NorthWestern Energy

INFORMATIONAL FILING

DOCKET NO. D2006.10.141

Before The Public Service Commission
Of the State of Montana

FOR
ELECTRIC AND NATURAL GAS
ALLOCATED COST OF SERVICE
AND
RATE DESIGN

STATEMENTS
&
WORKPAPERS

March 2007

NorthWestern Energy

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April 20, 2007

Ms. Kate Whitney
Administrator, Utility Division
Montana Public Service Commission
1701 Prospect Ave.
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Re: Docket No. D2006.10.141: NWE Informational Filing - Allocated Cost of Service and Rate Design Analysis

Dear Ms. Whitney:

NorthWestern Corporation, d/b/a NorthWestern Energy ("NorthWestern"), submits to the Montana Public Service Commission (Commission or MPSC), the electric and natural gas utility allocated cost of service ("ACOS") and rate design ("RD") portion of its Informational Filing in Docket No. D2006.10.141.

On June 2, 2006 NorthWestern requested permission of the Commission to bifurcate the ACOS/RD portion of the filing required in the Bankruptcy Settlement Agreement with the Commission and the Montana Consumer Counsel, and file only the revenue requirement analysis by September 30, 2006. The Commission granted permission to bifurcate the ACOS/RD portion of the filing on June 13, 2006.

It has been several years since NorthWestern filed its last electric or natural gas ACOS/RD studies. Since that time, the majority of the personnel who had previously prepared and performed ACOS and RD, including many of those who had provided cost data and other inputs valuable to such analyses, left NorthWestern (or formerly MPC). Therefore, in addition to complying with the Commission's minimum filing requirements, building on the ACOS/RD knowledge base of current employees and implementing an updated ACOS/RD model for use in future filings were among NWE's primary objectives in the development of this filing. NWE engaged the firm of RJ Rudden Associates, a Black and Veatch Company (Rudden), to work with NorthWestern personnel to complete the studies included in this filing and accomplish its objectives.

Enclosed in response to the Commission's filing requirements under Statement L and M is the following material:

- Electric Utility
  - Statement L -Cost Allocation Study
  - Statement M - Rate Design

- Natural Gas Utility
  - Statement L - Cost Allocation Study
  - Statement M - Rate Design

Since this is an informational filing, the Allocated Cost of Service Studies and Rate Designs include written explanations in lieu of the pre-filed testimony that would normally be included in a formal application.

NorthWestern would also like to inform the Commission and other interested parties that it is in the process of developing a 2006 Test Period Revenue Requirement Analyses in anticipation of making a formal cost of service filing[1] later this year, including a formal application for rate adjustments for its electric and natural gas delivery services.

In anticipation of that filing, NorthWestern believes it would be most productive to establish a series of ACOS/RD conferences that provide interested parties the opportunity, over the next several months, to review and critique the ACOS/RD analysis included in this filing. NWE anticipates an initial conference in which NorthWestern and Rudden would present details regarding the data and methodologies used, answer questions and obtain input. The initial conference should be held after the parties have had adequate time to review this filing. Additional conferences to follow up on areas of particular interest to the parties or NorthWestern would be held as/if needed. NorthWestern would then consider input received as it develops the ACOS/RD portion of its anticipated 2007 cost of service filing.

This filing has been distributed to the service list in D2006.10.141 (enclosed).

If you have any questions, please let me know.

Sincerely,

Patrick R Corcoran

Patrick R. Corcoran
Vice President
Government and Regulatory Affairs

[1] Revenue Requirement, Allocated Cost of Service and Rate Design Analyses.

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Docket D2006.10.141
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Report to
NorthWestern Energy

Electric Utility Cost Allocation Study

April 20, 2007

R·J·Rudden® ASSOCIATES
A Black & Veatch Company

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SECTION I
INTRODUCTION

This report provides the results of the electric marginal cost of service study prepared for NorthWestern Energy ("NWE" or "NorthWestern"). Briefly, the report provides the underlying theory for cost allocations and rate designs, discusses the process employed, provides cost allocation results, makes recommendations and presents conclusions related to the cost allocation study.

This report adheres to the current requirements of the Administrative Rules of Montana outlined in 38.5.176 ("Statement L"). The following outlines the steps taken relative to those requirements.

There are seven appendices that present the cost of service results in detail for each customer class. These Appendices are in 2009 dollars as escalated by NorthWestern using budgets, forecasts, and estimates. However, because the last NWE Cost of Service (COS) study approved by the Montana Public Service Commission ("Commission" or "PSC") was the result of a collaborative effort by several interested parties, there can be no clear comparison to this study. Marginal allocation unitized factors were the result of the collaboration; however, there was no agreed upon or determined methodology. Without a clear understanding of how these allocation factors were developed, a comparison of unitized values is meaningless or moot.

This study is performed using six functions (Generation/Supply, Transmission, Substation, Distribution Primary, Distribution Secondary, and Customer) and three classifications (Capacity, Energy, Customer). Marginal Costs are unitized and then multiplied by Annualization[1] factors to create marginal costs by function. Table 1-1 identifies the Function, Classification, Marginal Unit Cost, Annualization Factor, Description and Total Value, and Total Marginal Costs at the company level in a format adhering to the specification of the general electric model referenced in Statement L. The column labels reference the lettered subsections in the generic Electric Model description in Statement L. (i.e. "A", "B") Appendix 3-1 is a version of Table 1-1 with the resulting allocation to each customer class.

[1] Statement L references the multiplication of marginal units cost by Annualization factors. This report adopts the ARM term and its reference to the creation of all marginal allocation factors.

Table 1-1

Model Outline for the Electric Marginal Cost of Service Study

	Function* A	Classify B	Units C	Marginal Unit Cost C	Annualization Factor Description D	Annualization Factor Total Value D	Total Marginal Costs E
1	Generation/Supply	Demand	Marginal Supply Costs are Energy Only				
2	Generation/Supply	Energy	$/KWH	$ 51.76	Sales with Losses (MWh)	6,332,641	$ 327,747,471
3	Transmission	Demand	$/MW	$ 7,760	12CP with Losses (MW)	1,230	$ 9,548,802
4	Transmission	Energy	Transmission Energy Costs (Losses) are included in Supply				
5	Substation	Demand	$/MW	$ 6,942	Substation NCP with Losses (MW)	1,647	$ 11,435,895
6	Substation	Energy	Substations Energy Costs (Losses) are included in Supply				
7	Distribution Primary	Demand	$/MW	$ 47,543	Distribution NCP with Losses (MW)	1,296	$ 61,595,717
8	Distribution Primary	Energy	Distribution Primary Energy Costs (Losses) are included in Supply				
9	Distribution Primary	Customer	No Distribution Primary Customer costs due to no Min Sys Study Performed				
10	Distribution Secondary	Demand	No Distribution Secondary Demand costs due to no Min Sys Study Performed				
11	Distribution Secondary	Energy	Distribution Secondary Energy Costs (Losses) are included in Supply				
12	Distribution Secondary for Utility Customers	Customer	$/Utility Customer	$ 74.82	Number of Customer minus Lighting Customers	336,773	$ 25,197,581
13	Distribution Secondary for Lighting Customers	Customer	$/Lighting Fixture	$ 41.77	Number of Utility Lighting Fixtures	80,177	$ 3,348,775
14	Distribution Secondary Total	Customer	NA	NA	NA	NA	$ 28,546,357
15	Customer	Customer	$/Customer	$ 54.56	Number of Customers	366,256	$ 19,981,586

*Note: All utility common or overhead costs such as General Plant, Common Plant, and Administration and General costs are allocated in total to all of the above six functional categories and three classification categories using embedded allocation methods.

Notable differences between this study and previous studies include the treatment of supply costs, the use of percentage based marginal allocation factors, the treatment of line losses and the allocation of normal utility overheads such as general plant, administrative and general ("A&G") expenses, property taxes and other plant and expense items that are common to all utility functions.

Electric Supply costs are currently recovered in NWE's supply tracker, which is a pass-through of expense to Default Supply customers. Furthermore, NWE's electric supply contracts are based almost exclusively on a per kWh basis; therefore, the study allocates supply in total to the energy classification, allocates supply costs based on a kWh Annualization Factor and recovers supply costs with equal supply revenues. Simply, marginal energy cost equals the marginal purchase price of the energy multiplied by utility sales.

Similarly, energy losses are no longer allocated to transmission or distribution, because these costs are recovered in NWE's supply tracker, which, as stated earlier, is a pass-through of NWE expenses. Therefore, the study allocates these energy losses to the Supply function and recovers these costs with equal revenues. The marginal allocation of losses is handled along with Supply cost by adding energy losses to Sales volumes creating the Sales with Losses Annualization factor shown in Table 1-1. Given the nature of losses, it is reasonable to assume that marginal and average energy losses are approximately equal for each customer class.

The percentage-based marginal allocation factor is explained in detail in Section III.

Normal utility overheads as listed above are allocated to the six COS functions and three COS classifications in proportion to their related plant and expenses. This is also further explained in Section III. The allocation of overhead to the six functions and three classifications is based on embedded cost principles. By and large, overhead costs are fixed and do not change at the margin. For purposes of this study, it is assumed that marginal overheads equal zero. This assumption is consistent with the level of additional facilities added to estimated marginal costs. This creates separate function/classification revenue requirements, which are then, allocated in total, to customer classes on a marginal basis using the Annualization factor described in Table 1-1.

Section II of this report describes the principles followed in the development of the electric utility cost allocation presented in this report. Section III discusses electric rate design principles.

SECTION II
COST OF SERVICE THEORY AND PRACTICE - ELECTRIC

Introduction

Many purposes exist for electric utility cost analysis ranging from designing appropriate price signals to determining the share of costs borne by various customer classes. Just as there are many uses for cost analysis, there are different types of cost studies. In general, cost studies may be based on embedded costs or marginal costs. Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecast test year. Marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in cost associated with changes in service. Marginal cost studies are forward looking to the extent permitted by available data.

Cost studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs.[2] In addition, utility costs may be fixed or variable costs.[3] Finally, utility costs exhibit significant economies of scale.[4] These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, either marginal or embedded, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies, marginal and embedded, provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Economic theory holds that efficient prices equal short-run marginal cost. For an electric utility characterized by economies of scale, setting prices based on marginal costs will not produce adequate revenues because marginal cost is below average cost.[5] The concept that marginal cost is below average costs is often subject to some confusion because of the nature of utility costs. The existence of scale economies, defined as a declining long-run average cost curve, is only possible where marginal cost is less than average costs. Simply, for average cost to decline the marginal unit must be below the

[2] Common costs occur when the fixed costs of providing service to one or more classes or the cost of proving multiple products to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

[3] Fixed costs do not change with the level of output while variable costs change directly with the utility output. Most non-fuel related utility costs are fixed and do not vary with changes in load.

[4] Scale economies result in declining average cost as output increases and marginal costs below average costs.

[5] Some analysts mistakenly assume that marginal cost is above average cost because new facilities cost more than existing facilities. Under the economic definition for costs, the impacts of inflation and technology are held constant and, therefore, the scale economies do exist. Further, as demonstrated in our analysis, marginal costs are below the total costs in this case.

existing average cost.[6] Utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve customers. Since utilities could not satisfy the revenue adequacy constraint with prices based on marginal cost, economists developed a theoretical approach to reconciling marginal cost based prices with the revenue constraint. The theory of Ramsey pricing resolves the revenue adequacy issue by suggesting that raising prices above marginal cost in relation to the inverse of the price elasticity[7] of the product or service provided results in the least societal welfare loss from prices that differ from marginal cost.

Under Ramsey pricing (a form of differential pricing), customers' rates are increased above marginal cost until the rates produce adequate revenues to recover the revenue requirement. Increases are largest for those customers or classes of service whose demand is most inelastic (least responsive to changes in price). To implement Ramsey pricing requires, among other things, estimates of customer or class price elasticity. Since estimating price elasticity for electric or gas service is complex, utilities developed other practical methods for resolving the revenue adequacy issue. Alternatively, the theory of multi-part pricing suggests that it is possible to recover average costs from infra-marginal prices[8] while setting the marginal price equal to marginal cost. Thus, the use of block rates permits efficient prices while recovering total revenue requirements. Other examples of economic efficiency based rates include the concept of fixed variable rate design where fixed cost recovery occurs through fixed charges (since fixed costs do not contribute to marginal cost) and variable charges recover variable costs. For electric service rates, fixed variable rate design recovers the cost of transmission and distribution through fixed charges.

The theory of pricing also requires a theory of class or service cost allocation. However, the existence of joint and common costs makes any allocation of costs arbitrary. This is theoretically true for any of the various marginal or embedded cost methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy free so long as the price exceeds marginal cost but is less than stand alone costs (SAC)[9]. Indeed all of this theory provides useful insight to the regulatory process where, as a practical matter, costs must be allocated between classes of service and within classes of service. For example, if the process of cost allocation results in rates that exceed SAC for some customers, prices must be set below the SAC but above marginal cost to assure that those customers make the maximum practical contribution to common costs. SAC plays a role in addressing issues such as gas bypass or distributed generation where customers may potentially exit the grid. SAC represents

[6] The assumptions underlying marginal and average costs include constant real input prices and constant technology. Since embedded costs include differing input prices and different technologies, it is possible that current marginal costs may exceed embedded average costs. That is not the case for NorthWestern as the study illustrates.

[7] Price elasticity is a measure of the responsiveness of quantity demanded to a change in price. It is measured as the percentage change in quantity demanded divided by the percentage change in price. Demand is said to be inelastic when the ratio is less than one.

[8] Infra-marginal price means the units consumed prior to the marginal unit. The customer charge represents an infra-marginal price. For block rates, any block of a rate structure that is fully saturated under normal circumstances also represents an infra-marginal price.

[9] SAC is the cost required to serve one customer or a class of customers using the latest available technology in its most efficient configuration and essentially represents the replacement cost of service.

an element of the allocation process for cost studies and is an alternative to the concept of fully allocated costs. Unlike other more conventional allocation methods SAC relies on estimated replacement costs rather than actual costs.

As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service and rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. Under the traditional embedded cost allocation, the process follows three steps: functionalization, classification and allocation. This three-step process underlies the determination of cost causation. By identifying the functions of electric utility service - generation,[10] transmission, distribution and customer for electric service and the costs of these functions, the foundation is laid for classifying costs based on the factors that cause the utility to incur these costs-energy, demand and customers. The development of allocation factors by rate schedule or class uses principles of both economics and engineering to develop allocation factors appropriate for different elements of costs. Embedded cost allocation provides the class costs associated with actual test year revenue requirements. Embedded cost studies reflect the basis for cost recovery consistent with actual costs.

Marginal cost studies, in contrast, focus on the change in costs associated with a small change in output. Marginal costs are forward looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of normalized historical costs that constitute the utility revenue requirement. Marginal costs do not reflect these actual costs because:

1. Marginal costs are prospective costs and reflect changes in technology.
2. Sunk costs (the fixed costs of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement particularly where economies of scale are significant.
3. The underlying impacts of inflation on marginal costs cause such costs to differ from historical costs.
4. Additions to capacity are lumpy and, as a result, utilities optimal additions often include more capacity than the marginal change in load requires.

The Process

To estimate marginal cost, the first step requires determining the change in cost associated with the consumption of one more kilowatt-hour of electricity. Essentially, estimating marginal costs requires an understanding of the system planning process. Often, however, the planning process does not typically provide all of the information necessary to develop marginal cost estimates.

[10] As noted above and discussed more fully below, in the absence of generation, NWE purchases its power from the market and these purchases correspond to the traditional generation function.

Generation/Default Supply Function

The existence of competitive wholesale markets or regulated wholesale power markets (where the forces of competition do not provide the necessary market discipline for prices) provides a direct basis for estimating generation marginal costs. The rationale for this statement relies on the economics of competition where prices equal marginal cost in competitive markets or for the reflection of the regulated rate where purchased power represents the marginal cost of supply acquisition. In either case, marginal costs reflect actual purchases at the margin. Prior to the competitive market framework, the calculation of marginal costs required analysis of the system planning process to determine optimal additions to capacity and the marginal running costs for system resources. The existence of markets allows the direct estimation of marginal costs based on the market. In this case, the value of energy (including the capacity component) is based on a contractual purchase of power to provide default service to non-choice customers.

From a theoretical standpoint, marginal capacity cost cannot exceed the carrying costs of the least capital intensive source of new capacity. While this provides the upper bound for marginal generation capacity costs, the marginal capacity costs may be less. This is particularly true in competitive markets where purchase power contracts provide for a commodity-only rate option. In addition, when power is purchased on a delivered basis, marginal transmission costs are subsumed in the market price of power. This means that to the extent that markets provide services, the price of these services reflects marginal costs.

To the degree that marginal costs differ by hour or by season, wholesale markets also provide the basis for this determination. Where the utility purchases default service from the market at a fixed rate, this fixed rate provides the appropriate marginal energy cost determination. Thus, the existence of energy markets and active futures markets makes the estimation of energy marginal costs both less complex and more accurate.

The Wires Functions - Transmission and Distribution

The second step in the determination of marginal cost relates to the change in capacity requirements as measured by kilowatt demand. Unlike the energy determination, there is no competitive market for either transmission or distribution. Thus, it is necessary to estimate how capacity demand influences the costs for distribution and transmission, respectively. It is important to recognize that the transmission capacity demand is different from distribution because the load diversity increases as the analysis becomes remote from individual customers. Initially, the capacity requirements for transmission reflect the coincident demand for the transmission system as measured by the loads on the transmission system. Alternatively, the capacity requirements for the distribution system must reflect the non-coincident demands on the system. This is because the delivery must satisfy the local demands that may not be coincident with the system peaks for a number of reasons.

For electric distribution costs, scale economies exist with respect to service lines and transformers. However, the analysis is more complicated because of different service types - overhead and underground. Underground facilities have higher capital costs than overhead facilities but also typically have lower operation and maintenance expenses and less exposure to early replacement as the result of damage to facilities.[11] Further, line extension policies tend to compensate for the differences in the cost of overhead or underground service either directly or indirectly.

