BEFORE THE

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: ***The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended** **– 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**	**)**	**NSUARB – P-891**

Direct Evidence of

James T. Selecky

On behalf of

NewPage Port Hawkesbury Corp.
and Bowater Mersey Paper Company Limited
(collectively, "NPB")

Project 9401
February 9, 2011

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

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<u>Direct Evidence of James T. Selecky</u>

Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a managing principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q HAVE YOU PRESENTED ANY TESTIMONY IN PRIOR NOVA SCOTIA POWER INCORPORATED ("NSPI" OR "COMPANY") REGULATORY PROCEEDINGS BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD ("BOARD")?

A Yes. I have been involved in several NSPI proceedings before the Board and appeared in P-881 and P-882.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am testifying on behalf of NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Limited (collectively, "NPB"). These two customers are both large paper producers. They are the largest customers on the NSPI system, and in the aggregate account for approximately 20 percent of NSPI's total retail sales. Together these two customers comprise the totality of the ELI 2P-RTP rate class.

Q WHAT WILL BE THE SUBJECT MATTER OF YOUR EVIDENCE IN THIS PROCEEDING?

A My evidence will address NSPI's proposed depreciation rates. Specifically, I will be addressing the Equal Life Group ("ELG") procedure and NSPI's related proposal to adjust the depreciation rates during each rate case proceeding and recommend that the Board use the Average Life Group ("ALG") procedure to calculate the approved depreciation rates. I will also address the levels of net salvage that should be included in the production depreciation rates. In addition, I will separately address the level of net salvage and decommissioning that should be included in the hydro production rates. I will also address the use of the Asset Retirement Obligation method to calculate production depreciation rates. I will then address the service lives of the wind and steam production units. The fact that an issue is not addressed should not be construed as an endorsement of NSPI's position.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS.

A My recommendations and conclusions are as follows:

1. NSPI's depreciation rates should be calculated using the ALG procedure as opposed to the ELG procedure.

2. The decommissioning cost estimates should include a provision for the value of the existing production sites. For the thermal, other and wind production sites, recognition of the value of the sites can be accomplished by removing the contingency cost.

3. The contingency costs do not represent currently identifiable costs and provide an unnecessary safety net for future ratepayers.

4. The escalation rate used in the decommissioning studies is overstated when compared to current projections of the CPI and the escalation rate used in the 2009 IRP Update.

5. The hydro decommissioning cost could be excluded from the net salvage ratio used to develop the hydro depreciation rates. The net salvage component should reflect the net salvage cost that may be incurred with ongoing retirement activity. With the emphasis on renewable energy, it is likely that these sites will continue to be used into the foreseeable future since they are a reliable source of renewable energy.

6. The wind generation average service life should be lengthened by five years consistent with various wind generation life span projections. This would lengthen the remaining life of the current wind production by five years.

7. The Board should require NSPI to develop two sets of wind production depreciation rates. The first set of depreciation rates would apply to NSPI's existing wind investment. The second set of rates, which would use a life of 25 years, would apply to all new wind generation.

8. The Board should consider extending certain of the steam and other production unit lives.

<u>Book Depreciation Background</u>

Q WHAT IS DEPRECIATION ACCOUNTING FOR RATEMAKING PURPOSES?

A Depreciation accounting and expense provides for the recovery of the original cost of an asset over its useful life adjusted for net salvage.

Q PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.

A Book depreciation is a recognition in a utility's income statement for the consumption or use of assets used to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

Book depreciation provides for the recovery of the original cost of the utility's assets. Book depreciation expense is not intended to provide for the current replacement cost of current assets; instead, it provides for capital recovery of a utility's current or original investment. Generally, this capital recovery occurs over the average service life of the investment or assets. It is, therefore, critical that appropriate average service lives be used to develop the depreciation rates so that present and future ratepayers are treated equitably. Current ratepayers should not pay depreciation expense that should be borne by future ratepayers.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is the value of the scrap or reused materials less the removal cost of the asset being depreciated. A utility should reflect in its depreciation rates the expected net salvage over the useful life of the asset.

Q PLEASE EXPLAIN HOW NET SALVAGE RELATES TO DEPRECIATION EXPENSE.

A Net salvage is simply the value received from the sale or reuse of retired property (salvage value) less the cost of retiring such property (cost of removal). Net salvage can be either positive or negative. If the salvage value exceeds the cost of removal, the net salvage is positive. If the cost of removal is greater than the salvage value received as a result of retirement, the resulting net salvage is negative.

Q WHAT PROCEDURE, METHOD AND TECHNIQUE DO YOU PROPOSE TO UTILIZE TO DETERMINE NSPI'S BOOK DEPRECIATION RATES?

A I recommend using the ALG procedure, the straight line method, and the remaining life technique to calculate NSPI's depreciation rates. NSPI's proposed depreciation rates were developed using the ELG procedure, the straight line method and the remaining life technique.

<u>ALG vs. ELG</u>

Q PLEASE DESCRIBE HOW DEPRECIATION RATES ARE CALCULATED USING THE ALG PROCEDURE.

A To calculate depreciation rates using the ALG procedure, the average remaining life for all of the investment in a particular plant account is determined. The average remaining life associated with each plant account is then used to calculate the depreciation rate for each plant account. Most regulatory commissions that I am familiar with use the ALG procedure.

Q PLEASE DESCRIBE HOW DEPRECIATION RATES ARE CALCULATED USING THE ELG PROCEDURE.

A The ELG procedure is based on the assumption that the future life characteristics of the various vintages of investment in a particular account are precisely known. That is, the manner in which the assets will be retired in the future is predictable. The total investment in any specific plant account is made up of investments that were placed in service in various years. Each year is referred to as a vintage.

For depreciation purposes, the retirement pattern for the assets in a particular plant account is defined by a probability curve that is generally referred to as an Iowa curve. This Iowa curve provides an estimate of the timing and size of retirements that are to occur over the service life of the group of assets in question. NSPI uses Iowa curves in developing its proposed depreciation rates.

To calculate the ELG depreciation rates, the average service life of an asset with a corresponding Iowa curve has to be determined. Then the ELG procedure requires plant investment in a particular account to be separated into equal life groups in an attempt to recover the depreciation expense of the plant investment. The Iowa curve is the predictor of life spans of the assets in each vintage. The ELG procedure depreciates the total cost of an asset with an estimated short life over the shorter life. Conversely, assets that are expected to live longer are depreciated over their expected longer life.

The individual depreciation expenses for a particular plant account are then summed to produce a depreciation expense for the entire account. The depreciation rate is calculated from the total depreciation expense and outstanding depreciable balance.

