BEFORE THE NORTH DAKOTA
PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC SERVICE IN NORTH DAKOTA

CASE NO. PU-12-813

DIRECT TESTIMONY OF

DANTE MUGRACE

ON BEHALF OF THE ADVOCACY STAFF OF THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

Dante Mugrace

7/17/2013

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is Dante Mugrace. I am a Senior Consultant with the economic firm of Snavely King Majoros & Associates, Inc. (Snavely King) My business address is 8100 Professional Place, Suite 306, Landover, Maryland 20785. In my capacity as a Senior Consultant, I am responsible for analyzing rate case filings, preparing expert testimony and evaluating revenue requirement proposals, economic and policy issues and methodologies used to set rates for utility services.

Q. Please describe Snavely King.

A. Snavely- King was founded in 1970 to conduct research and consult on the rates, revenues, costs and economic performance of regulated firms and industries. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 30+ year's history, members of the firm have participated in hundreds of proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with Snavely King, I was employed by the New Jersey Board of Public Utilities Commission (NJBPU) from October 1983 to my retiring in June 2011. I have held various positions throughout my tenure with the NJBPU beginning with various Accountant positions, and being promoted to Supervising Rate Analyst, Administrative Analyst and finally with my last position as Bureau Chief of Rates in the Water Division. I held this last position for nearly 10 years. In my capacity as Bureau Chief, I was responsible for overseeing all rate filings and rate related applications filed with the NJBPU. I oversaw a staff of 12 on a daily basis with regard to the administrative, financial and managerial functions of the Bureau and the Division. My primary duties were to ensure that utilities had sufficient revenues to cover operating expenses, earn a reasonable return on investments and to ensure utilities provided safe, adequate and proper utility service at reasonable rates.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Appendix A is a summary of my qualifications and experience.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Advocacy Staff of the North Dakota Public Service Commission. (NDPSC).

Q. Have you previously testified in regulatory proceedings?

A. Yes, I am currently engaged in the Consolidated Edison Company of New York proceeding, representing the Intervener, the County of Westchester in Case No. 13-E-0030 (Electric Rate Case) and Case No. 12-G-0031 (Gas Rate Case).

Q. What is your educational background?

A. I received a Master of Business Administration, with a concentration in Strategic Management from Pace University-Lubin School of Business in New York City, New York. I received a Master of Public Administration from Kean University in Union, New Jersey. I received a B.S. in Accounting from Saint Peter's University in Jersey City, New Jersey.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to recommend the appropriate revenue requirement for Northern States Power Company (NSP or Company) for electric service in North Dakota. On December 18, 2012, NSP filed a rate application with the NDPSC seeking a change in its electric revenue in the amount of $16.9 million or 9.25% effective for service on and after January 17, 2013 based on a 2013 test year. The Company subsequently updated its revenue requirement proposal and offered corrections that reduced the North Dakota revenue requirement deficiency from its initial amount of $16.9 million to $16.020 million or about $900,000**.** The Company also requested implementation of a Transmission Cost Recovery Tariff (TCR) which would allow the Company to recover the capital and operating costs of investments in new or modified electric transmission facilities not included in the 2013 test year. Karl R. Pavlovic will be responding to this area of the rate application. Also included in the petition was a request for interim rates in the amount of $14.7 million or 8.05%, effective February 16, 2013, subject to refund, until final rates are placed into effect.[1] The Company's position is that the rate increase is needed to recover the costs of additional investments in electric distribution, generation (nuclear and non-nuclear) and transmission infrastructure to ensure system safety and reliability, continue to provide high quality service to customers and support economic growth.

Snavely King was engaged by the NDPSC Advocacy Staff to review the Company's filing and to provide recommendations regarding the Company's revenue requirement request. In developing my recommendations, I have relied upon the cost of capital structure testimony of Charles W. King, the depreciation and decommissioning testimony of Michael J. Majoros, and the jurisdictional allocation and rate design testimony of Karl R. Pavlovic.

Q. What are the most significant revenue requirement issues in this filing?

A. The most significant revenue requirement issues in this filing are the Company's request for a cost of equity of 10.6% and the request for rate base inclusion of new plant in service of which nearly half is related to its nuclear operations. The Company claims that $11.4 million or 67% of the requested $16.9 million of the revenue deficiency is related to plant additions, and $8.4 million of the $11.4 million is related to the Company's nuclear operations. The Company is also claiming additional increases in its operational costs. Increases in the cost of materials such as transmission related materials and services such as the use of highly skilled labor for

[1] On February 16, 2013, the NDPSC approved the interim rate increase in the amount of $14.7 million or 8.05%.

engineering, construction and maintenance services are also a reason for the Company's requested increase.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions and recommendations regarding the Company's revenue requirement request in the amount of $16.9 million or 9.25% increase?

A. I have reached the following revenue requirement conclusions in this rate filing:

1. The twelve months ended December 31, 2013, is a reasonable test year to use in this case to evaluate the reasonableness of the Company's proposed revenue requirement increase.
2. The appropriate rate base level should be set at $322,514,000 which is $53,164,000 lower that the Company's claim of $375,678,000.
3. The appropriate pro-forma operating revenues should be set to $213,556,000 which is $14,670,000 lower than the Company's claim of $228,226,000.
4. The appropriate present rate pro-forma operating income is $24,308,000 which is $4,506,000 higher than the Company's claim of $19,802,000.
5. The appropriate overall rate of return on rate base, as recommended by Snavely King Witness Charles King, is 7.138%, incorporating a recommended return on equity of 9.00%. This compares to the Company's proposed overall rate of return on rate base of 7.90%, including a requested return on equity of 10.60%.
6. The recommended ratemaking components as indicated above calculates to an overall revenue requirement decrease of $2,088,000, which is $18,108,000 lower than the Company's updated proposed revenue requirement increase of 16,020,000.

IV. RATE BASE ISSUES

A. Utility Plant in Service

Q. How did NSP determine its utility plant in service balance (UPIS) in this case?

A. NSP calculated its UPIS by beginning with its 12 months ending December 31, 2011, historical balance as shown on Company Exhibit AEH-1, Schedule 3 page 2 of 6, which indicates a year end average balance in the amount of $742,545,000 for the North Dakota jurisdiction. The Company then adjusted the calendar year end 2011 financial results for known ratemaking adjustments deemed necessary, and included changes in costs to provide a normalized level of rate base and expenses. The Company then budgeted projections for 2012, and applied these projections to the March 31, 2012 balance to arrive at a beginning test year balance. The Company's requested utility plant in service balance for the test year 2013 was computed by applying the 2013 capital budget to the beginning test year balance of $742,545,000 adjusted for plant additions, retirements, depreciation, salvage and removal costs projected to occur during the test year. The Company calculated a level of Utility Plant in Service in the amount of $870,972,000 or $128,427,000 higher than the 2011 historical period. The Company selected 2013 as the test year because it represented the most recent available budget year and a reasonable representation of the costs and expenses the Company would incur when interim and final rates would become effective.

The Company updated its UPIS pursuant to data response, NDPSC-5-026, Supplemental, reducing its proposed UPIS from $870,972,000 to $869,185,000, a decrease of $1,787,000.

Q. Do you believe that the base year (2011) and the proposed test year (2013) is a reasonable approach for the purposes of determining NSP's revenue requirement in this filing?

A. Yes, the use of a projected test year is consistent with the North Dakota Century Code (N.D.C.C) §49-5-04.1, subd. 1 which allows a utility to select a future test year. The N.D.C.C. also provides for the utility to present the following information:

a. A comparison of forecast data to historical period data to demonstrate the reliability and accuracy of the utility's forecast including a comparison of the prior year's forecast or budgeted data to actual data for those periods.

b. A statement that the public utility's forecast is reasonable, reliable, and was made in good faith and that all basic assumptions used in making or supporting the forecast are reasonable, evaluated, identified, and justified to allow the Commission to test the appropriateness of the forecast.

c. A statement of the accounting treatment that has been applied to anticipated events and transactions in the forecast is the same as the accounting treatment to be applied in recording the events once they have occurred.

However, the NDCC requires the test year be based on the previous 12 months so until the 2012 earnings report was available, the Company was not in full compliance with the law.

Q. Please explain the approach that you have used to determine the Company's 2013 Test Year plant in service balance in this case.

A. I began my approach by reviewing the Company's 2011 and 2012 Earnings Reports filed with the NDPSC. The results are shown in the table below:

Actual Plant in Service Based on Earnings Reports		
		($000)
2012	$	780,660
2011	$	742,545
Difference	$	38,115

I then reviewed Data Request NDPSC-2-010 and NDPSC 5-20, which asked for plant additions affecting the 2013 test year revenue requirement. Attachments A to the data requests page 32 (NDPSC 2-10) and page 46 (NDPSC-5-20), shows total 2013 plant additions for NSPM in the amount of $1,533,295,000. In Data Request NDPSC-5-086, Company Witness Foss indicated that the North Dakota demand allocator is 5.1121%. I took the Company's total plant additions for 2013 of $1,533,295,000 and multiplied that amount by the demand allocator of 5.1121% to arrive at the North Dakota Jurisdictional capital additions for 2013 in the amount of $78,383,000.

Q. Are those the only additions the Company had proposed to include in this rate filing?

A. No. According to Witness Heuer's response to data request NDPSC 2-010, these totals do not include the proposed test year adjustments, specifically the Bemidji CAPX2020 project in the amount of $1,906,000, the Brookings CAPX2020 project in the amount of $194,000 and the Nuclear Fuel Inventory update in the amount of $243,000.

1. Bemidji CAPX2020

Q. Please explain your recommendations with respect to the Bemidji CAPX2020 plant addition.

A. The Company included the Bemidji CAPX2020 transmission project in its plant in service balance to reflect the September 2012 in-service date for this project as reflected in the Company's Exhibit AEH-1, Schedule 5, page 1 of 1, Column 2 in the amount of $1,906,000. The rate base impact for this project is computed to be an increase of $1,160,000. This increases the test year revenue requirement in the amount of $193,000 as reflected in the Company's Exhibit AEH-1, Schedule 6, page 1 of 3, Column 2.

Q. What is your recommendation regarding the Company's inclusion of the Bemidji CapX2020 Transmission Project?

A. I agree with the Company. My recommendation is shown on Schedule DM-4.

2. Brookings CAPX2020

Q. Please describe the Company's Brookings CapX2020 Transmission Project.

A. The Company is requesting to add $194,000 to its utility plant in service for the Brookings CapX2020 Transmission Project. This is shown in Company Exhibit AEH-1, Schedule 5, page 1 of 1, Column 3. The average rate base impact for this project is computed to be an increase of $171,000. This proposal increases the test year revenue requirement in the amount of $22,000 as reflected in the Company's Exhibit AEH-1. Schedule 5, page 1 of 3, Column 3. From what I understand the Brooking's Project is a Multi-Value Project(MVP).

Q. What is your recommendation regarding the Brookings CapX2020 Transmission Project?

A. I agree with the Company. My recommendation is shown on Schedule DM-4.

3. Nuclear Fuel Inventory

Q. Please describe the Company's update to its Nuclear Fuel Inventory.

A. The Company updated its Nuclear Fuel Inventory after the Summer 2012 sales forecast was completed and after the capital budget was finalized. The result of this update was an increase to its utility plant in service balance in the amount of $243,000 as shown in Company Exhibit AEH-1, Schedule 5, page 1 of 1, Column 4. The rate base impact for the Nuclear Fuel Inventory is computed to be an increase of $229,000. This proposal decreases test year revenue requirement in the amount of $26,000. This is shown in the Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 4.

Q. What is your recommendation regarding the Company's Nuclear Fuel Inventory Update?

A. I agree with the Company. My recommendation is shown on Schedule DM-4.

4. Supplemental Updates to UPIS Balance

Q. Did the Company update its UPIS in data request NDPSC 5-026, Supplemental?

A. Yes. The Company included the following adjustments to its UPIS balance in its Supplement filing:

AFUDC Correction Discovery	$ 132,000
AFUDC MISO Correction Discovery	$ (3,000)
Monticello License Discovery	$(1,337,000)
Projects out of 2013 Discovery	$ (579,000)
Total	$(1,787,000)

I have accepted the Company's Supplemental information regarding these 4 items.

Based upon the Company's updated data request, I've concluded that the 2013 test year plant balance should be set at $859,600,000 before any allocation factors that Advocacy Staff Witness Pavlovic has included. Based upon Mr. Pavlovic's Allocation Factor of 87.10% pertaining to the Company's Transmission and Distribution Allocation (T&D) I have reduced the amount of my recommended Plant in Service Balance of $859,044,000 by 87.10% to arrive at a recommended Plant in Service Balance of $748,227,000. The Allocation Factor of 87.10% will be discussed in Mr. Pavlovic's testimony.

Q. Can you please summarize your recommended plant additions and plant balance for the test year 2013?

A. Yes, my summary is as listed below:

Plant Balance as of December 31, 2012	$780,660,000
Plant Additions through December 31, 2013	78,384,000
Subtotal	$859,044,000
Allocation Factor	87.10%
Recommended Beginning Balance	$748,227,000
Bemidji CAPX2020	1,906,000
Brookings CAPX2020	194,000
Nuclear Fuel Updates	243,000
Supplemental UPIS updates:	(1,787,000)
Total	$748,783,000

This amount is $120,402,000 less than the Company adjusted claim of $869,185,000.

My recommended balance is shown on Schedule DM-3 and 4.

B. Construction Work In Progress

Q. What has the Company included in its calculation of Rate Base with respect to Construction Work in Progress (CWIP)?

A. The Company has included $2,037,000 of CWIP in its calculation of Rate Base. This is shown on the Company's Exhibit AEH-1, Schedule 8, page 2 of 6.

Q. What is the Company's justification for including CWIP in its Rate Base calculation?

A. The Company has indicated that the only CWIP it has included in its calculation of Rate Base are costs that are related to projects of a short duration that do not accrue Allowance for Funds used During Construction (AFUDC). The Company claims that there is no AFUDC offset added to operating income.