In developing the marginal cost for the non-generation portions of the electric system, it is necessary to separate infrastructure replacement costs from the costs related to load growth. Where planning processes separately identify new projects to meet load growth from replacement projects, it is possible to identify the marginal costs directly. If this data does not exist, the alternative is estimation of the percentage of the change in plant costs each year that is associated with new load. One of the challenges for estimating marginal costs is that the nature of growth related projects considers the growth related to new facilities over the entire life of those facilities. To estimate unit costs requires an understanding of the potential long-term growth served by the projects.

The following discussion provides the theoretical foundations for estimating electric transmission marginal costs. Conceptually, marginal costs require the identification of new transmission designed to serve load growth. Transmission investment is caused by three factors:

1. The repair, refurbishment or replacement of existing assets to serve current load requirements;
2. The attachment of either new customers served at transmission voltage (these costs are assigned to the customer) or new sources of power (these costs are assigned to marginal generation costs); and
3. The expansion of existing facilities to meet load growth.

This third category is the only one that is used to calculate marginal transmission costs. The estimated costs for load growth projects divided by the load growth provides an estimate of the capital-related marginal costs. The marginal capital cost in dollars per kW must be converted into an annual revenue requirement. An economic carrying charge model is used to determine the levelized annual revenue requirement that equals the annual cost for capacity. In addition, it is necessary to estimate the associated operation and maintenance expenses and overheads. In most cases, the growth-related overheads represent a negligible amount because of the relative size of growth projects.

Marginal costs for the distribution system are determined by two major factors: (1) the number and location of customers, and (2) their demands. Utility cost studies, both marginal and embedded, have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. While it is true that marginal demand costs play a role in the installed facilities, the customer considerations play a much larger role since local facilities and policies reflect the underlying customer mix and density.

Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration customer density and the expected design loads of those customers. For example, an area with all-electric homes may have different design standards from an area where the homes are not electrically heated. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is

[11] We specifically exclude certain vintages of underground cable that must be replaced prematurely due to unsatisfactory performance.

designed based on the design load of the customers to be served, not specifically on the number of customers or their actual loads at any given moment. The concept of a network cost and a network charge[12] provides a convenient way to discuss the marginal distribution costs.

The importance of the network cost/network charge from the rate design and economic efficiency standpoint follows. Since the distribution network costs do not vary with the change in consumption and no distribution network costs are avoided through demand-side management, these costs should not be included in any volumetric charges. Hence, the network charge promotes economic efficiency only so long as it recovers any portion of the revenue requirement above the marginal cost so that the variable charges recover the marginal costs. For the distribution system, no portion of the cost varies with kWh, thus no variable charges are appropriate.

The Customer Function

Marginal customer costs for electric customers reflect the cost of equipment on the customer premise or in close proximity to the premise in the case of electric transformers. The marginal customer cost becomes part of the network charge as well. For customer service expenses such as meter reading and billing, the marginal customer cost for a single customer does not fairly represent the costs for groups of customers. To approximate marginal customer costs, average customer costs represent a reasonable proxy. In the event that growth is extremely rapid, it is necessary to recognize the significant scale of economies in customer service and billing and to reflect those scales of economies in estimating marginal customer costs. This would imply lower per customer costs than the current level.

[12] Network cost represents the costs associated with providing the distribution facilities applicable to each class of service and a network charge represents the price for using the network including customer-related costs. The network charge is a fixed annual charge payable in twelve equal installments.

SECTION III
ELECTRIC MARGINAL COST STUDY AND RATE DESIGN

Electric Marginal Cost of Service

The Electric Marginal Cost of Service Study (EM-COSS) for NWE's Montana electric utility (NWE) analyzes the returns by class of customers using estimated 13-month average plant balances and expenses for the twelve months ending December 31, 2009 (Test Period). The allocation factors for the study use marginal costs as the basis of the allocation process.

The purpose of the study is to unbundle all of NWE's costs and assign plant investments to determine the costs incurred by the electric utility in providing products and services to each customer class. Each component of plant, expense and revenue is allocated among the existing customer classes based on the marginal cost to serve, which is determined by identifying the next increment of service on a per unit cost basis. The unit cost is then multiplied by an Annualization Factor (i.e., kWh Sales, Distribution NCP, or Number of Customers) to allocate the portion of the total costs incurred by NWE in providing service to that customer class on a cost-causality basis.

A critical task in performing an EM-COSS is establishing relationships between customer requirements, load profiles and usage characteristics and the costs incurred to serve those requirements.

NWE purchases power from the market to supply its default service obligation. NWE plans its delivery system to provide safe, reliable service for customers whether they purchase energy in the market or take default service from the utility. NWE designs its electric delivery system to meet three primary objectives:

1. To extend transmission and distribution facilities to serve its customers efficiently;
2. To meet the aggregate coincident and non-coincident peak capacity requirements of all customers entitled to receive service; and, as a result,
3. To permit energy delivery to customers regardless of who their supplier is.

It is important that the allocation methods used within the EM-COSS recognize these ***cost causative*** characteristics of NWE's plant investments and operating expenses. The EM-COSS should objectively reflect cost causation factors attributable to NWE's customers, their energy usage requirements, and system operations. The selection of the appropriate approach for functionalizing, classifying and allocating each component of plant, expense and revenue was based on careful consideration of cost causality, as well as Commission precedent and sound utility practice.

An important result of the EM-COSS is the return on rate base achieved by each customer class for the Test Period, which can be analyzed to determine if the revenue produced by the current tariff creates inter-class subsidies. Another result is the calculation of revenue required from each customer class in order for that customer class to provide the system average rate of return. This information is then used as the basis for developing rates that will realistically produce class returns that are more in line with each class' cost of service. Reality and gradualism must play a significant role when creating rates to manage the overall change in any one customer's total bill. Nevertheless, it is imperative that customers pay the marginal customer costs to avoid the distortion of marginal cost price signals and to eliminate intra-class and inter-temporal cost subsidies.

The study is performed in three steps. The first step is the allocation of plant, expenses and revenue to major cost categories or functions based on cost causation, using the Uniform System of Accounts (FERC Accounts). There are six functional categories used in the EM-COSS. They are Supply, Transmission, Substation, Distribution Primary, Distribution Secondary and Customer.

The second step is classification of the plant, expenses and revenue by functions among Capacity, Energy and Customer. **Capacity**-related costs are associated with plant that is designed, installed and operated to meet maximum hourly requirements (coincident and non-coincident peak loads), such as the distribution substations. Capacity or demand-related costs associated with serving the system peak are allocated to each class based upon each class's contribution to the system peak requirements. **Energy**-related costs are those costs that vary with the electricity throughput sold to, or transported for, customers. **Customer**-related costs are incurred to attach a customer to the distribution system, meter any electric usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any electricity.

The third step involves the allocation of the functionalized and classified plant, expenses and revenue to classes. The first and second steps use embedded cost causation methods to allocate the plant, expenses and revenue to each function and classification. The allocation of plant and expenses to customer classes is accomplished by using six primary percentage based marginal allocation factors. The revenue for each customer class is based on the projected revenues for each class during the Test Period using rates proposed in the information filing in September, 2006.

The six primary marginal allocation factors are Energy Costs, Transmission Costs, Distribution Substation Costs, Primary Distribution Costs, Secondary Distribution Cost and Customer Billing and Collections Costs. These six primary allocation factors are then used to allocate the total functionalized and classified costs to each customer class. This percentage-based allocation of embedded costs provides precisely the same result as a marginal allocation of costs trued up by percentage to the total embedded cost level.

An example that compares the two methods is presented in Table 3-1.

Method 1 is the method NWE used in marginal cost of service studies previously filed with the Commission. The unit marginal cost is multiplied by an Annualization factor to determine the customer class's marginal cost of services. Next the marginal cost of service is scaled to the full embedded cost of service using the percentage created by the marginal allocation factor.

Method 2 is the method used in this EM-COSS. The marginal unit cost is determined and multiplied by the Annualization factor. This creates the marginal cost of services by function/classification referred to above as the six primary allocation factors. Next, the resulting marginal allocation factor percentage is used to allocate the total embedded revenue requirement by function/classification.

As noted on lines 8 and 19 on Table 3-1, the methods yield the same results.

Table 3-1

Comparison of Method Previously Filed and Method used in this EM-COSS

Allocation of Marginal and Embedded Revenue Requirement

		Total	Residential	Commercial	Industrial
1	**Method 1: Method Previously Filed**				
2	Embedded total of "X":	60,000			
3					
4	Marginal Allocation of "Y"	20,000	12,000	6,000	2,000
5					
6	Scaling of Marginal Costs to Embedded	40,000	24,000	12,000	4,000
7					
8	Resulting Embedded Allocation	**60,000**	**36,000**	**18,000**	**6,000**
9					
10	**Method 2: Method used in this EM-COSS**				
11	Marginal Allocator based on percentage				
12					
13	Marginal Allocation of "Y"	20,000	12,000	6,000	2,000
14					
15	Marginal Allocator Percentages		60%	30%	10%
16					
17	Allocation of Embedded Revene Req. "X"	60,000	= 60% * 60,000	= 30% * 60,000	= 10% * 60,000
18					
19	Resulting Embedded Allocation	**60,000**	**36,000**	**18,000**	**6,000**
20					
21	Note: "X" denotes any functionalized total embedded revenue requirement (i.e. Transmission, Substation)				
22	"Y" denotes the functionalized marginal revenue requirement.				

The mechanics of the study were performed by a proprietary personal computer model created by R.J. Rudden, a Black & Veatch Company (Rudden). The general approach to the study takes 2009 levels of plant, expenses, and revenue as the input to the EM-COSS. The model then allocates these values to six functional cost categories and three cost classification categories (i.e., Capacity, Energy, and Customer) using embedded allocation factors. These allocation factors are described below. Next, the study allocates the total embedded costs for each Functionalized and Classified plant and expense and allocates them using a percentage based marginal allocation factor. Table 3-2 describes the creation of these allocation factors at a high level and on a total NWE basis. Appendix 3-1 identifies the same information as Table 3-2 by rate class for each of the six primary marginal allocation factors.

Table 3-2

List of Six Primary Allocation Factors

	Function*	Classify	Units	Marginal Unit Cost	Annualization Factor Description	Annualization Factor Total Value	Total Marginal Costs
1	Generation/Supply	Energy	$/KWH	$ 51.76	Sales with Losses (MWh)	6,332,641	$327,747,471
2	Transmission	Demand	$/MW	$ 7,760	12CP with Losses (MW)	1,230	$ 9,548,802
3	Substation	Demand	$/MW	$ 6,942	Substation NCP with Losses (MW)	1,647	$ 11,435,895
4	Distribution Primary	Demand	$/MW	$ 47,117	Distribution NCP with Losses (MW)	1,296	$ 61,043,863
5.1	Distribution Secondary for Utility Customers	Customer	$/Utility Customer	$ 74.82	Number of Customer minus Lighting Customers	336,773	$ 25,197,581
5.2	Distribution Secondary for Lighting Customers	Customer	$/Lighting Fixture	$ 41.77	Number of Utility Lighting Fixtures	80,177	$ 3,348,775
5	Distribution Secondary Total	Customer	NA	NA	NA	NA	$ 28,546,357
6	Customer	Customer	$/Customer	$ 54.56	Number of Customers	366,256	$ 19,981,586

The results of the computer model functionalizing, classifying and allocating revenues, plant and expenses are presented in Table 3-3. The comparison of allocated revenues to allocated revenue requirements and produced rates of return by class of service are also shown in Table 3-3.

Table 3-3

NorthWestern Energy Electric Utility
Summary Results of 2009 EM-COS

		Totals	RES-1 Residential (000)	GS1-2 Primary (000)	GS1-3 Secondary (000)	GS2-4 Substation (000)	GS2-5 Transmission (000)	IRR-6 Irrigation (000)	LT-7 Lighting (000)
1	**Supply Revenue Requirement**	299,243	107,181	15,529	145,178	15,854	7,850	4,580	3,072
2	**Non-Supply Revenue Requirement**	291,908	125,608	14,947	102,200	25,055	2,294	11,045	10,758
3	**Total Revenue Requirement**	591,151	232,789	30,476	247,378	40,909	10,144	15,625	13,830
4	**Total Revenue Allocated**	591,151	214,897	27,887	263,268	48,001	11,451	10,222	15,424
5	**Total Expenses**	549,799	212,932	27,894	235,680	37,792	10,011	13,112	12,379
6	**Total Ratebase**	699,360	273,015	34,592	253,487	77,565	6,843	25,642	28,215
7	**Current Return on Ratebase**	41,352	1,966	(6)	27,588	10,210	1,440	(2,890)	3,046
8	**Current Return on Ratebase Percentage**	5.9%	0.72%	-0.02%	10.88%	13.16%	21.05%	-11.27%	10.79%

Marginal Allocation Factors

The allocation of costs to customer classes is performed by the Rudden EM-COSS Model using six primary marginal allocation factors as discussed below.

1) Marginal Allocation of Energy Costs:

Energy costs are allocated based on the weighted market price of electric energy as determined from the Mid-Continental Day-Ahead Market for each weekday in 2006. The daily day-ahead market price was obtained and the average by month of this daily price creates an unweighted monthly price. This unweighted monthly price is then weighted using monthly sales during the Test Period to produce an annual weighted energy price in year 2006. The annual energy cost for 2006 of $51.89 per MWH, which is shown on line 14 of Table 3-4 below, is then adjusted to 2009 using the Annual Energy Outlook (AEO) 2007 Mountain Region, "Average Price to All Users." This adjustment is based on the comparison of the AEO year 2006 price to the AEO year 2009 price and results in an adjusted 2009 weighted energy price of $51.76 per MWH, which is shown on line 16 of Table 3-4. The adjusted 2009 market price is then used as the marginal energy price and multiplied by each customer class' annual sales adjusted for line losses to produce the marginal energy allocator.

Table 3-4

Market Power Costs for Mid C Day-Ahead Market

	Month		Average Daily Cost $/MWh	Energy Sales by Month (MWh)
1	Jan	$	58.40	538,920
2	Feb	$	51.50	468,475
3	Mar	$	45.93	487,643
4	Apr	$	24.40	439,077
5	May	$	32.82	445,211
6	Jun	$	39.67	452,927
7	Jul	$	73.74	529,045
8	Aug	$	64.14	515,776
9	Sep	$	47.88	447,844
10	Oct	$	52.48	467,420
11	Nov	$	62.21	493,073
12	Dec	$	59.72	538,602
13				
14	**Weighted (Spot) 2006 ($/MWh)**	$	51.89	
15	**Adj. based on AEO 2007**		99.74%	
16	**Forecasted (Spot) 2009 ($/MWh)**	$	51.76	

2) Marginal Allocation of Transmission Costs:

Transmission costs are allocated based on the cost of new transmission projects divided by their additional capacity. A list of new transmission substations projects, as shown in Appendix 3-2, was provided by NWE. This list includes the costs of the projects by year and the additional MVA capacity the projects provide to the system. The costs are first escalated to a common year (2006) using the Handy-Whitman Construction Cost Index for transmission plant; then divided by the project's MW capacity, assuming that MVA equals MW. This produces the marginal capital cost per unit of capacity. Next, a list of transmission line projects, their costs and additional capacity where provided. These costs are also divided by their MW additional capacity in a similar fashion to transmission substations. Marginal capital costs must be converted to annual costs by calculating the levelized revenue requirement designed to recover the return of and on the capital assets.

Table 3-5 shows the life of the transmission substations and transmission lines with the resulting levelized carry charge percentage based on the proposed capital structure presented NWE's September 2006 informational COS filing (Proposed Capital Structure). This table also shows the resulting average costs per MW of new transmission substations and transmission lines.

Table 3-5

Life & Levelized Carrying Charge Factor used to Calculated Marginal Cost

Project Type	Year*	Cost $/MW	Carry Charge Factor	Marginal unit Cost of New Capacity $/MW
1 Dist-Substation	40.8	$ 50,238	0.13818	$ 6,942
2 Trans-Substation	51.4	$ 46,092	0.14005	$ 6,455
3 Transmission Lines	58.3	$ 9,391	0.13897	$ 1,305

*Based on NWE's 2005 Depreciation Study

The sum of the marginal cost of new transmission substation capacity and the marginal cost of new transmission line capacity is then multiplied by the transmission 12 CP[13] of each customer class adjusted for capacity losses to create the percentage based marginal allocator for Transmission. The use of 12 CP reflects the relatively constant demand on a monthly basis on the transmission system when considering the aggregate demand on all capacity resources and the integration of the transmission system with the grid.

3) Marginal Allocation of Distribution Substation Costs:

Distribution Substation costs are allocated based on the cost of new distribution substation projects divided by their additional capacity. A list of new distribution substations projects for the years 2004-

[13] 12 CP represents the average of the maximum monthly coincident demand on the transmission system for a 12 month period. The transmission system loading must be capable of delivery capacity to customers regardless of the status of individual generating units or the maintenance of transmission system resources. The use of 12 CP reflects the nature of the system demands.

2006, as shown in Appendix 3-2,[14] was provided by NWE. This list includes the costs of the projects by year and their additional MVA capacity. The costs are first escalated to a common year (2006) using the Handy-Whitman Construction Cost Index for distribution substation plant; then divided by the project's MW capacity, assuming that MVA equals MW.

Table 3-5 above shows the life of the distribution substations with the resulting levelized carry charge percentage based on the Proposed Capital Structure of NWE. This table also shows the resulting cost per MW of new distribution substations. The marginal cost of new distribution substation capacity is then multiplied by the non-coincident peak of each customer class at the substation level and adjusted for losses to create the percentage based marginal allocator for Distribution Substation. This calculation can be reviewed in Appendix 3-1.

4) Marginal Allocation of Distribution Primary Costs:

Distribution Primary costs are allocated based on the costs of new distribution plant divided by the additional distribution system capacity. Distribution Primary costs have four components: Distribution Poles, Overhead Wires, Underground Wire, and Underground Conduit. Table 3-6 shows each of these plant component's additions over the last four years (Lines 1-4). Also shown on Table 3-6 is the system peak from 2002-2005, as reported in NWE's FERC Form 1 for the Montana Division and the 2002-2005 average peak growth.

