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NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: THE PUBLIC UTILITIES ACT

-and-

IN THE MATTER OF: AN APPLICATION by Nova Scotia Power Incorporated ("NSPI") for Approval of Depreciation Rates to be applied to various classes of depreciable property of the Company

Direct Testimony and Exhibits of

Jacob Pous

on behalf of

Board Counsel

February 9, 2011

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Acronyms and Defined Terms

2009 Study	2009 Depreciation Study developed by Gannett Fleming
ACSR	Aluminum Conductor Steel Reinforced
AEP	American Electric Power Company
AICPA	American Institute of Certified Public Accountants
ALG	Average Life Group
APFD	Accumulated Provision for Depreciation
Board	Nova Scotia Utility and Review Board
Board Counsel	Nova Scotia Utility and Review Board Counsel
Company	Nova Scotia Power, Inc.
DUCI	Diversified Utility Consultants, Inc.
EIA	US Energy Information Administration
ELG	Equal Life Group
FERC	US Federal Energy Regulatory Commission
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
IRP	Integrated Resource Plan
NARUC	National Association of Regulatory Utility Commissioners
NPSC	Nevada Public Service Commission
NSUARB	Nova Scotia Utility and Review Board
OCC	Oklahoma Corporation Commission
SPR	Simulated Plant Records
Stantec	Stantec, Inc.
Yates	J.B. Yates Engineering

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Direct Testimony of Jacob Pous

SECTION I: INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jacob Pous and my business address is 1912 W Anderson Lane, Suite
202, Austin, Texas 78757.

Q. WHAT IS YOUR OCCUPATION?

A. I am a principal in the firm of Diversified Utility Consultants, Inc. ("DUCI"). A copy of
my qualifications appears as Appendix A.

Q. PLEASE DESCRIBE DIVERSIFIED UTILITY CONSULTANTS, INC.

A. DUCI is a consulting firm located in Austin, Texas with an international client base.
The personnel of DUCI provide engineering, accounting, economic, and financial
services to its clients. DUCI provides utility consulting services to municipal
governments with utility systems, to end-users of utility services, and to regulatory
bodies such as state public service commissions. DUCI provides complete rate case
analyses, expert testimony, negotiation services, and litigation support to clients in
electric, gas, telephone, water, sewer, and cable utility matters.

1 **Q. HAVE YOU PREVIOUSLY TESTIFIED IN PUBLIC UTILITY PROCEEDINGS?**

2 A. Yes. Appendix A also includes a list of proceedings in which I have previously
3 presented testimony. In addition, I have been involved in numerous utility rate
4 proceedings that resulted in settlements before testimony was filed. In total, I have
5 participated in well over 400 utility rate proceedings in the United States and
6 Canada. Also worthy of note is that I have testified on behalf of the staff of five
7 different state regulatory commissions.
8

9 **Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?**

10 A. I am a registered professional engineer. I am registered to practice as a Professional
11 Engineer in the State of Texas, as well as numerous other states.
12

13 **Q. ON WHOSE BEHALF ARE YOU PROVIDING THIS TESTIMONY?**

14 A. My recommendations are made on behalf of Nova Scotia Utility and Review Board
15 Counsel ("Board Counsel").
16

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 A. The purpose of my testimony is to address the request of Nova Scotia Power,
19 Incorporated, ("NSPI" or the "Company") before the Nova Scotia Utility and Review
20 Board ("NSUARB" or the "Board") for new depreciation rates and corresponding
21 expense based on several studies compiled within its 2010 depreciation expense
22 request. The various studies are comprised of a 2009 depreciation study developed
23 by Gannett Fleming ("2009 Study") and two decommissioning studies. The first
24 decommissioning study is by Stantec, Inc., ("Stantec") and pertains to Steam and
25 Other Production generating facilities. The second decommissioning study is by J.B.
26 Yates Engineering ("Yates") and pertains to Hydro and Wind Production generating
27 facilities. The combined request for depreciation expense based on plant as of
28 December 31, 2009 is \$165,417,656.¹
29

¹ 2009 Study at page III-7.

REVISED

Jacob Pous
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1 Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR TESTIMONY AND THE
2 RELATED IMPACTS OF ANY ADJUSTMENTS.

3 A. After review of the Company's 2009 Study and the decommissioning studies
4 reflected therein, review of various responses to information requests, as well as
5 information in the public record, I conclude that the Company's requested
6 depreciation rates and corresponding expense are significantly overstated. Based on
7 my review, within the confines of contractual limits and time and data constraints, I
8 recommend a \$47,973,903 reduction to the Company's depreciation expense
9 request, as set forth on Schedule (JP-1). The following is a brief synopsis of each
10 category of adjustments that I recommend to the Company's depreciation request.

- 11 • **Production Plant Life Spans.** The Company requests that
12 the life spans reflected in the "black box" settlement in 2003 be
13 retained, with certain limited exceptions for its Production
14 facilities. After review of the Company's request, I recommend
15 extension of life spans for all steam generating facilities to
16 reflect the longer of the planning horizon contained in the
17 Company's 2009 Integrated Resource Plan ("IRP") Update or a
18 50-year life span. In addition, I recommend extension of the
19 Company's proposed 20-year life span for wind turbine
20 investment to 30 years. While longer life spans for Hydro and
21 Other Production facilities may also be warranted at this time, I
22 have not investigated the reasonable further extension of life
23 spans for those investments. The impact of my
24 recommendations for Steam and Wind Production investment
25 results in a \$19.3 million reduction in requested depreciation
26 expense.
- 27 • **Production Plant Net Salvage.** The Company commissioned
28 Stantec and Yates to perform a specific type of
29 decommissioning cost estimate. The estimates are opinion-
30 based and are not supported by verifiable documentation. The
31 estimates produce excessive costs, at a minimum, based on
32 inclusion of 25% contingencies above and beyond the opinion-
33 based decommissioning costs, the inclusion of site restoration
34 costs without corresponding offsets for the sale or reuse of the
35 site, and essentially reflect a worst-case scenario of the range
36 of options that exist in association with the retirement of
37 generating facilities. In addition, Gannett Fleming has taken the
38 decommissioning cost estimates from Stantec and Yates and
39 escalated such amounts into the future to the point in time it
40 anticipates generating units will retire. This inflation proposal
41 increases the opinion-based decommissioning costs by almost
42 three times the current estimated level. Moreover, the future
43 estimates costs have not been discounted back to the present

1 so that current customers can pay for their fair share of
2 decommissioning costs in current dollars. Correcting only for
3 the 25% contingency factor and the inappropriate application of
4 future inflation to the depreciation calculation results in a \$12.7
5 million reduction in depreciation expense.

- 6 • **Interim Retirements.** The 2009 Study includes an
7 inappropriate means of quantifying interim retirements that
8 results in an excessive level of Production Plant depreciation
9 expense. However, given the limitations of data and time, no
10 specific adjustment is recommended other than presenting the
11 problem to the Board for consideration in future proceedings.
- 12 • **Mass Property Life.** The Company has taken the very
13 unusual approach of creating synthetic aged data so that
14 actuarial analyses can be performed for Transmission,
15 Distribution, and General plant investments. While this
16 approach is unusual and inappropriate, the results of the
17 actuarial analysis have been analyzed as presented. Based on
18 analysis of the information provided in the 2009 Study and
19 subsequent information provided through discovery,
20 adjustments are required for eight of the nine plant accounts
21 analyzed. The impact of these adjustments is a reduction in
22 depreciation expense of \$14.1 million.
- 23 • **Mass Property Net Salvage.** The Company's proposals are
24 based on a review of historical data without any meaningful
25 consideration and analysis to determine whether the results of
26 the historical analyses are appropriate for use as a proxy for
27 the future. Due to limited information provided by the Company,
28 I recommend adjustments to only three of the nine accounts
29 that were also analyzed for life purposes. The result of these
30 three adjustments is a \$900,000 reduction to requested
31 depreciation expense.
- 32 • **Calculation Procedure.** The Company has employed the
33 Equal Life Group ("ELG") calculation procedure. This procedure
34 is not appropriate for theoretical calculations, and, if employed,
35 results in accelerated depreciation. Moreover, Gannett
36 Fleming's calculation of ELG remaining life by vintages
37 contains an "anomaly" and cannot be relied upon. Reliance on
38 the industry standard Average Life Group ("ALG") calculation
39 procedure results in a \$15.9 million reduction to requested
40 depreciation expense.
- 41 • **Remaining Life Calculation.** The Gannett Fleming calculation
42 of the remaining life for the investment in each account is
43 based on a non-standard approach. The Gannett Fleming
44 approach also allows a change in net salvage to impact the
45 resulting remaining life. Correction of the inappropriate
46 remaining life calculation for mass property accounts results in
47 an increase in depreciation expense of \$2.5 million.

- **Fully Accrued Depreciation.** The Company has taken the inappropriate accounting action of unilaterally changing depreciation rates without Board authority. The Company has taken this action when it believes an account has become fully accrued. Such unilateral and unauthorized action deprives customers of the benefit associated with depreciation charges reflected in base rates. The booking of depreciation should only be ceased in instances where plant has either retired or the Board takes specific action to adopt such position. Reversal of the Company's inappropriate action for two accounts for plant as of the end of December 31, 2009, results in a \$350,000 increase to accumulated provision for depreciation and further results in the need to increase the accumulated provision for depreciation by a minimum of \$40,000 per month subsequent to December 31, 2009.
- **Combined Impact.** Due to the interrelationship of various issues, the combined impact is not simply the summation of individual impacts. Changes in life spans or average service lives will impact the magnitude of net salvage adjustments. The combined impact of the various above-noted adjustments results in a \$47,973,903 reduction in Company depreciation expense based on plant as of December 31, 2009, and is set forth on Schedule (JP-1).

SECTION II: DEPRECIATION – GENERAL

Q. WHAT IS DEPRECIATION?

- A. There are two commonly-cited definitions of depreciation. The first comes from the Federal Energy Regulatory Commission ("FERC"):²

'Depreciation,' as applied to depreciable 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 authorities.

The second definition, from the American Institute of Certified Public Accountants ("AICPA"), is similar:

² Title 18 of the Code of Federal Regulations ("CFR") Part 101, Definition 12.

Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is a portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.

Q. WHAT ARE THE TWO GENERAL FORMULAS USED IN DETERMINING DEPRECIATION RATES?

A. The whole life and the remaining life technique are the most commonly used formulas. The whole life technique is as follows:³

$$\text{Depreciation Rate (\%)} = \left[\frac{\frac{(\text{Original Cost} - \text{Net Salvage})}{\text{Average Service Life}}}{\text{Original Cost}} \right]$$

$$\text{Depreciation Rate (\%)} = \left[\frac{\frac{\text{Original Cost} - \text{Accumulated Provision For Depreciation} - \text{Net Salvage}}{\text{Average Service Life}}}{\text{Original Cost}} \right]$$

The two formulas should equal each other when the difference between the theoretical reserve and the actual APFD is recovered over the remaining life of the investment under the whole life technique.

Q. ARE THERE ADDITIONAL CONSIDERATIONS IN DEPRECIATION BEYOND THE DEFINITIONS?

A. Yes. The definitions provide only a general outline of the overall utility depreciation concept. A depreciation system must also be established.

³ A theoretical depreciation reserve calculation is developed and compared to the actual accumulated provision for depreciation in conjunction with the whole life technique. If the differential is significant, an amortization of the differential for some period of time may be recommended.

Q. WHAT IS A DEPRECIATION SYSTEM?

A. A depreciation system constitutes the method, procedure, and technique employed in the development of depreciation rates.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY “METHOD.”

A. “Method” identifies whether a straight-line, liberalized, compound interest, or other type of calculation is being performed. The straight-line method is normally employed for utility depreciation proceedings.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY “PROCEDURE.”

A. “Procedure” identifies a calculation approach or grouping. For example, procedures can reflect the grouping of only a single item, items by vintage (year of addition), items by broad group or total grouping, or equal life groupings. The ALG procedure is used by the vast majority of utilities.

Q. BRIEFLY DESCRIBE WHAT IS MEANT BY “TECHNIQUE.”

A. There are two main categories of techniques with various sub-groupings: the whole life technique and the remaining life technique. The whole life technique simply reflects calculation of a depreciation rate based on the whole life (e.g., a 10-year life would imply a 10% depreciation rate over the life of the plant). The remaining life technique recognizes that depreciation is a forecast or estimation process that is never precisely accurate and that requires true-ups in order to recovery exactly 100% of what a utility is entitled to over the entire life of the investment. Therefore, as time passes, the remaining life technique attempts to recover the remaining unrecovered balance over the remaining life or other period of time. Most utilities rely on a remaining life technique in utility rate matters.

Q. DO THE METHODS, PROCEDURES, AND TECHNIQUES INTERACT WITH ONE OTHER?

A. Yes. Different depreciation rates will result depending on what combination of method, procedure, and technique is employed. Differences will occur even when beginning with the same average service life and net salvage values.

Q. WHAT IS NET SALVAGE?

A. Net salvage is the value obtained from retired property (the gross salvage) less the cost of removal. Net salvage can be either positive, in cases where gross salvage exceeds cost of removal, or negative, in cases where cost of removal is greater than gross salvage.

Q. HOW DOES NET SALVAGE IMPACT THE CALCULATION OF DEPRECIATION?

A. The intent of the depreciation process is to allow the Company to recover 100% of investment less net salvage. Therefore, if net salvage is a positive 10%, then the utility should only recover 90% of its investment through annual depreciation charges, under the theory that it will recover the remaining 10% through net salvage at the time the asset retires ($90\% + 10\% = 100\%$). Alternatively, if net salvage is a negative 10%, then the utility should be allowed to recover 110% of its investment through annual depreciation charges so that the negative 10% net salvage that is expected to occur at the end of the property's life will still leave the utility whole ($110\% - 10\% = 100\%$).

Q. WHAT ARE THE KEY ELEMENTS OF THE DEPRECIATION FORMULA AT ISSUE IN THIS PROCEEDING?

A. All components for all plant functions in the above formula are at issue.

SECTION III: PRODUCTION PLANT LIFE SPANS

A. General

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the appropriate life spans for the Company's various generating units. In particular, it will address the lack of support and justification for the Company's proposals and the need to extend life spans.

Q. WHAT IS THE LIFE SPAN FOR A GENERATING UNIT?

A. A life span for a generating unit sets the time period during which a unit is expected to provide service. For example, if a generating unit were placed into service on

1 January 1, 1980, and had a 60-year life span, it would have a projected retirement
2 date of December 31, 2039. The life span does not change based on the movement
3 of a generating unit from providing base load service to standby service. The issue is
4 the date of installation through the date of retirement.

5
6 **Q. PLEASE EXPLAIN THE SIGNIFICANCE OF SETTING AN APPROPRIATE LIFE**
7 **SPAN.**

8 A. In determining the depreciation rate and thus depreciation expense for a generating
9 unit, it is necessary to establish the time frame over which customers are expected
10 to receive benefits and, in return, pay for such benefits. As previously noted, the
11 depreciation formula includes the original cost less net salvage less the accumulated
12 provision for depreciation, all divided by the remaining life. Thus, if the remaining life
13 is set at too short a time frame, current customers overpay, and vice versa. Failure
14 to set a proper estimated retirement date for a generating unit creates
15 intergenerational inequities and fails to comply with the matching principle of
16 ratemaking. It is important to note that depreciation in this case is not a measure of
17 value as it relates to the type of service being provided over time (*i.e.*, base,
18 intermediate, peaking, or reserve).

19
20 **Q. DOES THE COMPANY'S PRODUCTION PLANT DEPRECIATION EXPENSE**
21 **REQUEST REPRESENT A SIGNIFICANT REVENUE REQUIREMENT?**

22 A. Yes. The Company requests \$82.5 million for annual Production plant depreciation
23 expense.⁴ This level of requested depreciation expense is dependent on the
24 Company's proposed life spans and related to net salvage values adopted by the
25 Board for generating units.

26

⁴ 2009 Study at pages III-4 – 5.

B. Basis for Retirement Dates

Q. WHAT SPECIFICALLY DID THE COMPANY PROVIDE IN SUPPORT OF LIFE SPANS FOR ITS VARIOUS GENERATING UNITS?

A. Very little. The Company was specifically requested to provide “all analyses and workpapers supporting NSPI management’s probable retirement year for each steam generating unit” as well as all other generating units.⁵ Unfortunately, the various responses do not provide the underlying support and justification for the Company’s proposal.

Q. WHAT ARE THE COMPANY’S SPECIFIC PROPOSALS?

A. The Company states that it “has proposed to maintain the useful lives as adopted in the 2003 UARB approved settlement agreement with the exception of Trenton 5, Tusket, and Victoria Junction Combustion Turbines.”⁶ The following table sets forth the individual actual proposals.

⁵ Response to DUC IR-052, 053, 054, and 055, NPB IR-012, CA IR-010 and 022.

⁶ Response to CA IR-010.

Steam Production Plant	Fuel Source	Proposed Life Span
Lingan Units 1 and 2	coal/petcoke	46/45
Lingan Units 3 and 4	coal/petcoke	46/45
Point Aconi 1	petcoke/coal	45
Point Tupper 2	coal/petcoke	55
Trenton 5	coal/petcoke	55
Trenton 6	coal/petcoke	45
Tufts Cove 1	oil/gas	54
Tufts Cove 2	oil/gas	47
Tufts Cove 3	oil/gas	43
Point Tupper Marine Terminal		32
Hydro Production Plant	Fuel Source	Proposed Life Span
Avon	hydro	112/83
Bear River	hydro	109/78
Black River	hydro	131/111
Dickie Brook	hydro	113/84
Fall River	hydro	75
Harmony	hydro	88
Nictaux and Paradise River	hydro	92/88
Lequille	hydro	79
Roseway	hydro	120/102
St. Margaret's	hydro	114/108
Sheet Harbour	hydro	112/100
Tusket	hydro	112
Wreck Cove	hydro	83/79
Annapolis Tidal	hydro	63
Other Production Plant	Fuel Source	Proposed Life Span
Burnside	oil	46
Tusket	oil	45
Victoria Junction	oil	40
Tufts Cove CT 4	gas	42
Tufts Cove CT 5	gas	40
Wind Production Plant	Fuel Source	Proposed Life Span
Little Brook	wind	20
Grand Etang	wind	20

Q. DOES THE COMPANY HAVE A PLANNING DOCUMENT AS IT APPLIES TO THE USE OF EXISTING GENERATION INTO THE FUTURE?

A. Yes. The Company has developed an IRP. The most recent IRP is the 2009 IRP Update Report, dated November 30, 2009.⁷

⁷ Response to DUC IR-047 Attachment 4.

1 **Q. WHAT IS THE FUTURE PLANNING HORIZON ASSOCIATED WITH THE 2009**
2 **IRP UPDATE?**

3 A. The 2009 IRP Update reflects a 25-year planning horizon from the initial 2007 IRP.
4 The ending date of the IRP is 2032.⁸
5

6 **Q. WHAT IS THE STATUS OF EXISTING GENERATION AS REFLECTED IN THE**
7 **2009 IRP UPDATE?**

8 A. The Company states that “[a]ll existing generation facilities are assumed to continue
9 in operation throughout the planning period.”⁹ (*Emphasis added.*)
10

11 **Q. IS THIS POSITION REGARDING THE RETENTION OF ALL EXISTING**
12 **GENERATION SIGNIFICANT?**

13 A. Yes. Regulators have found that there should be a consistent position presented by
14 utilities between their future plans for meeting load and the expected useful life of
15 generating facilities. This relationship is logical and appropriate given that it attempts
16 to comply with the definition of depreciation to allocate costs over the useful life of a
17 facility in a systematic and rational manner. If depreciation lives are set shorter than
18 what is reflected in the planning process for meeting future loads, then intentional
19 intergenerational inequity is created, and such situation would violate the matching
20 principle guiding utility ratemaking.
21

22 **Q. DOES THE COMPANY’S DEPRECIATION REQUEST REFLECT RETIREMENT**
23 **OF EXISTING GENERATING FACILITIES PRIOR TO THE END OF THE**
24 **PLANNING HORIZON IN THE 2009 IRP UPDATE?**

25 A. Yes. All steam-fired generating facilities, except for Trenton 6 and Point Aconi 1
26 have assumed retirement dates in the 2009 Study prior to the end of the planning
27 period in the 2009 IRP Update.¹⁰ In other words, there are significant conflicts
28 between the 2009 Study assumed retirement dates for most steam-fired generating
29 facilities in comparison to the 2009 IRP Update.
30

⁸ 2009 IRP Update at page 11 and Appendix A at page 1.

⁹ 2009 IRP Update at page 19.

¹⁰ 2009 Study at page II-29.

1 **Q. IS THERE ANY CLAIM BY THE COMPANY THAT ITS STEAM-FIRED**
2 **GENERATING FACILITIES CANNOT PHYSICALLY LAST UNTIL OR BEYOND**
3 **THE END OF THE IRP PLANNING HORIZON?**

4 A. No. Trenton 5 is the oldest coal-fired plant, which was installed in 1970. Assuming a
5 2033 probable retirement date, the year following the IRP planning horizon, would
6 result in an approximately 63-year life span for this unit.
7

8 **Q. ARE APPROXIMATELY 60-YEAR LIFE SPANS FOR COAL-FIRED GENERATING**
9 **FACILITIES REASONABLE?**

10 A. Yes. The United States Energy Information Administration ("EIA") maintains a listing
11 of all generating facilities in the United States. The EIA database notes that as of
12 2008, there were over 800 coal-fired generating units in the United States of 100
13 MW or larger that were still in operation. Of those, two had already achieved 60
14 years of operation as of the end of 2008. Another 227 of those units had exceeded
15 50 years of operation, but had not yet reached 60 years of operation by the end of
16 2008. Further, there were no indications of any significant level of plant retirement
17 activity for these generating facilities. Thus, well over 25% of the existing coal-fired
18 generating units in the United States as of the end of 2008 that were larger than 100
19 MW had already exceeded 50 years and were rapidly approaching 60 years or more
20 of operation.
21

22 **Q. IS THERE ANOTHER BASIS FOR RECOGNIZING THAT COAL-FIRED**
23 **GENERATING UNITS CAN OPERATE FOR 60 YEARS OR LONGER?**

24 A. Yes. Several of the largest coal-fired operating utilities in the United States have
25 stated that their coal-fired generating facilities can operate for longer than 60 years,
26 and have relied upon such life expectancies for depreciation purposes. For example,
27 American Electric Power ("AEP") is one of the largest, if not the largest, operator of
28 coal-fired generating facilities in the United States. AEP's director of generation has
29 stated that "years of operating and maintenance experience with its solid fuel coal
30 fleet has developed enough institutional knowledge that an expected life span of 60
31 years for a coal steam unit is not only reasonable, but achievable, provided that unit

liabilities are addressed and key components are replaced as needed.”¹¹ In addition, Rocky Mountain Power Company, an operator of one of the largest coal-fired fleets in the western portion of the United States, filed for life spans in excess of 60 years for its coal-fired generating units, but as part of a settlement agreed to a 61-year life span for coal-fired generating units.¹² Yet another example of a major operator of coal-fired generating facilities in the central portion of the United States is Xcel Energy. It has agreed to accept 60-year life spans for its coal-fired generating facilities in rate proceedings.¹³ There are other examples of both litigated and settled cases where 60 years is being adopted for depreciation purposes.

Q. DOES GANNETT FLEMING BELIEVE THAT COAL-FIRED GENERATING UNITS CAN OPERATE FOR AT LEAST 60 YEARS?

A. Yes. For example, in a 2007 depreciation study for Northern Indiana Public Service Company, Gannett Fleming stated that the “life span estimate for coal-fired, base load units is 60 to 61 years, which is within the typical range of life spans for such units. The 60-year life span estimate applies to almost all of the steam units.”¹⁴

Q. CAN THE COMPANY’S OIL/GAS-FIRED STEAM GENERATING UNITS PHYSICALLY OPERATE FOR 60 YEARS OR LONGER?

A. Yes. There are a much greater number of gas-fired generating units in operation in North America than coal-fired units. Numerous oil/gas-fired generating facilities have already exceeded 60 years of operation and are still operating. Therefore, there should be no reasonable expectation, from a physical standpoint, that oil- and gas-fired generating facilities cannot exceed 60 years of operation.

Q. WHAT IS NORMALLY THE DRIVING FACTOR LIMITING LIFE SPANS FOR GENERATING FACILITIES?

A. Economic considerations are normally the limiting factor for life spans. If a unit is operating inefficiently and alternative sources of energy at lower cost are available,

¹¹ Response to AG 10-10 Attachment in Oklahoma Corporation Commission Cause No. 200600285, a Public Service of Oklahoma case.

¹² Utah Public Service Commission Docket No. 07-035-13.

¹³ Public Utility Commission of Texas Docket No. 35763, a Southwest Public Service Company, a subsidiary of Xcel Holding Company, case.

¹⁴ Northern Indiana Public Service Company 2007 depreciation study at page II-27.

1 economic pressures come to bear that may potentially result in the retirement of a
2 generating unit. In particular, older, smaller generating facilities that are inefficient
3 are at greater risk for being retired. Newer, larger, and more efficient generating
4 facilities can be expected to continue operating for extended periods of time based
5 on economic factors. Indeed, the director of generation for AEP stated the following
6 as it applies to a situation where the Company's coal-fired units would not be fixed:

7
8 As for what incident that may occur to drive an economic evaluation to
9 determine if it is better to 'fix or retire,' I can think of none. Even with a
10 catastrophic incident on the boiler, implosion or explosion, I'm
11 confident that the economics would reveal, 'Fix it.' The same would
12 apply to a catastrophic event on the turbine/generator. These units are
13 so deep in the money, we would fix them. This is not different to what
14 AEP did for Gavin when its boiler imploded some 15 years ago, or
15 Rockport when its turbine wrecked due to a motoring incident in the
16 80's. Only a catastrophic event of galactic proportions would raise the
17 issue of 'fix or retire,' in my mind, to where a significant portion of the
18 plant was damaged or destroyed.¹⁵

19
20 In other words, because of the high capital cost associated with larger steam-fired
21 generating facilities, economics normally dictate that capital expenditures will
22 continue to be made in order to keep the units operating.

23
24 **Q. IS THIS CONCEPT ALSO APPLICABLE TO NSPI UNITS?**

25 A. Yes. The Company has already made large capital expenditures to keep numerous
26 units operating by replacing static precipitators, replacing generators and installing
27 bag houses, as well as other investments.¹⁶ In addition, the Company expects to
28 make sizeable capital expenditures in the future to keep generating units operating.¹⁷

29
30 **Q. HAS NSPI RAISED CONCERNS REGARDING ITS IRP RESULTS?**

31 A. Yes. Any time forecasts are made for future periods, uncertainty exists. Indeed, the
32 Company specifically notes that there is significant uncertainty during the second
33 decade of the IRP planning period, "during which time the steam units approach and
34 potentially exceed the life estimates employed in its current Depreciation Study."¹⁸

¹⁵ Oklahoma Corporation Commission Cause No. 200600285, a Public Service of Oklahoma proceeding.

¹⁶ Response to DUC IR-050 Attachment 8 (CONFIDENTIAL).

¹⁷ *Id.*

¹⁸ Response to CA IR-010 at page 2, item 2.

1 However, it must be noted that the further out one moves in a multi-decade forecast,
2 a greater level of uncertainty is assigned to such periods.
3

4 **Q. ARE THERE PARTICULAR CONCERNS ASSOCIATED WITH HARD CARBON**
5 **CAPS IMPLEMENTED BY GOVERNMENTAL ENTITIES?**

6 A. Yes. It is my understanding that there are Greenhouse Gas Emissions Regulations
7 made under Subsection 28(6) in Section 112 of the Environmental Act.¹⁹
8

9 **Q. DO THESE REGULATIONS AND OTHER POTENTIAL REGULATIONS REQUIRE**
10 **THE COMPANY TO RETIRE COAL-FIRED GENERATING FACILITIES PRIOR TO**
11 **2020?**

12 A. Though the future is uncertain, as of now the Company believes that it can operate
13 its units beyond 2020. In addition, the Company is actively investigating options
14 associated with its steam-fired fleet of generation, including incremental investment
15 to increase “environmental performance” that are found to be cost effective, adding
16 scrubbers to the Langan plant, utilization of low-sulfur fuels, including blending of
17 biomass fuel with coal.²⁰ In other words, the Company is faced with many
18 uncertainties in the future, but this is no different than the situation that has existed in
19 the past. In addition, the capacity factors for coal units can be adjusted in order to
20 reduce emissions without requiring the units to retire. Therefore, at a minimum, the
21 Company’s adoption of the position that it will not retire any of its existing generating
22 facilities during the planning horizon of its 2009 IRP Update must be recognized.
23

24 **Q. IF THE 2032 PLANNING HORIZON FOR THE CURRENT IRP UPDATE IS**
25 **UTILIZED FOR MINIMUM LIFE SPAN CALCULATIONS, WHAT IS THE RESULT?**

26 A. As set forth in the table below, 9 of the Company’s 11 steam-fired generating units
27 would have their life spans extended from 3 to 13 years. Two of the generating units,
28 Point Aconi 1, Trenton 6, and the Point Tupper Marine Terminal, already have
29 Company-proposed life spans that exceed the planning horizon for the 2009 IRP
30 Update.
31

¹⁹ S.N.S. 1994-95, c.1 O.I.C. 2009-341 [August 14, 2009], N.S.Reg. 260/209.

²⁰ 2009 IRP Update at pages 4, 11, and 18.

Steam Unit	Year Installed	2009 Study Retirement Date	2009 Study Life	NSPI IRP Retirement Date	NSPI IRP Life	Difference
Lingan 1	1980	2026	46	2033	53	7
Lingan 2	1981	2026	45	2033	52	7
Lingan 3	1984	2030	46	2033	49	3
Lingan 4	1985	2030	45	2033	48	3
Point Aconi 1	1994	2039	45	2039	45	0
Point Tupper 2	1973	2028	55	2033	63	8
Trenton 5	1970	2025	55	2033	63	8
Trenton 6	1992	2037	45	2037	45	0
Tufts Cove 1	1966	2020	54	2033	67	13
Tufts Cove 2	1973	2020	47	2033	60	13
Tufts Cove 3	1977	2020	43	2033	56	13
Point Tupper Marine Terminal	2005	2037	32	2037	32	0

Q. DOES THE RECOGNITION OF THE END OF THE PLANNING HORIZON IN THE COMPANY'S 2009 IRP UPDATE REPRESENT A REASONABLE ALTERNATIVE TO THE COMPANY'S PROPOSAL?

A. In some instances, yes, while in other instances, no. For example, extending the Company's proposed retirement dates to a minimum of 2033 still results in life spans as short as 45 years for the two units that had already been projected to exceed the IRP planning horizon, and 48 to 49 years for units such as Lingan 3 and 4. These life spans are still too short, even taking into consideration hard carbon caps that may be implemented in the future.

Q. WHAT DO YOU RECOMMEND?

A. While 60+ year life spans are becoming the norm for the industry associated not only with oil- and gas-fired generating units, but also with coal-fired generating units, and taking into consideration concerns associated with environmental considerations reflected specifically in regulations and by government entities in Nova Scotia, a blending or gradual movement toward longer life spans may be warranted in this instance. Therefore, for purposes of this depreciation analysis, I recommend the longer of either a 2033 probable future retirement date or when a unit reaches a 50-year life span. This provides a gradual movement towards longer life spans while still

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Jacob Pous
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providing a time cushion until the next depreciation study, when current environmental regulations can be understood with better clarity, as well as the potential situation associated with other technologies currently being investigated by the Company as it relates to prolonging life spans for its generating investments. This recommendation results in the following life spans for the Company's steam generating facilities.

