EXHIBIT 5

Direct Testimony and Schedules
Anne E. Heuer

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation
For Authority to Increase Rates for Electric Service in North Dakota

Docket No. PU-10-____
Exhibit___(AEH-1)

2012 Step-In Adjustment

December 20, 2010

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Anne E. Heuer. I am the Manager of Revenue Analysis for Xcel Energy Services Inc. ("XES" or the "Service Company"). My qualifications and experience are summarized in the resume provided with my testimony as Exhibit___(AEH-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") operating in North Dakota regarding the Company's request for a 2012 step-in adjustment as described by Company witness Ms. Laura McCarten in her Direct Testimony. I present and support the Company's request for a step-in adjustment to recover the full-year effect of specific rate-base additions in 2011, as well as specific known and measureable 2012 wind related transmission payments and nuclear outage amortization costs that are critical to the successful operation of our electric utility business. First, I will explain the Company's request for a step-in adjustment to address a portion of the Company's 2012 revenue deficiency, and how the step-in adjustment would help address the challenges facing the Company as it moves out of the 2011 test year and directly into a year where another significant deficiency is expected. Second, I will describe the step-in adjustment the Company is seeking. Third, I will introduce the Company's 2012 Cost of Service Study ("COSS") as a tool by which parties can further evaluate the reasonableness of the step-in adjustment the Company is requesting. Finally, I respond to a Commission inquiry concerning the possibility of moving from base rate recovery of Company-owned wind-project costs to recovery via a rider mechanism. Ms. Laura McCarten provides a discussion of the reasons for the cost increases included in the 2012 Step and the Commission's authority to set rates that reflect these cost increases.

Q. HOW HAVE YOU ORGANIZED YOUR DIRECT TESTIMONY?

A. My testimony is presented in the sections outlined below:

- Request for Step-in Adjustment
- Components of Step-in Adjustment
- 2012 Jurisdictional Cost of Service Study
- Rider Recovery for Wind-Project Costs
- Conclusion

II. REQUEST FOR STEP-IN ADJUSTMENT

Q. PLEASE EXPLAIN THE COMPANY'S REQUEST.

A. As introduced in Ms. McCarten's Policy testimony, the Company requests permission to implement a 2012 step-in adjustment in final rates as a means of providing the Company a reasonable opportunity to earn a rate of return that is closer to the authorized rate of return approved by the North Dakota Public Service Commission ("Commission") in this proceeding. Without the step-in adjustment, the final rates placed into effect in 2012 (after the end of the 2011 test year) will result in an under-recovery of the Company's 2012 costs of providing service to customers in North Dakota. In fact, as the step-in adjustment request is only for a portion of the Company's forecasted 2012 revenue deficiency; the Company still expects to earn less than its authorized return, but the shortfall will be eased by inclusion of the step-in adjustment. Our specific step-in adjustment request is proposed to include, in 2012 rates, the revenue requirements of four specific items that are known and measurable. These items are necessary in order to maintain the Company's ability to provide safe and reliable electric service to its customers in North Dakota.

Q. HOW WOULD THE STEP-IN ADJUSTMENT WORK?

A. The step-in adjustment increase proposed for 2012 would consist of a set of four specific cost components that are contributing to the Company's forecasted revenue deficiency in 2012. The 2012 revenue requirement associated with these specific costs would be combined with the cost of service approved by the Commission for the 2011 test year in determining rates to be in effect for 2012. If adjustments are made to the 2011 Cost of Service that have a carry-over effect on the specific items included in the step-in adjustment (such as cost of capital), the step-in adjustment request would be adjusted to reflect such carry-over effect.

Q. WHEN WOULD THE STEP-IN ADJUSTMENT BECOME EFFECTIVE?

A. The Company requests the step-in adjustment be effective January 1, 2012. We will make a specific proposal regarding how to roll the step-in adjustment into rates once the revenue requirement is determined in the Commission's final Order. Company witness Mr. Steven V. Huso generally describes how the 2012 step-in adjustment would be recovered through final rates in his Direct Testimony.

Q. HOW MUCH IS THE COMPANY REQUESTING AS A STEP-IN ADJUSTMENT IN 2012?

A. The Company is requesting a $4.226 million revenue increase in 2012 above the 2011 test-year deficiency of $19.773 million based on the revenue requirements for the four specific components discussed below.

Q. WHAT IS THE PERCENTAGE INCREASE IN BASE RATES THAT THE COMPANY IS REQUESTING?

A. The total combined percent increase in retail revenues for 2011 and 2012 ($19.773 million + $4.226 million) is 14.59 percent. A COSS has been provided for both the 2011 test year and the step-in adjustment request. Company witness Mr. John M. Felling discusses the Cost of Service Studies in more detail in his Direct Testimony. *See* Exhibit___(JMF-1), Schedule 8a and 8b, respectively.

Q. WHAT IS THE COMPANY'S PROJECTED RETURN ON EQUITY WITH THE 2012 STEP-IN ADJUSTMENT?

A. The 2012 return on equity with the step-in adjustment is projected to be 10.90 percent, roughly 35 basis points below the 11.25 percent return on equity requested by the Company in this proceeding. This assumes, for simplicity, that 100 percent of the proposed $19.773 million revenue deficiency in 2011 is recovered along with the Company's request for the $4.226 million step-in adjustment in 2012. The Company's projected earned return on equity would be less than the return authorized by the Commission, but the Company would earn closer to its authorized return. Absent the step-in adjustment, the Company projects an earned return of 9.51 percent in the first year final rates are in effect, as shown in the 2012 COSS, as shown in Exhibit___(AEH-1), Schedule 7. The Company proposes that the cost of capital approved for the 2011 deficiency be applied to the 2012 step adjustment.

Considering the basis point difference is helpful in understanding the magnitude of the Company's concern. Without the proposed step-in adjustment, the Company's projected 2012 return on equity would be roughly 174 basis points below the authorized level in the year in which the final rates are first placed into effect. Because the step-in adjustment is primarily associated with capital items, any change to the cost of capital would likewise change the amount of the step-in adjustment, such that the relative basis point deficiencies would be fairly similar regardless of one's view on the appropriate cost of capital. This information underscores the need for a step-in adjustment as outlined by Ms. McCarten. It also shows that the Company is not likely to over-earn.

