	204.78	0.1060	1,332
	76,200.12		1,216.54		30,598
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.60					

NEWFOUNDLAND POWER INC.

ACCOUNT 353.10 - TRANSMISSION - OVERHEAD CONDUCTORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 55-R3					
NET SALVAGE PERCENT.. -35					
1931	25,844.00	1.21	422.16	0.9620	33,564
1952	24,004.00	1.48	479.60	0.8658	28,057
1953	3,460.00	1.50	70.06	0.8625	4,029
1954	17,046.51	1.51	347.49	0.8532	19,635
1955	1,851.00	1.52	37.98	0.8436	2,108
1956	55,869.06	1.54	1,161.52	0.8393	63,303
1957	27,004.00	1.55	565.06	0.8292	30,229
1958	93,699.13	1.57	1,985.95	0.8242	104,256
1959	158,968.00	1.58	3,390.79	0.8137	174,626
1960	36,009.00	1.59	772.93	0.8030	39,036
1961	54,192.84	1.61	1,177.88	0.7970	58,309
1962	4,302.00	1.62	94.08	0.7857	4,563
1963	206,753.00	1.63	4,549.60	0.7742	216,092
1964	1,541.00	1.64	34.12	0.7626	1,586
1965	564,305.50	1.66	12,646.09	0.7553	575,397
1966	58,046.29	1.67	1,308.65	0.7432	58,239
1967	110,257.00	1.68	2,500.63	0.7308	108,777
1968	341,245.31	1.69	7,785.51	0.7182	330,861
1969	78,780.87	1.70	1,808.02	0.7055	75,033
1970	56,878.17	1.72	1,320.71	0.6966	53,489
1971	235,199.03	1.73	5,493.07	0.6834	216,992
1972	250,864.28	1.74	5,892.80	0.6699	226,873
1973	276,938.42	1.75	6,542.67	0.6562	245,331
1974	378,986.76	1.76	9,004.73	0.6424	328,672
1975	853,404.56	1.77	20,392.10	0.6284	723,977
1976	1,939,310.74	1.78	46,601.64	0.6141	1,607,756
1977	742,774.54	1.80	18,049.42	0.6030	604,656
1978	561,595.35	1.81	13,722.58	0.5882	445,946
1979	8,248.00	1.82	202.65	0.5733	6,384
1980	318,343.00	1.83	7,864.66	0.5582	239,894
1981	1,541,205.00	1.84	38,283.53	0.5428	1,129,364
1982	723,942.20	1.85	18,080.46	0.5272	515,244
1983	601,203.51	1.86	15,096.22	0.5115	415,146
1984	280,806.00	1.87	7,088.95	0.4956	187,876
1985	426,232.00	1.88	10,817.77	0.4794	275,853
1986	376,049.00	1.89	9,594.89	0.4630	235,049
1987	69,916.55	1.90	1,793.36	0.4465	42,144
1988	233,573.00	1.91	6,022.68	0.4298	135,526
1989	388,051.34	1.92	10,058.29	0.4128	216,253
1990	513,696.83	1.93	13,384.37	0.3956	274,345
1991	422,657.00	1.94	11,069.39	0.3783	215,853
1992	614,119.33	1.95	16,166.69	0.3608	299,125
1993	403,340.00	1.95	10,617.93	0.3412	185,786

NEWFOUNDLAND POWER INC.

ACCOUNT 353.10 - TRANSMISSION - OVERHEAD CONDUCTORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 55-R3					
NET SALVAGE PERCENT.. -35					
1994	307,077.00	1.96	8,125.26	0.3234	134,067
1995	440,389.00	1.97	11,712.15	0.3054	181,568
1996	245,928.67	1.98	6,573.67	0.2871	95,318
1997	361,131.00	1.99	9,701.78	0.2686	130,950
1998	271,367.69	2.00	7,326.93	0.2500	91,587
1999	149,055.88	2.01	4,044.63	0.2312	46,523
2000	181,407.00	2.01	4,922.48	0.2110	51,674
2001	526,357.44	2.02	14,353.77	0.1919	136,361
2002	510,786.00	2.03	13,998.09	0.1726	119,018
2003	1,057,374.00	2.04	29,120.08	0.1530	218,401
2004	384,711.07	2.05	10,646.88	0.1332	69,179
2005	601,467.00	2.06	16,726.80	0.1133	91,997
2006	847,001.00	2.07	23,669.44	0.0932	106,570
2007	1,122,357.00	2.08	31,515.78	0.0728	110,305
2008	1,166,219.43	2.09	32,904.88	0.0522	82,183
2009	901,381.29	2.11	25,675.85	0.0316	38,453
2010	1,169,621.77	2.15	33,948.27	0.0108	17,053
24,324,145.36		629,266.42		12,476,441	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.59					

NEWFOUNDLAND POWER INC.

ACCOUNT 353.20 - TRANSMISSION - UNDERGROUND CABLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 50-R4					
NET SALVAGE PERCENT.. -25					
1967	168,788.00	1.86	3,924.32	0.8091	170,708
1979	1,676.00	2.01	42.11	0.6332	1,327
1980	776,120.00	2.01	19,500.02	0.6130	594,702
1984	18,099.00	2.05	463.79	0.5432	12,289
1997	6,161.00	2.11	162.50	0.2848	2,193
2009	63,799.53	2.13	1,698.66	0.0320	2,552
	1,034,643.53		25,791.40		783,771
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.49					

NEWFOUNDLAND POWER INC.

ACCOUNT 355.10 - TRANSMISSION - POLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 47-R2					
NET SALVAGE PERCENT.. -35					
1931	6,025.85	1.23	100.06	0.9778	7,954
1946	42,211.00	1.42	809.18	0.9159	52,192
1947	19,055.00	1.43	367.86	0.9080	23,358
1948	7,146.00	1.45	139.88	0.9062	8,742
1952	9,943.90	1.51	202.71	0.8834	11,859
1953	1,083.24	1.52	22.23	0.8740	1,278
1954	9,710.03	1.54	201.87	0.8701	11,406
1955	3,783.00	1.56	79.67	0.8658	4,422
1956	26,202.61	1.57	555.36	0.8556	30,266
1957	14,973.70	1.59	321.41	0.8506	17,194
1958	92,390.79	1.61	2,008.11	0.8452	105,420
1959	173,156.24	1.62	3,786.93	0.8343	195,027
1960	62,464.38	1.64	1,382.96	0.8282	69,840
1961	74,354.60	1.66	1,666.29	0.8217	82,481
1962	12,861.00	1.67	289.95	0.8100	14,064
1963	293,063.84	1.69	6,686.25	0.8028	317,617
1964	6,890.95	1.71	159.08	0.7952	7,398
1965	372,634.94	1.73	8,702.89	0.7872	396,007
1966	46,909.20	1.74	1,101.90	0.7743	49,034
1967	96,492.96	1.76	2,292.67	0.7656	99,731
1968	445,287.29	1.78	10,700.25	0.7565	454,761
1969	125,357.29	1.80	3,046.18	0.7470	126,417
1970	89,288.78	1.81	2,181.77	0.7330	88,356
1971	143,334.89	1.83	3,541.09	0.7228	139,863
1972	345,313.01	1.85	8,624.19	0.7122	332,008
1973	293,388.31	1.87	7,406.59	0.7012	277,727
1974	512,347.96	1.88	13,003.39	0.6862	474,624
1975	1,171,967.73	1.90	30,060.97	0.6745	1,067,165
1976	2,256,633.27	1.92	58,491.93	0.6624	2,017,972
1977	437,223.45	1.94	11,450.88	0.6499	383,605
1978	453,172.43	1.96	11,990.94	0.6370	389,706
1979	87,494.03	1.98	2,338.72	0.6237	73,670
1980	421,681.93	1.99	11,328.49	0.6070	345,547
1981	1,666,166.03	2.01	45,211.42	0.5930	1,333,849
1982	936,121.72	2.03	25,654.42	0.5786	731,214
1983	1,331,023.63	2.05	36,836.08	0.5638	1,013,082
1984	510,924.40	2.07	14,277.78	0.5486	378,396
1985	714,933.35	2.09	20,171.84	0.5330	514,430
1986	500,399.53	2.11	14,253.88	0.5170	349,254
1987	282,267.13	2.13	8,116.59	0.5006	190,759
1988	382,990.93	2.15	11,116.31	0.4838	250,143
1989	571,477.34	2.17	16,741.43	0.4666	359,979
1990	764,464.02	2.19	22,601.38	0.4490	463,380

NEWFOUNDLAND POWER INC.

ACCOUNT 355.10 - TRANSMISSION - POLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 47-R2					
NET SALVAGE PERCENT.. -35					
1991	569,603.15	2.21	16,994.11	0.4310	331,424
1992	569,647.83	2.23	17,149.25	0.4126	317,300
1993	488,943.22	2.26	14,917.66	0.3955	261,059
1994	442,639.23	2.28	13,624.44	0.3762	224,803
1995	532,297.19	2.30	16,527.83	0.3565	256,181
1996	333,033.73	2.33	10,475.58	0.3378	151,873
1997	577,564.12	2.35	18,323.22	0.3172	247,325
1998	482,484.90	2.38	15,502.24	0.2975	193,778
1999	646,899.33	2.41	21,046.87	0.2772	242,083
2000	251,228.69	2.43	8,241.56	0.2552	86,553
2001	559,005.90	2.46	18,564.59	0.2337	176,364
2002	1,053,440.94	2.50	35,553.63	0.2125	302,206
2003	1,160,971.24	2.53	39,652.97	0.1898	297,476
2004	446,642.20	2.57	15,496.25	0.1670	100,695
2005	871,049.49	2.61	30,691.43	0.1436	168,862
2006	1,353,003.27	2.66	48,586.35	0.1197	218,639
2007	1,305,068.68	2.72	47,922.12	0.0952	167,727
2008	1,719,637.48	2.80	65,002.30	0.0700	162,506
2009	1,494,319.80	2.92	58,906.09	0.0438	88,359
2010	1,682,074.85	3.19	72,438.55	0.0160	36,333
32,354,166.92		1,005,640.82		17,292,743	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.11					

NEWFOUNDLAND POWER INC.

ACCOUNT 355.20 - TRANSMISSION - POLE FIXTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 47-R2					
NET SALVAGE PERCENT.. -35					
1931	1,032.11	1.23	17.14	0.9778	1,362
1949	301.00	1.46	5.93	0.8979	365
1952	4,018.05	1.51	81.91	0.8834	4,792
1953	33.11	1.52	0.68	0.8740	39
1954	3,003.66	1.54	62.45	0.8701	3,528
1956	7,199.85	1.57	152.60	0.8556	8,316
1957	91.24	1.59	1.96	0.8506	105
1958	9,222.98	1.61	200.46	0.8452	10,524
1959	25,733.87	1.62	562.80	0.8343	28,984
1960	6,605.66	1.64	146.25	0.8282	7,386
1961	8,254.25	1.66	184.98	0.8217	9,156
1962	4,620.67	1.67	104.17	0.8100	5,053
1963	87,144.84	1.69	1,988.21	0.8028	94,446
1964	1,961.00	1.71	45.27	0.7952	2,105
1965	159,287.97	1.73	3,720.17	0.7872	169,279
1966	11,420.35	1.74	268.26	0.7743	11,938
1967	39,490.61	1.76	938.30	0.7656	40,816
1968	79,095.80	1.78	1,900.67	0.7565	80,779
1969	37,647.69	1.80	914.84	0.7470	37,966
1970	23,647.66	1.81	577.83	0.7330	23,401
1971	78,649.48	1.83	1,943.04	0.7228	76,745
1972	118,460.63	1.85	2,958.55	0.7122	113,896
1973	194,815.49	1.87	4,918.12	0.7012	184,416
1974	218,548.20	1.88	5,546.75	0.6862	202,456
1975	538,907.44	1.90	13,822.98	0.6745	490,716
1976	1,144,348.14	1.92	29,661.50	0.6624	1,023,322
1977	407,334.45	1.94	10,668.09	0.6499	357,381
1978	292,786.94	1.96	7,747.14	0.6370	251,782
1979	28,510.09	1.98	762.07	0.6237	24,005
1980	308,391.35	1.99	8,284.93	0.6070	252,711
1981	993,427.67	2.01	26,956.66	0.5930	795,289
1982	650,003.95	2.03	17,813.36	0.5786	507,725
1983	659,357.49	2.05	18,247.72	0.5638	501,857
1984	225,607.13	2.07	6,304.59	0.5486	167,087
1985	330,828.93	2.09	9,334.34	0.5330	238,048
1986	249,708.06	2.11	7,112.93	0.5170	174,284
1987	612,518.44	2.13	17,612.97	0.5006	413,946
1988	334,907.82	2.15	9,720.70	0.4838	218,738
1989	377,367.93	2.17	11,054.99	0.4666	237,708
1990	755,587.60	2.19	22,338.95	0.4490	457,999
1991	441,534.32	2.21	13,173.18	0.4310	256,907
1992	591,770.66	2.23	17,815.26	0.4126	329,622
1993	358,852.28	2.26	10,948.58	0.3955	191,600

NEWFOUNDLAND POWER INC.

ACCOUNT 355.20 - TRANSMISSION - POLE FIXTURES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 47-R2					
NET SALVAGE PERCENT.. -35					
1994	484,609.68	2.28	14,916.29	0.3762	246,119
1995	375,680.88	2.30	11,664.89	0.3565	180,806
1996	302,050.02	2.33	9,500.98	0.3378	137,744
1997	364,534.61	2.35	11,564.86	0.3172	156,101
1998	383,134.05	2.38	12,310.10	0.2975	153,876
1999	446,523.91	2.41	14,527.66	0.2772	167,098
2000	259,041.59	2.43	8,497.86	0.2552	89,245
2001	701,848.12	2.46	23,308.38	0.2337	221,430
2002	563,987.03	2.50	19,034.56	0.2125	161,794
2003	823,428.13	2.53	28,124.19	0.1898	210,987
2004	522,031.71	2.57	18,111.89	0.1670	117,692
2005	713,294.06	2.61	25,132.92	0.1436	138,279
2006	987,185.59	2.66	35,449.83	0.1197	159,524
2007	1,093,655.06	2.72	40,159.01	0.0952	140,557
2008	1,502,610.70	2.80	56,798.68	0.0700	141,997
2009	1,110,975.05	2.92	43,794.64	0.0438	65,692
2010	2,069,230.77	3.19	89,111.42	0.0160	44,695
23,125,857.82		748,630.44		10,542,216	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.24					

NEWFOUNDLAND POWER INC.

ACCOUNT 355.30 - TRANSMISSION - INSULATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 31-S1					
NET SALVAGE PERCENT.. -35					
1931	23.59			1.0000	32
1954	1,546.46	1.73	36.12	0.9774	2,041
1956	3,443.86	1.77	82.29	0.9646	4,485
1958	3,377.08	1.82	82.97	0.9555	4,356
1959	2,416.95	1.84	60.04	0.9476	3,092
1960	0.31	1.87	0.01	0.9444	0
1961	248.16	1.89	6.33	0.9356	313
1962	231.71	1.92	6.01	0.9312	291
1963	47,358.78	1.95	1,246.72	0.9262	59,216
1964	294.60	1.97	7.83	0.9160	364
1965	28,014.42	2.00	756.39	0.9100	34,416
1966	2,961.72	2.03	81.17	0.9034	3,612
1967	9,362.61	2.06	260.37	0.8961	11,326
1968	11,267.57	2.09	317.91	0.8882	13,511
1969	1,512.13	2.12	43.28	0.8798	1,796
1970	685.48	2.15	19.90	0.8708	806
1971	1,596.09	2.19	47.19	0.8650	1,864
1972	3,290.46	2.22	98.62	0.8547	3,797
1973	2,379.94	2.26	72.61	0.8475	2,723
1974	13,006.09	2.29	402.08	0.8358	14,675
1975	11,928.96	2.33	375.23	0.8272	13,321
1976	66,964.17	2.37	2,142.52	0.8176	73,912
1977	63,821.92	2.40	2,067.83	0.8040	69,272
1978	55,938.65	2.44	1,842.62	0.7930	59,885
1979	6,272.56	2.49	210.85	0.7844	6,642
1980	57,533.64	2.53	1,965.06	0.7716	59,930
1981	168,939.26	2.57	5,861.35	0.7582	172,921
1982	70,965.78	2.62	2,510.06	0.7467	71,537
1983	128,002.66	2.66	4,596.58	0.7315	126,406
1984	68,339.03	2.71	2,500.18	0.7182	66,259
1985	225,220.77	2.76	8,391.73	0.7038	213,989
1986	185,412.44	2.81	7,033.62	0.6884	172,311
1987	198,644.05	2.86	7,669.65	0.6721	180,237
1988	182,585.89	2.91	7,172.89	0.6548	161,402
1989	681,384.98	2.96	27,228.14	0.6364	585,405
1990	1,498,693.30	3.02	61,101.73	0.6191	1,252,585
1991	857,782.57	3.07	35,550.80	0.5986	693,183
1992	848,481.26	3.13	35,852.58	0.5790	663,215
1993	568,587.53	3.19	24,486.22	0.5582	428,471
1994	711,115.98	3.25	31,200.21	0.5362	514,756
1995	1,012,166.83	3.31	45,228.67	0.5130	700,976
1996	961,734.02	3.37	43,754.09	0.4886	634,369
1997	1,238,375.46	3.43	57,342.98	0.4630	774,047

NEWFOUNDLAND POWER INC.