Steam Unit	Year Installed	2009 Study Retirement Date	2009 Study Life	DUCI Recommended Date	DUCI Recommended Life	Difference
Lingan 1	1980	2026	46	2033	53	7
Lingan 2	1981	2026	45	2033	52	7
Lingan 3	1984	2030	46	2034	50	4
Lingan 4	1985	2030	45	2035	50	5
Point Aconi	1994	2039	45	2044	50	5
Point Tupper 2	1973	2028	55	2033	60	5
Trenton 5	1970	2025	55	2033	63	8
Trenton 6	1992	2037	45	2042	50	5
Tufts Cove 1	1966	2020	54	2033	67	13
Tufts Cove 2	1973	2020	47	2033	60	13
Tufts Cove 3	1977	2020	43	2033	56	13
Point Tupper Marine Terminal	2005	2037	32	2042	37	5

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation on a standalone basis results in a \$19,155,042 reduction to depreciation expense based on plant as of December 31, 2009.²¹

Q. AS IT RELATES TO WIND TURBINE GENERATION, WHAT LIFE SPAN IS THE COMPANY PROPOSING?

A. The Company proposes a 20-year life span for its investment in wind turbines.²²

²¹ The adjustment also includes the proportional impact of an ALG calculated remaining life in conjunction with the impact of interim retirements.

²² 2009 Study at page III-5.

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. When requested to provide all support and justification as well as all studies utilized to support the probable retirement dates for wind generation, the Company responded by stating the following:

The retirement date of 2023 is consistent with a range of 20 to 25 years design life common to wind turbine manufacturers. There is insufficient experience with turbines in the Nova Scotia conditions as yet to suggest other time frames.²³

Q. HAVE YOU IDENTIFIED ANY INFORMATION ASSOCIATED WITH WIND FARM LIFE EXPECTANCY IN NOVA SCOTIA?

A. Yes. A registration filing for the Nuttby Mountain Wind Farm project in Nova Scotia was developed by CBCL Limited. Contained within that document is a statement that the "design life of a wind farm is typically 20 or more years, and capital improvements and replacement programs may extend safe and efficient operation well beyond 40 years."²⁴ While this document still does not provide any underlying support and justification for the statement, it does identify that minimum life expectancies are in the 20-year range, but that capital improvements can extend the life to 40 years or more.

Q. WHAT DO YOU RECOMMEND FOR LIFE SPANS ASSOCIATED WITH WIND GENERATION?

A. Again, we are faced with a future projection with limited information. However, given that I am recommending a shorter life span for steam-fired generating units than is normally anticipated due to potential environmental regulations in Nova Scotia, it is only appropriate to reflect such considerations in the life spans for wind turbines. This is necessary since the push for renewable energy sources, such as wind turbines, is part of the reason for putting pressure on shorter life spans for coal-fired generating facilities. Therefore, as I recommend a gradual movement towards longer life spans for steam-fired generating facilities, well short of reasonable current life span expectations, I am also making the same recommendation for wind turbines. At

²³ Response to DUC IR-052 and NPB IR-012.

²⁴ <http://www.gov.ns.ca/nse/ea/nuttbymountainwindfarm/NuttbyMountainWindFarm-Registration.pdf> at page 15, Project Description, Section 2.3.3 Reclamation and Decommissioning.

1 this point, I recommend a 30-year life span, which reflects the approximate midpoint
2 of the low end of the life span range and the 40 years or beyond time frame, as
3 referenced in the CBCL Limited registration document.
4

5 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

6 A. My recommendation on a standalone basis results in a \$108,903 reduction in
7 depreciation expense based on wind turbine investment as of December 31, 2009.
8 However, the more significant impact of this recommendation will be the effect on
9 significant additional wind turbine investment soon to be placed into service.
10

11 **Q. ARE YOU RECOMMENDING ADJUSTMENTS TO THE COMPANY'S PROPOSED**
12 **LIFE SPANS FOR HYDRO AND OTHER PRODUCTION GENERATING**
13 **FACILITIES?**

14 A. Not at this time. However, I do believe that the Company's presentation most likely
15 understates the reasonable life expectancy for such investment, particularly for the
16 hydro investment. This concern is raised in association with the significant pressures
17 to add or maintain renewable energy sources in Nova Scotia. Hydro is one such
18 source, and life expectancy for such investment should be maximized. Indeed, it is
19 worth noting that Gannett Fleming has recommended life spans for hydro facilities in
20 the 112- to 113-year range in at least one other jurisdiction.²⁵ The majority of the life
21 spans proposed in the 2009 Study in this proceeding have life spans for hydro
22 generating units less than 113 years. Therefore, I recommend that the Board order
23 the Company to fully justify why its hydro units cannot realistically operate for at least
24 5 to 10 years beyond the current proposed life spans.
25

26 **Q. HAS THE COMPANY RAISED AN ADDITIONAL ISSUE THAT WARRANTS**
27 **DISCUSSION AS IT PERTAINS TO LIFE SPANS?**

28 A. Yes. In response to CA IR-010, the Company raises the concept of intergeneration
29 equity as a reason in support of its proposed life spans. However, it must be noted
30 that the Company's interpretation of intergeneration equity is incorrect, as it attempts
31 to tie the depreciation accounting allocation to a value of service concept by relating

²⁵ Northern Indiana Public Service Company 2007 depreciation study at page II-27.

1 capacity factor over time to equity for different generations of customers. If the
2 Company's presentation were correct, which it is not, it is still incomplete. For
3 example, the Company fails to note that the net book plant associated with older
4 generating facilities is greatly diminished in comparison to the net book plant when
5 first placed into service. Since the greatest component of rate base is net book costs
6 for plant, those customers taking service at the beginning of a new generation
7 investment pay a much greater share of costs due to the higher return and taxes
8 required at that point in a generating facility's life. Alternatively, depreciation expense
9 is intended to spread the recovery of the investment on a systematic and rational
10 basis over the useful life. Therefore, while intergeneration equity is a consideration,
11 the Company's presentation is incorrect. Indeed, artificially attempting to shorten life
12 spans is a form of intergenerational inequity that should be cured to the greatest
13 extent possible in this proceeding.
14

15 **Q. WHAT IS THE OVERALL IMPACT OF YOUR RECOMMENDATION?**

16 A. Increasing life spans to reflect the longer of a probable retirement date of 2033 or at
17 least 50 years of operation for steam-fired generating facilities and a 30-year life
18 span for wind turbine investment results in an approximate \$19,263,945 reduction to
19 depreciation expense. This calculation does not reflect the full proportional impact of
20 longer lives in association with interim retirements. Rather, it reflects a proportional
21 relationship. The issue of interim retirements is discussed elsewhere in my
22 testimony.
23

24 **SECTION IV: PRODUCTION PLANT NET SALVAGE**

25
26 **A. General**
27

28 **Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?**

29 A. This portion of my testimony addresses the Company's Production plant net salvage
30 request. Two studies were performed on behalf of the Company pertaining to
31 estimated Production plant generation decommissioning costs. The information
32 taken from the different decommissioning cost estimates were then escalated into
33 the future for assumed inflation by Gannett Fleming, with the future inflated cost

levels reflected in the development of depreciation rates. The entire process presented by the Company is inappropriate and results in excessive levels of Production plant net salvage.

Q. DOES THE COMPANY'S PRODUCTION PLANT NET SALVAGE REQUEST REFLECT ONLY TERMINAL NET SALVAGE?

A. Yes. The Company requests net salvage associated with terminal net salvage and claims that it is not seeking interim net salvage. Terminal net salvage corresponds to the retirement process when a unit is taken out of service and retired. Interim net salvage applies to components of power plants that will retire, but be replaced in order to keep a generating unit operating until its final retirement date.

Q. WHO PERFORMED THE PRODUCTION PLANT DECOMMISSIONING COST ESTIMATE STUDIES?

A. The Company employed Stantec, Inc., to perform decommissioning studies for its Steam and Other Production plants. For its Hydro and Wind Production plants, the Company employed J.B. Yates Engineering to perform those decommissioning studies.²⁶

Q. WHAT WERE THE RESULTS OF THE DECOMMISSIONING COST STUDIES?

A. The decommissioning cost estimates for the Company's Steam, Other, Wind, and Hydro Production facilities, both before and after inflation adjustments, are set forth in the table below.

Category	Current Estimated Decommissioning Costs	Future Estimated Decommissioning Costs	Increase Factor
Steam	\$103,875,462	\$220,855,327	2.13
Other	\$6,952,763	\$14,359,542	2.07
Wind	\$939,000	\$1,499,523	1.60
Hydro	\$57,995,376	\$242,142,165	4.18
Total	\$169,762,601	\$478,856,557	2.82

²⁶ 2009 Study at page II-31.

As can be seen in the table above, the Company's actions to include estimated future inflation increases the original decommissioning cost estimates by \$309 million, with the total escalated amount representing a negative net salvage level of 21%.²⁷ The corresponding negative net salvage reflected in the decommissioning cost estimates prior to future escalation due to inflation results in a 7.5% level of negative net salvage.

Q. HAS THE COMPANY PRESENTED A VALID OR JUSTIFIED REQUEST?

A. No. The decommissioning studies are based on claimed expertise of subcontractors without provision of underlying documentation and support. The Hydro and Wind decommissioning study results are opinion-based without the benefit of detailed analyses. Moreover, the decommissioning studies include 25% contingencies that further inflate the requested amounts above and beyond the claimed level of decommissioning costs derived through claimed expert subcontractor indications or opinion-based analyses. In addition, the Company's presentation is incomplete and reflects only the worst-case approach to the costs associated with the retirement of a generating facility. The following subsections of this portion of my testimony will address certain individual components of the Company's request.

B. Inflation Escalation of Decommissioning Costs

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony will address NSPI's inclusion of future inflation in its estimation of Production plant decommissioning costs. In addition, if the Board were to allow some level of impact in the decommissioning cost estimates for inflation, it should be at a lower level than the proposed 3.4% annual level.

Q. DOES NSPI RELY ON THE CONCEPT OF FUTURE INFLATION IN ESTABLISHING ITS PROPOSED PRODUCTION NET SALVAGE LEVELS?

A. Yes. By doing so, the Company incorrectly assumes inflation is the only changing factor in the future for the decommissioning of power plants. Moreover, NSPI fails to

²⁷ \$478,856,557 of requested negative net salvage for production plant ÷ \$2,275,948,366 of Production investment as of December 31, 2009, set forth on pages III-4 – 5 of the 2009 Study.

1 discount future inflated costs back to current dollars, thus creating an inappropriate
2 and unrealistic burden for current customers.

3
4 **Q. WHAT IS THE IMPACT ON THE COMPANY'S DEPRECIATION REQUEST**
5 **ASSOCIATED WITH ITS PROPOSAL TO INCLUDE FUTURE INFLATION IN THE**
6 **NET SALVAGE CALCULATION?**

7 A. The elimination of the inflation proposal in the Company's net salvage calculation
8 would result in a reduction to its depreciation expense of \$12.5 million as of
9 December 31, 2009.

10
11 **Q. IS THE COMPANY'S FUTURE INFLATION PROPOSAL IN THIS CASE**
12 **APPROPRIATE?**

13 A. No. The inclusion of inflation in the net salvage calculation as proposed by the
14 Company is inappropriate. Moreover, the Company's approach fails to recognize any
15 discounting of future inflated values back to the present period. This failure to
16 discount back to the present is a fatal flaw in the Company's proposal and
17 unreasonably attempts to saddle current customers with cost levels anticipated 30 to
18 50 years in the future.

19
20 **Q. HAVE OTHER REGULATORY AGENCIES DENIED REQUESTS FOR INCLUSION**
21 **OF FUTURE INFLATION IN THE CALCULATION OF PRODUCTION PLANT NET**
22 **SALVAGE?**

23 A. Yes. Recently, the Oklahoma Corporation Commission ("OCC") denied the identical
24 request.²⁸ Another example is the Nevada Public Service Commission ("NPSC") in
25 consolidated Docket Nos. 91-5032 and 91-5055. In that case, the NPSC stated the
26 following:²⁹

27
28 Since NPC has no terminal salvage and cost of removal experience for steam
29 and combustion turbine generating units, Mr. Ferguson [the utility witness]
30 relied on demolition studies of other utilities, adjusted for the expected
31 inflation between the study date and the date of removal, in determining his
32 recommended rates....
33

²⁸ OCC Cause No. 200800144.

²⁹ NPSC's Final Order for Nevada Power Company in Docket No. 91-5032 and 91-5055.

1 Mr. Pous criticized Mr. Ferguson for applying inflation to the cost of removal
2 or demolition studies without also taking into consideration other factors such
3 as the potential sale of production facilities or increased labor productivity,
4 which might have impact gross salvage or cost of removal....

5
6 Mr. Pous' arguments regarding the unreasonableness of Mr. Ferguson's
7 proposed net salvage factors for Steam Production Plant are persuasive. It is
8 apparent that Mr. Ferguson has selected only a limited number of demolition
9 studies and interpreted them in a manner to support his position without
10 adequately considering all factors involved. (*Emphasis added.*)
11

12 The concept underlying net salvage for depreciation purposes is to estimate a
13 reasonable level of net salvage to include in current rates so that current customers
14 will pay their fair share of such costs. To assume that inflation is the only factor that
15 impacts future cost of removal is simply wrong. Many areas of construction or
16 demolition that entail potentially large costs are subject to technological changes and
17 process improvements. For example, the demolition or toppling of large smoke
18 stacks rather than dismantling such structures brick by brick is one obvious such
19 improvement.
20

21 **Q. IS THERE ANOTHER SIGNIFICANT REASON WHY INFLATION AS PROPOSED**
22 **BY THE COMPANY IS INAPPROPRIATE?**

23 A. Yes. Current customers should pay their current cost in current dollars. Under the
24 Company's proposal, customers would be forced to pay for future costs established
25 at a future dollar level without any discounting back to current dollar levels. This is
26 simply not a logical conclusion and is not an accepted practice in utility ratemaking.
27 For example, when future inflation is taken into account in the establishment of
28 external decommissioning fund payments for nuclear plants, not just an inflation or
29 escalation rate is included in the overall calculation, but a discount rate is included
30 as well. The discount rate is included in order to recognize the time value of money
31 that manifests between a dollar being spent today and a dollar spent at some point
32 in the future. The Company's total failure to recognize a discount rate is a fatal flaw
33 in its proposal. Moreover, even when the impact of a rate base reduction for net
34 salvage is recognized, it still does not cure the problem. If current customers are
35 forced to pay for future inflated costs, it is future customers that will be subsidized

1 and will not pay for their fair share of costs, since historical customers would have
2 overpaid by paying for future costs with prior period current dollars.

3
4 **Q. ARE YOU AWARE OF ANY CASE WHERE FERC HAS APPROVED THE**
5 **RECOGNITION OF FUTURE INFLATED COST WITHOUT ALSO RECOGNIZING**
6 **THE DISCOUNTING OF COST BACK TO PRESENT PERIODS?**

7 A. No.

8
9 **C. Proposed Level of Inflation**

10
11 **Q. WHAT INFLATION LEVEL DOES THE COMPANY PROPOSE FOR ESCALATING**
12 **FUTURE DECOMMISSIONING COSTS FOR POWER PLANTS?**

13 A. Gannett Fleming proposes a 3.4% annual level of inflation associated with all
14 Production plant decommissioning estimates.³⁰

15
16 **Q. WHAT IS THE BASIS FOR THE 3.4% ASSUMED LEVEL OF INFLATION?**

17 A. Gannett Fleming bases its proposed level of future inflation on a 30-year historic
18 period as reflected in the Handy Whitman report, *Cost Trends of Electric Utility*
19 *Construction, North Atlantic Region* for the period 1980 through 2009.³¹ Gannett
20 Fleming assumes that the resulting value of 3.4% is “a proxy for long-term inflation
21 rate.”³²

22
23 **Q. WHY DID GANNETT FLEMING BELIEVE THAT RELIANCE ON THE LONG-TERM**
24 **HISTORICAL LEVEL OF INFLATION, AS REPORTED BY HANDY WHITMAN,**
25 **WAS AN APPROPRIATE PROXY TO USE?**

26 A. Gannett Fleming states that the Handy Whitman cost index has the advantages that
27 it is (1) electric utility-specific, and (2) specific to steam and hydro plants.³³

28

³⁰ 2009 Study at page II-31.

³¹ *Id.*

³² *Id.*

³³ Response to CA IR-01.

1 **Q. IN THE EVENT THE BOARD WERE TO CONSIDER RECOGNITION OF FUTURE**
2 **INFLATION, WOULD GANNETT FLEMING'S PROPOSED 3.4% ANNUAL LEVEL**
3 **BE APPROPRIATE?**

4 A. No, for several reasons. First, currently the world economy is much more integrated
5 than it was 20 or 30 years ago. The economies of China and India are expanding at
6 rapid rates and are demanding substantial quantities of raw materials. This
7 phenomenon is not reflected in the quantification of historical inflation rates 20 or 30
8 years ago. This is significant since prices for scrap material have increased more
9 rapidly than general inflation. For example, copper has gone up in the range of
10 1000% in the last six or seven years.

11
12 Since copper, brass, steel, and other raw materials are precisely the type of scrap
13 materials that are found in large quantities at power plants, recognition of future
14 inflation, if it were to transpire in developing depreciation rates, would be to reduce
15 future costs, since raw material costs will have escalated dramatically faster than
16 future anticipated labor costs. Thus, even the 1.92% future inflation value reflected in
17 the Company's 2009 IRP Update most likely does not properly recognize the impact
18 of inflation from the standpoint of net salvage for Production facilities. Inflation, as it
19 applies to construction of future generating stations, will exhibit a different pattern
20 than that associated with the decommissioning of existing generating facilities.

21
22 **Q. WHAT IS THE SECOND REASON WHY THE 3.4% INFLATION LEVEL**
23 **PROPOSED BY GANNETT FLEMING IS INAPPROPRIATE?**

24 A. Depreciation studies are generally performed every three to five years. The reason
25 for this is not only to capture the changes in plant additions and retirements, but also
26 to recognize changes in underlying factors that affect both life and salvage
27 parameters. Inflation is one of those factors that does have an impact, along with
28 other factors such as changes in productivity, changes in practices and policies, etc.
29 Since depreciation studies are normally performed every three to five years, using a
30 long-term inflation factor that is intended to cover periods of 30 to 50 years is
31 unnecessary and inappropriate. Obviously, longer planning horizons for inflation lead
32 to less precise estimates. Short-term estimates of three to five years and, in general,
33 no more than 10 years are more than adequate to capture anticipated future inflation

as it applies to its recognition in depreciation studies. Indeed, the recent turmoil in the financial markets has actually caused most inflation indices to identify a negative level of annual inflation in recent time periods. Due to the continued uncertainty associated with the world economic markets, short-term rates should be given greater credence in the event the Board is inclined to recognize them for escalating future decommissioning costs, a practice I believe is inappropriate.

Q. IF THE BOARD WERE INCLINED TO EMPLOY AN INFLATION RATE FOR DEPRECIATION PURPOSES, WHAT DO YOU BELIEVE IS A MORE APPROPRIATE VALUE?

A. The inflation calculator developed by the Bank of Canada for the last five or six years ranges from approximately 1.6% to almost 2%. If the Board were inclined to require the Company to file a new depreciation study within the next three to five years, then I believe the 1.92% rate reflected in the 2009 IRP Update would serve as a more realistic proxy, although is still potentially excessive due to the potential impact of net salvage. If the Board were inclined to leave the timing of the filing of the Company's next depreciation study up to the Company, then I would be more inclined to recommend the lower end of the above-noted range, 1.6%. Again, it must be noted that these percentages are not intended to measure future inflation for construction purposes, but are more so a high-side proxy for inflation from a decommissioning standpoint, if the Board is inclined to recognize future inflation.

D. Contingencies

Q. WHAT LEVEL OF CONTINGENCY HAS NSPI PROPOSED IN ITS DECOMMISSIONING COST ESTIMATE?

A. The Company proposes a 25% contingency.³⁴

Q. WHAT IS THE DOLLAR IMPACT OF CONTINGENCIES?

A. Out of the approximately \$170 million of decommissioning cost recommended by Stantec and Yates through the various decommissioning studies, approximately \$34

³⁴ Stantec, Inc., study, Appendix C at page 17, note 1; and Yates study, Appendix D at page 1.

1 million is attributed solely to the proposed 25% contingency.³⁵ This amount
2 increases significantly after Mr. Wiedmayer of Gannett Fleming performs his inflation
3 calculation.
4

5 **Q. WHAT IS THE BASIS FOR THE COMPANY'S INCLUSION OF A CONTINGENCY?**

6 A. The Company's basis for its 25% contingency is to eliminate any financial risk for
7 potential under-recovery of costs that may occur.³⁶ Further, the use of a 25%
8 contingency factor eliminates risks that the estimator failed to capture "all the
9 eventual costs" that might transpire in the future. The Company also claims that the
10 contingency is intended to ensure that the total cost estimate is a better
11 representation of probable cost.³⁷
12

13 **Q. DO YOU BELIEVE THAT THE 25% CONTINGENCY PROPOSED BY THE**
14 **COMPANY IS REASONABLE AND APPROPRIATE?**

15 A. No. First, it must be recognized that contingencies can be either positive or negative.
16 If very conservative cost estimates have been made throughout the
17 decommissioning cost estimating process, then a positive contingency may be
18 appropriate. However, if inefficient assumptions for productivity and labor rates are
19 employed in the estimation of decommissioning costs, then a negative contingency
20 would be appropriate. The cost estimation process for Stantec and Yates have been
21 characterized as opinion cost estimates.³⁸ Therefore, if a contingency is to be
22 recognized, it should be minimal, as one would expect the opinion to be the entity's
23 best estimate. Unfortunately, there are no detailed analyses that can be analyzed to
24 obtain a more definable position.
25

³⁵ 2009 Study at pages II-32 – 34.

³⁶ Response to DUC IR-100 and Avon IR-12.

³⁷ *Id.*

³⁸ Response to DUC IR-101.

1 **Q. HAVE OTHER REGULATORS LIMITED THE LEVEL OF CONTINGENCIES IN**
2 **DECOMMISSIONING COST STUDIES, EVEN WHEN SUPPORTED BY DETAILED**
3 **CALCULATIONS?**

4 A. Yes. For example, the Public Utility Commission of Texas limits contingencies for
5 nuclear decommissioning cost estimates to a maximum of 10%.³⁹ The uncertainties
6 in decommissioning a nuclear power plant with potential problems associated with
7 radioactive materials, burial costs, and so forth present situations requiring
8 potentially greater levels of contingency than those for demolishing non-radioactive
9 power plants. Therefore, the proposed 25% contingency is excessive and should be
10 denied.

11
12 **E. Worst-Case Scenario**
13

14 **Q. IS THE COMPANY'S PRESENTATION OF DECOMMISSIONING ACTIVITIES**
15 **REPRESENTATIVE OF THE VARIOUS TERMINAL RETIREMENT OPTIONS?**

16 A. No. The Company's proposal for decommissioning its plant and removing all
17 facilities, as well as removing facilities one meter below grade, basically represents
18 the worst-case scenario of the various options available.

19
20 **Q. WHAT IS THE RANGE OF OPTIONS AVAILABLE FOR TERMINAL RETIREMENT**
21 **OF POWER PLANTS?**

22 A. The post-retirement options normally range from complete demolition and site
23 restoration to sale of the facilities without any demolition activities. In between these
24 extremes are varying levels of limited demolition and limited sales of assets.

25
26 **Q. DID THE COMPANY PROVIDE ANY INVESTIGATION INTO POTENTIAL**
27 **ALTERNATIVES TO FACILITIES DEMOLITION AND SITE RESTORATION?**

28 A. No. The Company has not presented any evidence that would indicate that it
29 considered even partial sale of equipment. This, in effect, assumes that all assets at

³⁹ Application of Entergy Texas for Approval of Its Transition to Competition Plan and the Tariffs Implementing the Plan and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs, Docket No. 16705, Second Order on Rehearing, FOF 178 (Oct. 14, 1998).

1 a power plant will have no value other than scrap value. Such an approach is
2 inconsistent with the Company's request for interim retirements.

3
4 **Q. PLEASE EXPLAIN THE INCONSISTENCY BETWEEN THE COMPANY'S**
5 **DECOMMISSIONING COST ESTIMATES AND ITS REQUEST FOR INTERIM**
6 **RETIREMENTS?**

7 A. The Company's request for interim retirements represents the replacement of
8 components of a power plant that retire prior to the final retirement of the generating
9 facility. In other words, if a boiler feed pump were to retire and be replaced, that
10 would represent an interim retirement. Thus, when a generating plant is finally shut
11 down, there may be numerous items of investment that are relatively new, are still
12 functional, and can provide services to another owner or possibly at another
13 generating unit of the Company.

14
15 **Q. IS THERE CERTAINTY THAT THERE WILL BE A BUYER FOR USED**
16 **EQUIPMENT AT SOME POINT IN THE FUTURE?**

17 A. No. However, there is very little associated with depreciation that deals with
18 certainty, and thus certainty is not the appropriate standard. Depreciation is a
19 projection of potential events in the future, and the Company has not demonstrated,
20 nor can it demonstrate, that there is a zero probability of partial or full sale of
21 generating facilities at the time of retirement 30 or 40 years into the future. It is
22 unreasonable and inappropriate to assign no weight to a potential option and assign
23 100% weight to the scenario that transfers all of the financial risk from shareholders
24 to current customers.

25
26 **Q. ARE YOU AWARE OF A RECENT INSTANCE WHERE A POWER PLANT WAS**
27 **DEMOLISHED AND STILL PRODUCED A POSITIVE, RATHER THAN NEGATIVE,**
28 **NET SALVAGE?**

29 A. Yes. The King Generating Station in Ft. Pierce, Florida, was demolished in the last
30 few years. The demolition contractor actually paid the owner for the right to tear
31 down the plant. The demolition contractor anticipated selling portions of the
32 generating station as operating equipment and scrapping the remainder at high
33 scrap metal prices.

1
2 **Q. HAVE YOU TESTED THE ASSUME PRODUCTIVITY FACTORS, QUANTITIES OF**
3 **SCRAP METALS, SCRAP METAL PRICES, AND OTHER FACTORS THAT**
4 **IMPACT DECOMMISSIONING COST ESTIMATES?**

5 A. No, because they do not exist. Most decommissioning cost estimates are comprised
6 of various building blocks, such as labor rates, crew mixes, productivity factors,
7 quantities of materials, etc. Unfortunately, in this case, the Company's
8 decommissioning cost estimates do not contain a sufficient level of detail to provide
9 such factors. Indeed, the Company states that the decommissioning cost estimation
10 process for its Steam and Other Production power plants "does not call for a
11 breakdown of tasks and estimates of quantities of time and materials to be disposed.
12 Costs were the result of an estimate expressed by a sub-consultant-specialist, using
13 their experience of costs at many other similar sites."⁴⁰ (*Emphasis added.*) In
14 addition, the Company stated that it did not commission any analysis "to develop
15 estimates of the quantity of scrap metal that could be recovered at each plant, nor
16 were prices acquired for such scrap metal on a per-unit basis. The demolition
17 estimates were deemed to include any potential value that the contractor might
18 obtain from disposal by sale rather than by waste disposal to meet current
19 environmental regulations."⁴¹ (*Emphasis added.*) Finally, when requested to provide
20 cost factors associated with the decommissioning cost estimates and the underlying
21 supporting documentation and justification for each value, the Company responded
22 by stating that Stantec "did not use cost factors to develop an overall opinion of
23 probable costs. For Appendix D, J.B. Yates Engineering used its experience with
24 construction, maintenance, repair and refurbishment at all 34 active NPSI hydro
25 sites. This experience provides a perspective on actual requirements for demolition
26 and decommissioning at each site and affords the consultant an ability to
27 conceptualize project planning for those tasks at each site and to derive related
28 estimated demolition/decommissioning costs in accordance with the agreed scope of
29 the study."⁴² (*Emphasis added.*)

⁴⁰ Response to DUC IR-099.

⁴¹ Response to DUC IR-098.

⁴² Response to DUC IR-101.

1 **Q. DO THE COST ESTIMATES ASSOCIATED WITH THE HYDRO**
2 **DECOMMISSIONING COSTS INCLUDE AN ALLOWANCE FOR WHAT MIGHT BE**
3 **EXPECTED AS THE WORST-CASE ARCHAEOLOGICAL COST SCENARIO FOR**
4 **EACH SITE?**

5 A. Yes. The hydro decommissioning cost estimates specifically include some
6 unidentifiable level for an allowance associated with “a worst-case archaeological
7 cost scenario for each site.”⁴³
8

9 **Q. IS THERE ANY REASON TO ACCEPT THE RESULTS OF DECOMMISSIONING**
10 **COST STUDIES THAT ONLY LOOK AT ONE ALTERNATIVE IN DETERMINING**
11 **DEPRECIATION RATES?**

12 A. No. Just as is the case for setting life spans for generating units or other aspects of
13 depreciation, analysis of all meaningful facts and circumstances are appropriate. The
14 appropriate practice for determining realistic depreciation parameters is to
15 investigate reasonable alternatives in order to arrive at the most representative
16 result. Reliance on the worst-case scenario approach is inappropriate and fails to
17 properly recognize and consider other alternatives.
18

19 **F. Site Excavation and Disposal Costs**
20

21 **Q. WHAT DOES THE COMPANY PROPOSE FOR SITE EXCAVATION AND**
22 **DISPOSAL COSTS ONCE POWER PLANT FACILITIES AND EQUIPMENT HAVE**
23 **BEEN DEMOLISHED?**

24 A. The decommissioning studies either specifically or implicitly recognize the
25 “restoration of the site to grade, following removal of structures to a depth of 1 metre
26 below grade.”⁴⁴ This process results in excessive amounts for site excavation and
27 disposal costs for purposes of establishing depreciation rates in this case.

⁴³ Yates Engineering, Ltd., Decommissioning Study at page 3.

⁴⁴ Response to DUC IR-102.

Q. ARE THE PROPOSED SITE-RELATED RESTORATION COSTS REASONABLE AND APPROPRIATE?

A. No. First, it must be noted that neither Stantec nor Yates have provided support for any site restoration costs. More important is the fact that the offsetting value associated with the sale of the improved land is not reflected in the decommissioning cost estimate. It is inconsistent and unreasonable for NSPI to request any costs for site restoration and improvements if the related increase in land value is not also recognized. The request for site improvement costs aimed solely at providing a more user-friendly result for the future reuse or sale of the site further renders the studies unrealistic for depreciation purposes.

Q. WHY IS NSPI'S FAILURE TO INCLUDE THE POTENTIAL SALE VALUE OF LAND SIGNIFICANT?

A. Often, the vast majority or a significant level of the cost involved in the decommissioning of a power plant, as characterized by cost estimators, is associated with soil and ash removal, excavation, and reseeded related to the site or land. An example of the magnitude of such costs for NSPI is the Point Tupper Thermal Station. For that station, Stantec estimated that 48% of the decommissioning costs are due to site remediation issues.⁴⁵ These activities are not associated with items of depreciable plant, but rather they are components of the land upon which the Production facilities reside. In other words, the decommissioning of power plant equipment that was subject to depreciation is already addressed prior to the disposal of soil and ash from the ash pond or seeding the site. Those site-related components of the decommissioning cost estimates are not related to the removal of depreciable equipment, but are associated with the land. Therefore, if the cost to restore land to an improved condition is to be recognized, then the sale value of the land must also be recognized. Obviously, the restoration of the land and removal of ash enhances the value of the land. If land values are not at issue in the cost estimating process, then the cost for enhancing the value of the land should also be removed and treated as a component of the

⁴⁵ Stantec study, Appendix C at page 21.

offset to the sale value or reuse of the property. Consistency in the depreciation process is required.

Q. IF THE BOARD REQUIRES NSPI TO BE CONSISTENT IN ITS TREATMENT OF THE VALUE OF GENERATING SITES AND THE COST TO RESTORE THE GENERATING SITE, DOES THAT HAVE AN IMPACT ON THE DEPRECIATION REQUEST?

A. Yes. As previously noted, some portion of the proposed decommissioning costs for NSPI's generating units is related to the restoration of the generating site. Proper and consistent treatment of site value and site restoration costs can have a dramatic impact on decommissioning cost estimates. However, as previously noted, neither Stantec nor Yates performed their analyses in such a manner as to permit an investigation of such costs.