III. COMPONENTS OF STEP-IN ADJUSTMENT

Q. WHAT ARE THE SPECIFIC COMPONENTS OF THE STEP-IN ADJUSTMENT?

A. The step increase consists of four projects with three capital components and two operation and maintenance ("O&M") expense components. The capital components are: the Company-owned Merricourt Wind project ("Merricourt"), the Monticello Life Cycle Management and Extended Power Uprate ("Monticello LCM/EPU") project, and Transmission Plant. The O&M expense components are Nuclear Outage Amortization expense, which is driven in large part by outages occurring in 2010 and 2011, and Midwest ISO Tariff payments to Montana Dakota Utilities ("MDU") for transmission network upgrades necessary to connect the Merricourt project to the transmission system. Finally we include an associated impact on Cash Working Capital, which slightly decreases the total proposed step-in adjustment. The corresponding revenue requirement for each component is displayed in Table 1 below, and I will describe each component in my testimony. Furthermore, Schedules 2 through 5 to this testimony provide calculations of the revenue requirements for each component of the step-in adjustment.

Table 1

Revenue Requirements for Step-In Components

Component	2012 Revenue Requirement
Monticello LCM/EPU	$1.531M
Transmission Plant	$0.515M
Merricourt (Including MDU Transmission Payments)	$1.855M
Nuclear Outage Amortization	$0.339M
Subtotal	$4.240M
Change in Cash Working Capital	-$0.040M
Change in Cost of Capital	$0.028M
Rounding	-$0.002M
TOTAL	**$4.226M**

Q. CAN YOU DESCRIBE THE COMPANY'S CRITERIA FOR SELECTING THESE SPECIFIC ADJUSTMENTS?

A. Yes. First, we focused on capital costs associated with our core operational portions of the business: nuclear and transmission, which have the most direct benefit to ratepayers. Second, as Merricourt is scheduled to go into service at the end of 2011, the Company will incur a full year of costs in 2012. The project is needed as an essential step in meeting North Dakota's Renewable Energy Objective and the renewable energy policies established by the other jurisdictions we serve. Lastly, we attempted to tie the specific proposal to costs that would already be reviewed in the 2011 test year, thus eliminating the need for a full initial review of the 2012 cost of service.

A. Step-In Adjustment Capital and Expense Components

Q. PLEASE DESCRIBE THE MONTICELLO LCM/EPU COMPONENT IN MORE DETAIL.

A. As discussed in more detail in Company witness Mr. Dennis L. Koehl's Direct Testimony, the Monticello LCM/EPU project will increase the power output at Monticello by 71 megawatts ("MW") and also address necessary investments needed to keep the plant operating safely and reliably into its extended license life. The Monticello project received its Certificate of Need for license extension in 2007 and a Certificate of Need for the Extended Power Uprate in 2009. This is by far the largest of the projects and a significant driver of the 2012 step-in adjustment. Our total plant addition for the LCM/EPU modifications will be roughly $360 million. Approximately $75 million was placed into service prior to 2011 and is not part of the step-in adjustment. All but a small portion of the remaining $285 million will be placed into service by December 2011 (about $650,000 is scheduled to be in service in the first few months of 2012).

The result is a 2011 test year that reflects only a small portion of the annual depreciation expense and only slightly more than half of the total rate base. The 2012 step-in adjustment reflects a full year's worth of depreciation, property taxes and return on 2012 average rate base related to the project, thereby allowing the Company an opportunity to recover the investment and a fair return in 2012 rates. Exhibit___(AEH-1), Schedule 2 provides a calculation of the corresponding revenue requirement of $1.531 million.

Q. PLEASE DESCRIBE THE TRANSMISSION PLANT COMPONENT IN MORE DETAIL.

A. As described in Company witness Mr. Ian R. Benson's Direct Testimony, new transmission projects generally fall under three categories: system performance, which is primarily related to keeping the system operating reliably; interconnection, which is primarily related to new network transmission facilities that are necessary to connect a new generator or substation to the grid; and transmission serving generation. As Mr. Benson discusses, the Company expects to place approximately $183.5 million of transmission investments into service over the course of 2011, with $139.2 million of transmission capital being placed in to service in 2012, resulting in further increases to transmission plant-in-service.

The Company is seeking an adjustment of $515,000 to account for the full year's depreciation expense, property taxes and return component on 2011 investments that will be recognized in 2012 when final rates are placed into effect. Please refer to Exhibit___(AEH-1), Schedule 3 for the detailed revenue requirements calculation.

Q. PLEASE DESCRIBE THE MERRICOURT WIND PROJECT COMPONENT IN MORE DETAIL.

A. The Merricourt Wind Project is a 150 MW wind energy generation facility consisting of 100 GE 1.5 MW SLE wind turbines located within a project site encompassing approximately 9,600 acres in McIntosh and Dickey Counties, North Dakota. The Commission approved the wind project as a reasonable and prudent electric resource addition to NSP's system and granted a Certificate of Public Convenience and Necessity to construct and operate the 150 MW project via an Order issued on August 12, 2009 (Case Nos. PU-08-

908 and PU-08-910). enXco Development Corporation is constructing Merricourt pursuant to an Engineering, Procurement and Contracting ("EPC") agreement. Construction on the project is planned to start Spring of 2011 towards a projected in-service date of November 2011. Company witness Ms. Pamela K. Graika discusses in her Direct Testimony the benefits of the project to Xcel Energy's resource mix diversification and how it helps provide a hedge against fuel price volatility.

In addition to our capital investment in the Merricourt project, our 2012 step-in adjustment for this project includes an annualization of our payment to MDU for required network upgrades made under the terms of the Midwest ISO ("MISO") tariff. Please see Mr. Benson's Direct Testimony for a detailed description of the upgrade project.