Q. How did the Company calculate the $2,037,000 CWIP rate base amount in its filing?

A. The Company calculated the CWIP amount of $2,037,000 by a simple average of projected short term CWIP beginning and ending test year balances, which is what they claimed was used in its last NDPSC rate case and is consistent with the Company's calculation of average rate base.

Q. Do you have a recommendation regarding this item?

A. I have used Advocacy Staff Witness Pavlovic's Allocation Factor of 84.8% to compute my recommended level of CWIP to be included in Plant in Service. Using the Company's beginning balance of $2,037,000 and calculating 84.80% I compute a CWIP balance of $1,727,000. My recommendation is shown on Schedule DM-6. The allocation factor of 84.80% will be discussed in Mr. Pavlovic's testimony.

C. <u>Depreciation Reserve Balance</u>

Q. Please explain how the Company calculated its Depreciation Reserve balance in the updated amount of $419,306,000 as shown on Exhibit AEH-1, Schedule 5, page 1 of 1, updated as of June 6, 2013.

A. The Company started out with its ending average balance in the Depreciation Reserve in the amount of $364,662,000 for the year ended December 31, 2011, as shown on Exhibit AEH-1 Schedule 3, page 2 of 6. To that balance the Company added its budget projections to arrive at a test year Depreciation Reserve balance at year end 2012. The Company then applied its budget projections to the beginning Depreciation Reserve balance that it projected to occur during the test year to arrive at the year-end Depreciation Reserve of $419,306,000.

Q. What is your recommendation with respect to the level of Depreciation Reserve for the test year ending December 31, 2013?

A. I reviewed the Company's Average 2011 Depreciation Reserve Balance in Company Exhibit AEH-1, Schedule 3, page 2 of 6, showing an amount of $364,662,000. I have also reviewed the Company's updated Proposed 2013 test year Depreciation Reserve balance in the amount of $419,306,000 as shown on Exhibit AEH-1, Schedule 5, page 1 of 1, updated as of June 6, 2013. The below additions to the Company's proposed

Depreciation Reserve are in addition to the Company's Beginning Balance of Accumulated Depreciation:

		($000's)
	Beginning Balance	$418,885
1.	Bemidji CAPX2020	$ 40
2.	Brookings CAPX2020	$ (3)
3.	Nuclear Fuel Inventory Update	$ 25
4.	2012 Depreciation Study (various)	$ 521
5.	Production Remaining Life	$ (127)
6.	Black Dog Removal/Remediation	$ 0
7.	AFUDC Correction Discovery	$ 3
8.	Monticello License Discovery	$ (26)
9.	Projects out of 2013 Discovery	$ (2)
10.	Sherco 3 Discovery	$ (11)
Total proposed Depreciation Reserve		$ 419,306

Based upon the recommendation of Advocacy Staff Witness Pavlovic I have calculated the Company's Accumulated Depreciation Reserve balance by using Mr. Pavlovic's 87.20% Allocation Factor by the beginning balance of $418,885,000 to derive at a beginning balance of $365,268,000. I then accepted and included the Company's proposed adjustments as shown above to derive at a total proposed Accumulated Depreciation Reserve balance of $365,689,000 My recommendation is shown on Schedule DM-5

The allocation factor of 87.20% will be discussed in Mr. Pavlovic's testimony.

D. <u>Accumulated Deferred Income Taxes</u>

Q. Please explain the Company's computation of its Accumulated Deferred Income Tax Balance (ADIT) for the 2013 test year in the amount of $92,784,000 as shown on

Exhibit AEH-1, Schedule 5, and its updated amount of $92,805,000 as shown on Exhibit AEH-1, Schedule 8, Updated, page 2 of 6.

A. The Company calculated the ADIT balance in the amount of $92,805,000 by simply averaging the beginning and projected ending test year ADIT balances.

Q. Do you have any recommendation regarding the ADIT balance in the amount of $92,805,000?

A. Yes. I recommend an average ADIT balance for the end of the 2013 in the amount of $79,072,000.

Q. How did you derive the average ADIT balance in the amount of $90,774,000?

A. I began with the Company's proposed ADIT Balance as of December 31, 2013, unadjusted in the amount of $90,835,000. I then used Advocacy Staff's Witness Pavlovic allocation factor of 87.10% to derive at a beginning balance of $79,117,000. I then added the Company's adjustments as shown on Exhibit AEH-1, Schedule 5, page 1 of 1 to compute a ADIT balance of $81,087,000. Since the Company used an average of the beginning and ending test year balances to compute its proposed ADIT balance, I used an average percentage of the Company's beginning UPIS and ADIT balance which calculates to 10.45% ($90,835/$868,630) and the average percentage of the Company's ending UPIS and ADIT balance which calculates to 10.67% ($92,805/$869,185). The average of the two is 10.56%. Using my recommended UPIS balance of $748,783,000 and multiplying that balance by 10.56%, I arrived at my recommended ADIT balance of $79,072,000.

My recommendation is shown on Schedule DM-7. The allocation factor of 87.10% will be discussed in Mr. Pavlovic's testimony.

E. Cash Working Capital

Q. Please describe the Company's Cash Working Capital proposal.

A. The Company's Cash Working Capital (CWC) allowance is ($926,000). The calculation is shown on Company Exhibit AEH-1, Schedule 8 page 2 of 6. The Company updated this amount in its June 6, 2013 Schedules to ($1,080,000) The CWC was calculated by applying the results of a comprehensive lead/lag study to the projected test year revenues and expenses. The Company stated that the components of the test year CWC have been calculated consistent with the methods used in the most recent North Dakota rate case. The negative CWC indicates overall revenue collections occurred sooner than the date when the associated costs of services are paid. The negative CWC reduces Rate Base to compensate customers for funds provided to meet CWC requirements.

Q. What is your recommendation regarding the Company's Updated calculation of a ($1,080,000) CWC?

A. I do not have any changes to the formula or other components that the Company used to create and to calculate the CWC. However, I made several adjustments to the Company CWC calculations which correspond to my adjustments related to the Company's Revenues, O & M Expenses and Taxes. With those adjustments, my CWC allowance is computed at $(883,000)[2]. My recommendations are shown on Schedule DM-8, and Schedule DM-Attachment.

F. Materials and Supplies

Q. Please describe how the Company calculated its Materials and Supplies.

A. The Company calculated its Materials and Supplies amount of $7,613,000 by using a 13 month average balance of the account projected during the test year.

Q. What is your recommendation regarding the Company's calculation of its Materials and Supplies balance?

A. I agree with the Company's proposed Materials and Supplies balance of $7,613,000. My recommendation is shown on Schedule DM-9.

G. Fuel Inventory

Q. Please describe how the Company calculated its Fuel Inventory.

A. The Company calculated its Fuel Inventory amount of $5,899,000 the same way it calculated it's Materials and Supplies balance; by the use of a 13 month average balance of the account projected during the test year.

Q. What is your recommendation regarding the Company's calculation of its Fuel Inventory balance?

A. I agree with the Company's proposed Fuel Inventory balance.

[2] Due to the change in the Federal Income and State Income Tax with respect to my change in Depreciation Expense, the correct CWC is (881,000), however, this does not change my recommended revenue requirement.

My recommendation is shown on Schedule DM-9.

H. Non-Plant Assets and Liabilities

Q. Please describe how the Company calculated its Non-Plant Assets and Liabilities.

A. The balance of ($1,809,000) in Non-Plant Assets and Liabilities represents the 2013 estimates of these balances. The book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and Accumulated Deferred Income Tax balances as discussed previously in my testimony. The amount of ($1,809,000) is primarily composed of liabilities. The negative balance reduces the Company's rate base. In its updated June 6, 2013 exhibits, the Company adjusted its Non-Plant Assets and Liabilities to ($2,100,000), as shown on Exhibit AEH-1, Schedule 5, page 1 of 1, Column 10, line 25.

Q. What is your recommendation regarding the Company's calculation of Non-Plant Assets and Liabilities?

A. I agree with the Company's balance of Non-Plant Assets and Liabilities in the amount of ($2,100,000).

My recommendation is shown on Schedule DM-9.

I. Other Rate Base Items

Q. Please describe the Company's other Rate Base Items.

A. The Company's Other Rate Base Items are comprised of Prepayments, Nuclear Outage Amortization, Customer Advances, Customer Deposits and Other Working Capital. I will address each item below.

1. Prepayments

A. The Company calculated Prepayments in the amount of $1,050,000 using a 13 month average balance during the period ended May 31, 2012, as a proxy for the test year. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

Q. What is your recommendation regarding the Company's calculation of Prepayments in the amount of $1,050,000?

A. I agree with the Company's balance of its Prepayments in the amount of $1,050,000. My recommendation is shown on Schedule DM-9, Footnote 1.

2. Nuclear Outage Amortization

Q. Please describe how the Company calculated its Nuclear Outage Amortization.

A. The Company calculated its Nuclear Outage Amortization in the amount of $5,018,000 by reflecting an increase in the cost of the Fall of 2012 Prairie Island Unit 1 refueling outage. The Company claimed that because these additional costs were incurred in 2012, deferred to the balance sheet, and then amortized over the useful life of the outage, it was necessary to update the amortization included in the O &M Budget. The change in the cost of the outage has been reflected in the 2013 beginning of year and end of year rate base balances. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

Q. What is your recommendation regarding the Company's calculation of its level of Nuclear Outage Amortization in the amount of $5,018,000?

A. I agree with the Company's balance of its Nuclear Outage Amortization in the amount of $5,018,000. My recommendation is shown on Schedule DM-9.

3. <u>Customer Advances</u>

Q. Please describe how the Company calculated its Customer Advances.

A. The Company calculated Customer Advances in the amount of ($18,000) by using an actual 13 month average month balance during the period ended May 12, 2012 as a proxy for the test year. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

Q. What is your recommendation regarding the Company's calculation of Customer Advances in the amount of ($18,000)?

A. I agree with the Company's Customer Advances balance in the amount of ($18,000). My recommendation is shown on Schedule DM-9, Footnote 1.

4. <u>Customer Deposits</u>

Q. Please describe how the Company calculated Customer Deposits.

A. The Company calculated Customer Deposits in the amount of ($213,000) by using an actual 13 month average month balance for the period ending May 12, 2012 as a proxy for the test year. Company Exhibit AEH-1, Schedule 15, page 1 of 3 shows this amount.

Q. What is your recommendation regarding the Company's calculation of its level of Customer Deposits in the amount of ($213,000)?

A. I agree with the Company's Customers Deposits amount of ($213,000). My recommendation is shown on Schedule DM-9, Footnote 1.

5. <u>Other Working Capital</u>

Q. How has the Company computed its Other Working Capital Allowance?

A. The Company computed its Other Working Capital Allowance by using the average 13 month balance for the period ending May 12, 2012, as a proxy for the test year. The Company is proposing Other Working Capital in the amount of $398,000.

Q. What is your recommendation with respect to the Company's Other Working Capital balance?

A. I agree with the Company's balance of Other Working Capital level in the amount of $398,000.

My recommendation is shown on Schedule DM-9, Footnote 1.

Q. Please summarize your recommendations with respect to the Company's Other Rate Base Items balance.

A. My summary is as below:

Prepayments	$ 1,050,000
Nuclear Outage Amortization	$ 5,018,000
Customer Advances	$ (18,000)
Customer Deposits	$ (213,000)
Other Working Capital	$ 398,000
Total Other Rate Base Items	$ 6,235,000

J. Summary of Rate Base Issues

Q. What is the impact of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base from the proposed $375,678,000, as reflected in the Company's updated Exhibit AEH-1, Schedule 5, page 1 of 1, to $322,514,000, as summarized on Schedule DM-3.

V. COST OF CAPITAL

Q. What is your position regarding the Company's proposed Cost of Capital Structure?

A. I am relying on the testimony of Advocacy Staff witness Charles King and have used the capital structure as shown on my Schedule DM-2 to develop my recommended revenue requirement increase.

VI. INCOME STATEMENT

A. Revenues

Q. What is the Company proposing with respect to Test Year Present Rate Revenues for the period ending December 31, 2013?

A. The Company calculated unadjusted Test Year Present Rate Revenues in the amount of $231,340,000 as shown in Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1. This amount is comprised of Retail Operating Revenues in the amount of $182,724,000 and Other Operating Revenues in the amount of $48,616,000. The Retail Operating

Revenues is composed of two components: Base Revenues in the amount of $120,805,000 and Fuel in the amount of $61,919,000 (Company Work paper R2-1a). A further breakdown of the Company's Retail Operating Revenues is shown on Company Exhibit Notice, Schedule 2 page 1 of 1, and in Company Work paper R2-2.

The Company also adjusts its Other Operating Revenues by including the following:

a. Asset Margin Sharing	$(505,000)[3]
b. Non-Asset Margin Sharing	$(334,000)
c. Emission Credit Amortization	$(87,000)
d. MISO CWIP Revenue and Expense Adjustment	$(2,188,000)
Total Adjustments to Other Operating Revenues	$(3,114,000)

By applying the Company's adjustments to Other Operating Revenues, the Company calculated an adjusted Other Operating Revenue balance of ($48,616,000 - $3,114,000) $45,502,000. This is reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column entitled "Proposed 2013 Test Year."

With the adjustments to the Other Operating Revenues listed above, the total Test Year Revenue at Present Rates ending December 31, 2013, is calculated by the Company to be $228,226,000. (Company Exhibit AEH-1 , Schedule 6, page 3 of 3, Proposed 2013 Test Year Column, and Company Exhibit AEH-1, Schedule 11, page 1 of 2, Column A).

1. <u>Retail Operating Revenues</u>

Q. Did the Company propose any adjustments to its Retail Operating Revenues in the amount of $182,724,000?

A. The Company did not propose any adjustments to its Retail Operating Revenues.

[3] These amounts are listed in Company Exhibit AEH-1, Schedule 6, page 2 of 3, Columns 18 and 19, and page 3 of 3, Columns 30 and 31 under Operating Revenues.

Q. Do you have any recommendations with respect to the Company's Retail Operating Revenues in the amount of $182,724,000?