The cost of new distribution capacity is calculated by dividing the pro rata portion of the average new growth over the last three years by the average plant additions due to new construction. The additions due to new construction (as opposed to replacement of existing facilities) results from a study for overhead wire replacement vs. new construction. The levelized carrying costs of these new additions per KW are shown as Marginal Cost of Distribution Plant on line 16 of Table 3-6. The costs of these four components of primary distribution are summed to create the marginal cost of new primary distribution capacity of $47.54 per KW. The marginal cost of new primary distribution is then multiplied by the non-coincident peak of each customer class at the distribution level and adjusted for losses to create the percentage based marginal allocator for Distribution Primary. This calculation can be reviewed in Appendix 3-1.

[14] A list of both new transmission substations and new distribution substations are displayed in the same Appendix 3-2.

Table 3-6
Marginal Allocation of Primary Distribution

	Year	Poles & Fixtures - Dist-Addns (000)	Overhead Conductors- Dist-Addns (000)	Undrgrnd Conduit Dist-Addns (000)	Undrgrnd Conductors Dist-Addns (000)	System Peak (MW)
1	2002	4,303	1,668	2,996	3,026	1,390
2	2003	3,565	2,211	3,743	2,923	1,442
3	2004	5,008	3,391	4,917	4,313	1,547
4	2005	3,720	2,371	4,179	3,376	1,614
5	Average Plant Additions	4,149	2,410	3,959	3,410	
6	Growth in Average System Peak					75
7	Growth in Underground Capacity					24
8	Growth in Overhead Capacity					51
9						
10	% of Plant Additions for New Construction	69%	69%	69%	69%	
11	Avg System Growth for New Construction (MW)	51	51	24	24	
12	$/KW of New Construction	**$56.24**	**$32.67**	**$114.93**	**$98.99**	
13						
14	Depreciation Life (Yr)	39.9	45.1	45.0	40.0	
15	Levelized Carrying Charge Factor	0.158	0.156	0.156	0.158	
16	Marginal Cost of Distribution Plant ($/KW)	**$8.89**	**$5.11**	**$17.95**	**$15.60**	

5) Marginal Allocation of Distribution Secondary Costs:

Distribution Secondary costs are allocated based on the cost of new distribution plant needed to add the smallest customer to the system by customer class. Distribution Secondary costs have four components: Meters, Services, Transformers, and Street lighting fixtures. Appendix 3-3 shows each of these plant component's costs (Lines 2-5). Also shown on Appendix 3-3 is the expected plant life and levelized carrying charge by distribution secondary component (Lines 9-12).

The cost of new distribution secondary is calculated by component. The first component is Meters, shown on line 2. This is the least cost Meter for each customer class. The second component is Services, shown on line 3. This is the least cost Service for each customer class. The third component is Transformers, shown on line 4. This is the least cost Transformer divided by the number of customers that can connect to a single Transformer by customer class. The forth component is lighting, shown on line 5. This is the cost of a new lighting fixture and assumes it is attached to a utility pole to represent the least cost installation. The levelized carrying cost of these new additions per customer is summed to calculate the marginal cost per customer for each customer class. The marginal cost of new distribution secondary is the per customer costs multiplied by the number of customers/lighting fixtures in each customer class.

6) Marginal Allocation of Customer Billing and Collections Costs:

Customer Billing and Collection costs are allocated based on the cost of adding a block of new customers to the system. The marginal cost of adding a block of new customers to the system will approach the embedded allocation of costs when the block is large enough to cause investment in new employees and systems to handle the added requirements of the new customers. An example for new employees is the number of meter readers and customer service representatives needed to serve the new block of customers. An example of systems is new vehicles purchased to facilitate the work activities of the new meter readers, and new computers purchased to support the new customer service representatives.

Therefore, the marginal allocation of Customer Billing and Collections uses the average embedded allocation of costs outlined below.

Meter Reading Expense (Accounts 902): Meter Reading Expenses including Manual Meter Reading, Mobile AMR, and Turtle are allocated based on a number of customers by meter reading type. A study was performed to allocate meter reading cost based on the labor costs per type of meter read by customer class. Table 3-7 outlines the number of reads by customer class by month and forms the basis of the special study.

Table 3-7

Electric Meter Reading

1	**Mobile AMR Reading**		**Manual Reading**	
2	GS1 - Primary	5	Residential	3,758
3	GS1 - Secondary	34,067	GS1- Secondary	23,563
4	Irrigation	649	GS1- Primary	132
5	Lighting	124	GS2- Substation	1
6	Residential	260,275	Irrigation	3,182
7	**Total**	**295,120**	Lighting	5
8			**Manual Read Count**	**30,641**
9	**Turtle Reading**		**Allocated Labor Expense**	**$ 378,807**
10	Residential	3,966		
11	GS1 - Secondary	1,368	**Large Customer MV-90 Reading**	
12	GS1 - Primary	1	GS1 - Secondary	88
13	Irrigation	207	GS1 - Primary	35
14	**Total**	**5,542**	GS2- Substation	67
15			GS2- Transmission	18
16	**AMR & Turtle Count**	**300,662**	**MV-90 Read Count**	**208**
17	**Allocated Labor Expense**	**$ 312,745**	**Allocated Labor Expense**	**$ 25,589**

Customer Records & Collection Expense (Accounts 903): Customer Records & Collection Expense includes the activities identified in items a through e below. These costs are allocated based on the special study outlined below:

a. Billing: A special study was designed to identify the elements of Account 903 related to Billing and Postage. The labor and other costs directly related to the printing and mailing of bills are identified. These costs are then allocated based on the number of mailed bills by class.
b. Collections Services: The actual costs of Collections Services are allocated based on outstanding collection activity, by class, based on the 30, 60, 90 delinquency report for 2005.
c. Outside Collections Services: The actual cost of Outside Collections Services is identified and these costs are allocated based on outstanding collection dollars, by class, based on the 30, 60, 90 delinquency report for 2005.

d. Turn on/off Service Orders: The actual costs of turning on a customer or turning off a customer due to non-payment are allocated based on actual write-offs experienced in the 2005 calendar year by class.
e. Other Customer Accounts Expenses: The balance of Account 903 is allocated based on the combined class allocations of the rest of the account.

Call Center (Account 908): The Company records all calls received by account. Each call was assigned to a customer class based on the account's primary rate code. Costs for the call center are allocated based on the number of calls received to the call center by each customer class.

Information & Instructional Advertising (Account 909): This account includes the actual cost of sending out bill inserts and is allocated based on the number of bills sent annually.

Customer Assistance Expenses (Account 910): Customer Assistance Expenses that are functionalized and classified to Customer are allocated based on a study that reflects the time spent by the load research department of NWE on billing large hourly metered (MV-90) customers and collecting load sample data for all customers groups.

Functions and Classification Allocations by Account

Cost are functionalized and classified in this study based on embedded allocation factors. There are two types of allocation factors typically used in performing an embedded cost of service study and employed in the Rudden Model: external factors and internal factors. *External* allocation factors are based on direct knowledge from data in the utility's accounting and other records. For example, transmission costs are assigned to transmission FERC accounts and are assigned by an external transmission allocator. Another example of an external allocator is unbundled revenues by function. The rates for supply, transmission, and distribution are known and calculated based on billing determinates to form the basis of an external revenue allocator. *Internal* allocation factors are based on some combination of external allocation factors, previously directly assigned costs and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; it is necessary to compute the amount of plant by function before property insurance costs can be assigned. Both external and internal allocation factors are used in each of the functional and classification steps outlined below. The follow section outlines, by account, the allocation of costs to each function and classification.

A. Intangible Plant

Intangible Plant (Accounts 301 to 303) represents capitalized software costs for new and updated financial and operating systems. Intangible plant is functionalized, and classified based on plant or labor.

B. Production Plant - None

C. Transmission Plant and Expenses

1. Plant

Transmission Plant (Accounts 350-359) represents poles, towers, wires and substation used in the high voltage transmission system. The cost of this equipment is functionalized to Transmission, and classified to Demand.

2. Expense
   Transmission Operation & Maintenance (Accounts 560-573) are functionalized, and classified based on Accounts 350-359.

D. Distribution Plant and Expenses
   1. Distribution Plant (Accounts 360-373)
      a. Substations (Accounts 360-362)
         Substations are functionalized to Substation, and then classified as Demand.
      b. Poles, and Wires (Accounts 364-367)
         Poles and Wires are functionalized to Distribution Primary, and classified to Demand.
      c. Transformers, Meters and Services (Account 368-370)
         Transformers, Meter and Services Plant is functionalized to Distribution Secondary, and classified to Customer.
      d. Lighting (Account 373)
         Lighting is functionalized to Distribution Secondary, and classified to Customer.
   2. Distribution Expenses (Accounts 580-598)
      a. Load Dispatching (Account 581)
         Load Dispatching is functionalized to Distribution Primary, and classified to Demand.
      b. Substation Expenses (Accounts 582, 591-592)
         Station Expenses is functionalized to Substation and classified to Demand.
      c. OH and UG Lines Expenses (Accounts 583-584, 593-594)
         Line Expenses are functionalized to Distribution Primary and classified to Demand.
      d. Street Lighting & Signal Systems (Account 585,596)
         Street Lighting & Signal Systems are functionalized to Distribution Secondary and classified to Customer.
      e. Meter Expenses (Accounts 586, 597)
         Meter Expenses are functionalized to Distribution Secondary and classified to Customer.
      f. Customer Installation Expenses (Account 587)
         Customer Installation Expenses are functionalized to Distribution, classified to Customer.
      g. Distribution Rents and Misc. (Accounts 580, 588-590, 598)
         Rents and Misc. Distribution accounts are functionalized and classified based on other distribution accounts.

E. General Plant
   General Plant (Accounts 390-398) is functionalized and classified based on labor.

F. Depreciation Reserve
   Deprecation Reserve (Account 108) is functionalized and classified based on their corresponding gross plant values.

G. Other Rate Base Items:
   Various Accounts: These accounts are functionalized and classified based on labor or plant.

H. Customer Accounts Expenses
   1. Meter Reading Expense (Accounts 902)
      Meter Reading Expenses are functionalized and classified to Customer.

2. Customer Records & Collection Expense (Account 903)
   Customer Records & Collection Expense are functionalized and classified to Customer.
3. Uncollectible Account Expenses (Account 904)
   Uncollectible Accounts Expense is functionalized, and classified based on revenue requirements and allocated based on actual write-offs experienced in the 2005 Test Period.

I. Customer Service & Information Expenses

1. Call Center (Account 908)
   Call Center Expenses are functionalized and classified to Customer.
2. Informational & Instructional Advertising (Account 909)
   Informational & Instructional Advertising Expenses are functionalized and classified to Customer.
3. Customer Assistance Expenses (Account 910)
   Customer Assistance Expenses are functionalized to both Transmission and Customer as shown in Table 3-7 above. The account value functionalized to transmission is classified to Demand and the account value functionalized to Customer is classified to Customer.

J. Administrative and General Expenses

Administrative and General Expenses (Accounts 920-939) are identified in two groups: labor related, and plant related. Labor-related expenses are functionalized and classified according to the labor in each function. Plant-related expenses are functionalized and classified according to the plant in each function.

K. Depreciation and Amortization

Depreciation and Amortization (Accounts 403-407) are functionalized and classified based on Accumulated Depreciation and Amortization.

L. General Tax, Payroll and Real Estate Tax

Payroll taxes are functionalized and classified based on labor. Real Estate Taxes are functionalized and classified based on Plant.

M. Revenue Taxes

Revenue Taxes were functionalized, and classified based on revenue.

N. Income Taxes

Income Taxes were functionalized and classified based on a special study.

O. Revenue and Other Revenue

Revenues were functionalized based on unbundled rates, and classified based on revenue requirements and allocated based on actual revenues collected from each class in the Test Period.

ELECTRIC RATE DESIGN

A number of tariff and rate design principles or objectives find broad acceptance in regulatory and policy literature. These include:

1. Efficiency
2. Cost of Service
3. Value of Service
4. Stability
5. Non-Discrimination
6. Administrative Simplicity
7. Comparability
8. Balanced Budget

These rate design principles draw heavily on the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in effective rate design. To understand the role these principles play, the following discusses each of the principles.

The principle efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by electric producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities and facilitates the efficient use of existing transmission and distribution resources. Efficient prices reflect marginal cost while also recovering the total authorized cost of service. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with utility cost of service.

The cost of service and value of service principles each relate to designing rates that recover the total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. From a market perspective, marginal cost serves as the floor for pricing. Therefore, appropriate prices must lie between the marginal cost floor and the value of service ceiling.

The concept of cost of service is only relevant so long as it produces rates that fall within the floor and ceiling. These issues are most significant in relation to system bypass economics. If opportunities exist for economic bypass, the bypass option establishes the value of service ceiling. In the evaluation of a bypass response, the marginal cost floor limits the permitted level of discount. Where the marginal cost floor is below the value of service, the bypass is uneconomic from a societal perspective and discounting benefits all market participants. Further, the calculation of the precise cost of service is not possible where joint and common costs exist and allocation to customer classes is required. For this reason alone, the regulatory process produces multiple cost of service outcomes based on the assumptions regarding the allocation of joint and common costs. Nevertheless, cost of service studies, properly reflecting cost causation, provide a reasonable tool for the allocation of revenue requirements among customer groups.

The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are an important market feature. In competitive wholesale electric markets, the fundamental short-run nature of fixed supply and fluctuating demand creates short-term price volatility to clear the market. There will always be occasions where competitive market prices must rise in the short run to equate supply and demand. This volatility is a necessary condition for promoting economically efficient use of utility service. Utility consumers and regulators often desire price stability and consequently only product and service offerings that feature stability on a seasonal, annual or multi-year basis are authorized. Thus, either the utility or its customers bear the risk of real-time market price instability on a prospective basis. Where the utility bears this risk, an appropriate rate of return on investment must be included in rates to compensate for this unique risk element. The cost for managing market price volatility (as measured by return requirements) is typically quite significant. In general, the preferred solution is to manage the risk through electric markets and pass those costs to consumers through the electric cost adjustments resulting in a lower total cost for most consumers. It is important to note that price signals only work if consumers who respond by reducing demand to mitigate demand receive some benefit from doing so. Thus, fixing retail energy prices denies the signal to consumers and frustrates the rationing efficiency of price signals.

The non-discrimination principle requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers in the same class or across different classes of customers. Rates are subsidy free when no customer pays less than marginal cost or more than stand-alone costs as noted above. Non-discrimination requires that prices for comparable service be equal. A key point with respect to non-discrimination is comparability of service. There are many factors used to determine comparable service. Among the factors are location, type of meter and service, demand characteristics, size, and a variety of other considerations. The importance of comparability issues is critical to the development of non-discriminatory pricing. Equally important is the concept that no customer pays less than marginal cost. Further, volumetric rates that exceed marginal cost also produce inefficiencies.

The principle of administrative simplicity as it relates to tariff design requires rates that are reasonably simple to administer and understand. This concept includes price transparency. Prices are transparent when customers are able to reasonably calculate bill levels and interpret details about the charges resulting from the application of the tariff.

The principle of comparable services reflects consideration of the types and prices of services offered in other jurisdictions and by other companies in the same jurisdiction. It recognizes that fundamental service characteristics differ for many reasons and that there is much to gain from comparisons to the best knowledge and innovations reflected in other tariff designs. These other tariff designs should not be limited solely to a particular utility segment but should consider broadly the pricing structures that prevail in markets where comparable cost recovery issues occur.

Finally, there is the critical principle that rate design permits the utility a reasonable opportunity to recover the allowed revenue requirement based on the cost of service. Rate design becomes a critical element for cost recovery. Improperly designed rates deprive the utility of a reasonable opportunity to recover revenue requirements where actual billing determinants and test year billing determinants differ, as they almost certainly will. If rate elements reflect marginal cost, changes in the billing determinants over time match changes in cost and revenues. Rates calculated at average cost or that recover fixed costs based on volume may result in over or under recovery of costs as billing determinants change from those in the test year.

Following these principles often results in conflicting guidance. Detailed discussion of tariff principles recognizes the potential and actual conflicts imposed by these principles. Indeed, Bonbright discusses these conflicts in detail. Tariff and Rate design recommendations must deal effectively with such conflicts. For example, as noted above, there are potential conflicts related to cost and value of service principles. There are direct conflicts between the use of embedded cost of service for determining revenue requirements, using average cost to price services and marginal cost pricing to promote efficiency.

The conflict between good price signals based on marginal cost and a balanced budget or revenue recovery principle arises because marginal cost is below average cost due to the significant economies of scale in electric distribution service. Where fixed distribution costs do not vary with the volume of electric sales, marginal costs for commodity delivery equal zero. Marginal customer costs equal the additional cost of providing the entire delivery service to the customer. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost based pricing will produce either too much or too little revenue to support the revenue requirement. This suggests that efficient price signals require a multi-part tariff designed to meet the revenue requirements while sending marginal cost price signals related to consumption decisions. Properly designed, a multi-part tariff includes elements such as access charges, facilities charges, demand charges, consumption charges and the potential for revenue credits. Taken together, these elements permit good price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For example, it is not common to include demand charges in residential or small commercial rates. From the view of economically efficient price signals, some efficiency is sacrificed. However, from an overall cost efficiency, the sacrifice is small because of the added costs to meter customer demand compared to the ability of customers to manage demand on their own.

There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where companies face unique circumstances that must be considered as part of the tariff design process.

Having established principles for rate design, developing rates within the context of these principles requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as the embedded customer, demand and energy related costs as well as marginal costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics and bypass alternatives; and

4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of under-utilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates. Translation of objectives into rate design must also consider the anatomy of potential rates. The basic structure of a typical rate schedule consists of a customer charge and/or other fixed charges, demand charges, volumetric charges and automatic adjustment charges. There are numerous variations of rate designs using these basic components. In each case, a rate design seeks to recover the authorized level of revenue based on the actual billing determinants occurring during the test period used to develop the rates.

Based on the results of the marginal cost analysis, economically efficient rate design suggest substantial increases in the customer charge up to the level of at least the fully allocated customer cost from an embedded cost of service study. Sound rate design permits recovery of fixed costs in fixed charges, particularly where such recovery permits more efficient price signals. Importantly, the economic circumstances for NWE require higher customer charges to promote economic efficiency and to improve fixed cost recovery.