Q DOES THE ALG PROCEDURE ALSO USE IOWA CURVES TO DEVELOP DEPRECIATION RATES?

A Yes. The Iowa curves are used to develop the average service life and the average remaining life.

Q DO YOU SUPPORT NSPI'S PROPOSAL TO USE THE ELG PROCEDURE TO CALCULATE BOOK DEPRECIATION RATES?

A No. The ELG procedure results in ratepayers paying front end loaded depreciation expense and will likely result in intergenerational inequities because rates are not generally changed annually. Further, proponents of the ELG procedure claim that it more precisely estimates depreciation expense, however, this is not the case. Asset lives typically change over time. Therefore, this claimed precision of matching expense with life of the asset does not really exist. Therefore, I recommend that the Board use the ALG procedure to calculate the book depreciation rates for all NSPI plant accounts.

Q HAVE YOU PREPARED AN EXAMPLE THAT COMPARES THE ANNUAL DEPRECIATION EXPENSE AND RATES USING THE ELG AND THE ALG PROCEDURES?

A Yes. The attached Exhibit JTS-1 compares the annual depreciation expense and rates of a group asset with a total cost of $1,000 and a 10-year life assuming the ELG procedure and the ALG procedure. The example assumes an annual retirement ratio of 5% of the initial investment per year (i.e. $50 per year). That is, some portion of the assets will retire each year (i.e. $450 in the first nine years). Therefore, at the time of final retirement in year ten, 55% of the initial investment remains to be retired at that time.

Q WHAT DOES THE COMPARISON OF THE ELG AND ALG PROCEDURES SHOW?

A Exhibit JTS-1 shows the ELG procedure results in increased depreciation expense during the early years of an asset's life. Under the ELG procedure, the depreciation rate changes annually and depreciation expense is heavily front-loaded. If the depreciation rate is not changed, the ELG procedure will over collect depreciation expense, as the rate is initially higher than the average. However, under the ALG procedure, the depreciation rate remains constant over the life span of an asset.

Q DID NSPI PROVIDE ANY EVIDENCE THAT INDICATES THAT UNDER THE ELG PROCEDURE, THE DEPRECIATION RATES MUST CHANGE OVER TIME AND THAT THE DEPRECIATION RATES DECLINE OVER THE LIFE OF THE ASSET?

A Yes. On pages II-38 through II-40 of the 2010 Depreciation Study Appendix A, an example is provided showing the annual accruals using the ELG procedure. As column 9 of page II-39 shows, the annual depreciation rate under the ELG procedure changes annually and declines over time. This is consistent with the example I previously discussed.

However, if the ALG procedure would have been used, the depreciation rate for the example shown on page II-39 (which uses the 25-S2 survivor curve) would be a constant 4% (1/25) per year in column 9 over the entire life span. Under the ELG procedure, the depreciation rates exceed 4% for the first 15 years of the assets' life. This produces intergenerational inequities.

Q HOW DOES THE ELG PROCEDURE PRODUCE INTERGENERATIONAL INEQUITIES?

A The ELG procedure produces the highest depreciation rates when the rate base is the greatest. As a result, ratepayers in the early life of an asset not only pay a higher return and income tax component on the net investment or rate base but are also paying higher depreciation rates. As the asset is depreciated, the net investment or rate base declines as the depreciation reserve grows so the return and income tax requirement is less. Under the ELG procedure, as the rate base declines, so does the depreciation rate. Therefore, customers in the later years of an asset life benefit substantially from the ELG procedure because of the front end loading of the depreciation expense.

Q DOES THE ELG PROCEDURE ACCURATELY ASSIGN DEPRECIATION EXPENSE TO RATEPAYERS ON AN ANNUAL BASIS?

A No. The theoretical purpose of using the ELG procedure is to “accurately” assign depreciation expense to ratepayers who benefit from plant investment. However, in practice, the ELG procedure does not result in accurately assigning depreciation expense. The ELG procedure relies on the assumption that deviations from forecast of life and retirements will not occur or will be minimal. However, this is not the case. Also, the ELG procedure assumes that the annual retirements are orderly and predictable. Further, utilities do not typically change their rates every year to reflect changes in depreciation expense.

Q WHY DOES THE ELG PROCEDURE NOT ACCURATELY PRODUCE ANNUAL DEPRECIATION EXPENSE?

A Under the ELG procedure, it is assumed that the annual retirements will occur in a systematic basis. However, that is not the case. For example, a review of the retirement history for Account 353 - Station Equipment, which is the largest transmission plant account shows that for the five year period from 2001 through 2005, the annual retirements varied from $1.8 million in 2005 to $0 in 2003 (Appendix A, page B-2). This clearly demonstrates that the annual retirements are not smooth from year to year and/or predictable. However, the Iowa curves that define the retirement patterns and are used to develop the ELG depreciation rates are smooth.

Similarly, for Plant Account 364 – Poles, Towers and Fixtures, which is the largest distribution plant account, for the period of 2001 through 2005 the annual retirements range from a low of $502,144 in 2003 to $7.745 million in 2002 (Appendix A, page B-9). Once again, the retirements are not orderly as implied by the ELG procedure. Therefore, a review of NSPI's actual retirement history shows that the precision implied by the ELG procedure is simply not there.

Q IS IT REALISTIC TO ASSUME THAT THE LIFE CHARACTERISTICS THAT ARE USED TO DEVELOP THE ELG DEPRECIATION RATES ACCURATELY DEPICT THE FUTURE?

A No. The determination of depreciation rates is simply a forecast of what might transpire in the future regarding the service life of assets and the net salvage costs that will be incurred. Judgment plays a large part in establishing depreciation parameters (life and net salvage). The forecasted service life is quite long for utility assets and is subject to change.

Therefore, because of significantly changing life characteristics, it is unrealistic to apply a depreciation procedure that claims to precisely allocate the consumption of an asset over time with its useful life.

Q PLEASE EXPLAIN HOW RATEPAYERS WILL BE IMPACTED IF THE ELG PROCEDURE WERE ADOPTED AND DEPRECIATION RATES WERE NOT CHANGED OVER THE LIFE OF AN ASSET.

A As previously shown, the ELG procedure requires that the depreciation rate change over the useful life of the asset. This means that the ELG procedure results in an accelerated form of book depreciation since the depreciation rates are high in the early years and decline over time. As the depreciation rates are not reset annually, the ELG results in intergenerational inequities because current ratepayers will overpay depreciation expense that should be borne by future ratepayers.

Q HOW CAN ACTUAL EXPERIENCE DIFFER FROM FORECASTED DEPRECIATION PARAMETERS?