A. Yes. I reviewed the Company's NDPSC 2010, 2011 and 2012 Earnings Reports, specifically its Retail Operating Revenues and based upon the information contained I computed the following: ($000's)

	2010	2011	2012
	$155,671	$176,290	$179,657
Average			**$170,539**

I also reviewed the Company's Mwh Sales for the same years, and computed the following: (000's)

	2010	2011	2012
	2,206	2,243	2,207
Average			**2,219**

Finally I computed the average cost per Kwh for each of the years 2010, 2011 and 2012 and have computed the following: (in cents)

	2010	2011	2012
	7.06	7.86	8.13
Average Kwh price			**7.68**

I then reviewed and compared the Company's projected Mwh Sales as contained in Company Exhibit (Notice) Schedule 2 page 1 of 1 which shows total projected Mwh Sales for all customers in the amount of 2,270,721.

Q. Did you review any other documentation with respect to the Company's projected Retail Revenues?

A. Yes. In Data Response NDPSC-5-071, the Company has indicated that as of the first quarter of 2013, Total Retail Mwh Sales amounted to 615,374, which was an increase of 1.54% over the first quarter of 2012 in the amount of 606,038. Further the Company has indicated in Data Request NDPSC-5-039, Attachment A that as of the end of the first quarter of 2013, the Customer Count was 90,703, which is higher than what the Company had projected in its Notice of 89,985.

Q. What does this information provide regarding to the Company's Retail Operating Revenues?

A. This analysis shows that the Company has increased its customer count by an additional 718 (90,703-89,985). This analysis also shows that the Company's Mwh Sales has increased in the first quarter 2013 over its first quarter 2012 by 1.54%. Based upon this review, I am recommending increasing the Company's proposed Mwh Sales that it has projected in its Notice from 2,270,721 by 1.54% which is the actual increase in Mwh Sales from 1st quarter 2012 to 1st quarter 2013. I used the increase of 1.54% to compute the annual effect of the Company's initial Mwh Sales of 2,270,721 to arrive at known and measurable changes in its Mwh Sales that has actually occurred in 2013. My updated total Mwh Sales is therefore computed at (2,270,721 times 1.54%) 2,305,690.

Q. What else did you review to determine a proper level of Sales Revenues for the Company?

A. I used the Company's three year average of Kwh costs that I computed above in the amount of 7.68 cents and multiplied that by my recommended level of projected Mwh

Sales of 2,305,690. This computes to a projected level of Sales Revenues of $177,077,000.

Q. What have you concluded with respect to the Company's Retail Operating Revenues?

A. As I indicated above, it is evident that the Company's Mwh Sales have increased from the Company's Initial projections as shown in its Notice. It is also evident that the Company customer count has increased from its projected level of 89,985 as shown in its Notice to what is contained in Data Request NDPSC-5-039 in the 1st quarter 2013 of 90,703. By using most current data, a proper level of Sales Revenues is computed. Based upon the above, I recommend that the Company's Retail Operating Revenues be set in the amount of $177,077,000. My recommendation is shown on Schedule DM-11.

2. <u>Other Operating Revenues</u>

Q. What is included in the Company's Other Operating Revenues in the amount of $48,616,000 as calculated in Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1?

A. The Company's Other Operating Revenues of $48,616,000 is an unadjusted amount that includes various revenue adjustments allocated to the North Dakota Operations. (See response to NDPSC-DR-5-027).

Q. Do you have any recommendation with respect to the Company's Unadjusted Other Operating Revenues in the amount of $48,616,000?

A. Yes. I reviewed the Company's 2010, 2011 and 2012 NDPSC Earnings Report, specifically the Other Operating Revenues as shown on the each of the years on pages E-2. The following shows Other Operating Revenues for 2010 through 2012: (in $000's)

	2010	2011	2012
ND Jurisdiction	$41,149	$37,594	$39,949
Three Year Average			**$39,564**

Q. What conclusions did you arrive at with respect to the above computation?

A. It is clear that the allocations that the Company uses to set its Other Operating Revenues vary from year to year. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdiction is an annual process. Therefore, the allocations of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations change annually as well.

Given this information, I recommend a three year average for setting the Company's Other Operating Revenues before any adjustments made with respect to the four items as described above on page 28. The revenues are evident and historical in nature and are documented in the NDPSC Earnings Reports. By the use of a three year average, these revenues are smoothed out and normalized that takes into considerations fluctuations over the years and provides for a normalized level prospectively. My recommendation is shown on Schedule DM-12.

a. <u>Asset Based Margin Sharing</u>

Q. Please explain what Asset Based Margin Sharing is.

A. According to the Company, Asset Based Margin is one of two components of Wholesale Margins (revenues less costs). The other component is Non-Asset Based Margin. In other words, Wholesale Margins are composed of Asset Based Transactions and Non-Asset Based Transactions.

Asset Based Transactions are comprised of short term sales of excess energy from Company owned generation assets or purchased power agreements (PPA) executed to serve native load customers. Asset based margins are earned by selling energy from facilities or PPA's that are paid for by ratepayers. The Company is proposing to credit customers 85% of Asset Based Margins based on the rate application in the North Dakota Case No. PUC-07-776 of which 85% of the Asset Based Margins were credited to customers through the Fuel Cost Rider (FCR). The Company is proposing a credit in the amount of $505,000 as indicated in Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 18. The Company is requesting a continuation of the 85% credit to customers through the FCR, prospectively.

Q. What is your recommendation with respect to the Asset Margin credit of $505,000 the Company is proposing to include in its calculation of Operating Revenues?

A. I have reviewed the Company's Work paper A18-1 to 4, and have found that the Company's Minnesota and South Dakota operations do not require a sharing of the Asset Margin Credit. The Company assigns 100% of the Asset Margin Credit to its ratepayers in these states. Although this shift does not change the total Asset Margin Credit sharing, ($505,000) it does require an adjustment to account for 100% of the $505,000 to flow through to ratepayers. In NDPSC-1-008, the Company stated that the establishment of the 85%/15% allocation was adopted in a Settlement Agreement under Case No. PU-07-776, dated December 31, 2008. Since this 85%/15% sharing mechanism was adopted in a Settlement Agreement, the NDPSC did not fully review the arguments with respect to the future or prospective sharing mechanism between shareholders and ratepayers. Given this situation, the parties are free to argue the allocation between shareholders and ratepayers with respect to Asset Based Margins Credits. I recommend that the same treatment given to Minnesota and South Dakota ratepayers be given to North Dakota ratepayers, which provides for consistency across the NSP jurisdictions. Therefore I am proposing that 100% Asset Based Margin Credits be allocated to the ratepayers of North Dakota. My recommendation is shown on Schedule DM-12.

b. <u>Non Asset Based Margin Sharing</u>

Q. Please explain what Non Asset Based Margin Sharing is.

A. Non Asset Margin transaction is the second component of Wholesale Margins as I indicated above. According to the Company, Non Asset Based transactions are wholesale or trading transaction undertaken to obtain margins from purchases and sales of energy unrelated to meeting the energy needs of the Company's native load customers. The Company has stated that the only transactions that qualify as non-asset based transactions are third party supplied electricity or financial transactions that are not required to meet the needs of the Company's retail customers and that are resold. As with Asset Based Margins as described above, the Company is noting the North Dakota Case No. PUC-07-776 settlement agreed to the use of a 50%/50% sharing mechanism for Non Asset Based Margins. The Company is proposing a credit in the amount of $334,000 as indicated in Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 19. The Company has indicated that this sharing mechanism is a reasonable balance of ratepayer and shareholder interest. The Company also claims that this 50%/50% sharing mechanism, the incremental cost of producing the margins was reimbursed along with a reasonable contribution to joint and common costs. The Company stated that the customer portion was approved to be credited through the FCR. The Company is requesting continuation of the 50%/50% sharing mechanism in this rate proceeding as an appropriate balance of ratepayer and Company interests, along with continued credit of customers through the FCR.

Q. What is your recommendation with respect to the Non Asset Margin Based credit of $334,000 the Company is proposing to include in its calculation of Operating Revenues?

A. I have reviewed the Company's Work paper A19-1 through 3, and found that the Company's Minnesota jurisdictional customers do not share in Non Asset Margin Credit, and South Dakota Jurisdiction customers share Non Asset Margin Credit on the basis of 70%/30%, with 70% allocated to the ratepayers.

I recommend that the 50%/50% sharing mechanism between shareholders and ratepayers is appropriate. My recommendation is shown on Schedule DM-12

c. <u>Emission Credit Amortization</u>

Q. Please describe the Company's request to with respect to an adjustment made for the Emission Credit Amortization.

A. The Company has indicated that in the settlement agreement in the last rate case, the NDPSC approved a three year amortization of the cumulated balance of SO2 Allowance Credits as of December 2010. The Company is proposing to continue to amortize the outstanding balance as of December 31, 2012 in the estimated amount of $99,000, to which the Company is requesting a three year amortization or $33,000 per year. This is indicated in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 30. The proposed $33,000 per year amortization offsets the Company's SO2 Allowance credits of $87,000 for a net increase in test year revenue requirements of $54,000. This amount is also reflected in Company Exhibit-AEH-1, page 3 of 3, Column 30.

Q. What is your recommendation with respect to the Company's proposal on the Emission Credit Amortization?

A. Since this Emission Credit Revenue is linked with the expense portion of the amortization of the Emission Credits, I made adjustments with respect to the Company's beginning balance of ($87,000).

I agree with the Company with respect to the December 2012, balance in the amount of $99,000. (Company work paper A-29) However, as I stated my arguments with respect to the expense portion of the Emission Credit, it is likely that the NDPSC will approve new rates that will become effective toward the end of 2013, and therefore, a full year of credit will already have taken place with respect to the Company's prior Emission Credit balance in the amount of $87,000. Therefore, I am recalculating the outstanding credit balance by removing a full year of credit ($29,000) from the Company's outstanding credit and reducing it to ($58,000). ($87,000 - $29,000). I then used the outstanding unamortized balance of $58,000 as the amount to be included in Other Operating Revenues. This change reduces the Company's credit from its proposed ($87,000) per year to ($58,000) per year or a reduction of the credit in the amount of $29,000 per year. My recommendation is shown on my Schedule DM-12; under the Adjustment Column.

d. <u>MISO CWIP Revenue and Expense Adjustment</u>

Q. Please describe the Company's proposal with respect to the MISO CWIP Revenue and Expense Adjustment.

A. The Company claims that the NDPSC does not allow a return on long term CWIP. The Company, therefore, has removed MISO (Midcontinent Independent Transmission System Operations, Inc.) wholesale revenues that the Company has received that are related to a return on CWIP from the revenue requirement calculation for North Dakota. The Company has indicated that it received these revenues in lieu of accumulating AFUDC on these projects. The Company claims that without this adjustment, the Company would have been providing a revenue credit for wholesale CWIP recoveries even though the NDPSC does not allow a return on CWIP in base rates. The Company claims that North Dakota customers will see benefits in the form of reduced investment costs once these assets are placed in service. The Company has included a credit in the amount of $2,188,000 in its Operating Revenues calculation as indicated in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 31. The Company is offsetting this revenue credit with a Transmission expense credit of $537,000. This results in a revenue requirement deficiency in the amount of $1,651,000 as indicated in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 31.

Q. What is your recommendation with respect to the Company's MISO CWIP Revenue and Expense Adjustment?

A. I am recommending the Company's level of MISO CWIP Revenues in the amount of $2,188,000. My recommendation is shown on Schedule DM-12.

B. <u>Operating and Maintenance Expenses</u>

1. <u>Fuel and Purchased Energy</u>

Q. What is the Company proposing with respect to its Operating and Maintenance? Expenses, specifically its Fuel and Purchased Energy costs in the amount of $82,971,000?

A. The Company is not proposing any changes to its Fuel and Purchased Energy costs for its 2013 Test Year (Company Exhibit AEH-1, Schedule 11, page 2 of 2). The Company recovers any changes in Fuel and Purchased Energy costs through the Fuel Cost Rider (FCR) mechanism and true up process.

Q. How did the Company calculate its Fuel and Purchased Energy costs for the test year period?

A. The Company's 2011 actual Fuel and Purchased Energy Costs were $76,040,000 as stated in Company Exhibit AEH-1, Schedule 3, Page 3 of 6, under the ND Retail Electric column. The Company's 2012 actual Fuel and Purchased Energy Costs were

$77,805,000. The Company estimated its 2013 test year Fuel and Purchased Energy costs to be $82,971,000. The Company stated that its production expense budget is mainly for fuel and purchased power. These expenses are developed from a production budget that is prepared for the total NSP system (NSP-Minnesota and NSP-Wisconsin). The Company's Risk Management Department uses a production simulation model and forecasted system sales to derive the forecasted fuel and energy costs. The NSP system fuel and energy costs are then adjusted to remove the cost of inter-system sales (asset based sales) and other non-recoverable fuel items, so that a base cost of fuel and purchased energy is derived. The North Dakota jurisdiction is assigned its share of the NSP System costs.

Q. What is your position regarding the Company's Fuel and Purchased Energy costs?

A. I reviewed the Company's 2010, 2011 and 2012 NDPSC Earnings Reports, specifically the Fuel and Purchased Energy Expenses as shown on page E-2. The following shows the expenses for Fuel and Purchased Energy for 2010 through 2012: (in $000's)

	2010	2011	2012
ND Jurisdiction	$86,548	$76,040	$77,805
Three Year Average			**$80,131**

Q. What conclusions did you arrive at with respect to the above computations?

A. It is clear that the allocations that the Company uses vary from year to year. I recommend a three year average for setting the Fuel and Purchased Energy costs. The costs are evident and historical in nature and are documented in the NDPSC Earnings

Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdiction is an annual process. Therefore, the allocations of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations change annually as well.

Given this information, I recommend that for rate making purposes, the Fuel and Purchased Energy Costs be computed using a three year average to smooth out and normalize the Fuel and Purchased Energy Costs. My recommendation is shown on Schedule DM-14.

2. <u>Power Production</u>

Q. How did the Company calculate its Power Production Expense?

A. The Company calculates it Power Production Expense using the same methodology as it uses to calculate other Operating and Maintenance Expenses. As stated above, the Company prepares a production budget for the entire NSP system. The Company's Risk Management Department uses production simulation model and the forecasted system sales to derive the forecasted fuel and energy costs.