G. Summary

Q. PLEASE SUMMARIZE THE CONCERNS IDENTIFIED IN REVIEW OF THE COMPANY'S PROPOSED PRODUCTION PLANT NET SALVAGE.

A. The Company has commissioned two different entities to perform limited decommissioning cost estimates. These entities may have complied with their level of engagement, but the resulting studies are not adequate to support the significant request for negative net salvage associated with the Company's production facilities. Indeed, in a recent similar situation where the underlying basis for the cost estimates were provided, the actual decommissioning cost experienced by a utility was only 25¢ on the dollar of what the cost estimators had proposed.⁴⁶

Other problems reflected in the Company's analysis are the unjustified inclusion of a 25% contingency, inclusion of future inflation (and at an excessive rate), and failure to analyze other alternatives other than full dismantlement and site restoration.

⁴⁶ The demolition of Clark Units 1 – 3, owned by Nevada Power Company. Black & Veatch, an international engineering firm, developed the cost estimates in more detail than either the Stantec or Yates studies, but when the units were demolished, the actual decommissioning costs were dramatically less than had been estimated only a few years prior to the demolition.

Therefore, such studies and the subsequent inflation activities developed by Gannett Fleming render the Company's presentation unreasonable for regulatory purposes.

Q. WHAT DO YOU RECOMMEND?

A. While the Company's proposed level of negative net salvage is excessive and cannot be relied upon, some level of net salvage may be warranted until the Company can present a well-documented and well-supported alternative. Therefore, I recommend that the proposed decommissioning cost estimates, less the 25% contingency, be relied upon as a conservative estimate for depreciation purposes.

Q. WHAT DO YOU RECOMMEND REGARDING THE RECOGNITION OF FUTURE INFLATION?

A. As previously noted, such proposal by the Company is inappropriate. Therefore, it must be eliminated. The final negative net salvage costs to be utilized should exclude any inflation calculation as proposed by Gannett Fleming, thus rendering the Stantec and Yates decommissioning cost studies, without the impact of the 25% contingency, as my conservative recommendation.

Q. WHY DO YOU CONSIDER SUCH AN APPROACH CONSERVATIVE?

A. As previously noted, the Company has included substantial site remediation costs in its base decommissioning cost studies. Such costs should not be included, given that the Company has not included the potential offsetting value associated with the sale or reuse of the land once the site has been improved after decommissioning. Therefore, allowing such amounts to be included for purposes of this case renders my recommendation a conservative estimate, given the facts presented by the Company.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a \$141,458,259 level of Production plant negative net salvage compared to the Company's proposed \$467,801,286 level. This represents a reduction of \$326,343,027 in overall decommissioning costs. The annual impact of this recommendation is a \$12,740,955 reduction to depreciation expense based on plant as of December 31, 2009.

SECTION V: INTERIM RETIREMENTS

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. The Company has modified life spans for its generating facilities to reflect interim retirements. The approach utilized by the Company to implement the impact of interim retirements incorporates truncated Iowa Survivor curves estimated based on actuarial analysis of historical data. While the Company's approach is inappropriate, given the Company's presentation of data and the time available, no specific adjustments have been made in this proceeding. Thus the overall recommendation for Production plant depreciation rates is most likely excessively high due to recognition of the Company's proposed interim retirements.

Q. WHAT ARE INTERIM RETIREMENTS?

A. The short answer is that interim retirements represent the estimated replacement of investment at generating plants before the final termination or retirement of the plant. In other words, the investment in an item such as a boiler feed pump may be retired after 40 years, while the terminal retirement date for the plant is longer than 50 years of operation. Thus the original cost of the first boiler feed pump would need to be recovered before the final retirement date, plus the cost of the replacement boiler feed pump would also have to be recovered by the time of final retirement of the investment. Interim retirements attempt to fine-tune the life span approach to dollar weight the replacement activity that transpires over the life of the investment.

Q. WHAT APPROACH HAS THE COMPANY EMPLOYED?

A. The Company has employed an actuarial analysis of the retirement activity at its various generating facilities. The Company proposes one interim retirement life-curve combination for all investment at its Steam Production generating facilities, and a different interim retirement life-curve combination for Hydro and Other Production and the marine terminal at Point Tupper.

1 **Q. WHAT IS THE PROBLEM WITH THE COMPANY'S PRESENTATION?**

2 A. The investment in these accounts is not homogeneous to the extent necessary to
3 properly perform an actuarial analysis of interim retirements. While the calculations
4 in an actuarial analysis can be made with any combination of assets or categories,
5 one must recognize that the results may not be appropriate. For example, if a taxi
6 cab company has a fleet of vehicles comprised of Mercedes and Yugos, the
7 historical analysis can be greatly skewed compared to the remaining investment.
8 Mercedes are more costly and reflect a much higher quality of product, while a Yugo,
9 being much less costly, is of such poor quality that it is no longer being sold in North
10 America. The historical database most likely comprises a disproportionate share of
11 Yugo-related retirement activity compared to the current investment in the account.
12 Thus, the results of an actuarial analysis of this type of database would produce a
13 result, but it would not be appropriate to apply the actuarial results to the remaining
14 investment.

15
16 **Q. HAS ANOTHER REGULATORY BODY SPECIFICALLY REVIEWED THIS ISSUE**
17 **RECENTLY AND DETERMINED THAT THE APPROACH EMPLOYED BY**
18 **GANNETT FLEMING IS NOT ACCEPTABLE?**

19 A. Yes. The Florida Public Service Commission ("FPSC"), in a recent Florida Power &
20 Light ("FPL") proceeding, denied the use of the approach employed by Gannett
21 Fleming with regards to interim retirements in that proceeding.

22
23 **Q. WHY HAVE YOU NOT ADJUSTED THE COMPANY'S INTERIM RETIREMENT**
24 **CALCULATION IN THIS PROCEEDING?**

25 A. First and foremost, the data was not provided in a usable format on a timely basis.
26 Second, the overall time period available to review the Company's depreciation
27 presentation does not permit analysis of all components of the Company's request.
28 Third, the overall impact of modifying the interim retirements may not necessarily be
29 significant. However, it is still appropriate to identify the potential problem for the
30 Board.

31

SECTION VI: MASS PROPERTY LIFE ANALYSIS

A. General

Q. WHAT IS THE PURPOSE OF THE LIFE PORTION OF A DEPRECIATION ANALYSIS FOR MASS PROPERTY?

A. The purpose of a life analysis is to determine the average service life, the dispersion pattern, and remaining life for each account. This information is necessary in order to properly perform the depreciation calculation previously noted. A longer average service life normally results in a longer remaining life, and therefore a lower depreciation expense. Alternatively, a shorter average service life will normally reduce the remaining life and increase depreciation expense. The dispersion pattern is important, as it is critical in the overall selection process of the best-fitting Iowa Survivor curve indications and impacts the calculation of remaining life. The same average service life with different Iowa Survivor curves also results in different remaining lives due to the expected pattern of retirements.

Q. WHAT ARE THE MAIN TOOLS UTILIZED IN PERFORMING LIFE ANALYSES?

A. Life analyses are normally performed either through the use of actuarial or semi-actuarial analyses. Actuarial analyses rely on aged data. In other words, when an item of property is retired, the age at retirement is known. This is identical to the type of analysis performed by insurance companies in developing life tables in order to establish premiums. Semi-actuarial analyses are performed in instances where the age of plant retired is not known.

Q. WHAT METHOD DID THE COMPANY USE?

A. The Company took the very unusual step of taking unaged data for its mass property accounts, performing what is called a Computed Mortality analysis, which attempts to create an age distribution for the unaged data, and then performing actuarial analysis on the manufactured aged data.⁴⁷

⁴⁷ 2009 Study at page II-24 – 25 and Response to DUC IR-124.

1 **Q. HOW DID THE COMPANY PERFORM ITS COMPUTED MORTALITY ANALYSIS?**

2 A. The Company utilized the Simulated Plant Records ("SPR") semi-actuarial analysis
3 for support in the selection of survivor curves to be used to create synthetic aged
4 data through the Computed Mortality process.⁴⁸ In other words, Gannett Fleming
5 effectively guessed at dispersion patterns that were then used to create synthetic
6 aged data from unaged data, which was then used in actuarial analyses.
7

8 **Q. IS THIS PROCESS TYPICAL?**

9 A. No. It is very unusual. Normally, if aged data is not available, semi-actuarial analyses
10 utilizing the SPR process is the industry standard. Unfortunately, Gannett Fleming
11 used the SPR analysis only for an indication of the selected Iowa Survivor curve to
12 be used in its Computed Mortality analysis.
13

14 **Q. WHY DID THE COMPANY SIMPLY NOT USE THE SPR ANALYSIS?**

15 A. The Company states that Gannett Fleming "considered" the Computed Mortality
16 method to be superior to the SPR approach.⁴⁹ Gannett Fleming's consideration was
17 that an actuarial analysis allowed for more robust selection of life estimates, that
18 Computed Mortality provided aged balances (albeit manufactured), and the use of
19 the combined Computed Mortality and actuarial analysis did not require an
20 assumption inherent in the SPR analysis that property has experienced a constant
21 life and retirement dispersion for all years of analysis.⁵⁰
22

23 **Q. DO YOU AGREE WITH GANNETT FLEMING'S PRESENTATION?**

24 A. No, and neither do most utilities who do not utilize Computed Mortality as an
25 acceptable method, but rather rely on SPR analyses when unaged data is all that is
26 available.
27

⁴⁸ Response to DUC IR-126.

⁴⁹ *Id.*

⁵⁰ *Id.*

1 **Q. HOW HAVE YOU TREATED THE COMPANY'S PRESENTATION OF A HYBRID**
2 **APPROACH TO MASS PROPERTY LIFE ANALYSIS?**

3 A. Given the presentation by the Company and the time available, I have reviewed the
4 observed life tables that result from the Company's performed hybrid actuarial
5 analyses. The actuarial derived observed life table represents the pattern of
6 retirement by age of the assets being analyzed. It is presented in the form of a
7 survivor curve beginning at 100% surviving and declining as retirements are
8 observed. I would not recommend the Computed Mortality approach for future
9 proceedings.

10
11 **Q. PLEASE EXPLAIN THE LIFE ANALYSIS PROCESS EMPLOYED BY THE**
12 **COMPANY TO DERIVE ITS PROPOSED LIFE-CURVE COMBINATION FOR**
13 **DEPRECIATION PURPOSES.**

14 A. Subsequent to the Company's Computed Mortality decision, it performed actuarial
15 analysis. This simply means that Gannett Fleming analyzed different historical time
16 periods and estimated what it believed to be a representative retirement frequency
17 pattern or survivor pattern from such historical data. The results of the actuarial
18 analyses are identified as observed life tables. The numerical observed life table is
19 plotted and then compared to standard Iowa Survivor curves in order to estimate the
20 best-fitting life-curve combination, which provides a complete statistical indication of
21 the expected average service life of the investment from a historical basis.

22
23 **Q. IS THE PROCESS OF MATCHING AN OBSERVED LIFE TABLE WITH**
24 **STANDARD IOWA CURVES A SITUATION WHERE ALL POINTS IN THE**
25 **CURVE-FITTING PROCESS ARE GIVEN EQUAL WEIGHT?**

26 A. No. Both the Company and I recognize that the dollar level of exposures to
27 retirement in any given age interval has an impact on the degree of significance
28 given to that point in the matching process. In other words, it would be unreasonable
29 to select an Iowa Survivor curve that better matches the observed life table near the
30 "tail" or lower portion of the observed life table while sacrificing a better match in the
31 middle or upper portion of the survivor curve because of the dollar level of
32 exposures. For example, for the life-curve combination and actuarial analysis
33 presented by Gannett Fleming in the 2009 Study for Account 364, the beginning

dollar level of exposures at age 0 is approximately \$480 million. Alternatively, the dollar level of exposures drops to only \$6,730 at age 62.5 years. It would be foolish to force the curve to fit the \$6,730 level of exposures while sacrificing a better fit to exposures in the tens or hundreds of millions of dollars.⁵¹

Q. ARE THERE OTHER CONSIDERATIONS IN THE CURVE-FITTING PROCESS?

A. Yes. While Gannett Fleming only providing the longest band analysis in its depreciation study, it actually performed two additional shorter band analyses for each account. The band analyses consist of both placement and experience bands and may provide different life indications depending on the bands selected.

Placement bands can be varied to capture the impact of different types of material within an account. For example, the Company has used different types of underground cable over time. Some of the earlier generations of cable have not performed well and have retired on a premature basis. If one wanted to exclude the impact of certain types of faulty product that are generally no longer in service, a placement band that excludes those investments should be selected. Alternatively, experience bands capture trends in the life indications of the plant due to changing practices, policies, laws, etc. For example, the Company has implemented a pole inspection program in the last 20 years and has increased the frequency of pole inspections since the beginning of 2003. Thus, 10- and 20-year experience bands would tend to capture the impact of such change in operating practice, while reliance on an experience band that dates back 50 or 60 years would diminish the recognition of such new practice.

Q. WHY IS THE RECOGNITION OF SHORTER EXPERIENCE BAND ANALYSES PERFORMED BY GANNETT FLEMING IMPORTANT IN THIS PROCEEDING?

A. While Gannett Fleming chose not to acknowledge the existence of or present the results of the additional analyses in the 2009 Study, as will be demonstrated later in the testimony, those results provide significant and meaningful information in the selection process. The Company, as well as the rest of the industry, has been

⁵¹ Response to CA IR-006.

1 experiencing longer expected lives for investment over time. Such trend for longer
2 lives are reflected in the shorter experience band analyses performed, but not
3 initially provided, by Gannett Fleming. The Gannett Fleming presentations and
4 selections, as reflected in the 2009 Study are indicative of the very long placement
5 and experience band combinations that tend to hide the impact of changes in plant
6 investment, Company policies and practices, as well as other recent impacts.

7
8 **Q. HAS THE COMPANY SPECIFICALLY IDENTIFIED THE UNDERLYING**
9 **FACTORS, BY ACCOUNT, UPON WHICH IT MADE ITS PROPOSALS?**

10 A. No. The Company has made a generalized statement covering the concept of
11 judgment, statistical analyses, Company policies and outlook, estimates from
12 previous studies, and comparison with other utilities.⁵² While Gannett Fleming made
13 such reference, when requested to provide a detailed narrative identifying the
14 specific steps undertaken to arrive at its proposed average service life by account,
15 the response stated that the statistical support for the estimated survivor curves is
16 set forth in Appendix A, which is the 2009 Study.⁵³ The Company also admits that
17 general information external to the statistical analysis led to no significant departure
18 from the indicated survivor curves for the mass property accounts analyzed.⁵⁴ In
19 other words, the statistical information provided in the 2009 Study is the only basis
20 for the Company's proposal. It is important to recall that the information contained
21 within the 2009 Study failed to reference or identify the shorter statistical band
22 analyses performed by Gannett Fleming for each account.

23
24 **Q. HAVE YOU REVIEWED ALL OF THE COMPANY'S SUPPORT FOR ITS VARIOUS**
25 **ANALYSES?**

26 A. Yes. I have reviewed the Company's analyses and support. Based on this review, I
27 have identified numerous problems with the Company's various proposals
28 associated with the accounts analyzed. Therefore, of the nine accounts analyzed, I
29 am recommending longer service lives for eight of those accounts. The nine
30 accounts analyzed represent 76% of the investment in mass property accounts and

⁵² 2009 Study at page II-26.

⁵³ Response to DUC IR-063.

⁵⁴ *Id.*

67% of the requested depreciation expense. My recommendations, as well as the Company's proposal for each account, are set forth in the table below.

Account	Company's Proposed Curve	DUCI Recommended Curve	Adjustment
353 – Transmission Station Equipment	42 R2.5	47 R2.5	\$1,521,493
355 – Transmission Poles and Fixtures	47 R2	49 R2	\$1,343,517
356 – Transmission Overhead Conductors and Devices	45 R3	45 R3	No Adjustment
362 – Distribution Station Equipment	48 R1.5	50 R2.5	\$20,947
364 – Distribution Poles, Towers and Fixtures	38 R2.5	41 R2	\$3,714,158
365 – Distribution Overhead Conductors and Devices	38 R2.5	41 R2	\$1,630,929
367 – Distribution Underground Conductors and Devices	43 R3	46 R3	\$254,924
368 – Distribution Line Transformers	30 R1	35 S-0.5	\$4,408,062
369 – Distribution Services	42 S3	44 S3	\$1,245,262
Total			\$14,139,292

The combined impact of the various adjustments I recommend above results in a reduction in annual depreciation expense of \$14,139,292 based on plant as of December 31, 2009, and further reflects the impact of relying on an ALG calculation procedure.⁵⁵

⁵⁵ No attempt has been made to quantify the impact on an ELG calculation procedure basis given the format of the available data and the problems with the ELG life group calculation procedure discussed elsewhere.

B. Account-Specific

1. Account 353

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 353 – TRANSMISSION STATION EQUIPMENT?

A. The Company proposes a 42 R2.5 life-curve combination.⁵⁶

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSAL?

A. In addition to the previously-noted generalized standard statements contained in the reference by Gannett Fleming in its depreciation study, the Gannett Fleming interview notes added that the primary cause of retirement of transformers is failure due to lightning, poor design, water ingress, internal deterioration, and through fault currents. Reference is also made to transformers built in 1960 and before being over-designed and built with more insulation and copper. In addition, reference is made to another major investment component corresponding to circuit breakers, and the potential problems with moving parts and maintenance as circuit breakers age. However, the Company has implemented diligent maintenance practices, such as re-coating, such that circuit breakers are now expected by the Company to last 40 to 50 years. The Company also identified the fact that it is now performing more diagnostic tests on its transformers, which helps to identify problems and allows for corrective actions such that the investment will provide service for a longer period of time.⁵⁷

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal, while a step in the right direction, still reflects an artificially short average service life. Therefore, at this time, I recommend a further increase in average service life to 47 years, while retaining the R2.5 dispersion pattern.

⁵⁶ 2009 Study at page III-6.

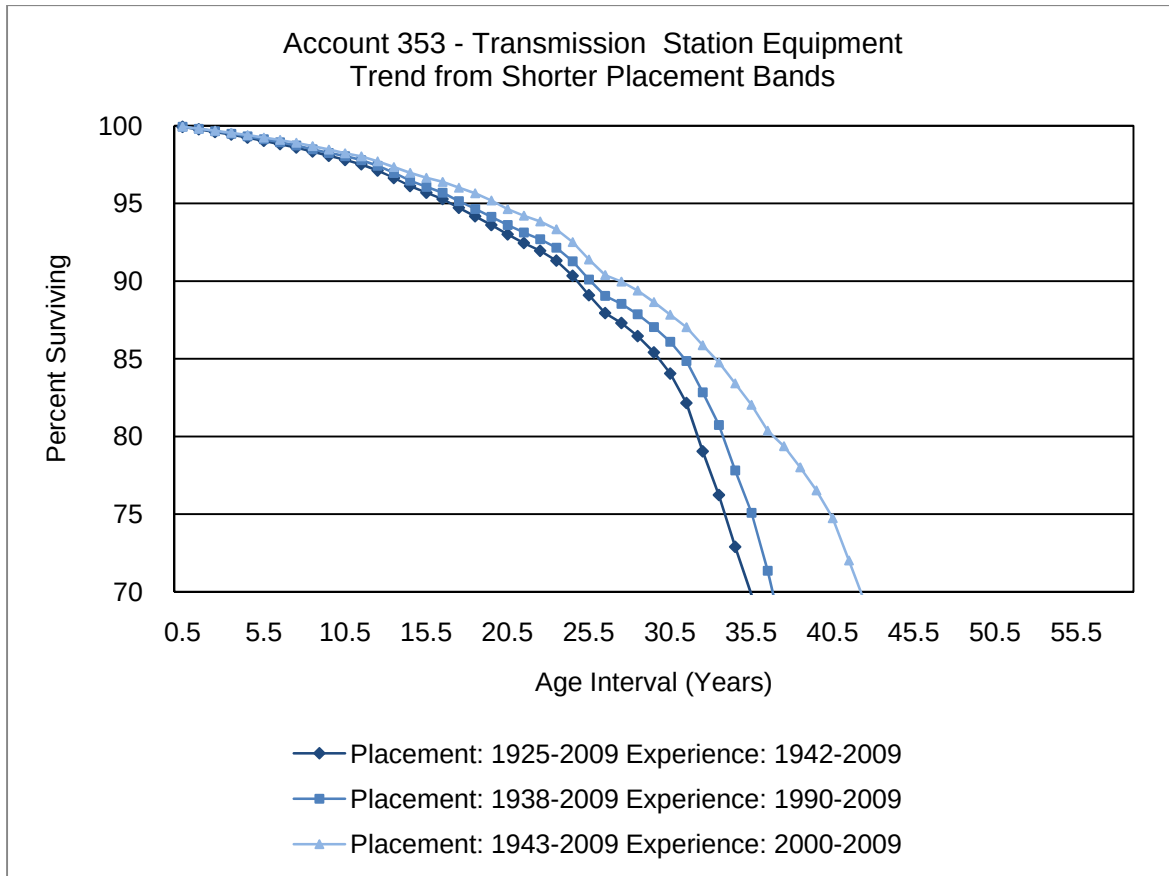
⁵⁷ Response to DUC IR-019 Attachment 1 at pages 9-10.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

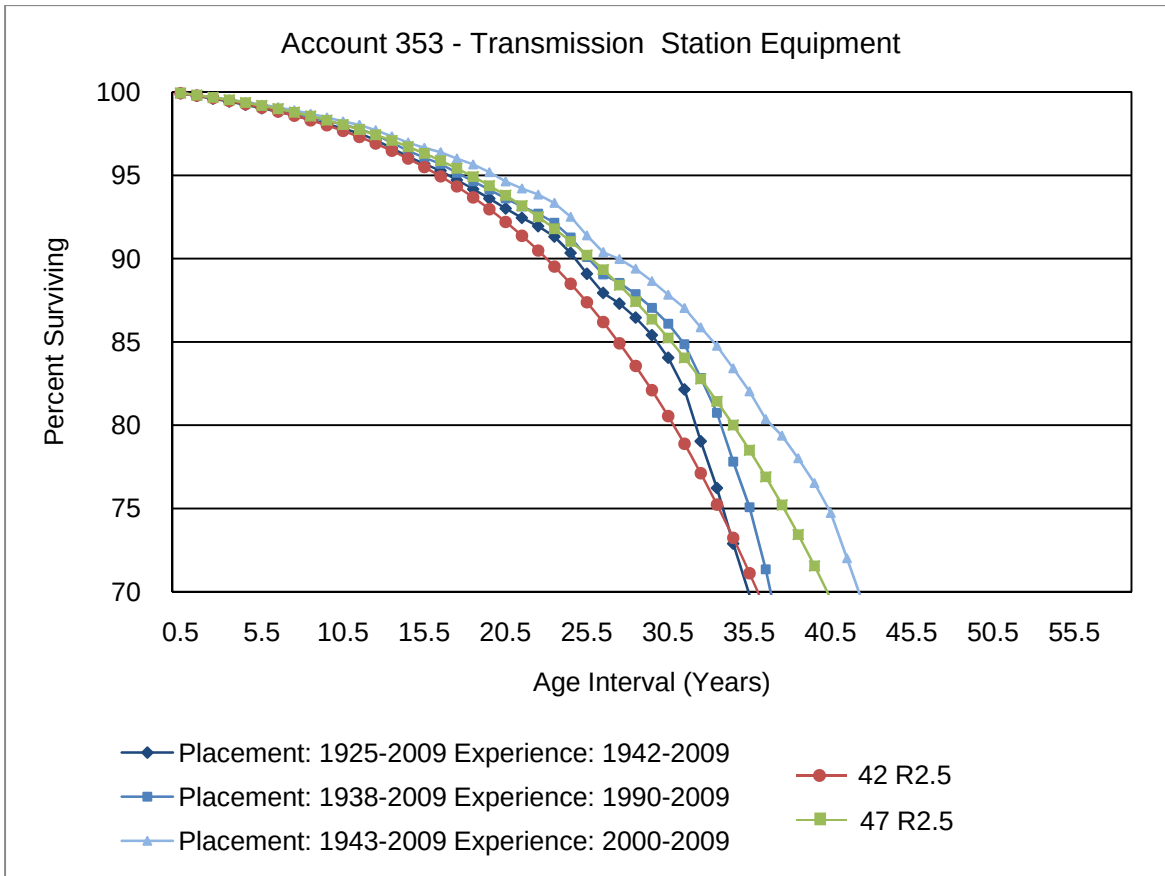
A. First, the Company's prior proposals for this account are worth noting. The Company's 1994 depreciation study proposed a 35-year life, its 2001 study proposed a 39-year life, and the 2006 study proposed a 40-year life. This identifies a continuous pattern of underestimating reasonable average service lives for the investment in this account.

Turning to the Company's statistical analyses, the Company proposed a 42 R2.5 life-curve combination based on a 1925 – 2009 placement band and a corresponding 1942 – 2009 experience band.⁵⁸ This statistical presentation reflects what appears to be the full band analysis of all data for this account. However, in discovery, the Company did provide additional statistical analyses. These additional statistical analyses reflected slightly shortened placement bands, but relied on 10- and 20-year experience bands. This simply means that to the extent a trend is reflected in the data, it could be identified through the review of the shorter experience band analyses. Indeed, as shown in the graph below, the observed life table trends upward in relationship to shorter experience bands. This means that even if the Company's proposed life-curve combination set forth in the 2009 Study were the best statistical fit of the overall historical data, it would still understate the appropriate average service life due to the trend obtained from statistical analyses. The trend for a longer average service life identified through more current statistical analyses is in addition to the trend exhibited by the Company for a longer average service life for this account, as reflected in the Company's prior three depreciation studies. The following graph presents the observed life tables from all actuarial analyses performed by Gannett Fleming. Since the average service life corresponds to the area under each curve, there can be no doubt that there exists a trend toward a longer average service life, as more current experience bands are higher or more elevated than is the 1942 – 2009 experience band.

⁵⁸ 2009 Study at page A-11.



A more appropriate curve-fitting process must take into account the additional observed life tables obtained from Gannett Fleming's actuarial analyses. The trend in the more current band analyses is to longer service lives. As shown in the graph below, my recommended 47 R2.5 life-curve combination is a superior fit, not only to the meaningful portion of the observed life table obtained from the longest band analysis, but is also a significantly better fit to the trend exhibited by the more current experience band analyses.



Turning to identifiable Company policies, outlook, and other information that might have been obtained from Company management, a longer average service life is also warranted. The Company admits that the two major categories of investment in this account are transformers and circuit breakers.⁵⁹ Company personnel apparently raised an issue of design tolerance being much less in newer transformers than in older transformers. This has been an argument raised for decades by other utilities, and in spite of such claim, the average service life for transformers is increasing rather than decreasing. Part of the reason for the increase in average service life for transformers may be due to better maintenance and testing of equipment in more recent periods compared to what existed in the distant past. In addition, Company management admits that circuit breakers “are expected to last 40 – 50 years.”⁶⁰ Thus, the limited identifiable information obtained from Company management would further indicate that an average service life greater than the 42-year level

⁵⁹ Response to DUC IR-019 Attachment 1 at page 9.

⁶⁰ *Id.*, at page 10.

proposed by the Company is appropriate, especially given that the majority of the investment in the account has been identified as being associated with transformers and circuit breakers.

Turning to industry comparative data, especially those associated with prior Gannett Fleming studies, a longer average service life than proposed by the Company is further supported. Indeed, the mean, median, and mode from Gannett Fleming's prior studies are 48 years, 50 years, and 50 years, respectively.⁶¹

In summary, the Company's proposed 42 R2.5 life-curve combination is artificially short, whether viewed from a statistical standpoint, a Company input standpoint, investment type standpoint, or an industry comparative standpoint. While a 50-year average service life may actually be more appropriate, I have recommended a conservative estimate of 47 years.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of my recommendation is a reduction in depreciation expense of \$1,521,493 based on plant as of December 31, 2009. The impact is reflective not only of the change from a 42-year to a 47-year average service life, but also the change from an ELG to a corrected ALG calculation procedure.

2. Account 355

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 355 – TRANSMISSION POLES AND FIXTURES?

A. The Company proposes a 47 R2 life-curve combination.⁶²

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states the same basis as previously noted for Account 353 above. However, as it relates to Company-specific information obtained from management, references have been made to the practice of retreating wood transmission poles on

⁶¹ Response to DUC IR-002 Attachment 2.

⁶² 2009 Study at page III-6.