The customer charge is an important element of an economically efficient and sound rate design. At a minimum, the customer charge recovers the out-of-pocket cost of serving a customer (the marginal customer costs). At the maximum, an efficient customer charge recovers all of the fixed costs of service to customers. The marginal customer cost includes the carrying cost of the capital invested in facilities at the customer's location (meter, service transformer and line extension), the cost of meter reading, billing, customer service and any other costs associated with the facilities at the customer's premises. The customer charge is also the element of rate design that is the appropriate element to recover average costs above marginal costs in an efficient rate design. To provide context for the role of the customer charge in rate design and to guide the choice of an efficient customer charge from within the theoretical range, the appropriate basis for analysis relies on the principles of rate design discussed above. The principles of rate design provide important guidance for the appropriate level of the customer charge as discussed below. Importantly, these principles support increases to the customer charge component of the rates.

With respect to the balanced budget or revenue-related attributes, increased customer charges result in a better opportunity for the Company to recover the approved revenue requirement. The obvious reason is that the normal weather used to design rates is unlikely to occur. Higher customer charges lessen the impact of weather variation on the revenues from higher or lower energy sales. For the delivery or distribution service portion of revenue requirements, the costs are fixed and do not vary with the weather or even with the level of electricity consumed. Customers experience greater bill predictability from this proposal. Implementing increased customer charges takes the first step toward significantly improved rates in terms of both marginal cost price signals and establishing cost-based rates.

Economic efficiency requires that price (rates) equal short-run marginal cost. All of the costs for electric distribution are fixed. For this reason alone, the short-run marginal cost of the electric distribution or delivery system is small. This simply means that minimizing the per kWh charges for electric rates and increasing the customer-based charges produces more economically efficient rates.

By recovering fixed costs in fixed charges, rate design satisfies the various cost-related principles discussed above. Among the important benefits of the proposed customer charge increase is the elimination of subsidies related to the distribution component of NWE rates. The cost of service principle and the value of service principle require an understanding of the importance of the allocation of common costs. The argument related to the allocation of common costs among customer classes and within customer classes supports an increase in the customer charge. The test for subsidy free rates (in the economic context as opposed to the regulatory return analysis) requires that each rate element exceed marginal cost and that no customer pay more than the stand-alone cost of service. Failure to approve subsidy free rates causes economic distortions that harm all market participants. Subsidy free rates result in a sharing of common costs among customers and improve the economics for all customers. Where rates seek recovery of common costs above marginal cost in commodity-related charges, there is a predictable result. Namely, customers make uneconomic decisions about their use of energy. Higher customer charges permit lower per kWh charges and move rates for consumption closer to the economically efficient level of marginal cost.

Customer charge increases also satisfy the practical attributes of rate design. Customers currently pay for other services with fixed costs through fixed charges. For example, network service providers use customer charges to recover costs and, in some cases, customers pay the entire network cost as a fixed charge. Telephone and cell phone users pay for the fixed cost network with customer charges. Movement to more efficient rate designs is a critical element in the process of improving the market for utility services.

Calculation of Customer Class Rates and Rate Design:

The calculation of customer class revenues and rate design are provided separate from this report.

SECTION V
RECOMMENDATIONS AND CONCLUSIONS

Based on the results of the marginal cost analysis and the resulting rate designs, it seems reasonable to establish a plan that will move rate designs to permit substantially more fixed cost recovery in fixed charges. This process should be phased in by revenue neutral rate design changes over a two- to three-year period. There is little value to a marginal cost study unless it is used to set marginal rates at marginal costs and to recover the remaining revenue requirement in infra-marginal rates.

It also seems reasonable to alter the preferred cost allocation methodology from a marginal cost basis to an embedded cost basis for a number of reasons. First, allocation of cost of service (an embedded cost or normalized historical cost) on the basis of marginal costs has, in our view, even more arbitrary requirements than the more traditional cost of service methodologies. This results from the use of cost estimates that, while reasonable, cannot ever be subjected to audit because they may never be incurred. Second, the magnitude of the adjustments from marginal costs to the revenue requirement may be quite large and will vary from one study to the next. This variation may be quite large depending on the rate of technological change and the underlying inflation rates. Third, the value of marginal cost arises in the context of rate design and provides clear guidance with respect to efficient prices. By using marginal costs to calculate rates, the efficiency objectives sought through regulation may be achieved. Finally, allocating the revenue requirement on embedded cost principles informed by both the concept of marginal cost and SAC allows for subsidy free rates that fall within a range of outcomes consistent with other goals of regulation such as rate gradualism and social equity.

APPENDICES

Appendix 3-1): Presents the creation of the six primary allocation factors on a customer class basis.

Appendix 3-2): Lists the new transmission and new distribution substations, which form the basis of the Transmission and Substation Marginal allocation factors.

Appendix 3-3): Identifies the minimum cost for the four distribution secondary components, Meters, Services, Transformers, and Street lighting fixtures by Customer Class.

Appendix 3-4): Shows detailed plant, expenses, and revenue for the six functional categories.

Appendix 3-5): Includes a Summary Report and Revenue Requirements Report for the six Functional categories.

Appendix 3-6): Shows detailed plant, expenses, and revenue for NWE for each customer class on a Marginal basis.

Appendix 3-7): Includes a Summary Report and Revenue Requirements Report for NWE for each customer class, showing the total revenue requirement that would be required from each customer class in order for it to produce the system average rate of return.

The Six Primary Allocation Factors by Customer Class

	Annualization Factors Description	Totals\ Unit Costs	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
Marginal Unit Costs											
Generation\Supply	Sales with Losses (MWh)	51.76	2,164,152	5,406	98,621	-	327,924	-	701	-	312,112
Transmission	12 CP with Losses (MW)	7,760	359.0	0.9	16.3	13.4	44.4	0.0	0.1	0.2	49.2
Substations	Substation NCP with Losses (MW)	6,942	495.7	1.2	22.5	16.0	108.8	0.0	0.2	0.2	67.5
Distribution Primary	Distribution NCP with Losses (MW)	47,117	492.1	1.2	22.4	15.4	105.0	0.0	0.2	0.2	67.1
Distribution Secondary	Number of Customers minus Lightin	74.82	259,201	572	13,432	8	113	1	45	160	41,947
Distribution Secondary	Number of Lighting Fixtures	41.77									
Customer	Number of Customers	54.56	259,201	572	13,432	8	113	1	45	160	41,947
Total Marginal Costs											
Generation\Supply		327,747,471	112,006,256	279,764	5,104,167	-	16,971,811	-	36,302	-	16,153,427
Transmission		9,548,802	2,785,978	6,958	126,838	104,300	344,352	27	623	1,275	381,560
Substations		11,435,895	3,440,895	8,575	156,477	110,936	755,650	125	1,240	1,570	468,886
Distribution Primary		61,043,863	23,186,422	57,781	1,054,421	726,168	4,946,354	618	8,117	10,576	3,159,578
Distribution Secondary		25,197,581	19,393,592	42,797	1,004,991	599	8,455	75	3,367	11,971	3,138,503
Distribution Secondary		3,348,775	-	-	-	-	-	-	-	-	-
Total Distribution Secondary		28,546,357	19,393,592	42,797	1,004,991	599	8,455	75	3,367	11,971	3,138,503
Customer		19,981,586	14,141,057	31,206	732,801	436	6,165	55	2,455	8,729	2,288,475

The Six Primary Allocation Factors by Customer Class

	Annualization Factors Description	Totals\ Unit Costs	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation
Marginal Unit Costs											
Generation\Supply	Sales with Losses (MWh)	51.76	-	2,760,164	-	335,500	-	156,877	9,252	-	91,779
Transmission	12 CP with Losses (MW)	7,760	10.5	410.2	236.5	39.0	7.6	21.3	0.1	0.0	13.6
Substations	Substation NCP with Losses (MW)	6,942	12.9	505.7	291.6	47.2	-	-	-	0.2	55.7
Distribution Primary	Distribution NCP with Losses (MW)	47,117	12.8	502.1	-	-	-	-	-	0.2	55.3
Distribution Secondary	Number of Customers minus Lightin	74.82	119	18,001	35	19	1	10	7	2	2,100
Distribution Secondary	Number of Lighting Fixtures	41.77									
Customer	Number of Customers	54.56	119	18,001	35	19	1	10	7	2	2,100
Total Marginal Costs											
Generation\Supply		327,747,471	-	142,853,014	-	17,363,907	-	8,119,223	478,860	-	4,750,067
Transmission		9,548,802	81,283	3,183,086	1,835,399	302,831	59,155	165,434	1,038	293	105,249
Substations		11,435,895	89,836	3,510,610	2,024,218	327,872	-	-	-	1,080	386,965
Distribution Primary		61,043,863	605,357	23,656,191	-	-	-	-	-	7,280	2,607,560
Distribution Secondary		25,197,581	8,904	1,346,847	2,619	1,422	75	748	524	150	157,123
Distribution Secondary		3,348,775	-	-	-	-	-	-	-	-	-
Total Distribution Secondary		28,546,357	8,904	1,346,847	2,619	1,422	75	748	524	150	157,123
Customer		19,981,586	6,492	982,069	1,909	1,037	55	546	382	109	114,568

The Six Primary Allocation Factors by Customer Class

	Annualization Factors Description	Totals\ Unit Costs	IRR-6C Non-Demand Non-Choice Irrigation	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7A Non-Demand Non-Choice Lighting
Marginal Unit Costs							
Generation\Supply	Sales with Losses (MWh)	51.76	5,137	-	61,333	2,060	1,620
Transmission	12 CP with Losses (MW)	7,760	0.8	0.5	6.5	0.2	0.2
Substations	Substation NCP with Losses (MW)	6,942	3.1	1.6	16.0	0.5	0.4
Distribution Primary	Distribution NCP with Losses (MW)	47,117	3.1	1.6	15.9	0.5	0.4
Distribution Secondary	Number of Customers minus Lightin	74.82	1,000				
Distribution Secondary	Number of Lighting Fixtures	41.77		9,467	70,116	121	473
Customer	Number of Customers	54.56	1,000	283	28,606	121	473
Total Marginal Costs							
Generation\Supply		327,747,471	265,869	-	3,174,317	106,631	83,855
Transmission		9,548,802	5,891	3,899	50,313	1,690	1,329
Substations		11,435,895	21,659	11,421	111,208	3,735	2,937
Distribution Primary		61,043,863	145,949	76,959	749,372	25,169	19,793
Distribution Secondary		25,197,581	74,821	-	-	-	-
Distribution Secondary		3,348,775	-	395,411	2,928,555	5,054	19,756
Total Distribution Secondary		28,546,357	74,821	395,411	2,928,555	5,054	19,756
Customer		19,981,586	54,556	15,439	1,560,639	6,601	25,805

Marginal Transmission and Substation Allocator

#	Project Description	MPC #		Facility Type	04 Project Cost	05 Project Cost	06 Project Cost	Total Project Cost	Project Cost 2006 $	High MVA	MVA to MW Factor 1	Distribution Substations	Transmission Substations	Transmission Lines
1	**Electric Substation Projects**													
2	Project Description	MPC #		Facility Type	04 Project Cost	05 Project Cost	06 Project Cost	Total Project Cost	Project Cost 2006 $	High MVA	1	Distribution Substations	Transmission Substations	Transmission Lines
3	Helena Golf Course #2	25000-H	2	Distribution	$ 353	$ 1,006,206	$ 12,597	$ 1,019,157	$ 1,090,139.98	42	42	$ 25,956		
4	Hardin City Sub Rebuild	12000-AY	3	Distribution	$ 296	$ 860,479	$ -	$ 860,775	$ 921,476.76	20	20	$ 46,074		
5	Bozeman Sourdough Substation	12000-AX	4	Distribution	$ 288,376	$ 1,463,361	$ 286,124	$ 2,037,861	$ 2,215,753.79	20	20	$ 110,788		
6	Billings 8th St Bank #1 Changeout	25000-I	7	Distribution	$ 604,842	$ -	$ -	$ 604,842	$ 761,712.96	42	42	$ 18,136		
7														
8	Mill Creek Bank #4 Replacement	240000-A	1	Transmission	$ -	$ 309,958	$ 2,119,213	$ 2,429,171	$ 2,450,014.48	400	400		$ 6,125	
9	Three Rivers Auto	90000-B	5	Transmission	$ 135,367	$ 4,303,702	$ 1,405,524	$ 5,844,594	$ 6,163,482.71	150	150		$ 41,090	
10	Stanford Auto (Network)	12000-AW	6	Transmission	$ 577,425	$ 1,047,578	$ -	$ 1,625,003	$ 1,821,223.25	20	20		$ 91,061	
11														
12														
13	Handy-Whitman Index by Year - Station Equip - Trans				404.00	461.00	492.00							
14	Handy-Whitman Index by Year - Station Equip - Dist				374.00	440.00	471.00							
15														
16														
17	**Electric Transmission Line Projects**													
18	Laurel Auto to Laurel city - new 100kv line 92MVA capacity				$ 359,977			$ 359,977	438,388	92	92			$ 4,765
19	Richardson Coulee to Glasgow WS 69kV ReConductor increase of capacity of 41MVA				$ 312,479			$ 312,479	380,544	41	41			$ 9,282
20	New TRJR 161kV line 204 MVA capacity, with associated 50 kV underbuild					$ 2,700,000		$ 2,700,000	2,881,562	204	204			$ 14,125
21														
22														
23														
24	Average Cost of New Distribution Substation Capacity											$ 50,238		
25	Average Cost of New Transmission Substation Capacity												$ 46,092	
26	Average Cost of New Transmission Line Capacity													9,391
27														
28														
29														

30 **Life & Levelized Carrying Charge Factor used to Calculated Marginal Cost**

#	Project Type	Year*	Cost $/MW	Carry Charge Factor	Marginal unit Cost of New Capacity $/MW
31	**Project Type**	**Year***	**Cost $/MW**	**Carry Charge Factor**	**Marginal unit Cost of New Capacity $/MW**
32					
33	Dist-Substation	40.8	$ 50,238	0.13818	$ 6,942
34	Trans-Substation	51.4	$ 46,092	0.14005	$ 6,455
35	Transmission Lines	58.3	$ 9,391	0.13897	$ 1,305

*Based on NWE's 2005 Depreciation Study

Marginal Distribution Secondary Costs

			RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	Appendix 3-3 GS2-4A Demand Choice Substation
1	**Cost per item**	Life/Total												
2	New Single Phase Meter		51	51	51	3,580	3,580	1,036	1,036	51	51	461	461	3,580
3	New Single Phase Service		171	171	171	-	-	-	-	204	204	224	224	-
4	New Single Phase Transformer		189	188	189					473	473	698	698	
5	New Street Lighting Fixture													
6	Subtotal		411	411	411	3,580	3,580	1,036	1,036	728	728	1,384	1,384	3,580
7														
8	**Life & Levelized Carrying Charge Factor**													
9	New Single Phase Meter	15	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915
10	New Single Phase Service	46.2	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282
11	New Single Phase Transformer	40.7	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452
12	New Street Lighting Fixture	40.3	0.15081	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138
13														
14	**Marginal Distribution Customer Allocator**	**28,546,357**	**14,717,133**	**32,477**	**762,653**	**4,844**	**68,428**	**175**	**7,887**	**15,900**	**4,168,556**	**24,006**	**3,631,336**	**21,195**

Marginal Distribution Secondary Costs

	Life/Total	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
1 **Cost per item**												
2 New Single Phase Meter		3,580	33,695	33,695	33,695	461	461	51	-	-	-	-
3 New Single Phase Service		-	-	-	-	204	204	204	-	-	-	-
4 New Single Phase Transformer						4,189	4,189	1,396				
5 New Street Lighting Fixture									375	375	375	375
6 Subtotal		3,580	33,695	33,695	33,695	4,854	4,854	1,651	-	-	-	-
7												
8 **Life & Levelized Carrying Charge Factor**												
9 New Single Phase Meter	15	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915	0.16915
10 New Single Phase Service	46.2	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282	0.13282
11 New Single Phase Transformer	40.7	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452	0.13452
12 New Street Lighting Fixture	40.3	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138	0.11138
13												
14 **Marginal Distribution Customer Allocator**	**28,546,357**	**11,506**	**5,699**	**56,995**	**39,896**	**1,337**	**1,404,020**	**223,536**	**395,411**	**2,928,555**	**5,054**	**19,756**

Northwestern Energy Cost of Service Study
Electric - Year Ending December 31, 2009

Account Description	Account Code	Account Balance	Functional Allocation Factor	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Organization	301	19,995	TPIS	0	7,114	1,804	5,676	5,276	124
Franchise and Consents	302	2,004	TPIS	0	713	181	569	529	12
Computer Software 5 Yrs	303.1	307,661	LABOR	0	87,470	19,110	87,698	70,270	43,112
BPA - Rattlesnake Line	303.3	868,284	TRAN	0	868,284	0	0	0	0
Computer Software 3 Yrs	303.5	0	TPIS	0	0	0	0	0	0
Other	303.6	0	TPIS	0	0	0	0	0	0
Subtotal - INTANGIBLE PLANT	301-303	1,197,944		0	963,581	21,096	93,944	76,075	43,249
B. PRODUCTION PLANT									
Land and Land Rights	340	0	SUPPLY	0	0	0	0	0	0
Steam Plant	341-345	0	SUPPLY	0	0	0	0	0	0
Other Equipment	346	0	SUPPLY	0	0	0	0	0	0
Subtotal - PRODUCTION PLANT	340-346	0		0	0	0	0	0	0
C. TRANSMISSION PLANT									
Land	350.1	1,423,554	TRAN	0	1,423,554	0	0	0	0
Land Rights	350.2	17,659,321	TRAN	0	17,659,321	0	0	0	0
Structures & Improvements	352	10,545,970	TRAN	0	10,545,970	0	0	0	0
Substation Equipment	353	150,230,016	TRAN	0	150,230,016	0	0	0	0
Towers	354.1	23,992,817	TRAN	0	23,992,817	0	0	0	0
Clearing Land Towers	354.2	1,320,960	TRAN	0	1,320,960	0	0	0	0
Poles	355	142,776,548	TRAN	0	142,776,548	0	0	0	0
Clearing Land Poles	355.2	4,736,505	TRAN	0	4,736,505	0	0	0	0
Conductors	356	125,898,984	TRAN	0	125,898,984	0	0	0	0
Switching Station Equip	356.1	7,683,607	TRAN	0	7,683,607	0	0	0	0
Underground Conduit	357	38,108	TRAN	0	38,108	0	0	0	0
Underground Conductor	358	917,061	TRAN	0	917,061	0	0	0	0
Roads & Trails	359	1,999,593	TRAN	0	1,999,593	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	489,223,045		0	489,223,045	0	0	0	0
D. DISTRIBUTION PLANT									
Land	360.1	1,953,837	SUBS	0	0	1,953,837	0	0	0
Land Rights	360.2	2,394,523	SUBS	0	0	2,394,523	0	0	0
Structures and Improvements	361	6,025,729	SUBS	0	0	6,025,729	0	0	0
Substation Equipment	362	114,559,697	SUBS	0	0	114,559,697	0	0	0
Poles	364	146,696,799	DIST_P	0	0	0	146,696,799	0	0
Conductor	365	91,974,109	DIST_P	0	0	0	91,974,109	0	0
Underground Conduit	366	48,309,554	DIST_P	0	0	0	48,309,554	0	0
Underground Conductor	367	100,388,884	DIST_P	0	0	0	100,388,884	0	0
Transformers	368	168,138,371	DIST_S	0	0	0	0	168,138,371	0
Services-Overhead	369.1	27,410,044	DIST_S	0	0	0	0	27,410,044	0
Services-Underground	369.2	57,965,975	DIST_S	0	0	0	0	57,965,975	0
Meter	370	38,331,977	DIST_S	0	0	0	0	38,331,977	0
AMR Lease	370.2	14,020,115	DIST_S	0	0	0	0	14,020,115	0
Street Lights	373.1	28,481,035	DIST_S	0	0	0	0	28,481,035	0
Yard Lights	373.2	19,770,304	DIST_S	0	0	0	0	19,770,304	0
Post Top Lights	373.3	8,246,587	DIST_S	0	0	0	0	8,246,587	0
Subtotal - DISTRIBUTION PLANT	360-373	874,667,539		0	0	124,933,785	387,369,346	362,364,409	0