ACCOUNT 355.30 - TRANSMISSION - INSULATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 31-S1					
NET SALVAGE PERCENT.. -35					
1998	880,669.07	3.50	41,611.61	0.4375	520,145
1999	857,605.30	3.56	41,216.51	0.4094	473,990
2000	527,328.11	3.62	25,770.52	0.3801	270,591
2001	863,244.07	3.69	43,002.50	0.3506	408,582
2002	1,033,158.04	3.75	52,303.63	0.3188	444,651
2003	848,508.01	3.81	43,643.01	0.2858	327,380
2004	658,018.96	3.87	34,378.20	0.2516	223,503
2005	609,880.00	3.92	32,274.85	0.2156	177,512
2006	1,132,950.80	3.97	60,720.50	0.1786	273,166
2007	776,466.36	4.02	42,138.83	0.1407	147,486
2008	989,033.73	4.06	54,208.94	0.1015	135,522
2009	859,178.63	4.09	47,439.55	0.0614	71,217
2010	906,978.13	4.11	50,323.68	0.0206	25,223
20,944,928.93		988,745.76		11,356,715	
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.72					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.10 - O/H CONDUCTOR - BARE COPPER

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 48-R1.5					
NET SALVAGE PERCENT.. -25					
1964	6,303.50	1.64	129.22	0.7626	6,009
1965	137,417.00	1.66	2,851.40	0.7553	129,739
1966	84,498.00	1.67	1,763.90	0.7432	78,499
1967	92,696.74	1.69	1,958.22	0.7352	85,188
1968	89,552.97	1.71	1,914.19	0.7268	81,359
1969	26,827.15	1.72	576.78	0.7138	23,937
1970	13,981.10	1.74	304.09	0.7047	12,316
1971	23,676.82	1.76	520.89	0.6952	20,575
1972	11,420.14	1.77	252.67	0.6814	9,727
1973	12,102.08	1.79	270.78	0.6712	10,154
1975	60,287.12	1.83	1,379.07	0.6496	48,953
1976	53,891.76	1.85	1,246.25	0.6382	42,992
1977	10,136.83	1.86	235.68	0.6231	7,895
1978	4,811.85	1.88	113.08	0.6110	3,675
1979	6,010.57	1.90	142.75	0.5985	4,497
1982	0.09			0.5586	0
1983	15,992.35	1.98	395.81	0.5445	10,885
1984	18,000.10	2.00	450.00	0.5300	11,925
1985	310.23	2.02	7.83	0.5151	200
1992	0.13			0.4033	0
	667,916.53		14,512.61		588,525
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.17					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.11 - O/H CONDUCTOR - W/P COPPER

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 44-R2					
NET SALVAGE PERCENT.. -25					
1959	117,840.81	1.67	2,459.93	0.8600	126,679
1960	181,362.00	1.69	3,831.27	0.8534	193,468
1961	101,492.00	1.71	2,169.39	0.8464	107,379
1962	214,459.00	1.73	4,637.68	0.8390	224,914
1963	122,599.00	1.75	2,681.85	0.8312	127,380
1964	157,907.00	1.77	3,493.69	0.8230	162,447
1965	232,729.00	1.79	5,207.31	0.8144	236,918
1966	109,964.00	1.81	2,487.94	0.8054	110,706
1967	115,148.51	1.83	2,634.02	0.7960	114,573
1968	95,665.06	1.85	2,212.25	0.7862	94,015
1969	35,641.34	1.87	833.12	0.7760	34,572
1970	714.51	1.89	16.88	0.7654	684
1971	39,646.76	1.91	946.57	0.7544	37,387
1972	18,429.68	1.93	444.62	0.7430	17,117
1973	41,134.12	1.95	1,002.64	0.7312	37,597
1974	15,244.23	1.97	375.39	0.7190	13,701
1975	44,527.04	1.99	1,107.61	0.7064	39,317
1976	30,240.86	2.01	759.80	0.6934	26,211
1977	0.19			0.6800	0
1978	47,321.59	2.05	1,212.62	0.6662	39,407
1979	3,377.21	2.07	87.39	0.6520	2,752
1980	1,099.54	2.09	28.73	0.6374	876
1981	9,069.21	2.11	239.20	0.6224	7,056
1988	1,740.27	2.26	49.16	0.5085	1,106
1992	0.54	2.36	0.02	0.4366	0
	1,737,353.47		38,919.08		1,756,262

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.24

NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 - O/H CONDUCTOR - BARE ALUMINUM

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 55-R2.5					
NET SALVAGE PERCENT.. -30					
1963	83,003.89	1.59	1,715.69	0.7552	81,490
1964	130,633.82	1.60	2,717.18	0.7440	126,349
1965	889,853.16	1.62	18,740.31	0.7371	852,684
1966	628,764.04	1.63	13,323.51	0.7254	592,937
1967	149,199.28	1.64	3,180.93	0.7134	138,370
1968	143,741.08	1.65	3,083.25	0.7012	131,029
1969	355,604.97	1.67	7,720.18	0.6930	320,365
1970	204,867.12	1.68	4,474.30	0.6804	181,209
1971	487,980.55	1.69	10,720.93	0.6676	423,509
1972	477,170.81	1.70	10,545.47	0.6545	406,001
1973	761,463.53	1.72	17,026.32	0.6450	638,487
1974	960,415.06	1.73	21,599.73	0.6314	788,328
1975	1,593,595.71	1.74	36,047.13	0.6177	1,279,673
1976	1,472,365.19	1.75	33,496.31	0.6038	1,155,718
1977	1,977,207.61	1.77	45,495.55	0.5930	1,524,229
1978	1,753,824.15	1.78	40,583.49	0.5785	1,318,963
1979	1,726,229.62	1.79	40,169.36	0.5638	1,265,223
1980	2,690,292.79	1.80	62,952.85	0.5490	1,920,062
1981	2,322,766.29	1.82	54,956.65	0.5369	1,621,221
1982	2,185,238.73	1.83	51,986.83	0.5216	1,481,767
1983	2,060,959.27	1.84	49,298.15	0.5060	1,355,699
1984	2,574,058.05	1.85	61,906.10	0.4902	1,640,344
1985	2,092,253.87	1.86	50,590.70	0.4743	1,290,063
1986	2,151,207.49	1.88	52,575.51	0.4606	1,288,100
1987	2,404,252.70	1.89	59,072.49	0.4442	1,388,360
1988	2,685,950.13	1.90	66,342.97	0.4275	1,492,717
1989	2,987,361.66	1.92	74,564.55	0.4128	1,603,138
1990	3,705,663.41	1.93	92,975.09	0.3956	1,905,749
1991	3,040,536.94	1.94	76,682.34	0.3783	1,495,306
1992	3,383,713.50	1.95	85,777.14	0.3608	1,587,097
1993	2,757,440.37	1.97	70,618.05	0.3448	1,235,995
1994	2,496,118.43	1.98	64,250.09	0.3267	1,060,126
1995	1,958,905.81	1.99	50,676.89	0.3084	785,365
1996	1,737,763.31	2.01	45,407.76	0.2914	658,299
1997	2,134,832.40	2.02	56,060.70	0.2727	756,819
1998	2,123,951.10	2.04	56,327.18	0.2550	704,090
1999	3,098,013.29	2.05	82,562.05	0.2358	949,665
2000	2,876,234.32	2.07	77,399.47	0.2174	812,881
2001	3,267,761.11	2.08	88,360.26	0.1976	839,422
2002	2,406,278.13	2.10	65,691.39	0.1785	558,377
2003	3,782,770.45	2.12	104,253.15	0.1590	781,899
2004	3,578,583.87	2.14	99,556.20	0.1391	647,115
2005	3,665,728.01	2.16	102,933.64	0.1188	566,135

NEWFOUNDLAND POWER INC.

ACCOUNT 361.12 - O/H CONDUCTOR - BARE ALUMINUM

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 55-R2.5					
NET SALVAGE PERCENT.. -30					
2006	5,012,049.71	2.19	142,693.06	0.0986	642,445
2007	3,203,639.30	2.22	92,457.03	0.0777	323,600
2008	4,590,763.72	2.26	134,876.64	0.0565	337,192
2009	3,643,621.41	2.32	109,891.62	0.0348	164,837
2010	5,281,311.59	2.45	168,209.77	0.0122	83,762
	105,695,940.75		2,762,545.96		43,202,211
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.61					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.13 - O/H CONDUCTOR - W/P ALUMINUM

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 32-R1.5					
NET SALVAGE PERCENT.. -30					
1963	657.90	1.93	16.51	0.9168	784
1964	323.90	1.95	8.21	0.9068	382
1965	823.20	1.98	21.19	0.9009	964
1966	335.80	2.01	8.77	0.8944	390
1969	16.05	2.10	0.44	0.8715	18
1970	1,234.75	2.13	34.19	0.8626	1,385
1971	1,289.30	2.17	36.37	0.8572	1,437
1972	315.15	2.20	9.01	0.8470	347
1973	313.85	2.23	9.10	0.8362	341
1974	1,452.23	2.27	42.86	0.8286	1,564
1975	716.05	2.30	21.41	0.8165	760
1976	265,169.61	2.34	8,066.46	0.8073	278,293
1977	622,689.76	2.37	19,185.07	0.7940	642,740
1978	660,174.78	2.41	20,683.28	0.7832	672,164
1979	951,888.78	2.44	30,193.91	0.7686	951,108
1980	829,812.36	2.48	26,753.15	0.7564	815,971
1981	989,252.92	2.52	32,407.93	0.7434	956,034
1982	610,631.44	2.55	20,242.43	0.7268	576,949
1983	537,474.88	2.59	18,096.78	0.7122	497,626
1984	511,478.23	2.63	17,487.44	0.6970	463,450
1985	505,905.62	2.67	17,559.98	0.6808	447,747
1986	495,664.07	2.71	17,462.25	0.6640	427,857
1987	454,042.36	2.75	16,232.01	0.6462	381,423
1988	592,146.36	2.79	21,477.15	0.6278	483,274
1989	794,455.63	2.83	29,228.02	0.6084	628,351
1990	1,061,451.32	2.87	39,602.75	0.5884	811,925
1991	802,765.78	2.92	30,472.99	0.5694	594,223
1992	1,082,358.87	2.96	41,649.17	0.5476	770,510
1993	916,203.27	3.01	35,851.03	0.5268	627,453
1994	828,371.48	3.05	32,844.93	0.5032	541,887
1995	648,132.67	3.10	26,119.75	0.4805	404,856
1996	620,511.44	3.15	25,409.94	0.4568	368,485
1997	598,397.32	3.20	24,893.33	0.4320	336,060
1998	592,328.46	3.26	25,102.88	0.4075	313,786
1999	543,768.59	3.32	23,469.05	0.3818	269,894
2000	354,556.44	3.38	15,579.21	0.3549	163,582
2001	618,903.83	3.45	27,757.84	0.3278	263,740
2002	618,482.85	3.52	28,301.78	0.2992	240,565
2003	894,983.14	3.61	42,001.56	0.2708	315,070
2004	960,025.06	3.70	46,177.21	0.2405	300,152
2005	1,036,330.02	3.80	51,194.70	0.2090	281,571
2006	1,258,414.58	3.92	64,128.81	0.1764	288,580
2007	1,559,314.55	4.07	82,503.33	0.1424	288,660

NEWFOUNDLAND POWER INC.

ACCOUNT 361.13 - O/H CONDUCTOR - W/P ALUMINUM

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 32-R1.5					
NET SALVAGE PERCENT.. -30					
2008	1,642,835.18	4.27	91,193.78	0.1068	228,091
2009	1,572,332.33	4.58	93,616.67	0.0687	140,425
2010	1,755,352.01	5.31	121,171.95	0.0266	60,700
	28,794,084.17		1,264,326.58		15,841,574
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.39					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.14 - O/H CONDUCTOR - AERIAL CABLE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 26-R1					
NET SALVAGE PERCENT.. -25					
1972	1,463.00	2.34	42.79	0.9009	1,648
1973	4,618.00	2.38	137.39	0.8925	5,152
1974	752.00	2.42	22.75	0.8833	830
1975	398.00	2.46	12.24	0.8733	434
1976	30,034.00	2.50	938.56	0.8625	32,380
1977	23,553.00	2.54	747.81	0.8509	25,052
1978	9,476.00	2.59	306.79	0.8418	9,971
1979	265.00	2.63	8.71	0.8284	274
1981	14,897.00	2.72	506.50	0.8024	14,942
1982	7,182.00	2.77	248.68	0.7894	7,087
1983	53,221.00	2.82	1,876.04	0.7755	51,591
1985	6,323.00	2.92	230.79	0.7446	5,885
1987	176,538.00	3.03	6,686.38	0.7120	157,119
1988	2,787.00	3.08	107.30	0.6930	2,414
1989	123,698.00	3.14	4,855.15	0.6751	104,386
1990	3,192.00	3.20	127.68	0.6560	2,617
1991	26,303.00	3.26	1,071.85	0.6357	20,901
1995	66,308.00	3.52	2,917.55	0.5456	45,222
1998	9,151.00	3.76	430.10	0.4700	5,376
1999	82,684.00	3.85	3,979.17	0.4428	45,766
2000	55,223.00	3.94	2,719.73	0.4137	28,557
2006	11,806.00	4.81	709.84	0.2164	3,194
	709,872.00		28,683.80		570,798

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.04

NEWFOUNDLAND POWER INC.

ACCOUNT 361.15 - O/H CONDUCTOR - DUPLEX, TRIPLEX, QUADRUPLX

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED DEPREC. -- FACTOR (5)	AMOUNT (6)
SURVIVOR CURVE.. IOWA 44-R2					
NET SALVAGE PERCENT.. -30					
1966	18,667.00	1.81	439.23	0.8054	19,545
1967	14,957.00	1.83	355.83	0.7960	15,478
1968	19,574.00	1.85	470.75	0.7862	20,006
1969	16,175.00	1.87	393.21	0.7760	16,317
1970	19,620.00	1.89	482.06	0.7654	19,522
1971	15,087.00	1.91	374.61	0.7544	14,796
1972	27,612.00	1.93	692.79	0.7430	26,670
1973	27,336.00	1.95	692.97	0.7312	25,985
1974	23,029.00	1.97	589.77	0.7190	21,525
1975	31,459.00	1.99	813.84	0.7064	28,889
1976	30,055.00	2.01	785.34	0.6934	27,092
1977	27,591.00	2.03	728.13	0.6800	24,390
1978	44,880.00	2.05	1,196.05	0.6662	38,869
1979	48,020.00	2.07	1,292.22	0.6520	40,702
1980	41,804.00	2.09	1,135.81	0.6374	34,640
1981	55,228.00	2.11	1,514.90	0.6224	44,686
1982	62,320.00	2.13	1,725.64	0.6070	49,177
1983	68,089.00	2.15	1,903.09	0.5912	52,330
1984	84,937.00	2.18	2,407.11	0.5777	63,789
1985	61,877.00	2.20	1,769.68	0.5610	45,127
1986	103,642.00	2.22	2,991.11	0.5439	73,282
1987	109,958.00	2.24	3,201.98	0.5264	75,246
1988	78,735.00	2.26	2,313.23	0.5085	52,048
1989	93,468.00	2.29	2,782.54	0.4924	59,831
1990	71,998.00	2.31	2,162.10	0.4736	44,328
1991	80,732.00	2.33	2,445.37	0.4544	47,690
1992	68,618.00	2.36	2,105.20	0.4366	38,946
1993	93,883.00	2.38	2,904.74	0.4165	50,833
1994	65,564.00	2.41	2,054.12	0.3976	33,889
1995	70,487.00	2.43	2,226.68	0.3766	34,509
1996	34,083.00	2.46	1,089.97	0.3567	15,805
1997	65,395.00	2.49	2,116.84	0.3362	28,582
1998	59,147.00	2.52	1,937.66	0.3150	24,221
1999	92,753.00	2.55	3,074.76	0.2932	35,354
2000	133,476.00	2.58	4,476.79	0.2709	47,006
2001	162,951.00	2.61	5,528.93	0.2480	52,535
2002	187,023.00	2.65	6,442.94	0.2252	54,753
2003	156,593.00	2.69	5,476.06	0.2018	41,081
2004	173,267.95	2.73	6,149.28	0.1774	39,959
2005	217,035.00	2.77	7,815.43	0.1524	42,999
2006	265,613.00	2.83	9,771.90	0.1274	43,991
2007	234,609.00	2.89	8,814.26	0.1012	30,865
2008	338,918.58	2.98	13,129.71	0.0745	32,824

NEWFOUNDLAND POWER INC.