1 an as-needed basis with boron to arrest rot and decay.⁶³ In addition, the Company
2 acknowledges that the lives in this account “continue to slightly trend up due to
3 better maintenance of the assets.”⁶⁴
4

5 **Q. DO YOU AGREE WITH THE COMPANY’S PROPOSAL?**

6 A. No. The Company has made a slight increase in average service life, but a further
7 increase is warranted. Therefore, I recommend a 49-year R2 life-curve combination.
8

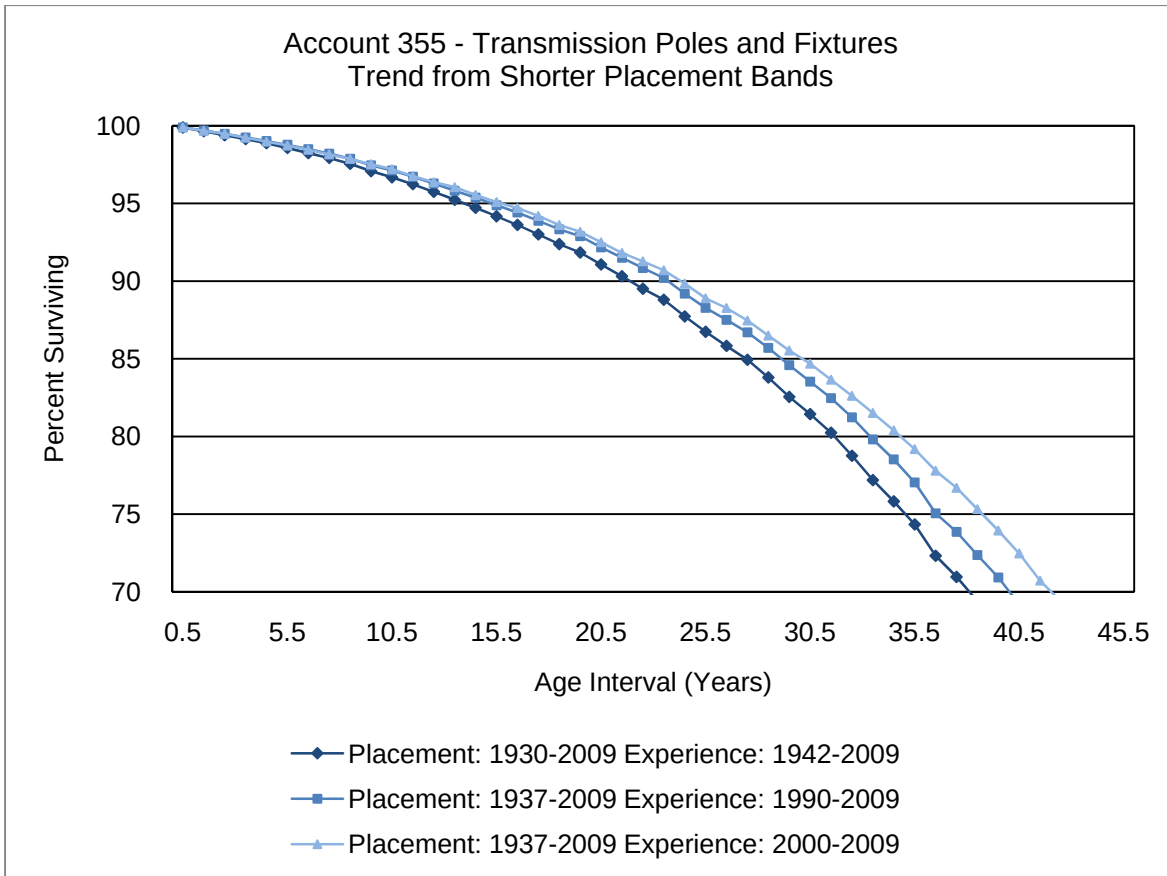
9 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

10 A. Again, putting the Company’s proposal in proper perspective, the Company has
11 historically underestimated life expectancy for the investment in this account. The
12 1994 and 2001 depreciation studies proposed a 42-year average service life, while
13 the 2006 study proposed an increase to a 46-year average service life.
14

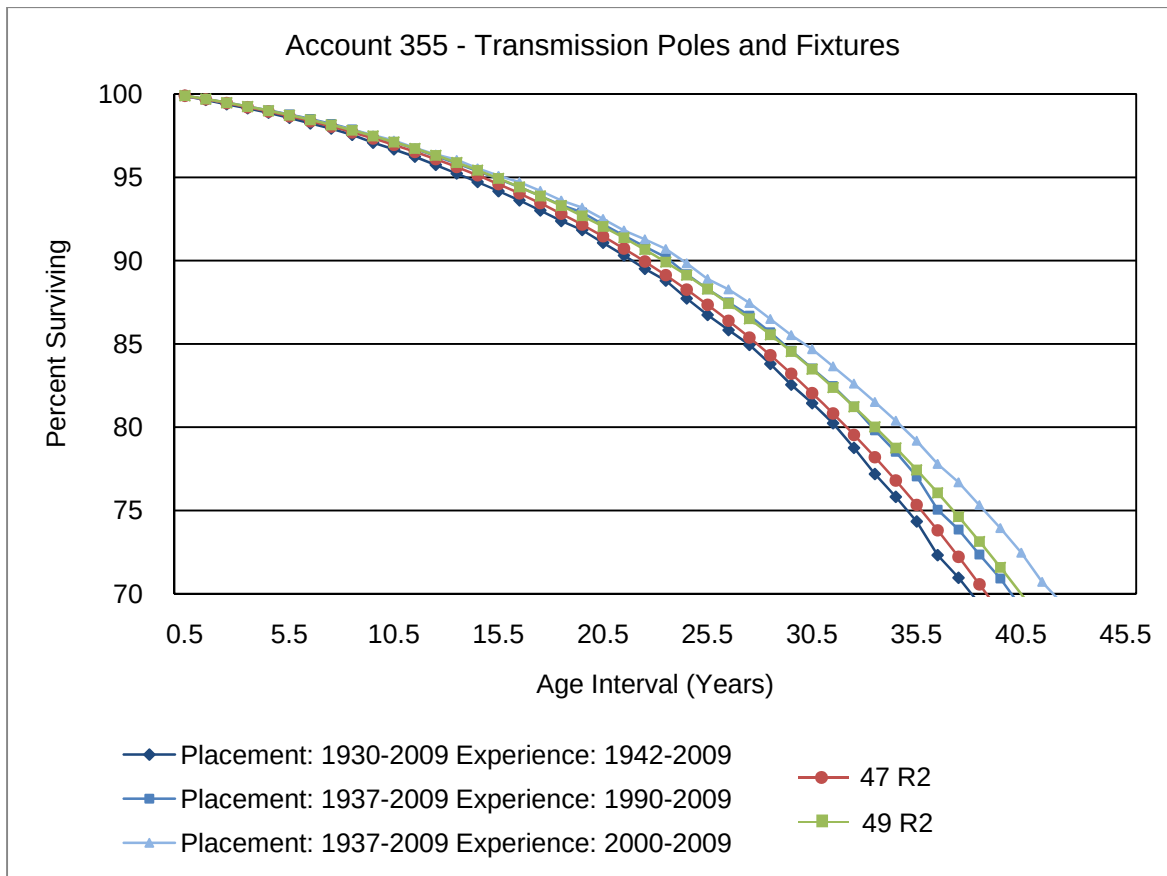
15 Turning to the statistical analysis, the Company’s proposed life-curve combination is
16 an excellent fit to the longest placement-experience band combination. However, as
17 shown in the graph below, when the shorter experience bands are brought into the
18 curve-fitting process, an elevation in the observed life tables is identified. This means
19 that a trend to a longer average service life is indicated by the Company’s data.
20

⁶³ Response to DUC IR-019 Attachment 1 at page 4.

⁶⁴ *Id.*



Given the trend to longer average service life, an additional modest increase is necessary. As shown in the graph below, the 49 R2 life-curve combination that I recommend is an excellent fit to the 20-year experience band and splits the difference between the longest experience band and the 10-year experience band. If this trend continues until the next depreciation study, an even longer average service life would be warranted.



Turning to information provided by Company management, a longer service life is also justified. Management states that additional preventative maintenance practices have been implemented that treat Transmission wood poles as needed with boron to arrest rot and decay. In addition, poles are inspected on a more frequent basis than was the case in the past. More frequent inspections should result in a longer average service life than simply allowing poles to fail absent such inspections.

Turning to comparative data with both the Company's prior depreciation studies and the industry as defined by Gannett Fleming, a 49-year average service life is also more reasonable than the Company's proposal. There has been a steady increase in average service life between depreciation studies for the Company. In addition, Gannett Fleming's database of other industry values indicates a 50- to 51-year average service life is more indicative of the industry.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of my recommendation is a reduction in depreciation expense of \$1,343,517 based on plant as of December 31, 2009. The impact is reflective not only of the change from a 47-year to a 49-year average service life, but also the change from an ELG to a corrected ALG calculation procedure.

3. Account 356

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 356 – TRANSMISSION OVERHEAD CONDUCTORS AND DEVICES?

A. The Company proposes a 45 R3 life-curve combination.⁶⁵ This represents no change from the Company's prior 2006 depreciation study, but is a three-year increase from the value proposed in the Company's 2001 study.⁶⁶

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company's proposal is based on the same generalized statement as previously identified. In addition, interview notes indicate that the primary cause of retirement is inadequacy, which primarily occurs due to load changes. The Company has expressed certain additional concerns about thermal stresses, which might shorten the life of its conductors, as well as weather concerns. One final concern raised by the Company's management is distributive generation, even though it does not believe such situation will affect the Company in the near-term future.⁶⁷

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. Yes. Based on statistical comparisons, historical data, and the Company's historical proposals for this account, I believe Gannett Fleming's selection for this account is appropriate. Therefore, no adjustment is required.

⁶⁵ 2009 Study at page III-6.

⁶⁶ Response to DUC IR-011 Attachments 2 and 1 at page III-6, respectively.

⁶⁷ Response to DUC IR-019 Attachment 1 at pages 8-9.

4. Account 362

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 362 – DISTRIBUTION STATION EQUIPMENT?

A. The Company proposes a 48 R1.5 life-curve combination.⁶⁸

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The previously-stated standard bases for the Company's life proposals are also applicable here. In addition, the Company states that the primary cause of retirements is transformer failures and that such failures occur due to lightning, design, water ingress, internal deterioration of insulation, and through fault currents.⁶⁹ Gannett Fleming's interview notes also indicate that load growth is another issue associated with replacing transformers, but that the Company employs a cradle-to-grave approach, which means that such transformers are not retired, just relocated. Finally, the Company states that large transformers are tested every six months.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal should be increased by two years. Therefore, I recommend a 50 R2.5 life-curve combination.

Q. WHAT IS THE BASIS FOR YOUR PROPOSAL?

A. First, it must be noted that the Company has increased its life expectation for investment in this account as reflected in its prior depreciation studies. For example, both the 1994 and 2001 studies relied on a 40-year average service life. However, the 2006 study increased that life expectancy to 47 years.⁷⁰ Therefore, the Company's proposal in this case reflects a further increase, but only by one year.

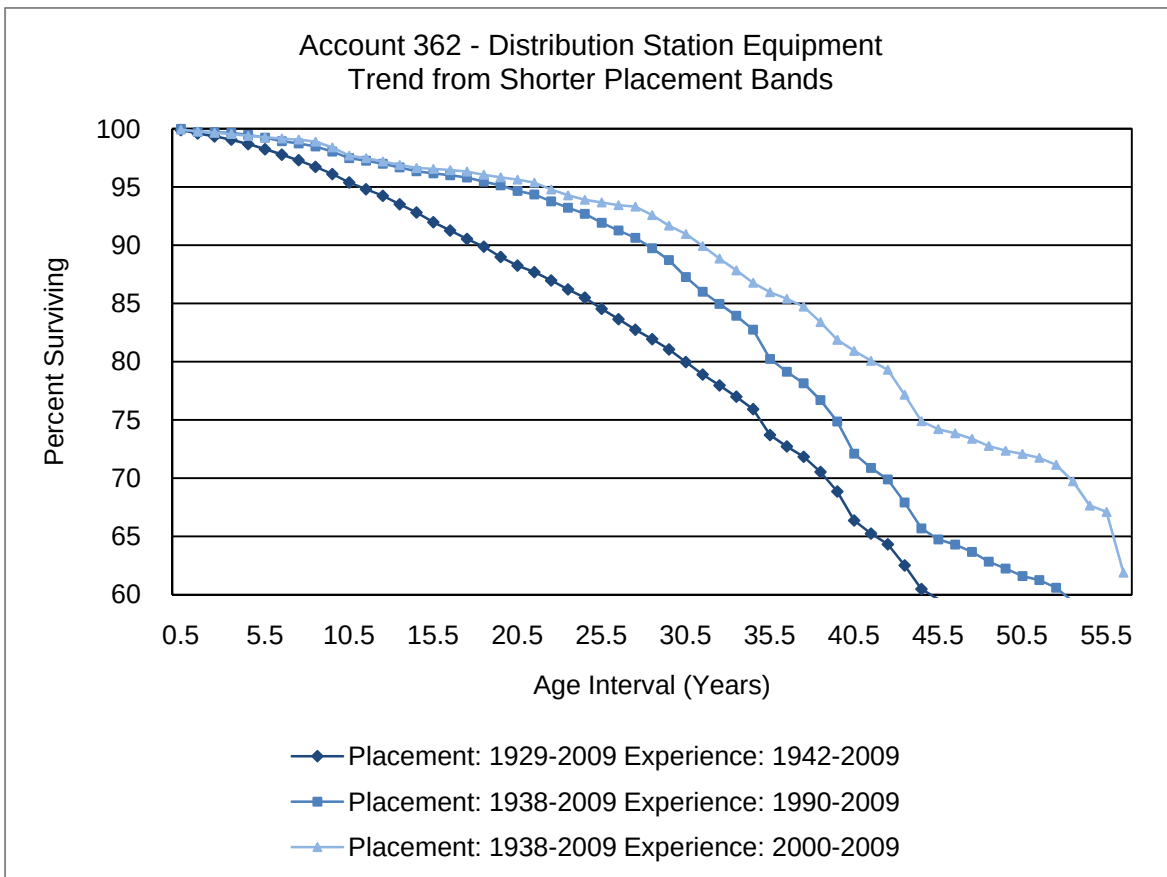
Turning to the review of statistical analyses, a longer life expectancy is also warranted. The Company's presentation in its 2009 Study attempts to match only the

⁶⁸ 2009 Study at page III-6.

⁶⁹ Response to DUC IR-019 Attachment 1 at page 10.

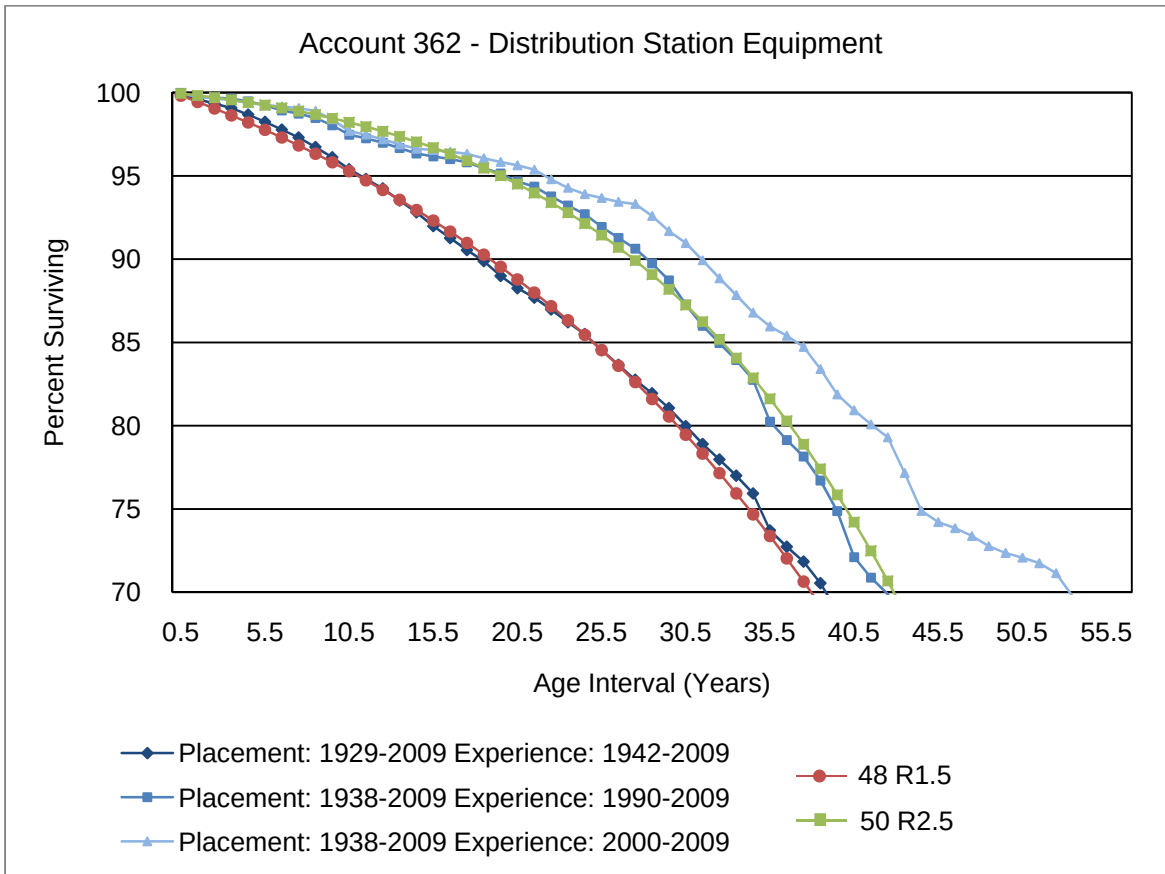
⁷⁰ Response to DUC IR-011 Attachment 2 at page III-6.

1 longest placement-experience band combination. In discovery, the Company
2 provided additional analyses that it had performed, but had not presented. Those
3 additional presentations reflected 10- and 20-year experience bands, also with long
4 placement bands. As shown in the graph below, the trend in the data is noticeably
5 different than the placement-experience band presented by the Company in the
6 2009 Study. Thus, while the Company's proposal may be a good fit to the singular
7 statistical analysis presented in the 2009 Study, it is not a good fit to additional
8 analyses, which indicate a trend to a longer average service life and a change in the
9 dispersion pattern. It is worth noting again that a higher or more elevated observed
10 life table means a longer average service life.



12 Some recognition must be given to the trend in the statistical data analyzed by the
13 Company. The 50 R2.5 life-curve combination I recommend reflects an appropriate
14 compromise between the long experience band and the trend exhibited in more
15 recent history. My recommendation blends both the longer experience band result
16
17

with more recent experience band results, but does not extend the life to reflect the full impact of recent trends. The three observed life tables, as well as the Company's proposal and my recommendation are set forth in the graph below.



Turning to the Company's policies, outlooks, and other information obtained from management, a longer average service life than that proposed by the Company is also warranted. First, as previously discussed in association with Account 353 – Transmission Station Equipment, the concern associated with core design of transformers built in the 1960s does not appear to be a meaningful issue for the investment in this account, as all life indications are lengthening, not shortening. Second, the Company's policy of cradle-to-grave accounting implies a longer life expectancy than other utilities that do location accounting, where replacement of transformers results in a retirement rather than a relocation. Next, the Company's policy to test large transformers every six months should result in longer life expectancy for the major transformer investment in this account. Finally, even the

1 Company recognized that its investment in Distribution station equipment lasts
2 noticeably longer than the investment in its Transmission station equipment account.
3 Given that I am recommending a 47-year average service life for Transmission
4 station equipment, a longer average service life than the 48 years proposed by the
5 Company is warranted.

6
7 Comparisons with other utilities do not provide a meaningful benchmark for this
8 particular account, as the industry range is significant. However, as previously noted,
9 the life expectancy reflected in historical depreciation studies for this utility indicates
10 a trend toward longer service lives.

11
12 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

13 A. The impact of my recommendation is a reduction in depreciation expense of \$20,947
14 based on plant as of December 31, 2009. The impact is reflective not only of the
15 change from a 48 R1.5 to a 50 R2.5 life-curve combination, but also the change from
16 an ELG to a corrected ALG calculation procedure.

17
18 **5. Account 364**

19
20 **Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 364 – DISTRIBUTION**
21 **POLES, TOWERS AND FIXTURES?**

22 A. The Company proposes a 38 R2.5 life-curve combination.⁷¹

23
24 **Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?**

25 A. In addition to its previously-noted standard response, the Company states that it
26 treats most of its wooden poles with preservatives. Certain poles are left untreated
27 and have a much shorter service life than treated poles. In addition, the Company
28 notes that it has implemented a policy for at least the past 20 years to perform pole
29 inspections. Further, as a result of such inspections, it reinforces and bandages
30 poles near the ground when it finds poles in fair condition. Such activity increases
31 the physical integrity of the pole for an additional 10 to 15 years. The Company has

⁷¹ 2009 Study at III-6.

1 also increased its pole inspection program since 2003, when Hurricane Juan struck
2 the area. Due, in part, to such elevated inspection activities, the Company expects
3 the average service life for the account “to continue to slightly trend up due to better
4 maintenance of the assets.”⁷²
5

6 **Q. DO YOU AGREE WITH THE COMPANY’S PROPOSAL?**

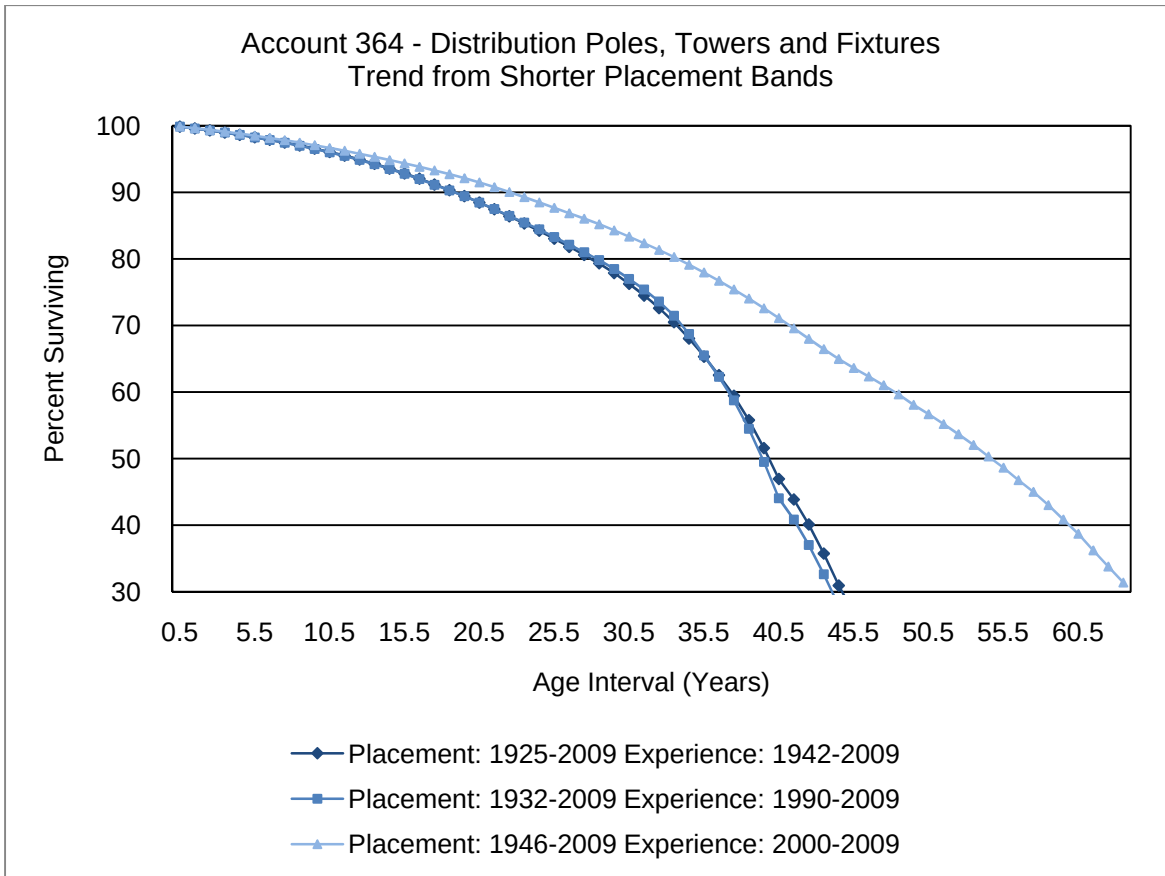
7 A. No. I believe the Company’s proposed average service life needs to be increased.
8 Therefore, I am recommending a moderate increase to a 41-year average service
9 life with a corresponding R2 dispersion pattern.
10

11 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

12 A. First, it is important to note that the Company has been increasing its proposed
13 average service life through historical depreciation studies. The Company’s 1994
14 and 2001 depreciation studies relied on 34-year average service lives, while the
15 2006 study identified a 37-year average service life. Thus, the Company’s proposal
16 for a 38-year life only increases the proposal from its prior study by one year.
17

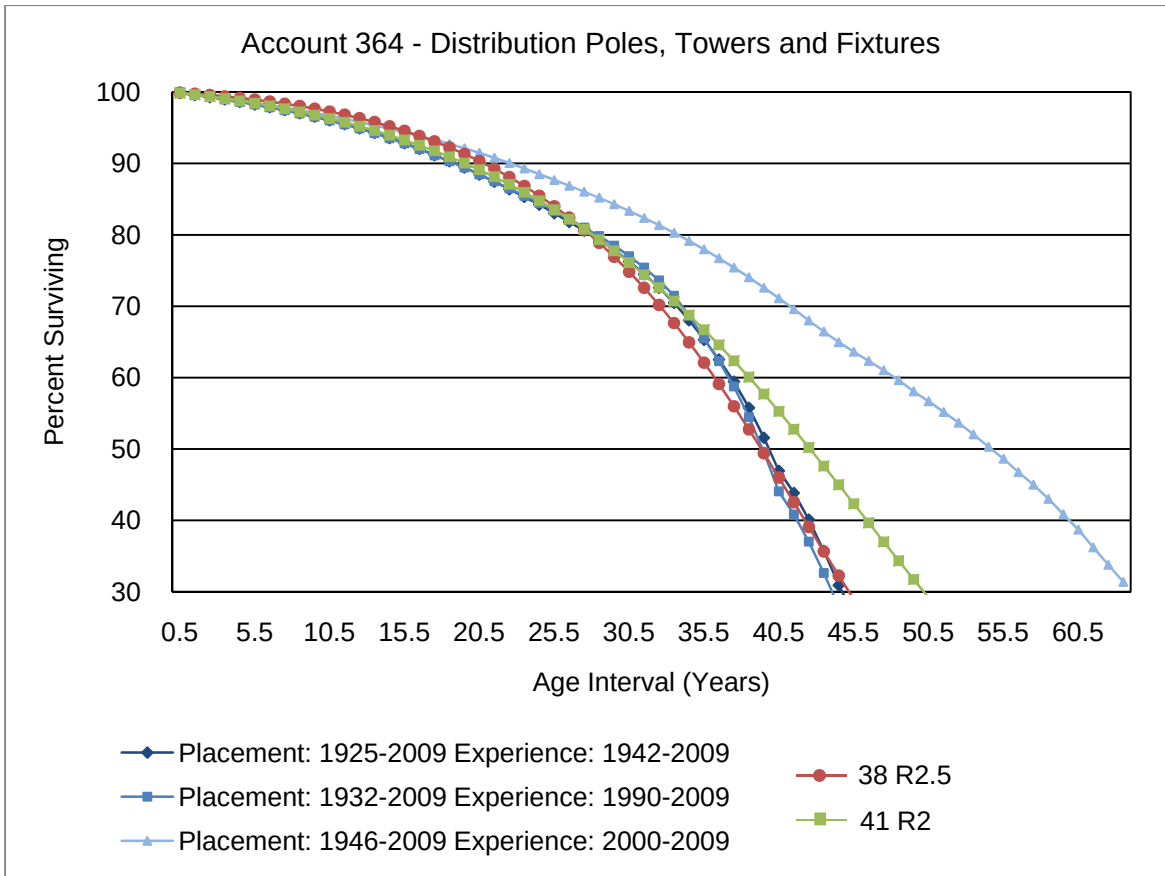
18 Turning to the results of statistical analyses, a further increase in average service life
19 is also warranted. The Company’s presentation in its 2009 Study only provided its
20 longest historical band analysis. Set forth in the graph below are the two additional
21 analyses performed by the Company yet not provided in its depreciation study. As
22 can be seen, the 20-year band mirrors the long band analysis very well. However,
23 the 10-year band identifies a noticeable elevation in the observed life table.
24

⁷² Response to DUC IR-019 Attachment 1 at page 4.



The elevation in the observed life table from the 10-year experience band appears to capture the beneficial aspects of the recent implementation of the pole inspection program that was begun 20 years ago, but increased after Hurricane Juan in 2003. Thus, longer life expectations are warranted, as the trend in the data is for a longer service life, reflecting the improved maintenance and treatment of poles.

As shown in the graph below, the 41 R2 life-curve combination I recommend is equally as good a fit to the historical data for the two longer band analyses. However, changing the dispersion to an R2 Iowa Survivor curve begins to capture the elevation in the observed life table that is reflected in the 10-year band. As shown in the graph below, an even longer average service life will be warranted if the trend in the data exhibited by the 10-year band continues. Therefore, from a statistical standpoint, the Company's proposal understates the average service life and does not capture the change in the data through its proposed dispersion pattern.



Turning to the impact of information obtained from Company personnel, a longer average service life is also warranted. First, the initiation of a pole inspection program approximately 20 years ago will have life-lengthening impacts in the future. Moreover, the increase in the maintenance program begun in 2003 will further result in longer life expectancies for the investment in this account. Indeed, the Company's management believes 10 to 15 years of additional life can be obtained for poles found in fair condition through the inspection process, but reinforced and bandaged in order to remain in service. The recommendation to only increase the average service life to 41 years, rather than a longer average service life, also takes into consideration the fact that some portion of the Company's poles are untreated because they are near bodies of water. The blending of this item of input from management along with its expectations for continued upward trend in life due to maintenance helps establish a 41-year average service life as a conservative but reasonable expectation.

Turning to comparison with other utilities also warrants a longer average service life than proposed by the Company. Review of Gannett Fleming's industry database yields mean, median, and mode values of approximately 45, 45, and 40 years, respectively.⁷³ Thus, from an industry standpoint, the increase in average service life to a 41-year level still places my recommended value at the low end of the mid range for the industry. This placement is reasonable given that some utilities may not have implemented the level of chemical treatments or inspection programs that NSPI has implemented, but does capture the fact that portions of the Company's service territory are near bodies of water.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of my recommendation is a reduction in depreciation expense of \$3,714,158 based on plant as of December 31, 2009. The impact is reflective not only of the change from a 38 R2.5 to a 41 R2 life-curve combination, but also the change from an ELG to a corrected ALG calculation procedure.

6. Account 365

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 365 – DISTRIBUTION OVERHEAD CONDUCTORS AND DEVICES?

A. The Company proposes a 38 R2.5 life-curve combination.⁷⁴

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. In addition to the previously-noted standard bases, the Company also adds the facts that: (1) there are both copper and aluminum conductors on the system, with copper conductors already reaching 40 to 50 years of age and may require replacement in the near-term future; (2) there have been premature retirements with aluminum conductor steel reinforced ("ACSR") due to deterioration of the steel core of the cable; (3) the primary cause of retirements is due to inadequacy, where the conductor was not designed to handle the increasing loads that are being placed upon it; and (4) the climate in its service territory is more severe than elsewhere, and

⁷³ Response to DUC IR-002 Attachment 2 at pages 244-309.

⁷⁴ 2009 Study at page III-6.