Account Description	Account Code	Account Balance	Functional Allocation Factor	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
E. GENERAL PLANT									
Land	389	68,444	LABOR	0	19,459	4,251	19,510	15,633	9,591
Land - Communication	389.6	333,607	LABOR	0	94,847	20,722	95,094	76,196	46,747
Structures - Office	390	6,798,953	LABOR	0	1,932,992	422,320	1,938,032	1,552,891	952,719
Structures - Communication	390.6	622,826	LABOR	0	177,074	38,687	177,536	142,254	87,275
Office Furniture	391	357,470	LABOR	0	101,631	22,204	101,896	81,647	50,091
Data Handling Equipment	391.1	160,026	LABOR	0	45,496	9,940	45,615	36,550	22,424
Compuer Equipment	391.2	529,424	LABOR	0	150,519	32,885	150,911	120,921	74,187
Transporation - Trailers	392.2	1,438,725	LABOR	0	409,040	89,367	410,107	328,607	201,605
Transporation - Automobiles	392.3	351,455	LABOR	0	99,921	21,831	100,182	80,273	49,248
Transporation - Large Trucks	392.4	15,312,554	LABOR	0	4,353,470	951,146	4,364,821	3,497,410	2,145,707
Transporation -Trucks	392.5	7,911,768	LABOR	0	2,249,373	491,443	2,255,238	1,807,060	1,108,655
Transporation - Snow/ATVs	392.7	534,067	LABOR	0	151,839	33,174	152,235	121,982	74,837
Stores Equipment	393	400,192	LABOR	0	113,777	24,858	114,074	91,404	56,078
Tools and Shop Equipment	394	3,993,996	LABOR	0	1,135,522	248,089	1,138,483	912,235	559,668
Laboratory Equipment	395	3,312,247	LABOR	0	941,696	205,742	944,151	756,522	464,136
Power Operated Equipment	396	2,133,362	LABOR	0	606,530	132,515	608,112	487,263	298,942
Microwave Equipment	397.1	2,846,052	LABOR	0	809,153	176,784	811,263	650,043	398,810
Other Communication	397.2	15,555,593	LABOR	0	4,422,567	966,242	4,434,099	3,552,921	2,179,763
Office Communication	397.3	325,997	LABOR	0	92,683	20,249	92,925	74,458	45,681
Miscellaneous General	398	155,494	LABOR	0	44,208	9,659	44,323	35,515	21,789
Subtotal - GENERAL PLANT	389-389	63,142,251		0	17,951,797	3,922,107	17,998,607	14,421,786	8,847,953
TOTAL PLANT IN SERVICE		1,428,230,779		0	508,138,424	128,876,988	405,461,896	376,862,269	8,891,202
II. DEPRECIATION RESERVE									
Intangible Plant	108.1	371,341	TPIS	0	132,116	33,508	105,420	97,984	2,312
Intangible Plant Computers	108.2	28,264	TPIS	0	10,056	2,550	8,024	7,458	176
Production Plant	108.3	0	SUPPLY	0	0	0	0	0	0
Transmission Plant	108.4	214,833,190	TRAN	0	214,833,190	0	0	0	0
Distribution Substations	108.5	30,066,940	SUBS	0	0	30,066,940	0	0	0
Distribution Poles&Wires	108.6	220,808,327	DIST_P	0	0	0	220,808,327	0	0
Distribution Onsite	108.7	147,211,347	DIST_S	0	0	0	0	147,211,347	0
Distribution Lighting	108.8	31,099,471	DIST_S	0	0	0	0	31,099,471	0
General Plant	108.9	32,294,642	LABOR	0	9,181,600	2,005,995	9,205,541	7,376,145	4,525,361
Subtotal - DEPRECIATION RESERVE	108	676,713,524		0	224,156,963	32,108,994	230,127,312	185,792,406	4,527,849
Common Plant	118	36,871,939	LABOR	0	10,482,958	2,290,316	10,510,293	8,421,607	5,166,765
III. OTHER RATE BASE ITEMS									
Cost of Refinancing Debt		1,782,840	TPIS	0	634,302	160,875	506,132	470,432	11,099
SAP Development Costs		2,394,128	LABOR	0	680,668	148,712	682,443	546,822	335,483
Regulatory Asset FAS 109		0	TPIS	0	0	0	0	0	0
Customer Education Program		5,895	CUST	0	0	0	0	0	5,895
MPSC Taxes - Reg Asset		82,655	REVREQ	0	0	10,022	34,996	29,031	8,606
MCC Taxes - Reg Asset		71,245	REVREQ	0	0	8,639	30,165	25,024	7,418
Property Self-Insurance Reserve		(63,045)	TPIS	0	(22,430)	(5,689)	(17,898)	(16,635)	(392)
Personal Injury & Property Damage		(1,259,648)	LABOR	0	(358,127)	(78,244)	(359,061)	(287,706)	(176,511)
Customer Advances for Construction		3,549,626	DIST_S	0	0	0	0	3,549,626	0
USBC - Electric		(2,822,416)	REVREQ	0	0	(342,225)	(1,194,996)	(991,323)	(293,873)
Materials and Supplies		5,749,950	TPIS	0	2,045,727	518,849	1,632,359	1,517,219	35,795
Deferred Revenue		(751,653)	TRAN	0	(751,653)	0	0	0	0

Account Description	Account Code	Account Balance	Functional Allocation Factor	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
Accrued Incentive Compensation		1,033,012	LABOR	0	293,693	64,166	294,459	235,942	144,753
Post Retirement Benefits		928,296	LABOR	0	263,921	57,661	264,609	212,024	130,080
BPA Residential Buyback		137,872	TPIS	0	49,052	12,441	39,141	36,380	858
Accelerated Depreciation		(76,376,404)	TPIS	0	(27,173,330)	(6,891,856)	(21,682,576)	(20,153,175)	(475,468)
Environmental Reserve		106,742	TPIS	0	37,977	9,632	30,303	28,166	665
Total - OTHER RATE BASE ITEMS		(65,430,906)		0	(24,300,200)	(6,327,016)	(19,739,924)	(14,798,174)	(265,593)
TOTAL RATE BASE (Excl. Working Capit		722,958,288		0	270,164,220	92,731,294	166,104,952	184,693,296	9,264,526
Working Capital- WC Report		(23,785,344)	WORKCAP	0	(8,462,391)	(2,146,280)	(6,752,446)	(6,276,156)	(148,072)
TOTAL RATE BASE		699,172,944		0	261,701,829	90,585,014	159,352,507	178,417,141	9,116,455
I. OPERATION & MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
1. Power Generation Expenses									
Supervision & Engineering	500	0	SUPPLY	0	0	0	0	0	0
FUEL	501	0	SUPPLY	0	0	0	0	0	0
Steam Expenses	502	0	SUPPLY	0	0	0	0	0	0
Electric Plant	505	0	SUPPLY	0	0	0	0	0	0
Miscellaneous Steam Power	506	0	SUPPLY	0	0	0	0	0	0
Rents	507	0	SUPPLY	0	0	0	0	0	0
Supervision & Engineering	510	0	SUPPLY	0	0	0	0	0	0
Structures	511	0	SUPPLY	0	0	0	0	0	0
Steam Boiler Plant	512	0	SUPPLY	0	0	0	0	0	0
Electric Plant	513	0	SUPPLY	0	0	0	0	0	0
Miscellaneous Steam Power	514	0	SUPPLY	0	0	0	0	0	0
Subtotal - Manufactured Gas Production	500-514	0		0	0	0	0	0	0
2. Other Power Supply Expenses									
Purchased Power	555	294,996,114	SUPPLY	294,996,114	0	0	0	0	0
System Control & Load Dispatch	556	0	SUPPLY	0	0	0	0	0	0
Other Expenses (DSM Related)	557	4,246,860	SUPPLY	4,246,860	0	0	0	0	0
Subtotal - PRODUCTION EXPENSES	500-557	299,242,974		299,242,974	0	0	0	0	0
B. TRANSMISSION EXPENSES									
Supervision & Engineering	560	3,073,614	TRAN	0	3,073,614	0	0	0	0
Load Dispatching	561	2,193,774	TRAN	0	2,193,774	0	0	0	0
Station Expenses	562	510,201	TRAN	0	510,201	0	0	0	0
Overhead Lines	563	709,952	TRAN	0	709,952	0	0	0	0
Underground Lines	564	0	TRAN	0	0	0	0	0	0
Transmission of Elec. By Others	565	3,814,938	TRAN	0	3,814,938	0	0	0	0
Miscellaneous Transmission	566	70,936	TRAN	0	70,936	0	0	0	0
Rents	567	670,687	TRAN	0	670,687	0	0	0	0
Supervision & Engineering	568	177,893	TRAN	0	177,893	0	0	0	0
Structures	569	18,393	TRAN	0	18,393	0	0	0	0
Station Equipment	570	2,530,946	TRAN	0	2,530,946	0	0	0	0

Account Description	Account Code	Account Balance	Functional Allocation Factor	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
Overhead Lines	571	3,285,760	TRAN	0	3,285,760	0	0	0	0
Underground Lines	572	3,421	TRAN	0	3,421	0	0	0	0
Miscellaneous Transmission	573	0	TRAN	0	0	0	0	0	0
Subtotal - TRANSMISSION EXPENSES	560-573	17,060,515		0	17,060,515	0	0	0	0
C. DISTRIBUTION EXPENSES									
Operation Supervision & Engineering	580	2,338,810	DISTPT	0	0	334,066	1,035,803	968,941	0
Load Dispatching	581	896,607	DIST_P	0	0	0	896,607	0	0
Station Expenses	582	982,966	SUBS	0	0	982,966	0	0	0
Overhead Lines	583	2,611,008	DIST_P	0	0	0	2,611,008	0	0
Underground Lines	584	2,230,678	DIST_P	0	0	0	2,230,678	0	0
Street Lighting & Signal Systems	585	1,560,715	DIST_S	0	0	0	0	1,560,715	0
Meters	586	2,502,945	DIST_S	0	0	0	0	2,502,945	0
Customer Installations	587	1,370,050	DIST_S	0	0	0	0	1,370,050	0
Miscellaneous Distribution	588	2,359,603	DISTPT	0	0	337,036	1,045,012	977,556	0
Rents	589	40,375	DISTPT	0	0	5,767	17,881	16,727	0
Operation Supervision & Engineering	590	1,096,456	DISTPT	0	0	156,613	485,594	454,249	0
Structures	591	1,140	SUBS	0	0	1,140	0	0	0
Station Expenses	592	1,182,531	SUBS	0	0	1,182,531	0	0	0
Overhead Lines	593	7,716,233	DIST_P	0	0	0	7,716,233	0	0
Underground Lines	594	1,569,479	DIST_P	0	0	0	1,569,479	0	0
Line Transfomers	595	860,700	DIST_S	0	0	0	0	860,700	0
Street Lighting & Signal Systems	596	126,500	DIST_S	0	0	0	0	126,500	0
Meters	597	1,060,993	DIST_S	0	0	0	0	1,060,993	0
Miscellaneous Distribution	598	0	DISTPT	0	0	0	0	0	0
Subtotal - DISTRIBUTION EXPENSES	870-894	30,507,788		0	0	3,000,119	17,608,295	9,899,374	0
Total - OPERATION & MAINTENANCE I		346,811,278		299,242,974	17,060,515	3,000,119	17,608,295	9,899,374	0
II. CUSTOMER ACCOUNTS EXPENSES									
Supervision	901	0	CUST	0	0	0	0	0	0
Meter Reading Expenses	902	1,367,170	CUST	0	0	0	0	0	1,367,170
Customer Records & Collection Expense	903	6,446,558	CUST	0	0	0	0	0	6,446,558
Uncollectible Accounts Expense	904	1,451,223	REVREQ	0	0	175,964	614,440	509,716	151,103
Miscellaneous Customer Accts	905	4,093	CUST	0	0	0	0	0	4,093
Total - CUSTOMER ACCOUNTS EXPEN	901-905	9,269,045		0	0	175,964	614,440	509,716	7,968,925
III. CUSTOMER SERVICE & INFORMAT									
Customer Assistance Expenses	908	2,805,448	CUST	0	0	0	0	0	2,805,448
Inform. & Instruct Advertising	909	618,281	CUST	0	0	0	0	0	618,281
Misc. Customer Service & Info	910	730,537	TRANS-BILL	0	284,909	0	0	0	445,627
Subtotal - CUSTOMER SERVICE	907-910	4,154,266		0	284,909	0	0	0	3,869,356
IV. SALES EXPENSES									
Supervision	911	0	CUST	0	0	0	0	0	0
Demonstration and Selling Expense	912	205,805	CUST	0	0	0	0	0	205,805

Account Description	Account Code	Account Balance	Functional Allocation Factor	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
Advertising Expense	913	0	CUST	0	0	0	0	0	0
Misc Sales Promo Expense	916	0	CUST	0	0	0	0	0	0
Total - SALES EXPENSES	911-919	205,805		0	0	0	0	0	205,805
Total - CUSTOMER ACCOUNTS, SERVI	901-919	13,629,116		0	284,909	175,964	614,440	509,716	12,044,086
V. ADMINISTRATIVE & GENERAL EXPI									
1. Labor-Related:									
Administrative & General Salaries	920	16,515,054	LABOR	0	4,695,349	1,025,840	4,707,592	3,772,063	2,314,210
Office and Supplies Expense	921	4,924,573	LABOR	0	1,400,092	305,892	1,403,742	1,124,780	690,067
Admin. Expense Transferred	922	(4,958,580)	LABOR	0	(1,409,760)	(308,004)	(1,413,436)	(1,132,547)	(694,832)
Outside Services Employed	923	6,853,416	LABOR	0	1,948,476	425,703	1,953,556	1,565,331	960,351
Injuries & Damages	925	3,957,178	LABOR	0	1,125,054	245,802	1,127,988	903,825	554,509
Employee Pensions & Benefits	926	8,575,680	LABOR	0	2,438,128	532,682	2,444,485	1,958,698	1,201,687
General Plant - Maintenace	935	2,896,456	LABOR	0	823,483	179,915	825,630	661,555	405,873
Property Insurance									
Subtotal - O&M Accounts 920-926		38,763,776		0	11,020,821	2,407,828	11,049,558	8,853,705	5,431,864
2. Other-Related:									
Property Insurance	924	510,696	TPIS	0	181,696	46,083	144,982	134,756	3,179
Franchise Requirements	927	0	TPIS	0	0	0	0	0	0
Regulatory Commission Expenses	928	898,532	LABOR	0	255,459	55,813	256,125	205,226	125,909
Duplicate Charges	929	0	TPIS	0	0	0	0	0	0
Miscellaneous General Expenses	930	862,286	LABOR	0	245,154	53,561	245,793	196,947	120,830
Rents	931	2,191,252	LABOR	0	622,989	136,111	624,613	500,485	307,054
Subtotal - O&M Accounts 927-935		4,462,767		0	1,305,299	291,567	1,271,514	1,037,415	556,972
Total - ADMINISTRATIVE & GENERAL E	920-935	43,226,543		0	12,326,120	2,699,396	12,321,072	9,891,120	5,988,836
TOTAL - OPERATING EXPENSES (X Dı		104,423,962		0	29,671,544	5,875,479	30,543,807	20,300,210	18,032,922
VI. DEPRECIATION EXPENSE									
Depreciaton Exp - Int	403	234,178	INTAN_PT	0	188,364	4,124	18,364	14,871	8,454
Depreciation Exp-Production	403.1	0	SUPPLY	0	0	0	0	0	0
Depreciation Exp- Transmission	403.2	14,010,590	TRAN	0	14,010,590	0	0	0	0
Depreciation Exp - Substations	403.3	2,423,314	SUBS	0	0	2,423,314	0	0	0
Depreciation Exp - Poles	403.4	15,564,172	DIST_P	0	0	0	15,564,172	0	0
Depreciation Exp - Onsite	403.5	11,511,896	DIST_S	0	0	0	0	11,511,896	0
Depreciation Exp - Dist Lighting	403.6	2,454,107	DISTPT	0	0	350,534	1,086,865	1,016,708	0
Depreciation Exp-General/Common	403.7	8,413,711	GENPT	0	2,392,079	522,621	2,398,316	1,921,704	1,178,991
Depreciation Exp-Other	404-406	94,914	RATEBASE	0	35,469	12,174	21,807	24,248	1,216
Amort Regulatory Debits	407	12,563,810	RATEBASE	0	4,695,004	1,611,515	2,886,627	3,209,662	161,002
Total - DEPRECIATION EXPENSE		67,270,692		0	21,321,505	4,924,283	21,976,153	17,699,088	1,349,663
VII. TAXES OTHER THAN INCOME TAX									
A. General Taxes									