ACCOUNT 361.15 - O/H CONDUCTOR - DUPLEX, TRIPLEX, QUADRUPLX

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 44-R2					
NET SALVAGE PERCENT.. -30					
2009	518,196.75	3.10	20,883.33	0.0465	31,325
2010	603,267.57	3.39	26,586.00	0.0170	13,332
	4,817,730.85		168,243.96		1,674,769
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.49					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.20 - DISTRIBUTION - UNDERGROUND CABLE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -5					
1966	149,962.00	1.88	2,960.25	0.8366	131,731
1967	208,895.00	1.90	4,167.46	0.8265	181,284
1968	132,244.00	1.92	2,666.04	0.8160	113,307
1969	99,036.00	1.94	2,017.36	0.8051	83,721
1970	117,745.00	1.96	2,423.19	0.7938	98,139
1971	106,663.00	1.98	2,217.52	0.7821	87,592
1972	146,270.00	2.00	3,071.67	0.7700	118,259
1973	98,027.00	2.02	2,079.15	0.7575	77,968
1974	264,780.00	2.04	5,671.59	0.7446	207,013
1975	260,967.00	2.06	5,644.72	0.7313	200,387
1976	242,548.00	2.07	5,271.78	0.7142	181,889
1977	302,581.00	2.09	6,640.14	0.7002	222,461
1978	500,618.00	2.11	11,091.19	0.6858	360,490
1979	107,402.00	2.13	2,402.05	0.6710	75,670
1980	655,606.00	2.14	14,731.47	0.6527	449,310
1981	470,883.00	2.16	10,679.63	0.6372	315,049
1982	306,894.00	2.18	7,024.80	0.6213	200,207
1983	315,848.00	2.19	7,262.92	0.6022	199,714
1984	447,265.00	2.21	10,378.78	0.5856	275,014
1985	391,392.00	2.22	9,123.35	0.5661	232,645
1986	1,284,106.00	2.24	30,202.17	0.5488	739,953
1987	704,228.00	2.26	16,711.33	0.5311	392,716
1988	829,335.00	2.27	19,767.20	0.5108	444,806
1989	1,173,790.00	2.29	28,223.78	0.4924	606,873
1990	747,039.00	2.30	18,040.99	0.4715	369,840
1991	1,052,181.00	2.32	25,631.13	0.4524	499,807
1992	860,797.00	2.33	21,059.40	0.4310	389,554
1993	609,181.00	2.35	15,031.54	0.4112	263,020
1994	410,062.00	2.36	10,161.34	0.3894	167,662
1995	489,128.00	2.37	12,171.95	0.3674	188,691
1996	307,501.00	2.39	7,716.74	0.3466	111,909
1997	291,813.00	2.40	7,353.69	0.3240	99,275
1998	261,543.00	2.41	6,618.35	0.3012	82,716
1999	233,208.00	2.43	5,950.30	0.2794	68,416
2000	242,855.00	2.44	6,221.95	0.2562	65,330
2001	344,594.00	2.45	8,864.68	0.2328	84,233
2002	481,256.00	2.46	12,430.84	0.2091	105,662
2003	624,851.00	2.48	16,271.12	0.1860	122,033
2004	607,036.26	2.49	15,870.96	0.1618	103,129
2005	667,352.00	2.50	17,517.99	0.1375	96,349
2006	404,149.00	2.52	10,693.78	0.1134	48,122
2007	466,960.00	2.53	12,404.79	0.0886	43,441
2008	387,589.07	2.55	10,377.70	0.0638	25,965

NEWFOUNDLAND POWER INC.

ACCOUNT 361.20 - DISTRIBUTION - UNDERGROUND CABLE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -5					
2009	1,098,064.16	2.57	29,631.26	0.0386	44,505
2010	985,388.95	2.62	27,108.05	0.0131	13,554
	20,889,633.44		509,558.09		8,989,411
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.44					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.30 - DISTRIBUTION - SPECIAL INSUL. COPPER CABLE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 26-R1					
NET SALVAGE PERCENT.. -25					
1977	11,698.00	2.54	371.41	0.8509	12,442
1978	9,008.00	2.59	291.63	0.8418	9,479
1982	44,266.00	2.77	1,532.71	0.7894	43,679
1983	36,950.00	2.82	1,302.49	0.7755	35,818
1984	154.00	2.87	5.52	0.7606	146
	102,076.00		3,503.76		101,564
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.43					

NEWFOUNDLAND POWER INC.

ACCOUNT 361.40 - DISTRIBUTION - SUBMARINE CABLE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-R3					
NET SALVAGE PERCENT.. 0					
1965	23,650.00	1.96	463.54	0.8918	21,091
1988	1,951,898.00	2.51	48,992.64	0.5648	1,102,432
1990	1,472,083.00	2.55	37,538.12	0.5228	769,605
2005	83,769.33	2.80	2,345.54	0.1540	12,900
2008	75,849.14	2.86	2,169.29	0.0715	5,423
	3,607,249.47		91,509.13		1,911,451
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.54					

NEWFOUNDLAND POWER INC.

ACCOUNT 362.10 - DISTRIBUTION - POLES (UNDER 35')

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 48-R1.5					
NET SALVAGE PERCENT.. -25					
1962	293,977.00	1.61	5,916.29	0.7808	286,922
1963	350,688.29	1.62	7,101.44	0.7695	337,318
1964	357,126.75	1.64	7,321.10	0.7626	340,431
1965	640,452.36	1.66	13,289.39	0.7553	604,667
1966	356,373.19	1.67	7,439.29	0.7432	331,071
1967	177,064.18	1.69	3,740.48	0.7352	162,722
1968	148,834.57	1.71	3,181.34	0.7268	135,216
1969	281,650.11	1.72	6,055.48	0.7138	251,302
1970	208,377.80	1.74	4,532.22	0.7047	183,555
1971	422,931.46	1.76	9,304.49	0.6952	367,527
1972	339,550.18	1.77	7,512.55	0.6814	289,212
1973	571,192.69	1.79	12,780.44	0.6712	479,231
1974	661,101.13	1.81	14,957.41	0.6606	545,904
1975	792,417.66	1.83	18,126.55	0.6496	643,443
1976	1,719,247.42	1.85	39,757.60	0.6382	1,371,530
1977	935,065.92	1.86	21,740.28	0.6231	728,299
1978	884,453.79	1.88	20,784.66	0.6110	675,502
1979	1,136,039.90	1.90	26,980.95	0.5985	849,900
1980	846,926.23	1.92	20,326.23	0.5856	619,950
1981	1,683,619.57	1.94	40,827.77	0.5723	1,204,419
1982	1,146,985.64	1.96	28,101.15	0.5586	800,883
1983	1,367,244.65	1.98	33,839.31	0.5445	930,581
1984	1,566,980.63	2.00	39,174.52	0.5300	1,038,125
1985	1,394,997.02	2.02	35,223.67	0.5151	898,204
1986	1,594,078.03	2.04	40,648.99	0.4998	995,900
1987	1,710,331.34	2.06	44,041.03	0.4841	1,034,964
1988	1,792,195.28	2.08	46,597.08	0.4680	1,048,434
1989	1,940,222.41	2.11	51,173.37	0.4536	1,100,106
1990	2,395,493.00	2.13	63,780.00	0.4366	1,307,340
1991	2,095,325.39	2.15	56,311.87	0.4192	1,097,951
1992	2,470,082.57	2.18	67,309.75	0.4033	1,245,230
1993	2,772,041.99	2.21	76,577.66	0.3868	1,340,282
1994	1,855,083.37	2.23	51,710.45	0.3680	853,338
1995	2,668,164.79	2.26	75,375.66	0.3503	1,168,323
1996	2,000,112.38	2.29	57,253.22	0.3320	830,047
1997	1,318,430.78	2.32	38,234.49	0.3132	516,166
1998	1,211,727.02	2.36	35,745.95	0.2950	446,824
1999	1,713,590.54	2.39	51,193.52	0.2748	588,618
2000	1,664,862.32	2.43	50,570.19	0.2552	531,091
2001	1,890,896.11	2.48	58,617.78	0.2356	556,869
2002	1,377,207.91	2.52	43,382.05	0.2142	368,747
2003	1,761,436.86	2.57	56,586.16	0.1928	424,506

NEWFOUNDLAND POWER INC.

ACCOUNT 362.10 - DISTRIBUTION - POLES (UNDER 35')

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 48-R1.5					
NET SALVAGE PERCENT.. -25					
2004	2,053,010.48	2.63	67,492.72	0.1710	438,831
2005	1,504,901.81	2.70	50,790.44	0.1485	279,347
2006	2,046,297.86	2.78	71,108.85	0.1251	319,990
2007	1,568,855.01	2.87	56,282.67	0.1004	196,891
2008	1,501,112.80	3.00	56,291.73	0.0750	140,729
2009	2,319,861.61	3.20	92,794.46	0.0480	139,192
2010	386,168.46	3.69	17,812.02	0.0184	8,882
	63,894,788.26		1,805,696.72		31,054,512
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.83					

NEWFOUNDLAND POWER INC.

ACCOUNT 362.20 - DISTRIBUTION - POLES (35' & OVER)

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 48-R1.5					
NET SALVAGE PERCENT.. -25					
1964	275,462.67	1.64	5,646.98	0.7626	262,585
1965	1,559,758.38	1.66	32,364.99	0.7553	1,472,607
1966	1,255,191.79	1.67	26,202.13	0.7432	1,166,073
1967	442,818.57	1.69	9,354.54	0.7352	406,950
1968	388,510.89	1.71	8,304.42	0.7268	352,962
1969	882,421.56	1.72	18,972.06	0.7138	787,341
1970	609,666.92	1.74	13,260.26	0.7047	537,040
1971	1,038,773.91	1.76	22,853.03	0.6952	902,695
1972	906,633.89	1.77	20,059.27	0.6814	772,225
1973	1,190,107.84	1.79	26,628.66	0.6712	998,500
1974	1,713,019.03	1.81	38,757.06	0.6606	1,414,525
1975	2,881,931.83	1.83	65,924.19	0.6496	2,340,129
1976	1,790,897.12	1.85	41,414.50	0.6382	1,428,688
1977	2,930,768.11	1.86	68,140.36	0.6231	2,282,702
1978	3,118,241.57	1.88	73,278.68	0.6110	2,381,557
1979	3,247,951.90	1.90	77,138.86	0.5985	2,429,874
1980	4,735,046.71	1.92	113,641.12	0.5856	3,466,054
1981	3,564,651.93	1.94	86,442.81	0.5723	2,550,063
1982	4,091,052.80	1.96	100,230.79	0.5586	2,856,578
1983	4,128,127.85	1.98	102,171.16	0.5445	2,809,707
1984	5,794,855.59	2.00	144,871.39	0.5300	3,839,092
1985	5,150,617.80	2.02	130,053.10	0.5151	3,316,354
1986	5,745,584.31	2.04	146,512.40	0.4998	3,589,554
1987	6,769,961.85	2.06	174,326.52	0.4841	4,096,673
1988	6,597,810.07	2.08	171,543.06	0.4680	3,859,719
1989	7,730,680.97	2.11	203,896.71	0.4536	4,383,296
1990	10,246,936.32	2.13	272,824.68	0.4366	5,592,265
1991	9,042,874.70	2.15	243,027.26	0.4192	4,738,466
1992	9,054,868.40	2.18	246,745.16	0.4033	4,564,786
1993	8,340,429.50	2.21	230,404.36	0.3868	4,032,598
1994	8,487,232.47	2.23	236,581.61	0.3680	3,904,127
1995	7,966,073.21	2.26	225,041.57	0.3503	3,488,144
1996	7,272,784.72	2.29	208,183.46	0.3320	3,018,206
1997	5,693,456.38	2.32	165,110.24	0.3132	2,228,988
1998	6,738,067.40	2.36	198,772.99	0.2950	2,484,662
1999	6,145,430.40	2.39	183,594.73	0.2748	2,110,955
2000	8,229,771.96	2.43	249,979.32	0.2552	2,625,297
2001	8,154,986.55	2.48	252,804.58	0.2356	2,401,644
2002	7,709,882.23	2.52	242,861.29	0.2142	2,064,321
2003	7,681,794.67	2.57	246,777.65	0.1928	1,851,313
2004	8,417,298.35	2.63	276,718.68	0.1710	1,799,198
2005	9,010,145.50	2.70	304,092.41	0.1485	1,672,508

NEWFOUNDLAND POWER INC.

ACCOUNT 362.20 - DISTRIBUTION - POLES (35' & OVER)

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 48-R1.5					
NET SALVAGE PERCENT.. -25					
2006	11,731,217.99	2.78	407,659.83	0.1251	1,834,469
2007	9,821,139.31	2.87	352,333.37	0.1004	1,232,553
2008	10,740,472.45	3.00	402,767.72	0.0750	1,006,919
2009	11,224,758.17	3.20	448,990.33	0.0480	673,485
2010	14,968,729.46	3.69	690,432.65	0.0184	344,281
	265,218,896.00		8,007,692.94		108,372,728
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.02					

NEWFOUNDLAND POWER INC.

ACCOUNT 362.30 - DISTRIBUTION - POLES - CONCRETE & STEEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-R2.5					
NET SALVAGE PERCENT.. -25					
1966	11,927.90	1.94	289.25	0.8633	12,872
1967	125.88	1.96	3.08	0.8526	134
1971	43,553.32	2.06	1,121.50	0.8137	44,299
1972	56,524.95	2.09	1,476.71	0.8046	56,850
1973	68,010.62	2.11	1,793.78	0.7912	67,263
1974	58,434.23	2.14	1,563.12	0.7811	57,054
1975	134,187.76	2.16	3,623.07	0.7668	128,619
1976	105,140.96	2.19	2,878.23	0.7556	99,306
1977	80,122.00	2.21	2,213.37	0.7404	74,153
1978	77,678.11	2.24	2,174.99	0.7280	70,687
1979	68,891.00	2.26	1,946.17	0.7119	61,304
1980	144,424.43	2.28	4,116.10	0.6954	125,541
1981	223,497.00	2.31	6,453.48	0.6814	190,364
1982	123,437.00	2.33	3,595.10	0.6640	102,453
1983	19,227.00	2.36	567.20	0.6490	15,598
1984	216,724.52	2.38	6,447.55	0.6307	170,860
1985	143,403.04	2.40	4,302.09	0.6120	109,703
1986	318,190.02	2.43	9,665.02	0.5954	236,813
1987	206,777.00	2.45	6,332.55	0.5758	148,828
1988	254,251.00	2.47	7,850.00	0.5558	176,641
1989	332,270.00	2.50	10,383.44	0.5375	223,244
1990	224,937.00	2.52	7,085.52	0.5166	145,253
1991	213,222.17	2.54	6,769.80	0.4953	132,011
1992	287,484.67	2.57	9,235.45	0.4754	170,838
1993	319,839.78	2.59	10,354.81	0.4532	181,189
1994	243,714.24	2.61	7,951.18	0.4306	131,179
1995	181,535.84	2.64	5,990.68	0.4092	92,856
1996	206,899.70	2.66	6,879.42	0.3857	99,752
1997	152,310.00	2.69	5,121.42	0.3632	69,149
1998	111,497.00	2.71	3,776.96	0.3388	47,219
1999	88,105.40	2.74	3,017.61	0.3151	34,703
2000	90,967.00	2.76	3,138.36	0.2898	32,953
2001	67,967.74	2.79	2,370.37	0.2650	22,514
2002	132,302.00	2.82	4,663.65	0.2397	39,641
2003	133,167.02	2.85	4,744.08	0.2138	35,589
2004	236,472.06	2.88	8,512.99	0.1872	55,334
2005	249,808.76	2.91	9,086.79	0.1600	49,962
2006	161,924.34	2.95	5,970.96	0.1328	26,879
2007	223,946.36	3.00	8,397.99	0.1050	29,393

NEWFOUNDLAND POWER INC.

ACCOUNT 362.30 - DISTRIBUTION - POLES - CONCRETE & STEEL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-R2.5					
NET SALVAGE PERCENT.. -25					
2008	308,357.32	3.05	11,756.12	0.0762	29,371
2009	339,051.46	3.14	13,307.77	0.0471	19,962
2010	238,653.37	3.33	9,933.95	0.0166	4,952
	6,898,960.97		226,861.68		3,623,285

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 3.29

NEWFOUNDLAND POWER INC.

ACCOUNT 362.40 - DISTRIBUTION - STEEL TOWERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2011

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -25					
1980	184,774.00	2.14	4,942.70	0.6527	150,752
	184,774.00		4,942.70		150,752
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 2.67					

NEWFOUNDLAND POWER INC.

ACCOUNT 363.00 - DISTRIBUTION - STREET LIGHTS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 20-R0.5					
NET SALVAGE PERCENT.. -10					
1980	89,070.74	2.91	2,851.15	0.8876	86,965
1981	397,529.77	2.96	12,943.57	0.8732	381,835
1982	255,868.96	3.02	8,499.97	0.8607	242,249
1983	129,179.03	3.08	4,376.59	0.8470	120,356
1984	388,046.47	3.14	13,403.13	0.8321	355,183
1985	715,205.07	3.21	25,253.89	0.8186	644,014
1986	969,665.09	3.28	34,985.52	0.8036	857,145
1987	747,994.95	3.35	27,563.61	0.7872	647,704
1988	426,945.27	3.42	16,061.68	0.7695	361,388
1989	544,532.73	3.50	20,964.51	0.7525	450,737
1990	598,312.50	3.58	23,561.55	0.7339	483,012
1991	864,292.29	3.66	34,796.41	0.7137	678,530
1992	716,071.12	3.75	29,537.93	0.6938	546,491
1993	692,108.49	3.84	29,234.66	0.6720	511,607
1994	568,036.18	3.94	24,618.69	0.6501	406,208
1995	319,912.32	4.04	14,216.90	0.6262	220,362
1996	1,056,325.53	4.14	48,105.06	0.6003	697,523
1997	659,353.32	4.26	30,897.30	0.5751	417,114
1998	231,089.39	4.38	11,133.89	0.5475	139,174
1999	111,383.65	4.51	5,525.74	0.5186	63,540
2000	240,144.67	4.66	12,309.82	0.4893	129,253
2001	359,725.68	4.81	19,033.09	0.4570	180,834
2002	401,563.43	4.99	22,041.82	0.4242	187,378
2003	506,939.04	5.19	28,941.15	0.3892	217,031
2004	530,190.76	5.42	31,609.97	0.3523	205,465
2005	738,216.26	5.70	46,286.16	0.3135	254,574
2006	785,982.78	6.04	52,220.70	0.2718	234,993
2007	1,084,029.38	6.47	77,150.37	0.2264	269,967
2008	1,055,476.32	7.06	81,968.29	0.1765	204,921
2009	1,776,766.08	8.00	156,355.42	0.1200	234,533
2010	1,951,127.01	10.43	223,852.80	0.0522	112,034
19,911,084.28		1,170,301.34		10,542,120	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.88

NEWFOUNDLAND POWER INC.