1 that such conditions should be afforded proper consideration in the life estimation
2 process.⁷⁵
3

4 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

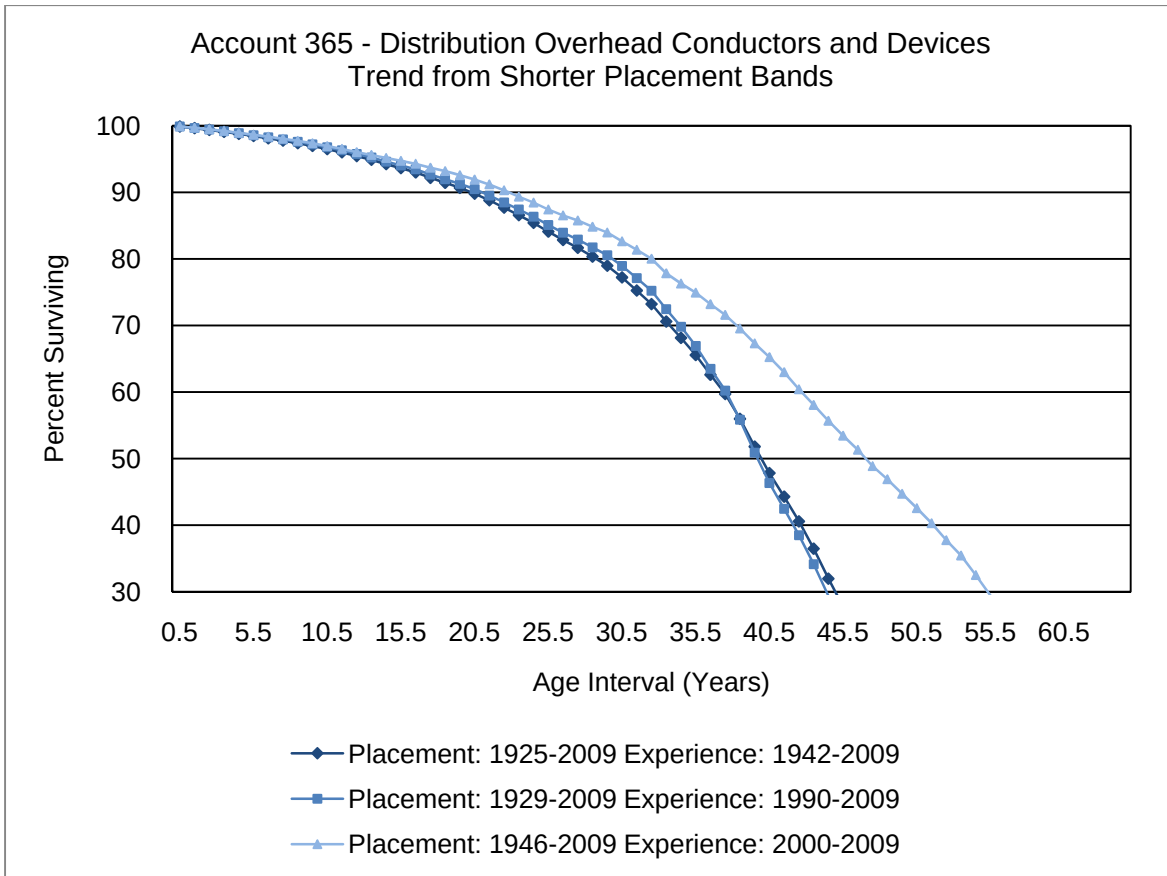
5 A. No. Just as was the case for Account 364 – Distribution Poles, Towers and Fixtures,
6 a modest increase in average service life is warranted at this time. Therefore, I
7 recommend a 41 R2 life-curve combination.
8

9 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

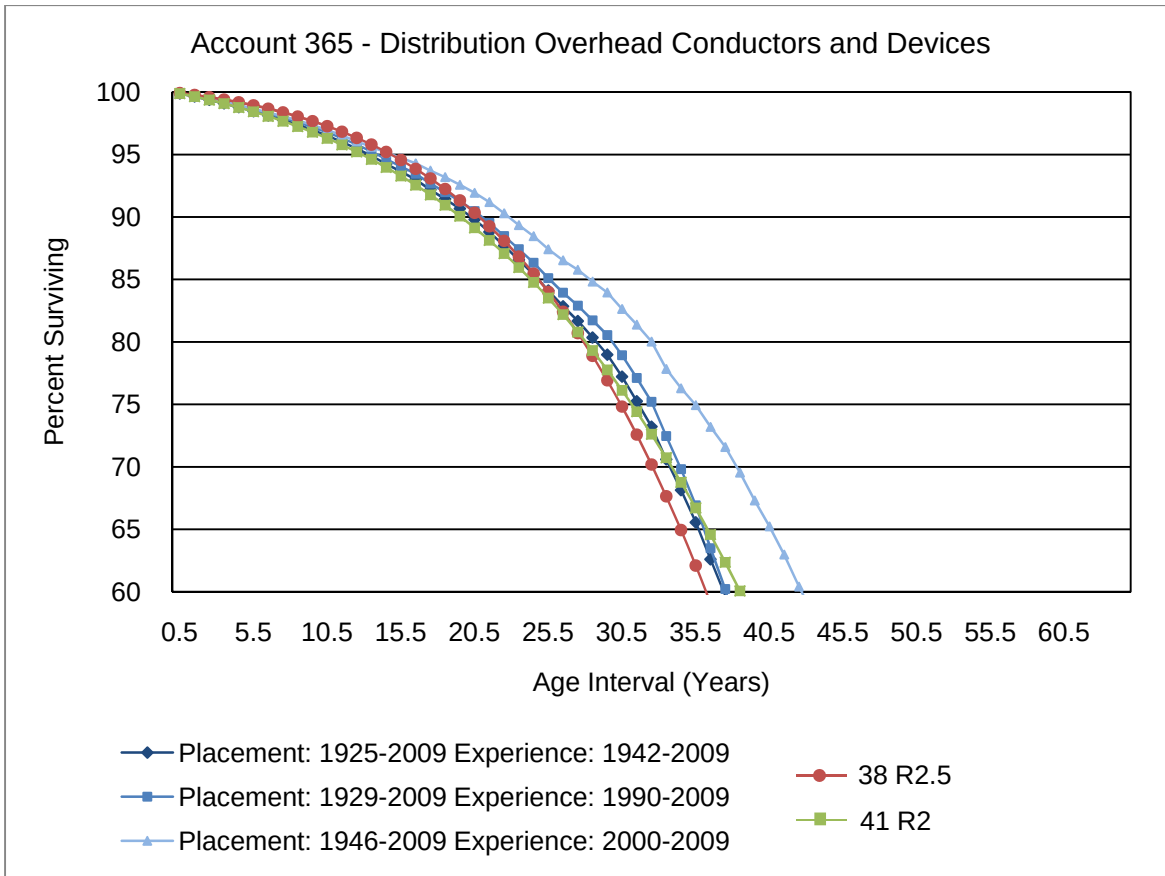
10 A. First, it should be noted that the Company has continuously increased, albeit in one-
11 year increments, its proposed average service life in its various historic depreciation
12 studies. The 1994 study reflected a 35-year average service life, which was
13 increased to 36 years in the 2001 study, then increased to 37 years in the 2006
14 study, and now increased to a proposed 38 years in the current study.
15

16 From a statistical analysis standpoint, a somewhat longer average service life than
17 that proposed by the Company is also warranted. As shown in the graph below, the
18 same elevation of the observed life table in the most recent band analysis performed
19 by the Company indicates a trend to a longer average service life. However, the
20 Company's presentation in its 2009 Study only included the results of its longest
21 band analysis, and thus did not capture the trend exhibited from historical data. The
22 increase in life expectancy reflected in the most recent band analysis is consistent
23 with what would be expected due to the increased pole maintenance program
24 initiated by the Company approximately 20 years ago and increased beginning in
25 2003. While the pole maintenance program applies to poles, one would anticipate
26 Company personnel would notice any fraying in conductors or other conditions that
27 could be remedied with immediate maintenance, thus potentially prolonging life for
28 conductors through the pole inspection program.
29

⁷⁵ Response to DUC IR-019 Attachment 1 at page 5.



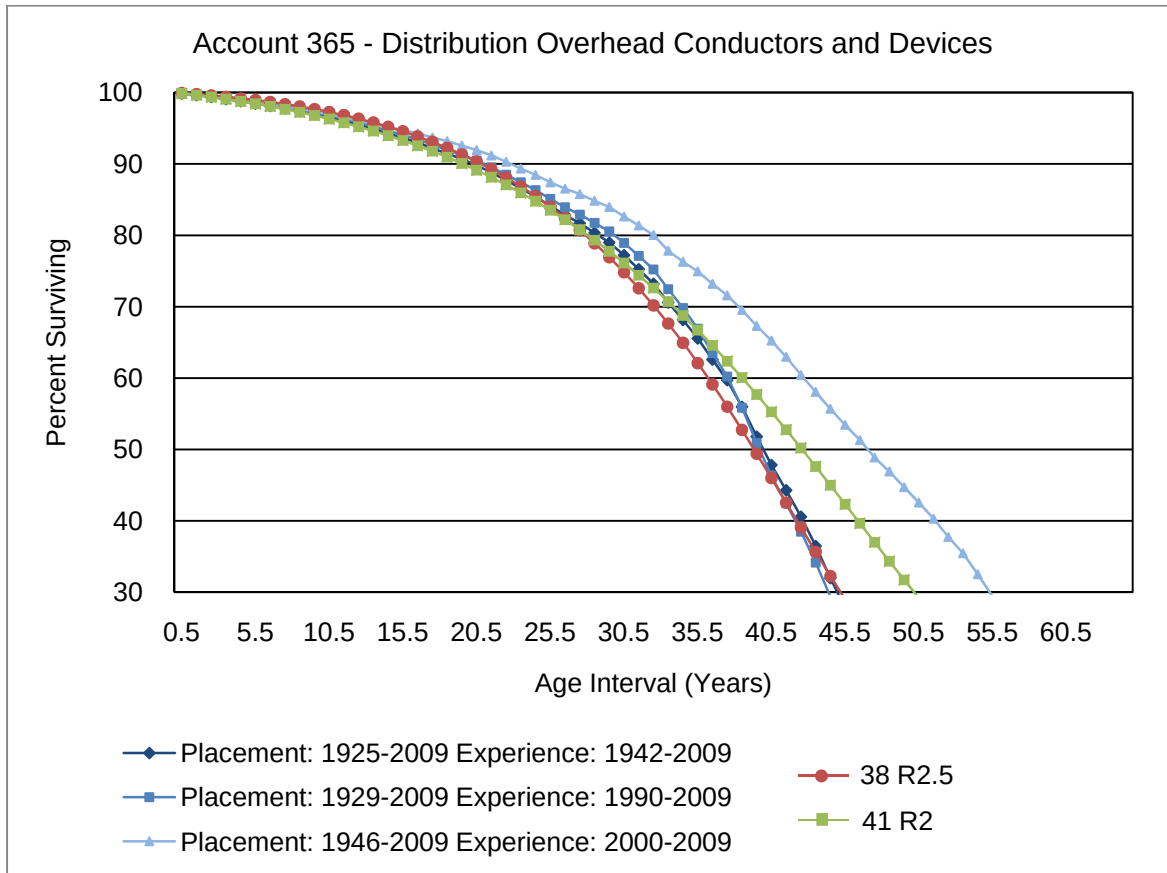
Turning to the actual curve-matching process, a longer average service life than proposed by the Company is warranted. As shown in the graph below, the 41 R2 life-curve combination represents as good a fit, if not a better fit, of the data through the first 35 years of age as it relates to the oldest band analyses.



Moreover, as shown in the graph above, my recommendation does not attempt to capture any potential longer average service life as indicated in the historic trend obtained from the most recent band analyses. However, when the scale of the graph is expanded such that it illustrates the continuation of the various lines on the graph down to approximately 30% surviving, as shown in the graph below, it can be seen that the latter portions of my recommendation begin to blend limited, but potential impacts of a longer average service life exhibited through the most recent band analyses. It must also be noted that in the upper-30-year age period, where my recommended life curve combination begins to capture limited impact of the trend in the data, the dollar level of exposures have declined dramatically from those depicted at earlier ages. For example, the top portion of the curve exhibits exposures to retirement activity in excess of \$200,000,000, while at the upper-30-year age period the exposures to retirement activity are less than \$10,000,000.⁷⁶ In other

⁷⁶ 2009 Study at page A-36.

words, the degree of significance of my recommendation deviating from the older bands in order to capture some portion of potential future trends in the data is at a level where exposures are minimal and the stability of the observed life table is the lowest from the standpoint of future analyses.



Turning to information obtained from Company personnel, a nominal increase in average service life from that proposed by the Company is warranted. First, an unidentified level of copper conductor still exists on the system. Company personnel admit that such conductor is already 40 to 50 years old. To the extent the Company does not retire such investment in the next several years, it begins to approach the maximum life expectancy associated with the Company's proposed 38 R2.5 life-curve combination. Another consideration, as previously noted, is the Company's pole inspection program. Such inspection program can only have a beneficial aspect associated with identifying problems with conductors prior to conditions that would cause failure, and thus most likely will only prolong life expectancy for the investment

1 in this account. Further, to the extent the ACSR cable deterioration problems have
2 already been captured in the historical data, then their impact in the future will be
3 diminished from a statistical standpoint, and therefore will also place upward
4 pressure on expected average service life. Indeed, this may be part of the reason for
5 the increase in average service life depicted in the Company's most recent band
6 analysis.

7
8 Turning to an industry comparative standpoint, the industry statistics for overhead
9 conductors are very similar to those for distribution poles. Therefore, extending the
10 average service life to 41 years still places my recommendation at the lower end of
11 the mid range for the industry. Such position captures some of the concerns raised
12 by the Company's management regarding the climate conditions in its service
13 territory.

14
15 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

16 A. The impact of my recommendation is a reduction in depreciation expense of
17 \$1,630,929 based on plant as of December 31, 2009. The impact is reflective not
18 only of the change from a 38 R2.5 to a 41 R2 life-curve combination, but also the
19 change from an ELG to a corrected ALG calculation procedure.

20
21 **7. Account 367**

22
23 **Q. WHAT DOES THE PROPOSE FOR ACCOUNT 367 – DISTRIBUTION**
24 **UNDERGROUND CONDUCTORS AND DEVICES?**

25 A. The Company proposes a 43 R3 life-curve combination.⁷⁷

26
27 **Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?**

28 A. In addition to the previously-noted standard response, Gannett Fleming's interview
29 notes provide several additional items of information. First, the interview notes state
30 that the investment is comprised of direct-buried cable and cable in conduit. Direct-
31 buried cable was employed in residential areas until the early 1990s and has since

⁷⁷ 2009 Study at III-6.

1 been replaced by conduit. The Company experienced early retirements associated
2 with direct-buried cable due to water infiltration problems and other failures. The
3 Company installed lead-jacketed cable in its downtown Halifax network, which
4 should last longer than direct-buried cable. The Company also installed molecular
5 weight polyethylene underground cable during the mid-1960s through the 1970s and
6 experienced premature retirements with such investments at ages 10 through 15
7 years. Management's expectation for this type of cable is between 20 and 25 years
8 of service. The Company also installed cross-linked polyethylene from the mid-
9 1970s through the mid-1980s, and while it has had better experience with this type
10 of cable, it still has experienced some problems and expects a service life of around
11 30 years for this type of investment. Finally, beginning in the late 1980s, the
12 Company began installing ethylene propylene rubber cable and has had excellent
13 experience with this type of cable, with life expectations in the 50- to 60-year
14 range.⁷⁸

15
16 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

17 A. No. The Company's proposal understates the reasonable expectation for average
18 service life for the investment in this account. Therefore, I recommend a 46 R3 life-
19 curve combination.

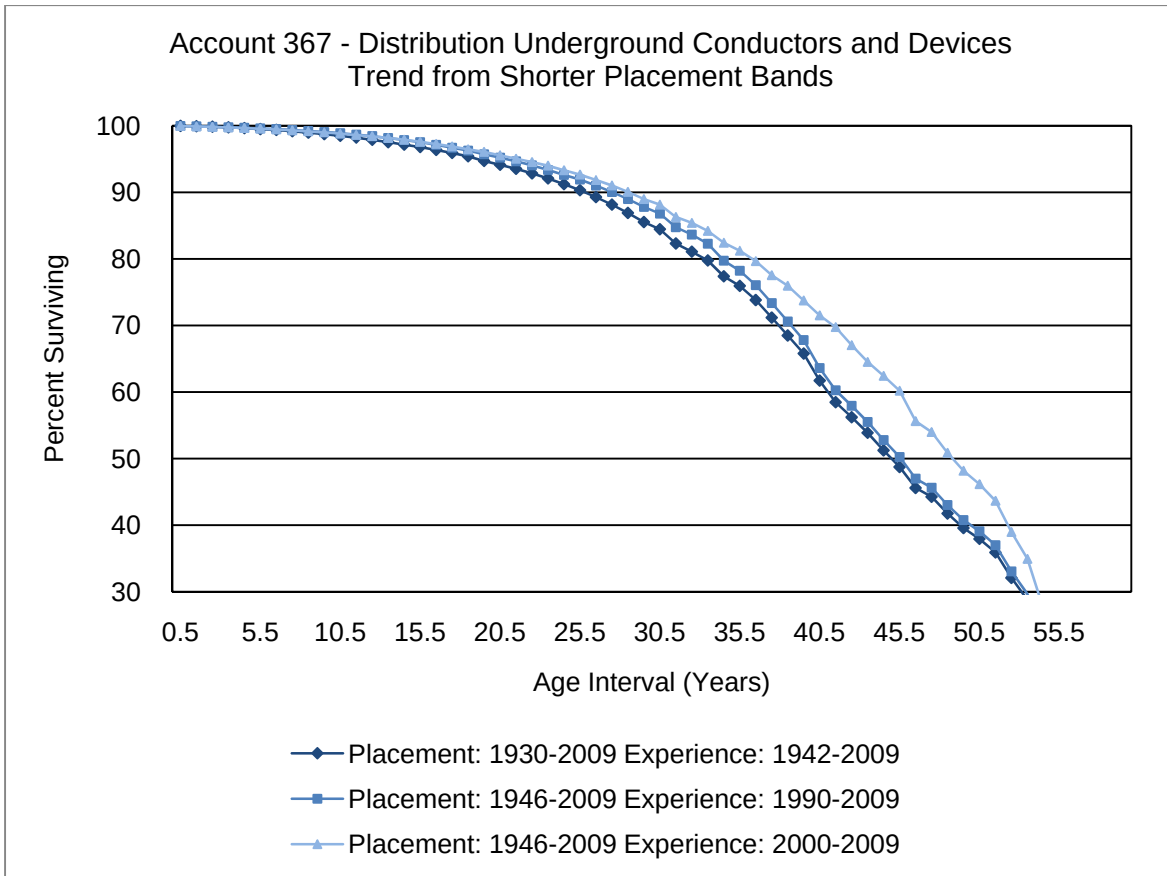
20
21 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

22 A. First, it must be noted that the Company has previously understated life expectations
23 for this account. The 1994 and 2001 depreciation studies proposed a 38-year
24 average service life, while the 2006 study proposed a 41-year average service life.

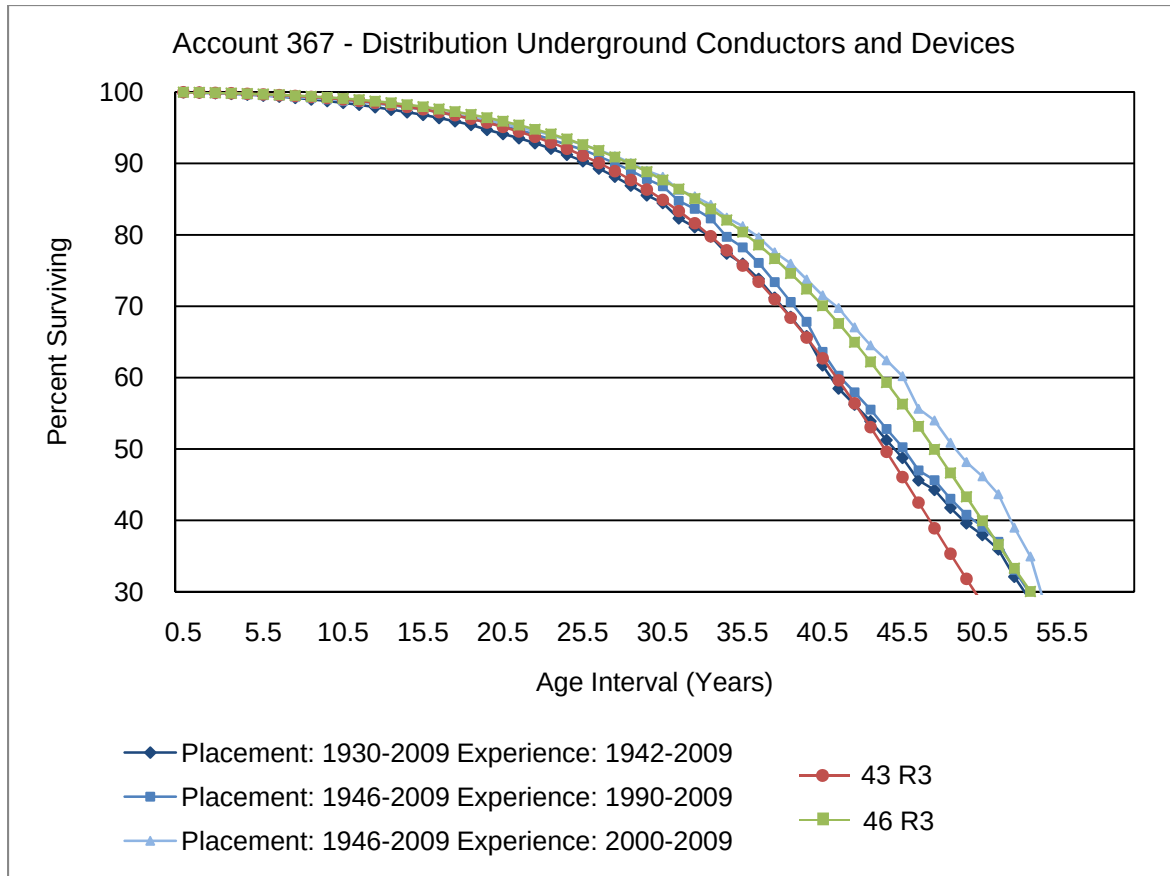
25
26 Turning to statistical analyses, the Company inappropriately relied on a very long
27 band analysis for its current proposed 43-year average service life. As shown in the
28 graph below, the shorter experience band analyses performed by the Company
29 indicate elevations in the observed life table, which means there is a trend in the
30 data to a longer average service life.

31

⁷⁸ Response to DUC IR-019 Attachment 1 at pages 5-6.



As shown in the graph below, from a pure statistical analysis standpoint of historical data and recognition of the trend in the data, a more appropriate average service life is 46 years.



In addition, specific information from Company management strongly suggests a longer average service life than that proposed by the Company, and reinforces my recommendation for a longer average service life. The Company admits that its latest type of installation, corresponding to ethylene propylene rubber cable, has been installed since the late 1980s. Moreover, the Company has had excellent experience with such cable and expects 50- to 60-year service life for such investment. The fact that the plant balance in the 1994 study for this account was \$20 million indicates that the majority of the investment in the account at this point in time is associated with longer-lasting cable than reflected in the historical statistical analysis relied upon by the Company. Indeed, the Company's presentation relies on plant placed in service beginning in 1930 and reflects activity from 1942 through 2009. Given the continuous change in the type of underground cable and the life expectancy with each newer generation of underground cable, it is inappropriate to rely on long band analyses in an effort to capture current life expectations for the

1 remaining investment in service. Based on Company input, an average service life in
2 the upper-40-year range would be appropriate at this point in time.

3
4 Turning to industry information also provides some insight. The comparative data
5 provided by Gannett Fleming indicates two different patterns of expected life. One
6 pattern exhibited indicates a 50- to 60-year range and another indicates a 30- to 40-
7 year range. Such type of dispersion would be expected depending on the generation
8 of cable in each individual utility system. To the extent a utility has a greater level of
9 early generation cable, one would expect a lower life expectancy. However, for those
10 utilities, such as NSPI, that have the majority of their investment in newer
11 generations of cable, and who have performed a proper depreciation investigation,
12 one would expect life indications in the 50- to 60-year range. Therefore, industry
13 comparative information supports a much longer average service life than proposed
14 by the Company.

15
16 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

17 A. The impact of my recommendation is a reduction in depreciation expense of
18 \$254,924 based on plant as of December 31, 2009. The impact is reflective not only
19 of the change from a 43-year to a 46-year average service life, but also the change
20 from an ELG to a corrected ALG calculation procedure.

21
22 **8. Account 368**

23
24 **Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 368 – DISTRIBUTION**
25 **LINE TRANSFORMERS?**

26 A. The Company proposes a 30 R1 life-curve combination.⁷⁹

27
28 **Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?**

29 A. In addition to the previously-noted standard bases, Gannett Fleming's interview
30 notes indicate management stated that retirements are due to overload conditions as
31 well as line conversion, deterioration, and damage resulting from lightning. Further,

⁷⁹ 2009 Study III-6.

1 the transformer tanks are made of cast iron and steel and are subject to rust. The
2 fact that stainless steel tanks and improved coating materials are being used has
3 reduced corrosion-related failures in recent years. Finally, the Company notes that,
4 since 1982, all transformers installed are PCB-free, and that it has replaced all
5 transformers containing PCB-treated oil located in sensitive sites in recent years.⁸⁰
6

7 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

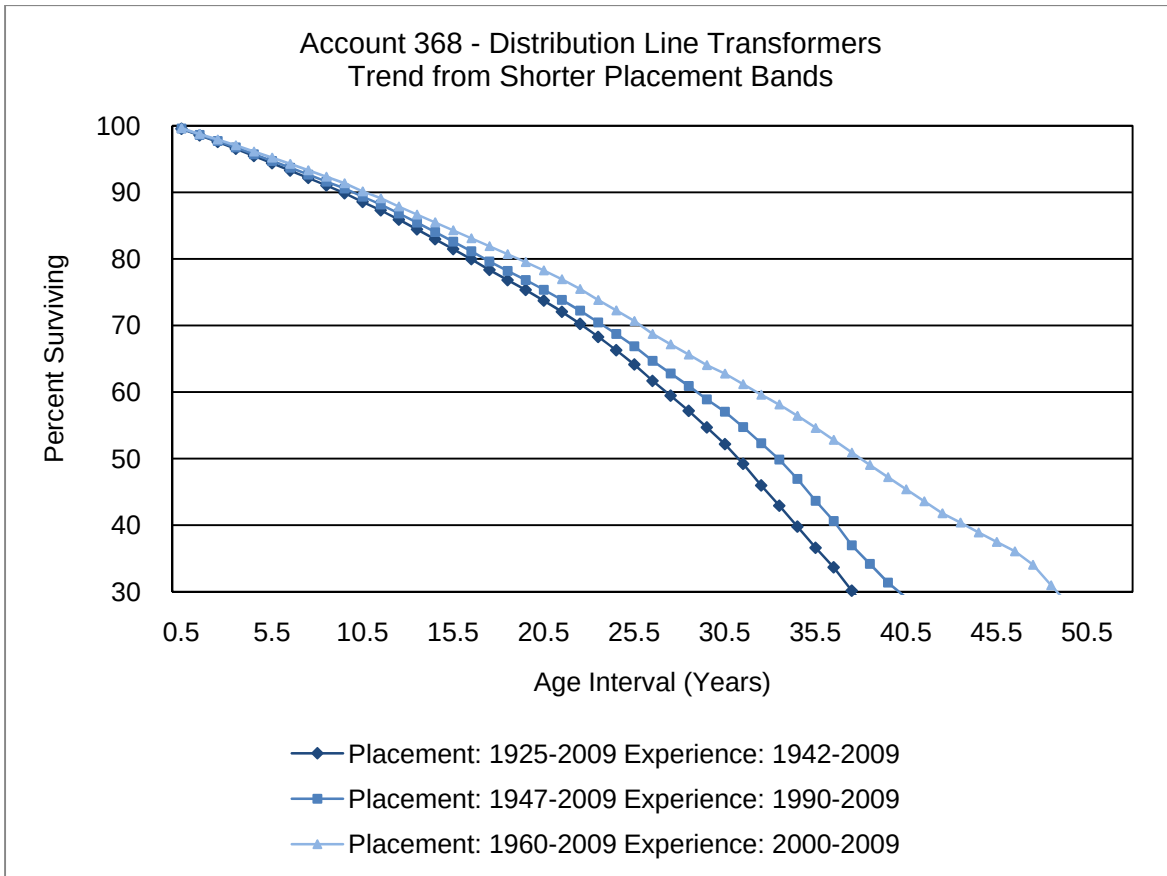
8 A. No. The proposed average service life is inadequate. Therefore, I recommend
9 movement to a 35 S-0.5 life-curve combination.
10

11 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

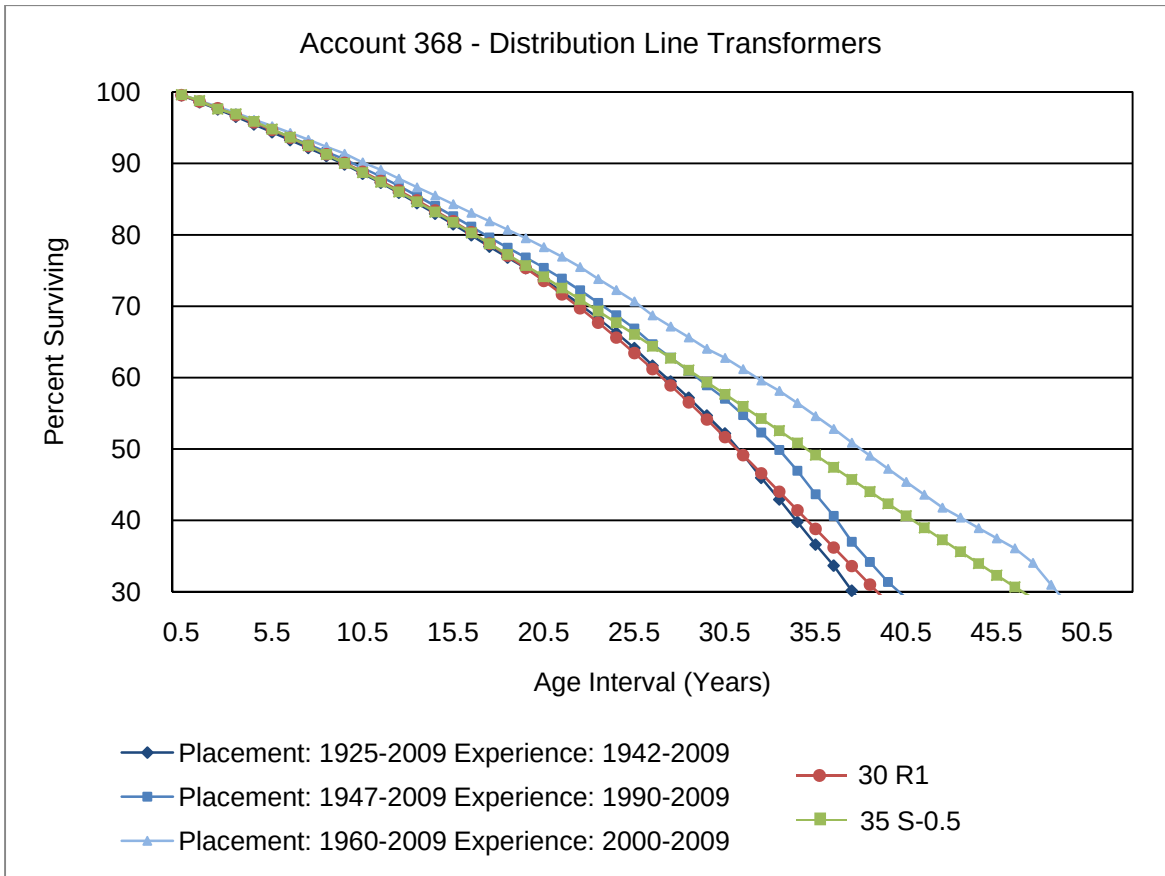
12 A. First, it must be noted that the Company has continuously and significantly increased
13 its proposed average service life for the investment in this account. Beginning with
14 the 1994 study, the Company proposed a 21-year average service life. It then
15 increased the level to 25 years with the 2001 study, and 28 years with the 2006
16 study. While the Company's currently proposed 32-year average service life
17 continues in the right direction, a more significant step must be taken at this time.
18

19 Turning to the statistical analysis, the Company has presented solely the results
20 from its longest band analysis. Reliance on the longest band analysis understates
21 the reasonable expected average service life for the investment in this account. The
22 longer band analysis gives undue influence to PCB-related transformer retirements
23 and fails to reasonably capture the use of stainless steel tanks and improved coating
24 material, as identified by the Company as life-impacting items of information. As
25 shown in the graph below, reliance on the more recent band analyses performed by
26 the Company clearly demonstrates an elevation in the observed life tables and a
27 trend to a longer average service life.
28

⁸⁰ Response to DUC IR-019 Attachment 1 at page 6.



Rather than attempting to match the life indications exhibited from the longest band analysis, such observed life table should be given the least amount of weight in the statistical analysis. As shown in the graph below, when the more recent band analyses performed by the Company are analyzed, the Company's proposed life-curve combination clearly understates reasonable expected mortality characteristics for the investment currently in service.



Turning to items of input obtained from Company personnel, a longer average service life is further warranted. The Company is now using a combination of stainless steel tanks and improved coating material in efforts to reduce the retirements associated with rust on its cast iron and steel tanks. In other words, different materials and maintenance practices should result in a longer service life than reflected in analyses of longer historical bands. Also, the impact of PCB-contaminated transformers artificially shortens the life expectation for the remaining investment. At this time, most, if not all, contaminated PCB line transformers have already been retired, thus leaving the remaining investment to be depreciated free of such hindrance. PCB-free transformers will not be subject to the same artificially short life experienced during the 1980s, 1990s, and 2000s. Given that most utilities removed most, if not all, of their PCB-contaminated transformers during the late 1980s and early 1990s, one would expect that the trend towards longer service lives exhibited by the Company's analyses is due, in part, to fewer PCB-contaminated transformers reflected in the historical data.

From a comparative standpoint, it is clear that the Company has historically understated the reasonable expected service life for the investment in this account. The Company's proposal in this proceeding further hinders recognition of a proper average service life, given the remainder of the industry. Relying on Gannett Fleming's industry database yields a mean, median, and mode of 38, 38, and 40 years, respectively. Thus, my recommendation for a 35-year average service life is below the industry indications for such investment.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of my recommendation is a reduction in depreciation expense of \$4,408,062 based on plant as of December 31, 2009. The impact is reflective not only of the change from a 30 R1 to a 35 S-0.5 life-curve combination, but also the change from an ELG to a corrected ALG calculation procedure.

9. Account 369

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 369 – DISTRIBUTION SERVICES?

A. The Company proposes a 42 S3 life-curve combination.⁸¹

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. In addition to its standard response previously noted, Gannett Fleming's interview notes add that the primary cause of retirement for overhead services is customer conversion, with other causes being related to cracked insulation, changes in pole heights, third-party damages, abandonment of service, fires, and other damage. As it relates to underground services, the interview notes identify that underground services began to be installed in the mid-1960s and that the services are somewhat over-designed for residential customers. Further, underground services not in the downtown network were direct-buried until 1993. Since 1993, all underground services have been placed in conduit. One final item of information identified is that

⁸¹ 2009 Study at page III-6.