Account Description	Account Code	Account Balance		Functional Allocation Factor	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
Tax Other Than Inc Util Ops- Labor	408Lab	0		LABOR	0	0	0	0	0	0
Tax Other Than Inc Util Ops- Property	408Plant	64,213,246		TPIS	0	22,845,900	5,794,308	18,229,564	16,943,725	399,748
General Taxes	408Oth	0		TPIS	0	0	0	0	0	0
Subtotal - General Taxes		64,213,246			0	22,845,900	5,794,308	18,229,564	16,943,725	399,748
TOTAL EXPENSES (excl. Gross Receipt Taxes & Supply)	408.1	235,907,900			0	73,838,949	16,594,070	70,749,524	54,943,023	19,782,334
B. Revenue Taxes: (GRT)										
State Gross Earnings	408.11	0		REVREQ	0	0	0	0	0	0
Other	408.12	0		REVREQ	0	0	0	0	0	0
Subtotal - Revenue Taxes (GRT)		0			0	0	0	0	0	0
C. INCOME TAXES										
Subtotal - Income Taxes		14,648,265		Report	0	5,505,312	1,945,474	3,270,756	3,727,470	199,252
TOTAL TAXES (Excl. General Taxes)		14,648,265			0	5,505,312	1,945,474	3,270,756	3,727,470	199,252
TOTAL EXPENSES		549,799,140			299,242,974	79,344,261	18,539,544	74,020,280	58,670,494	19,981,586
VIII. OPERATING REVENUES			Direct							
Residential	440	203,363,552	107,180,655	REVREQ	107,180,655	19,286,508	9,323,877	32,557,512	27,008,476	8,006,524
Comm & Industrial	442	335,390,739	188,990,156	REVREQ	188,990,156	48,823,066	11,831,515	41,313,789	34,272,351	10,159,863
Lighting	444	15,209,629	3,072,163	REVREQ	3,072,163	230,823	1,443,710	5,041,208	4,181,995	1,239,731
Employee Revenue Allocation	450	(229,458)		REVREQ	0	0	(27,822)	(97,151)	(80,593)	(23,891)
Miscellaneous Service Revenue	451	0		REVREQ	0	0	0	0	0	0
Rent From Electric Property	454	2,551,536	1,275,768	REVREQ	0	1,275,768	154,690	540,153	448,091	132,834
Transmission	456	34,865,450		TRAN	0	34,865,450	0	0	0	0
Other Misc. Revenues	456	0		REVREQ	0	0	0	0	0	0
TOTAL REVENUE		591,151,448			299,242,974	104,481,616	22,725,969	79,355,510	65,830,319	19,515,060
NET INCOME		41,352,309			0	25,137,354	4,186,425	5,335,230	7,159,825	(466,526)
Return		5.9%			NA	9.6%	4.6%	3.3%	4.0%	-5.1%

Northwestern Energy Cost of Service Study
Electric - Year Ending December 31, 2009

Account Description	Account Balance	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
SUMMARY							
OPERATING REVENUES							
Total Operating Revenues	591,151,448	299,242,974	104,481,616	22,725,969	79,355,510	65,830,319	19,515,060
OPERATING EXPENSES							
Production Expenses	299,242,974	299,242,974	0	0	0	0	0
Transmission Expenses	17,060,515	0	17,060,515	0	0	0	0
Distribution Expenses	30,507,788	0	0	3,000,119	17,608,295	9,899,374	0
Total Operating Expenses	346,811,278	299,242,974	17,060,515	3,000,119	17,608,295	9,899,374	0
CUSTOMER ACCOUNTS, SERVICES, & SALES	13,629,116	0	284,909	175,964	614,440	509,716	12,044,086
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	0	12,326,120	2,699,396	12,321,072	9,891,120	5,988,836
DEPRECIATION EXPENSE	67,270,692	0	21,321,505	4,924,283	21,976,153	17,699,088	1,349,663
TAXES OTHER THAN INCOME TAXES	64,213,246	0	22,845,900	5,794,308	18,229,564	16,943,725	399,748
INCOME BEFORE INCOME TAXES	56,000,574	0	30,642,666	6,131,899	8,605,986	10,887,296	(267,274)
INCOME TAXES	14,648,265	0	5,505,312	1,945,474	3,270,756	3,727,470	199,252
Effective Tax Rate- Actual	26.16%	NA	17.97%	31.73%	38.01%	34.24%	-74.55%
NET OPERATING INCOME	41,352,309	0	25,137,354	4,186,425	5,335,230	7,159,825	(466,526)
RATE BASE	699,172,944	0	261,701,829	90,585,014	159,352,507	178,417,141	9,116,455
RATE OF RETURN	5.91%	NA	9.61%	4.62%	3.35%	4.01%	-5.12%
	1.00	0.00	1.62	0.78	0.57	0.68	(0.87)
ELECTRIC PLANT IN SERVICE							
Intangible Plant	1,197,944	0	963,581	21,096	93,944	76,075	43,249
Production Plant	0	0	0	0	0	0	0
Transmission Plant	489,223,045	0	489,223,045	0	0	0	0
Distribution Plant:							
Substations	124,933,785	0	0	124,933,785	0	0	0
Poles & Wires	387,369,346	0	0	0	387,369,346	0	0
Onsite	305,866,483	0	0	0	0	305,866,483	0
Other Distribution Plant	56,497,926	0	0	0	0	56,497,926	0
General Plant	63,142,251	0	17,951,797	3,922,107	17,998,607	14,421,786	8,847,953
TOTAL PLANT IN SERVICE	1,428,230,779	0	508,138,424	128,876,988	405,461,896	376,862,269	8,891,202
COMMON PLANT	36,871,939	0	10,482,958	2,290,316	10,510,293	8,421,607	5,166,765
DEPRECIATION RESERVE	676,713,524	0	224,156,963	32,108,994	230,127,312	185,792,406	4,527,849
OTHER RATE BASE ITEMS							
Accelerated Depreciation	(76,376,404)	0	(27,173,330)	(6,891,856)	(21,682,576)	(20,153,175)	(475,468)
Materials and Supplies	5,749,950	0	2,045,727	518,849	1,632,359	1,517,219	35,795
Working Capital Requirement	(23,785,344)	0	(8,462,391)	(2,146,280)	(6,752,446)	(6,276,156)	(148,072)
Customer Advances for Construction	3,549,626	0	0	0	0	3,549,626	0
All other, net	1,645,923	0	827,403	45,991	310,293	288,156	174,080
SubTotal Other Rate Base Items	(89,216,250)	0	(32,762,591)	(8,473,296)	(26,492,369)	(21,074,330)	(413,664)
RATE BASE	699,172,944	0	261,701,829	90,585,014	159,352,507	178,417,141	9,116,455

Northwestern Energy Cost of Service Study
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Account Description	Account Balance	Supply	Transmission	Substation	Primary Distribution	Secondary Distribution	Customer
REVENUE REQUIREMENTS							
Target Average Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
RATE BASE	699,172,944	0	261,701,829	90,585,014	159,352,507	178,417,141	9,116,455
OPERATING EXPENSES	346,811,278	299,242,974	17,060,515	3,000,119	17,608,295	9,899,374	0
CUST. ACCTS., SERVICES, & SALES EXP.	13,629,116	0	284,909	175,964	614,440	509,716	12,044,086
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	0	12,326,120	2,699,396	12,321,072	9,891,120	5,988,836
DEPRECIATION EXPENSE	67,270,692	0	21,321,505	4,924,283	21,976,153	17,699,088	1,349,663
GENERAL TAXES	64,213,246	0	22,845,900	5,794,308	18,229,564	16,943,725	399,748
TOTAL	535,150,874	299,242,974	73,838,949	16,594,070	70,749,524	54,943,023	19,782,334
RETURN ON RATEBASE	41,352,309	0	15,478,252	5,357,615	9,424,841	10,552,412	539,189
FIT / State Inc tax- Actual	14,648,265	0	5,505,312	1,945,474	3,270,756	3,727,470	199,252
FIT/State Tax on Incr in Net Income	(0)	0	(2,526,565)	306,352	1,069,734	887,411	263,068
Total FIT/State Tax ON RETURN	14,648,265	0	2,978,747	2,251,827	4,340,490	4,614,881	462,320
GROSS RECEIPTS TAX	0	0	0	0	0	0	0
Other Utility Operating Inc (Exp)	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT	**591,151,448**	**299,242,974**	**92,295,948**	**24,203,511**	**84,514,855**	**70,110,316**	**20,783,843**

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Account Description	Account Code	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
I. ELECTRIC PLANT IN SERVICE											
A. INTANGIBLE PLANT											
Organization	301	19,995	7,577	18	362	164	849	0	3	5	1,434
Franchise and Consents	302	2,004	759	2	36	16	85	0	0	1	144
Computer Software 5 Yrs	303	307,661	129,496	306	6,285	2,226	12,013	2	47	84	23,117
BPA - Rattlesnake Line	303	868,284	253,332	633	11,534	9,484	31,312	2	57	116	34,696
Computer Software 3 Yrs	304	0	0	0	0	0	0	0	0	0	0
Other	304	0	0	0	0	0	0	0	0	0	0
Subtotal - INTANGIBLE PLANT	301-303	1,197,944	391,165	959	18,217	11,890	44,259	5	107	205	59,390
			3	4	5	6	7	8	9	10	11
B. PRODUCTION PLANT											
Land and Land Rights	340	0	0	0	0	0	0	0	0	0	0
Steam Plant	341-345	0	0	0	0	0	0	0	0	0	0
Other Equipment	346	0	0	0	0	0	0	0	0	0	0
Subtotal - PRODUCTION PLANT	340-346	0	0	0	0	0	0	0	0	0	0
C. TRANSMISSION PLANT											
Land	350	1,423,554	415,339	1,037	18,909	15,549	51,337	4	93	190	56,884
Land Rights	350	17,659,321	5,152,319	12,869	234,571	192,890	636,837	51	1,153	2,357	705,648
Structures & Improvements	352	10,545,970	3,076,914	7,685	140,084	115,192	380,313	30	688	1,408	421,406
Substation Equipment	353	150,230,016	43,831,412	109,475	1,995,529	1,640,939	5,417,649	430	9,807	20,053	6,003,032
Towers	354	23,992,817	7,000,193	17,484	318,700	262,070	865,238	69	1,566	3,203	958,728
Clearing Land Towers	354	1,320,960	385,406	963	17,547	14,429	47,637	4	86	176	52,784
Poles	355	142,776,548	41,656,773	104,044	1,896,523	1,559,526	5,148,860	408	9,321	19,058	5,705,200
Clearing Land Poles	355	4,736,505	1,381,932	3,452	62,916	51,736	170,810	14	309	632	189,266
Conductors	356	125,898,984	36,732,541	91,745	1,672,336	1,375,175	4,540,215	360	8,219	16,805	5,030,790
Switching Station Equip	356	7,683,607	2,241,785	5,599	102,063	83,927	277,089	22	502	1,026	307,029
Underground Conduit	357	38,108	11,119	28	506	416	1,374	0	2	5	1,523
Underground Conductor	358	917,061	267,563	668	12,181	10,017	33,071	3	60	122	36,645
Roads & Trails	359	1,999,593	583,405	1,457	26,561	21,841	72,110	6	131	267	79,902
Subtotal - TRANSMISSION PLANT	350-359	489,223,045	142,736,701	356,506	6,498,425	5,343,708	17,642,539	1,399	31,937	65,303	19,548,835
D. DISTRIBUTION PLANT											
Land	360	1,953,837	587,881	1,465	26,734	18,954	129,104	21	212	268	80,110
Land Rights	360	2,394,523	720,477	1,795	32,764	23,228	158,223	26	260	329	98,178
Structures and Improvements	361	6,025,729	1,813,055	4,518	82,450	58,454	398,162	66	653	827	247,062
Substation Equipment	362	114,559,697	34,469,356	85,898	1,567,521	1,111,307	7,569,765	1,252	12,422	15,723	4,697,086
Poles	364	146,696,799	55,720,160	138,855	2,533,918	1,745,081	11,886,769	1,966	19,506	25,416	7,592,901
Conductor	365	91,974,109	34,934,723	87,057	1,588,684	1,094,109	7,452,617	1,233	12,229	15,935	4,760,501
Underground Conduit	366	48,309,554	18,349,522	45,727	834,459	574,682	3,914,499	647	6,423	8,370	2,500,461
Underground Conductor	367	100,388,884	38,130,926	95,022	1,734,034	1,194,209	8,134,462	1,345	13,348	17,393	5,196,043
Transformers	368	168,138,371	98,204,454	216,716	5,089,032	32,326	456,608	1,170	52,631	106,099	27,815,932
Services-Overhead	369	27,410,044	16,009,364	35,329	829,618	5,270	74,437	191	8,580	17,296	4,534,574
Services-Underground	369	57,965,975	33,856,144	74,713	1,754,452	11,145	157,416	403	18,145	36,578	9,589,588
Meter	370	38,331,977	22,388,530	49,407	1,160,191	7,370	104,097	267	11,999	24,188	6,341,442
AMR Lease	370	14,020,115	8,188,718	18,071	424,346	2,696	38,074	98	4,389	8,847	2,319,414
Street Lights	373	28,481,035	0	0	0	0	0	0	0	0	0
Yard Lights	373	19,770,304	0	0	0	0	0	0	0	0	0
Post Top Lights	373	8,246,587	0	0	0	0	0	0	0	0	0
Subtotal - DISTRIBUTION PLANT	360-373	874,667,539	363,373,311	854,572	17,658,203	5,878,830	40,474,233	8,685	160,796	277,270	75,773,292

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Account Description	Account Code	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
I. ELECTRIC PLANT IN SERVICE												
A. INTANGIBLE PLANT												
Organization	301	19,995	136	5,810	1,692	280	45	134	8	1	642	63
Franchise and Consents	302	2,004	14	582	170	28	5	13	1	0	64	6
Computer Software 5 Yrs	303	307,661	1,858	82,653	20,692	3,531	569	1,750	157	19	9,162	968
BPA - Rattlesnake Line	303	868,284	7,391	289,442	166,895	27,537	5,379	15,043	94	27	9,570	536
Computer Software 3 Yrs	304	0	0	0	0	0	0	0	0	0	0	0
Other	304	0	0	0	0	0	0	0	0	0	0	0
Subtotal - INTANGIBLE PLANT	301-303	1,197,944	9,398	378,487	189,449	31,376	5,998	16,941	260	47	19,439	1,573
			12	13	14	15	16	17	18	19	20	21
B. PRODUCTION PLANT												
Land and Land Rights	340	0	0	0	0	0	0	0	0	0	0	0
Steam Plant	341-345	0	0	0	0	0	0	0	0	0	0	0
Other Equipment	346	0	0	0	0	0	0	0	0	0	0	0
Subtotal - PRODUCTION PLANT	340-346	0	0	0	0	0	0	0	0	0	0	0
C. TRANSMISSION PLANT												
Land	350	1,423,554	12,118	474,541	273,625	45,147	8,819	24,663	155	44	15,691	878
Land Rights	350	17,659,321	150,323	5,886,722	3,394,342	560,049	109,400	305,950	1,920	542	194,644	10,895
Structures & Improvements	352	10,545,970	89,771	3,515,492	2,027,067	334,456	65,332	182,710	1,147	324	116,239	6,506
Substation Equipment	353	150,230,016	1,278,814	50,079,066	28,876,082	4,764,404	930,675	2,602,753	16,337	4,612	1,655,861	92,681
Towers	354	23,992,817	204,236	7,997,988	4,611,718	760,910	148,636	415,678	2,609	737	264,453	14,802
Clearing Land Towers	354	1,320,960	11,245	440,341	253,905	41,893	8,183	22,886	144	41	14,560	815
Poles	355	142,776,548	1,215,368	47,594,458	27,443,432	4,528,024	884,501	2,473,620	15,526	4,383	1,573,707	88,083
Clearing Land Poles	355	4,736,505	40,319	1,578,911	910,415	150,214	29,343	82,061	515	145	52,207	2,922
Conductors	356	125,898,984	1,071,699	41,968,335	24,199,354	3,992,768	779,945	2,181,215	13,691	3,865	1,387,680	77,671
Switching Station Equip	356	7,683,607	65,406	2,561,325	1,476,885	243,678	47,600	133,119	836	236	84,690	4,740
Underground Conduit	357	38,108	324	12,703	7,325	1,209	236	660	4	1	420	24
Underground Conductor	358	917,061	7,806	305,702	176,271	29,084	5,681	15,888	100	28	10,108	566
Roads & Trails	359	1,999,593	17,021	666,563	384,347	63,415	12,387	34,643	217	61	22,040	1,234
Subtotal - TRANSMISSION PLANT	350-359	489,223,045	4,164,450	163,082,146	94,034,767	15,515,250	3,030,738	8,475,847	53,201	15,019	5,392,299	301,815
D. DISTRIBUTION PLANT												
Land	360	1,953,837	15,349	599,792	345,840	56,017	0	0	0	185	66,114	3,700
Land Rights	360	2,394,523	18,810	735,074	423,844	68,652	0	0	0	226	81,025	4,535
Structures and Improvements	361	6,025,729	47,336	1,849,788	1,066,588	172,760	0	0	0	569	203,897	11,412
Substation Equipment	362	114,559,697	899,935	35,167,723	20,277,715	3,284,476	0	0	0	10,822	3,876,445	216,971
Poles	364	146,696,799	1,454,756	56,849,080	0	0	0	0	0	17,494	6,266,324	350,736
Conductor	365	91,974,109	912,085	35,642,519	0	0	0	0	0	10,968	3,928,781	219,900
Underground Conduit	366	48,309,554	479,074	18,721,293	0	0	0	0	0	5,761	2,063,599	115,503
Underground Conductor	367	100,388,884	995,532	38,903,478	0	0	0	0	0	11,971	4,288,228	240,019
Transformers	368	168,138,371	160,186	24,231,170	141,427	76,775	38,032	380,316	266,221	8,923	9,368,743	1,491,611
Services-Overhead	369	27,410,044	26,114	3,950,184	23,056	12,516	6,200	61,999	43,400	1,455	1,527,300	243,164
Services-Underground	369	57,965,975	55,224	8,353,735	48,757	26,468	13,111	131,114	91,780	3,076	3,229,889	514,235
Meter	370	38,331,977	36,519	5,524,192	32,242	17,503	8,670	86,704	60,693	2,034	2,135,874	340,056
AMR Lease	370	14,020,115	13,357	2,020,501	11,793	6,402	3,171	31,712	22,199	744	781,207	124,377
Street Lights	373	28,481,035	0	0	0	0	0	0	0	0	0	0
Yard Lights	373	19,770,304	0	0	0	0	0	0	0	0	0	0
Post Top Lights	373	8,246,587	0	0	0	0	0	0	0	0	0	0
Subtotal - DISTRIBUTION PLANT	360-373	874,667,539	5,114,276	232,548,530	22,371,263	3,721,570	69,185	691,845	484,292	74,227	37,817,426	3,876,219