ACCOUNT 364.10 - DISTRIBUTION - TRANSFORMERS (UPTO 15 KVA)

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
1963	0.04			0.8408	0
1965	24,139.80	1.81	445.67	0.8236	20,279
1967	12,444.34	1.86	236.09	0.8091	10,270
1968	22,166.26	1.88	425.06	0.7990	18,065
1969	55,439.67	1.90	1,074.42	0.7885	44,588
1970	0.38	1.93	0.01	0.7816	0
1971	22,789.47	1.96	455.61	0.7742	17,996
1972	44,936.78	1.98	907.54	0.7623	34,940
1973	46,629.08	2.01	955.99	0.7538	35,852
1974	52,529.85	2.03	1,087.68	0.7410	39,703
1975	154,396.44	2.06	3,244.18	0.7313	115,168
1976	136,692.78	2.09	2,914.02	0.7210	100,527
1977	83,508.31	2.12	1,805.78	0.7102	60,494
1978	436.40	2.15	9.57	0.6988	311
1980	1.01	2.21	0.02	0.6740	1
1981	15,587.82	2.24	356.15	0.6608	10,506
1982	75,208.76	2.27	1,741.38	0.6470	49,633
1983	63,758.63	2.30	1,495.78	0.6325	41,134
1984	133,190.01	2.34	3,178.98	0.6201	84,243
1985	11,703.08	2.37	282.91	0.6044	7,215
1986	207,398.31	2.40	5,077.11	0.5880	124,389
1987	186,993.85	2.44	4,653.90	0.5734	109,367
1988	6,488.17	2.47	163.46	0.5558	3,678
1989	106,268.80	2.51	2,720.69	0.5396	58,489
1990	91,557.68	2.55	2,381.42	0.5228	48,824
1991	1,566.67	2.58	41.23	0.5031	804
1992	196,226.66	2.62	5,243.96	0.4847	97,013
1993	102,889.03	2.66	2,791.59	0.4655	48,853
1994	40,213.51	2.70	1,107.48	0.4455	18,273
1995	89,752.20	2.73	2,499.24	0.4232	38,743
1996	157,402.58	2.77	4,447.25	0.4016	64,477
1997	190,701.64	2.81	5,465.89	0.3794	73,799
1998	496,640.55	2.85	14,437.34	0.3562	180,441
1999	439,547.45	2.88	12,912.15	0.3312	148,490
2000	759,547.48	2.92	22,622.36	0.3066	237,535
2001	538,034.97	2.96	16,244.35	0.2812	154,321
2002	579,144.31	2.99	17,662.74	0.2542	150,163
2003	568,941.49	3.03	17,583.71	0.2272	131,849
2004	468,065.09	3.06	14,609.25	0.1989	94,960
2005	403,856.00	3.09	12,728.73	0.1700	70,029
2006	444,610.76	3.11	14,103.94	0.1400	63,490
2007	620,925.00	3.14	19,886.99	0.1099	69,604
2008	596,289.43	3.16	19,219.60	0.0790	48,049

NEWFOUNDLAND POWER INC.

ACCOUNT 364.10 - DISTRIBUTION - TRANSFORMERS (UPTO 15 KVA)

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
2009	226,576.24	3.17	7,326.12	0.0476	11,001
2010	330,095.51	3.18	10,706.98	0.0159	5,353
	8,805,292.29		257,254.32		2,742,919
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.92					

NEWFOUNDLAND POWER INC.

ACCOUNT 364.11 - DISTRIBUTION - TRANSFORMERS (OVER 15 KVA)

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
1965	83,379.24	1.81	1,539.35	0.8236	70,045
1967	67,178.02	1.86	1,274.50	0.8091	55,441
1968	59,266.83	1.88	1,136.50	0.7990	48,301
1969	35,397.39	1.90	686.00	0.7885	28,469
1970	9,680.78	1.93	190.58	0.7816	7,718
1971	28,429.33	1.96	568.36	0.7742	22,450
1972	65,326.71	1.98	1,319.34	0.7623	50,795
1973	130,702.97	2.01	2,679.67	0.7538	100,494
1974	206,901.86	2.03	4,284.11	0.7410	156,381
1975	843,046.07	2.06	17,714.08	0.7313	628,850
1976	1,056,399.55	2.09	22,520.33	0.7210	776,897
1977	412,723.12	2.12	8,924.72	0.7102	298,978
1978	332,519.20	2.15	7,292.15	0.6988	237,012
1979	126,311.75	2.18	2,808.67	0.6867	88,473
1980	836,101.77	2.21	18,847.41	0.6740	574,803
1981	889,586.70	2.24	20,325.28	0.6608	599,596
1982	1,033,358.07	2.27	23,926.37	0.6470	681,954
1983	520,830.63	2.30	12,218.69	0.6325	336,014
1984	943,349.63	2.34	22,515.87	0.6201	596,671
1985	450,143.49	2.37	10,881.77	0.6044	277,508
1986	1,578,762.71	2.40	38,648.11	0.5880	946,879
1987	1,535,451.73	2.44	38,214.32	0.5734	898,037
1988	1,755,897.29	2.47	44,238.08	0.5558	995,446
1989	2,386,110.52	2.51	61,089.20	0.5396	1,313,296
1990	3,250,407.97	2.55	84,543.11	0.5228	1,733,300
1991	2,341,934.27	2.58	61,630.34	0.5031	1,201,792
1992	1,134,121.63	2.62	30,308.27	0.4847	560,703
1993	1,178,369.15	2.66	31,971.51	0.4655	559,501
1994	1,079,956.65	2.70	29,742.01	0.4455	490,743
1995	1,384,781.67	2.73	38,560.63	0.4232	597,760
1996	1,340,989.94	2.77	37,888.33	0.4016	549,312
1997	1,684,395.62	2.81	48,278.15	0.3794	651,841
1998	3,137,259.81	2.85	91,200.14	0.3562	1,139,842
1999	3,160,514.96	2.88	92,843.29	0.3312	1,067,698
2000	4,162,286.74	2.92	123,969.55	0.3066	1,301,680
2001	4,315,701.17	2.96	130,299.65	0.2812	1,237,847
2002	4,901,723.41	2.99	149,492.76	0.2542	1,270,938
2003	5,374,840.50	3.03	166,114.82	0.2272	1,245,587
2004	5,303,889.24	3.06	165,544.99	0.1989	1,076,042
2005	4,866,278.69	3.09	153,375.37	0.1700	843,813
2006	5,472,143.62	3.11	173,587.34	0.1400	781,422
2007	6,697,915.06	3.14	214,520.82	0.1099	750,823
2008	8,332,137.63	3.16	268,561.46	0.0790	671,404

NEWFOUNDLAND POWER INC.

ACCOUNT 364.11 - DISTRIBUTION - TRANSFORMERS (OVER 15 KVA)

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
2009	7,010,780.00	3.17	226,686.56	0.0476	340,387
2010	6,741,899.67	3.18	218,680.26	0.0159	109,340
	98,259,182.76		2,901,642.82		27,972,283
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.95					

NEWFOUNDLAND POWER INC.

ACCOUNT 364.20 - DISTRIBUTION - VOLTAGE REGULATORS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
1956	3,400.00	1.63	56.53	0.8884	3,081
1959	7,578.98	1.68	129.87	0.8652	6,688
1960	1,860.00	1.70	32.25	0.8585	1,629
1961	9,353.85	1.72	164.10	0.8514	8,123
1965	2,622.33	1.81	48.41	0.8236	2,203
1968	12,278.33	1.88	235.45	0.7990	10,007
1969	21,142.30	1.90	409.74	0.7885	17,004
1970	60,325.26	1.93	1,187.56	0.7816	48,093
1971	72,408.92	1.96	1,447.60	0.7742	57,180
1972	62,366.31	1.98	1,259.55	0.7623	48,493
1973	51,105.35	2.01	1,047.76	0.7538	39,294
1974	138,486.67	2.03	2,867.50	0.7410	104,671
1975	91,041.36	2.06	1,912.96	0.7313	67,910
1976	65,628.12	2.09	1,399.06	0.7210	48,264
1977	23,266.03	2.12	503.10	0.7102	16,854
1978	4,298.94	2.15	94.28	0.6988	3,064
1979	6,639.44	2.18	147.63	0.6867	4,650
1980	134,294.82	2.21	3,027.27	0.6740	92,325
1981	17,154.87	2.24	391.95	0.6608	11,563
1982	20,548.56	2.27	475.78	0.6470	13,561
1983	71,880.00	2.30	1,686.30	0.6325	46,373
1984	25,428.00	2.34	606.92	0.6201	16,083
1985	243,749.07	2.37	5,892.39	0.6044	150,268
1986	33,792.73	2.40	827.25	0.5880	20,268
1987	190,808.28	2.44	4,748.84	0.5734	111,598
1988	85,335.24	2.47	2,149.94	0.5558	48,378
1989	161,444.00	2.51	4,133.29	0.5396	88,857
1990	148,749.74	2.55	3,868.98	0.5228	79,322
1991	275,194.88	2.58	7,242.03	0.5031	141,220
1992	95,658.87	2.62	2,556.39	0.4847	47,293
1994	193,275.00	2.70	5,322.79	0.4455	87,826
1999	30,312.00	2.88	890.45	0.3312	10,240
2004	61,381.30	3.06	1,915.83	0.1989	12,453
2005	208,180.00	3.09	6,561.42	0.1700	36,098
2006	106,916.00	3.11	3,391.59	0.1400	15,268
2010	266,792.45	3.18	8,653.68	0.0159	4,327
3,004,698.00		77,286.44		1,520,529	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.57

NEWFOUNDLAND POWER INC.

ACCOUNT 364.30 - DISTRIBUTION - CAPACITOR BANKS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
1984	21,730.00	2.34	518.65	0.6201	13,744
1990	3,406.00	2.55	88.59	0.5228	1,816
1991	2,680.00	2.58	70.53	0.5031	1,375
1993	19,978.00	2.66	542.04	0.4655	9,486
1995	4,786.00	2.73	133.27	0.4232	2,066
1997	14,492.00	2.81	415.37	0.3794	5,608
1998	38,064.00	2.85	1,106.52	0.3562	13,830
1999	77,432.00	2.88	2,274.64	0.3312	26,158
2000	20,434.00	2.92	608.61	0.3066	6,390
2008	5,656.85	3.16	182.33	0.0790	456
2009	90,993.49	3.17	2,942.18	0.0476	4,418
	299,652.34		8,882.73		85,347

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.96

NEWFOUNDLAND POWER INC.

ACCOUNT 364.40 - DISTRIBUTION - RECLOSERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 40-S1					
NET SALVAGE PERCENT.. -2					
1973	1.00	2.01	0.02	0.7538	1
1974	1,781.00	2.03	36.88	0.7410	1,346
1976	12,134.30	2.09	258.68	0.7210	8,924
1982	16,164.54	2.27	374.27	0.6470	10,668
1985	3,866.00	2.37	93.46	0.6044	2,383
1986	28,178.00	2.40	689.80	0.5880	16,900
1987	28,565.00	2.44	710.93	0.5734	16,707
1989	50,722.00	2.51	1,298.58	0.5396	27,917
1990	28,048.00	2.55	729.53	0.5228	14,957
1991	16,016.00	2.58	421.48	0.5031	8,219
2000	159,836.00	2.92	4,760.56	0.3066	49,986
2001	273,714.00	2.96	8,263.97	0.2812	78,508
2008	34,942.14	3.16	1,126.26	0.0790	2,816
	653,967.98		18,764.42		239,332
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.87					

NEWFOUNDLAND POWER INC.

ACCOUNT 365.10 - DISTRIBUTION - SERVICES OVERHEAD

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 44-R2					
NET SALVAGE PERCENT.. -60					
1968	99,510.95	1.85	2,945.52	0.7862	125,177
1969	179,885.11	1.87	5,382.16	0.7760	223,345
1970	138,722.68	1.89	4,194.97	0.7654	169,885
1971	309,915.31	1.91	9,471.01	0.7544	374,080
1972	349,850.94	1.93	10,803.40	0.7430	415,903
1973	498,562.24	1.95	15,555.14	0.7312	583,278
1974	656,371.00	1.97	20,688.81	0.7190	755,089
1975	830,250.88	1.99	26,435.19	0.7064	938,383
1976	889,345.77	2.01	28,601.36	0.6934	986,676
1977	933,040.90	2.03	30,305.17	0.6800	1,015,148
1978	1,025,396.61	2.05	33,633.01	0.6662	1,092,991
1979	1,236,997.96	2.07	40,969.37	0.6520	1,290,436
1980	1,347,883.00	2.09	45,073.21	0.6374	1,374,625
1981	1,574,989.26	2.11	53,171.64	0.6224	1,568,437
1982	1,519,669.69	2.13	51,790.34	0.6070	1,475,903
1983	1,856,020.81	2.15	63,847.12	0.5912	1,755,647
1984	2,357,432.03	2.18	82,227.23	0.5777	2,179,022
1985	2,107,451.51	2.20	74,182.29	0.5610	1,891,648
1986	2,203,622.06	2.22	78,272.66	0.5439	1,917,680
1987	2,328,638.24	2.24	83,458.39	0.5264	1,961,272
1988	2,601,328.21	2.26	94,064.03	0.5085	2,116,441
1989	2,917,504.15	2.29	106,897.35	0.4924	2,298,526
1990	2,809,895.31	2.31	103,853.73	0.4736	2,129,226
1991	2,980,935.33	2.33	111,129.27	0.4544	2,167,259
1992	2,915,193.54	2.36	110,077.71	0.4366	2,036,438
1993	2,813,600.63	2.38	107,141.91	0.4165	1,874,983
1994	2,309,556.32	2.41	89,056.49	0.3976	1,469,247
1995	1,913,040.21	2.43	74,379.00	0.3766	1,152,722
1996	1,694,615.89	2.46	66,700.08	0.3567	967,151
1997	1,531,994.69	2.49	61,034.67	0.3362	824,091
1998	1,417,986.30	2.52	57,173.21	0.3150	714,665
1999	1,463,449.08	2.55	59,708.72	0.2932	686,533
2000	1,458,228.06	2.58	60,195.65	0.2709	632,054
2001	1,808,063.07	2.61	75,504.71	0.2480	717,439
2002	1,786,974.61	2.65	75,767.72	0.2252	643,883
2003	1,677,747.79	2.69	72,210.26	0.2018	541,711
2004	1,917,443.47	2.73	83,753.93	0.1774	544,247
2005	2,167,042.63	2.77	96,043.33	0.1524	528,412
2006	2,219,642.50	2.83	100,505.41	0.1274	452,452
2007	2,369,201.72	2.89	109,551.89	0.1012	383,621
2008	3,134,324.34	2.98	149,444.58	0.0745	373,611

NEWFOUNDLAND POWER INC.

ACCOUNT 365.10 - DISTRIBUTION - SERVICES OVERHEAD

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 44-R2					
NET SALVAGE PERCENT.. -60					
2009	3,721,975.32	3.10	184,609.98	0.0465	276,915
2010	4,440,938.28	3.39	240,876.49	0.0170	120,794
	76,514,238.40		3,050,688.11		45,747,046
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.99					

NEWFOUNDLAND POWER INC.

ACCOUNT 365.20 - DISTRIBUTION - SERVICES UNDERGROUND

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -10					
1965	5,690.00	1.86	116.42	0.8463	5,297
1966	10,278.00	1.88	212.55	0.8366	9,458
1967	44,406.00	1.90	928.09	0.8265	40,372
1968	19,627.00	1.92	414.52	0.8160	17,617
1969	13,560.00	1.94	289.37	0.8051	12,009
1970	13,945.00	1.96	300.65	0.7938	12,176
1974	75,003.00	2.04	1,683.07	0.7446	61,432
1975	284,667.00	2.06	6,450.55	0.7313	228,995
1976	119,140.00	2.07	2,712.82	0.7142	93,599
1977	109,660.00	2.09	2,521.08	0.7002	84,462
1978	34,576.00	2.11	802.51	0.6858	26,083
1979	52,990.00	2.13	1,241.56	0.6710	39,112
1980	134,057.00	2.14	3,155.70	0.6527	96,249
1981	83,751.00	2.16	1,989.92	0.6372	58,703
1982	179,142.00	2.18	4,295.83	0.6213	122,431
1983	69,183.00	2.19	1,666.62	0.6022	45,828
1984	134,754.00	2.21	3,275.87	0.5856	86,803
1985	139,028.00	2.22	3,395.06	0.5661	86,574
1986	64,590.00	2.24	1,591.50	0.5488	38,992
1987	125,196.00	2.26	3,112.37	0.5311	73,141
1988	220,655.00	2.27	5,509.76	0.5108	123,982
1989	295,200.00	2.29	7,436.09	0.4924	159,892
1990	282,563.00	2.30	7,148.84	0.4715	146,551
1991	167,294.00	2.32	4,269.34	0.4524	83,252
1992	159,624.00	2.33	4,091.16	0.4310	75,678
1993	216,632.00	2.35	5,599.94	0.4112	97,987
1994	241,688.00	2.36	6,274.22	0.3894	103,525
1995	262,203.00	2.37	6,835.63	0.3674	105,967
1996	376,219.00	2.39	9,890.80	0.3466	143,437
1997	269,613.00	2.40	7,117.78	0.3240	96,090
1998	14,149.00	2.41	375.09	0.3012	4,688
2000	175,064.00	2.44	4,698.72	0.2562	49,337
2001	72,659.00	2.45	1,958.16	0.2328	18,607
2002	150,357.00	2.46	4,068.66	0.2091	34,584
2003	318,679.00	2.48	8,693.56	0.1860	65,202
2004	251,568.71	2.49	6,890.47	0.1618	44,774
2005	180,630.00	2.50	4,967.32	0.1375	27,320
2006	152,657.00	2.52	4,231.65	0.1134	19,042
2007	344,664.00	2.53	9,592.00	0.0886	33,591
2008	365,769.84	2.55	10,259.84	0.0638	25,670

NEWFOUNDLAND POWER INC.