The Company is seeking an adjustment of $1.855 million for Merricourt costs that will be incurred and recognized in 2012 when final rates are placed into effect. Of this amount, $1.639 million is related to our capital investment in this project (including depreciation, property taxes and return on rate base) and $216,000 represents our annualized payment to MDU for transmission network upgrades. Please refer to Exhibit___(AEH-1), Schedule 4 for the detailed revenue requirements calculation.

Q. PLEASE DESCRIBE THE NUCLEAR AMORTIZATION EXPENSE COMPONENT IN MORE DETAIL.

A. The nuclear amortization cost reflects the actual outage costs that have been (or will be) deferred and subsequently amortized over the useful life of the outages. As shown in Table 2 below, the amortized outage costs in 2012 are driven in large part by costs that are being incurred by the Company in 2010 and 2011 as well as an outage that will begin shortly after the test year ends, in February of 2012.

Table 2

Nuclear Amortized Outage Costs (NSPM Company Electric)

Unit/Year	PI U2 2010 Actual	Monti 2011 Budget	PI U1 2011 Budget	PI U2 2012 Budget	PI U1 2012 Budget	Total
Total Outage Cost	$ 36.3M	$ 41.6M	$ 26.7M	$39.5M	$41.2M	
Portion included in 2012 Amortization Expense	$ 3.3M	$ 20.8M	$ 15.7M	$20.1M	$4.6M	$64.5M

Including amortization expenses, the Company's overall nuclear O&M budget is projected to increase by 6.1 percent from 2011 to 2012, resulting in an additional $17.8 million in costs for 2012. The step-in adjustment for the nuclear amortization component only seeks to recover the increased costs directly related to the nuclear plant outages.

This adjustment relies on 2012 budget data. The timing of our nuclear outages are well known, as they are driven by the rate of fuel burn and the need to take refueling outages to maintain operations of the plant at safe and efficient levels. Similarly, the cost of an outage is well known, because the scope of an outage is driven by regulatory requirements or known capital additions. If anything, our experience is that we underestimate the cost of our outages, because we do not attempt to budget a contingency for emergent work that may arise during the course of an outage. Our outage plan is developed many years in advance, and significant requirements of the outages and their scope are thus well known in advance. These increases are driven by the total number of outages and the increased scope of work during the outages needed to address safety and regulatory requirements. The incremental revenue requirement driven by the increased nuclear outage amortization cost and associated rate-base component is $339,000 in 2012, as shown in Exhibit___(AEH-1), Schedule 5. Please refer to Mr. Koehl's Direct Testimony for details on the nuclear outage costs and scope of work.

B. Calculation of the Plant-Related Step-in Adjustment Revenue Requirements

Q. PLEASE EXPLAIN HOW THE PROPOSED PLANT-RELATED STEP-IN COMPONENTS WERE CALCULATED.

A. The revenue requirements for the Monticello LCM/EPU and Merricourt step-in adjustments and the transmission plant step-in adjustment were calculated using two different methods. For the Monticello LCM/EPU and Merricourt components, the revenue requirements were calculated in a manner similar to the calculations used for the Company's rate case test year. In other words, the return on rate base was calculated using the 2012 average of beginning of year ("BOY") and end of year ("EOY") net utility plant in service multiplied by the 2011 rate of return. Total depreciation expense was calculated using the monthly book depreciation schedule for 2012. Tax effects (income, deferred, and property) were also considered in addition to the AFUDC offset and avoided tax interest.

For the Transmission Plant component, the revenue requirements were calculated using the 2011 Year End net rate base to establish the return component, a full year of depreciation based on the 2011 composite depreciation rate applied to the 2011 Year End plant balance, and the recognition of property taxes related to the increased property value.

The revenue requirements shown in Exhibit___(AEH-1), Schedules 2 through 5 are calculated using the 2008 capital structure. I used the 2008 capital structure so that any change in the overall cost of capital would not also cause a corresponding revenue requirement change for each item included in the step-in. An adjustment to reconcile the capital structure differences was made in the 2012 Step Adjustment COSS (Exhibit___(JMF-1), Schedule 8b), and shown in Table 1. The 2012 revenue requirement for the change in cost of capital is $28,000 and is also shown on the Test Year Income Statement Adjustment Schedule (Exhibit___(JMF-1), Schedule 5b, Column 43). This methodology is consistent with the methodology used to develop the 2011 Cost of Service.

Q. WHY WERE THE REVENUE REQUIREMENTS FOR THE CAPITAL PROJECTS CALCULATED DIFFERENTLY?

A. There are two related reasons for the different methodologies. First, the depreciation timelines for the Monticello LCM/EPU and Merricourt projects are much shorter than the depreciation timelines for transmission capital investments. The depreciation lives of the Monticello EPU and Merricourt projects are 20 years and 25 years respectively. By contrast, the average depreciation life for transmission projects is approximately 40 years. Therefore, the depreciation effect on the net plant balance of the Monticello and Merricourt projects will be much more significant in 2012, and it is necessary to use an average 2012 net plant-in-service balance to recognize that effect.

Second, the Monticello LCM/EPU and Merricourt projects are large projects that will begin depreciating in late 2011 with minimal additional investments (for the specific project) after 2011. Because the projects will mostly be placed in service in late 2011 (December and November, respectively), the 2011 test-year result captures only a very small portion of this projects' ongoing annual depreciation expense. The step-in adjustments are necessary to capture this ongoing annual expense. On the other hand, the Transmission Plant component represents the total transmission plant-in-service at EOY 2011. This amount will continue to grow in 2012 and beyond as the Company maintains its high level of investment in Transmission Plant. Using 2011 year-end figures results in a lower rate base than using 2012 average transmission net rate base, and it provides the Commission and Parties with assurance that customers will only be paying rates in 2012 for transmission investments that are used and useful for all of 2012.

According to our current 2011 and 2012 capital budgets and the resulting 2012 Cost of Service, the 2012 average net rate base for Transmission will be $56 million, while the comparable 2011 year-end rate base is $54 million, as shown in Exhibit___(AEH-1), Schedule 6. The step-in adjustment request is for less than the total revenue requirements associated with the additional rate base resulting from Transmission plant additions in 2012. This gives assurance that the approach taken to calculate the 2012 step-in adjustment request will not result in the Company collecting more than its actual costs of expected 2012 Transmission in the rates developed through the step-in adjustment.