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Account Description	Account Code	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
I. ELECTRIC PLANT IN SERVICE						
A. INTANGIBLE PLANT						
Organization	301	19,995	85	673	5	7
Franchise and Consents	302	2,004	9	67	1	1
Computer Software 5 Yrs	303	307,661	1,167	11,343	81	134
BPA - Rattlesnake Line	303	868,284	355	4,575	154	121
Computer Software 3 Yrs	304	0	0	0	0	0
Other	304	0	0	0	0	0
Subtotal - INTANGIBLE PLANT	301-303	1,197,944	1,615	16,659	240	263
			22	23	24	25
B. PRODUCTION PLANT						
Land and Land Rights	340	0	0	0	0	0
Steam Plant	341-345	0	0	0	0	0
Other Equipment	346	0	0	0	0	0
Subtotal - PRODUCTION PLANT	340-346	0	0	0	0	0
C. TRANSMISSION PLANT						
Land	350	1,423,554	581	7,501	252	198
Land Rights	350	17,659,321	7,210	93,048	3,125	2,458
Structures & Improvements	352	10,545,970	4,306	55,568	1,866	1,468
Substation Equipment	353	150,230,016	61,337	791,573	26,586	20,908
Towers	354	23,992,817	9,796	126,420	4,246	3,339
Clearing Land Towers	354	1,320,960	539	6,960	234	184
Poles	355	142,776,548	58,293	752,300	25,267	19,870
Clearing Land Poles	355	4,736,505	1,934	24,957	838	659
Conductors	356	125,898,984	51,403	663,371	22,281	17,521
Switching Station Equip	356	7,683,607	3,137	40,486	1,360	1,069
Underground Conduit	357	38,108	16	201	7	5
Underground Conductor	358	917,061	374	4,832	162	128
Roads & Trails	359	1,999,593	816	10,536	354	278
Subtotal - TRANSMISSION PLANT	350-359	489,223,045	199,742	2,577,753	86,579	68,085
D. DISTRIBUTION PLANT						
Land	360	1,953,837	1,951	19,000	638	502
Land Rights	360	2,394,523	2,391	23,285	782	615
Structures and Improvements	361	6,025,729	6,018	58,597	1,968	1,548
Substation Equipment	362	114,559,697	114,409	1,114,030	37,417	29,425
Poles	364	146,696,799	184,944	1,800,844	60,485	47,565
Conductor	365	91,974,109	115,954	1,129,070	37,922	29,822
Underground Conduit	366	48,309,554	60,905	593,046	19,919	15,664
Underground Conductor	367	100,388,884	126,562	1,232,370	41,391	32,550
Transformers	368	168,138,371	0	0	0	0
Services-Overhead	369	27,410,044	0	0	0	0
Services-Underground	369	57,965,975	0	0	0	0
Meter	370	38,331,977	0	0	0	0
AMR Lease	370	14,020,115	0	0	0	0
Street Lights	373	28,481,035	4,538,930	23,938,732	0	3,374
Yard Lights	373	19,770,304	64,864	16,083,186	0	3,622,253
Post Top Lights	373	8,246,587	162,873	8,023,305	60,409	0
Subtotal - DISTRIBUTION PLANT	360-373	874,667,539	5,379,802	54,015,465	260,931	3,783,317

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Account Description	Account Code	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
E. GENERAL PLANT											
Land	389	68,444	28,808	68	1,398	495	2,672	0	10	19	5,143
Land - Communication	390	333,607	140,417	332	6,815	2,413	13,026	2	51	91	25,066
Structures - Office	390	6,798,953	2,861,722	6,772	138,890	49,182	265,466	49	1,039	1,854	510,853
Structures - Communication	391	622,826	262,151	620	12,723	4,505	24,318	5	95	170	46,797
Office Furniture	391	357,470	150,461	356	7,302	2,586	13,957	3	55	97	26,859
Data Handling Equipment	391	160,026	67,356	159	3,269	1,158	6,248	1	24	44	12,024
Compuer Equipment	391	529,424	222,838	527	10,815	3,830	20,671	4	81	144	39,779
Transporation - Trailers	392	1,438,725	605,568	1,433	29,391	10,407	56,175	10	220	392	108,101
Transporation - Automobiles	392	351,455	147,930	350	7,180	2,542	13,723	3	54	96	26,407
Transporation - Large Trucks	392	15,312,554	6,445,149	15,252	312,807	110,768	597,881	111	2,340	4,176	1,150,539
Transporation -Trucks	393	7,911,768	3,330,112	7,881	161,623	57,232	308,916	57	1,209	2,158	594,466
Transporation - Snow/ATVs	393	534,067	224,792	532	10,910	3,863	20,853	4	82	146	40,128
Stores Equipment	393	400,192	168,443	399	8,175	2,895	15,626	3	61	109	30,069
Tools and Shop Equipment	394	3,993,996	1,681,098	3,978	81,590	28,892	155,946	29	610	1,089	300,097
Laboratory Equipment	395	3,312,247	1,394,145	3,299	67,663	23,960	129,327	24	506	903	248,872
Power Operated Equipment	396	2,133,362	897,945	2,125	43,581	15,432	83,297	15	326	582	160,294
Microwave Equipment	397	2,846,052	1,197,921	2,835	58,140	20,588	111,124	21	435	776	213,844
Other Communication	397	15,555,593	6,547,446	15,494	317,772	112,526	607,370	113	2,377	4,242	1,168,801
Office Communication	397	325,997	137,214	325	6,660	2,358	12,729	2	50	89	24,494
Miscellaneous General	398	155,494	65,448	155	3,176	1,125	6,071	1	24	42	11,683
Subtotal - GENERAL PLANT	389-389	63,142,251	26,576,966	62,893	1,289,880	456,759	2,465,397	458	9,650	17,219	4,744,319
TOTAL PLANT IN SERVICE		1,428,230,779	533,078,143	1,274,931	25,464,726	11,691,187	60,626,428	10,548	202,490	359,997	100,125,836
II. DEPRECIATION RESERVE											
Intangible Plant	108	371,341	140,725	336	6,731	3,040	15,773	3	54	96	26,634
Intangible Plant Computers	108	28,264	10,711	26	512	231	1,201	0	4	7	2,027
Production Plant	108	0	0	0	0	0	0	0	0	0	0
Transmission Plant	108	214,833,190	62,680,164	156,553	2,853,662	2,346,590	7,747,392	615	14,025	28,677	8,584,507
Distribution Substations	109	30,066,940	9,046,708	22,544	411,406	291,670	1,986,734	329	3,260	4,127	1,232,781
Distribution Poles&Wires	109	220,808,327	83,870,102	209,004	3,814,058	2,626,699	17,891,990	2,959	29,360	38,257	11,428,850
Distribution Onsite	109	147,211,347	85,981,622	189,743	4,455,635	28,303	399,777	1,024	46,080	92,894	24,353,875
Distribution Lighting	109	31,099,471	0	0	0	0	0	0	0	0	0
General Plant	109	32,294,642	13,593,016	32,167	659,720	233,614	1,260,948	234	4,936	8,807	2,426,522
Subtotal - DEPRECIATION RESERVE	108	676,713,524	255,323,048	610,373	12,201,726	5,530,147	29,303,815	5,164	97,718	172,864	48,055,196
Common Plant	118	36,871,939	15,519,628	36,727	753,226	266,725	1,439,670	268	5,635	10,055	2,770,447
III. OTHER RATE BASE ITEMS											
Cost of Refinancing Debt		1,782,840	675,633	1,614	32,316	14,597	75,727	13	258	460	127,874
SAP Development Costs		2,394,128	1,007,703	2,385	48,908	17,319	93,479	17	366	653	179,888
Regulatory Asset FAS 109		0	0	0	0	0	0	0	0	0	0
Customer Education Program		5,895	3,923	9	201	4	44	0	1	2	552
MPSC Taxes - Reg Asset		82,655	37,002	87	1,811	524	3,632	1	15	27	7,268
MCC Taxes - Reg Asset		71,245	31,894	75	1,561	452	3,130	1	13	23	6,264
Property Self-Insurance Reserve		(63,045)	(23,892)	(57)	(1,143)	(516)	(2,678)	(0)	(9)	(16)	(4,522)
Personal Injury & Property Damage		(1,259,648)	(530,194)	(1,255)	(25,732)	(9,112)	(49,183)	(9)	(193)	(344)	(94,646)
Customer Advances for Construction		3,549,626	1,830,017	4,038	94,833	602	8,509	22	981	1,977	518,343
USBC - Electric		(2,822,416)	(1,263,495)	(2,961)	(61,825)	(17,905)	(124,007)	(27)	(526)	(910)	(248,165)
Materials and Supplies		5,749,950	2,179,026	5,205	104,224	47,079	244,230	43	833	1,485	412,416
Deferred Revenue		(751,653)	(219,304)	(548)	(9,984)	(8,210)	(27,106)	(2)	(49)	(100)	(30,035)
Accrued Incentive Compensation		1,033,012	434,801	1,029	21,103	7,473	40,334	8	158	282	77,617
Post Retirement Benefits		928,296	390,726	925	18,963	6,715	36,245	7	142	253	69,749

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Account Description	Account Code	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
E. GENERAL PLANT												
Land	389	68,444	413	18,387	4,603	786	127	389	35	4	2,038	215
Land - Communication	390	333,607	2,014	89,623	22,438	3,829	617	1,898	170	20	9,934	1,050
Structures - Office	390	6,798,953	41,051	1,826,537	457,280	78,033	12,577	38,682	3,468	417	202,460	21,402
Structures - Communication	391	622,826	3,760	167,322	41,890	7,148	1,152	3,544	318	38	18,547	1,961
Office Furniture	391	357,470	2,158	96,034	24,043	4,103	661	2,034	182	22	10,645	1,125
Data Handling Equipment	391	160,026	966	42,991	10,763	1,837	296	910	82	10	4,765	504
Compuer Equipment	391	529,424	3,197	142,230	35,608	6,076	979	3,012	270	32	15,765	1,667
Transporation - Trailers	392	1,438,725	8,687	386,513	96,765	16,513	2,661	8,186	734	88	42,843	4,529
Transporation - Automobiles	392	351,455	2,122	94,418	23,638	4,034	650	2,000	179	22	10,466	1,106
Transporation - Large Trucks	392	15,312,554	92,454	4,113,713	1,029,883	175,746	28,325	87,120	7,810	940	455,979	48,201
Transporation -Trucks	393	7,911,768	47,770	2,125,494	532,125	90,805	14,635	45,014	4,035	486	235,597	24,905
Transporation - Snow/ATVs	393	534,067	3,225	143,477	35,920	6,130	988	3,039	272	33	15,903	1,681
Stores Equipment	393	400,192	2,416	107,511	26,916	4,593	740	2,277	204	25	11,917	1,260
Tools and Shop Equipment	394	3,993,996	24,115	1,072,986	268,626	45,840	7,388	22,724	2,037	245	118,934	12,572
Laboratory Equipment	395	3,312,247	19,999	889,834	222,773	38,015	6,127	18,845	1,689	203	98,632	10,426
Power Operated Equipment	396	2,133,362	12,881	573,127	143,485	24,485	3,946	12,138	1,088	131	63,527	6,715
Microwave Equipment	397	2,846,052	17,184	764,591	191,418	32,665	5,265	16,193	1,452	175	84,750	8,959
Other Communication	397	15,555,593	93,921	4,179,005	1,046,229	178,535	28,775	88,503	7,934	955	463,216	48,966
Office Communication	397	325,997	1,968	87,579	21,926	3,742	603	1,855	166	20	9,708	1,026
Miscellaneous General	398	155,494	939	41,773	10,458	1,785	288	885	79	10	4,630	489
Subtotal - GENERAL PLANT	389-389	63,142,251	381,240	16,963,146	4,246,787	724,698	116,801	359,246	32,204	3,875	1,880,256	198,759
TOTAL PLANT IN SERVICE		1,428,230,779	9,669,364	412,972,309	120,842,266	19,992,894	3,222,722	9,543,880	569,957	93,168	45,109,420	4,378,367
II. DEPRECIATION RESERVE												
Intangible Plant	108	371,341	2,518	107,897	31,422	5,200	839	2,490	154	24	11,931	1,171
Intangible Plant Computers	108	28,264	192	8,213	2,392	396	64	189	12	2	908	89
Production Plant	108	0	0	0	0	0	0	0	0	0	0	0
Transmission Plant	108	214,833,190	1,828,741	71,614,488	41,293,617	6,813,233	1,330,892	3,722,010	23,362	6,595	2,367,928	132,537
Distribution Substations	109	30,066,940	236,194	9,229,999	5,322,019	862,032	0	0	0	2,840	1,017,398	56,945
Distribution Poles&Wires	109	220,808,327	2,189,702	85,569,354	0	0	0	0	0	26,332	9,432,084	527,929
Distribution Onsite	109	147,211,347	140,249	21,215,283	123,825	67,219	33,298	332,980	233,086	7,812	8,202,680	1,305,960
Distribution Lighting	109	31,099,471	0	0	0	0	0	0	0	0	0	0
General Plant	109	32,294,642	194,988	8,675,946	2,172,055	370,653	59,739	183,740	16,471	1,982	961,673	101,657
Subtotal - DEPRECIATION RESERVE	108	676,713,524	4,592,583	196,421,179	48,945,330	8,118,733	1,424,832	4,241,409	273,085	45,587	21,994,603	2,126,288
Common Plant	118	36,871,939	222,625	9,905,635	2,479,913	423,188	68,206	209,782	18,805	2,263	1,097,976	116,066
III. OTHER RATE BASE ITEMS												
Cost of Refinancing Debt		1,782,840	12,087	518,024	150,860	24,965	4,027	11,953	739	117	57,282	5,620
SAP Development Costs		2,394,128	14,455	643,182	161,023	27,478	4,429	13,621	1,221	147	71,293	7,536
Regulatory Asset FAS 109		0	0	0	0	0	0	0	0	0	0	0
Customer Education Program		5,895	5	643	61	25	2	13	7	0	48	16
MPSC Taxes - Reg Asset		82,655	457	21,270	1,884	335	8	77	50	7	3,331	354
MCC Taxes - Reg Asset		71,245	394	18,334	1,624	289	7	66	43	6	2,872	305
Property Self-Insurance Reserve		(63,045)	(427)	(18,318)	(5,335)	(883)	(142)	(423)	(26)	(4)	(2,026)	(199)
Personal Injury & Property Damage		(1,259,648)	(7,605)	(338,404)	(84,721)	(14,457)	(2,330)	(7,167)	(642)	(77)	(37,510)	(3,965)
Customer Advances for Construction		3,549,626	2,985	451,542	2,635	1,431	709	7,087	4,961	166	174,584	27,796
USBC - Electric		(2,822,416)	(15,605)	(726,319)	(64,344)	(11,444)	(288)	(2,625)	(1,721)	(226)	(113,758)	(12,075)
Materials and Supplies		5,749,950	38,982	1,670,712	486,549	80,516	12,987	38,550	2,384	378	184,745	18,127
Deferred Revenue		(751,653)	(6,398)	(250,563)	(144,477)	(23,838)	(4,656)	(13,022)	(82)	(23)	(8,285)	(464)
Accrued Incentive Compensation		1,033,012	6,237	277,518	69,478	11,856	1,911	5,877	527	63	30,761	3,252
Post Retirement Benefits		928,296	5,605	249,186	62,435	10,654	1,717	5,282	473	57	27,643	2,922

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Account Description	Account Code	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
E. GENERAL PLANT						
Land	389	68,444	260	2,523	18	30
Land - Communication	390	333,607	1,266	12,300	88	145
Structures - Office	390	6,798,953	25,792	250,674	1,789	2,964
Structures - Communication	391	622,826	2,363	22,963	164	271
Office Furniture	391	357,470	1,356	13,180	94	156
Data Handling Equipment	391	160,026	607	5,900	42	70
Compuer Equipment	391	529,424	2,008	19,520	139	231
Transporation - Trailers	392	1,438,725	5,458	53,045	379	627
Transporation - Automobiles	392	351,455	1,333	12,958	92	153
Transporation - Large Trucks	392	15,312,554	58,089	564,566	4,029	6,675
Transporation -Trucks	393	7,911,768	30,014	291,703	2,082	3,449
Transporation - Snow/ATVs	393	534,067	2,026	19,691	141	233
Stores Equipment	393	400,192	1,518	14,755	105	174
Tools and Shop Equipment	394	3,993,996	15,151	147,257	1,051	1,741
Laboratory Equipment	395	3,312,247	12,565	122,121	872	1,444
Power Operated Equipment	396	2,133,362	8,093	78,656	561	930
Microwave Equipment	397	2,846,052	10,797	104,933	749	1,241
Other Communication	397	15,555,593	59,011	573,527	4,093	6,780
Office Communication	397	325,997	1,237	12,019	86	142
Miscellaneous General	398	155,494	590	5,733	41	68
Subtotal - GENERAL PLANT	389-389	63,142,251	239,534	2,328,024	16,614	27,523
TOTAL PLANT IN SERVICE		1,428,230,779	5,820,693	58,937,901	364,364	3,879,188
II. DEPRECIATION RESERVE						
Intangible Plant	108	371,341	1,579	12,498	96	131
Intangible Plant Computers	108	28,264	120	951	7	10
Production Plant	108	0	0	0	0	0
Transmission Plant	108	214,833,190	87,713	1,131,972	38,019	29,898
Distribution Substations	109	30,066,940	30,027	292,384	9,820	7,723
Distribution Poles& Wires	109	220,808,327	278,378	2,710,634	91,042	71,595
Distribution Onsite	109	147,211,347	0	0	0	0
Distribution Lighting	109	31,099,471	2,623,828	26,446,653	33,252	1,995,738
General Plant	109	32,294,642	122,512	1,190,688	8,498	14,077
Subtotal - DEPRECIATION RESERVE	108	676,713,524	3,144,157	31,785,780	180,734	2,119,173
Common Plant	118	36,871,939	139,876	1,359,450	9,702	16,072
III. OTHER RATE BASE ITEMS						
Cost of Refinancing Debt		1,782,840	7,581	60,002	460	630
SAP Development Costs		2,394,128	9,082	88,270	630	1,044
Regulatory Asset FAS 109		0	0	0	0	0
Customer Education Program		5,895	4	330	1	5
MPSC Taxes - Reg Asset		82,655	462	3,987	25	42
MCC Taxes - Reg Asset		71,245	398	3,436	22	36
Property Self-Insurance Reserve		(63,045)	(268)	(2,122)	(16)	(22)
Personal Injury & Property Damage		(1,259,648)	(4,779)	(46,443)	(331)	(549)
Customer Advances for Construction		3,549,626	49,168	364,154	628	2,457
USBC - Electric		(2,822,416)	(15,773)	(136,132)	(852)	(1,434)
Materials and Supplies		5,749,950	24,451	193,516	1,482	2,030
Deferred Revenue		(751,653)	(307)	(3,961)	(133)	(105)
Accrued Incentive Compensation		1,033,012	3,919	38,087	272	450
Post Retirement Benefits		928,296	3,522	34,226	244	405