1 the Company expects the average service life for services to be less than
2 underground conductor booked in Account 367.⁸²

3
4 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

5 A. No. The Company's proposed average service life is inadequate. Therefore, I
6 recommend a minimal increase to a 44 S3 life-curve combination.

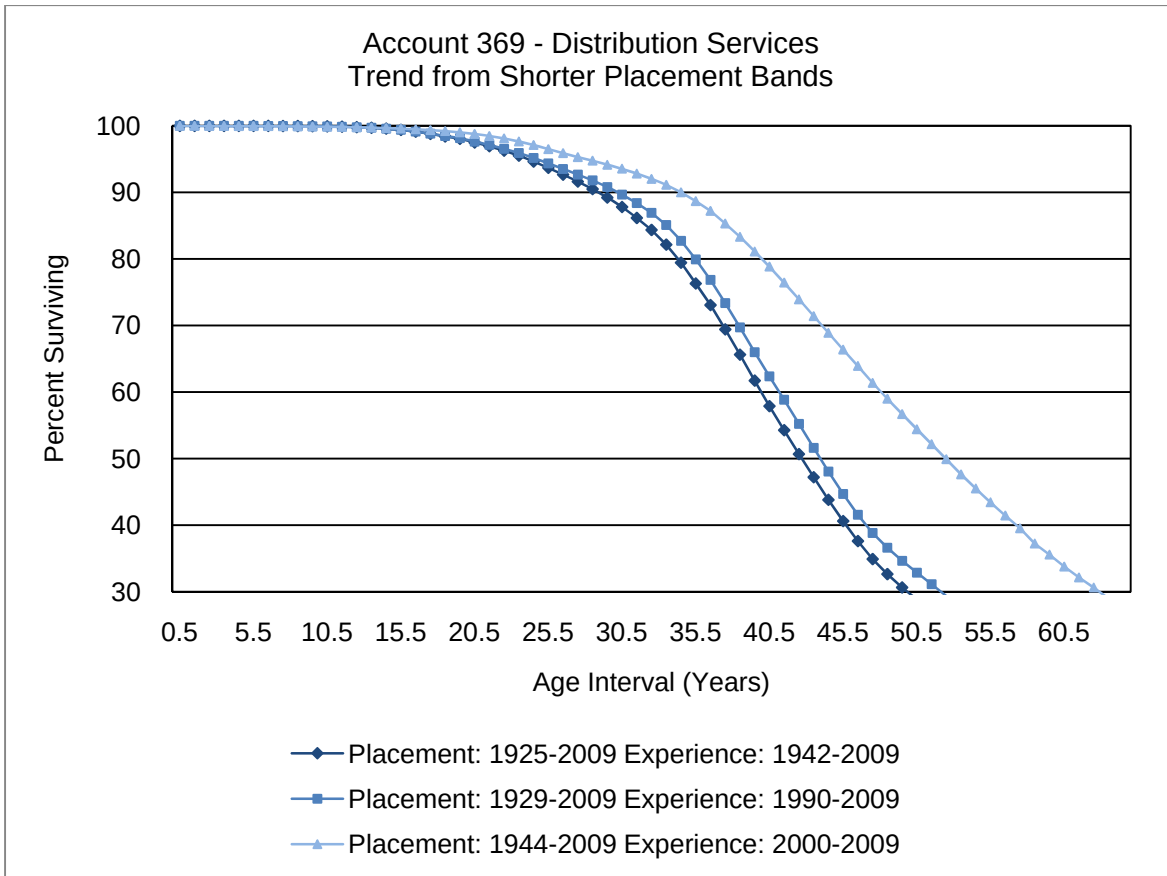
7
8 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

9 A. First, it must be noted that the Company has increased the average service life from
10 prior periods. The Company's 1994 and 2001 depreciation studies both relied on 38-
11 year average service lives, while the 2006 study increased the life to 40 years. The
12 Company is now proposing a 42-year life. Therefore, the Company has historically
13 underestimated reasonable life expectancy for the investment in this account.

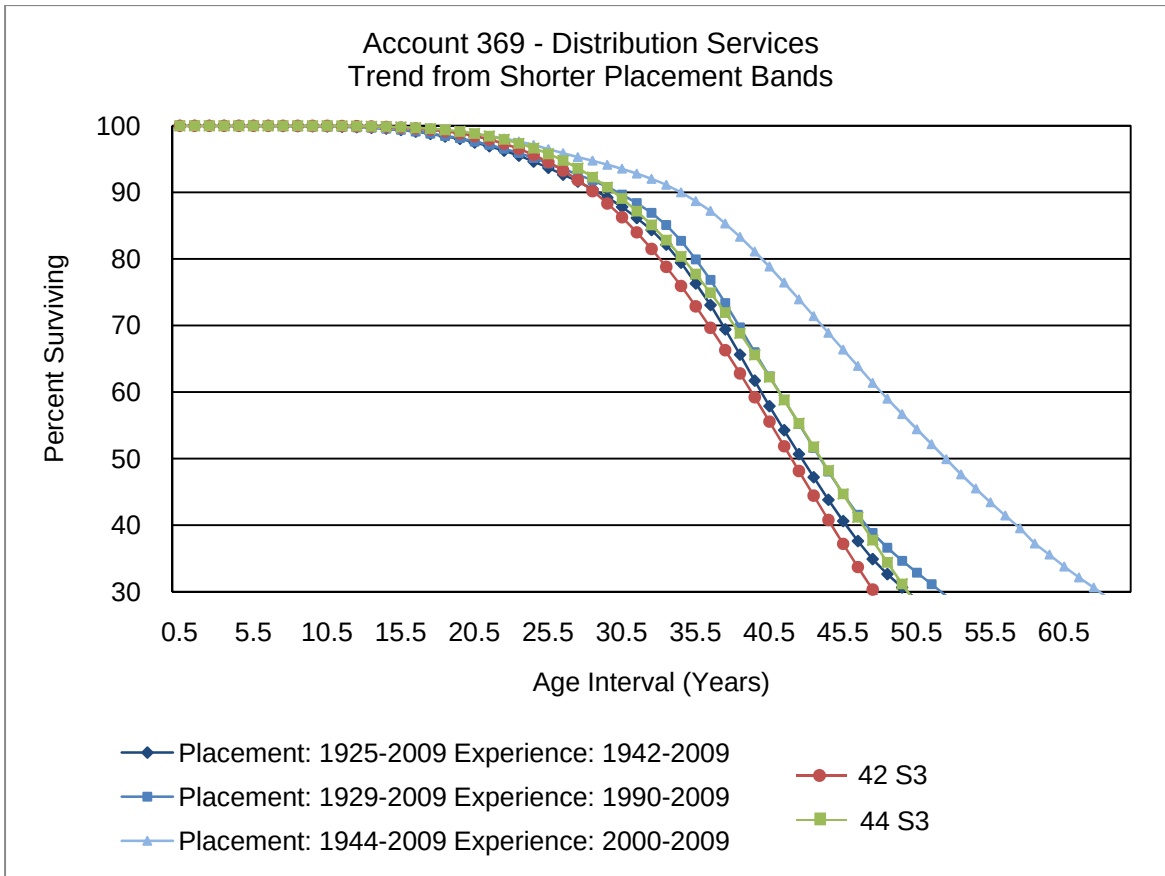
14
15 Turning to statistical analysis, a longer average service life is also warranted. The
16 Company's presentation in its 2009 Study relies on the results from its longest
17 experience band. However, as provided in discovery, the Company performed
18 additional, shorter band analyses, which indicated shorter average service lives. As
19 set forth in the graph below, the newer band analyses produce observed life tables
20 that are elevated compared to the longer band analysis. This trend in the data
21 indicates a longer average service life is warranted.

22

⁸² Response to DUC IR-019 Attachment 1 pages 6-7.



Performing graphical comparisons with all the historical analyses performed by the Company yields a 44 S3 life-curve combination as a more representative depiction of the life characteristics for this account, yet it is still a conservative recommendation. As can be seen in the graph below, my recommendation not only matches the longest band analysis as well as the Company's proposal does, but better matches the 20-year band and gives limited recognition to the trend for a longer average service life depicted by the 10-year band.



Turning to the additional information provided by Company personnel, an increase in average service life from that proposed by the Company is also warranted. In particular, underground services can reasonably be expected to have longer life characteristics than overhead services, given the climate for the service territory. In addition, while the Company previously installed direct-buried cable, as of 1993 it has placed its underground services in conduit, which provides additional protection and should result in a longer average service life. These items of information provided by Company personnel help support the longer average service life trends indicated by the shorter band analyses performed by the Company.

From an industry comparative standpoint, it is clear that the Company's historical practice has been to underestimate the average service life for the investment in this account. This historic practice would lend weight to a longer life expectancy in this case. In addition, a comparison with the overall industry as reported by Gannett Fleming is less meaningful for this account given the fact that many utilities

segregate their depreciation analysis between overhead and underground services investment, while NSPI does not. My recommendation for a 44-year average service life compares very well with the reported mean, median, and mode of 43, 43, and 40 years, respectively.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. The impact of my recommendation is a reduction in depreciation expense of \$1,245,262 based on plant as of December 31, 2009. The impact is reflective not only of the change from a 42-year to a 44-year average service life, but also the change from an ELG to a corrected ALG calculation procedure.

SECTION VII: MASS PROPERTY NET SALVAGE

A. General

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. The Company proposes net salvage factors that produce \$464 million of negative net salvage requirements over the life of the mass property accounts. I have reviewed the same nine accounts that I reviewed for life purposes. Many of the Company's requested levels of net salvage are excessively negative. I recommend adjustments to three mass property accounts, which results in a reduction of \$912,122 in annual depreciation expense.

Q. WHAT HISTORICAL PERIOD HAS THE COMPANY ANALYZED ASSOCIATED WITH ITS NET SALVAGE ANALYSES?

A. The Company has elected to analyze a 17-year period, 1993 through 2009.⁸³

Q. HAVE YOU REVIEWED ALL THE INFORMATION PRESENTED BY THE COMPANY IN SUPPORT OF ITS NET SALVAGE REQUEST?

A. Yes. The information provided is inadequate to support or demonstrate the reasonableness of its request for an overall negative 21.8% net salvage for mass

⁸³ 2009 Study, Section B.

1 property.⁸⁴ Unfortunately, the information provided, even through discovery, was
2 insufficient to permit a meaningful review of the Company's various proposals and
3 potentially limited the number of accounts adjusted.
4

5 **Q. PLEASE ELABORATE ON SOME OF THE LACK OF INFORMATION THE**
6 **COMPANY PROVIDED IN SUPPORT OF ITS PROPOSED MASS PROPERTY**
7 **NET SALVAGE LEVELS.**

8 A. While the Company performed an arithmetic process of analyzing historical data, it
9 provided no other support or justification for its proposals. Depreciation is a forward-
10 looking process and is applicable to the current plant in service that will be retiring in
11 the future, not plant that has retired. Therefore, historical analyses, while useful, only
12 provide an indication of what has transpired historically. In order to test the validity of
13 the indications from historical activity, other analyses should be performed. This is
14 where the Company's presentation, unfortunately, fails.
15

16 As an example, the Company could identify certain types of plant that had retired
17 within an account, but could not identify the same breakdown for the investment in
18 the account. This type of information is important to determine if the mix of
19 retirements reflected in the historical data are indicative of the mix of investment in
20 the account as it exists currently. If an account has a high percentage of investment
21 in transformers, yet the historical retirement activity reflects items such as circuit
22 breakers or lightning arresters, then the indications obtained from the historical
23 analysis can be skewed.
24

25 Another item of information that is normally helpful is an indication of the number of
26 units retired in any given year. Such information can provide useful indications
27 whether the historical data is indicative of individual retirements or of larger projects
28 that may have already captured a portion of economies of scale that occurs when
29 large quantities of similar assets retire in a given period. Again, the Company could
30 not provide such information.
31

⁸⁴ *Id.*, pages III-6 – 7.

Yet another concern is the level of emergency-related situations associated with historical retirements and the costs associated with such activity. If the historical costs reflect a disproportionate level of emergency transactions, which normally results in high per-unit cost of removal activity, the resulting indications are not appropriate as a proxy for future expectations, when the majority of the investment will retire. As noted later, the Company did identify a high degree of premature failures associated with a certain type of underground conductor that it no longer installs. Unfortunately, the Company did not provide any information associated with this particular type of activity, in what years it might have occurred, and to what extent.

Yet another example of potential problems with the historical data is associated with the need to retire and dispose of PCB-contaminated line transformers. The number of such contaminated transformers remaining on the system should be small, and thus future retirements will not likely incur the high cost of disposal associated with such contaminated material. The information provided by the Company in support of its proposals are devoid of precisely this type of information.

Q. TO WHICH ACCOUNTS ARE YOU RECOMMENDING CHANGES IN NET SALVAGE?

A. For the nine accounts reviewed, I am recommending changes to the following three mass property accounts:

Account	NSPI Proposal	DUCI Recommendation	Difference
356 – Transmission Overhead Conductors and Devices	(10)	(5)	5
365 – Distribution Overhead Conductors and Devices	(15)	(10)	5
367 – Distribution Underground Conductors and Devices	(25)	(10)	15

B. Account-Specific

1. Account 356

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 356 – TRANSMISSION OVERHEAD CONDUCTORS AND DEVICES?

A. The Company proposes a negative 10% net salvage.⁸⁵

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company states in its 2009 Study that its net salvage estimate was based on judgment, considering a number of factors, including analysis of historical data, net salvage characteristics of other utilities, knowledge of management's plans and operating policies, as well as net salvage from previous studies of the Company and other electric utilities.⁸⁶ In addition, the Company specifically states that the net salvage estimate for this account was based on the statistical analysis of historical data.⁸⁷

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. The Company's proposal reflects a movement from a negative 5% net salvage set forth by Gannett Fleming in its 2006 depreciation study to the current estimate of negative 10%. However, in the three years subsequent to the 2006 study, the Company has reported unusual activity between its cost of removal and retirements. In particular, the Company has reported a zero (0) level of retirement activity for 2007 and 2008, but has reported a total of approximately \$688,000 of cost of removal.⁸⁸ In addition, the reported 2009 retirements were \$8.1 million with a corresponding \$134,000 of cost of removal and \$8,000 of gross salvage. In other words, the Company's lack of timing synchronization between recording of its retirements and cost of removal results in an unusual series of values and calls into question the validity and justification for movement from the previously proposed negative 5% level. Another consideration is the fact that 90% of the retirement

⁸⁵ 2009 Study at page III-6.

⁸⁶ Response to DUC IR-043.

⁸⁷ *Id.*

⁸⁸ 2009 Study at page B-5.

activity in this account during the last 10 years occurred in 2009. In that year, the Company reported only a negative net salvage of 1.6%. This relationship of less negative levels of net salvage, in conjunction with large quantities of retirements, represents a situation identified as economies of scale. This relationship would indicate that retaining the negative 5% net salvage level is more appropriate at this time.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation results in a \$168,911 reduction to depreciation expense based on plant as of December 31, 2009.

2. Account 365

Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 365 – DISTRIBUTION OVERHEAD CONDUCTORS AND DEVICES?

A. The Company proposes a negative 15% net salvage.⁸⁹

Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?

A. The Company's basis is as previously noted for Account 356. In other words, the Company relied on its analysis of historical data.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. I believe the Company's proposal is excessively negative and should be modified to a negative 10% net salvage.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Based on the provided historical information, the Company retired substantial levels of plant in 3 of the last 10 years.⁹⁰ During the years with the largest levels of retirement activity, the Company reported a negative 7.4%, a negative 16.2%, and a negative 6.0% for 2009, 2004, and 2002, respectively. The average level of negative

⁸⁹ 2009 Study at page III-6.

⁹⁰ 2009 Study at page B-10 (2002, 2004, and 2009, which comprise 75% of all retirements booked during the past 10 years).

1 net salvage during these three years was negative 10%, and provides indications of
2 potential economies of scale when retiring greater levels of plant. In addition, the
3 Company admits that there "is some copper conduit still in service in Distribution
4 plant."⁹¹ Given the recent dramatic increase in scrap price for copper, a less negative
5 net salvage is also warranted. The current price of copper is in the mid \$4.00 per
6 pound range, while in the early 2000s, the corresponding price was in the 40¢ per
7 pound range. In other words, there has been approximately a 1000% increase in the
8 scrap price for copper during recent years. Moreover, given the expanding
9 economies in China and India, the high price for scrap metal is anticipated to
10 continue, if not further escalate.

11
12 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

13 A. My recommendation for a negative 10% net salvage results in a \$404,524 reduction
14 in depreciation expense for plant as of December 31, 2009.

15
16 **3. Account 367**

17
18 **Q. WHAT DOES THE COMPANY PROPOSE FOR ACCOUNT 367 – DISTRIBUTION**
19 **UNDERGROUND CONDUCTORS AND DEVICES?**

20 A. The Company proposes a negative 25% net salvage.⁹²

21
22 **Q. WHAT IS THE COMPANY'S BASIS FOR ITS PROPOSAL?**

23 A. As was the case for the previous accounts, the Company claims it has relied on its
24 analysis of historical data with generally no change due to information external to the
25 statistical analysis.⁹³

26
27 **Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

28 A. No. The Company's proposal is excessively negative. Therefore, I recommend a
29 negative 10% net salvage.

30

⁹¹ Response to DUC IR-019 Attachment 1 at page 5.

⁹² 2009 Study at page III-6.

⁹³ Response to DUC IR-043.

1 **Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?**

2 A. First, underground conductor is normally abandoned in place, where possible. While
3 there are still costs associated with abandoning underground plant, the costs should
4 be noticeably less than the cost to remove such conductor. Second, the Company
5 admits it has had trouble with premature failure of older generations of underground
6 conductor, such as high molecular weight polyethylene.⁹⁴ Premature failures can
7 require an emergency response, potentially resulting in a higher per-unit cost of
8 removal than would occur in non-emergency situations. Thus, the historical data
9 would tend to minimize the concept of economies of scale and maximize the higher
10 cost associated with emergency situation replacements.

11
12 Turning to the statistical analysis provided by the Company, a less negative level of
13 net salvage is also warranted. First, the year when approximately half of the
14 investment that retired during the past 10 years occurred exhibited only a negative
15 1.2% net salvage.⁹⁵ In addition, the last three years of data in between the prior
16 study, when Gannett Fleming proposed a negative 25%, and the current study
17 reflect a negative 11.4% net salvage. These facts should have indicated to Gannett
18 Fleming that a less negative value was appropriate in this proceeding.

19
20 In summary, taking into account the likelihood of abandonment of underground
21 conductor, the fact that when large historical levels of retirement activity have
22 transpired, an average negative 10% net salvage has resulted, and the fact that only
23 a negative 11% net salvage was experienced since the last depreciation study, all
24 support a negative 10% net salvage as a reasonable level for the investment in this
25 account at this time.

26
27 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

28 A. My recommendation for a negative 10% net salvage results in a \$210,151 reduction
29 to depreciation expense based on plant as of December 31, 2009.

30

⁹⁴ Response to DUC IR-019 Attachment 1 at page 6.

⁹⁵ 2009 Study at page B-11.

SECTION VIII: ELG vs. ALG

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony will address the Company's request for ELG-based depreciation. I will demonstrate that the ELG calculation procedure represents the best theoretical procedure, but the worst calculation procedure in the real world of utility operation and ratemaking.

Q. PLEASE BRIEFLY IDENTIFY WHAT THE ELG PROCEDURE IS.

A. The ELG procedure, as the name implies, segregates plant into expected equal life groups. Each group is assumed to be one year long. For example, if a utility has 100,000 Distribution poles of equal cost, the ELG procedure attempts to precisely predict how many of those 100,000 poles will retire on an annual basis for the next 60 to 70 years into the future. Those poles predicted to retire in the first year are assigned a 100% depreciation rate. Those poles projected to retire after two years are assigned a 50% depreciation rate. The process is continued through the estimation of retirements in the 70th year of operation. Each individual equal life group depreciation rate is then summed, and a composite depreciation rate is developed based on all the various one-year equal life groups.

Q. PLEASE EXPLAIN THE ALG CALCULATION PROCEDURE.

A. Unlike the ELG procedure, the ALG procedure recognizes that it is impossible to predict with any degree of accuracy the number of poles that will retire on an annual basis for the next 70 years into the future. The ALG procedure simply takes an average approach, recognizing that some items of property will retire long before the average, while others will last much longer than the average.

Q. DO THE ELG AND ALG PROCEDURES, RELYING ON THE SAME DATA, PRODUCE THE SAME RESULTING DEPRECIATION RATE?

A. No. In all instances for new plant additions, the ELG procedure will yield a higher depreciation rate than the ALG procedure.

1 **Q. IF THE ELG PROCEDURE WILL ALWAYS PRODUCE A HIGHER**
2 **DEPRECIATION RATE FOR NEW PLANT COMPARED TO THE ALG**
3 **PROCEDURE, IS IT A FORM OF ACCELERATED DEPRECIATION?**

4 A. Yes, by definition. While proponents of ELG will claim that it is also a straight-line
5 method, those proponents can only do so by changing the measurement index.
6 Under the ELG procedure, the measurement index becomes the assumed equal life
7 group. However, as noted above, in reality, the only thing that is known with certainty
8 about the future is the uncertainty associated with predicting it with precise accuracy.
9 Indeed, the National Association of Regulatory Utility Commissioners ("NARUC"), in
10 their publication entitled *Public Utility Depreciation Practices*, defines accelerated
11 depreciation as a method that allows

12
13 larger depreciation accruals in the early years of an asset's life and
14 diminishes accruals in later years compared to straight-line methods.
15 The various accelerated depreciation methods accomplish the same
16 goal, i.e., to recover the investment over the life of the plant, but the
17 timing of depreciation accruals is varied depending on the method
18 selected. Accelerated depreciation is currently used for tax
19 depreciation, but not for regulated book depreciation.⁹⁶ (*Emphasis*
20 *added.*)
21

22 In other words, while proponents may claim that ELG is a straight-line method, such
23 claims are belied, not only by definition, but also by the fact that the method does
24 result in higher levels of depreciation in earlier periods with diminishing levels in later
25 periods for the same data.
26

27 **Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE THAT COMPARES THE ELG**
28 **AND ALG CALCULATION PROCEDURES?**

29 A. Yes. Set forth as Exhibit (JP-2) are pages from a recent rebuttal testimony filed by
30 Gannett Fleming addressing the issue of ELG versus ALG.⁹⁷ Gannett Fleming's
31 example is a simple two-unit example with one unit having a 5-year life and a second
32 unit having a 15-year life. The average life of the two units is 10 years. ALG would
33 produce a 10% (1/10) depreciation rate, while the ELG procedure would yield a
34 13.34% depreciation rate, 33% higher than the ALG rate.

⁹⁶ NARUC 1996 publication at page 313.

⁹⁷ PUCT Docket No. 37744, an Entergy Texas, Inc., proceeding.

1
2 **Q. USING GANNETT FLEMING'S EXAMPLE, CAN YOU FURTHER EXPLAIN THE**
3 **FALLACIES ASSOCIATED WITH RELYING ON AN ELG CALCULATION**
4 **PROCEDURE?**

5 A. Yes. First, the example assumes that the future prediction of a 5-year and a 15-year
6 life for the two items can be measured precisely. In reality, the actual life will most
7 likely be either shorter or longer than that assumed in the example. When this
8 happens and required corrective action is taken, the ELG procedure magnifies the
9 degree of error that has to be corrected and will result in greater fluctuation between
10 depreciation studies. Moreover, if the error in the future estimation of life is that the
11 items of plant actually last longer than predicted, the ELG procedure significantly
12 accelerates the recovery of invested capital and causes the greatest level of need for
13 modification in future depreciation analyses. This is significant given that the utility
14 industry has historically lengthened the expected average service life of investment
15 in accounts over the past 40 years. Indeed, NSPI has followed the industry pattern of
16 lengthening average service lives over time, at least since its 1994 depreciation
17 study.

18
19 **Q. IS THE ELG DEPRECIATION RATE TIME-SENSITIVE COMPARED TO THE ALG**
20 **PROCEDURE?**

21 A. Absolutely. After one year, the one-year equal life group rate will already have been
22 fully recovered and should no longer be included in the calculation of a composite
23 depreciation rate, unless, of course, new plant additions precisely equaled the level
24 of retirements that occurred. This situation simply does not occur in real utility
25 operations. Thus, the ELG calculation procedure produces a depreciation rate that is
26 already outdated at the time of its development and even more outdated by the time
27 it is implemented in a rate proceeding. Alternatively, the ALG procedure is based on
28 an average approach, and its sensitivity to time, all else equal, is minimal in
29 comparison to the ELG approach.

30

1 **Q. IS THERE A FURTHER SIGNIFICANT TIME DISCONNECT BETWEEN THE ELG**
2 **CALCULATION PROCEDURE AND UTILITY RATEMAKING?**

3 A. Yes. Utility depreciation rates do not change on an annual basis. Thus, the ELG
4 rates that may already be one, two, or more years out-of-date by the time
5 implemented, unfortunately still remain constant, even if the time period between
6 rate cases is five additional years. No depreciation study based on historical data
7 can be performed and the results implemented corresponding to the life parameters
8 associated with the plant the depreciation study is based upon. In other words, the
9 ELG procedure not only requires absolute precision for forecasting annual slices of
10 future retirement expectations for more than 50 years into the future, but it also
11 requires the impossible quantification of depreciation results on an instantaneous
12 basis along with instantaneous implementation in order to be accurate. The ELG
13 theory simply does not comply with reality.
14

15 **Q. HOW OFTEN SHOULD DEPRECIATION STUDIES BE PERFORMED?**

16 A. Most experts in the industry, including Gannett Fleming, normally rely on a three- to
17 five-year period in between depreciation studies.⁹⁸
18

19 **Q. IS THE ELG PROCEDURE THE COMMON PROCEDURE USED IN UTILITY RATE**
20 **PROCEEDINGS?**

21 A. No. In fact, quite the opposite is true. The vast majority of utility depreciation rates
22 are based on the ALG procedure, not the ELG procedure. Indeed, Gannett Fleming
23 often proposes ALG-based depreciation rates.
24

25 **Q. IS THE NET SALVAGE, WHICH IS AN INTEGRAL PART OF THE**
26 **DEPRECIATION FORMULA, ALSO BASED ON AN ELG APPROACH?**

27 A. No. Gannett Fleming has presented what would have to be considered an ALG
28 approach to net salvage rather than an ELG approach. An ELG approach would
29 recognize that greater net salvage associated with brand-new investment that is
30 retired might reasonably be expected to have a positive net salvage or a less
31 negative net salvage than investment retired at the age of 50 or 60 years. Indeed,

⁹⁸ Page 8 of 27 of Mr. Spanos' rebuttal testimony in PUCT Docket No. 37744.

1 quite often, early retirement of plant is associated with items under warranty or is
2 reimbursed by the party that may have damaged such property long before its
3 expected useful life had been achieved. Thus, the Company attempts to
4 inconsistently utilize the depreciation formula by relying on ELG and ALG
5 approaches.

6
7 **Q. DOES THE COMPANY MAINTAIN ITS DEPRECIATION RESERVE ON AN ELG**
8 **BASIS?**

9 A. Again, no. The depreciation reserve is maintained on the equivalent of an ALG
10 basis. Thus, another inconsistency in the depreciation formula is presented by
11 Gannett Fleming.⁹⁹ While Gannett Fleming may claim that such differences are
12 immaterial, they are not.

13
14 **Q. IF THE BOARD WERE INCLINED TO UTILIZE THE ELG PROCEDURE, CAN IT**
15 **REASONABLY DO SO BASED ON GANNETT FLEMING'S PRESENTATION?**

16 A. No. Gannett Fleming's calculation of ELG values is incorrect. Indeed, in a recent
17 proceeding, Mr. Weidemayer's supervisor admitted that Gannett Fleming's ELG
18 computer-driven calculation appears to contain an "anomaly."¹⁰⁰

19
20 **Q. DOES THE SAME ANOMALY THAT OCCURRED IN THE TEXAS PROCEEDING**
21 **ADDRESSED BY MR. WEIDEMAYER'S SUPERIOR ALSO OCCUR IN MR.**
22 **WEIDEMAYER'S STUDY?**

23 A. Yes. For example, in Account 368 – Distribution Line Transformers, set forth on
24 pages 201 and 202 of the 2009 Study in Appendix A, the same anomaly occurs.
25 That anomaly, more correctly characterized as an error, shows a 15.1-year
26 remaining life for plant added in 2009, but increasing remaining lives for plant added
27 between 2004 and 2008. Only beginning in 2003 does the remaining life calculation
28 perform as expected. The expectation and reality is that remaining life declines
29 continuously once plant is added, but should never increase. Gannett Fleming's
30 results are illogical. The situation cannot be categorized as a major or minor

⁹⁹ When the telephone industry in the United States first began implementing ELG depreciation, one of the concerns raised by the Federal Communication Commission was the failure of telephone companies to maintain their depreciation reserves on an ELG basis.

¹⁰⁰ April 20, 2010 deposition of Mr. Spanos at transcript page 140 in PUCT Docket No. 37744.

1 anomaly; it is simply wrong. It is contrary to basic depreciation theory and even basic
2 logic and common sense. Indeed, as shown for Account 368, it takes until 1992 for
3 the vintage remaining life to fall below the 2009 remaining life proposed by Gannett
4 Fleming. This situation is simply not credible.

5
6 **Q. PLEASE SUMMARIZE THE ELG VERSUS ALG ISSUE.**

7 A. The Company proposes an ELG calculation procedure. The ELG procedure
8 produces higher depreciation rates than the standard straight-line ALG calculation
9 procedure. The ELG procedure claims to be precise, but can only make such claim
10 under the impossible assumption that one-year slices of the future can be predicted
11 with absolute precision. For those that might believe that such a situation can exist,
12 then the ELG procedure might be acceptable. However, to those who recognize that
13 it is difficult to predict next week, let alone 50, 60, or 70 years into the future with
14 precision, the ELG procedure is anything but precise. Indeed, as the future unfolds
15 and differences between projections and actual events can be measured, the ELG
16 procedure will require greater degrees of correction in order to maintain the
17 underlying premise of depreciation, which is to limit the recovery through
18 depreciation to 100% of the investment less net salvage in a systematic and rational
19 manner.

20
21 The ELG procedure is also much more time-sensitive than the ALG procedure.
22 Indeed, the ELG procedure is already stale by the time it can be presented in a
23 depreciation study, let alone by the time it can be presented and implemented in a
24 rate proceeding. The Company's proposal for implementation of the ELG calculation
25 procedure is also inconsistent with other components of the depreciation formula.
26 The Company has not performed or attempted to perform any matching of the net
27 salvage and reserve components of the depreciation formula with the life component
28 on a consistent ELG approach.

29
30 If all of the above were not sufficient to demonstrate the failure of the ELG procedure
31 to produce acceptable depreciation rates in the real world, Gannett Fleming's error in
32 quantifying the remaining life for vintage additions prohibits the recognition of ELG in

1 this proceeding. The Gannett Fleming calculation model contains a fatal flaw and
2 cannot be relied upon.

3
4 **Q. WHAT IS THE IMPACT OF RELYING ON AN ALG CALCULATION PROCEDURE**
5 **RATHER THAN AN ELG CALCULATION PROCEDURE?**

6 A. The Company claims that relying on Gannett Fleming's ALG calculation procedure
7 results in a \$15,931,840 reduction to annual depreciation expense.¹⁰¹ This
8 calculation is also flawed due to Gannett Fleming's remaining life calculation
9 discussed later.

10
11 **SECTION IX: REMAINING LIFE CALCULATION**

12
13 **Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?**

14 A. Normally, the actual quantification of the remaining life for an account is not an
15 issue. However, the presentation by the Company in this case relies on an
16 inappropriate and inaccurate calculation.

17
18 **Q. HAS GANNETT FLEMING CALCULATED THE REMAINING LIFE FOR THE**
19 **COMPANY'S INVESTMENT CORRECTLY?**

20 A. No. Based on my extensive experience dealing with numerous consultants and
21 utilities, Gannett Fleming's calculation of remaining life is unique and incorrect.