The Company calculated its 2011 Power Production costs at $43,220,000. (Company Exhibit AEH-1, Schedule 3, page 3 of 6, under ND Retail Electric Column). The Company shows its 2012 actual Power Production costs at $42,550,000. (2012 Earnings Report). The Company has proposed unadjusted Power Production Expenses of $45,530,000 for its 2013 test year period. (Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1, and its updated Schedule 6, page 1 of 3, Column 1).

Q. Do you have any changes to the Company's Unadjusted Power Production balance in the amount of $45,530,000?

A. Yes. I reviewed the Company's NDPSC Annual Reports for the years 2010, 2011 and 2012 and as I calculated an average three year balance for the Fuel and Purchased Power Costs, I also calculated a three year average for the Power Production costs. The results are as indicated below (in 000's):

	2010	2011	2012
ND Jurisdiction	$40,558	$43,220	$42,550
Three year average			**$42,109**

Q. What other adjustments did you make with respect to the Company's Unadjusted Power Production Expenses?

A. I adjusted the Company's three year average Power Production costs by the Allocation Factor of 83.3% provided to me by Advocacy Witness Mr. Pavlovic. Using that factor, I reduced the three year average from $42,109 times 83.30% or $35,077.

Q. What do you recommend with respect to the Company's Unadjusted Power Production balance?

A. I recommend the use of a three year average (2010, 2011 and 2012) as the beginning balance for Power Production costs allocated by a factor of 83.30% provided to be by Mr.Pavlovic as the beginning unadjusted balance. These costs are evident, historical in nature and documented in the NDPSC Annual Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdiction is an annual process. Therefore, the allocations of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations that are assigned to the North Dakota jurisdiction change annually also.

Given this information, I recommend that for rate making purposes, the Power Production Costs beginning unadjusted balance be computed using a three year average, multiplied by the allocation factor of 83.30% provided to me by Mr. Pavlovic. My recommendation is shown on Schedule DM-15.

The allocation factor of 83.30% will be discussed in Mr. Pavlovic's testimony.

Q. What adjustments does the Company make with respect to Power Production Costs for the 2013 test year?

A. The Company makes four adjustments to the Power Production account, the first adjustment being Nuclear Outage Amortization in the amount of $121,000. The second adjustment is for the Nuclear O&M Budget update in the amount of $493,000. The third adjustment is for the Nuclear Management and the Employee Retention Program in the amount of $77,000, and the fourth adjustment was included in the Company's updated June 6, 2013, Exhibits (AEH-1, Schedule 6, page 3 of 3 for the removal of Sherco 3 Project costs in the amount of ($227,000) . I will discuss each of these adjustments below.

a. <u>Nuclear Outage Amortization</u>

Q. What is the Company claiming regarding its update to the Nuclear Outage Amortization balance for the test year 2013?

A. The Company is including a $121,000 increase for the 2013 test year to reflect the Fall 2012 Prairie Island Unit 1 refueling outage. The Company stated that these additional costs were incurred in 2012, deferred to the balance sheet, and are amortized over the useful life of the outage. The Company claims that it is necessary to update the amortization that is included in the O & M budget. The Company stated that the change in the outage costs were reflected in the 2013 beginning of year and end of year rate base balances.

Q. What is your recommendation with respect to the Company's $121,000 increase to reflect the increase in the 2012 Prairie Island Unit 1 refueling outage costs?

A. The Company has computed total Company Outage Amortization by FERC for the year 2013, in the amount of $2,009,000 (WP-A6-4). The total allocation applicable to the North Dakota service area is 6.023% of the total or $121,000 as shown on WP-A6-3. However, the 2014 projection indicates a decrease in the Company's Nuclear Outage Amortization in the amount of $1,507,000 (WP-A6-4, 2014 column). This computes to a projected decrease to the ND Jurisdiction in the amount of $30,000.

Q. What do you conclude with respect to the Company's pro-forma Nuclear Outage Amortization level?

A. I conclude that the Company's pro-forma expense will decrease in 2014, at the time new rates are established in this rate proceeding. Therefore, I am recommending the use of the projected Total Company 2014 Nuclear Outage Amortization in the amount of $1,507,000, of which 6.023% is allocated to the North Dakota service area or $90,000, a reduction of $30,000 from the Company's proposal of $121,000. My recommendation is shown on my Schedule DM-15, under the Adjustment Column.

b. Nuclear O & M Budget Update

Q. What is the Company's Nuclear O & M Budget proposal?

A. The Company proposed an increase in the amount of $493,000 to reflect significant non-outage cost changes related to contract labor, materials and nuclear fees identified after the original O & M Budgets had been completed. This is the second adjustment to the Company's Power Production expense and is listed on Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 7.

Q. Has the Company updated its proposal with respect to this adjustment?

A. Yes. I reviewed the Company data request NDPSC-5-026, Supplement in which Company witness Heuer has stated on page 2, item 5 that the Monticello uprate "will not be in service until the unit has completed its power ascension testing such that the unit is reliable to operate at a higher capacity level." The Company estimates that the license will be received in early 2014. The Company has removed this adjustment from its plant in service for the test year.

Q. How does this adjustment affect the Company's costs for the Monticello uprate In-Service date?

A. In the Company's workpaper WP-A7-3, the Nuclear O&M Budget Adjustment shows costs associated with the Monticello and Prairie Island plants. The total O&M amounts are Monticello at $4,700,000 and Prairie Island at $4,949,000 for a total of $9,649,000. Using the 5.1121% allocation factor also shown on this work paper, the original estimated cost is $493,000. Since the Company has indicated that the Monticello In-Service date will not occur in 2013, and has removed this investment from the test year, it is also necessary to remove the associated O&M budget from the test year. The remaining costs for the Prairie Island of $4,949,000 should be allocated to the North Dakota service area at the 5.1121% jurisdictional allocation factor and calculates to $253,000, a decrease of $240,000. My recommendation is shown on my Schedule DM-15, under the Adjustment Column. This is a Power Production adjustment exhibit.

c. <u>Nuclear Employee Retention Program</u>

Q. What is the Company proposing with respect to its Nuclear Management Employee Retention Program?

A. The Company has proposed an increase in the amount of $77,000 that reflects management retention agreements that were issued to key nuclear operations employees after the budget cycle was completed and which were not included in the Company's original 2013 budget. This is the third adjustment to the Company's Power Production expense and is listed on Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 8.

Q. What is your recommendation regarding the Company's Nuclear Management Employee Retention Program?

A. The NDPSC Advocacy Staff has concerns about incentives in general seeing that in particular NSP-Wisconsin is not allowed to include employee incentives in rates. Additionally, based on the amounts of the incentives, we are concerned that these amounts are overly generous. Furthermore, it is not clear that wages in general are the main driver for employee retention. Studies usually indicate that worker satisfaction ranks higher as an employee concern than wages. If the Company is allowed these incentives in all jurisdictions, including Wisconsin, in the future, the Company can again request these costs. Results of a worker satisfaction study that assesses the concerns of workers would also be helpful to assess how salaries compared to other employee concerns.

My recommendation is shown on Exhibit DM-15.

d. <u>Sherco 3 Project</u>

Q. What is the Company's fourth adjustment to its Power Production Costs?

A. The Company, in its June 6, 2013, update, has indicated that Sherco 3 will not be returning to service until the third quarter of 2013. The Company has updated the costs to remove the depreciation expense ($22,000) and the O&M expenses in the amount of ($227,000) related to Sherco 3 from January through September 2013.

Q. What is your recommendation regarding this update?

A. I agree with the Company, my recommendation is shown on Schedule DM-15.

Q. What is your summary regarding the Power Production Expense and the four adjustments as described above?

A. My summary regarding the Power Production Expense and the three Power Production Expense adjustments are summarized below:

		Recommendation
Company Unadjusted - 2013	$45,530,000	$35,077,000
Nuclear Outage Amortization	121,000	91,000
Nuclear O & M Budget Update	493,000	253,000
Nuclear Management Retention Program	77,000	0
Sherco 3 Update	(227,000)	(227,000)
Company Proposed 2013 Test Year	$45,994,000	$35,194,000

3. <u>Transmission Expense</u>

Q. What is the Company proposing with respect to its Transmission Expense, unadjusted?

A. In Company Exhibit AEH-1 Schedule 6 page 1 of 3, Transmission Expense is listed in the amount of $14,568,000. The Company then added MISO CWIP Expense ($537,000) to derive a projected Transmission Expense of $14,031,000.

Q. Do you have any changes to the Company's level of Transmission Expense in the amount of $14,568,000, unadjusted?

A. As I computed a three year average for the Company's Power Production Expenses, I am computing the same for the Company's Transmission Expense as the beginning balance before any of the Company's projected 2013 adjustments.

Q. What is the result of the use of a three year average for the Company's Transmission Expense?

A. As shown in the Company's North Dakota Earnings Reports for 2010, 2011 and 2012, (NDPSC-5-013, Supplemental) the following are the Company's Transmission Expense for the selected three years in ($000's):

	2010	2011	2012
Transmission Expenses	$9,725	$11,219	$12,309
Three Year Average			**$11,084**

Q. What other adjustments did you make with respect to the Company's three year average?

A. I adjusted the Company's three year average by an allocation factor of 84.50% that was provided to me by Advocacy Staff Witness Mr. Pavlovic. Using that allocation factor I have reduced the Company's three year average from $11,084 to $9,366.

Q. Why are you recommending a three year average for the Company's Transmission Expenses?

A. I recommend the use of a three year average (2010, 2011 and 2012) as the beginning balance for Power Production costs because these costs are evident, historical in nature and documented in the NDPSC Earnings Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdictions is an annual process. Therefore, the allocation of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations that are assigned to the North Dakota jurisdiction change annually also. Given that this information adjusts annually, the use of a three year average provides for a smoothing of the costs over time and normalizes the expenses. I recommend that for rate making purposes, the Transmission Expense beginning unadjusted balance be computed using a three year average and allocated by the allocation factor of 84.50% as discussed by Advocacy Staff Witness Mr. Pavlovic. My recommendation is shown on Schedule DM-16.

a. <u>MISO CWIP Revenue and Expense</u>

Q. How did the Company account for its MISO CWIP Revenues and Expenses in this rate proceeding?

A. The Company has removed the MISO Revenues and Expenses associated with transmission projects currently in CWIP. North Dakota does not allow long term CWIP in rate base. Thus, the North Dakota jurisdictional share of the transmission revenue and expenses associated with CWIP transmission projects is being excluded from the test year.

Q. What is your recommendation with respect to the Company's adjustment to remove MISO CWIP expenses in the amount of ($537,000)?

A. As I recommended for the Company's proposal to include ($2,188,000) of MISO CWIP Revenues, I am also recommending the associated ($537,000) of related costs. My recommendation is shown on Schedule DM-16.

4. <u>Distribution</u>

Q. What is your recommendation regarding the Company's Distribution Expense in the amount of $6,763,000?

A. The Company's actual 2010 Distribution Expense was $5,779,000 as shown on the ND Earnings Report, page E-2. The Company's Distribution Expense for 2011 was $6,737,000 (Company Exhibit AEH-1, Schedule 3, page 3 of 6, ND Retail Electric column). The Company's Distribution Expense for 2012 was $6,387,000. The Company's Distribution Expense for its 2013 test year was calculated as $6,528,000, unadjusted. (Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1).

Q. What is your position regarding the Company's projected 2013 Distribution Expense before adjustments in the amount of $6,528,000?

A. As with the other Company expenses, I am recommending the use of a three year average with respect to the Company's 2013 projected Distribution Expense before adjustments in the amount of $6,301,000. This is the average of the 2010, 2011 and 2012 Distribution Expense levels as shown on page E-2 of the ND Earnings Reports (NDPSC-5-013, Supplemental).

Q. Why are you recommending a three year average for the Company's Transmission Expenses?

A. I recommend the use of a three year average (2010, 2011 and 2012) as the beginning balance for Distribution Expenses because these costs are evident, historical in nature and documented in the NDPSC Earnings Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdictions is an annual process. Therefore, the allocation of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations that are assigned to the North Dakota jurisdiction change annually also. Given that this information adjusts annually, the use of a three year average provides for a smoothing of the costs over time and normalizes the expenses. I recommend that for rate making purposes, the Distribution Expense beginning unadjusted balance be computed using a three year average as follows (in 000's)

	2010	2011	2012
Distribution Expense	$5,779	$6,737	$6,387
Three Year average			**$6,301**

My recommendation is shown on my Schedule DM-17.

a. <u>ND Line Crew Employees</u>

Q. What is the Company's proposal with respect to an adjustment to include additional North Dakota Line Crew Employees?

A. The Company has added an additional line crew in its North Dakota operations in order to meet growth in the Minot service area and to improve service reliability in the Fargo and Grand Forks service areas. The cost is $235,000. (Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 10). Company Witness, Stephen R. Foss, stated that the additional line crew is needed in anticipation of retirements during the next several years and to account for increased workloads. The additional line crew in the amount of $235,000 is included in the Company's Distribution Expense account.

Q. What is your recommendation regarding the Company's addition of 4 linemen in the amount of $235,000?

A. In the Company's WP-A10, it notes that this adjustment reflects a starting date of April 1, 2013. Therefore, I agree with the Company to include the four linemen at a total cost of $235,000. My recommendation is shown on Schedule DM-17.

5. <u>Customer Accounting</u>

Q. What is the Company proposing with respect to its Customer Accounting Expenses?

A. The Company's proposed Customer Accounting expense is $4,358,000. (Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1). This unadjusted amount does not include the Company's Bad Debt Expense adjustment of $72,000.

The Company's 2010 Customer Accounting expense was $4,394,000 as shown on its 2010 ND Earnings Report, page E-2. The Company's 2011 actual Customer Accounting expense was $4,411,000 (Company Exhibit AEH-1, Schedule 3, page 3 of 6, Column

ND Retail Electric). The Company's ND 2012 earnings report shows actual Customer Accounting expenses of $4,128,000. (NDPSC-5-013, Supplemental).

Q. What are you recommending with respect to the level of the Company's Customer Accounting Expense?

A. I am recommended a three year average for the Company Customer Accounting Expenses as used for other expenses as indicated previously in my testimony.