Q. IS THERE ANOTHER BENEFIT TO USING THE 2011 END-OF-YEAR PLANT BALANCE FOR THE TRANSMISSION CALCULATION?

A. Yes. By using the 2011 EOY balance, we are dealing with items that are known at the end of the test year and can be measured for their 2012 effect by examining the 2011 test-year information. The same reasoning applies to the use of a 2011 composite depreciation rate used to annualize depreciation expense.

Q. PLEASE EXPLAIN THE ASSOCIATED DECREASE IN REVENUE REQUIREMENTS FOR CASH WORKING CAPITAL.

A. The adjustments made for these components impact a variety of expense items that are considered in the Company's cash working capital determination. The primary driver related to the capital adjustments pertains to the property tax changes. In this calculation, these expenses are accrued on average roughly one year in advance of cash payment to the taxing authorities. The result of the Company having use of these funds is a rate-base deduction causing a decrease in 2012 revenue requirements of $40,000. Please refer to Mr. Felling's Direct Testimony for a general discussion regarding cash working capital, to Exhibit___(JMF-1), Schedule 8b, page 6 for the detailed cash working capital calculation and to Exhibit___(JMF-1), Schedule 5b, Column 44) for the revenue requirement calculation.

IV. 2012 JURISDICTIONAL COST OF SERVICE STUDY

Q. WHY IS THE COMPANY PROVIDING A 2012 JURISDICTIONAL COST OF SERVICE STUDY?

A. The 2012 COSS is being provided with my testimony for informational purposes. Its primary purpose is to assure the Commission that our step-in adjustment is not capturing costs that are increasing without also acknowledging items that may be decreasing the cost of service. For example, the 2012 COS deficiency occurs despite an increase in revenues from sales growth forecast for that period. The Company is not requesting that rates be established based on the overall 2012 COSS; our approach with the step-in adjustment is to avoid the need for Parties to perform an in-depth analysis of the 2012 test year COSS. The 2012 COSS data is included to provide assurance to the Commission and stakeholders that the Company will not earn above its authorized return in 2012 if granted the proposed step-in adjustment. Parties will need to determine how relevant this information is to their analysis of the step-in adjustment, but the Company is providing the 2012 COSS to be more transparent about our anticipated 2012 costs and thus the reasonableness of our approach.

Q. HOW WAS THE 2012 COMPANY BUDGET DEVELOPED?

A. The 2012 Company budget was developed in a very similar fashion as the 2011 budget discussed in Mr. Felling's testimony. The budget is assembled separately by its various components, including Sales Forecast (customers and consumption), Retail and Other Revenues, Cost of Production, Operating and Maintenance ("O&M") Expenses, Capital Invested, Other Rate-Base Investment and Capital Structure Components. The component budgets are based on documented assumptions concerning anticipated cost and business trends and follow corporate budget guidance. The various budgets are submitted to the Xcel Energy Finance Council for review.

In preparing for this rate case, the traditional regulatory adjustments were made to derive the 2012 COSS from the Company's 2012 budget. Please refer to Mr. Felling's Direct Testimony for a more complete description of the budgeting and test year development process.

Q. DOES THE SECOND YEAR BUDGET (2012) PROVIDE A REASONABLE REPRESENTATION OF THE COMPANY'S 2012 REVENUE REQUIREMENTS?

A. Yes, I believe the 2012 budget provides a reasonable representation of the Company's revenue requirements when final rates in this case will be placed into effect. While we acknowledge that the precision of the budgeting process decreases with each additional out year, the Company requires budget documentation for both the first and second year budgets during the annual budgeting process. The budgeting process provides the Company with a well-documented forecast in 2012 that provides a reasonable basis for calculating the 2012 revenue requirements.

Q. WHAT IS THE AMOUNT OF THE 2012 JURISDICTIONAL REVENUE REQUIREMENT FOR NORTH DAKOTA?

A. The 2012 jurisdictional retail revenue requirement for North Dakota electric utility operations is $191 million, based on average rate base and projected net operating income for the 2012 test year, the average capital structure, short-term debt, long-term debt and 11.25 percent cost of equity, based on the return on equity ("ROE") recommended for the 2011 test year. The 2012 COSS is attached to my testimony as Exhibit___(AEH-1), Schedule 7, pages 1 through 6.

Q. WHAT IS THE AMOUNT OF THE COMPANY'S FORECAST 2012 REVENUE DEFICIENCY?

A. The 2012 COSS shows a 2012 revenue deficiency of $5.268 million. This revenue deficiency assumes 100 percent recovery of the $19.773 million 2011 deficiency supported in Mr. Felling's Direct Testimony.

V. RIDER RECOVERY FOR WIND-PROJECT COSTS

Q. DOES THE COMPANY PROPOSE RECOVERING THE COST OF COMPANY-OWNED WIND PROJECTS IN BASE RATES?

A. Yes. The 2011 test year and 2012 step-in adjustments includes the Grand Meadow, Nobles and Merricourt Company-owned wind projects as a component of base rates.

Q. THE COMMISSION HAS EXPRESSED INTEREST IN THE COMPANY USING A RIDER MECHANISM TO RECOVER WIND-PROJECT COSTS FOR 2011 AND BEYOND. PLEASE DISCUSS THE COMPANY'S RESPONSE.