ACCOUNT 365.20 - DISTRIBUTION - SERVICES UNDERGROUND

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -10					
2009	334,997.11	2.57	9,470.37	0.0386	14,224
2010	307,644.03	2.62	8,866.30	0.0131	4,433
	6,873,772.69		178,401.76		2,717,166
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.60					

NEWFOUNDLAND POWER INC.

ACCOUNT 366.10 - DISTRIBUTION - WATT-HOUR METERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 25-S1					
NET SALVAGE PERCENT.. -5					
1968	0.44	2.25	0.01	0.9562	0
1970	61.13	2.32	1.49	0.9396	60
1972	82,499.83	2.40	2,079.00	0.9240	80,041
1973	119,609.13	2.45	3,076.94	0.9188	115,392
1974	213,403.90	2.49	5,579.44	0.9088	203,639
1975	97,197.87	2.54	2,592.27	0.9017	92,025
1976	209,561.61	2.58	5,677.02	0.8901	195,857
1977	247,077.49	2.63	6,823.04	0.8810	228,559
1978	124,307.68	2.68	3,498.02	0.8710	113,686
1979	107,569.41	2.73	3,083.48	0.8600	97,135
1980	161,696.76	2.78	4,719.93	0.8479	143,958
1981	326,962.73	2.84	9,750.03	0.8378	287,626
1982	154,050.55	2.89	4,674.66	0.8236	133,220
1983	354,671.61	2.95	10,985.95	0.8112	302,095
1984	287,417.82	3.01	9,083.84	0.7976	240,707
1985	336,601.43	3.08	10,885.69	0.7854	277,585
1986	233,566.90	3.14	7,700.70	0.7693	188,667
1987	40,636.92	3.21	1,369.67	0.7544	32,189
1988	298,460.83	3.28	10,278.99	0.7380	231,277
1989	130,633.61	3.35	4,595.04	0.7202	98,786
1990	318,676.61	3.42	11,443.68	0.7011	234,595
1991	219,196.43	3.50	8,055.47	0.6825	157,082
1992	89,431.89	3.58	3,361.74	0.6623	62,192
1993	8,168.41	3.66	313.91	0.6405	5,493
1995	112,004.48	3.83	4,504.26	0.5936	69,810
1996	62,285.86	3.92	2,563.69	0.5684	37,173
1997	16,208.84	4.01	682.47	0.5414	9,214
1998	235,535.46	4.10	10,139.80	0.5125	126,748
1999	422,084.57	4.20	18,613.93	0.4830	214,060
2000	373,277.04	4.29	16,814.26	0.4504	176,530
2001	241,590.33	4.39	11,136.11	0.4170	105,780
2002	406,952.40	4.49	19,185.77	0.3816	163,058
2003	433,655.57	4.59	20,900.03	0.3442	156,727
2004	963,474.79	4.68	47,345.15	0.3042	307,743
2005	1,015,457.50	4.77	50,859.19	0.2624	279,779
2006	1,091,786.37	4.86	55,713.86	0.2187	250,712
2007	628,016.66	4.93	32,509.28	0.1726	113,815
2008	1,182,562.51	5.00	62,084.53	0.1250	155,211

NEWFOUNDLAND POWER INC.

ACCOUNT 366.10 - DISTRIBUTION - WATT-HOUR METERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 25-S1					
NET SALVAGE PERCENT.. -5					
2009	1,503,296.94	5.06	79,870.17	0.0759	119,805
2010	1,241,060.48	5.09	66,328.48	0.0254	33,099
	14,090,710.79		628,880.99		5,841,130
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.46					

NEWFOUNDLAND POWER INC.

ACCOUNT 366.20 - DISTRIBUTION - DEMAND METERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 22-S0.5					
NET SALVAGE PERCENT.. -5					
1970	0.35	2.40	0.01	0.9720	0
1972	0.30	2.48	0.01	0.9548	0
1973	0.31	2.52	0.01	0.9450	0
1974	0.45	2.57	0.01	0.9380	0
1976	72,161.01	2.66	2,015.46	0.9177	69,533
1977	56,532.05	2.71	1,608.62	0.9078	53,886
1978	89,233.27	2.76	2,585.98	0.8970	84,044
1979	47,234.16	2.82	1,398.60	0.8883	44,056
1980	114,880.93	2.87	3,461.94	0.8754	105,595
1981	187,997.78	2.93	5,783.75	0.8644	170,631
1982	45,639.39	2.99	1,432.85	0.8522	40,839
1983	107,831.35	3.05	3,453.30	0.8388	94,971
1984	22,130.44	3.12	724.99	0.8268	19,212
1986	119,382.39	3.26	4,086.46	0.7987	100,118
1987	246,379.28	3.33	8,614.65	0.7826	202,457
1988	1,513.18	3.41	54.18	0.7672	1,219
1989	0.05			0.7504	0
1991	0.43	3.66	0.02	0.7137	0
1992	25,935.73	3.75	1,021.22	0.6938	18,894
1993	53,216.23	3.84	2,145.68	0.6720	37,549
1994	47,734.51	3.94	1,974.78	0.6501	32,584
1995	71,237.60	4.05	3,029.38	0.6278	46,959
1996	30,614.57	4.16	1,337.24	0.6032	19,390
1997	18,727.51	4.27	839.65	0.5764	11,334
1998	21,184.69	4.39	976.51	0.5488	12,207
1999	82,806.67	4.52	3,930.00	0.5198	45,195
2000	139,806.83	4.65	6,826.07	0.4882	71,666
2001	181,570.55	4.78	9,113.03	0.4541	86,574
2002	129,105.24	4.93	6,683.13	0.4190	56,800
2003	447,251.34	5.08	23,856.39	0.3810	178,923
2004	294,214.51	5.24	16,187.68	0.3406	105,220
2005	281,659.67	5.41	15,999.68	0.2976	88,013
2006	339,099.39	5.59	19,903.44	0.2516	89,583
2007	468,463.22	5.78	28,431.03	0.2023	99,509
2008	197,400.88	5.98	12,394.80	0.1495	30,987
2009	453,752.86	6.21	29,586.96	0.0932	44,404
2010	797,969.59	6.48	54,293.85	0.0324	27,147
5,192,668.71		273,751.36		2,089,499	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.27

NEWFOUNDLAND POWER INC.

ACCOUNT 366.30 - DISTRIBUTION - INSTRUMENT TRANSFORMERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 36-R2.5					
NET SALVAGE PERCENT.. -5					
1958	3.33	1.79	0.06	0.9398	3
1959	6,643.23	1.81	126.25	0.9322	6,502
1960	4,979.41	1.84	96.20	0.9292	4,858
1961	2,061.70	1.87	40.48	0.9256	2,004
1962	5,464.91	1.90	109.02	0.9215	5,288
1963	10,057.65	1.92	202.76	0.9120	9,631
1964	4,797.83	1.95	98.24	0.9068	4,568
1965	7,515.12	1.98	156.24	0.9009	7,109
1966	13,071.34	2.01	275.87	0.8944	12,276
1967	12,981.16	2.04	278.06	0.8874	12,095
1968	14,790.83	2.08	323.03	0.8840	13,729
1969	9,632.52	2.11	213.41	0.8756	8,856
1970	8,090.53	2.14	181.79	0.8667	7,363
1971	12,502.73	2.17	284.87	0.8572	11,253
1972	8,480.96	2.20	195.91	0.8470	7,543
1973	26,972.40	2.23	631.56	0.8362	23,682
1974	30,026.62	2.26	712.53	0.8249	26,007
1975	42,387.20	2.30	1,023.65	0.8165	36,340
1976	41,324.71	2.33	1,011.01	0.8038	34,878
1977	41,468.60	2.36	1,027.59	0.7906	34,424
1978	35,097.62	2.39	880.77	0.7768	28,627
1979	50,980.03	2.42	1,295.40	0.7623	40,805
1980	60,816.00	2.45	1,564.49	0.7472	47,714
1981	51,478.97	2.48	1,340.51	0.7316	39,545
1982	14,584.64	2.51	384.38	0.7154	10,956
1983	44,133.80	2.54	1,177.05	0.6985	32,369
1984	100,578.38	2.57	2,714.11	0.6810	71,919
1985	75,507.81	2.60	2,061.36	0.6630	52,565
1986	77,370.14	2.62	2,128.45	0.6419	52,147
1987	94,289.76	2.65	2,623.61	0.6228	61,660
1988	69,025.96	2.68	1,942.39	0.6030	43,704
1989	81,232.04	2.71	2,311.46	0.5826	49,692
1990	96,650.83	2.74	2,780.64	0.5617	57,003
1991	75,502.55	2.77	2,195.99	0.5402	42,826
1992	42,594.29	2.80	1,252.27	0.5180	23,167
1993	2,193.00	2.83	65.16	0.4952	1,140
1994	22,932.07	2.85	686.24	0.4702	11,322
1995	26,645.71	2.88	805.77	0.4464	12,489
1996	31,926.68	2.91	975.52	0.4220	14,147
1997	19,275.04	2.94	595.02	0.3969	8,033
1998	22,513.00	2.97	702.07	0.3712	8,775
1999	21,297.92	3.00	670.88	0.3450	7,715
2000	31,631.00	3.03	1,006.34	0.3182	10,568

NEWFOUNDLAND POWER INC.

ACCOUNT 366.30 - DISTRIBUTION - INSTRUMENT TRANSFORMERS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 36-R2.5					
NET SALVAGE PERCENT.. -5					
2001	60,425.05	3.07	1,947.80	0.2916	18,501
2002	70,056.56	3.10	2,280.34	0.2635	19,383
2003	47,980.57	3.14	1,581.92	0.2355	11,864
2004	63,522.47	3.17	2,114.35	0.2060	13,740
2005	86,594.62	3.21	2,918.67	0.1766	16,057
2006	58,447.10	3.26	2,000.64	0.1467	9,003
2007	86,588.67	3.31	3,009.39	0.1158	10,528
2008	79,835.79	3.37	2,824.99	0.0842	7,058
2009	92,202.93	3.47	3,359.41	0.0520	5,034
2010	82,514.82	3.68	3,188.37	0.0184	1,594
	2,179,678.60		64,374.29		1,110,059
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.95					

NEWFOUNDLAND POWER INC.

ACCOUNT 366.40 - DISTRIBUTION - METERING TANKS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL -- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 36-R2.5					
NET SALVAGE PERCENT.. -5					
1963	0.31	1.92	0.01	0.9120	0
1964	6,643.00	1.95	136.02	0.9068	6,325
1965	6,127.00	1.98	127.38	0.9009	5,796
1966	19,841.00	2.01	418.74	0.8944	18,633
1968	6,844.86	2.08	149.49	0.8840	6,353
1969	1,082.00	2.11	23.97	0.8756	995
1970	24,168.89	2.14	543.07	0.8667	21,995
1971	6,165.84	2.17	140.49	0.8572	5,550
1972	34,228.09	2.20	790.67	0.8470	30,441
1973	6,416.00	2.23	150.23	0.8362	5,633
1974	6,717.73	2.26	159.41	0.8249	5,819
1975	86,786.76	2.30	2,095.90	0.8165	74,404
1976	51,417.00	2.33	1,257.92	0.8038	43,395
1977	73,687.36	2.36	1,825.97	0.7906	61,170
1978	41,856.00	2.39	1,050.38	0.7768	34,139
1979	79,845.30	2.42	2,028.87	0.7623	63,909
1980	14,961.22	2.45	384.88	0.7472	11,738
1981	22,803.00	2.48	593.79	0.7316	17,517
1982	13,215.00	2.51	348.28	0.7154	9,927
1983	23,672.00	2.54	631.33	0.6985	17,362
1984	65,538.02	2.57	1,768.54	0.6810	46,863
1988	54,481.00	2.68	1,533.10	0.6030	34,495
1989	21,181.00	2.71	602.71	0.5826	12,957
1990	87,647.00	2.74	2,521.60	0.5617	51,693
1991	17,213.00	2.77	500.64	0.5402	9,763
1992	158,551.00	2.80	4,661.40	0.5180	86,236
1994	50,424.00	2.85	1,508.94	0.4702	24,895
2001	11,458.00	3.07	369.35	0.2916	3,508
2002	14,228.00	3.10	463.12	0.2635	3,937
2003	13,124.00	3.14	432.70	0.2355	3,245
2004	16,315.01	3.17	543.05	0.2060	3,529
2005	20,336.00	3.21	685.42	0.1766	3,771
2006	10,357.00	3.26	354.52	0.1467	1,595
2007	9,428.00	3.31	327.67	0.1158	1,146
2008	20,936.30	3.37	740.83	0.0842	1,851
	1,097,695.69		29,870.39		730,585

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.72

NEWFOUNDLAND POWER INC.

ACCOUNT 367.10 - DISTRIBUTION - UNDERGROUND DUCTS & MANHOLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. -- AMOUNT (6)
SURVIVOR CURVE.. IOWA 60-R4					
NET SALVAGE PERCENT.. -5					
1947	99,263.00	1.42	1,480.01	0.9017	93,981
1956	68,214.00	1.53	1,095.86	0.8338	59,721
1959	6,158.00	1.56	100.87	0.8034	5,195
1965	30,319.00	1.61	512.54	0.7326	23,322
1966	260,618.00	1.62	4,433.11	0.7209	197,273
1967	84,812.00	1.63	1,451.56	0.7090	63,138
1970	3,592.00	1.65	62.23	0.6682	2,520
1971	7,951.00	1.66	138.59	0.6557	5,474
1972	4,329.00	1.67	75.91	0.6430	2,923
1973	849.00	1.67	14.89	0.6262	558
1974	259,185.00	1.68	4,572.02	0.6132	166,879
1975	109,104.00	1.69	1,936.05	0.6000	68,736
1976	145,315.00	1.69	2,578.61	0.5830	88,955
1977	425,400.00	1.70	7,593.39	0.5695	254,379
1978	43,145.00	1.70	770.14	0.5525	25,029
1979	87,494.00	1.71	1,570.95	0.5386	49,480
1980	720,706.00	1.71	12,940.28	0.5216	394,716
1981	237,784.00	1.72	4,294.38	0.5074	126,684
1982	85,112.00	1.72	1,537.12	0.4902	43,808
1983	40,095.00	1.73	728.33	0.4758	20,031
1984	11,987.00	1.73	217.74	0.4584	5,770
1985	35,115.00	1.73	637.86	0.4412	16,267
1986	432,264.00	1.74	7,897.46	0.4263	193,488
1987	54,460.00	1.74	994.98	0.4089	23,382
1989	31,569.00	1.75	580.08	0.3762	12,470
1990	43,291.00	1.75	795.47	0.3588	16,309
1991	601,034.00	1.75	11,044.00	0.3412	215,326
1992	261,001.00	1.75	4,795.89	0.3238	88,738
1993	34,895.00	1.76	644.86	0.3080	11,285
1994	17,571.00	1.76	324.71	0.2904	5,358
1996	24,634.00	1.76	455.24	0.2552	6,601
2000	83,314.00	1.76	1,539.64	0.1848	16,166
2001	47,167.00	1.77	876.60	0.1682	8,330
2002	193,816.00	1.77	3,602.07	0.1504	30,607
2003	179,777.00	1.77	3,341.16	0.1328	25,068
2004	62,954.10	1.77	1,170.00	0.1150	7,602
2005	70,347.00	1.77	1,307.40	0.0974	7,194
2006	48,085.00	1.77	893.66	0.0796	4,019
2007	25,821.00	1.77	479.88	0.0620	1,681
2008	98,587.57	1.77	1,832.25	0.0442	4,575

NEWFOUNDLAND POWER INC.

ACCOUNT 367.10 - DISTRIBUTION - UNDERGROUND DUCTS & MANHOLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 60-R4					
NET SALVAGE PERCENT.. -5					
2009	109,063.27	1.77	2,026.94	0.0266	3,046
2010	6,824.42	1.77	126.83	0.0088	63
	5,193,022.36		93,471.56		2,396,147
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 1.80					

NEWFOUNDLAND POWER INC.

ACCOUNT 367.20 - DISTRIBUTION - UNDERGROUND SWITCHES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 45-R3					
NET SALVAGE PERCENT.. -5					
1956	825.00	1.67	14.47	0.9102	788
1960	9,993.00	1.76	184.67	0.8888	9,326
1967	39,940.00	1.90	796.80	0.8265	34,661
1969	30,832.00	1.94	628.05	0.8051	26,064
1972	15,443.00	2.00	324.30	0.7700	12,486
1973	4,874.00	2.02	103.38	0.7575	3,877
1975	15,509.00	2.06	335.46	0.7313	11,909
1986	47,961.00	2.24	1,128.04	0.5488	27,637
1991	141,500.00	2.32	3,446.94	0.4524	67,215
1992	87,047.00	2.33	2,129.60	0.4310	39,393
1998	51,766.78	2.41	1,309.96	0.3012	16,372
1999	103,587.00	2.43	2,643.02	0.2794	30,389
2000	221,146.00	2.44	5,665.76	0.2562	59,490
2001	262,514.00	2.45	6,753.17	0.2328	64,169
2002	134,280.00	2.46	3,468.45	0.2091	29,482
2003	355,740.00	2.48	9,263.47	0.1860	69,476
2004	141,267.74	2.49	3,693.45	0.1618	24,000
2010	77,113.70	2.62	2,121.40	0.0131	1,061
1,741,339.22		44,010.39		527,795	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.53

NEWFOUNDLAND POWER INC.