A Changes in technology, laws and regulations can substantially affect service lives, retirement patterns and estimates of net salvage. In addition, economic considerations can also affect the relationship between forecasted lives and actual experience. Therefore, it is difficult to predict future events with the kind of accuracy that is implied with the ELG procedure. Finally, the application of the ELG procedure implies that the pattern of future retirements is known. If the pattern of future retirements is different from that forecasted, the precision associated with the ELG procedure is lost.

Q DO YOU SUPPORT NSPI'S PROPOSAL TO IMPLEMENT A TECHNICAL STUDY APPROACH THAT WOULD REVISE DEPRECIATION RATES IN A RATE PROCEEDING?

A No. NSPI's proposal is only needed if the Board adopts the ELG procedure. The technical study approach is not needed if the depreciation rates are calculated using the ALG procedure. As I have indicated, the ELG procedure implies an accuracy that does not exist. In addition this adds another degree of complexity to NSPI's rate case filings. As can be seen by NSPI's response to NPB IR-27(b), there would be a need to significantly update and re-run the Depreciation Study and undoubtedly issues would arise as to even what elements were appropriate for updating.

Q DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING NSPI'S PROPOSED ELG DEPRECIATION RATES?

A Yes. A review of NSPI's depreciation calculations uncovers some anomalies that overstate their ELG depreciation rates and detract from their claim that the ELG rates are more accurate. For example, a review of the development of the depreciation rate for Account 368 – Line Transformer indicates that the investment that went in service in 2009 has a shorter remaining life than the investment that went in service in 2008 (Appendix A, page C-64). The remaining life for the newer 2009 vintage is over two years shorter than the remaining life for the 2008 vintage. Also, the 2008 vintage has a shorter remaining life than the 2007 vintage. In fact, the 2009 investment's remaining life is shorter than the remaining lives for all of the vintages or years through 1993. The newer investments should have longer remaining lives, not a shorter remaining life since the same Iowa curve describes the life in each vintage. A similar situation exists for many other plant accounts.

The shorter remaining life used to calculate the certain vintage depreciation expenses overstate the depreciation expense and rate for this plant account. Any of the claimed precision that is produced by the ELG procedure is diminished by the inconsistencies that appear to exist in the computer program that is used to calculate they proposed ELG depreciation rates.

In DUC IR-73, NSPI was asked to demonstrate how the remaining life for older vintages can increase for five years in a row from 2009 back through 2004. NSPI stated (in part):

> "Depending on the estimated survivor curve for an asset class, because the equal life groups representing earlier retirements (i.e. those retirements indicated by the survivor curve's dispersion pattern to occur before the average service life) will have shorter lives and higher annual accrual rates, the ELG composite remaining life calculated for a newer vintage can **theoretically** be shorter than that of an older vintage."
>
> [Emphasis added]

NSPI also provided a theoretical example. However, the response simply fails to address the fundamental problem that it is illogical for the remaining life of the newer 2009 vintage to be shorter than earlier vintages.

Q HAVE YOU ESTIMATED THE AMOUNT OF DEPRECIATION EXPENSE THAT MAY HAVE BEEN OVERSTATED FOR THE 2009 VINTAGE OF ACCOUNT 368 BECAUSE OF THE PROBLEMS WITH NSPI'S DEPRECIATION CALCULATIONS?

A Yes. I have estimated that for the 2009 vintage for this account alone, NSPI may have overstated its depreciation expense by approximately $184,000 by apparently understating the remaining life of this vintage. This calculation assumes that the 2009 vintage would have the longest remaining life shown for this Account in Appendix A, page C-64.

Q WOULD YOU PLEASE SUMMARIZE THE REASONS YOU BELIEVE THE ELG PROCEDURE SHOULD NOT BE USED TO CALCULATE NSPI'S DEPRECIATION RATES?

A The ELG procedure should not be used to determine NSPI's depreciation rates for the following reasons:

1. The claim that depreciation rates based on the ELG procedure are more accurate is flawed.
2. The ELG procedure front end loads book depreciation.
3. The ELG procedure requires annual changes in the depreciation rates. This is not practical since rates charged to customers would also have to change annually.
4. The ELG depreciation rates provided by NSPI are developed from vintage remaining life estimates some of which appear incorrect.
5. The ELG procedure produces intergenerational inequities.

Therefore, the Board should reject using the ELG procedure to calculate the approved depreciation rates.

Q WHAT IS YOUR RECOMMENDATION?

A Once the Board has determined the appropriate life and net salvage parameters for calculating NSPI's approved depreciation rates, the depreciation rates should be calculated using the approved life and net salvage characteristics using the ALG procedure which provides for full recovery of the depreciation expense. NSPI has developed as part of the Information Request process depreciation rates for the production, transmission and distribution functions using the ALG procedure. The use of the ALG procedure will reduce the proposed depreciation expense by approximately $15.933 million (see DUC IR-85, Attachment 1, Page 4 which shows an annual depreciation accrual of approximately $149.5 million using ALG vs. NSPI's proposed approximately $165.4 million using ELG, from Appendix A, page III-7).

Decommissioning Cost Assumptions

Q DO NSPI's PROPOSED STEAM, OTHER, HYDRO AND WIND PRODUCTION DEPRECIATION RATES INCLUDE A PROVISION FOR NET SALVAGE?

A Yes. NSPI's proposed production depreciation rates contain a provision for the net salvage associated with the final decommissioning costs. NSPI developed decommissioning cost estimates for each of its steam, other, hydro and wind production plants in current dollars and then escalated the dollars to the proposed date of final retirement. These escalated dollars were used to develop a negative net salvage ratio that was used to develop the proposed production depreciation rates.

Q DO YOU HAVE ANY COMMENTS REGARDING THE DEVELOPMENT OF THE DECOMMISSIONING COST ESTIMATES?

A Yes. The decommissioning cost estimates are overstated because the estimates place no value on the existing production sites, include a contingency factor that does not represent a true cost and employ an unnecessarily high escalation rate to calculate the final decommissioning costs.

First, the decommissioning cost estimates do not give recognition to the value of the production sites. In response to NPB Information Request IR-22(b), NSPI stated that the decommissioning studies do not reflect any value to the sites after decommissioning. The decommissioning cost estimates ignore this benefit that reduces the costs and depreciation rates.

An existing production site should have some value to NSPI and/or an independent power producer for the next generation of power plants. Although NSPI states in response to NPB IR-22(d) that the IRP suggests a preponderance of renewable generation in their generation expansion plans, and NSPI's view that these are likely to be dominated by wind, this does not diminish the fact that an existing production site is valuable because it has access to electric transmission lines, water supplies and transportation networks. Developing greenfield generation sites or transmission lines to a new production site not only involves significant costs but has added risk due to a host of factors, including potential local or environmental opposition. The value of such a site is generally considerably higher than typical raw land. Current ratepayers should benefit from the value that these sites can provide to the next generation of ratepayers.