A. Company representatives discussed this matter with Commission staff on November 22, 2010, and staff noted their preference for recovering Company-owned wind projects through a rider mechanism. Due to the timing of our meeting with the Commission staff, it was not possible to incorporate rider cost recovery into our overall rate recovery proposal. However, the Company is open to exploring rate recovery alternatives with the Commission during the course of this proceeding, including using a special rate rider to recover wind project costs.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. The Company's proposal for a 2012 step-in adjustment is necessary to address a significant Company revenue requirement deficiency in 2012 that would not be adequately addressed if final rates in this case are based only on the 2011 test-year cost of service. The development of the proposed 2012 step-in adjustment is consistent with cost-based ratemaking that has been the historic cornerstone of all past and current recovery mechanisms. Finally, the 2012 COSS is an informational reference tool useful in understanding the impact of the proposed step-in adjustments as compared to the Company's complete financial picture for 2012.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-10-___

AFFIDAVIT OF
Anne E. Heuer

I, the undersigned, being duly sworn, depose and say that the foregoing is the Direct Testimony of the undersigned, and that such Direct Testimony and the exhibits or schedules sponsored by me to the best of my knowledge, information and belief, are true, correct, accurate and complete, and I hereby adopt said testimony as if given by me in formal hearing, under oath.

Anne E. Heuer

Anne E. Heuer

Subscribed and sworn to before me, this 15th day of December, 2010.

Notary Public

CYNTHIA D. HARRINGTON
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2015

Manager
Revenue Analysis

Xcel Energy Services, Inc.
414 Nicollet Mall
Minneapolis, Minnesota 55401

Current Responsibilities

Since January 2007, I have been the manager of Revenue Analysis. In this position, I am responsible for the general administration of the Revenue Analysis area and for the preparation and presentation of cost of service studies, revenue requirement determinations and jurisdictional annual reports for the electric and gas rates filed on behalf of Northern States Power Company, a Minnesota corporation, with the Minnesota Public Utilities Commission, the North Dakota Public Service Commission, the South Dakota Public Utilities Commission and the Federal Energy Regulatory Commission.

Previous Employment (1975 to 2007)

Rate Consultant – Xcel Energy Services Inc.
Manager, Regulatory Development - NSP
Principal Rate Analyst – NSP
Senior Electric Financial Analyst – Electric Finance – NSP
Senior Budget Analyst – Financial Accounting - NSP
Senior Systems Cost Analyst – Information Services - NSP

Education

Augsburg College, Minneapolis, Minnesota
Bachelor of Arts – Business Administration - Finance
December 1985

Prior Testimony

Minnesota – Overall Revenue Requirements, Rate Base, Income Statement, Docket No. E002/GR-10-971, 2010
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement, Docket No. G002/GR-09-1153, 2009
South Dakota - Overall Revenue Requirements, Rate Base, Income Statement, Docket No. EL09-009, 2009
Minnesota – Overall Revenue Requirements, Rate Base, Income Statement, Docket No. E002/GR-08-1065, 2008
North Dakota - Overall Revenue Requirements, Rate Base, Income Statement, Case No. PU 07-776, 2007

2012 Step-in Adjustment
Revenue Requirement Calculation
Nuclear Production - Monticello EPU & LCM
($000s)

Rate Analysis	2012 Total Company	2012 ND Jurisdiction	2011 Total Company	2011 ND Jurisdiction	Net Change Total Company	Net Change ND Jurisdiction
Plant Investment	285,738	13,926	142,707	6,955	143,031	6,971
Depreciation Reserve	(69,101)	(3,368)	(51,377)	(2,504)	(17,724)	(864)
CWIP	-	-	-	-	-	-
Accumulated Deferred Taxes	42,913	2,091	27,784	1,354	15,129	737
	311,926	15,203	166,300	8,105	145,626	7,098
Average Rate Base	311,926	15,203	166,300	8,105	145,626	7,098
Debt Return	10,075	491	5,371	262	4,704	229
Equity Return	17,374	847	9,263	451	8,111	395
Current Income Tax Requirement	9,325	454	(14,776)	(719)	24,101	1,174
Book Depreciation	19,460	948	5,019	245	14,441	704
Annual Deferred Tax	3,529	172	26,729	1,303	(23,200)	(1,131)
ITC Flow Thru	-	-	-	-	-	-
Tax Depreciation & Removal Expense	25,919	1,263	73,197	3,567	(47,278)	(2,304)
AFUDC Expenditure	-	-	-	-	-	-
Avoided Tax Interest	1	-	9,297	453	(9,296)	(453)
Property Taxes	3,254	159	-	-	3,254	159
Total Revenue Requirements	**63,018**	**3,071**	**31,606**	**1,542**	**31,411**	**1,531**

2008 Rate Case Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	**6.7600%**	**45.6100%**	**3.0800%**
Short Term Debt	**5.7400%**	**2.6200%**	**0.1500%**
Preferred Stock	**0.0000%**	**0.0000%**	**0.0000%**
Common Equity	**10.7500%**	**51.7700%**	**5.5700%**
Required Rate of Return			**8.8000%**
Tax Rate (ND)	**39.2300%**		

Allocators	
Demand Prod ND Jur %	**5.8107%**
Demand MN Co % (1)	**83.8756%**
Composite Demand	**4.8738%**

2012 Step-In Adjustment
Revenue Requirement Calculation
Electric Transmission
($000s)

Adjustment Summary

Rate Base	**2011 Ending Bal**	**2011 Average Bal**	**Net Change**
Plant In Service	97,431	93,223	4,208
Depreciation Reserve	30,128	29,259	869
ADIT Basic	13,033	12,356	677
Net Rate Base =	54,270	51,608	2,662
		Debt Return =	86
		Equity Return =	148
		Tax on Equity Return (2) =	96
		Total Rate Base Revenue Requirement =	**330**

Book Depreciation	**2011 Book Depr. Calc. Based on Ending Balance**	**2011 Book Depreciation**	**Net Change**
2011 Year End Plant =	97,431		
Comp Depr Rate (1) =	2.05%		
Adjusted Deprec =	1,999	1,913	86
		Total Book Depreciation Adjustment =	**86**

Property Tax	**2011 Ending Bal**	**2011 Beginning Bal**	**Net Change**
Plant Balances =	97,431	89,014	8,417
		Property Tax Rate (3) =	1.18%
		Total Property Tax Adjustment =	**99**
		Revenue Requirement Total =	**515**

(1) Composite Book Depr Rate	**2.05%**
2011 Average Plant in Service	93,223
2011 Book Depreciation	1,913
(2) Composite Tax Rate	**39.23%**
(3) Composite Property Tax Rate	**1.18%**