Q. What is the result of your calculation regarding the use of a three year average for the Company's Customer Accounting Expense?

A. My adjustment is computed as follows (in 000's):

	2010	2011	2012
Distribution Expense	$4,394	$4,411	$4,128
Three Year Average			**$4,311**

Q. Why are you recommending a three year average for the Company's Customer Accounting Expense?

A. I am recommending the use of a three year average (2010, 2011 and 2012) as the beginning balance for Distribution Expenses because these costs are evident, historical in nature and documented in the NDPSC Earnings Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdictions is an annual process. Therefore, the allocation of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations that are assigned to the North Dakota jurisdiction change annually also. Given that this information adjusts annually, the use of a three year average provides for a smoothing of the costs over time and normalizes the expenses. I recommend that for rate making purposes, the Customer Accounting Expense beginning unadjusted balance be computed using a three year average as computed above. My recommendation is also shown on my Schedule DM-18.

a. Bad Debt Expense

Q. What is the Company proposing with respect to its Bad Debt Expense?

A. The Company is proposing a decrease in the amount of $72,000 for its 2013 test year Bad Debt Expense relating to its billed commodity revenue for the cost of utility service, including fuel charges and all regulated charges to customers, such as riders.

Q. Please describe the Company's methodology of calculating its Bad Debt Expense?

A. The Company recognizes bad debt expense on its commodity revenue for electric and natural gas customers by estimating an amount of Accounts Reserve or Provision associated with outstanding receivables that will be unrecoverable and, writing off uncollectible accounts not previously reflected in the Accounts Reserve. The Company then calculates a weighted average ratio of bad debt to overall commodity revenue. The Company then applies this bad debt ratio to forecasted commodity revenues and allocates it between the Company's electric and natural gas operations. (WP-A9-1).

Q. Did the Company update its Bad Debt Expense for the 2013 test year?

A. Yes, the Company used information from its June 2012 budget showing that the Bad Debt Expense should be reduced from the initial 0.41% to a 0.39% ratio. The Company then applied this ratio to the Company's commodity revenues for its North Dakota operations to compute a decrease in the amount of $72,000.

Q. What is your recommendation with respect to the Company's decrease in its Bad Debt Expense in the amount of $72,000?

A. Since I have made adjustments to the Company's Retail Revenues, I also need to make adjustments with respect to the Bad Debt Expense. I utilized the Company's .39% ratio and multiplied it by my recommended Present Rate Retail Revenues of $177,077,000 to compute a Bad Debt Expense Level of $69,000 My recommendation is shown on Schedule DM-18**.**

6. <u>Customer Service</u>

Q. What is the Company proposed with respect to its Customer Service & Information Expense?

A. The Company is proposing Customer Service & Information Expense in the amount of $457,000 (Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column "Proposed 2013 Test Year.")

Q. How did the Company compute this level of Customer Service & Accounting Expense?

A. The Company computed 2013 Customer Service & Accounting Expense by using its unadjusted balance of $505,000 and then deducting its projected level of Advertising Expense of $48,000. (Company Exhibit AEH-1, Schedule 6, page 2 of 3).

Q. What is your recommendation with respect to the Company's total Customer Service & Information Expense in the unadjusted amount of $505,000?

A. As I computed three year averages for the beginning balances of the Company's other Operating Expenses, I am also recommending the use of a three year average for the Company's Customer Service & Information Expenses.

Q. Please explain the use of your recommended three year average.

A. I am recommending the use of a three year average (2010, 2011 and 2012) as the beginning balance for the Company's Customer Service and Information Expenses because these costs are evident, historical in nature and documented in the NDPSC Earnings Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdiction is an annual process. Therefore, the allocation of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations that are assigned to the North Dakota jurisdiction change annually also. Given that this information adjusts and changes annually, the use of a three year average provides for a smoothing of the costs over time and normalizes the expenses. I recommend that for rate making purposes, the Customer Service and Information Expense beginning unadjusted balance be computed using a three year average as computed below. (in 000's) (ND-PSC Earnings Reports, 2010, 2011 and 2012, pages E-2)

	2010	2011	2012
Customer Service & Information	$262	$489	$370
Three Year average			**$374**

My recommendation is shown on my Schedule DM-19.

a. <u>Advertising</u>

Q. What is the Company's proposal with respect to its Advertising Expense?

A. The Company is proposing a decrease in its Advertising Expense in the amount of $191,000. This is shown on Company Exhibit AEH-1, Schedule 17, page 2 of 2. The Company has indicated that this reduction in Advertising is consistent with past North Dakota rate case Orders. (Heuer Testimony page 65, lines 21-22). This $191,000 is comprised of a decrease of $48,000 related to Customer Programs and is part of the Customer Service & Information Account (Exhibit AEH-1, Schedule 6, page 2 of 3, Column 11), and a decrease of $143,000 related to Brand/Image and Sponsorship and Non-Recoverable DSM and is part of the A&G Account (Exhibit AEH-1, Schedule 6, page 2 of 3, Column 11.

The Brand/Image and Sponsorship and Non-Recoverable DSM costs of $143,000 will be discussed below under the A & G section.

Q. What is your recommendation with respect to the Company's proposed $48,000 decrease in its Customer Service & Information Expense, Advertising Expense?

A. I agree with the Company that a decrease in its Advertising Expense in the amount of ($48,000) is appropriate. My recommendation is shown on Schedule DM-19.

7. <u>Sales, Economic Development & Other Expenses</u>

Q. What are the Company's Sales, Economic Development & Other Expenses?

A. The Company has included $2,000, unadjusted, for 2013, for Sales, Economic Development & Other Expenses. (Exhibit AEH-1, Schedule 6, page 1 of 3). The Company's 2011 Sales, Economic Development and Other costs were $135,000 (Exhibit AEH-1, Schedule 3, page 3 of 6, Column ND Retail Electric). In its 2010 ND Earnings report, the Company's Sales, Economic Development and Other costs were $151,000. In its 2012 ND Earnings report, the Company's Sales, Economic Development and Other costs were $2,000. The Company is now proposing to include an additional $171,000 of Sales, Economic Development & Other Expenses for test year 2013 for a total amount of $173,000 (Company Exhibit AEH-1, Schedule 6 page 3 of 3, "Proposed 2013 Test Year" column).

Q. What is the Company's rationale with respect to including $173,000 of Economic Development costs in its 2013 test year expenses?

A. Company witness Heuer has stated that because economic development donations were recorded as below-the-line expense, an adjustment is necessary to include economic development contributions in the test year cost of service. This treatment is consistent with prior regulatory treatment in North Dakota. (Heuer Testimony page 68, lines 9-12).

Q. What is your recommendation with respect to the Company's inclusion of $173,000 in Economic Development Costs for its 2013 test year period?

A. From what I understand the Company through stipulation agreements has been allowed to recover the costs associated with Economic Development Costs in the past. Since these allowances were through a Settlement, I believe that the NDPSC did not have the opportunity to fully review these costs and make a thorough and complete decision. Therefore, Ms. Heuer's characterization that these Economic Development costs allowance as being consistent with prior regulatory treatment in North Dakota is not fully accurate. These costs were allowed in rates pursuant to a Settlement among the parties to the proceeding and not brought before the NDPSC for decision. I am recommending no inclusion of Economic Development Costs for its 2013 test year period.

Short of the Company being a good Corporate Citizen, these expenditures are not required to provide safe and reliable utility service. These donations to reportedly attract economic development do not affect utility services or the Company's safety and reliability standards. In these difficult economic times, with continued high unemployment rates occurring nationwide, and where the price of many goods and services are increasing, ratepayers have to eke out a living with what income they have, and are having difficulty paying their bills. More so, ratepayers do not have a selective choice as to where their utility dollars are going regarding Economic and Development costs. This item should therefore, be accounted for below the line and the Company Shareholders should be directed to absorb 100% of the costs related to Economic Development costs.

Furthermore, the Commission Advocacy Staff would appreciate it if the Company did not propose to include these costs in future rate cases as well and proposes to request the Commission specifically mention this in its final order in this case. My recommendation is shown on Schedule DM-20.

8. Administrative & General Expenses

Q. What is the Company proposing with respect to its Administrative & General Expenses (A&G)?

A. The Company began with unadjusted 2013 A&G Expenses of $15,600,000 as shown on Company Exhibit AEH-1, Schedule 6, page 1 of 3). To that amount, the Company included the 13 adjustments listed below to calculate an adjusted 2013 test year level in the amount of $14,822,000 as shown on Company Exhibit AEH-1 Schedule 6, page 3 of 3 column "Proposed 2013 Test Year."

Company Unadjusted – 2013	$ 15,600,000
Shared Asset Allocation	(196,000)
Advertising	(143,000)
Association Dues	19,000
Donations	157,000
Customer Deposits	1
Aviation	(52,000)
Wholesale Billing	(3,000)
Cell Phone Policy	(7,000)
Rate Case Budget Exclusion	(24,000)
Incentive Compensation	(530,000)
Incentive Compensation Correction[4]	(6,000)
Pension Update[5]	246,000
Active Health Care Update[6]	(250,000)

[4] This expense was included in the Company's June 6, 2013, Update, Exhibit AEH-1, Schedule 6, page 3 of 3, column 35, line 13.
[5] This expense was included in the Company's June 6, 2013, Update, Exhibit AEH-1, Schedule 6, page 3 of 3, column 39, line 13.
[6] This expense was included in the Company's June 6, 2013, Update, Exhibit AEH-1, Schedule 6, Page 3 of 3, Column 40, line 13.

Total Company Proposed	$ 14,812,000

Q. What is your approach with respect to the Company's proposed A&G Expenses?

A. The Company began with its 2011 actual A&G expenses in the amount of $11,770,000. (Company Exhibit AEH-1, Schedule 3, page 3 of 6, under ND Retail Electric Column. In 2010, the Company's NDPSC Earnings Report showed A&G Expenses in the amount of $12,374,000. The Company's 2012 NDPSC Earnings Report showed 2012 A&G expenses of $12,969,000. The Company has proposed A&G expenses of $15,600,000 for its 2013 test year, unadjusted. (Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1).

Q. What are you recommending as a beginning balance on an unadjusted basis for the Company's 2013 A&G Expenses?

A. I am recommending using a three year average as the beginning balance for the Company's A&G expense, unadjusted as the starting point. My calculation is as listed below: (in 000's) (NDPSC Annual Reports for the years 2010, 2011 and 2012, pages E2).

	2010	2011	2012
A&G Expenses	$12,374	$11,770	$12,969
Three Year Average			**$12,371**

Q. Why are you recommending a three year average as the Company's beginning balance for A&G Expenses?

A. I am recommending the use of a three year average (2010, 2011 and 2012) as the beginning balance for the Company's A&G Expenses because these costs are evident, historical in nature and documented in the NDPSC Earnings Reports. As stated in the Company's Cost Assignment and Allocation Manual (Exhibit AEH-1, Schedule 12, page 50) determination of the assignment and allocation of costs to jurisdiction is an annual process. Therefore, the allocation of plant and plant related costs, rate base investment, etc. change annually, and thus the percentage allocations that are assigned to the North Dakota jurisdiction change annually also. Given that this information is adjusted and changed annually, the use of a three year average provides for a smoothing of the costs over time and normalizes the expenses. For ratemaking purposes I am recommending the use of a three year average. My recommendation is shown on Schedule DM-21.

Q. Please describe the thirteen adjustments the Company makes to its A&G balance for 2013.

A. As I indicated above, the Company makes thirteen adjustments to the A&G expense account. I will discuss each adjustment below.

a. <u>Shared Asset Allocation</u>

Q. What is the Company's claiming regarding its Shared Asset Allocation balance for the test year 2013?

A. The Company is including in the 2013 test year period, a decrease in the amount of $196,000 for costs associated with assets that are shared with all Xcel Energy operating companies. (Exhibit AEH-1, Schedule 6, page 1 of 3). The Company stated that each operating company shares in the total cost of assets from which the operating company derives benefits and the operating company that owns the assets is reimbursed for the other operating companies' use of its assets. The Company stated that the Shared Asset Allocation adjustment applies the shared asset to the Company's updated Capital Budget data.

Q. What is your recommendation with respect to the Company's Shared Asset Allocation decrease adjustment of $196,000?

A. I agree with the Company's proposal to decrease the amount of its Shared Asset Allocation by $196,000. My recommendation is shown on Schedule DM-21.

b. <u>Advertising</u>

Q. What is the Company's proposal with respect to total Advertising Expense?

A. The Company is proposing a decrease in its Advertising Expense in the amount of $191,000. This is shown on Company Exhibit AEH-1, Schedule 17, page 2 of 2. The Company has indicated that this reduction in Advertising is consistent with past North Dakota rate case Orders. (Heuer Testimony page 65, lines 21-22). This $191,000 is comprised of a decrease of $48,000 related to Customer Program and is part of the Customer Service & Information Account as I described above, (Exhibit AEH-1, Schedule 6, page 2 of 3, Column 11), and a decrease of $143,000 related to Brand/Image and Sponsorship and Non-Recoverable DSM and is part of the A&G Account (Exhibit AEH-1, Schedule 6, page 2 of 3, Column 11, which I will address below.

Q. What is your recommendation with respect to the Company's proposal regarding the decrease in Advertising Expense related to Brand/Image and Sponsorship and Branding?

A. I agree with the Company. However, I would like to point out, that this recommendation was not based on past rate Orders. The NDPSC has not made a recent determination as to how these costs should be reflected in rates. Nevertheless, my recommendation is shown on my Schedule DM-21.

c. <u>Professional and Association Dues</u>

Q. What is the Company proposing with respect to Professional and Utility Association Dues?

A. The Company is claiming that in its 1992 electric rate case application, Case No. PU-400-92-399, the NDPSC determined that only organizational dues related to its North Dakota operations were allowable for recovery in electric rates. The Company states in this current rate application that they have removed any organizational dues that are not related to the electric operations supporting the State of North Dakota. The total Professional and Utility Association Dues that the Company is proposing to recover in this rate application is $19,000 as reflected in Company Exhibit AEH-1, Schedule 6, page 2, Column 12. This $19,000 reflects the addition of the $23,000 of the Chamber of Commerce membership dues, and the exclusion of $4,000 of non-recoverable Professional and Utility Association Dues as shown on Company Exhibit AEH-1, Schedule 18.