In addition, the sites may provide value as an industrial site. This potential benefit should be passed on to ratepayers by lowering the decommissioning cost estimates and thus the depreciation rates. The Board should recognize the value of the production sites in the decommissioning cost estimates.

Second, the decommissioning cost estimates contain a contingency factor of 25% which increases the decommissioning cost estimates. The contingency factor does not represent a specific identified cost. This contingency factor increases the decommissioning cost estimates, which in turn increases the depreciation rates and ratemaking depreciation expense. In response to Avon IR-12(a), it is stated with respect to the cost estimates in Appendix C (Thermal Generating Station & Gas Turbine Site Remediation Study), that for an estimate of probable costs at the level of effort of the report an accuracy of plus or minus 25% is reasonable, and NSPI proposes using plus 25%. With respect to Appendix D (Hydro Production Site Decommissioning Estimate Summary), the contingency is plus 25%. This appears to account for the fact that the study was only done to a conceptual level (response to Avon IR-12(a)). The Board should remove or, at a minimum, significantly moderate the contingency costs included in the decommissioning cost estimates.

Third, the escalation rate used to inflate the decommissioning cost estimates to date of the final decommissioning is too high. NSPI used an annual escalation rate of 3.4% to escalate these costs based on historic data. Projections of future inflation are much lower.

Q REGARDING THE VALUE OF THE CURRENT PRODUCTION SITES, ARE THERE ADVANTAGES TO UTILIZING AN EXISTING SITE FOR NEW PRODUCTION UNITS RATHER THAN A NEW GREENFIELD SITE?

A Yes. The cost of new production at a new greenfield site is significantly higher than the comparable of that same generation at an existing production site. If an existing site is utilized, ratepayers will see a reduction in the cost of future generation because of the reusable infrastructure. Existing generation sites have access to the utility's existing transmission system and an infrastructure in place that makes the sites useable for future generation. This benefit should be retained by current customers who are currently paying for the existing production plants in rates. This benefit should not be passed on to future ratepayers. If the site can be reused by NSPI, the Board should view this as a sale of the site and infrastructure from current customers to future customers.

Q ARE YOU AWARE OF ANY UTILITY THAT HAS ESTIMATED THE VALUE OF AN EXISTING SITE?

A Yes. In Michigan, Consumers Energy Company ("CE") studied its options for constructing a new clean coal-fired unit. CE concluded that constructing the plant at an existing site was the least cost alternative.[1]

[1] Michigan Public Service Commission, Case No. U-15290, Supplemental Direct Testimony of William E. Garrity, Sept. 21, 2007.

Specifically, in the Supplemental Direct Testimony of CE witness William Garrity, he stated the following regarding the results of the siting study:

> "Consumers Energy examined more than 100 potential sites for the new clean coal plant that the earlier BEI analysis concluded was needed by 2015. Based on that extensive investigation, Consumers Energy selected the Karn/Weadock Generating Complex near Bay City, Michigan as the most favorable site for an 800 MW clean coal generating facility. This site was chosen for a number of reasons: (i) it offers multiple fuel delivery options, including two different rail systems as well as lake vessel delivery, (ii) there is substantial ash storage capability on site, (iii) and the incremental transmission costs are minimal, (iv) it allows a more efficient use of existing infrastructure and operating resources than would a greenfield site, (v) the site would accommodate a second coal unit which, if it is determined to be needed in the future, would take advantage of significant economies."[2]

Q DID CE PROVIDE ANY QUANTIFICATION OF THE ECONOMIC BENEFITS OF USING AN EXISTING GENERATION SITE AS OPPOSED TO A NEW GREENFIELD?

A Yes. CE's witness stated in that case that the installed cost of a coal plant in US 2007 dollars of utilizing the existing Karn/Weadock site was US $2,884 per kW. However, to construct that same coal plant at a new site, the cost was US $3,143 per kW. The difference between these two figures represents a savings of approximately US $259 per kW. This cost analysis clearly shows an existing production site can have significant value. However, NSPI totally neglected this important consideration in developing its proposed production depreciation rates.

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[2] *__Id.__* at 2, lines 10-20.

Q IN THE MICHIGAN CASE THAT YOU PREVIOUSLY REFERRED TO, DID CE GIVE ANY INDICATION THAT THERE COULD BE SAVINGS IF A GAS COMBINED CYCLE UNIT WAS BUILT AT AN EXISTING SITE?

A Yes. CE indicated that a gas combined cycle unit built at the existing Thetford site would cost US $1,058 per kW. However, constructing this same plant at a new site would cost US $1,098 per kW. This produced a total savings of US $40 per kW.

As a point of reference, NSPI's total current decommissioning cost estimate for all of its steam and other production plant is $111 million (Appendix A, pages II-32 and II-34, $104 million plus $7 million). Therefore, reusing just one site for the next generation of production plants could provide savings that offset a significant portion of the decommissioning cost estimates. Since today's ratepayers are supporting the existing plants in their rates, they should see at least a portion of this benefit.

Q HAS ANY OTHER UTILITY GIVEN ANY INDICATION THAT THE EXISTING PRODUCTION PLANT SITES ARE VALUABLE?

A Yes. Public Service Company of Colorado addressed this issue in its 2003 Least-Cost Resource Plan, and stated:

> "Both a green-field and brown-field site were considered when deciding on the Colorado Coal Project site. The green-field site consists of land that has never been subject to modern construction. There is no existing infrastructure to support the project, (*i.e.*: access roads, rail (for equipment transportation during construction, and for coal deliveries), water supply, emissions permitting, electric transmission access, *etc*.) so the site would need to be developed. These development costs will significantly impact the project schedule and cost. A brown-field site is a site that has already been developed so this infrastructure is available for the expansion of the facility.
>
> For the subject project, the brown-field sites at either Comanche or Pawnee, have substantial existing infrastructure that will reduce the construction and capital costs significantly. Natural gas pipelines, raw water supplies, transmission interconnects, roads, and rail lines already exist or are near the site, which would be new construction at a

> green-field site. At a brown-field site, the personnel, equipment, warehouses, vehicles, and infrastructure may be shared between the existing units and the new unit, reducing construction, capital and operating cost of the units involved."[3]

As indicated above, the development costs associated with using a greenfield site are "significant." Current ratepayers should receive the benefit that the existing brown-field sites will provide to future ratepayers. This benefit should be realized through reducing the terminal net salvage component of the production depreciation rates.