2008 Rate Case Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.6100%	46.2500%	3.08%
Short Term Debt	4.4100%	1.2800%	0.15%
Common Equity	10.8800%	52.4700%	5.57%
Required Rate of Return			8.80%

2012 Step-in Adjustment
Revenue Requirement Calculation
Other Production - Merricourt
($000s)

Case No. PU-10-____
Exhibit___(AEH-1), Schedule 4
Page 1 of 1

	2012		2011		Net Change	
Rate Analysis	Total Company	ND Jurisdiction	Total Company	ND Jurisdiction	Total Company	ND Jurisdiction
Plant Investment	399,965	19,493	199,933	9,744	200,032	9,749
Depreciation Reserve	10,843	528	1,081	53	9,762	476
CWIP	-	-	-	-	-	-
Accumulated Deferred Taxes	51,692	2,519	14,641	714	37,051	1,806
	337,430	16,446	184,211	8,977	153,219	7,467
Average Rate Base	337,430	16,446	184,211	8,977	153,219	7,467
Debt Return	10,899	531	5,950	290	4,949	241
Equity Return	18,795	916	10,261	500	8,534	416
Current Income Tax Requirement	(29,063)	(1,416)	(17,015)	(829)	(12,048)	(588)
Book Depreciation	17,365	846	2,161	105	15,204	741
Annual Deferred Tax	44,413	2,165	29,689	1,447	14,724	718
ITC Flow Thru	-	-	-	-	-	-
Tax Depreciation & Removal Expense	125,594	6,121	78,471	3,824	47,123	2,297
AFUDC Expenditure	-	-	-	-	-	-
Avoided Tax Interest	-	-	10,003	488	(10,003)	(488)
Property Taxes	2,267	110	-	-	2,267	110
MDU Transmission Payments	5,920	289	1,480	72	4,440	216
Total Revenue Requirements	**70,595**	**3,441**	**32,526**	**1,585**	**38,070**	**1,855**

2008 Rate Case Capital Structure	**Rate**	**Ratio**	**Weighted Cost**
Long Term Debt	**6.7600%**	**45.6100%**	**3.0800%**
Short Term Debt	**5.7400%**	**2.6200%**	**0.1500%**
Preferred Stock	**0.0000%**	**0.0000%**	**0.0000%**
Common Equity	**10.7500%**	**51.7700%**	**5.5700%**
Required Rate of Return			**8.8000%**
Tax Rate (ND)	**39.2300%**		

Allocators	
Demand Prod ND Jur %	**5.8107%**
Demand MN Co % (1)	**83.8756%**
Composite Demand	**4.8738%**

2012 Step-in Adjustment
Revenue Requirement Calculation
Nuclear Outage Amortization
($000s)

	ND Jurisdiction 2012	ND Jurisdiction 2011	Difference	Composite IA Factor*	Net Change
Accumulated Deferred Taxes BOY	1,179	1,036	143	83.8527%	120
Accumulated Deferred Taxes EOY	1,675	1,179	496	83.8527%	416
Prepaids & Other BOY	2,886	2,537	349	83.8527%	293
Prepaids & Other EOY	4,102	2,886	1,216	83.8527%	1,020
Power Production	3,903	3,580	323	83.8527%	271
Deferred Income Tax & ITC	497	143	354	83.8527%	297
Nuclear Outage Accounting Tax Add	3,903	3,580	323	83.8527%	271
Tax Depreciation & Removal Tax Ded	5,119	3,929	1,190	83.8527%	998

Rate Analysis	ND Jurisdiction Before IA Adjustment	ND Jurisdiction After IA Adjustment
Average Prepaid & Other Rate Base	783	656
Average Accumulated Deferred Taxes	320	268
Average Rate Base	463	388
Debt Return	15	13
Equity Return	26	22
Current Income Tax Requirement	(315)	(263)
Outage Amortization Expense	323	271
Annual Deferred Tax	354	297
ITC Flow Thru	0	0
Outage Cost Tax Deduction	1,190	998
AFUDC Expenditure	0	0
Avoided Tax Interest	0	0
Property Taxes	0	0
Total Revenue Requirements	**403**	**339**

2008 Rate Case Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	6.6100%	46.2500%	3.08%
Short Term Debt	4.4100%	1.2800%	0.15%
Common Equity	10.8800%	52.4700%	5.57%
Required Rate of Return			8.8000%
Tax Rate (ND)	39.2300%		

* Composite IA Allocation Factor		Interchange Agreement Factors	Composite
% Allocated on Demand	48.5607%	83.8756%	40.7306%
% Allocated on Energy	51.4393%	83.8310%	43.1221%
	100.0000%		83.8527%

North Dakota Retail Jurisdiction
Average Rate Base (Excluding CWIP)
Transmission Rate Base Comparison

Transmission	Average 2011 Test Year	2012 Step	End of Year 2011 Test Year	Average 2012 Bud	Difference
Plant In Service	93,223	4,209	97,431	100,601	3,170
Depreciation Reserve	29,259	869	30,128	30,946	818
Accumulated Deferred Taxes	12,356	677	13,033	13,502	469
Total Rate Base	51,608	2,663	54,270	56,153	1,883

Note: Transmission Rate Base has been adjusted to reflect the impacts of the Interchange Agreement.