Q. What is your recommendation with respect to the Company's inclusion of Professional and Utility Association Dues of $19,000?

A. I am recommending the removing of the Company's proposed Chamber of Commerce membership dues in the amount of $23,000. My recommendation is based upon the fact that these types of membership dues are similar to other brand imaging costs and provide no benefit to ratepayers. These costs have no effect on the Company's duty to provide safe and reliable utility service. As shown on WP-A-12, 2013 Budget Chamber of Commerce Dues lists costs that are not specifically associated with any Chamber. The remaining dues are associated with United States Chamber and Local area Chamber Lobbying. These types of Chamber dues provide benefits solely to the Company, especially in the area of Lobbying, and therefore should not be included for ratemaking purposes. I am therefore, recommending removal of these costs. My recommendation is shown on my Schedule DM-21.

d. <u>Charitable Donations</u>

Q. What is the Company claiming in respect to Charitable Donations?

A. The Company is proposing to recover Charitable Donations in the amount of $157,000 in its 2013 test year. This is shown on Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 13. The Company has proposed to include 50% of Corporate Charitable Contributions that it claims benefit the State of North Dakota. The Company included 50% of the Corporate Charitable contributions to ensure that only the amounts contributed to charities and institutions that could be associated with the Company's electric service territory in the North Dakota jurisdiction were included in the cost of service.

Q. What is your recommendation with respect to the Company's inclusion of 50% of Charitable Contributions?

A. In reviewing WP-A13 1 through 8, I note that there are organizations listed in the detailed data for the Company 2013 budget that the Company had donated to that should not be passed onto the North Dakota ratepayers. A selected list on WP-A13-5 shows the following:

Minot Indoor Rodeo, Inc.
Knollwood Liquor Store
Williams-Sonoma
Ordway Circle of Stars
Como Friends
Just Give
Razoo Donations
Bridging, Inc.
Fireworks Foundation
BREDE
Xcel Energy Company Store

Q. What do you glean from the above regarding Company donations?

A. Given the list above, I do not recommend that any Charitable Donations be passed onto North Dakota ratepayers. There is no way to determine whether or not these selected or any additional donees shown on WP-AP-13, 5 through 7 provide any known utility service benefits to the North Dakota ratepayers. Even though the Company has only included 50% of its Charitable Donations in rates, I am of the opinion that none of the Charitable Donations be included as part of the Company's revenue requirement proposal. Short of the Company being a good Corporate Citizen, any kind of donations is not a requirement to provide safe and reliable utility service.

Q. What other arguments do you have regarding Charitable Donations?

A. In these difficult economic times, with still high unemployment rates nationwide, and where the prices of many goods and services are increasing, consumers have to eke out a living with what income they have. Ratepayer monies should not be used for the Company approved charitable donations. Ratepayers do not have the option to select the charities where their utility rate dollars go. The only benefit that arises out of Company donations stays within the Company. It enhances corporate image and corporate sponsorship, but it does not do anything to enhance the provision of utility service. This item should be accounted for below the line item, and the Shareholders should pay and absorb 100% of the costs related to charitable donations.

Q. What is your recommendation with respect to the Company's inclusion of $157,000?

A. I recommend that none of the $157,000 be included in the Company's revenue requirement proposal. Furthermore, Advocacy Staff recommends that the Company not propose inclusion of these costs in future rate cases and will recommend that the Commission's final Order in this case include a specific finding in this regard. My recommendation is shown on Schedule DM-21.

e. <u>Interest on Customer Deposits</u>

Q. What is the Company proposing with respect to Interest on Customer Deposits?

A. The Company is proposing to include an increase of $1,000 to reflect the return on ratepayers' monies. This adjustment is reflected in Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 15.

Q. What is your recommendation regarding the inclusion of Customer Deposits in the amount of $1,000?

A. I agree with the Company and recommend $1,000 to be included for Customer Deposits. My recommendation is shown on Schedule DM-21.

f. <u>Aviation Expense</u>

Q. Please describe the Company's Aviation Adjustment?

A. The NSPM electric utility has proposed to allocate approximately $1.7 million in costs related to the operation of its two corporate aircraft used by Company personnel for the test year 2013, with $105,000 being allocated to the State of North Dakota electric jurisdiction. The Company has stated that these costs are incurred in lieu of commercial aviation transportation and helps facilitate the efficient use of executive time and other employee time. The Company has indicated that the use of corporate aircraft is cost efficient. This is the sixth adjustment to the Company's A & G Expenses.

Q. Did the Company provide any supporting documentation with respect to the benefits of the use of corporate aircraft?

A. Yes, the Company retained a third party consultant to perform a cost-benefit analysis for the Company's corporate aircraft usage for the periods of 2011 through June 2012. The Company provided the study as Exhibit AEH, Schedule 23.

Q. What were the results of the study?

A. The study sought to compare the benefits the Company obtained from the use of its corporate aircraft in comparison to the use of commercial airlines. The study compared door-to-door travel time, average flight times between the Company's six most common city pairs based on a comparison of actual flight times and published flight times for commercial airlines. The Study also factored in commercial air travel delays based on the Transportation Security Administration statistics. Finally the Study factored in a measure of potential lost productivity that resulted from air travel and analyzed the Company's cost per flight and commercial airfares based on historical data for a 14-day, a 3-day and a 1-day advance round trip purchase.

Q. What did the Study results realize?

A. The Company claims that efficiencies are realized in that destinations are reached faster which allows employees to maximize their work days, as well as allowing employees to get work done in transit. The Company claimed that approximately 69% of corporate aviation costs provide a benefit when compared to the costs of commercial air travel.

Q. What did the Company calculate with respect to its Aviation Expense?

A. The Company decreased its Aviation Expense by $52,000. (Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 16). The Company stated that this amount was consistent with its last electric rate case, where it removed 50% of the aviation related costs. The Company also stated that the level of corporate aviation is approximately the same as was approved in its last electric rate case, which was a decrease of $49,000. In WP-A16-1, the Company has stated that the costs included in the current rate proceeding are only for a single airplane, even though the Company maintains two airplanes.

Q. What is your recommendation with respect to the Company's adjustment of a decrease in Aviation Expenses in the amount of $52,000?

A. Questions were raised with respect to non-employee use of airplanes, i.e. spousal use. The Company has indicated that between the years 2008-2012, the percentage of use of by non-employees of the Company is about 1%. (NDPSC-2-013). The Company has also indicated that attendance of executive and Board member spouses sometimes occur for certain corporate and Board of Directors functions. The Company has indicated that it does not track whether other employees were ever required to use alternative travel arrangements because of spousal or non-employee travel.

Given this information, I am recommending that the Commission require the Company to track the use of its Company Aviation policy and report on its expenses, adherence and policy changes as part of its earnings reports. The report should also include evidence that the Company is using alternatives such as video-conferencing and other electronically available devices to decrease the need for travel and to allow for more usage of commercial travel. With the increased availability to use electronic devices on commercial airlines, any advantages to corporate aircraft should be decreasing.

I am recommending the Commission set a firm budgeted amount as a benchmark for Aviation expenses in this case of $104,000, which is the total Company proposed Aviation expenses and allow 50% of the costs or $52,000 associated with Aviation expenses. Before any increase in the benchmark amount ($104,000) can be allowed, the Company will have to show comparable costs of the use of Commercial airline travel service. Additionally, in the Company's next rate case proceeding, the Company should show whether or not the continued use of Corporate Airplane service is feasible or practical and less costly than Commercial Airplane service, video conferencing and greater use of electronic devices on commercial options.

My recommendation is shown on Schedule DM-21.

g. Wholesale Billing

Q. Please describe the Company's Wholesale Billing Adjustment?

A. The Company stated that it performed a study of the cost to serve its single wholesale full requirements customer at cost-based rates. The Company stated that it undertook this study to ensure that the wholesale jurisdiction's cost assignment fairly represented the cost of providing service to this particular customer. The Company discussed the results of the study in Heuer's Testimony, Section VII, Utility and Jurisdictional Allocations.

The Company's adjustment directly assigns $43,000 that is related to customer billing, account management and distribution expense to the wholesale jurisdiction and decreases costs that is assigned to the retail jurisdictions by the amount of $43,000, which a decrease of $3,000 to the North Dakota retail jurisdiction. (Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 17). The Company claimed that it does not plan to serve any cost-based wholesale requirements customers after 2013.

Q. What is your recommendation with respect to the Company's adjustment in the amount of ($3,000) with respect to Wholesale Billing?

A. I agree with the Company and have no changes to the Company's Wholesale Billing adjustment of ($3,000). My recommendation is shown on Schedule DM-21.

h. <u>Cell Phone Policy Expense</u>

Q. Please describe the Company's Cell Phone Policy Adjustment?

A. The Company has included a decrease of $7,000 in its 2013 test year revenue requirements to reflect costs associated with employees' use of Company cell phones. The Company claims that it instituted an internal audit that revealed inconsistencies among its business units in spending for personal communication devices such as cell phones. The Company updated its policy and clarified which employees were eligible for cell phone usage and, or personal reimbursement. The Company's adjustment is reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 24.

Q. What is your recommendation with respect to the decrease of $7,000 that reflects the costs associated with employee's use of Company cell phones?

A. I agree to the decrease in the Company's Cell Phone Policy Expense in the amount of $7,000. I also suggest that the Commission direct the Company to provide annual updates with respect to the Company Cellular Phone Plan costs and changes as part of its earnings reports to assure that the Company is consistently seeking out and taking advantage of expense savings that can minimize the cost impact to the ratepayers in the North Dakota jurisdiction. My recommendation is shown on Schedule DM-21.

i. <u>Incentive Compensation</u>

Q. What adjustments has the Company proposed with respect to Incentive Compensation in this current rate application?

A. The Company has included an adjustment to exclude budgeted costs for the long term portion of incentive compensation, any non-corporate incentive plan costs and, all annual incentive plan costs that are above 25% of base pay. The amount that the Company computed for the 25% threshold level is $(530,000). The Company has also included certain long-term incentive costs that are associated with Restricted Stock Units that are related to Nuclear Operations employees which are also included in the revenue requirement. This is reflected in Company work paper WP-A27.

Q. What is the rationale for the Company to include Incentive Compensation in its proposed revenue requirements?

A. The Company stated that its 2007 rate case application included an adjustment to exclude annual incentive plan costs above 15% of base pay. The Company is now proposing a cap of 25% of base pay. The Company claims that the 25% level is more appropriate because a 25% cap limits rate recovery associated with executive compensation without affecting rate recovery for incentive compensation for other employees.

The Company stated that this approach is similar to the adjustments made to remove long term incentive executive compensation. The Company is not requesting rate recovery of any portion of long term incentive compensation costs, with the exception of eligible employees in its Nuclear Business Unit. This approach is more detailed by the Company's Witness Timothy J. O'Connor. The Company stated that a 25% base salary cap would go beyond limiting executive incentive compensation and would also limit the recovery of incentive compensation for the other individual contributors and managers in the Company.

Q. What is the impact with respect to the Company's inclusion of Incentive Compensation in this current rate application?

A. The inclusion of a 25% cap on incentive compensation would be a decrease to its revenue requirement in the amount of $530,000. This is reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 26. The inclusion of a 15% cap on incentive compensation calculates to a decrease of $619,000 as shown on data request NDPSC 1-018, Attachment A.

Q. What is your recommendation with respect to Incentive Compensation capped at 25% for Nuclear Operations employees?

A. I am recommending that no Incentive Compensation base pay be included in the Company's proposed 2013 revenue requirement. The Company has not provided any documentation in its rate case application to support its incentive compensation in its revenue requirement proposal. Although the Company has stated that it has various incentive programs as part of its overall compensation package, (WP-A27-1), there were no such documentation filed with the rate application to support it.

Further, in the Application of the Northern States Power Company – Wisconsin for Authority to Adjust Electric and Natural Gas Rates, Case No. 4220-UR-117, Final Decision dated December 22, 2011, the Commission decided that "Consistent with the other large investor – owned utilities in Wisconsin in which the costs associated with incentive pay plans are not included in revenue requirements and the current economic conditions in Wisconsin, it is appropriate to limit the financial impacts on ratepayers and exclude these costs from NSPW's revenue requirements. (page 27).

Q. What is your adjustment with respect to the Company level of Incentive Compensation capped at 25% of base pay in the amount of $530,000?

A. Given that the Commission in Wisconsin disallowed Incentive Compensation for the Northern States Power – Wisconsin, an affiliate of Northern States Power- North Dakota; it is reasonable and consistent to disallow the same in this proceeding. I have calculated removing of all of the Company's Incentive Compensation costs as follows:

The level of $(530,000) (rounded up from $529,810) represents the amount of Incentive Compensation at a cap of 25% of base pay (WP-A27-1 through 3). The Commission had previously included a cap of 15% of base pay which calculated to an amount of $(619,125) (NDPSC-1-018, Attachment A).

By lowering the cap from the original 15% cap from the 25% cap, a difference of $89,315 is derived. ($619,125-$529,810). This is a 10% difference (from 15% to 25%). By dividing the $89,315 by 10%, the result is $8,931.50 for each percent up or down. I then multiplied the $8,931.50 times 15 to reduce the remaining 15% of the incentive compensation still embedded at the 15% cap to arrive at $133,972.50. I then added this amount to $619,125 to arrive at the total exclusion of incentive compensation of $753,098. My recommendation is shown on Schedule DM-21.

j. Rate Case Budget Exclusion

Q. Please describe the Company's position with respect to its Rate Case Budget Expense Adjustment?

A. The Company stated that the NDPSC approves a level of rate case expense recovery as a part of each test year. The Company stated that in past years, actual rate case expenses have exceeded amounts that were approved by the NDPSC. The Company claimed that this resulted in amounts that were over the approved expense written off in the year that it occurred. The Company stated that the 2013 O & M Budget included an allowance for the write off of prior rate case expenses. The Company, in the review of its 2013 budget, identified this amount and excluded it from the test year. The Company has calculated a decrease of $24,000 from the 2013 test year revenue requirement. This is reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 25.