Q DID THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO GIVE ANY INDICATION THAT EXISTING STEAM PRODUCTION SITES IN COLORADO ARE VALUABLE?

A Yes. With respect to PSCo, the Colorado Commission stated the following:

> "We find that Public Service has adequately demonstrated that Comanche 3 will provide savings compared to other base load generation options. Because Comanche 3 is a 'Brownfield' expansion of an existing coal plant, the common use of existing coal handling, rail, and general site facilities provide many cost savings when compared to Greenfield options. In addition to these cost savings, there are potential savings in operation and maintenance cost from the combined Comanche operations. Another advantage of Comanche 3 is for the potential for it to be operational one to two years before a Greenfield coal plant. This earlier in service date for Comanche 3 is projected to save ratepayers hundreds of millions of dollars."[4]

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[3] Least-Cost Resource Plan, Docket Nos. 04A-214E, 04A-215E and 04A-216E, Volume 1, pages 1-23 and 24.

[4] Decision No. C5-0049, Docket Nos. 04A-214E, 04A-215E, and 04A-216E, paragraph 64, page 26.

Q SHOULD CURRENT RATEPAYERS BE REQUIRED TO PAY FOR DISMANTLING COSTS THAT WILL ALLOW FUTURE RATEPAYERS TO GAIN THE BENEFIT OF UTILIZING THE EXISTING SITES?

A No. Current ratepayers' rates include costs associated with supporting and maintaining existing production sites. These sites are valuable to NSPI or any other entity seeking to construct a production unit or for possible industrial or other uses. It is unfair to require current customers to forfeit the value of the existing production sites for the benefit of future customers. By ignoring this benefit, intergenerational inequities are created by virtue of requiring current ratepayers to pay costs for the benefit of future ratepayers.

Q SHOULD THE CONTINGENCY COST BE EXCLUDED FROM THE DECOMMISSIONING COST ESTIMATES?

A Yes. The contingency cost unnecessarily increases the estimated cost to decommission the production plants. The contingency cost does not reflect a real cost but provides a safeguard for NSPI and future ratepayers at the expense of current ratepayers in the event that the cost estimates are low. However, if the estimates are accurate, the current ratepayers will be paying depreciation rates higher than they should be.

The contingency factor does not represent a specific cost but is identified as an add-on cost based on judgment and experience. It should be noted that to determine the final level of the decommissioning cost estimates, all the costs were escalated to the date that the costs will be incurred. Therefore, the contingency factor should not be viewed as a substitute for the effects of inflation because that is accounted for through the application of the escalation rate.

Q WHAT IS THE IMPACT ON THE DISMANTLING STUDIES INCLUDING THE CONTINGENCY FACTOR?

A The application of the contingency factor increases the decommissioning cost estimates by 25%. That is, if the cost estimate is $100, the contingency factor increases the cost estimate to $125.

NSPI's 2010 Depreciation Study, Appendix A, pages II-32 through II-34 shows that the escalated or future cost for the decommissioning of the steam, hydro, other and wind production units is approximately $478 million ($221 million+$242 million+$14 million+$1 million). That cost is included in NSPI's proposed depreciation rates. By applying the contingency factor, the final retirement cost is approximately $96 million greater than it otherwise would have been.

Q HAS NSPI PROVIDED ANY SUPPORT FOR THE USE OF THE 25% CONTINGENCY FACTOR IN DEVELOPING ITS DECOMMISSIONING COST ESTIMATES?

A Yes. Avon Information Request IR-12 (a) asked the following:

> "Please explain the basis for the 25% contingency allowance and what this allowance is intended to account for at each site."

NSPI responded as follows:

> "(a) The cost estimates in Appendix C show an estimate of a probable cost at the time of the report. The contingency allowance reflects the risk that not all of the eventual cost will be captured and considered. The contingency amount reflects the subject-matter expert's opinion and is intended to ensure the total cost estimate, including the contingency, provides a better representation of probable cost. This approach does not change the estimator's prediction of

> accuracy. For an estimate of probable cost at this level of effort, an accuracy of +/-25% is reasonable.
>
> Development and preparation of the contents of Appendix D was a estimation for engineering at a conceptual level. Conceptual work is typically a prerequisite to preliminary engineering. Preliminary engineering is prerequisite to detailed engineering. As such, a contingency of 25% (or more) is appropriate."

In the response, NSPI states that the cost estimates for thermal plant represent a probable cost at the time of the report. The response goes on to say for the cost in Appendix C that these cost estimates are within a band of plus or minus 25%. That is, the actual cost could come in 25% more or 25% less than the cost estimates. If the cost estimates are as likely to be 25% less as they are likely to be 25% greater, it does not seem appropriate to include the plus 25% contingency factor. Ratepayers should not be saddled with excess cost estimates when there is an equal chance that the cost estimates may be overstated.

For contingency costs identified in Appendix D, NSPI states in its response that the estimations were done "at a conceptual level". With respect to these cost estimates, it should be noted that NSPI's response to NPB IR-16 (Attachment 3, Page 1) indicates an increase on account of decommissioning of $18.47 million compared to the study conducted by the same consultant at the end of 2007. NSPI's response to NPB IR-16(c) states that this increase (which is in addition to the increases for archaeological considerations and contingency):

> "...is due to increases in labour, equipment and fuel costs as well as increased costs for implementation of site safety and site environmental considerations. These increases are due to **a more refined and/or further detailed analysis and consideration of each aspect of the decommissioning**." [Emphasis Added.]

This statement suggests a more detailed analysis than simply at the conceptual level.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE INCLUSION OF THE CONTINGENCY FACTOR IN THE DECOMMISSIONING COST ESTIMATES?

A The 25% contingency factor should be excluded from any decommissioning cost estimates. As depreciation studies are submitted to the Board on a periodic basis, these cost estimates can be updated.

Q DO YOU HAVE OTHER COMMENTS ON THE FINAL PRODUCTION DECOMMISSIONING COST ESTIMATES?

A Yes. NSPI escalated the decommissioning costs from the study date of 2010 to the future date when the decommissioning is projected to occur. To escalate these costs, NSPI used an annual escalation rate of 3.4%. I recommend that the escalation rate be lowered to 2.0% per year.

Q HOW DID NSPI DEVELOP ITS ESCALATION RATE OF 3.4% PER YEAR THAT WAS USED TO ESCALATE THE DECOMMISSIONING COST FOR THE VARIOUS PRODUCTION UNITS?