ACCOUNT 371.10 - BUILDINGS AND STRUCTURES - SMALL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
SURVIVOR CURVE.. IOWA 35-S0					
NET SALVAGE PERCENT.. -5					
1958	2,329.00	1.70	41.57	0.8925	2,183
1959	35,765.00	1.72	645.92	0.8858	33,265
1961	8,951.00	1.76	165.41	0.8712	8,188
1962	2,829.00	1.78	52.87	0.8633	2,564
1963	94,127.02	1.80	1,779.00	0.8550	84,503
1964	68,703.00	1.82	1,312.91	0.8463	61,051
1965	1,805.00	1.84	34.87	0.8372	1,587
1966	17,029.00	1.87	334.36	0.8322	14,880
1967	9,589.00	1.89	190.29	0.8222	8,278
1968	21,228.00	1.91	425.73	0.8118	18,095
1969	23,088.00	1.94	470.30	0.8051	19,518
1970	51,174.00	1.96	1,053.16	0.7938	42,653
1971	19,623.00	1.99	410.02	0.7860	16,195
1972	39,627.00	2.01	836.33	0.7738	32,197
1973	28,754.00	2.04	615.91	0.7650	23,097
1974	84,769.00	2.07	1,842.45	0.7556	67,254
1975	3,581.47	2.10	78.97	0.7455	2,803
1976	36,762.08	2.13	822.18	0.7348	28,363
1977	48,235.00	2.16	1,093.97	0.7236	36,648
1978	63,902.00	2.19	1,469.43	0.7118	47,760
1979	18,697.13	2.22	435.83	0.6993	13,729
1980	4,262.00	2.26	101.14	0.6893	3,085
1981	16,539.00	2.29	397.68	0.6756	11,732
1982	48,886.00	2.33	1,196.00	0.6640	34,083
1983	149,691.00	2.36	3,709.34	0.6490	102,007
1984	69,952.36	2.40	1,762.80	0.6360	46,714
1985	188,493.00	2.44	4,829.19	0.6222	123,144
1986	56,126.00	2.48	1,461.52	0.6076	35,807
1987	59,677.00	2.53	1,585.32	0.5946	37,258
1988	97,616.00	2.57	2,634.17	0.5782	59,264
1989	23,483.00	2.62	646.02	0.5633	13,889
1990	41,655.00	2.66	1,163.42	0.5453	23,850
1991	73,633.00	2.71	2,095.23	0.5284	40,853
1993	2,017.00	2.82	59.72	0.4935	1,045
1994	10,970.00	2.88	331.73	0.4752	5,474
1996	5,864.28	3.00	184.72	0.4350	2,679
1997	41,577.00	3.07	1,340.23	0.4144	18,091
1998	28,304.00	3.14	933.18	0.3925	11,665
1999	36,168.00	3.21	1,219.04	0.3692	14,021
2000	39,637.40	3.29	1,369.27	0.3454	14,375
2001	21,876.64	3.38	776.40	0.3211	7,376
2002	12,779.59	3.46	464.28	0.2941	3,946
2005	897.00	3.77	35.51	0.2074	195

NEWFOUNDLAND POWER INC.

ACCOUNT 371.10 - BUILDINGS AND STRUCTURES - SMALL

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 35-S0					
NET SALVAGE PERCENT.. -5					
2006	19,426.09	3.90	795.50	0.1755	3,580
2007	1,168.00	4.03	49.42	0.1410	173
2008	48,180.15	4.18	2,114.63	0.1045	5,287
2009	6,028.36	4.36	275.98	0.0654	414
2010	97,634.44	4.59	4,705.49	0.0230	2,358
	1,883,109.01		50,348.41		1,187,176
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.67					

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC. AMOUNT (6)
TOPSAIL ROAD - TRANSFORMER SHOP					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2026					
NET SALVAGE PERCENT.. 0					
1957	28,575.00	1.49	425.77	0.7972	22,780
1962	3,343.00	1.60	53.49	0.7760	2,594
1963	10,791.00	1.63	175.89	0.7742	8,354
1966	104,408.00	1.71	1,785.38	0.7610	79,454
1967	647.00	1.74	11.26	0.7569	490
1968	5,519.00	1.77	97.69	0.7522	4,151
1969	264.00	1.80	4.75	0.7470	197
1971	2,609.00	1.86	48.53	0.7347	1,917
1972	8,229.00	1.90	156.35	0.7315	6,020
1973	16,864.00	1.93	325.48	0.7238	12,206
1974	8,878.00	1.97	174.90	0.7190	6,383
1975	13,639.00	2.01	274.14	0.7136	9,733
1977	14,677.00	2.09	306.75	0.7002	10,277
1978	1,665.00	2.14	35.63	0.6955	1,158
1979	19,955.00	2.18	435.02	0.6867	13,703
1980	76,579.00	2.23	1,707.71	0.6802	52,089
1981	66,393.00	2.28	1,513.76	0.6726	44,656
1982	152,875.00	2.33	3,561.99	0.6640	101,509
1984	2,953.00	2.44	72.05	0.6466	1,909
1986	20,475.00	2.57	526.21	0.6296	12,891
1987	17,994.00	2.63	473.24	0.6180	11,120
1988	10,512.00	2.70	283.82	0.6075	6,386
1990	7,407.00	2.86	211.84	0.5863	4,343
1991	11,926.00	2.94	350.62	0.5733	6,837
1992	20,026.00	3.03	606.79	0.5606	11,227
1993	58,970.00	3.12	1,839.86	0.5460	32,198
1994	32,428.00	3.22	1,044.18	0.5313	17,229
1996	8,605.00	3.45	296.87	0.5002	4,304
1997	14,741.00	3.57	526.25	0.4820	7,105
1998	2,534.00	3.70	93.76	0.4625	1,172
1999	6,144.00	3.85	236.54	0.4428	2,721
2000	75,242.00	4.00	3,009.68	0.4200	31,602
2001	67,068.00	4.17	2,796.74	0.3962	26,572
2002	139,445.74	4.35	6,065.89	0.3698	51,567
2003	33,290.00	4.56	1,518.02	0.3420	11,385
2004	47,860.00	4.78	2,287.71	0.3107	14,870
2005	55,375.00	5.03	2,785.36	0.2766	15,317
2006	25,789.00	5.31	1,369.40	0.2390	6,164

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
TOPSAIL ROAD - TRANSFORMER SHOP					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2026					
NET SALVAGE PERCENT.. 0					
2007	3,251.00	5.64	183.36	0.1974	642
2008	5,511.13	6.02	331.77	0.1505	829
	1,203,456.87		38,004.45		656,061

TOPSAIL ROAD - SYSTEM CONTROL CENTER
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2054
NET SALVAGE PERCENT.. 0

1991	3,785.00	1.91	72.29	0.3724	1,410
1999	989,399.00	2.25	22,261.48	0.2588	256,056
2000	19,634.00	2.31	453.55	0.2426	4,763
2001	69,701.00	2.37	1,651.91	0.2252	15,697
2002	33,052.00	2.43	803.16	0.2066	6,829
2003	10,181.00	2.51	255.54	0.1882	1,916
2004	8,220.63	2.59	212.91	0.1684	1,384
2005	12,409.00	2.67	331.32	0.1468	1,822
2006	10,978.00	2.78	305.19	0.1251	1,373
2007	52,055.00	2.90	1,509.60	0.1015	5,284
2008	5,654.92	3.06	173.04	0.0765	433
2009	1,429.76	3.29	47.04	0.0494	71
2010	193,982.95	3.81	7,390.75	0.0190	3,686
	1,410,482.26		35,467.78		300,724

KENMOUNT ROAD
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2046
NET SALVAGE PERCENT.. 0

1969	713,277.24	1.47	10,485.18	0.6100	435,099
1970	6,082.07	1.49	90.62	0.6034	3,670
1971	404.25	1.51	6.10	0.5964	241
1973	2,425.91	1.55	37.60	0.5812	1,410
1975	4,613.00	1.59	73.35	0.5644	2,604
1978	4,063.00	1.66	67.45	0.5395	2,192
1980	2,505,233.20	1.71	42,839.49	0.5216	1,306,730
1981	122,437.00	1.74	2,130.40	0.5133	62,847
1982	24,033.00	1.76	422.98	0.5016	12,055
1983	17,415.00	1.79	311.73	0.4922	8,572

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
KENMOUNT ROAD					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2046					
NET SALVAGE PERCENT.. 0					
1985	2,553.00	1.85	47.23	0.4718	1,205
1986	90,850.58	1.89	1,717.08	0.4630	42,064
1987	683,686.50	1.92	13,126.78	0.4512	308,479
1988	109,874.00	1.95	2,142.54	0.4388	48,213
1990	23,228.00	2.03	471.53	0.4162	9,667
1991	118,155.00	2.07	2,445.81	0.4036	47,687
1992	398,785.74	2.11	8,414.38	0.3904	155,686
1993	97,637.88	2.16	2,108.98	0.3780	36,907
1994	61,449.00	2.20	1,351.88	0.3630	22,306
1995	41,129.00	2.25	925.40	0.3488	14,346
1997	56,016.26	2.36	1,321.98	0.3186	17,847
1998	276,355.00	2.42	6,687.79	0.3025	83,597
1999	80,134.00	2.48	1,987.32	0.2852	22,854
2000	52,480.66	2.55	1,338.26	0.2678	14,054
2002	18,488.00	2.70	499.18	0.2295	4,243
2003	70,436.00	2.78	1,958.12	0.2085	14,686
2004	44,400.10	2.88	1,278.72	0.1872	8,312
2005	147,003.00	2.98	4,380.69	0.1639	24,094
2006	8,923.00	3.10	276.61	0.1395	1,245
2007	32,174.00	3.24	1,042.44	0.1134	3,649
2008	661,783.38	3.42	22,632.99	0.0855	56,582
2009	64,059.28	3.67	2,350.98	0.0550	3,523
2010	589,218.21	4.21	24,806.09	0.0210	12,374
	7,128,803.26		159,777.68		2,789,040

DUFFY PLACE

INTERIM SURVIVOR CURVE.. IOWA 70-R1

PROBABLE RETIREMENT YEAR.. 6-2060

NET SALVAGE PERCENT.. 0

1990	9,496,830.00	1.79	169,993.26	0.3670	3,485,337
1991	94,221.00	1.82	1,714.82	0.3549	33,439
1992	3,706.00	1.85	68.56	0.3422	1,268
1993	6,936.00	1.89	131.09	0.3308	2,294
1994	44,508.00	1.92	854.55	0.3168	14,100
1995	20,084.00	1.96	393.65	0.3038	6,102
1996	23,539.00	2.00	470.78	0.2900	6,826
1997	47,264.00	2.04	964.19	0.2754	13,017
1998	75,022.00	2.08	1,560.46	0.2600	19,506
1999	173,897.00	2.13	3,704.01	0.2450	42,605

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
DUFFY PLACE					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2060					
NET SALVAGE PERCENT.. 0					
2000	609,123.23	2.18	13,278.89	0.2289	139,428
2001	151,471.00	2.24	3,392.95	0.2128	32,233
2002	113,750.00	2.29	2,604.88	0.1946	22,136
2003	83,426.00	2.36	1,968.85	0.1770	14,766
2004	116,272.22	2.43	2,825.41	0.1580	18,371
2005	215,773.00	2.51	5,415.90	0.1380	29,777
2006	611,257.00	2.61	15,953.81	0.1174	71,762
2007	107,939.37	2.73	2,946.74	0.0956	10,319
2008	114,884.98	2.88	3,308.69	0.0720	8,272
2009	90,801.33	3.09	2,805.76	0.0464	4,213
2010	18,711.33	3.61	675.48	0.0180	337
	12,219,416.46		235,032.73		3,976,108

CARBONEAR - OFFICE/WAREHOUSE
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2030
NET SALVAGE PERCENT.. 0

1970	1,526.00	1.73	26.40	0.7006	1,069
1974	2,314.00	1.86	43.04	0.6789	1,571
1977	332,306.00	1.96	6,513.20	0.6566	218,192
1978	10,941.00	2.00	218.82	0.6500	7,112
1979	7,756.00	2.04	158.22	0.6426	4,984
1980	5,329.00	2.08	110.84	0.6344	3,381
1981	34,844.00	2.12	738.69	0.6254	21,791
1984	11,262.00	2.26	254.52	0.5989	6,745
1985	8,460.00	2.31	195.43	0.5890	4,983
1987	238,674.00	2.42	5,775.91	0.5687	135,734
1988	31,368.00	2.48	777.93	0.5580	17,503
1989	676,132.00	2.55	17,241.37	0.5482	370,656
1990	207,760.00	2.61	5,422.54	0.5350	111,152
1991	8,171.00	2.68	218.98	0.5226	4,270
1992	3,672.00	2.75	100.98	0.5088	1,868
1993	26,190.00	2.83	741.18	0.4952	12,969
1996	51,963.00	3.09	1,605.66	0.4480	23,279
1997	8,410.00	3.19	268.28	0.4306	3,621
1998	102,256.74	3.30	3,374.47	0.4125	42,181
2005	4,565.00	4.33	197.66	0.2382	1,087
2006	12,398.00	4.55	564.11	0.2048	2,539
2007	5,802.00	4.80	278.50	0.1680	975

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
CARBONEAR - OFFICE/WAREHOUSE					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2030					
NET SALVAGE PERCENT.. 0					
2008	5,301.98	5.09	269.87	0.1272	674
2009	3,184.16	5.47	174.17	0.0820	261
2010	40,370.26	6.17	2,490.85	0.0308	1,243
	1,840,956.14		47,761.62		999,840

WHITBOURNE
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2023
NET SALVAGE PERCENT.. 0

1973	6,000.00	2.03	121.80	0.7612	4,567
1977	2,351.00	2.21	51.96	0.7404	1,741
1978	225,553.00	2.26	5,097.50	0.7345	165,669
1979	49,742.00	2.31	1,149.04	0.7276	36,192
1980	1,056.00	2.36	24.92	0.7198	760
1982	5,746.00	2.48	142.50	0.7068	4,061
1983	2,890.00	2.54	73.41	0.6985	2,019
1984	8,632.00	2.61	225.30	0.6916	5,970
1985	32.00	2.68	0.86	0.6834	22
1987	17,448.00	2.83	493.78	0.6650	11,603
1988	131,804.00	2.91	3,835.50	0.6548	86,305
1989	8,222.00	3.00	246.66	0.6450	5,303
1990	9,920.00	3.09	306.53	0.6334	6,283
1991	25,854.00	3.19	824.74	0.6220	16,081
1992	3,575.00	3.29	117.62	0.6086	2,176
1996	4,379.00	3.79	165.96	0.5496	2,407
1997	14,652.00	3.94	577.29	0.5319	7,793
1998	72,716.00	4.10	2,981.36	0.5125	37,267
2007	1,977.00	6.56	129.69	0.2296	454
2008	3,262.76	7.06	230.35	0.1765	576
	595,811.76		16,796.77		397,249

SALT POND
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2023
NET SALVAGE PERCENT.. 0

1968	746.00	1.85	13.80	0.7862	587
1969	47,127.00	1.88	885.99	0.7802	36,768

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SALT POND					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2023					
NET SALVAGE PERCENT.. 0					
1970	820.00	1.92	15.74	0.7776	638
1971	1,072.00	1.96	21.01	0.7742	830
1972	11,862.00	1.99	236.05	0.7662	9,089
1974	166,663.00	2.07	3,449.92	0.7556	125,931
1976	8,022.00	2.16	173.28	0.7452	5,978
1977	896.00	2.21	19.80	0.7404	663
1978	30,690.00	2.26	693.59	0.7345	22,542
1979	549.00	2.31	12.68	0.7276	399
1982	6,795.00	2.48	168.52	0.7068	4,803
1984	1,652.00	2.61	43.12	0.6916	1,143
1985	811.00	2.68	21.73	0.6834	554
1986	28,547.00	2.75	785.04	0.6738	19,235
1987	151,842.72	2.83	4,297.15	0.6650	100,975
1988	2,114.00	2.91	61.52	0.6548	1,384
1989	1,322.00	3.00	39.66	0.6450	853
1990	22,374.00	3.09	691.36	0.6334	14,172
1993	41,492.23	3.40	1,410.74	0.5950	24,688
1995	79,070.00	3.65	2,886.06	0.5658	44,738
2002	41,411.65	4.91	2,033.31	0.4174	17,285
2003	4,277.87	5.16	220.74	0.3870	1,656
2004	41,384.08	5.45	2,255.43	0.3542	14,658
2005	10,070.00	5.77	581.04	0.3174	3,196
2006	0.09-	6.14	0.01-	0.2763	0
2007	4,070.00	6.56	266.99	0.2296	934
2008	163,006.35	7.06	11,508.25	0.1765	28,771
2009	3,083.87	7.69	237.15	0.1154	356
	871,770.68		33,029.66		482,826

CLARENVILLE REGIONAL BUILDING
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2042
NET SALVAGE PERCENT.. 0

1990	1,651,044.00	2.13	35,167.24	0.4366	720,846
1991	141,476.00	2.18	3,084.18	0.4251	60,141
1992	8,811.00	2.23	196.49	0.4126	3,635
1993	6,094.00	2.28	138.94	0.3990	2,432
1995	18,780.00	2.38	446.96	0.3689	6,928
1999	19,303.00	2.64	509.60	0.3036	5,860
2000	21,716.00	2.72	590.68	0.2856	6,202

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
CLARENVILLE REGIONAL BUILDING					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2042					
NET SALVAGE PERCENT.. 0					
2005	5,317.00	3.20	170.14	0.1760	936
2006	124,297.00	3.33	4,139.09	0.1498	18,620
2007	13,473.00	3.49	470.21	0.1222	1,646
2008	4,867.89	3.68	179.14	0.0920	448
2010	32,584.44	4.50	1,466.30	0.0225	733
	2,047,763.33		46,558.97		828,427

GANDER
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2037
NET SALVAGE PERCENT.. 0