22
23 **Q. HOW DOES GANNETT FLEMING CALCULATE THE REMAINING LIFE FOR THE**
24 **COMPANY'S INVESTMENT?**

25 A. The Company's process allocates the actual book reserve to the individual surviving
26 vintage balances for each account based on the theoretical or calculated reserve.
27 However, in the process of performing such allocation, Gannett Fleming incorporates
28 two unique aspects into the remaining life calculation.

29
30 **Q. WHAT IS THE FIRST UNIQUE ASPECT OF GANNETT FLEMING'S REMAINING**
31 **LIFE CALCULATIONS?**

¹⁰¹ Response to DUC IR-085 Attachment 1 compared to the 2009 Study at pages III-4 – 7.

1 A. Gannett Fleming incorrectly limits the allocated book reserve to the surviving
2 balance of an individual vintage, adjusted for proposed net salvage. As shown on
3 page C-86 of the 2009 Study for Account 397.1 – Communications Equipment –
4 SCADA Equipment, the Company has limited column 4, allocated book reserve, for
5 the years 1979 through 2005 to the original cost as set forth in column 2. Gannett
6 Fleming incorporates this artificial limitation in spite of the fact that the investment
7 from 2005 back through 1979 is still in service and is still part of the original cost to
8 which the Company applies its approved depreciation rate. In other words, the
9 Company did not actually stop calculating and booking depreciation expense for the
10 investments made between 1979 and 2005, since those investments are still in
11 service, and the account is not fully accrued. Therefore, the Company's artificial
12 limitation is inconsistent with the Company's actual practice for the calculation and
13 booking of depreciation expense.

14
15 **Q. IS GANNETT FLEMING'S APPROACH CONSISTENT WITH STANDARD GROUP**
16 **OR MASS PROPERTY DEPRECIATION CONCEPTS?**

17 A. No. When performing mass property or group depreciation analysis, the individual
18 items should not be segregated for individual treatment. Some items of plant will
19 retire before the group average service life, while others will retire after the average
20 service life, but as the name implies, on average the accruals over the life will equal
21 the total investment adjusted for salvage. Simply put, one item of plant may actually
22 accrue 150% of its original cost while another equivalent dollar level of investment
23 may actually only last 50% of the average life and under-accrue its recovery.
24 However, the average of the two items still recovers 100% of the combined
25 investment for the Company. This is standard depreciation theory, which has been
26 violated by Gannett Fleming's remaining life calculation approach.

27
28 **Q. WHAT IS THE SECOND PROBLEM WITH GANNETT FLEMING'S REMAINING**
29 **LIFE CALCULATION?**

30 A. Gannett Fleming also recognizes the impact of net salvage parameters in the
31 remaining life calculation rather than after the remaining life calculation.

32

1 Q. ARE YOU STATING THAT UNDER GANNETT FLEMING'S APPROACH, A
2 CHANGE IN NET SALVAGE WOULD CHANGE THE REMAINING LIFE
3 CALCULATION FOR AN ACCOUNT?

4 A. Yes. By incorporating the impact of net salvage into the allocation of reserve and
5 limiting the allocation of reserve in those years where the recovery of the full
6 investment and the net salvage are assumed to be completed, Gannett Fleming has
7 presented a scenario where net salvage changes impact the calculation of remaining
8 life. This is illogical and inappropriate.

10 Q. IS YOUR APPROACH FOR CALCULATING THE REMAINING LIFE THE
11 STANDARD IN THE INDUSTRY?

12 A. Yes. Over the past 35-plus years of performing hundreds of depreciation studies
13 across the United States and Canada, I have duplicated the remaining life
14 calculation performed by every major consulting firm dealing in the area of
15 depreciation and for many of the largest utilities in the United States, some of which
16 perform their studies in-house. It is only Gannett Fleming that calculates the
17 remaining life in a manner that is different from every other entity I have dealt with in
18 the past 35-plus years.

20 Q. HAS THE FPSC RECENTLY RULED ON THIS PRECISE ISSUE AS IT RELATES
21 TO GANNETT FLEMING'S REMAINING LIFE CALCULATION?

22 A. Yes. In a recent FPL case, Gannett Fleming presented the same methodology for
23 calculating remaining life. The FPSC stated the following in its order for FP&L:

24
25 For the reasons explained below, we are of the opinion that FPL's
26 calculation of remaining life leads to questionable results. Accordingly,
27 we approve of the remaining life calculation based on using the
28 average age of the given account, with the selected survivor curve.
29 The remaining lives we approve below are based on this calculation....

30
31 We do not agree with FPL that its remaining life calculation is
32 consistent with FPL's actual practice. FPL does not maintain its plant
33 account reserves by vintage; they are maintained on a total account
34 basis. Also, depreciation rates are not applied to individual vintages;
35 the rates are applied to the total account balance. Allocating the book
36 reserve to individual vintages based on a theoretical reserve
37 calculation is not necessarily a concern. However, in its allocation,

1 FPL determined that the reserve for any given vintage could not
2 exceed the survivors for that vintage less net salvage. For example, in
3 reviewing the calculation presented for Account 396.1, Power
4 Operated Equipment, no reserve was allocated to the 1986-2000
5 vintages because the allocation of the reserve indicated that these
6 vintages were fully accrued. That is because the most allocated to any
7 given vintage was the surviving investment for that vintage less net
8 salvage. These vintages represent more than 36 percent of the plant
9 account investment. We believe this is a significant amount of
10 investment that has no remaining life. Looking at Account 396.8, Other
11 Power Operated Equipment, FPL uses an L0.5 Iowa curve and 9-year
12 life combination. The average age of the account is 7.5 years. Using
13 the method endorsed by OPC [Florida Office of Public Counsel], the
14 remaining life of the account is 5.2 years, compared to the Company's
15 calculation of zero. While this account has an existing reserve surplus,
16 that should not deter from the fact that it does indeed have a
17 remaining life using PFL's proposed curve and life combination.

18
19 FPL did not dispute that net salvage impacts its calculation of
20 remaining life. Net salvage impacts the remaining life depreciation
21 rate, not the average remaining life itself.¹⁰² Unfortunately, because
22 FPL's calculation assumes that no vintage can have more reserve
23 allocated than the surviving investment less net salvage, as net
24 salvage varies, so does the remaining life. For all the foregoing
25 reasons, FPL's remaining life calculation leads to questionable results.
26 Accordingly, the remaining lives we address below are calculated by
27 applying the average age of the account to the selected survivor
28 curve. This is similar to OPC's calculation of remaining life and PEF's
29 [Progress Energy Florida] calculation in its depreciation study in
30 Docket No. 090079-EI. The remaining lives we approve below use this
31 calculation.¹⁰³ (*Emphasis added.*)
32

33 In other words, after a fully-litigated analysis of the remaining life calculation, the
34 FPSC found that it could not rely on Gannett Fleming's remaining life calculation
35 since it produces questionable results and is affected by changes in net salvage.
36

37 **Q. WHAT DO YOU RECOMMEND?**

38 A. In each instance where I have recommended a change in the life or dispersion
39 pattern for a mass property account or where I have proposed an ALG calculation
40 procedure, I have employed the standard remaining life calculation that all other

¹⁰² Remaining Life Rate = (100 – Net Salvage – Reserve)/Average Remaining Life. Rule 25-6.0436(1)(e), F.A.C.

¹⁰³ Order No. PSC-10-0153-FOF-EI in Docket Nos. 080677-EI, 090130-EI at pages 26-27.

depreciation consultants employ other than Gannett Fleming. I recommend the Board order the Company to follow the industry standard approach in future studies.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Recognition of the proper ALG remaining life calculation for mass property accounts results in an increase in depreciation expense of \$2,536,314 based on plant as of December 31, 2009. The resulting depreciation rates employing the standard industry approach to remaining life are contained in Schedule (JP-1). For those accounts where I have not recommended a specific change in life characteristics, as discussed elsewhere in my testimony, I have also used the standard remaining life calculation, but have also reflected my recommended change to either average service life or dispersion pattern.

SECTION X: FULLY ACCRUED DEPRECIATION

Q. WHAT IS THE ISSUE IN THIS PORTION OF YOUR TESTIMONY?

A. This portion of my testimony addresses the Company's action to cease the booking of depreciation in instances where an account is unilaterally assumed to be fully accrued.

Q. WHO HAS THE AUTHORITY TO CHANGE DEPRECAITION OR AMORTIZATION RATES?

A. The authority to set depreciation or amortization rates rests solely with the regulator, not with the Company. This regulatory principle is essential in order to protect customers from inappropriate action that a utility might take. For example, if a utility had the unilateral right to change its depreciation rates as desired, it would be in the best interest of the utility's shareholders to immediately reduce or cease the booking of depreciation expense after the end of a rate case. If such practice were allowed, the utility would still recover the depreciation-related revenue requirement level built into base rates, but customers would not receive the benefit expected with payment of depreciation expense over time. The benefit customers receive for depreciation expenses is an offset to rate base for the utility's recovery of its invested capital. Depreciation expense is booked into the accumulated provision for depreciation

1 (“APFD”) or depreciation reserve. The APFD is subtracted from gross plant in order
2 to determine net plant. Net plant is the largest component of rate base.

3
4 **Q. HOW IS THE DEPRECIATION PROCESS PROPERLY PERFORMED BY A**
5 **UTILITY?**

6 A. Once a depreciation rate is set by the regulator, that rate should be applied to gross
7 plant in service on a monthly basis until the plant retires. As long as plant is still in
8 service and a depreciation rate has been approved, then depreciation expenses
9 should be booked each accounting period.

10
11 **Q. DOES THE COMPANY FOLLOW THIS FORMAT?**

12 A. No. The Company's policy is that once it makes a unilateral decision that it believes
13 an account has become fully accrued, it ceases the booking of depreciation expense
14 to the APFD.¹⁰⁴ Thus, by not continuing the booking of depreciation expense, NSPI
15 has changed the applicable depreciation rate to zero (0) rather than the rate the
16 Board previously directed the Company to use. The decision to cease the booking of
17 depreciation expense is made even though the plant has not retired.

18
19 **Q. WHAT IS NSPI'S STANDARD FOR ASSUMING AN ASSET HAS BECOME**
20 **FULLY ACCRUED?**

21 A. When the Company believes it has recovered the total investment plus the impact of
22 its estimate of net salvage, it ceases the booking of depreciation expense. Thus, the
23 standard employed by NSPI is its unilateral determination that the account has
24 become fully accrued.¹⁰⁵

25
26 **Q. WHAT IS THE IMPACT OF THIS INAPPROPRIATE ACTION?**

27 A. By ceasing the booking of depreciation expense, the Company understates the
28 APFD and, on a going forward basis, overstates rate base, since the APFD is
29 artificially not permitted to increase. Moreover, this inappropriate practice deprives
30 customers of the return of their overpayment of depreciation expense through the
31 remaining life depreciation technique.

¹⁰⁴ Response to DUC IR-023.

¹⁰⁵ *Id.*

1
2 **Q. WHAT IS THE REMAINING LIFE DEPRECIATION TECHNIQUE?**

3 A. As set forth under the General section of my testimony on depreciation, the
4 remaining life technique attempts to recover the net depreciable investment less net
5 salvage over the expected remaining life of the account. The remaining net
6 depreciable investment less net salvage can be either positive or negative. This
7 approach recognizes that while recovery of net depreciable investment less net
8 salvage may be under- or over-recovered, the intent is to allow only 100% recover,
9 not more or less.

10
11 **Q. WHAT DID THIS BOARD ORDER REGARDING THE APPLICATION OF**
12 **DEPRECIATION FOR THIS COMPANY?**

13 A. In 2003, the Board approved a settlement between the parties that set forth specific
14 depreciation rates.

15
16 **Q. DOES THE COMPANY ADMIT THAT IT CEASED USING THE BOARD-**
17 **APPROVED RATES?**

18 A. Yes. The Company admits that it stopped booking depreciation for two accounts.¹⁰⁶
19

20 **Q. WHO AT THE COMPANY MAKES THE DECISION AS TO WHEN AN ACCOUNT**
21 **BECOMES FULLY ACCRUED?**

22 A. The Company has not stated who makes such unilateral decision.
23

24 **Q. HOW DOES THE COMPANY JUSTIFY ITS ACTIONS?**

25 A. The Company does not justify its actions. It simply states that the ceasing of the
26 booking of depreciation when it believes an account has been fully accrued is its
27 policy.¹⁰⁷
28

29 **Q. IS THE COMPANY'S POLICY CORRECT?**

30 A. No. Depreciation in a regulated arena has a different meaning than for an
31 unregulated company. Depreciation for a regulated entity does not stand on its own,

¹⁰⁶ Response to DUC IR-024.

¹⁰⁷ Response to DUC IR-025.

1 but rather is incorporated into the ratesetting process. There must be realistic
2 recognition between the ratesetting process, the establishment of depreciation rates,
3 and the application of those rates. As previously noted, it would be inappropriate for
4 the Company to unilaterally cease the booking of all depreciation immediately after a
5 rate proceeding in which the depreciation rates and corresponding expense were an
6 integral part of the revenue requirement that customers must pay. This recognition
7 between the establishment of depreciation rates and the ratesetting process is
8 further supported by the definition of depreciation, which requires a systematic and
9 rational system. Moreover, the ceasing of depreciation once a company unilaterally
10 assumes that an account is fully accrued is the same as changing the Board-
11 approved depreciation rate to zero (0) rather than the continued use of the
12 authorized rate. It is inappropriate to allow a utility to unilaterally change any type of
13 rate previously adopted by its regulator.
14

15 **Q. WOULD THE COMPANY'S ACTIONS BE APPROPRIATE IF IT WERE AN**
16 **UNREGULATED COMPANY?**

17 A. Yes. However, since NSPI is a regulated utility, its actions are inappropriate because
18 captive customers would be forced to pay depreciation expense through rates
19 approved by the Board without getting the benefit of the depreciation being added to
20 the APFD. Therefore, the Company's proposal must be rejected.
21

22 **Q. WHAT DO YOU RECOMMEND?**

23 A. I recommend that the Board recognize the amount of loss of prior depreciation
24 expense that should have been booked to the APFD associated with two accounts
25 identified by the Company. The amount of additional depreciation expense that
26 should have been recognized on the Company's books and records through the end
27 of the test year in this case is \$351,717 plus at least \$40,705 per month thereafter. I
28 further recommend that the Board order the Company to correct its accounting
29 system so as to comply with the booking of the Board-approved depreciation rate.
30

1 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

2 A. Yes; however, to the extent that I have not addressed a method, issue, parameter,
3 or proposal by the Company, it should not be taken that I agree with the Company's
4 presentation.

JACOB POUS, P.E.

PRESIDENT, DIVERSIFIED UTILITY CONSULTANTS, INC.

B.S. INDUSTRIAL ENGINEERING, M.S. MANAGEMENT

I graduated from the University of Missouri in 1972, receiving a Bachelor of Science Degree in Engineering, and I graduated with a Master of Science in Management from Rollins College in 1980. I have also completed a series of depreciation programs sponsored by Western Michigan University, and have attended numerous other utility related seminars.

Since my graduation from college, I have been continuously employed in various aspects of the utility business. I started with Kansas City Power & Light Company, working in the Rate Department, Corporate Planning and Economic Controls Department, and for a short time in a power plant. My responsibilities included preparation of testimony and exhibits for retail and wholesale rate cases. I participated in cost of service studies, a loss of load probability study, fixed charge analysis, and economic comparison studies. I was also a principal member of project teams that wrote, installed, maintained, and operated both a computerized series of depreciation programs and a computerized financial corporate model.

I joined the firm of R. W. Beck and Associates, an international consulting engineering firm with over 500 employees performing predominantly utility related work, in 1976 as an Engineer in the Rate Department of its Southeastern Regional Office. While employed with that firm, I prepared and presented rate studies for various electric, gas, water, and sewer systems, prepared and assisted in the preparation of cost of service studies, prepared depreciation and decommissioning analyses for wholesale and retail rate proceedings, and assisted in the development of power supply studies for electric systems. I resigned from that firm in November 1986 in order to co-found Diversified Utility Consultants, Inc. At the time of my resignation, I held the titles of Executive Engineer, Associate and Supervisor of Rates in the Austin office of R. W. Beck and Associates. I later founded P&L Concepts, Inc.

As a principal of the firm of Diversified Utility Consultants, Inc., I have presented and prepared numerous electric, gas, and water analyses in both retail and wholesale proceedings. These analyses have been performed on behalf of clients, including public utility commissions, throughout the United States and Canada. As president of P&L Concepts, Inc., I perform the same type of services as performed under Diversified Utility Consultants, Inc.

I have been involved in over 400 different utility rate proceedings, many of which have resulted in settlements prior to the presentation of testimony before regulatory bodies.

I am registered to practice as a Professional Engineer in the states of Florida, Texas, Mississippi, North Carolina, Arizona, New Mexico, Arkansas, and Oklahoma.

UTILITY RATE PROCEEDINGS IN WHICH TESTIMONY HAS BEEN PRESENTED BY JACOB POUS

ALASKA		
ALASKA REGULATORY COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Beluga Pipe Line Company	P-04-81	Refundable Rates
Beluga Pipe Line Company	U-07-141	Depreciation
Kenai Nikiski Pipeline	U-04-81	Rate Base
ARIZONA		
ARIZONA CORPORATION COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Citizens Utilities Company	E-1032-93-111	Depreciation
ARKANSAS		
ARKANSAS PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Reliant Energy ARKLA	01-0243-U	Depreciation
CALIFORNIA		
CALIFORNIA PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Pacific Gas & Electric Company	App. No. 97-12-020	Depreciation, Net Salvage, and Amortization of True-Up
Pacific Gas & Electric Company	App. No. 02-11-017	Mass Property Salvage, Net Salvage, Mass Property Life, Life Analysis, Remaining Life, Depreciation
San Diego Gas & Electric Company		Value of Power Plants
Southern California Edison Company	App 02-05-004	Depreciation, Net Salvage
CANADA		
ALBERTA ENERGY AND UTILITIES BOARD		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
AltaLink Management/ Transalta Utilities Corporation	App. Nos. 1279345 and 1279347	Depreciation
Epcor Distribution, Inc.	App. No. 1306821	Depreciation
Enmax Corporation	App. No. 1306818	Depreciation
Transalta Utilities Corporation	TFO Tariff App. 1287507	Depreciation
UtiliCorp Networks Canada (Alberta) Ltd.	App. No. 1250392	Depreciation
Atco Electric	App. No. 1275494	Depreciation
ALBERTA PUBLIC UTILITIES BOARD		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Alberta Power Limited	E 91095	Depreciation
Alberta Power Limited	E 97065	Depreciation
Canadian Western Natural Gas Company, Ltd.		Depreciation
Centra Gas Alberta, Inc.		Depreciation

Edmonton Power Company	E 97065	Depreciation
Edmonton Power Generation, Inc.	1999/2000	GUR Compliance, Depreciation
Northwestern Utilities, Ltd	E 91044	Depreciation
NOVA Gas Transmission, Ltd.	RE95006	Depreciation
TransAlta Utilities Corporation	E 91093	Depreciation
TransAlta Utilities Corporation	E 97065	Depreciation
TransAlta Utilities Corporation	App. No. 200051	Gain on Sale
NORTHWEST TERRITORIES PUBLIC UTILITIES BOARD		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Northwest Territories Power Corporation	1995/96 and 1996-97	Depreciation
Northwest Territories Power Corporation	2001	Depreciation
COURTS		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
112th Judicial District Court of Texas	5093	Ratemaking Principles, Calculation of damages
253rd Judicial District Court of Texas	45,615	Ratemaking Principles, Level of Bond
126th Judicial District Court of Texas	91-1519	Ratemaking Principles, Level of Bond
172 Judicial District Court of Texas		Franchise Fees
United States Bankruptcy Court Eastern District of Texas	93-10408S	Level of Harm, Ratemaking, Equity for Creditors
3rd Judicial District Court of Texas		Adequacy of Notice
DISTRICT OF COLUMBIA		
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Washington Gas Light Company	768	Depreciation
FLORIDA		
FLORIDA PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Progress Energy Florida, Inc.	090079-EI	Depreciation, Excess Reserve
Progress Energy Florida, Inc.	050078-EL	Depreciation, Excess Reserve
Florida Power & Light Company	790380-EU	Territorial Dispute
Florida Power & Light Company	080677-EI 090130-EI	Depreciation, Excess Reserve
FEDERAL ENERGY REGULATORY COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Alabama Power Company	ER83-369	Depreciation
Connecticut Municipal Electric Energy Cooperative v. Connecticut Light & Power Company	EL83-14	Decommissioning
Florida Power & Light Company	ER84-379	Depreciation, Decommissioning
Florida Power & Light Company	ER93-327-000	Transmission Access
Georgia Power Company	ER76-587	Rate Base
Georgia Power Company	ER79-88	Depreciation
Georgia Power Company	ER81-730	Coal Fuel Stock Inventory, Depreciation
ISO New England, Inc.	ER07-166-000	Depreciation

Maine Yankee Atomic Power Company	ER84-344-001	Depreciation, Decommissioning
Maine Yankee Atomic Power Company	ER88-202	Decommissioning
Pacific Gas & Electric	ER80-214	Depreciation
Public Service of Indiana	ER95-625-000, ER95-626-000 & ER95-039-000	Depreciation, Dismantlement
Southern California Edison Company	ER81-177	Depreciation
Southern California Edison Company	ER82-427	Depreciation, Decommissioning
Southern California Edison Company	ER84-75	Depreciation, Decommissioning
Southwestern Public Service Company	EL 89-50	Depreciation, Decommissioning
System Energy Resource, Inc.	ER95-1042-000	Depreciation, Decommissioning
Vermont Electric Power Company	ER83 342000 & 343000	Decommissioning
Virginia Electric and Power Company	ER78-522	Depreciation, Rate Base
INDIANA		
INDIANA UTILITY REGULATORY COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Indianapolis Water Company	39128	Depreciation
Indiana Michigan Power Company	39314	Depreciation, Decommissioning
KANSAS		
KANSAS CORPORATION COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Arkansas Louisiana Gas Company	181,200-U	Depreciation
United Cities Gas Company	181,940-U	Depreciation
LOUISIANA		
LOUISIANA PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Louisiana Power & Light Company	U-16945	Nuclear Prudence, Depreciation
CITY OF NEW ORLEANS		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Entergy New Orleans, Inc.	UD-00-2	Rate Base, Depreciation
MASSACHUSETTS		
MASSACHUSETTS TELECOMMUNICATION AND ENERGY		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Bay State Gas	D.T.E.-0527	Depreciation
National Grid/KeySpan	07-30	Quality of Service
MISSISSIPPI		
MISSISSIPPI PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Mississippi Power Company	U-3739	Cost of Service, Rate Base, Depreciation
MONTANA		
MONTANA PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Montana Power Company (Gas)	90.6.39	Depreciation
Montana Power Company (Electric)	90.3.17	Depreciation, Decommissioning

Montana Power Company (Electric and Gas)	95.9.128	Depreciation
Montana-Dakota Utilities	D2007.7.79	Depreciation
Montana-Dakota Utilities	D2010.8.82	Depreciation, Interim Retirements, Production Plant Life and Net Salvage
NEVADA		
PUBLIC UTILITIES COMMISSION OF NEVADA		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Nevada Power Company	81-602, 81-685 Cons.	Depreciation
Nevada Power Company	83-667, Consolidated	Depreciation
Nevada Power Company	91-5032	Depreciation, Decommissioning
Nevada Power Company	03-10002	Depreciation
Nevada Power Company	08-12002	Depreciation, CWC
Nevada Power Company	06-06051	Depreciation, Life Spans, Decommissioning Costs, Deferred Accounting
Nevada Power Company	06-11022	General Rate Case
Nevada Power Company	10-02009	Production Life Spans
Sierra Pacific Gas Company	06-07010	Depreciation, Generating Plant Life Spans, Decommissioning Costs, Carrying Costs
Sierra Pacific Power Company	83-955	Depreciation (Electric, Gas, Water, Common)
Sierra Pacific Power Company	86-557	Depreciation, Decommissioning
Sierra Pacific Power Company	89-516, 517, 518	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	91-7079, 80, 81	Depreciation, Decommissioning (Electric, Gas, Water, Common)
Sierra Pacific Power Company	03-12002	Allowable Level of Plant in Service
Sierra Pacific Power Company	05-10004	Depreciation
Sierra Pacific Power Company	05-10006	Depreciation
Sierra Pacific Power Company	07-12001	Depreciation, CWC
Sierra Pacific Power Company	10-06003	Depreciation, Excess Reserve, Life Spans, Net Salvage
Sierra Pacific Power Company	10-06004	Depreciation, Net Salvage
Southwest Gas Corporation	93-3025 & 93-3005	Depreciation
Southwest Gas Corporation	04-3011	Depreciation
Southwest Gas Corporation	07-09030	Depreciation
NORTH CAROLINA		
NORTH CAROLINA UTILITIES COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
North Carolina Natural Gas	G-21, Sub 177	Cost of Service, Rate Design, Depreciation

OKLAHOMA		
OKLAHOMA CORPORATION COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Arkansas Oklahoma Gas Corporation	PUD 200300088	CWC, Legal Expenses, Factoring, Cost Allocation, Depreciation
Oklahoma Natural Gas Company	PUD 980000683	Depreciation, Calculation Procedure, Depreciation on CWIP
Reliant Energy ARKLA	PUD 200200166	Depreciation, Net Salvage, Software Amortization
Public Service Company of Oklahoma	PUD 960000214	Depreciation, Interim Activity, Net Salvage, Mass Property, Rate Calculation Technique
Public Service Company of Oklahoma	PUD 200600285	Depreciation
Public Service Company of Oklahoma	PUD 200800144	Depreciation
Public Service Company of Oklahoma	PUD 201000050	Depreciation, Evaluation vs. Measurement, Interim and Terminal Net Salvage, Economies of Scale
TEXAS		
PUBLIC UTILITY COMMISSION OF TEXAS		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
CenterPoint Energy Houston Electric, LLC	29526	Stranded Costs
CenterPoint Energy Houston Electric, LLC	36918	Hurricane Cost Recovery
CenterPoint Energy Houston Electric, LLC	38339	Depreciation, Net Salvage, Excess Reserve, Gain on Sale
Central Power & Light Company	6375	Depreciation, Rate Base, Cost of Service
Central Power & Light Company	8439	Fuel Factor
Central Power & Light Company	8646	Rate Base, Excess Capacity, Depreciation, Rate Design, Rate Case Expense
Central Power & Light Company	9561	Depreciation, Excess Capacity, Cost of Service, Rate Base, Taxes
Central Power & Light Company	11371	Economic Development Rate
Central Power & Light Company	12820	Nuclear Fuel and Process, OPEB, Pension, Factoring, Depreciation
Central Power & Light Company	14965	Depreciation, Cash Working Capital, Pension, OPEB, Factoring, Demonstration and Selling Expense, Non-Nuclear Decommissioning
Central Power & Light Company	22352	Depreciation
Central Telephone & United Telephone Company of Texas d/b/a Sprint	17809	Rate Case Expenses
City of Fredericksburg	7661	Territorial Dispute
El Paso Electric Company	9165	Depreciation
Entergy Gulf States, Inc.	16705	Depreciation, Prepayments, Payroll Expense, Pension Expense, OPEB, CWC, Transfer of T&D Depreciation
Entergy Gulf States, Inc.	21111	Reconcilable Fuel Costs

Entergy Gulf States, Inc.	21384	Fuel Surcharge
Entergy Gulf States, Inc.	23000	Fuel Surcharge
Entergy Gulf States, Inc.	22356	Unbundling, Competition, Cost of Service
Entergy Gulf States, Inc.	23550	Reconcilable Fuel Costs
Entergy Gulf States, Inc.	24336	Price to Beat
Entergy Gulf States, Inc.	24460	Implement PUC Subst.R.25.41(f)(3)(D)
Entergy Gulf States, Inc.	24469	Delay of Deregulation
Entergy Gulf States, Inc.	24953	Interim Fuel Surcharge
Entergy Gulf States, Inc.	26612	Fuel Surcharge
Entergy Gulf States, Inc.	28504	Interim Fuel Surcharge
Entergy Gulf States, Inc.	28818	Cert. for Independent Organization
Entergy Gulf States, Inc.	29408	Fuel Reconciliation
Entergy Gulf States, Inc.	30163	Interim Fuel Surcharge
Entergy Gulf States, Inc.	31315	Incremental Purchase Capacity Rider
Entergy Gulf States, Inc.	31544	Transition to Competition Cost
Entergy Gulf States, Inc.	32465	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32710	River Bend 30%, Explicit Capacity, Imputed Capacity, IPCR, SGSF Operating Costs and Depreciation Recovery, Option Costs
Entergy Gulf States, Inc.	33687	Transition to Competition
Entergy Gulf States, Inc.	33966	Interim Fuel Surcharge
Entergy Gulf States, Inc.	32907	Hurricane Reconstruction
Entergy Gulf States, Inc.	34724	IPCR
Entergy Gulf States, Inc.	34800	JSP, Depreciation, Decommissioning, Amortization, CWC, Franchise Fees, Rate Case Exp.
Entergy Texas International	37744	Depreciation, Property Insurance Reserve, Cash Working Capital, Decommissioning Funding, Gas Storage
Gulf States Utilities Company	5560	Depreciation, Fuel Cost Factor
Gulf States Utilities Company	5820	Fuel Cost, Capacity Factors, Heat Rates
Gulf States Utilities Company	6525	Depreciation, Rate Case Expenses
Gulf States Utilities Company	7195 & 6755	Depreciation, Interim Cash Study, Excess Capacity, Rate Case Expense
Gulf States Utilities Company	8702	Rate Case Expenses, Depreciation
Gulf States Utilities Company	10,894	Fuel Reconciliation, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	11292	Acquisition Adjustment Regulatory Plan, Base Rate, Rate Case Expenses
Gulf States Utilities Company & Entergy Corporation	12423	North Star Steel Agreement
Gulf States Utilities Company & Entergy Corporation	12852	Depreciation, OPEB, Pensions, Cash Working Capital, Other Cost of Service, and Rate Base Items
Houston Light & Power Company	6765	Depreciation, Production Plant, Early Retirement
Lower Colorado River Authority	8400	Rate Design
Magic Valley Electric Cooperative, Inc.	10820	Cost of Service, Financial Integrity, Rate Case Expenses

Oncor Delivery	35717	Depreciation, Self-Insurance, Payroll, Automated Meters, Regulatory Assets, PHFU
Southwestern Bell Telephone Company	18513	Rate Case Expenses
Southwestern Electric Power Company	3716	Depreciation
Southwestern Electric Power Company	4628	Depreciation
Southwestern Electric Power Company	5301	Depreciation, Fuel Charges, Franchise Fees
Southwestern Electric Power Company	24449	Fuel Factor Component of Price to Beat Rates
Southwestern Electric Power Company	24468	Delay of Deregulation
Southwestern Public Service Company	11520	Depreciation, Cash Working Capital, Rate Case Expenses
Southwestern Public Service Company	32766	Depreciation Expense Revenue Requirements
Southwestern Public Service Company	35763	Depreciation
Texas-New Mexico Power Company	9491	Avoided Cost, Rate Case Expenses
Texas-New Mexico Power Company	10200	Jurisdictional Separation, Cost Allocation, Rate Case Expenses
Texas-New Mexico Power Company	17751	Rate Case Expenses
Texas-New Mexico Power Company	36025	Depreciation
Texas-New Mexico Power Company	38480	Depreciation, Mass Property Life, Net Salvage
Texas Utilities Electric Company	5640	Franchise Fees
Texas Utilities Electric Company	9300	Depreciation, Rate Base, Cost of Service, Fuel Charges, Rate Case Expenses
Texas Utilities Electric Company	11735	Cost Allocation, Rate Design, Rate Case Expenses
Texas Utilities Electric Company	18490	Depreciation Reclassification
West Texas Utilities Company	7510	Depreciation, Decommissioning, Rate Base, Cost of Service, Rate Design, Rate Case Expenses
West Texas Utilities Company	10035	Fuel Reconciliation, Rate Case Expenses
West Texas Utilities Company	13369	Depreciation, Payroll, Pension, OPEB, Cash Working Capital, Fuel Inventory, Cost Allocation
West Texas Utilities Company	22354	Depreciation
RAILROAD COMMISSION OF TEXAS		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Atmos Energy Corporation	9530	Gas Cost, Gas Purchases, Price Mitigation, Rate Case Expense
Atmos Energy Corporation	9670	CWC, Depreciation, Expenses, Shared Services, Taxes Other Than FIT, Excess Return
Atmos Energy Corporation	9695	Rate Case Expense
Atmos Energy Corporation	9762	Depreciation, O&M Expense
Atmos Energy Corporation	9732	Rate Case Expense
Atmos Energy Corporation	9869	Revenue Requirements