ROE = 9.51%
Deficiency = $5,268
% Increase = 2.83%
Required ROE = 11.25%

Northern States Power Company, a Minnesota corporation
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Summary Reports

December 20, 2010

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Rate Base Summary

		Total Company Electric			ND Retail Electric			All Other		
		Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance	Beginning Balance	Ending Balance	Average Balance
1	Plant Investment	14,509,692	15,106,539	14,808,116	800,651	830,614	815,633	13,709,041	14,275,925	13,992,483
2	Depreciation Reserve	(6,780,241)	(7,259,201)	(7,019,721)	(378,758)	(404,900)	(391,829)	(6,401,483)	(6,854,301)	(6,627,892)
3	Net Utility Plant	7,729,451	7,847,338	7,788,395	421,893	425,714	423,804	7,307,558	7,421,624	7,364,591
4	C.W.I.P.	26,741	43,192	34,967	1,706	2,821	2,264	25,035	40,371	32,703
5	Accumulated Deferred Taxes	(1,530,140)	(1,675,571)	(1,602,856)	(85,559)	(94,349)	(89,954)	(1,444,581)	(1,581,222)	(1,512,902)
	Other Rate Base:									
6	Cash Working Capital	15,726	15,726	15,726	2,109	2,109	2,109	13,617	13,617	13,617
7	Materials & Supplies	105,544	105,544	105,544	6,170	6,170	6,170	99,374	99,374	99,374
8	Fuel Inventory	90,609	90,609	90,609	5,656	5,656	5,656	84,953	84,953	84,953
9	Non-Plant Assets & Liab	(91,197)	(50,661)	(70,929)	(5,468)	(3,035)	(4,252)	(85,729)	(47,626)	(66,677)
10	Prepaids & Other	69,021	88,311	78,666	4,186	5,398	4,792	64,835	82,913	73,874
11	**Total Rate Base**	**6,415,755**	**6,464,488**	**6,440,122**	**350,693**	**350,484**	**350,589**	**6,065,062**	**6,114,004**	**6,089,533**

Northern States Power Company, a Minnesota corporation
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Income Statement Summary

		Total Company Electric	ND Retail Electric	All Other
	Operating Revenues			
1	Retail	3,126,154	186,039	2,940,115
2	CIP Adjustment to Program Costs	0	-	0
3	Interdepartmental	610	-	610
4	Other Operating	797,887	46,996	750,891
5	Gross Earnings Tax	0	-	0
6	**Total Operating Revenues**	**3,924,651**	**233,035**	**3,691,616**
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	1,342,384	83,182	1,259,202
8	Power Production	769,373	45,112	724,261
9	Transmission	230,037	13,329	216,709
10	Distribution	109,792	6,535	103,257
11	Customer Accounting	63,771	4,502	59,269
12	Customer Service & Information	92,301	551	91,750
13	Sales, Econ Dvlp & Other	272	66	206
14	Administrative & General	220,690	14,235	206,454
15	Total Operating Expenses	2,828,620	167,512	2,661,108
16	Depreciation	390,676	20,356	370,320
17	Amortization	24,371	575	23,796
	Taxes:			
18	Property	127,340	6,101	121,239
19	Gross Earnings	0	-	0
20	Deferred Income Tax & ITC	142,553	8,673	133,880
21	State & Federal Income (see Page 3)	(31,030)	524	(31,554)
22	Payroll & Other	30,785	1,854	28,931
23	Total Taxes	269,648	17,152	252,496
24	**Total Expenses**	**3,513,315**	**205,595**	**3,307,720**
25	AFUDC	-	-	-
26	**Total Operating Income**	**411,336**	**27,440**	**383,896**

Northern States Power Company, a Minnesota corporation
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Income Tax Summary

		Total Company Electric	ND Retail Electric	All Other
	Income Before Taxes			
1	Total Operating Revenues	3,924,651	233,035	3,691,616
2	less: Total Operating Expenses	(2,828,620)	(167,512)	(2,661,108)
3	Book Depreciation & Amortization	(415,047)	(20,931)	(394,116)
4	Taxes (Other Than Current Income)	(300,678)	(16,628)	(284,050)
5	**Total Before Tax Book Income**	**380,306**	**27,964**	**352,342**
	Tax Additions			
6	Book Depreciation	390,676	20,356	370,320
7	Deferred Income Taxes & ITC	142,553	8,673	133,880
8	Nuclear Fuel Burn (ex D&D)	130,722	7,574	123,148
9	Nuclear Outage Accounting	64,513	3,891	60,622
10	Avoided Tax Interest	30,187	1,698	28,489
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	**Total Tax Additions**	**758,651**	**42,192**	**716,459**
	Tax Deductions			
18	Debt Interest Expense	182,255	9,922	172,334
19	Tax Depreciation & Removal	905,516	50,901	854,615
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	41,590	2,495	39,095
25	Net Preferred Stock Deduction	0	0	0
26	**Total Tax Deductions**	**1,129,361**	**63,318**	**1,066,044**
27	**State Taxable Income**	**9,595**	**6,838**	**2,757**
28	State Income Tax Rate	9.03%	6.50%	N/A
29	State Taxes before Credits	866	444	422
30	State Credits	531	0	531
31	**Total State Income Taxes**	**335**	**444**	**(109)**
32	**Federal Taxable Income**	**9,260**	**6,394**	**2,866**
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	3,241	2,238	1,003
35	Federal Tax Credits	34,606	2,158	32,448
36	**Total Federal Income Taxes**	**(31,365)**	**80**	**(31,445)**
37	**Total Federal & State Income Taxes**	(31,030)	524	(31,554)

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Revenue Requirement & Return Summary

	Capital Structure	Rate	Ratio	Weighted Cost
1	Long Term Debt	6.0700%	46.3000%	2.8100%
2	Short Term Debt	2.0600%	1.1400%	0.0200%
3	Preferred Stock	0.0000%	0.0000%	0.0000%
4	Common Equity	11.2500%	52.5600%	5.9100%
5	**Required Rate of Return**			**8.7400%**

Composite Income Tax Rates		
State of North Dakota Tax rate		6.50%
Federal Statutory Tax rate	35.00%	
Federal Effective Tax Rate (1-State Rate*Fed Rate)		32.73%
Total North Dakota Composite Tax Rate		**39.23%**
Total Corporate Composite Tax Rate		**40.87%**