A The basis for the cost escalation rates is discussed in the 2010 Depreciation Study Appendix A, page II-31 (40 of 229). That page states the following regarding the 3.4% per year escalation rate:

> "The basis for the cost escalation rates were cost indexes set forth in the Handy Whitman report, *Cost Trends of Electric Utility Construction, North Atlantic Region*. The period selected for the Handy-Whitman cost indexes as a proxy for the long term inflation rate was the period 1980-2009."

Q DO YOU HAVE ANY ISSUES WITH THE USE OF A 3.4% ESCALATION RATE?

A Yes. First, NSPI relied on an historic escalation rate to apply to future periods. Future projections of inflation were ignored. Specifically, in response to CA Information Request IR-1, NSPI provided the annual inflation rates for several 45 year historic periods based on the Canadian Consumer Price Index ("CPI"). This data indicate that from the period from 1963-2008, the annual CPI was 4.42%. The Handy Whitman index that was used to develop the escalation rate was also developed from historical data. However, on a going forward basis, the CPI for Canada was projected to be significantly less.

In response to CA Information Request IR-2, NSPI provided a link to the Bank of Canada inflation forecast. The Bank of Canada's Rates and Statistics, which provides a consensus forecast of the CPI inflation rate for two to three years and six to 10 years, indicates that the inflation rates are projected to be 2.2% and 2.0%, respectively. That is, over the next 10 years, the CPI is expected to be slightly in excess of 2%.

These CPI forecasts are consistent with the inflation assumptions that were developed by NSPI and Board Staff, with input from stakeholders, as part of the 2007 and 2009 IRP processes. The 2007 IRP used a Basic Assumption of 2.0% for the "Inflation Rate 2007-2029" (see response to DUC IR-47, Attachment 2, Page 306) and the 2009 IRP Update used a Basic Assumption of 1.92% for the "Inflation Rate 2008-2032" (see response to DUC IR-47, Attachment 4, Page 102). As described in the 2009 IRP Update at page 8 (DUC IR-47, Attachment 4, Page 10):

> "...the updating of the Basic Assumptions phase took place over several months and involved NSPI staff working jointly with Board staff and consultants, as well as consultation with stakeholders."

One last note, the Handy Whitman index is generally related to construction costs associated with electric utility investment by plant account and is not directly related to dismantling cost estimates.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE APPROPRIATE ESCALATION RATE THAT SHOULD BE UTILIZED TO ESCALATE ANY DECOMMISSIONING COST ESTIMATES?

A I recommend that the Board utilize an annual escalation rate of 2.0% to escalate any decommissioning cost estimates that it deems appropriate consistent with the IRP long-term inflation rate and the forecasted CPI for the six to 10 year period.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE DECOMMISSIONING COST ESTIMATES THAT NSPI HAS INCLUDED IN ITS DEPRECIATION STUDIES?

A The Board should develop decommissioning cost estimates that exclude the contingency costs and reflect an annual escalation rate of 2.0%. The contingency cost should be excluded because it does not represent a specific identified cost and by recognizing the potential value of the sites in the decommissioning cost estimates the need to include a contingency factor is substantially reduced or eliminated.

Hydro Net Salvage Component of Depreciation Rates

Q EARLIER IN YOUR TESTIMONY, YOU DISCUSSED YOUR CONCERNS ABOUT THE LEVEL OF DECOMMISSIONING COSTS FOR THE HYDRO PLANTS. IS IT YOUR POSITION THAT THE BOARD SHOULD APPROVE HYDRO DEPRECIATION RATES THAT REFLECT THE REVISIONS TO THE HYDRO DECOMMISSIONING STUDIES THAT YOU PREVIOUSLY DISCUSSED?

A No. That is not my primary position. The proposed depreciation rates assume that the hydro plants will be retired and decommissioned. Given the emphasis that the Provincial and Federal government is placing on renewable energy sources, it is not appropriate at this time to assume that the hydro units will be retired. In my opinion, the lives of the units will be extended through capital additions. The only retirements that would thus occur would be ongoing retirements and not final retirements of the hydro plants.

Q DO THE HYDRO PLANTS CONTAIN VALUE BECAUSE THEY PROVIDE A SOURCE OF RENEWABLE ENERGY?

A Yes. As governments implement renewable standards, the value of hydro production plants increase. The hydro plants provide a source of renewable energy to meet renewable energy standards. Therefore, it is premature to assume that this production resource will be permanently retired. Thus, it is not appropriate to saddle current ratepayers with a significant cost item that may not occur.

Q WILL NSPI'S CURRENT HYDRO GENERATION BE CLASSIFIED AS A RENEWABLE ELECTRICITY SOURCE?

A Apparently, yes. In response to NPB IR-10, NSPI stated the following:

> "For the purposes of the Renewable Electricity Standard (RES), NSPI's hydro generation would, subject to the opinion of the Minister, be classified as "heritage renewable electricity".

That same response defines "heritage renewable electricity" as follows:

> "heritage renewable electricity" means all electricity that was contracted for or supplied by a load-serving entity in the Province before January 1, 2002, and that, in the opinion of the Minister, is generated from renewable sources;"

It is reasonable to assume that NSPI's hydro production will continue to be classified as renewable electricity. As a result, if NSPI retires its existing hydro plants, it will have to replace them with other sources of renewable energy just to keep their percent of renewable energy constant. Therefore, it would be inappropriate to provide in the current depreciation rates a provision for decommissioning these plants, and the related costs of archaeology, when the decommissioning may not actually occur.

Q ARE YOU SAYING THAT THE CURRENT INVESTMENT IN HYDRO PRODUCTION PLANTS WILL NEVER BE RETIRED?

A No. More likely, as plant is retired, it will be replaced with new capital additions. This is exactly what occurs on an annual basis for all production plants.

Q WHAT IS YOUR RECOMMENDATION FOR THE NET SALVAGE COMPONENT OF THE HYDRO DEPRECIATION RATES?

A The depreciation rates for these plants should have a net salvage component for the net removal costs associated with the ongoing retirements. In response to NPB

IR-28, Attachment 1, NSPI provided its regular or ongoing retirements and net salvage experience associated with its hydro production plant from 1993 through 2009. That data indicates that the annual levels of retirements that occurred over that period is approximately $120,000 per year on average. This represents less than one-tenth of 1% of the current hydro plant balance. Therefore, based on 17 years of recent history, the ongoing retirement activity is not significant. Therefore, I would recommend that the Board reflect in the hydro production depreciation rates a net salvage component of no more than a -2%. This should more than cover NSPI's average annual net salvage cost.

Q HOW MUCH NET SALVAGE EXPENSE WOULD A -2% PRODUCE?