1963	2,039.00	1.45	29.57	0.6888	1,404
1968	1,096.00	1.56	17.10	0.6630	727
1975	231,781.00	1.73	4,009.81	0.6142	142,360
1976	24,084.00	1.76	423.88	0.6072	14,624
1977	8,245.00	1.79	147.59	0.5996	4,944
1978	14,751.00	1.82	268.47	0.5915	8,725
1979	2,688.00	1.85	49.73	0.5828	1,567
1981	1,109.00	1.92	21.29	0.5664	628
1983	40,197.00	1.99	799.92	0.5472	21,996
1984	30,568.00	2.03	620.53	0.5380	16,446
1985	17,867.00	2.07	369.85	0.5278	9,430
1986	189,763.00	2.11	4,004.00	0.5170	98,107
1987	71,157.00	2.15	1,529.88	0.5052	35,949
1988	1,273.00	2.20	28.01	0.4950	630
1989	8,645.00	2.25	194.51	0.4838	4,182
1990	1,197.00	2.30	27.53	0.4715	564
1997	613,545.00	2.73	16,749.78	0.3686	226,153
1998	21,825.00	2.81	613.28	0.3512	7,665
1999	385.00	2.89	11.13	0.3324	128
2001	47,190.00	3.08	1,453.45	0.2926	13,808
2003	22,015.00	3.30	726.50	0.2475	5,449
2004	53,349.91	3.42	1,824.57	0.2223	11,860
2005	9,965.00	3.56	354.75	0.1958	1,951
2007	28,630.00	3.89	1,113.71	0.1362	3,899
2009	3,773.81	4.41	166.43	0.0662	250
	1,447,138.72		35,555.27		633,446

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
GRAND FALLS SERVICE BUILDING					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2056					
NET SALVAGE PERCENT.. 0					
1958	35,695.00	1.25	446.19	0.6562	23,423
1959	2,047.00	1.26	25.79	0.6489	1,328
1960	1,036.00	1.27	13.16	0.6414	664
1961	500.00	1.28	6.40	0.6336	317
1965	88.00	1.34	1.18	0.6097	54
1967	1,147.00	1.36	15.60	0.5916	679
1970	1,369.00	1.41	19.30	0.5710	782
1972	3,706.00	1.44	53.37	0.5544	2,055
1973	2,735.00	1.46	39.93	0.5475	1,497
1974	2,961.00	1.47	43.53	0.5366	1,589
1975	13,026.00	1.49	194.09	0.5290	6,891
1977	2,666.00	1.53	40.79	0.5126	1,367
1979	30,724.00	1.57	482.37	0.4946	15,196
1980	1,113.00	1.59	17.70	0.4850	540
1981	17,128.00	1.61	275.76	0.4750	8,136
1982	18,645.00	1.63	303.91	0.4646	8,662
1987	3,918.00	1.76	68.96	0.4136	1,620
1988	324,529.00	1.78	5,776.62	0.4005	129,974
1989	11,220.00	1.81	203.08	0.3892	4,367
1994	18,827.00	1.98	372.77	0.3267	6,151
1999	10,552.00	2.21	233.20	0.2542	2,682
2001	6,518.00	2.32	151.22	0.2204	1,437
2006	686,364.00	2.72	18,669.10	0.1224	84,011
2007	198,434.00	2.84	5,635.53	0.0994	19,724
2008	32,102.46	2.99	959.86	0.0748	2,401
2009	17,044.93	3.22	548.85	0.0483	823
	1,444,095.39		34,598.26		326,370

CORNER BROOK - MAPLE VALLEY SERVICE BUILDING
INTERIM SURVIVOR CURVE.. IOWA 70-R1
PROBABLE RETIREMENT YEAR.. 6-2057
NET SALVAGE PERCENT.. 0

1979	352,375.00	1.56	5,497.05	0.4914	173,157
1981	1,806.00	1.60	28.90	0.4720	852
1986	4,895.29	1.72	84.20	0.4214	2,063
1988	2,379.00	1.77	42.11	0.3982	947
1989	81,883.00	1.80	1,473.89	0.3870	31,689
1994	35,269.00	1.97	694.80	0.3250	11,462
2000	2,080.00	2.24	46.59	0.2352	489

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
CORNER BROOK - MAPLE VALLEY SERVICE BUILDING					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2057					
NET SALVAGE PERCENT.. 0					
2001	96,882.00	2.30	2,228.29	0.2185	21,169
2003	37,979.00	2.43	922.89	0.1822	6,920
2004	2,517.81	2.50	62.95	0.1625	409
2007	905,647.00	2.81	25,448.68	0.0984	89,116
2008	3,556.88	2.96	105.28	0.0740	263
2009	38,002.37	3.18	1,208.48	0.0477	1,813
	1,565,272.35		37,844.11		340,349
STEPHENVILLE OFFICE AND SERVICE BUILDING					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2028					
NET SALVAGE PERCENT.. 0					
1958	142,910.00	1.48	2,115.07	0.7770	111,041
1976	27,384.00	1.98	542.20	0.6831	18,706
1977	669.00	2.02	13.51	0.6767	453
1978	828.00	2.06	17.06	0.6695	554
1982	9,461.00	2.25	212.87	0.6412	6,066
1983	945.00	2.30	21.74	0.6325	598
1987	2,438.00	2.52	61.44	0.5922	1,444
1988	485,668.88	2.59	12,578.82	0.5828	283,048
1989	148,708.00	2.66	3,955.63	0.5719	85,046
1990	28,279.00	2.73	772.02	0.5596	15,825
1992	17,045.00	2.88	490.90	0.5328	9,082
1994	32,158.00	3.06	984.03	0.5049	16,237
1997	22,245.00	3.37	749.66	0.4550	10,121
1999	2,135.00	3.61	77.07	0.4152	886
2000	21,859.00	3.75	819.71	0.3938	8,608
2003	22,917.00	4.24	971.68	0.3180	7,288
2004	61,952.10	4.43	2,744.48	0.2880	17,842
2007	42,103.00	5.17	2,176.73	0.1810	7,621
2008	2,701.27	5.51	148.84	0.1378	372
2009	8,951.58	5.93	530.83	0.0890	797
2010	1,884.81	6.68	125.91	0.0334	63
	1,083,242.64		30,110.20		601,698

NEWFOUNDLAND POWER INC.

ACCOUNT 371.20 - BUILDINGS AND STRUCTURES - LARGE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
PORT AUX BASQUES					
INTERIM SURVIVOR CURVE.. IOWA 70-R1					
PROBABLE RETIREMENT YEAR.. 6-2026					
NET SALVAGE PERCENT.. 0					
1953	2,100.00	1.41	29.61	0.8108	1,703
1966	5,552.00	1.71	94.94	0.7610	4,225
1982	151,108.00	2.33	3,520.82	0.6640	100,336
1983	22,703.00	2.39	542.60	0.6572	14,920
1984	4,673.00	2.44	114.02	0.6466	3,022
1985	1,545.00	2.50	38.62	0.6375	985
1987	7,518.00	2.63	197.72	0.6180	4,646
1988	40,396.00	2.70	1,090.69	0.6075	24,541
1989	6,142.00	2.78	170.75	0.5977	3,671
1990	20,209.00	2.86	577.98	0.5863	11,849
1997	610.00	3.57	21.78	0.4820	294
2000	7,150.00	4.00	286.00	0.4200	3,003
2010	1,767.71	7.32	129.40	0.0366	65
	271,473.71		6,814.93		173,260
	33,129,683.57		757,352.43		12,505,398
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 2.29					

NEWFOUNDLAND POWER INC.

ACCOUNT 372.00 - GENERAL - OFFICE EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 25-SQUARE NET SALVAGE PERCENT.. 0					
1985	158,048.00			1.0000	158,048
1986	201,372.00	4.00	8,054.88	0.9800	197,345
1987	319,451.00	4.00	12,778.04	0.9400	300,284
1988	347,317.00	4.00	13,892.68	0.9000	312,585
1989	423,921.00	4.00	16,956.84	0.8600	364,572
1990	742,516.00	4.00	29,700.64	0.8200	608,863
1991	270,246.00	4.00	10,809.84	0.7800	210,792
1992	357,631.00	4.00	14,305.24	0.7400	264,647
1993	127,487.00	4.00	5,099.48	0.7000	89,241
1994	716,551.00	4.00	28,662.04	0.6600	472,924
1995	198,331.00	4.00	7,933.24	0.6200	122,965
1996	105,582.00	4.00	4,223.28	0.5800	61,238
1997	433,487.00	4.00	17,339.48	0.5400	234,083
1998	258,621.00	4.00	10,344.84	0.5000	129,310
1999	146,317.00	4.00	5,852.68	0.4600	67,306
2000	414,211.77	4.00	16,568.47	0.4200	173,969
2001	360,559.00	4.00	14,422.36	0.3800	137,012
2002	148,751.61	4.00	5,950.06	0.3400	50,576
2003	329,744.13	4.00	13,189.77	0.3000	98,923
2004	123,705.97	4.00	4,948.24	0.2600	32,164
2005	71,535.00	4.00	2,861.40	0.2200	15,738
2006	93,438.00	4.00	3,737.52	0.1800	16,819
2007	48,757.00	4.00	1,950.28	0.1400	6,826
2008	94,246.50	4.00	3,769.86	0.1000	9,425
2009	113,536.76	4.00	4,541.47	0.0600	6,812
2010	122,002.10	4.00	4,880.08	0.0200	2,440
	6,727,365.84		262,772.71		4,144,907

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.91

NEWFOUNDLAND POWER INC.

ACCOUNT 373.00 - GENERAL - STORES EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 25-SQUARE NET SALVAGE PERCENT.. 0					
1985	19,093.00			1.0000	19,093
1986	9,305.00	4.00	372.20	0.9800	9,119
1987	5,256.00	4.00	210.24	0.9400	4,941
1988	24,062.00	4.00	962.48	0.9000	21,656
1989	113,142.00	4.00	4,525.68	0.8600	97,302
1990	90,012.00	4.00	3,600.48	0.8200	73,810
1991	23,515.00	4.00	940.60	0.7800	18,342
1992	22,969.00	4.00	918.76	0.7400	16,997
1993	4,556.00	4.00	182.24	0.7000	3,189
1994	58,688.00	4.00	2,347.52	0.6600	38,734
1995	94,538.00	4.00	3,781.52	0.6200	58,614
1996	38,389.00	4.00	1,535.56	0.5800	22,266
1997	27,661.00	4.00	1,106.44	0.5400	14,937
2000	16,786.00	4.00	671.44	0.4200	7,050
2001	8,787.00	4.00	351.48	0.3800	3,339
2003	4,302.00	4.00	172.08	0.3000	1,291
2004	8,902.53	4.00	356.10	0.2600	2,315
2005	28,110.00	4.00	1,124.40	0.2200	6,184
2006	5,824.00	4.00	232.96	0.1800	1,048
2007	4,126.00	4.00	165.04	0.1400	578
	608,023.53		23,557.22		420,805
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.87					

NEWFOUNDLAND POWER INC.

ACCOUNT 374.00 - GENERAL - SHOP EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL ACCRUAL-- RATE (3)	AMOUNT (4)	--ACCRUED DEPREC.-- FACTOR (5)	AMOUNT (6)
SURVIVOR CURVE.. 25-SQUARE NET SALVAGE PERCENT.. 0					
1985	7,713.00			1.0000	7,713
1986	10,556.00	4.00	422.24	0.9800	10,345
1987	47,591.00	4.00	1,903.64	0.9400	44,736
1988	11,628.00	4.00	465.12	0.9000	10,465
1989	44,822.00	4.00	1,792.88	0.8600	38,547
1990	70,910.00	4.00	2,836.40	0.8200	58,146
1991	81,854.00	4.00	3,274.16	0.7800	63,846
1992	46,628.00	4.00	1,865.12	0.7400	34,505
1993	18,953.00	4.00	758.12	0.7000	13,267
1994	29,504.00	4.00	1,180.16	0.6600	19,473
1995	22,264.00	4.00	890.56	0.6200	13,804
1996	38,385.00	4.00	1,535.40	0.5800	22,263
1997	4,964.00	4.00	198.56	0.5400	2,681
1998	38,347.00	4.00	1,533.88	0.5000	19,174
1999	99,654.00	4.00	3,986.16	0.4600	45,841
2000	32,361.00	4.00	1,294.44	0.4200	13,592
2001	57,908.00	4.00	2,316.32	0.3800	22,005
2003	1,457.61	4.00	58.30	0.3000	437
2004	3,278.33	4.00	131.13	0.2600	852
2005	3,599.00	4.00	143.96	0.2200	792
2006	1,602.00	4.00	64.08	0.1800	288
2008	31,577.12	4.00	1,263.08	0.1000	3,158
2009	1,688.05	4.00	67.52	0.0600	101
2010	11,024.91	4.00	441.00	0.0200	220
	718,269.02		28,422.23		446,251

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.96

NEWFOUNDLAND POWER INC.

ACCOUNT 375.00 - GENERAL - LABORATORY & TESTING EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 25-SQUARE NET SALVAGE PERCENT.. 0					
1985	56,193.00			1.0000	56,193
1986	270,072.00	4.00	10,802.88	0.9800	264,671
1987	129,497.00	4.00	5,179.88	0.9400	121,727
1988	131,809.00	4.00	5,272.36	0.9000	118,628
1989	168,124.00	4.00	6,724.96	0.8600	144,587
1990	359,251.00	4.00	14,370.04	0.8200	294,586
1991	87,473.00	4.00	3,498.92	0.7800	68,229
1992	692,594.00	4.00	27,703.76	0.7400	512,520
1993	258,557.00	4.00	10,342.28	0.7000	180,990
1994	187,890.00	4.00	7,515.60	0.6600	124,007
1995	91,335.00	4.00	3,653.40	0.6200	56,628
1996	265,873.00	4.00	10,634.92	0.5800	154,206
1997	204,056.00	4.00	8,162.24	0.5400	110,190
1998	433,249.00	4.00	17,329.96	0.5000	216,624
1999	367,649.00	4.00	14,705.96	0.4600	169,119
2000	57,184.00	4.00	2,287.36	0.4200	24,017
2001	52,376.00	4.00	2,095.04	0.3800	19,903
2002	222,014.00	4.00	8,880.56	0.3400	75,485
2003	139,900.56	4.00	5,596.02	0.3000	41,970
2004	251,504.35	4.00	10,060.17	0.2600	65,391
2005	360,052.00	4.00	14,402.08	0.2200	79,211
2006	338,028.00	4.00	13,521.12	0.1800	60,845
2007	217,379.00	4.00	8,695.16	0.1400	30,433
2008	300,125.44	4.00	12,005.02	0.1000	30,013
2009	139,558.51	4.00	5,582.34	0.0600	8,374
2010	131,840.44	4.00	5,273.62	0.0200	2,637
	5,913,584.30		234,295.65		3,031,184

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.96

NEWFOUNDLAND POWER INC.

ACCOUNT 376.00 - GENERAL - MISCELLANEOUS EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 15-SQUARE NET SALVAGE PERCENT.. 0					
1995	56,297.00			1.0000	56,297
1996	99,402.00	6.67	6,630.11	0.9667	96,089
1997	208,469.00	6.67	13,904.88	0.9000	187,622
1998	43,040.00	6.67	2,870.77	0.8333	35,867
1999	96,730.00	6.67	6,451.89	0.7667	74,160
2000	108,765.00	6.67	7,254.63	0.7000	76,136
2001	79,001.00	6.67	5,269.37	0.6333	50,034
2002	65,622.05	6.67	4,376.99	0.5667	37,186
2003	431,737.83	6.67	28,796.91	0.5000	215,869
2004	224,366.94	6.67	14,965.27	0.4333	97,225
2005	262,457.00	6.67	17,505.88	0.3667	96,235
2006	269,899.00	6.67	18,002.26	0.3000	80,970
2007	191,883.00	6.67	12,798.60	0.2333	44,772
2008	258,748.52	6.67	17,258.53	0.1667	43,126
2009	146,446.92	6.67	9,768.01	0.1000	14,645
2010	135,833.66	6.67	9,060.11	0.0333	4,527
	2,678,698.92		174,914.21		1,210,760
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.53					

NEWFOUNDLAND POWER INC.

ACCOUNT 377.00 - GENERAL - ENGINEERING EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 25-SQUARE					
NET SALVAGE PERCENT.. 0					
1985	4,561.00			1.0000	4,561
1986	36,479.00	4.00	1,459.16	0.9800	35,749
1987	125,253.00	4.00	5,010.12	0.9400	117,738
1988	37,696.00	4.00	1,507.84	0.9000	33,926
1989	8,642.00	4.00	345.68	0.8600	7,432
1990	10,841.00	4.00	433.64	0.8200	8,890
1991	9,859.00	4.00	394.36	0.7800	7,690
1992	1,980.00	4.00	79.20	0.7400	1,465
1993	3,932.00	4.00	157.28	0.7000	2,752
1995	707.00	4.00	28.28	0.6200	438
1996	2,540.00	4.00	101.60	0.5800	1,473
1998	6,983.00	4.00	279.32	0.5000	3,492
1999	24,076.00	4.00	963.04	0.4600	11,075
2008	21,708.70	4.00	868.35	0.1000	2,171
2009	2,534.00	4.00	101.36	0.0600	152
	297,791.70		11,729.23		239,004

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.94

NEWFOUNDLAND POWER INC.

ACCOUNT 378.10 - TRANSPORTATION - SEDANS & STATION WAGONS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 5-R1.5					
NET SALVAGE PERCENT.. +16					
2005	98,662.54	14.87	12,323.74	0.8178	67,776
2007	0.28	17.91	0.04	0.6268	0
	98,662.82		12,323.78		67,776
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 12.49					

NEWFOUNDLAND POWER INC.