		Total Company Electric	ND Retail Electric	All Other
	Rate of Return (ROR)			
6	Total Operating Income	411,336	27,440	383,896
7	Total Average Rate Base	6,440,122	350,589	6,089,533
8	**ROR** (Operating Income / Rate Base)	**6.39%**	**7.83%**	**6.30%**
	Return on Equity (ROE)			
9	Total Operating Income	411,336	27,440	383,896
10	Debt Interest (Rate Base * Weighted Debt Cost)	(182,255)	(9,922)	(172,334)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0	0
12	Earnings Available for Common	229,080	17,518	211,562
13	Equity Rate Base (Rate Base * Equity Ratio)	3,384,928	184,270	3,200,659
14	**ROE** (Earnings for Common / Equity Rate Base)	**6.77%**	**9.51%**	**6.61%**
	Revenue Deficiency			
15	Require Operating Income (Rate Base * Required Return)	562,867	30,641	532,225
16	Operating Income	411,336	27,440	383,896
17	Operating Income Deficiency	151,531	3,202	148,329
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69110	1.64541	N/A
19	**Revenue Deficiency** (Income Deficiency * Conversion Factor)	**256,254**	**5,268**	**250,986**
	Total Retail Revenue Requirements			
20	Retail Related Revenues	3,126,764	186,039	2,940,725
21	Revenue Deficiency	256,254	5,268	250,986
22	**Total Retail Revenue Requirements**	**3,383,018**	**191,307**	**3,191,711**
23	**Percentage Increase (Decrease)**	**8.20%**	**2.83%**	**8.53%**

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Rate Base Detail - Cash Working Capital

Line		Days	Total Company Electric Dollars	Total Company Electric Dollar x Days		ND Retail Electric Dollars	ND Retail Electric Dollar x Days		All Other Dollars	All Other Dollar x Days
	Expenses									
	Includable Expenses	**Lead Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
	Fuel Expenses									
1	Coal & Rail Transport	21.08	361,157	7,613,190		22,544	475,228		338,613	7,137,962
2	Gas for Generation	38.45	167,107	6,425,264		10,431	401,072		156,676	6,024,192
3	Oil	22.51	1,283	28,880		80	1,801		1,203	27,080
4	Nuclear & EOL	0.00	130,722	0		8,160	0		122,562	0
5	Nuclear Disposal	76.00	13,050	991,800		756	57,456		12,294	934,344
6			673,319	15,059,134		41,971	935,556		631,348	14,123,578
	Purchased Power									
7	Purchases	28.12	876,729	24,653,619		53,111	1,493,481		823,618	23,160,138
8	Interchange	38.21	127,715	4,879,990		7,488	286,116		120,227	4,593,874
			1,004,444	29,533,610		60,599	1,779,598		943,845	27,754,012
	Labor & Related Costs									
9	Regular Payroll	12.31	376,540	4,635,207		22,629	278,563		353,911	4,356,644
10	Incentive Compensation	255.05	22,679	5,784,279		1,419	361,916		21,260	5,422,363
11	Pension & Benefits	19.20	92,631	1,778,515		5,639	108,269		86,992	1,670,246
12	Subtotal Labor & Related		491,850	12,198,002		29,687	748,748		462,163	11,449,254
13										
14	All Other Operating Expenses	35.01	659,007	23,071,844		35,255	1,234,271		623,752	21,837,573
15	Property Tax	356.72	127,340	45,424,725		6,101	2,176,349		121,239	43,248,376
16	Employer's Payroll Taxes	26.56	30,785	817,650		1,854	49,242		28,931	768,407
17	Gross Earnings Tax	41.48	0	0		0	0		0	0
18	Federal Income Tax	37.75	(31,365)	(1,184,025)		80	3,014		(31,445)	(1,187,038)
19	State Income Tax	37.75	335	12,649		444	16,780		(109)	(4,130)
20	State Sales Tax Customer Billings	35.73	141,992	5,073,374		0	0		141,992	5,073,374
21	Total Expenses	41.97	3,097,707	130,006,962	39.45	175,991	6,943,557	42.12	2,921,716	123,063,405
22	**Net Annual Expense Amount**			356,183			19,023			337,160
	Revenues	**Lag Days**	**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**		**Dollars**	**Dollar x Days**
23	Computer Billing 100.00%	45.45	3,126,154	142,092,140		186,039	8,455,975		2,940,115	133,636,165
24	Hand Billed 0.00%	43.07	0	0		0	0		0	0
25	Retail Revenue Adjustments	0.00	0	0		0	0		0	0
26	Interdepartmental	0.00	610	0		0	0		610	0
27	Late Payment	0.00	5,615	0		361	0		5,254	0
28	Connect and Trouble Charges	42.85	2,275	97,488		245	10,499		2,030	86,990
29	CIP Incentive	0.00	0	0		0	0		0	0
30	Rentals	114.17	4,032	460,333		255	29,113		3,777	431,220
31	Interchange Revenues	38.21	472,754	18,063,930		28,335	1,082,680		444,419	16,981,250
32	Sales for Resale	37.10	168,294	6,243,709		10,391	385,493		157,903	5,858,217
33	Production Associated Revenues	37.10	6,460	239,666		403	14,951		6,057	224,715
34	MISO	14.00	14,658	205,219		849	11,885		13,810	193,333
35	Point to Point Firm	37.10	61,421	2,278,719		3,558	132,002		57,863	2,146,717
36	Services & Facilities	37.10	8,817	327,111		505	18,736		8,312	308,375
37	Ancillary	37.10	60,233	2,234,644		3,490	129,479		56,743	2,105,165
38	Distribution Associated Revenues	42.85	1,872	80,219		0	0		1,872	80,219
39	Other	42.85	(3,648)	(156,342)		(1,090)	(46,700)		(2,559)	(109,642)
40	JOA - Rev fr/to PSC	37.10	(4,896)	(181,642)		(306)	(11,353)		(4,590)	(170,289)
41	(blank)	0.00	0	0		0	0		0	0
42	(blank)	0.00	0	0		0	0		0	0
43	(blank)	0.00	0	0		0	0		0	0
44	Total Revenues	43.82	3,924,651	171,985,195	43.83	233,035	10,212,760	43.82	3,691,616	161,772,435
45	Net Annual Amount			471,192			27,980			443,212
46	Expense / Revenue Factor			0.789294986			0.755213995			
47	**Allocated Revenue Amount**			371,910			21,131			
48	**Net Cash Working Capital**	Page 1 - Line 6		15,726			2,108			13,619