A A -2% net salvage ratio would produce an annual net salvage expense of approximately $192,000 per year. As a means of comparison, the net salvage expense that NSPI has incurred for its hydro units from 1993 through 2009 is approximately $396,000 in total (NPB IR-28, Attachment 1, page 2 of 3, Net Salvage column) or $23,000 per year on average. Therefore, a negative net salvage percentage of -2% should be sufficient to provide NSPI with a net salvage allowance that will compensate them for the net salvage cost incurred in connection with ongoing retirement activity.

Asset Retirement Obligation Methodology

Q IS NSPI PROPOSING ANY REVISIONS TO THE METHOD THAT IT UTILIZES TO DEVELOP ITS PRODUCTION DEPRECIATION RATES?

A Yes. NSPI is proposing to change the method that is utilized to calculate the decommissioning cost component of the production plant depreciation rates and expenses. NSPI is proposing to change from the accounting method based on the asset retirement obligation ("ARO") to accruing for the decommissioning expense evenly over the useful life of the asset using the straight line net salvage accrual method. This change, in the depreciation methodology, results in increasing the depreciation expense by $5.9 million (NPB IR-11, Attachment 1).

Q WOULD YOU PLEASE BRIEFLY EXPLAIN WHAT IS THE PURPOSE OF THE ARO METHOD?

A Under the ARO method, decommissioning costs are not recovered uniformly over the life or remaining life of the assets. The ARO method gives recognition to the time value of money. Under the ARO method, future removal costs are not recorded as current costs but are stated as a present value of estimated future cash flows or net salvage costs. Simply put, the ARO method recognizes that inflation will exist and it is inequitable and unfair to charge every vintage of ratepayers the same net salvage cost.

Q CRITICS OF THE ARO METHOD CONTEND THAT IT UNFAIRLY BURDENS FUTURE RATEPAYERS BY SHIFTING A LARGE PORTION OF THE DECOMMISSIONING COST TO FUTURE RATEPAYERS. HOW DO YOU RESPOND TO THAT CRITICISM?

A This criticism is unwarranted. Evenly spreading the decommissioning cost over the useful life of the asset produces intergenerational inequities because it ignores a fundamental economic principle. That fundamental economic principle is a dollar spent in the current year is worth more than a dollar spent 20 years in the future because of inflation. The method proposed by NSPI ignores the purchasing power of the dollar. NSPI's approach acknowledges that inflation exists when they develop their final decommissioning cost estimates but does not acknowledge that it exists when it comes to the recovery of its decommissioning cost estimates.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE DEVELOPMENT OF THE PRODUCTION DEPRECIATION RATES?

A Once the Board determines what is the proper level of decommissioning expense for the production assets, it should then instruct NSPI to develop the decommissioning provision to be included in rates utilizing the ARO methodology. However, I would note that if the Board does accept my recommendation to eliminate the decommissioning provision for the hydro production assets, that calculation will not be needed for the hydro assets.

Production Plant Lives

Q WHAT IS THE PROJECTED RETIREMENT DATE OF NSPI'S CURRENT WIND PRODUCTION PLANT?

A NSPI is proposing to retire its current wind production plant in 2023 (NSPI Evidence, page 20). Since this plant was placed into service in 2003, NSPI is proposing an average service life of 20 years. Therefore, the wind production depreciation rates are based on a remaining life of 14 years (Appendix A, page C-34).

Q TO DEVELOP THE RETIREMENT DATE WHAT AVERAGE SERVICE LIFE DID NSPI STATE IS APPROPRIATE?

A In response to NPB IR-12, NSPI stated that the retirement date of 2023 is consistent with the range of 20 to 25 years design life common to wind turbine manufacturers.

NSPI also stated that there is insufficient experience with wind turbines in Nova Scotia conditions as yet to suggest other time frames. In response to Supplementary DUC IR-52, NSPI states that the wind turbines recently installed at Nuttby Mountain, Digby and Point Tupper have a certified design life of 20 years. It should be noted that the generation that is currently in service has a rated capacity of 1.3 MW (Appendix A, page II-34).

Q ARE YOU AWARE OF ANY OTHER STUDIES OR ANALYSES THAT HAVE BEEN PERFORMED THAT PROVIDE AN INDICATION OF THE EXPECTED LIFE OF WIND GENERATION IN NOVA SCOTIA?

A Yes. CBCL Limited conducted an Environmental Assessment report for 3217284 Nova Scotia Limited, a subsidiary of EarthFirst Canada Inc., as required by the Canadian Environmental Assessment Act, that addressed the Nuttby Mountain Wind Farm proposed for Nova Scotia. The size of the project was projected to be up to 45 MW of wind generation.

Q DOES THE NUTTBY MOUNTAIN WIND FARM DOCUMENT PROVIDE ANY INDICATION AS TO THE EXPECTED SERVICE LIFE?

A Yes. The referenced document states the following regarding a life of wind generation:

> The design life of a wind farm is typically 20 or more years and capital improvements and replacement programs may extend safe and efficient operations well beyond 40 years. [5]

[5] http://www.gov.ns.ca/nse/ea/nuttbymountainwindfarm/NuttbyMountainWindFarm-registration.pdf

Q ARE YOU AWARE OF OTHER ENVIRONMENTAL ASSESSMENT REPORTS FOR NOVA SCOTIA WIND FARMS THAT CONTAIN COMMENTS REGARDING THE EXPECTED USEFUL LIVES OF WIND TURBINES?

A Yes. The Environmental Assessment conducted by Stantec for the Digby Wind Power Project states as follows at page 2.8:

> "The Digby Wind Power Project is expected to be operational for at least 20 years... Well-designed and constructed wind energy facilities may be operated for decades. Individual wind turbines are expected to perform for up to 35 years without significant repair or replacement."[6]

The Environmental Assessment conducted by CBCL Limited for the Point Tupper Wind Farm states as follows at page 18:

> "The design life of a wind turbine is typically 20 years, and capital improvement and replacement programs can extend safe and efficient operations beyond 25 years."
>
> "Once the wind farm has reached the end of its life span (anticipated being approximately 25 years)..."[7]

Q WHAT IS YOUR RECOMMENDATION FOR THE REMAINING LIFE SPAN OF NSPI'S CURRENT WIND GENERATION?

A I am recommending that the remaining life span of the wind generation be increased by five years. This will reflect an average service life five years longer than that proposed by NSPI. This will result in increasing the remaining life for the wind generation accounts from 14 years to 19 years.

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[6] http://www.gov.ns.ca/nse/ea/digby.wind.sky.power/Section-01-04.pdf
[7] http://www.gov.ns.ca/nse/ea/point.tupper.wind.farm/point.tupper.wind.farm_Report.pdf

Q SHOULD THE DEPRECIATION RATE THAT IS DEVELOPED IN THIS CASE TO DEPRECIATE NSPI'S EXISTING WIND GENERATION BE ALSO APPLIED TO THE NEW PROJECTS THAT HAVE RECENTLY OR ARE EXPECTED TO COME ONLINE IN THE NEXT FEW YEARS?