Q. What is your recommendation with respect to this adjustment?

A. I agree with the Company with respect to removal of prior rate case expenses in the amount of $24,000. My recommendation is shown on Schedule DM-21.

k. <u>Pension Update</u>

Q. What has the Company included in its Updated filing, dated June 6, 2013, regarding its Pension costs?

A. The Company in its Updated June 6, 2013, filing has included an additional $246,000 related to its Pension expense. (Exhibit AEH-1, updated, Schedule 6, page 3 of 3, Column 39, line 13) (NDPSC 2-19, Attachment A, page 1 of 1).

Q. Why did the Company update this expense item?

A. Company Witness Heuer stated in her response to NDPSC-5-026, Supplement, that the Pension Calculation was refreshed with 2012 year-end assumptions to account for the change in the Earned Return on Assets as being 7.25%, down from 7.50%, the SFAS 87 Discount Rate as being 4.03%, down from 5.00%, the Aggregate Cost Method Discount Rate as being 7.25%, down from 7.50% and the Wage Increase assumption as being 3.75%, down from 4.00%.

Q. What is your recommendation with respect to the Company's updated Pension Expense?

A. I am in agreement with the Company in that pension costs have increased in the amount of $246,000. I would also ask that the Company provide updates to the NDPSC beginning on December 31, 2013, and yearly thereafter to assess and evaluate the costs associated with the Company's pension balance and assumptions. In NDPSC-1-001, Company Witness, McCarten has indicated two proposals to smooth out pension costs. The first proposal is to extend the NSPM Plan amortization period for unrecognized pension costs. The second proposal is to cap the Xcel Energy Services Company pension expense at the 2011 level of $373,615 and defer the difference in excess of this level to future years. Given this information, the Company should provide scenarios and shown which method minimizes the impact on rates.

My recommendation is shown on Schedule DM-21.

l. <u>Active Health Care Update</u>

Q. What is the Company proposing with respect to its updated Active Health Care Cost?

A. The Company, in its June 6, 2013, update, has included a decrease in its Active Health Care costs of $250, 000 as shown on Exhibit AEH-1, Schedule 6, page 3 of 3, Column 40, Line 13, and WP-40.

Q. What was the reason that the Company updated its Active Health Care costs?

A. The Company has stated that it refreshed its budgeted 2013 active health care costs with 2012 year-end cost data. The Company stated that the primary driver for the difference is a decline in the number of health insurance claims that were made by its employees in October through December 2012. (NDPSC-5-086, supplement).

Q. What is your position regarding this update?

A. I agree with the Company. The Company should provide updates regarding its Active Health Care costs as costs become known. My recommendation is shown on Schedule DM-21.

m. Incentive Compensation Correction

Q. What is the Company proposing with respect to its Incentive Compensation update?

A. As shown on Data Request NDPSC-5-086, Supplemental, the Company made a correction to other Incentive Compensation to exclude Other Bonuses/Incentives that were calculated to include costs in its Interchange Agreement billings to NSPW. The Company determined that these costs should not have applied an Interchange Agreement impact factor and it removed $6 thousand with respect to Incentive Compensation.

Q. What is your recommendation with respect to the Company's update on its Incentive Compensation?

A. As I stated previously, I recommended all Incentive Compensation to be removed from the Company's revenue requirement increase. Additionally Advocacy Staff recommends that the Company not propose recovery of incentive compensation in any future rate cases unless the Company is allowed to recover these costs in all other jurisdictions including Wisconsin. We will ask for specific findings in the final Order in this regard. Given this statement, I have used the same calculated to reduce the removal of incentive compensation from the Company's proposed 25% limitation.

Company Incentive Compensation at 25%	$529,810
Company Incentive Compensation Correction	$ 6,000
% to total	1.13%
Company Incentive Compensation at 15%	$619,125
% removal	1.13%
Incentive Compensation Correction	$6,996
Difference	$996
$996 divided by 10% points	$99.6

996 times 15% to reduce Incentive to zero	$1,494
Total Incentive Compensation Correction:	
$6,996 plus $1,494	$8,490

My recommendation is shown on Schedule DM-21 rounded to $8,000.

Q. Is there any other adjustment related to the Company's A&G Expense that you would like to raise?

A. Yes. As shown on Company data request NDPSC-5-045, Attachment A, the Company has broken down O&M Expenses by labor category. I have removed all incentive compensation related to the Company's Labor. The following accounts under the Labor Category are considered incentive related pay:

Fuel Handling- Incentive Labor Loading	$ 844
Fuel Procurement – Incentive Labor Loading	$ 3,456
Incentive Labor Loading	$ 483,076
Incentive	$ 887,381
Total	$1,374,757

I previously removed $753,000 and $77,000 in incentive related labor as indicated in section i. above, (Incentive Compensation) and in section 2, Power Production, item c, Nuclear Retention Program, respectively. The balance of the incentive compensation is therefore:

Total Incentive Compensation	$1,374,757
Incentive Compensation (section i)	$ 753,000
Nuclear Retention Program (section 2-Power Production, item c)	$ 77,000

Balance of Incentive Compensation	$ 544,757

I have added a line item as shown on Schedule DM-10, line 18, to remove the remaining Incentive Compensation not specifically identified in the Company's schedules.

C. Depreciation Expense

Q. Please explain the Company's calculation of its proposed Depreciation Expense level in this current proceeding?

A. The Company computed a beginning unadjusted balance in its Depreciation Expense in the amount of $21,238,000 as shown on Company Exhibit AEH-1, Schedule 6, page 1 of 3, Column 1. In its Updated Exhibits dated June 6, 2013, and as shown on AEH-1, Schedule 6, the Company made nine adjustments to compute a proposed 2013 test year balance for Depreciation Expense in the amount of $21,986,000.

Q. What are the nine adjustments the Company made to its 2013 Unadjusted Depreciation Expense Balance and as updated in its June 6, 2013, Exhibits?

A. The nine adjustments that were made to the Company's 2013 unadjusted Depreciation Balance is as follows:

	Beginning Balance	$21,238,000
1.	Bemidji CapX2020 Project	$ 39,000
2.	Brookings CapX2020 Project	$ 1,000
3.	2012 Depreciation Study	$ 1,042,000
4.	2012 Remaining Life Depreciation Study For Productive Assets	$ (254,000)
5.	Black Dog Steam Plant Remediation	$ 497,000
6.	AFUDC Correction	$ 5,000
7.	Monticello License	$ (56,000)
8.	Projects out of 2013	$ (7,000)
9.	Sherco 3	$ (22,000)

Ending Balance	$ 21,986,000

Q. What is your recommendation with respect to the Company's proposed Depreciation Expense and the related adjustments?

A. Based upon the testimony of Advocacy Staff Witness Michael Majoros, I am recommending no change to the Company's Depreciation Schedule except for the allocation factor recommended by Advocacy Staff Witness Mr. Pavlovic of 87.20%. Based upon this allocation factor the recommended Depreciation Expense is reduced by $2,814,000 for a recommended Depreciation Expense of $19,172,000. My recommendation is shown on Schedule DM-22.

D. <u>Amortization Expense</u>

Q. What is the Company proposing with respect to its Amortization Expense in this rate case proceeding?

A. The Company has calculated an unadjusted balance in its Amortization Expense in the amount of $4,000 as shown on Company Exhibit AEH-1, Schedule 6, page 1 of 3. To that amount, the Company has made 5 adjustments as follows:

	Beginning Balance	$ 4,000
1.	ND Demand Side Management	$ 56,000
2.	Rate Case Expense Amortization	$206,000
3.	Prior ND Rate Case	$ 71,000
4.	Private Fuel Storage Amortization	$ 69,000
5.	Emission Credit Amortization	$ (33,000)
	Projected Balance	$ 373,000

Q. Please explain each of the five Amortization Adjustments and your recommendations for each.

1. <u>ND Deferred DSM</u>

Q. Please describe the Company's proposal with respect to its Demand Side Management Amortization.

A. The Company stated that in Case-No. PU-08-171, (Demand Side Management and Cost Recovery Rider Tariff) the NDPSC authorized the Company (NSP) "to record expenditures to further promote its existing Savers Switch and Peak Energy Control Service load management programs in a deferred account for amortization in NSP's next general rate case. The amount deferred may not exceed $266,904 per year."

The Settlement that was approved by the NDPSC in the Company's last rate case included a three year amortization of the accumulated DSM balance from the 2009 and 2010 calendar years in the amount of $450,639. The Company calculated the estimated unamortized DSM balance as of December 31, 2012 in the amount of $168,486. The Company is proposing a three year amortization of this balance, of which $56,000 is included in this current rate proceeding. This is shown on Company Exhibit AEH-1, Schedule 6, page 2 of 3, Column 20.

The Company has also included $266,583 in its 2013 O & M Budget related to DSM to represent the anticipated ongoing annual expense for DSM. The three year amortization is calculated in Company Exhibit AEH-1, Schedule 20.

Q. What is your recommendation with respect to the ND DSM annual amortization of $56,000?

A. While I agree with the Company's three year amortization period, I believe that the balance of $168,486 that the Company is proposing should be adjusted.

Q. What adjustments do you recommend?

A. Since the Company is proposing to recover the ND DSM costs over three years beginning with the year 2013 and continuing through 2015 (WP-A20-1) and it is likely that new rates will not become effective until towards the end of 2013, a full year amortization will have taken place with respect to the Company's ND DSM amortization balance of $168,486. Therefore, I am recalculating the outstanding amortization balance by removing a full year of amortization expense ($56,162) from the Company's outstanding amortization balance and reducing it to $112,324. ($168,486-$56,162). I then amortize the $112,324 balance over the three year period to normalize the amortization. This change reduces the Company's amortization from its proposed $56,162 per year to $37,441 per year ($112,324/3) or a reduction of $18,721 per year. My recommendation is shown on my Schedule DM-23.

2. <u>2013 Rate Case Expense Amortization</u>

Q. What is the Company proposing with respect to its Rate Case Amortizations in this current application?

A. The Company is proposing to amortize certain test year expenses over a three-year period in order to normalize those expenses and prevent an over recovery.

Q. What is the proposed amount of the Company's Rate Case Expenses in this current rate application?

A. The Company is requesting approval of $618,000 for projected direct expenses associated with this rate application, along with the use of a three-year amortization period. This results in an annual amortization amount in the amount of $206,000. (Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 27 and, AEH-1. Schedule 19 and 20).

Q. What is your recommendation with respect to the level of proposed Rate Case Expenses of $618,000 and the related proposed three-year amortization period?

A. I've review the data response NDPSC-1-015, Supplemental which shows total rate case costs as of June 21, 2013, in the amount of $282,720. Included in the costs to date are costs associated with outside legal fees in the amount of $83,478. These costs comprise nearly one-third of the total rate case expenses in this proceeding.

Given that the North Dakota electric operation is a small jurisdiction, the Company should be able to handle the case with one or two in-house attorneys. The Company should be able to minimize rate case costs without having to rely on outside legal counsel. Secondly in the area of consultants, approximately $60,418 has been charged to outside consulting, which is 21% of the total rate case costs to date. I believe that a company of Xcel Energy's size should be able to utilize its own internal personnel to process and provide consulting services including the preparation of DCF and CAPM model results. There is nothing out of the ordinary that prevents Company employees from performing these tasks.

Therefore, I am recommending that the costs for the Company's outside legal fees and its outside legal consultants should be removed from rate case expenses. Removal of these costs reduces the Company's to date rate case costs to $139,124. I am then doubling this amount to $278,248 to compute a recommended year end amount for the entire rate case process. I am also recommending a three year amortization period to compute an annual amount of $92,749 (rounded to $93,000) to be reflected in rates. My recommendation is shown on Schedule DM-23.

3. <u>Prior Rate Case Expense</u>

Q. What is the Company proposing with respect to its Prior Rate Case Amortization?

A. The Company claims that its last rate case application was approved via a settlement by the NDPSC. The rate case costs in that settlement agreement included an amount of $562,000 as well as the use of a three year amortization period. The Company has calculated an unamortized balance as of December 31, 2012, in the amount of $212,000. The Company is requesting to extend this period for an additional three years. The resulting annual amortization expense is calculated at $71,000. This adjustment is reflected in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 28, and Schedule 20, and in WP-A29-1.

Q. What is your recommendation with respect to these Prior Rate Case Adjustments?

A. I agree with the Company with respect to the December 2012 balance in the amount of $212,000. However, as I stated above with respect to the Company's recovery of its ND DSM costs, it is likely that the NDPSC will approve new rates towards the end of 2013, and therefore, a full year amortization will have taken place with respect to the Company's prior rate case costs of $212,000. Therefore, I am recalculating the outstanding amortization balance by removing a full years of amortization expense ($71,000) from the Company's outstanding amortization balance and reducing it to $141,000. ($212,000-71,000). I am then amortizing the $141,000 balance over the three year period to normalize the amortization expense. This change reduces the Company's amortization from its proposed $71,000 per year to $47,000 per year ($141,000/3) or a reduction of $24,000 per year. My recommendation is shown on my Schedule DM-22.

4. <u>Private Fuel Storage</u>

Q. Please describe the Company's proposal with respect to its Private Fuel Storage Amortization.

A. The Company claimed that it spent approximately $23 million in order to obtain a Nuclear Regulatory Commission license for Private Fuel Storage, a private independent spent fuel storage installation within the Goshue Indian tribal land located in Utah. The Company calculated that out of the $23 million spent, $1.14 million was assigned to the State of North Dakota. In Case No. PU-07-776, the NDPSC approved a six-year amortization period for the $1.14 million beginning in 2008. If the Company continued to use the six-year amortization period as directed by the NDPSC, 2013 would be the final year of amortization. The Company calculated an unamortized balance at December 31, 2012 in the amount of $208,000. The Company is proposing an additional three year amortization for this unamortized balance. This would result in an annual amortization amount of $69,000. This is shown in Company Exhibit AEH-1, Schedule 6, page 3 of 3, Column 29, and Schedule 20, and in WP-A29-1.