Atmos Pipeline-Texas	10000	Rate Base, Depreciation Life and Net Salvage, Incentive Compensation, Merit Increase, Outside Director Retirement Costs, SEBP
CenterPoint Energy Entex – City of Tyler	9364	Capital Investment, Affiliates
CenterPoint Energy Entex – Gulf Coast Division	9791	Rate Base, Cost Allocation, Affiliate Expenses, Depreciation Net Salvage, Call Center, Litigation, Uncollectibles, Post Test Year Adjustments
CenterPoint Energy Entex – City of Houston	9902	CWC, Plant Adjustments, Depreciation, Payroll, Pensions, Cost Allocation
CenterPoint Energy Entex – South Texas Division	10038	CWC, Incentive Compensation, Payroll, Depreciation
CenterPoint Energy – Texas Coast Division	10007	Cost of Service Adjustment, CWC, ADIT, Incentive Compensation, Pension, Meter Reading, Customer Records and Collection, Investor Relations/Investor Services
Energas Company	5793	Depreciation
Energas Company v. Westar Transmissions Company	5168 & 4892 Cons.	Cost of Service, Refunds, Contracts, Depreciation
Energas Company	8205	Cost of Service, Rate Base, Depreciation, Affiliate Transactions, Sale/Leaseback, Losses, Income Taxes
Energas Company	9002-9135	Depreciation, Pension, Cash Working Capital, OPEB, Rate Design
Lone Star Gas Company	8664	Cash Working Capital, Depreciation Expense, Gain on Sale of Plant, OPEB, Rate Case Expenses
Rio Grande Valley Gas Company	7604	Depreciation
Southern Union Gas Company	2738, 2958, 3002, 3018, 3019 Cons.	Cost of Service, Rate Design, Depreciation
Southern Union Gas Company	6968 Interim & Cons.	Affiliate Transactions, Rate Base, Income Taxes, Revenues, Cost of Service, Conservation, Depreciation
Southern Union Gas Company	8033 Consolidated	Acquisition Adjustment, Depreciation, Excess Reserve, Distribution Plant, Cost of Gas Clause, Rate Case Expenses
Southern Union Gas Company	8878	Depreciation, Cash Working Capital, Gain on Sale of Building, Rate Case Expenses, Rate Design

Texas Gas Service Company	9988 & 9992 Cons.	Cash Working Capital, Post Test Year Plant, ADFIT, Excess Reserve, Depreciation Expense, Amortization of General Plant, Corporate and Division Expenses, Incentive Compensation, Hotel and Meals Expense, Pipeline Integrity Costs
TXU Gas Distribution	9145-9147	Depreciation, Cash Working Capital, Revenues, Gain on Sale of Assets, Clearing Accounts, Over-Recovery of Clearing Accounts, SFAS 106, Wages and Salaries, Merger Costs, Intra System Allocation, Zero Intercept, Customer Weighting Factor, Rate Design
TXU Gas Distribution	9400	Depreciation, Net Salvage, Cash Working Capital, Affiliate Transactions, Software Amortization, Securitization, O&M Expenses, Safety Compliance
TXU Lone Star Pipeline	8976	Depreciation, Net Salvage, Cash Working Capital, ALG vs. ELG
Westar Transmissions Company	5787	Depreciation, Rate Base, Cost of Service, Rate Design, Contract Issues, Revenues, Losses, Income Taxes
TEXAS WATER COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
City of Harlingen-Certificate for Convenience & Necessity	8480C/8485C/851 2C	Rate Impact for CCN
City of Round Rock	8599/8600M	Rate Discrimination, Cost of Service
Devers Canal System	8388-M	Affiliate Transactions, O&M Expense, Return, Allocation, Acquisition Adjustment, Retroactive Ratemaking, Rate Case Expenses, Depreciation
Devers Canal System	30102-M	Cost of Service, Rate Base, Ratemaking Principles, Affiliate Transactions
Southern Utilities Company	7371-R	Affiliate Transactions, Cost of Service
Scenic Oaks Water Supply Corporation	8097-G	Affiliate Transactions, Cost of Service, Rate base, Cost of Capital, Rate Design, Depreciation
Sharyland Water Supply vs. United Irrigation District	8293-M	Rate Discrimination, Cost of Service, Rate Case Expenses
Southern Water Corporation	2008-1811-UCR	Cost of Service
Travis County Water Control & Improv. District No. 20		Cost of Service
EL PASO PUBLIC UTILITY REGULATION BOARD		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
Southern Union Gas Company	1991	Depreciation, Calculation Procedure
Southern Union Gas Company	1997	Depreciation, Calculation Procedure
Southern Union Gas Company	GUD 8878 – 1998	Depreciation, Cash Working Capital, Rate Design, Rate Case Expenses
Texas Gas Services Company	2007	Revenue Requirements

UTAH		
UTAH PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
PacifiCorp	98-2035-03	Production Plant Net Salvage, Production Life Span, Interim Additions, Mass Property, Depreciation
Questar	05-057-T01	Conservation Enabling Tariff Adjustment Option and Accounting Orders
Rocky Mountain Power	07-035-13	Depreciation
WYOMING		
WYOMING PUBLIC SERVICE COMMISSION		
<u>JURISDICTION / COMPANY</u>	<u>DOCKET NO.</u>	<u>TESTIMONY TOPIC</u>
PacifiCorp	20000-ER-00-162	Rate Parity

**DEPRECIATION RECOMMENDATION OF BOARD COUNSEL
NOVA SCOTIA POWER, INC.
PLANT AS OF DECEMBER 31, 2009**

Line No.	Asset or Account Description (a)	Balance 12/31/2009 (b)	Net Salvage		Reserve 12/31/2009 (e)	Depreciable Net Plant (f)	Remaining Life (g)	Annual Accrual	
			% (c)	\$ (d)				\$ (h)	% (i)
1	DEPRECIABLE PLANT								
2	Steam Production Plant								
3	Lingan								
4	Lingan 1-2	\$ 184,774,073	(4)	\$ (7,390,963)	\$ 126,388,361	\$ 65,776,675	21.34	\$ 3,083,019	1.67%
5	Lingan 3-4	\$ 239,054,566	(4)	\$ (9,562,183)	\$ 138,144,200	\$ 110,472,549	22.42	\$ 4,927,503	2.06%
6	Lingan - Common	\$ 99,913,587	(4)	\$ (3,996,543)	\$ 9,563,863	\$ 94,346,267	26.79	\$ 3,521,385	3.52%
7	<i>Total Lingan</i>	<u>\$ 523,742,226</u>		<u>\$ (20,949,689)</u>	<u>\$ 274,096,424</u>	<u>\$ 270,595,491</u>		<u>\$ 11,531,907</u>	<u>2.20%</u>
8	Point Aconi	\$ 504,952,024	(2)	\$ (10,099,040)	\$ 169,438,169	\$ 345,612,895	31.03	\$ 11,136,312	2.21%
9	Point Tupper								
10	Point Tupper - Common	\$ 9,507,855	(10)	\$ (950,786)	\$ 3,246,958	\$ 7,211,683	21.97	\$ 328,255	3.45%
11	Point Tupper 2	\$ 149,848,292	(10)	\$ (14,984,829)	\$ 82,333,135	\$ 82,499,986	21.97	\$ 3,755,165	2.51%
12	<i>Total Point Tupper</i>	<u>\$ 159,356,147</u>		<u>\$ (15,935,615)</u>	<u>\$ 85,580,093</u>	<u>\$ 89,711,669</u>		<u>\$ 4,083,421</u>	<u>2.56%</u>
13	Trenton								
14	Trenton 5	\$ 111,556,866	(5)	\$ (5,577,843)	\$ 41,453,717	\$ 75,680,992	22.98	\$ 3,293,227	2.95%
15	Trenton 6	\$ 257,048,025	(5)	\$ (12,852,401)	\$ 99,077,662	\$ 170,822,764	28.99	\$ 5,891,841	2.29%
16	Trenton - Common	\$ 18,775,838	(5)	\$ (938,792)	\$ 17,655,565	\$ 2,059,065	26.77	\$ 76,927	0.41%
17	<i>Total Trenton</i>	<u>\$ 387,380,729</u>		<u>\$ (19,369,036)</u>	<u>\$ 158,186,944</u>	<u>\$ 248,562,821</u>		<u>\$ 9,261,996</u>	<u>2.39%</u>
18	Tufts Cove								
19	Tufts Cove 1	\$ 32,831,309	(7)	\$ (2,298,192)	\$ 19,484,615	\$ 15,644,886	22.58	\$ 692,759	2.11%
20	Tufts Cove 2	\$ 31,695,828	(7)	\$ (2,218,708)	\$ 20,577,041	\$ 13,337,495	22.79	\$ 585,117	1.85%
21	Tufts Cove 3	\$ 60,430,748	(7)	\$ (4,230,152)	\$ 36,941,440	\$ 27,719,460	22.79	\$ 1,216,487	2.01%
22	Tufts Cove - Common	\$ 66,253,084	(7)	\$ (4,637,716)	\$ 24,510,820	\$ 46,379,980	23.05	\$ 2,012,192	3.04%
23	<i>Total Tufts Cove</i>	<u>\$ 191,210,969</u>		<u>\$ (13,384,768)</u>	<u>\$ 101,513,916</u>	<u>\$ 103,081,821</u>		<u>\$ 4,506,555</u>	<u>2.36%</u>
24	Point Tupper Marine Terminal	\$ 33,233,001	(25)	\$ (8,308,250)	\$ 4,985,383	\$ 36,555,868	31.12	\$ 1,174,770	3.53%
25	General	\$ 4,677,406	0	\$ -	\$ 1,182,947	\$ 3,494,459	21.18	\$ 164,986	3.53%
26	Total Steam Plant	\$ 1,804,552,502		\$ (88,046,399)	\$ 794,983,876	\$ 1,097,615,025		\$ 41,859,946	2.32%

**DEPRECIATION RECOMMENDATION OF BOARD COUNSEL
NOVA SCOTIA POWER, INC.
PLANT AS OF DECEMBER 31, 2009**

Line No.	Asset or Account Description	Balance 12/31/2009 (b)	Net Salvage		Reserve 12/31/2009 (e)	Depreciable Net Plant (f)	Remaining Life (g)	Annual Accrual	
			% (c)	\$ (d)				\$ (h)	% (i)
27	Hydraulic Production Plant								
28	Avon	\$ 13,582,083	(19)	\$ (2,580,596)	\$ 3,240,396	\$ 12,922,283	30.60	\$ 422,314	3.11%
29	Bear River	\$ 36,282,999	(25)	\$ (9,070,750)	\$ 13,500,212	\$ 31,853,537	45.37	\$ 702,007	1.93%
30	Black River	\$ 28,359,899	(21)	\$ (5,955,579)	\$ 6,655,947	\$ 27,659,531	46.69	\$ 592,459	2.09%
31	Dickie Brook	\$ 8,158,836	(17)	\$ (1,387,002)	\$ 1,264,935	\$ 8,280,903	31.78	\$ 260,564	3.19%
32	Fall River	\$ 1,427,135	(63)	\$ (899,095)	\$ 501,529	\$ 1,824,701	46.36	\$ 39,360	2.76%
33	Harmony	\$ 3,471,334	(34)	\$ (1,180,254)	\$ 648,595	\$ 4,002,993	21.27	\$ 188,168	5.42%
34	Lequille System								
35	Nictaux and Paradise	\$ 13,159,138	(33)	\$ (4,342,516)	\$ 7,506,747	\$ 9,994,907	30.78	\$ 324,759	2.47%
36	Lequille	\$ 5,363,588	(33)	\$ (1,769,984)	\$ -	\$ 7,133,572	34.67	\$ 205,780	3.84%
37	<i>Total Lequille System</i>	<i>\$ 18,522,726</i>		<i>\$ (6,112,500)</i>	<i>\$ 7,506,747</i>	<i>\$ 17,128,479</i>		<i>\$ 530,539</i>	<i>2.86%</i>
38	Roseway	\$ 2,252,351	(43)	\$ (968,511)	\$ 632,058	\$ 2,588,804	39.20	\$ 66,044	2.93%
39	St. Margaret's	\$ 13,372,197	(45)	\$ (6,017,489)	\$ 5,763,690	\$ 13,625,996	25.12	\$ 542,355	4.06%
40	Sheet Harbour	\$ 22,864,098	(16)	\$ (3,658,256)	\$ 6,541,906	\$ 19,980,448	25.77	\$ 775,358	3.39%
41	Tusket	\$ 5,531,611	(35)	\$ (1,936,064)	\$ 2,009,279	\$ 5,458,396	29.88	\$ 182,649	3.30%
42	Wreck Cove System								
43	Wreck Cove	\$ 161,917,415	(3)	\$ (4,857,522)	\$ 72,330,369	\$ 94,444,568	44.68	\$ 2,113,921	1.31%
44	South Lake	\$ 1,081,300		\$ -	\$ 1,156,991	\$ (75,691)	0.00	\$ -	0.00%
45	<i>Total Wreck Cove System</i>	<i>\$ 162,998,715</i>		<i>\$ (4,857,522)</i>	<i>\$ 73,487,360</i>	<i>\$ 94,368,877</i>		<i>\$ 2,113,921</i>	<i>1.30%</i>
46	Annapolis Tidal	\$ 36,272,247	(6)	\$ (2,176,335)	\$ 12,635,170	\$ 25,813,412	35.63	\$ 724,535	2.00%
47	General	\$ 9,282,526	0	\$ -	\$ 466,799	\$ 8,815,727	27.41	\$ 321,674	3.47%
48	Total Hydraulic Production	\$ 362,378,757		\$ (46,799,951)	\$ 134,854,623	\$ 274,324,085		\$ 7,461,947	2.06%
49	Wind Turbine	\$ 2,975,368	(25)	\$ (743,842)	\$ 1,008,105	\$ 2,711,105	23.50	\$ 115,366	3.88%
50	Other Production - Gas Turbines								
51	Burnside	\$ 19,741,676	(8)	\$ (1,579,334)	\$ 15,525,782	\$ 5,795,228	13.15	\$ 440,702	2.23%
52	Tusket	\$ 5,044,977	(19)	\$ (958,546)	\$ 3,753,824	\$ 2,249,699	7.42	\$ 303,339	6.01%
53	Victoria Junction	\$ 7,437,789	(15)	\$ (1,115,668)	\$ 7,200,052	\$ 1,353,405	6.41	\$ 211,297	2.84%
54	Tufts Cove CT Unit 4	\$ 42,424,316	(3)	\$ (1,272,729)	\$ 10,032,974	\$ 33,664,071	33.84	\$ 994,779	2.34%
55	Tufts Cove CT Unit 5	\$ 31,392,980	(3)	\$ (941,789)	\$ 5,031,451	\$ 27,303,318	34.01	\$ 802,767	2.56%
56	Total Other Production - Gas Turbines	\$ 106,041,738		\$ (5,868,067)	\$ 41,544,083	\$ 70,365,722		\$ 2,752,885	2.60%
57	TOTAL PRODUCTION PLANT	\$ 2,275,948,365		\$ (141,458,259)	\$ 972,390,687	\$ 1,445,015,937		\$ 52,190,144	2.29%

**DEPRECIATION RECOMMENDATION OF BOARD COUNSEL
NOVA SCOTIA POWER, INC.
PLANT AS OF DECEMBER 31, 2009**

Line No.	Asset or Account Description	Balance 12/31/2009 (b)	Net Salvage		Reserve 12/31/2009 (e)	Depreciable Net Plant (f)	Remaining Life (g)	Annual Accrual	
			% (c)	\$ (d)				\$ (h)	% (i)
58	Transmission Plant								
59	Land Rights - Easements	\$ 51,683,256	0	\$ -	\$ 15,703,196	\$ 35,980,060	55.25	\$ 651,189	1.26%
60	Station Equipment	\$ 299,914,635	(5)	\$ (14,995,732)	\$ 163,126,081	\$ 151,784,286	31.09	\$ 4,882,093	1.63%
61	Towers and Fixtures	\$ 71,448,854	(35)	\$ (25,007,099)	\$ 64,992,904	\$ 31,463,049	36.67	\$ 858,005	1.20%
62	Poles and Fixtures	\$ 120,459,555	(40)	\$ (48,183,822)	\$ 36,000,908	\$ 132,642,469	34.35	\$ 3,861,498	3.21%
63	Overhead Conductors	\$ 90,836,531	(5)	\$ (4,541,827)	\$ 57,830,087	\$ 37,548,271	25.43	\$ 1,476,534	1.63%
64	Underground Conduit	\$ 1,245,673	0	\$ -	\$ 317,402	\$ 928,271	52.95	\$ 17,531	1.41%
65	Underground Conductors and Devices	\$ 228,092	0	\$ -	\$ 75,339	\$ 152,753	27.75	\$ 5,505	2.41%
66	Roads, Trails and Bridges	\$ 167,271	0	\$ -	\$ 68,977	\$ 98,294	33.85	\$ 2,904	1.74%
67	TOTAL TRANSMISSION PLANT	\$ 635,983,867		\$ (92,728,479)	\$ 338,114,894	\$ 390,597,452		\$ 11,755,260	1.85%
68	Distribution Plant								
69	Land Rights - Esemnts, Surveys & Clearing	\$ 17,174,453	0	\$ -	\$ 5,094,813	\$ 12,079,640	45.05	\$ 268,149	1.56%
70	Structures and Improvements	\$ 432,845	(5)	\$ (21,642)	\$ 18,222	\$ 436,265	27.91	\$ 15,631	3.61%
71	Station Equipment	\$ 72,118,886	(5)	\$ (3,605,944)	\$ 51,955,682	\$ 23,769,148	26.40	\$ 900,347	1.25%
72	SCADA Equipment	\$ 403,867	0	\$ -	\$ 131,919	\$ 271,948	8.25	\$ 32,963	8.16%
73	Remote Monitoring Equipment	\$ 309,013	0	\$ -	\$ 81,224	\$ 227,789	8.25	\$ 27,611	8.94%
74	Station Equipment - Miscellaneous	\$ 442,396	0	\$ -	\$ 123,260	\$ 319,136	7.31	\$ 43,657	9.87%
75	Poles, Towers and Fixtures	\$ 413,143,951	(40)	\$ (165,257,580)	\$ 252,042,585	\$ 326,358,946	27.33	\$ 11,941,418	2.89%
76	Overhead Conductors and Devices	\$ 195,166,722	(10)	\$ (19,516,672)	\$ 92,318,174	\$ 122,365,220	27.18	\$ 4,502,032	2.31%
77	Underground Conduit	\$ 7,120,116	0	\$ -	\$ 2,827,249	\$ 4,292,867	42.95	\$ 99,950	1.40%
78	Underground Conductors and Devices	\$ 42,001,518	(10)	\$ (4,200,152)	\$ 17,682,794	\$ 28,518,876	32.40	\$ 880,212	2.10%
79	Line Transformers	\$ 275,869,937	(20)	\$ (55,173,987)	\$ 146,592,639	\$ 184,451,285	26.88	\$ 6,862,027	2.49%
80	Services	\$ 120,194,451	(75)	\$ (90,145,838)	\$ 70,063,477	\$ 140,276,812	27.20	\$ 5,157,236	4.29%
81	Meters	\$ 42,735,594	0	\$ -	\$ 19,845,112	\$ 22,890,482	13.93	\$ 1,643,251	3.85%
82	Street Lighting and Signal Systems	\$ 49,164,199	(30)	\$ (14,749,260)	\$ 28,162,727	\$ 35,750,732	16.29	\$ 2,194,643	4.46%
83	TOTAL DISTRIBUTION PLANT	\$ 1,236,277,948		\$ (352,671,076)	\$ 686,939,877	\$ 902,009,147		\$ 34,569,126	2.80%

DEPRECIATION RECOMMENDATION OF BOARD COUNSEL
NOVA SCOTIA POWER, INC.
PLANT AS OF DECEMBER 31, 2009

Line No.	Asset or Account Description	Balance 12/31/2009 (b)	Net Salvage		Reserve 12/31/2009 (e)	Depreciable Net Plant (f)	Remaining Life (g)	Annual Accrual	
			% (c)	\$ (d)				\$ (h)	% (i)
84	General Plant								
85	Land Rights - General Plant	\$ 1,665,801	0	\$ -	\$ 215,220	\$ 1,450,581	45.21	\$ 32,082	1.93%
86	Structures and Improvements	\$ 66,631,159	(5)	\$ (3,331,558)	\$ 25,122,486	\$ 44,840,231	26.66	\$ 1,681,929	2.52%
87	Office Furniture and Equipment	\$ 9,392,682	0	\$ -	\$ 6,648,785	\$ 2,743,897	3.15	\$ 870,048	9.26%
88	Office Furniture & Equip - Comp Hardware	\$ 22,896,174	0	\$ -	\$ 5,089,582	\$ 17,806,592	3.89	\$ 4,579,235	20.00%
89	Reserve Variance Amort - Comp Hardware					\$ 8,436,715	5.00	\$ 1,687,343	
90	Office Furniture & Equip - Comp Software	\$ 18,089,266	0	\$ -	\$ 4,675,568	\$ 13,413,698	7.42	\$ 1,808,927	10.00%
91	Reserve Variance Amort - Comp Software					\$ 7,750,428	5.00	\$ 1,550,086	
92	Transportation Equipment	\$ 54,010,684	10	\$ 5,401,068	\$ 18,724,237	\$ 29,885,379	8.42	\$ 3,549,332	6.57%
93	Stores Equipment	\$ 472,905	0	\$ -	\$ 330,290	\$ 142,615	2.01	\$ 70,792	14.97%
94	Tools, Shop and Garage Equipment	\$ 4,411,748	0	\$ -	\$ 4,411,748	\$ -	0.00	\$ -	
95	Laboratory Equipment	\$ 389,937	0	\$ -	\$ 389,937	\$ -	0.00	\$ -	
96	Communication Equipment	\$ 45,402,470	0	\$ -	\$ 27,057,595	\$ 18,344,875	9.65	\$ 1,901,023	4.19%
97	Communication Equipment - SCADA Eq	\$ 10,690,059	0	\$ -	\$ 9,208,963	\$ 1,481,096	6.98	\$ 212,191	1.98%
98	Remote Monitoring Equipment	\$ 220,775	0	\$ -	\$ 36,360	\$ 184,415	9.69	\$ 19,031	8.62%
99	Miscellaneous Equipment	\$ 17,946,586	0	\$ -	\$ 6,431,077	\$ 11,515,509	12.77	\$ 901,812	5.02%
100	Roads, Bridges and Trails (Kelly Rock)	\$ 503,621	0	\$ -	\$ 120,819	\$ 382,802	29.50	\$ 12,976	2.58%
101	Mining Equipment (Kelly Rock)	\$ 2,009,449	(5)	\$ (100,472)	\$ 834,036	\$ 1,275,885	24.34	\$ 52,415	2.61%
102	TOTAL GENERAL PLANT	\$ 254,733,316		\$ 1,969,038	\$ 109,296,703	\$ 159,654,718		\$ 18,929,223	7.43%
103	Total Fully Accrued Depreciation	\$ 54,879,320			\$ 54,879,321				
104	TOTAL DEPRECIABLE PLANT	\$ 4,457,822,816		\$ (584,888,776)	\$ 2,161,621,482	\$ 2,897,277,254		\$ 117,443,754	2.63%
105	Company Requested							\$ 165,417,657	
106	Adjustment							\$ (47,973,903)	

SOAH DOCKET NO. 473-10-1962
DOCKET NO. 37744

APPLICATION OF ENTERGY
TEXAS, INC. FOR AUTHORITY
TO CHANGE RATES AND
RECONCILE FUEL COSTS

§
§
§
§

BEFORE THE
STATE OFFICE OF
ADMINISTRATIVE HEARINGS

RECEIVED
JUN 30 PM 2:23
PUBLIC UTILITY COMMISSION
FILED BY CLERK

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

ON BEHALF OF

ENTERGY TEXAS, INC.

JUNE 30, 2010

1 decommissioning component to be applied as a net salvage percent for
2 production facilities; (3) the service lives of many transmission and
3 distribution plant accounts; (4) the use of the interim survivor curves for
4 production facilities; and (5) the appropriate life span for the River Bend
5 nuclear facility.

6
7 II. THE EQUAL LIFE GROUP PROCEDURE

8 Q. PLEASE DESCRIBE THE EQUAL LIFE GROUP PROCEDURE.

9 A. In the ELG procedure, the property group or account is subdivided into
10 groups of equal life based on the estimated survivor characteristics of the
11 account. The depreciation for each equal life group is based on the
12 straight line method, that is, an equal amount of the group's service value
13 is recorded as depreciation in each year of service. The total depreciation
14 for the account is the summation of the depreciation for each equal life
15 group. For this reason, this procedure is also known as the unit
16 summation procedure.

17
18 Q. PLEASE PROVIDE IN A SIMPLE EXAMPLE HOW THE EQUAL LIFE
19 GROUP PROCEDURE COMPARES TO THE AVERAGE LIFE GROUP
20 (ALG) PROCEDURE?

21 A. A simple two unit hypothetical will demonstrate how the ELG procedure
22 more appropriately matches recovery to consumption. I begin by
23 assuming each unit costs \$1,000. Unit A will be in service for 5 years and

1 Unit B will be in service for 15 years. No net salvage is assumed for these
2 units.

3 Using the ALG Procedure, the average service life for the two units
4 is 10 years $((5 + 15)/2)$ and the depreciation rate is 10% (1/10 years; \$100
5 per year). Therefore, the total account original cost is \$2,000 and the
6 annual depreciation amount is \$200 (\$2,000 times 10%). At the end of
7 year 5, the total annual accrual for the account is \$1,000 (200 times 5).
8 Also affecting the accumulated depreciation is the retirement of Unit A for
9 \$1,000 in that the retirement is reflected by a reduction of Plant in Service
10 and a concurrent reduction in the accumulated depreciation in accordance
11 with the Uniform System of Accounts.¹ Thus, the accumulated
12 depreciation for the account at the end of year 5 is zero (\$1,000 annual
13 accruals minus \$1,000 retirements). At the beginning of year 6, the
14 original cost of Unit B (\$1,000) remains in Plant in Service and is offset by
15 the accumulated depreciation of \$0. One-third of that unit's service life
16 has expired. Under the ALG procedure, the 10% rate, or \$100, of annual
17 expense is booked for years 6 through 15 and at the end of year 15 Unit B
18 is retired. Depreciation accruals for the years 6 through 15 equal \$1,000.
19 When Unit B is retired the original cost and accumulated depreciation will
20 both equal zero. Thus, the Company fully reflected the total depreciable
21 cost of both Units. However, at the end of year 5 only one unit remained

¹ 8 CFR Ch. 1 Part 101 Electric Plant Instruction 10 B (2).

1 with two-thirds of its life expectancy still to be consumed, and 100% of the
2 original investment in that Unit (\$1,000) to be recovered. This method is
3 ineffective in matching cost recovery to asset consumption.

4 In contrast, if depreciation is determined using the ELG procedure,
5 depreciation expense would be recorded quite differently. For
6 comparison, I will use the same two unit example to illustrate the ELG
7 calculation. Unit A will be in service for 5 years, therefore it will have a
8 20% (100 divided by 5 years) depreciation rate. Unit B will be in service
9 for 15 years, and will have a 6.67% (100 divided by 15 years) depreciation
10 rate. Consequently, depreciation expense for years 1 through 5 would be
11 \$200 (\$1,000 times 20%) for Unit A and \$66.67 (\$1,000 times 6.67%) for
12 Unit B. At the end of year 5, the total annual accruals would be
13 approximately \$1,334 (\$1,000 for Unit A and \$334 for Unit B). Unit A
14 would be retired at the end of year 5, so the accumulated depreciation at
15 the end of year 5 is \$334 (\$1,334 of annual accruals minus \$1,000
16 retirement). In years 6 through 15, the annual accruals would be \$66.67
17 for a total to \$666 for the 10-year period. Thus, at the end of year 15, the
18 accumulated depreciation is \$0 (\$1,000 of accruals minus the \$1,000
19 retirement of Unit B), so full recovery was once again achieved. However,
20 if we look back at the end of year 5, we can see recovery of Unit A
21 matched consumption of Unit A at the time the unit went out of service,
22 and more importantly Unit B has survived one-third of its expected life and

1 recovery was one-third (\$334/\$1,000) of the expected recovery. A much
2 more appropriate recovery pattern is recorded using the ELG procedure.

3 This two unit example is used to understand the recovery patterns
4 of the two procedures; however, there are many historical transactions
5 that affect the rate of each of these procedures that complicates the
6 depreciation rate for each account. I must also state, that if the
7 depreciation expense for two units were all that was to be considered,
8 neither ALG nor ELG would be the preferred method for determining
9 depreciation rates. Instead, I would propose the use of the unit
10 depreciation method whereby the depreciation expense for each individual
11 unit is determined independently. The reason for using either the ALG or
12 the ELG methods for determining depreciation rates is due to the large
13 number of items at issue. The complexity of specifically identifying the life
14 span for each item of property would be more than offset by the cost of
15 administering such a system. Historically, the ALG method has been
16 preferred due to its simplicity. However, simplicity should not drive
17 ratemaking if a more exact method of determining the appropriate amount
18 of depreciation expense to be recovered through the rate making process.

19 The following table sets forth the activity for the accumulated
20 depreciation using the two methodologies.

COMPARISON OF ACCUMULATED DEPRECIATION
 AND ANNUAL ACCRUALS USING THE
 ALG VS ELG PROCEDURES

	ALG				ELG		
				Accum.			Accum.
	Plant	Annual*		Depr.	Annual**		Depr.
<u>Year</u>	<u>Balance</u>	<u>Accruals</u>	<u>Retirements</u>	<u>Balance</u>	<u>Accruals</u>	<u>Retirements</u>	<u>Balance</u>
1	2,000	200	0	200	267	0	267
2	2,000	200	0	400	267	0	534
3	2,000	200	0	600	266	0	800
4	2,000	200	0	800	267	0	1,067
5	2,000	200	1,000	0	267	1,000	334
6	1,000	100	0	100	66	0	400
7	1,000	100	0	200	67	0	467
8	1,000	100	0	300	67	0	534
9	1,000	100	0	400	66	0	600
10	1,000	100	0	500	67	0	667
11	1,000	100	0	600	67	0	734
12	1,000	100	0	700	66	0	800
13	1,000	100	0	800	67	0	867
14	1,000	100	0	900	67	0	934
15	1,000	100	1,000	0	66	1,000	0

* Annual Accruals = Plant Balance Multiplied by Rate (10%)

** Annual Accruals = Plant Balance Multiplied by Rate for Each Unit

1

2 Q. PLEASE SUMMARIZE SOME OF THE COMMENTS BY INTERVENORS
 3 AND STAFF WITH RESPECT TO THE ELG PROCEDURE.

4 A. The two main criticisms stated by these witnesses of the ELG procedure
 5 relate to: (1) their perceived notion that ELG-developed rates are a form of
 6 accelerated depreciation; and (2) the perception that ELG-developed rates
 7 are less accurate than ALG-developed rates unless the ELG-based rates
 8 are subject to more periodic (or continual) review and adjustment.