ACCOUNT 378.20 - TRANSPORTATION-PICK-UP TRUCKS, WINDOW VANS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 6-S2.5					
NET SALVAGE PERCENT.. +16					
2001	3.29	10.22	0.28	0.9709	3
2002	0.38	11.11	0.04	0.9444	0
2003	24,353.13	12.14	2,483.43	0.9105	18,626
2004	110,027.78	13.29	12,283.06	0.8638	79,835
2005	1,027,167.55	14.54	125,454.14	0.7997	689,998
2006	886,739.95	15.81	117,762.61	0.7114	529,895
2007	768,962.31	16.96	109,549.45	0.5936	383,423
2008	1,399,000.98	17.82	209,413.66	0.4455	523,534
2009	1,091,177.27	18.29	167,644.11	0.2744	251,512
2010	581,285.47	18.46	90,136.45	0.0923	45,068
	5,888,718.11		834,727.23		2,521,894

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 14.18

NEWFOUNDLAND POWER INC.

ACCOUNT 378.30 - TRANSPORTATION - TRUCKS W/ DERRICKS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 11-R2.5					
NET SALVAGE PERCENT.. +8					
1992	0.26	5.30	0.01	0.9805	0
1993	98,268.81	5.51	4,981.44	0.9642	87,171
1994	3.79	5.76	0.20	0.9504	3
1998	285,724.27	6.97	18,321.78	0.8712	229,009
1999	571,024.80	7.30	38,350.03	0.8395	441,025
2000	1,334,148.90	7.63	93,651.92	0.8012	983,406
2001	959,733.27	7.96	70,283.19	0.7562	667,690
2002	247,607.10	8.27	18,838.94	0.7030	160,142
2003	2,369,097.00	8.59	187,225.00	0.6442	1,404,079
2004	1,665,107.00	8.89	136,185.77	0.5778	885,131
2005	740,579.12	9.20	62,682.62	0.5060	344,754
2006	1,561,410.00	9.51	136,610.88	0.4280	614,821
2007	449,419.00	9.84	40,685.00	0.3444	142,398
2008	658,405.86	10.19	61,724.23	0.2548	154,341
2009	963,747.31	10.62	94,161.97	0.1593	141,243
2010	1,548,112.41	11.42	162,650.88	0.0571	81,325
	13,452,388.90		1,126,353.86		6,336,538

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.37

NEWFOUNDLAND POWER INC.

ACCOUNT 378.40 - TRANSPORTATION - TRUCKS W/ STAKE BODIES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 11-R2.5					
NET SALVAGE PERCENT.. +8					
1998	92,345.14	6.97	5,921.54	0.8712	74,015
2000	158,002.65	7.63	11,091.15	0.8012	116,464
2001	10,654.64	7.96	780.26	0.7562	7,412
2002	4,528.28	8.27	344.53	0.7030	2,929
2003	453,156.59	8.59	35,812.06	0.6442	268,570
2004	402,507.96	8.89	32,920.32	0.5778	213,964
2005	601,963.88	9.20	50,950.22	0.5060	280,226
2006	321,761.00	9.51	28,151.51	0.4280	126,697
2007	864,238.00	9.84	78,237.74	0.3444	273,832
2008	177,227.78	10.19	16,614.75	0.2548	41,545
2010	264,842.35	11.42	27,825.40	0.0571	13,913
	3,351,228.27		288,649.48		1,419,567
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 8.61					

NEWFOUNDLAND POWER INC.

ACCOUNT 378.50 - TRANSPORTATION - MISCELLANEOUS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 15-L1.5					
NET SALVAGE PERCENT.. +8					
1966	4,182.46	2.23	85.81	0.9924	3,819
1968	39,739.00	2.31	844.53	0.9818	35,894
1974	15,153.00	2.62	365.25	0.9563	13,332
1975	17,325.31	2.68	427.17	0.9514	15,165
1979	55,162.90	2.94	1,492.05	0.9261	46,999
1986	27,617.00	3.55	901.97	0.8698	22,100
1987	650.00	3.65	21.83	0.8578	513
1988	3,337.04	3.77	115.74	0.8482	2,604
1989	35,017.27	3.88	1,249.98	0.8342	26,874
1990	2,066.00	4.01	76.22	0.8220	1,562
1992	4,239.00	4.29	167.30	0.7936	3,095
1993	8,338.00	4.45	341.36	0.7788	5,974
1994	50,777.35	4.62	2,158.24	0.7623	35,611
1996	32,812.05	5.00	1,509.35	0.7250	21,886
1997	22,456.89	5.22	1,078.47	0.7047	14,559
1998	22,183.78	5.46	1,114.34	0.6825	13,929
1999	10,805.86	5.72	568.65	0.6578	6,539
2000	49,901.28	6.00	2,754.55	0.6300	28,923
2001	17,501.05	6.30	1,014.36	0.5985	9,636
2002	48,545.00	6.61	2,952.12	0.5618	25,091
2003	36,488.28	6.93	2,326.35	0.5198	17,449
2004	156,694.05	7.26	10,465.91	0.4719	68,028
2005	119,441.55	7.58	8,329.38	0.4169	45,812
2006	116,111.00	7.90	8,438.95	0.3555	37,975
2007	7,335.00	8.23	555.38	0.2880	1,943
2008	254,789.25	8.55	20,041.72	0.2138	50,116
2009	126,215.32	8.89	10,322.90	0.1334	15,490
	1,284,884.69		79,719.88		570,918

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.20

NEWFOUNDLAND POWER INC.

ACCOUNT 379.10 - COMPUTERS - HARDWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 5-SQUARE					
NET SALVAGE PERCENT.. 0					
2002	1.00			1.0000	1
2005	1,371,220.00			1.0000	1,371,220
2006	916,711.00	20.00	183,342.20	0.9000	825,040
2007	1,347,965.00	20.00	269,593.00	0.7000	943,576
2008	1,653,490.00	20.00	330,698.00	0.5000	826,745
2009	1,528,748.00	20.00	305,749.60	0.3000	458,624
2010	1,549,925.00	20.00	309,985.00	0.1000	154,992
	8,368,060.00		1,399,367.80		4,580,198
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 16.72					

NEWFOUNDLAND POWER INC.

ACCOUNT 379.20 - COMPUTERS - SOFTWARE

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 10-SQUARE					
NET SALVAGE PERCENT.. 0					
1997	1.00			1.0000	1
2000	2,377,562.00			1.0000	2,377,562
2001	1,876,081.00	10.00	187,608.10	0.9500	1,782,277
2002	4,554,641.00	10.00	455,464.10	0.8500	3,871,445
2003	4,608,132.00	10.00	460,813.20	0.7500	3,456,099
2004	2,550,912.00	10.00	255,091.20	0.6500	1,658,093
2005	2,170,524.00	10.00	217,052.40	0.5500	1,193,788
2006	2,761,636.00	10.00	276,163.60	0.4500	1,242,736
2007	2,327,922.00	10.00	232,792.20	0.3500	814,773
2008	2,251,084.00	10.00	225,108.40	0.2500	562,771
2009	2,105,206.00	10.00	210,520.60	0.1500	315,781
2010	1,870,248.00	10.00	187,024.80	0.0500	93,512
	29,453,949.00		2,707,638.60		17,368,838
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 9.19					

NEWFOUNDLAND POWER INC.

ACCOUNT 381.10 - MOBILE RADIOS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1996	45,704.00	6.67	3,048.46	0.9667	44,181
1997	86,422.00	6.67	5,764.35	0.9000	77,780
1998	26,370.00	6.67	1,758.88	0.8333	21,975
2000	31,928.27	6.67	2,129.62	0.7000	22,350
2001	26,431.00	6.67	1,762.95	0.6333	16,740
2002	31,615.00	6.67	2,108.72	0.5667	17,915
2003	26,481.00	6.67	1,766.28	0.5000	13,240
2004	15,437.92	6.67	1,029.71	0.4333	6,690
2005	21,838.00	6.67	1,456.59	0.3667	8,007
2006	24,721.00	6.67	1,648.89	0.3000	7,416
	336,948.19		22,474.45		236,294

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67

NEWFOUNDLAND POWER INC.

ACCOUNT 381.20 - MOBILE RADIOS - PORTABLE RADIOS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1995	41,511.00			1.0000	41,511
1997	23,216.00	6.67	1,548.51	0.9000	20,894
1998	18,161.00	6.67	1,211.34	0.8333	15,134
1999	19,565.00	6.67	1,304.99	0.7667	15,000
2001	13,654.00	6.67	910.72	0.6333	8,647
2002	22,354.00	6.67	1,491.01	0.5667	12,667
2005	4,891.00	6.67	326.23	0.3667	1,793
2007	1,001.00	6.67	66.77	0.2333	234
2008	14,448.47	6.67	963.71	0.1667	2,408
	158,801.47		7,823.28		118,288

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.93

NEWFOUNDLAND POWER INC.

ACCOUNT 381.30 - MOBILE RADIOS - BASE STATIONS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1995	1,320.00			1.0000	1,320
1996	5,562.00	6.67	370.99	0.9667	5,377
	6,882.00		370.99		6,697
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.39					

NEWFOUNDLAND POWER INC.

ACCOUNT 382.10 - RADIO SITES - ROADS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 30-R4					
NET SALVAGE PERCENT.. 0					
1966	3,097.00	2.24	69.37	0.9968	3,087
1967	1,469.05	2.28	33.49	0.9918	1,457
1975	6,136.00	2.64	161.99	0.9372	5,751
1977	5,545.00	2.75	152.49	0.9212	5,108
1982	3,700.00	3.00	111.00	0.8550	3,164
1983	2,729.00	3.04	82.96	0.8360	2,281
1984	5,083.00	3.08	156.56	0.8162	4,149
1985	40,119.00	3.12	1,251.71	0.7956	31,919
1986	38,398.00	3.16	1,213.38	0.7742	29,728
1992	965.00	3.35	32.33	0.6198	598
2010	34,559.75	3.55	1,226.87	0.0178	615
	141,800.80		4,492.15		87,857

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.17

NEWFOUNDLAND POWER INC.

ACCOUNT 382.20 - RADIO SITES - BUILDINGS

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 30-R4					
NET SALVAGE PERCENT.. -5					
1977	42,386.00	2.75	1,223.90	0.9212	40,998
1983	116,762.00	3.04	3,727.04	0.8360	102,494
1984	55,719.00	3.08	1,801.95	0.8162	47,752
1985	100,065.00	3.12	3,278.13	0.7956	83,592
1986	33,061.00	3.16	1,096.96	0.7742	26,876
1988	17,664.00	3.23	599.07	0.7268	13,480
2000	16,120.00	3.50	592.41	0.3675	6,220
2001	1,869.00	3.50	68.69	0.3325	653
2004	1,512.00	3.52	55.88	0.2288	363
	385,158.00		12,444.03		322,428

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 3.23

NEWFOUNDLAND POWER INC.

ACCOUNT 383.00 - RADIO EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. 15-SQUARE					
NET SALVAGE PERCENT.. 0					
1993	0.21			1.0000	0
1994	0.24			1.0000	0
1996	180,896.00	6.67	12,065.76	0.9667	174,867
1997	56,686.00	6.67	3,780.96	0.9000	51,017
1998	186,751.00	6.67	12,456.29	0.8333	155,625
2000	61,961.98	6.67	4,132.86	0.7000	43,373
2001	100,392.00	6.67	6,696.15	0.6333	63,581
2002	37,617.00	6.67	2,509.05	0.5667	21,316
2004	160,211.91	6.67	10,686.13	0.4333	69,425
2005	1,737.00	6.67	115.86	0.3667	637
2007	5,048.00	6.67	336.70	0.2333	1,178
2008	49,724.04	6.67	3,316.59	0.1667	8,288
2009	109,270.85	6.67	7,288.37	0.1000	10,927
2010	2,355.46	6.67	157.11	0.0333	79
	952,651.69		63,541.83		600,313
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.67					

NEWFOUNDLAND POWER INC.

ACCOUNT 384.00 - COMMUNICATION CABLES

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 25-R3					
NET SALVAGE PERCENT.. -5					
1982	36,861.38	3.13	1,211.45	0.8920	34,524
1985	22,758.00	3.34	798.12	0.8517	20,352
1988	4,523.00	3.53	167.64	0.7942	3,772
1989	0.43	3.59	0.02	0.7718	0
1990	218,933.86	3.65	8,390.64	0.7482	171,997
1991	492,621.55	3.71	19,190.07	0.7234	374,181
1994	10,967.00	3.88	446.80	0.6402	7,372
1995	0.02			0.6107	0
1996	26,235.00	3.99	1,099.12	0.5786	15,939
1998	204,122.39	4.09	8,766.04	0.5112	109,565
1999	24,228.62	4.14	1,053.22	0.4761	12,112
2000	163,755.08	4.19	7,204.40	0.4400	75,655
2001	232,622.86	4.23	10,331.94	0.4018	98,141
2002	139,979.00	4.28	6,290.66	0.3638	53,471
2003	221,175.00	4.32	10,032.50	0.3240	75,244
2004	1,461.32	4.36	66.90	0.2834	435
2005	68,476.00	4.40	3,163.59	0.2420	17,400
2006	123,127.00	4.44	5,740.18	0.1998	25,831
2007	23,731.00	4.48	1,116.31	0.1568	3,907
2008	147,283.73	4.53	7,005.55	0.1132	17,506
2009	329,105.10	4.58	15,826.66	0.0687	23,740
2010	183,823.11	4.68	9,033.07	0.0234	4,517
	2,675,790.45		116,934.88		1,145,661
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.37					

NEWFOUNDLAND POWER INC.

ACCOUNT 386.00 - COMMUNICATIONS - SCADA EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 14-L2					
NET SALVAGE PERCENT.. 0					
1980	5,618.00	3.12	175.28	0.9516	5,346
1983	355,449.67	3.38	12,014.20	0.9295	330,390
1984	199,589.00	3.47	6,925.74	0.9196	183,542
1985	28,476.00	3.57	1,016.59	0.9104	25,925
1986	134,883.00	3.68	4,963.69	0.9016	121,611
1987	91,820.00	3.79	3,479.98	0.8906	81,775
1988	70,096.98	3.91	2,740.79	0.8798	61,671
1989	394,335.33	4.04	15,931.15	0.8686	342,520
1990	9,448.00	4.17	393.98	0.8548	8,076
1991	185,587.00	4.32	8,017.36	0.8424	156,338
1992	62,006.00	4.47	2,771.67	0.8270	51,279
1993	44,088.00	4.64	2,045.68	0.8120	35,799
1994	3,395.94	4.83	164.02	0.7970	2,707
1995	6,449.06	5.03	324.39	0.7796	5,028
1996	31,656.00	5.25	1,661.94	0.7612	24,097
1997	158.56	5.50	8.72	0.7425	118
1999	193,547.00	6.07	11,748.30	0.6980	135,096
2000	1,232,595.00	6.39	78,762.82	0.6710	827,071
2001	598,778.14	6.73	40,297.77	0.6394	382,859
2002	310,079.00	7.08	21,953.59	0.6018	186,606
2004	27,355.85	7.74	2,117.34	0.5031	13,763
2005	17,993.00	8.02	1,443.04	0.4411	7,937
2006	20,899.00	8.27	1,728.35	0.3722	7,779
2007	85,438.00	8.51	7,270.77	0.2978	25,443
2008	36,961.56	8.73	3,226.74	0.2182	8,065
2010	118,894.87	9.02	10,724.32	0.0451	5,362
4,265,597.96		241,908.22		3,036,203	

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 5.67

NEWFOUNDLAND POWER INC.

ACCOUNT 389.10 - TELEPHONE & DATA COLLECTION EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 10-L2.5					
NET SALVAGE PERCENT.. 0					
1990	11,588.00	4.61	534.21	0.9450	10,951
1992	15,004.00	5.00	750.20	0.9250	13,879
1993	2,415.00	5.22	126.06	0.9135	2,206
1994	4,740.64	5.45	258.36	0.8992	4,263
1995	29,188.00	5.71	1,666.63	0.8850	25,831
1996	123,680.00	5.98	7,396.06	0.8671	107,243
1997	27,642.00	6.29	1,738.68	0.8492	23,474
1998	791,990.00	6.63	52,508.94	0.8288	656,401
1999	1,571.00	7.03	110.44	0.8084	1,270
2000	23,423.00	7.49	1,754.38	0.7864	18,420
2005	4,678.00	10.38	485.58	0.5709	2,671
2006	12,729.00	10.85	1,381.10	0.4882	6,214
2008	29,309.05	11.57	3,391.06	0.2892	8,476
2009	2,258.89	11.82	267.00	0.1773	401
	1,080,216.58		72,368.70		881,700
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 6.70					

NEWFOUNDLAND POWER INC.

ACCOUNT 391.00 - COMMUNICATIONS - TEST EQUIPMENT

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST AT DECEMBER 31, 2010

YEAR (1)	ORIGINAL COST (2)	--ANNUAL RATE (3)	ACCRUAL-- AMOUNT (4)	--ACCRUED FACTOR (5)	DEPREC.-- AMOUNT (6)
SURVIVOR CURVE.. IOWA 15-R3					
NET SALVAGE PERCENT.. 0					
1985	28,392.00			1.0000	28,392
1986	53,903.00	4.08	2,199.24	0.9996	53,881
1987	40,799.00	4.20	1,713.56	0.9870	40,269
1988	80,065.00	4.34	3,474.82	0.9765	78,183
1989	122,101.00	4.48	5,470.12	0.9632	117,608
1990	95,083.00	4.63	4,402.34	0.9492	90,253
1991	30,442.00	4.80	1,461.22	0.9360	28,494
1992	43,810.00	4.97	2,177.36	0.9194	40,279
1993	26,087.00	5.16	1,346.09	0.9030	23,557
1995	22,544.00	5.53	1,246.68	0.8572	19,325
1996	25,491.00	5.71	1,455.54	0.8280	21,107
1997	21,608.00	5.89	1,272.71	0.7952	17,183
1998	35,716.00	6.06	2,164.39	0.7575	27,055
1999	10,612.00	6.22	660.07	0.7153	7,591
	636,653.00		29,044.14		593,177
COMPOSITE ANNUAL ACCRUAL RATE, PERCENT.. 4.56					