A No. The Board should develop a depreciation rate for the new wind investment that at minimum reflects a depreciable life of 25 years as the rate NSPI is proposing for the existing wind may result in overstating the depreciation rate for the new wind generation. This is because NSPI contends that the past depreciation rate for the existing wind was too low, and the rate it is putting forward in part picks up this stated deficiency. Such an issue of course would not exist for new wind production. The net salvage ratio for both existing and new wind production should be adjusted to reflect a credit for the sites, removal of the contingency factor and a lower inflation rate.

Q BASED ON YOUR NET SALVAGE AND LIFE RECOMMENDATIONS, WHAT ARE YOU PROPOSING AS THE APPROPRIATE DEPRECIATION RATE FOR THE WIND GENERATION?

A I recommend that the Board request NSPI to develop the wind generation depreciation rates for both the existing and new wind projects once it has determined the appropriate life and net salvage parameters.

Q DO YOU HAVE ANY COMMENTS TO MAKE REGARDING THE RETIREMENT DATES THAT NSPI UTILIZED TO DEVELOP ITS STEAM PRODUCTION PLANT DEPRECIATION RATES?

A Yes. NSPI indicated in its response to CA Information Request IR-11 that both the 2007 Integrated Resource Plan (IRP) and the 2009 IRP Update have all of their steam generation plants in service throughout the entirety of their respective planning periods (i.e. 2029 and 2032). However, NSPI is proposing to retire its steam generation plants at Lingan, Point Tupper 2, Trenton 5, and Tufts Cove before these dates. The retirement dates for the steam production units are shown on the 2010 Depreciation Study Appendix A, page II-29.

Q DID NSPI INDICATE THAT IT HAS REVISED ITS IRP PLANS FOR RETIREMENTS BEFORE 2032?

A No. In response to DUC Information Request IR-48, NSPI stated that it does not have current plans to retire specific generating facilities.

Q WHY ARE NSPI'S RETIREMENT DATES OF CERTAIN OF ITS STEAM PRODUCTION UNITS SHORTER THAN THOSE SPECIFIED IN THE IRP?

A In NSPI's 2010 Depreciation Study, NSPI indicated that there was uncertainty beyond 2020 due to further carbon emissions regulations and a new anticipated federal government framework (Evidence, page 13 and Appendix A, page II-28). This appears to be why the lives for several of the thermal production plants are significantly shorter than the lives in the 2009 IRP Update.

Q DOES THE FEDERAL GOVERNMENT FRAMEWORK THAT WOULD REQUIRE COAL PLANTS UPON REACHING THEIR 45TH ANNIVERSARY TO MEET NATURAL GAS COMBINED CYCLE PERFORMANCE STANDARDS FOR CARBON DIOXIDE EMISSIONS OR TO BE SHUT DOWN REPRESENT AN EXISTING REQUIREMENT?

A No. In response to NPB Information Request IR-24, NSPI indicated that the framework does not represent an existing actual requirement and Environment Canada continues to prepare draft regulations in line with the announced framework.

Q WHAT IS YOUR RECOMMENDATION REGARDING THE LIVES OF THE STEAM PRODUCTION PLANTS?

A Consistent with NSPI's 2009 IRP Update and NSPI's current lack of plans for the retirement of any specific units, I recommend that the Board consider extending the steam production lives of Lingan, Point Tupper 2, Trenton 5 and Tufts Cove 1-3 consistent with the 2009 IRP Update which assumed no retirements until at least 2032, the end of the IRP planning period. (This should also be considered for Burnside, Tusket and Victoria Junction absent any evidence to support otherwise.)

Q HAVE YOU DEVELOPED STEAM PRODUCTION DEPRECIATION RATES?

A No. I recommend that the Board have NSPI develop the depreciation rates after it has determined the appropriate life and net salvage depreciation parameters.

Summary

Q COULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A

1. NSPI's depreciation rates should be calculated using the ALG procedure.
2. The decommissioning cost estimates for the thermal, other and wind production should exclude the contingency cost and recognize the value of these production sites.
3. The escalation rate used to calculate the final decommissioning cost should be 2.0%.
4. The hydro decommissioning rates should exclude a provision for final decommissioning and should only include a net salvage ratio of -2% to reflect ongoing retirement activity.
5. The average service life of the wind production units should be lengthened by five years and the Board should consider extending certain of the steam production unit lives.
6. The Board should require NSPI to develop two sets of wind production depreciation rates. One set of the rates would apply to the existing wind production investment and the second set of the rates would apply to a new wind production investment.

Q DOES THIS CONCLUDE YOUR DIRECT EVIDENCE?

A Yes, it does.

(10402416.3)

Qualifications of James T. Selecky

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James T. Selecky. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and am a managing principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978, I received the degree of Master of Business Administration with a major in Finance from Wayne State University.

I was employed by The Detroit Edison Company (DECo) in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and troubleshooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies; developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DECo; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. (DBA). In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and staff. At DBA and BAI I have testified in electric, gas and water proceedings involving almost all aspects of regulation. I have participated in regulatory proceedings that established utility book depreciation rates for utility investment.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A Yes. I have testified on behalf of DECo in its steam heating and main electric cases. In these cases I have testified to rate base, income statement adjustments, changes in book depreciation rates, rate design, and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of Alberta, Nova Scotia and Saskatchewan. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Montana, New York and Pennsylvania and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates and rate design.

Q ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A Yes, I am a registered professional engineer in the State of Michigan.

Exhibit JTS-1

Comparison of Employing the ALG and ELG Procedure to Calculate Annual Depreciation Rates and Expense

Line	Years (1)	Depreciation Balance (2)	ALG Depreciation Rates (3)	ALG Depreciation Expense (4)	ELG Depreciation Rates (5)	ELG Depreciation Expense (6)
1	1	$1,000	12.90%	$129	19.64%	$196
2	2	950	12.90%	$123	15.42%	$146
3	3	900	12.90%	$116	13.49%	$121
4	4	850	12.90%	$110	12.33%	$105
5	5	800	12.90%	$103	11.54%	$92
6	6	750	12.90%	$97	10.97%	$82
7	7	700	12.90%	$90	10.56%	$74
8	8	650	12.90%	$84	10.28%	$67
9	9	600	12.90%	$77	10.09%	$61
10	10	550	12.90%	$71	10.00%	$55
				$1,000		$1,000