Q. What is your recommendation with respect to the Company's amortization of its Private Fuel Storage?

A. I agree with the Company with respect to the December 2012 balance in the amount of $208,000. However, as I stated above with respect to the Company's other recovery of amortized costs, it is likely that the NDPSC will approve new rates towards the end of 2013, and therefore, a full year of amortization will have taken place with respect to the Company's prior Private Fuel Storage costs of $208,000. Therefore, I am recalculating the outstanding amortization balance by removing a full year of amortization expense ($69,000) from the Company's outstanding amortization balance and reducing it to $139,000. ($208,000-$69,000). I am then amortizing the $139,000 balance over the three year period to normalize the amortization expense. This change reduces the Company's amortization from its proposed $71,000 per year to $46,000 per year ($139,000/3) or a reduction of $25,000 per year. My recommendation is shown on my Schedule DM-23.

5. <u>Emission Credit Amortization</u>

Q. Please describe the Company's proposed Emission Credit Amortization.

A. The Company has stated that the Settlement approved by the Commission in its last rate case included a three year amortization of the cumulative balance of deferred Emission SO2 Allowance Credits as of December 2010. The Company is proposing to continue to amortize the outstanding balance as of December 31, 2012 in the amount of $99,000 over a three year period. (Exhibit AEH-1, Schedule 6, Page 3, Column 30). Also included in this are costs of $87,000 in SO2 allowance credits. This adjustment removes the budget SO2 allowance credit of $87,000 from other revenue and adds an annual SO2 allowance amortization expense credit of approximately $33,000 (one third of the $99,000 December 31, 2012 estimated balance). The net effect of this adjustment is an increase in test year revenue requirements of $54,000. (WP-A29-3 and 4).

Q. What is your recommendation with respect to the Company's proposal to amortize the Emission Credit in the amount of $99,000 over a three year period?

A. I agree with the Company with respect to the December 2012 balance in the amount of $99,000. However, as I stated above with respect to the Company's other amortized costs, it is likely that the new rates will become effective toward the end of 2013, and therefore, a full year amortization credit will have taken place with respect to the Company's prior Emission Credit balance in the amount of $99,000. Therefore, I am recalculating the outstanding amortization balance by removing a full year of amortization credit expense ($33,000) from the Company's outstanding amortization balance and reducing it to $(66,000). ($99,000-$33,000). I am then amortizing the ($66,000) credit balance over the three year period to normalize the amortization expense. This change reduces the Company's amortization credit from its proposed ($33,000) per year to ($22,000) per year ($66,000/3) or a reduction of the credit in the amount of $11,000 per year. My recommendation is shown on my Schedule DM-23.

E. <u>Taxes</u>

1. <u>Property Taxes</u>

Q. What has the Company proposed with respect to Property Taxes?

A. The Company has proposed Property Taxes in the amount of $7,940,000 (Exhibit AEH-1, Schedule 6, Page 3 of 3, Proposed Test Year Column. The Company began with an unadjusted Property Tax balance of $7,915,000 and added $25,000 related to the Company's Bemidji CapX2020 project (Exhibit AEH-1, Schedule 6, page 1 of 3, Column 2).

Q. Has the Company provided updates to its Property Taxes during the rate proceeding?

A. Yes. In response to NDPSC-5-056, the Company updated its Property Taxes as shown on Attachment A, page 5 of 5. The updated amounts reflect total Company 2013 Electric Property Taxes in the amount of $147,282,000 and the jurisdiction amount apportioned to the North Dakota operations in the amount of $7,142,000. This update reduces the Company's as filed amount from $7,940,000 to $7,142,000 or a decrease of $798,000.

Q. Has the Company further updated its Property Tax Expense?

A. Yes. In Company response to NDPSC-5-026, supplemental, the Company has indicated that it received its Truth in Taxation notices related to increases in its 2013 State of Minnesota property taxes. The Company has indicated in its WP-A-41 updated, that its 2013 property tax is calculated at $8,119,000. (WP-A-41, Schedule 4, page 4 of 4).

Q. What are you recommending with respect to the Company's Property Taxes?

A. I am recommending the use of the Company's updated Property Tax as shown on WP-A-41, Schedule 1, page 4 of 4). I would like to note that in the Company's Exhibit AEH-1, Schedule 6, page 3 of 3, the Company has shown total Property Taxes in the amount of $8,114,000 a difference of $5,000. This is the amount that I am recommending. My recommendation is shown on Schedule DM-24.

2. <u>Deferred Income Tax and ITC</u>

Q. What has the Company proposed with respect to its Deferred Income Tax and Investment Tax Credit (ITC) in this rate proceeding?

A. The Company began with an unadjusted beginning balance in its Deferred Income Tax and ITC balance in the amount of $10,212, 000 as shown on Exhibit AEH-1, Schedule 6, page 1 of 3, Column 2, line 18. The Company updated this amount to $12,676,000 as shown on AEH-1, Schedule 6, page 3 of 3, Proposed Test Year 2013, Column, line 18. The Company's proposed Deferred Income Taxes and ITC balance for the Projected 2013 Test Year was therefore calculated at $10,212,000 plus $2,548,000 for a total of $12,760,000, which is also shown on Exhibit AEH-1, Schedule 6, page 3 of 3, Proposed Test Year Column, line 18).

Q. What is your recommendation with respect to the Company are Deferred Income Tax and its ITC balance?

A. I've reviewed The Company's updated workpapers as shown on NDSPC-5-026, supplemental and the updated Cost of Service documents. (Jurisdictional Input Panel

Tab). I have made an adjustment to the Company's Net Operating Loss as well. I will discuss this later on in my testimony. My recommendation is shown on Schedule DM-25.

3. Federal and State Income Taxes

Q. What has the Company proposed with respect to the calculation of its Federal and State Income Taxes?

A. The Company has calculated total proposed Federal Income Taxes in the amount of ($5,610,000) (Exhibit AEH-1, Schedule 8 page 4 of 6, line 36, and total State Income Taxes in the amount of ($870,000) line 31, for a total amount of ($6,481,000).

Q. What is your recommendation with respect to the Company's calculation of its Federal and State Income Taxes?

A. I used the same format as the Company to calculate my recommended Federal and State Income Taxes along with my recommended adjustments for the various components of my recommended revenue requirement. As shown on my Schedule DM-26, I am recommending total Federal Income Taxes in the amount of $2,046,000 and total State Income Taxes in the amount of ($286,000), for a total Income Tax amount of $1,760,000.

4. Payroll and Other Taxes

Q. What has the Company proposed with respect to its Payroll Taxes?

A. The Company has proposed Payroll Taxes in the amount of $1,931,000 as shown on Exhibit AEH-1, Schedule 6, page 3 of 3, Proposed Test Year 2013 Column, line 20, Updated.

Q. Do you have any changes to the Company's proposed Payroll Tax amount?

A. Yes. As I have removed all incentive compensation related to the Company's Labor as I previously testified to, I also reviewed Company data request NDPSC 5-045, Attachment A, page 1 of 1, which shows total labor costs. I also need to adjust the payroll related expenses for same. The following accounts under the Labor Category contained in NDPSC-5-045 are incentive related pay:

Fuel Handling- Incentive Labor Loading	$ 844
Fuel Procurement – Incentive Labor Loading	$ 3,456
Incentive Labor Loading	$ 483,076
Incentive	$ 887,381
Total	$1,374,757

Q. What are your changes with respect to the Incentive Pay and the calculation of your recommended Payroll Taxes?

A. As shown on my Schedule DM-27, the removal of the Incentive Pay reduces the Company's regular payroll from the proposed amount of $23,893,000 as shown on Exhibit AEH-1, Schedule 8, Updated, Page 6 of 8, line 9, North Dakota Retail Electric Column, to the amount of $22,518,000. (a reduction of $1,374,000).
This change reduces the payroll expense to $1,819,000 as shown on my Schedule DM-27.

F. <u>Interest Synchronization</u>

Q. What is the Company proposing with respect to its Debt Interest Expense?

A. As shown on Exhibit AEH-1, Schedule 8, page 4 of 6, line 18, the Company has calculated Debt Interest Expense in the amount of $8,799,000. The Company computed its Debt Interest Expense by applying its proposed Rate Base in the amount of $377,648,000 multiplied by its proposed weighed cost of debt of 2.3% (Exhibit AEH-1, Schedule 8, page 5 of 6, line 10).

Q. What are you proposing with respect to the calculation of Debt Interest Expense?

A. I am recommending the use of Debt Interest Synchronization with my recommended Rate Base in the amount of $369,475,000 and Charlie King's recommended cost of debt in the amount of 2.33%.

My recommended Debt Interest Calculation is computed at $7,500,000, as shown on my Schedule DM-28.

G. <u>Other Ratemaking Adjustments</u>

1. <u>Net Operating Loss</u>

Q. Please describe the Company position with respect to its Net Operating Loss Adjustment.

A. The Company claimed that it has experienced income tax losses as a result of the combinations of its extensive investments and the effect of bonus federal income tax depreciation. The Company stated that bonus federal income tax depreciation is the result of provisions in federal tax laws that allow the Company to deduct either 50% or

100% or qualifying capital investments in the first year the qualifying investment is placed in service. The Company stated that the Tax Relief Act of 2010, which became law in December 2010, provided 100% bonus tax depreciation for certain projects placed in service from September 9, 2010 through December 31, 2011. The Company claimed that as a result, the entire amount of the investment in qualified projects that were placed in service by the Company during that period was permitted as a tax deduction in the first year the project is placed in service.

Q. What effect did the Tax Relief Act of 2010 have on the Company's operations?

A. The Company claims that two significant impacts occurred. The first impact was that the bonus tax depreciation generated larger amounts of deferred income taxes. The second impact was that the increased tax depreciation expense effectively resulted in more deductions than the Company can utilize in the current income tax periods. These two impacts resulted in the generation of net operating losses (NOLs) for the calendar periods 2010 and 2011. The Company stated that these NOLs represented the value of tax deductions that need to be carried forward to a future period because these NOLs could not be used as deductions in current income tax periods or applied to prior periods to obtain refunds. Therefore, the Company claimed that these excess deductions and unused tax credits have been deferred and are being tracked for use in future periods.

Q. How do these NOLs affect the Company's Rate Base?

The Company stated that the NOLs require an adjustment that offsets the part of the Accumulated Deferred Income Tax (ADIT) rate base deduction associated with the accelerated and bonus depreciation deductions that have exceeded the Company's taxable income and have not resulted in deferral or income taxes.

Q. Why do these NOL's require adjustments with respect to the Company's Rate Base?

A. The Company claims that these NOL's require an adjustment in order to be consistent with the income tax deductions that the Company has been able to use. The Company stated that by keeping a balance of rate base reductions resulting from the ADIT and the use of accelerated and bonus depreciation deductions is a requirement under federal income tax laws as are of normalization for both accounting and ratemaking purposes.

Q. Did the Company prepare a schedule that reflects these deferred and unused excess deductions?

A. Yes, the Company prepared a schedule of these deferred and unused excess deductions for 2011 through 2013. The calculations are shown on Company Exhibit AEH-1, Schedule 21.

Q. Please explain the Company's adjustment and how it affects the revenue requirement proposed in this current rate application.

A. The Company has proposed to include $2,735,000 in Net Operating Losses to account for its timing differences in booked plant depreciation and taxable plant depreciation (Exhibit AEH-1, Schedule 6, Updated, page 3 of 3, column 42.

Q. What is your recommendation with respect to the Company's proposed NOL in the amount of $2,735,000?

A. I have taken the Company's proposed Rate Base in the amount of $375,678,000 and the Company's proposed NOL of $2,735,000 and computed a percentage to total in the amount of .728% ($2,735,000/$375,678,000). I then used my recommended Rate Base amount of $322,514,000 and multiplied it by .728% to arrive at $2,347,000. By using a lower Rate Base and plant addition balance, the NOL becomes lower. My recommendation is shown on Schedule DM-25.

Q. With respect to the NOLs proposed by the Company, were any additional revenues associated with this rate application computed to determine the impact of the NOLs on test year revenues?

A. Yes. The Company has included the additional revenues it is requesting in this rate application when computing the NOL adjustment. The Company also stated that any change in the rate increase which will be granted by the NDPSC will create a change to taxable income and thus, will require a change to the calculation of the NOL adjustment.

Q. What will be required by the Company in order to finalize the NOL adjustment at the conclusion of this rate application?

A. The Company claimed that it will have to recalculate the NOL in order to determine the level of deductions the Company can use in the current period to reduce taxable income to zero, which will then result in a balance of unused deductions that is to be carried forward to a future period. The Company also claimed that the recalculation at the end of the rate case application will be affected by current tax depreciation deductions, annual deferred tax expense and the ADIT balance.

VII. Interim Rate Order

Q. Has the Company requested and received Interim Rate Relief in this current Case No. PU-12-813?

A. The Company requested and received interim rate relief in the amount of $14,704,000 or 8.05% dated January 30, 2013 and effective for service on February 16, 2013.

Q. How much revenue did the Company bill and collect from its customers?

A. In Data Request NDPSC-5-65, the Company has calculated for the months of February and March 2013, total Rate Revenues in the amount of $1,751,175.

Q. Has the Company updated its Collection of Interim Rate Revenues?

A. No. Not as of the date of my testimony. I would recommend that the Company update its Collection of Interim Rate Revenues as soon as practicable for the months of April, May, and June, 2013. As noted in Data Request NDPSC-5-65, a request was made to continue to provide monthly incremental sales revenues collected from customers throughout this proceeding.

Further, since the Company has remove depreciation expense regarding the Sherco 3 update (NDPSC-5-026), and the related Expenses associated with Sherco 3, the Company should not be afforded to recover these costs in its Interim Rate Relief. The Company should be required to update its Interim Rate Relief to exclude any costs associated with the Sherco 3 plant since it is not in service.

Q. Given the fact that your recommended revenue requirement increase is less than what the Company has been allowed to recover ($14,704,000), what is your recommendation with respect to the refunded the North Dakota customers the excess of the revenues collected?

A. Under the North Dakota Century Code §49-05-06(4), in the event the interim rate amounts collected by the Company are in excess of the final rates approved by the Commission, the Company is required to refund the excess, included interest at a rate to be determined by the Commission.

Q. Does this complete your testimony?

A. Yes it does.