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Account Description	Account Code	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
BPA Residential Buyback		137,872	52,249	125	2,499	1,129	5,856	1	20	36	9,889
Accelerated Depreciation		(76,376,404)	(28,943,940)	(69,143)	(1,384,400)	(625,344)	(3,244,105)	(569)	(11,063)	(19,723)	(5,478,110)
Environmental Reserve		106,742	40,451	97	1,935	874	4,534	1	15	28	7,656
Total - OTHER RATE BASE ITEMS		(65,430,906)	(24,297,399)	(58,376)	(1,154,732)	(564,320)	(2,931,359)	(495)	(9,036)	(15,869)	(4,437,961)
TOTAL RATE BASE (Excl. Working Capital)		722,958,288	268,977,324	642,908	12,861,494	5,863,445	29,830,923	5,156	101,371	181,320	50,403,125
Working Capital- WC Report		(23,785,344)	(9,013,799)	(21,533)	(431,133)	(194,746)	(1,010,288)	(177)	(3,445)	(6,142)	(1,706,008)
TOTAL RATE BASE		699,172,944	259,963,525	621,376	12,430,361	5,668,698	28,820,636	4,979	97,926	175,178	48,697,117
		0	0	0	0	0	0	0	0	0	0
I. OPERATION & MAINTENANCE EXPENSE											
A. PRODUCTION EXPENSES											
1. Power Generation Expenses											
Supervision & Engineering	500	0	0	0	0	0	0	0	0	0	0
FUEL	501	0	0	0	0	0	0	0	0	0	0
Steam Expenses	502	0	0	0	0	0	0	0	0	0	0
Electric Plant	505	0	0	0	0	0	0	0	0	0	0
Miscellaneous Steam Power	506	0	0	0	0	0	0	0	0	0	0
Rents	507	0	0	0	0	0	0	0	0	0	0
Supervision & Engineering	510	0	0	0	0	0	0	0	0	0	0
Structures	511	0	0	0	0	0	0	0	0	0	0
Steam Boiler Plant	512	0	0	0	0	0	0	0	0	0	0
Electric Plant	513	0	0	0	0	0	0	0	0	0	0
Miscellaneous Steam Power	514	0	0	0	0	0	0	0	0	0	0
Subtotal - Manufactured Gas Production	500-514	0	0	0	0	0	0	0	0	0	0
2. Other Power Supply Expenses											
Purchased Power	555	294,996,114	100,813,624	251,807	4,594,115	0	15,275,842	0	32,674	0	14,539,237
System Control & Load Dispatch	556	0	0	0	0	0	0	0	0	0	0
Other Expenses (DSM Related)	557	4,246,860	1,451,346	3,625	66,138	0	219,916	0	470	0	209,312
Subtotal - PRODUCTION EXPENSES	500-557	299,242,974	102,264,970	255,432	4,660,253	0	15,495,758	0	33,145	0	14,748,548
B. TRANSMISSION EXPENSES											
Supervision & Engineering	560	3,073,614	896,764	2,240	40,827	33,573	110,842	9	201	410	122,818
Load Dispatching	561	2,193,774	640,060	1,599	29,140	23,962	79,113	6	143	293	87,661
Station Expenses	562	510,201	148,857	372	6,777	5,573	18,399	1	33	68	20,387
Overhead Lines	563	709,952	207,137	517	9,430	7,755	25,603	2	46	95	28,369
Underground Lines	564	0	0	0	0	0	0	0	0	0	0
Transmission of Elec. By Others	565	3,814,938	1,113,054	2,780	50,674	41,670	137,576	11	249	509	152,441
Miscellaneous Transmission	566	70,936	20,696	52	942	775	2,558	0	5	9	2,835
Rents	567	670,687	195,681	489	8,909	7,326	24,187	2	44	90	26,800
Supervision & Engineering	568	177,893	51,903	130	2,363	1,943	6,415	1	12	24	7,108
Structures	569	18,393	5,366	13	244	201	663	0	1	2	735
Station Equipment	570	2,530,946	738,434	1,844	33,619	27,645	91,272	7	165	338	101,134
Overhead Lines	571	3,285,760	958,660	2,394	43,645	35,890	118,492	9	214	439	131,295
Underground Lines	572	3,421	998	2	45	37	123	0	0	0	137
Miscellaneous Transmission	573	0	0	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
BPA Residential Buyback		137,872	935	40,060	11,666	1,931	311	924	57	9	4,430	435
Accelerated Depreciation		(76,376,404)	(517,794)	(22,192,013)	(6,462,819)	(1,069,486)	(172,508)	(512,063)	(31,664)	(5,022)	(2,453,965)	(240,775)
Environmental Reserve		106,742	724	31,015	9,032	1,495	241	716	44	7	3,430	337
Total - OTHER RATE BASE ITEMS		(65,430,906)	(464,965)	(19,603,930)	(5,804,446)	(959,135)	(153,576)	(451,133)	(23,628)	(4,395)	(2,055,125)	(190,779)
TOTAL RATE BASE (Excl. Working Capital)		722,958,288	4,834,441	206,852,836	68,572,403	11,338,214	1,712,520	5,061,119	292,050	45,449	22,157,668	2,177,366
Working Capital- WC Report		(23,785,344)	(161,253)	(6,911,096)	(2,012,668)	(333,062)	(53,723)	(159,468)	(9,861)	(1,564)	(764,220)	(74,983)
TOTAL RATE BASE		699,172,944	4,673,188	199,941,740	66,559,734	11,005,151	1,658,797	4,901,651	282,189	43,885	21,393,448	2,102,383
		0	0	0	0	0	0	0	0	0	0	0
I. OPERATION & MAINTENANCE EXPENSE												
A. PRODUCTION EXPENSES												
1. Power Generation Expenses												
Supervision & Engineering	500	0	0	0	0	0	0	0	0	0	0	0
FUEL	501	0	0	0	0	0	0	0	0	0	0	0
Steam Expenses	502	0	0	0	0	0	0	0	0	0	0	0
Electric Plant	505	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous Steam Power	506	0	0	0	0	0	0	0	0	0	0	0
Rents	507	0	0	0	0	0	0	0	0	0	0	0
Supervision & Engineering	510	0	0	0	0	0	0	0	0	0	0	0
Structures	511	0	0	0	0	0	0	0	0	0	0	0
Steam Boiler Plant	512	0	0	0	0	0	0	0	0	0	0	0
Electric Plant	513	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous Steam Power	514	0	0	0	0	0	0	0	0	0	0	0
Subtotal - Manufactured Gas Production	500-514	0	0	0	0	0	0	0	0	0	0	0
2. Other Power Supply Expenses												
Purchased Power	555	294,996,114	0	128,577,908	0	15,628,755	0	7,307,880	431,009	0	4,275,399	239,301
System Control & Load Dispatch	556	0	0	0	0	0	0	0	0	0	0	0
Other Expenses (DSM Related)	557	4,246,860	0	1,851,049	0	224,997	0	105,207	6,205	0	61,550	3,445
Subtotal - PRODUCTION EXPENSES	500-557	299,242,974	0	130,428,957	0	15,853,752	0	7,413,087	437,214	0	4,336,949	242,746
B. TRANSMISSION EXPENSES												
Supervision & Engineering	560	3,073,614	26,164	1,024,587	590,787	97,477	19,041	53,251	334	94	33,878	1,896
Load Dispatching	561	2,193,774	18,674	731,293	421,671	69,573	13,590	38,007	239	67	24,180	1,353
Station Expenses	562	510,201	4,343	170,075	98,067	16,181	3,161	8,839	55	16	5,624	315
Overhead Lines	563	709,952	6,043	236,662	136,462	22,515	4,398	12,300	77	22	7,825	438
Underground Lines	564	0	0	0	0	0	0	0	0	0	0	0
Transmission of Elec. By Others	565	3,814,938	32,474	1,271,707	733,279	120,987	23,634	66,094	415	117	42,049	2,354
Miscellaneous Transmission	566	70,936	604	23,647	13,635	2,250	439	1,229	8	2	782	44
Rents	567	670,687	5,709	223,573	128,914	21,270	4,155	11,620	73	21	7,392	414
Supervision & Engineering	568	177,893	1,514	59,301	34,193	5,642	1,102	3,082	19	5	1,961	110
Structures	569	18,393	157	6,131	3,535	583	114	319	2	1	203	11
Station Equipment	570	2,530,946	21,544	843,689	486,479	80,267	15,679	43,849	275	78	27,897	1,561
Overhead Lines	571	3,285,760	27,970	1,095,306	631,564	104,205	20,355	56,926	357	101	36,216	2,027
Underground Lines	572	3,421	29	1,140	658	108	21	59	0	0	38	2
Miscellaneous Transmission	573	0	0	0	0	0	0	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
BPA Residential Buyback		137,872	586	4,640	36	49
Accelerated Depreciation		(76,376,404)	(324,779)	(2,570,466)	(19,685)	(26,970)
Environmental Reserve		106,742	454	3,592	28	38
Total - OTHER RATE BASE ITEMS		(65,430,906)	(246,279)	(1,964,882)	(17,191)	(21,895)
TOTAL RATE BASE (Excl. Working Capital)		722,958,288	2,570,133	26,546,689	176,141	1,754,193
Working Capital- WC Report		(23,785,344)	(101,143)	(800,501)	(6,130)	(8,399)
TOTAL RATE BASE		699,172,944	2,468,989	25,746,188	170,010	1,745,793
		0	0	0	0	0
I. OPERATION & MAINTENANCE EXPENSE						
A. PRODUCTION EXPENSES						
1. Power Generation Expenses						
Supervision & Engineering	500	0	0	0	0	0
FUEL	501	0	0	0	0	0
Steam Expenses	502	0	0	0	0	0
Electric Plant	505	0	0	0	0	0
Miscellaneous Steam Power	506	0	0	0	0	0
Rents	507	0	0	0	0	0
Supervision & Engineering	510	0	0	0	0	0
Structures	511	0	0	0	0	0
Steam Boiler Plant	512	0	0	0	0	0
Electric Plant	513	0	0	0	0	0
Miscellaneous Steam Power	514	0	0	0	0	0
Subtotal - Manufactured Gas Production	500-514	0	0	0	0	0
2. Other Power Supply Expenses						
Purchased Power	555	294,996,114	0	2,857,112	95,976	75,475
System Control & Load Dispatch	556	0	0	0	0	0
Other Expenses (DSM Related)	557	4,246,860	0	41,132	1,382	1,087
Subtotal - PRODUCTION EXPENSES	500-557	299,242,974	0	2,898,244	97,357	76,562
B. TRANSMISSION EXPENSES						
Supervision & Engineering	560	3,073,614	1,255	16,195	544	428
Load Dispatching	561	2,193,774	896	11,559	388	305
Station Expenses	562	510,201	208	2,688	90	71
Overhead Lines	563	709,952	290	3,741	126	99
Underground Lines	564	0	0	0	0	0
Transmission of Elec. By Others	565	3,814,938	1,558	20,101	675	531
Miscellaneous Transmission	566	70,936	29	374	13	10
Rents	567	670,687	274	3,534	119	93
Supervision & Engineering	568	177,893	73	937	31	25
Structures	569	18,393	8	97	3	3
Station Equipment	570	2,530,946	1,033	13,336	448	352
Overhead Lines	571	3,285,760	1,342	17,313	581	457
Underground Lines	572	3,421	1	18	1	0
Miscellaneous Transmission	573	0	0	0	0	0

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Account Description	Account Code	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
Subtotal - TRANSMISSION EXPENSES	560-573	17,060,515	4,977,610	12.432	226,617	186,349	615,242	49	1,114	2,277	681,720
C. DISTRIBUTION EXPENSES											
Operation Supervision & Engineering	580	2,338,810	993,487	2,333	48,349	15,727	108,327	23	442	765	208,802
Load Dispatching	581	896,607	340,560	849	15,487	10,666	72,652	12	119	155	46,408
Station Expenses	582	982,966	295,760	737	13,450	9,535	64,951	11	107	135	40,303
Overhead Lines	583	2,611,008	991,745	2,471	45,100	31,060	211,569	35	347	452	135,144
Underground Lines	584	2,230,678	847,283	2,111	38,531	26,536	180,751	30	297	386	115,458
Street Lighting & Signal Systems	585	1,560,715	0	0	0	0	0	0	0	0	0
Meters	586	2,502,945	1,461,893	3,226	75,756	481	6,797	17	783	1,579	414,074
Customer Installations	587	1,370,050	800,204	1,766	41,467	263	3,721	10	429	865	226,654
Miscellaneous Distribution	588	2,359,603	1,002,319	2,354	48,779	15,867	109,290	24	446	772	210,658
Rents	589	40,375	17,150	40	835	271	1,870	0	8	13	3,605
Operation Supervision & Engineering	590	1,096,456	465,756	1,094	22,667	7,373	50,785	11	207	359	97,888
Structures	591	1,140	343	1	16	11	75	0	0	0	47
Station Expenses	592	1,182,531	355,807	887	16,181	11,471	78,138	13	128	162	48,485
Overhead Lines	593	7,716,233	2,930,873	7,304	133,284	91,791	625,243	103	1,026	1,337	399,386
Underground Lines	594	1,569,479	596,139	1,486	27,110	18,670	127,174	21	209	272	81,235
Line Transfomers	595	860,700	502,708	1,109	26,051	165	2,337	6	269	543	142,390
Street Lighting & Signal Systems	596	126,500	0	0	0	0	0	0	0	0	0
Meters	597	1,060,993	619,693	1,368	32,113	204	2,881	7	332	670	175,525
Miscellaneous Distribution	598	0	0	0	0	0	0	0	0	0	0
Subtotal - DISTRIBUTION EXPENSES	870-894	30,507,788	12,221,721	29,136	585,175	240,093	1,646,562	324	5,148	8,466	2,346,059
Total - OPERATION & MAINTENANCE EXPENSES		346,811,278	119,464,300	297,000	5,472,046	426,442	17,757,562	373	39,407	10,743	17,776,328
			17,199,331	41,568	811,792	426,442	2,261,804	373	6,262	10,743	3,027,779
II. CUSTOMER ACCOUNTS EXPENSES											
Supervision	901	0	0	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,367,170	909,738	2,075	46,598	938	10,177	5	259	484	128,034
Customer Records & Collection Expense	903	6,446,558	4,289,649	9,782	219,720	4,424	47,987	25	1,220	2,283	603,714
Uncollectible Accounts Expense	904	1,451,223	649,661	1,523	31,789	9,206	63,762	14	270	468	127,601
Miscellaneous Customer Accts	905	4,093	2,724	6	140	3	30	0	1	1	383
Total - CUSTOMER ACCOUNTS EXPENSES	901-905	9,269,045	5,851,771	13,386	298,246	14,571	121,957	44	1,750	3,236	859,732
III. CUSTOMER SERVICE & INFORMATIONAL EXPI											
Customer Assistance Expenses	908	2,805,448	1,866,792	4,257	95,619	1,925	20,883	11	531	993	262,727
Inform. & Instruct Advertising	909	618,281	411,415	938	21,073	424	4,602	2	117	219	57,901
Misc. Customer Service & Info	910	730,537	379,654	884	18,973	3,418	13,592	3	103	196	53,117
Subtotal - CUSTOMER SERVICE	907-910	4,154,266	2,657,861	6,079	135,665	5,767	39,078	16	751	1,408	373,746
IV. SALES EXPENSES											
Supervision	911	0	0	0	0	0	0	0	0	0	0
Demonstration and Selling Expense	912	205,805	136,946	312	7,015	141	1,532	1	39	73	19,273
Advertising Expense	913	0	0	0	0	0	0	0	0	0	0
Misc Sales Promo Expense	916	0	0	0	0	0	0	0	0	0	0
Total - SALES EXPENSES	911-919	205,805	136,946	312	7,015	141	1,532	1	39	73	19,273

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Account Description	Account Code	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
Subtotal - TRANSMISSION EXPENSES	560-573	17,060,515	145,226	5,687,110	3,279,244	541,058	105,690	295,575	1,855	524	188,044	10,525
C. DISTRIBUTION EXPENSES												
Operation Supervision & Engineering	580	2,338,810	13,711	627,212	59,851	9,968	193	1,935	1,354	200	103,206	10,697
Load Dispatching	581	896,607	8,891	347,460	0	0	0	0	0	107	38,300	2,144
Station Expenses	582	982,966	7,722	301,752	173,991	28,182	0	0	0	93	33,261	1,862
Overhead Lines	583	2,611,008	25,893	1,011,838	0	0	0	0	0	311	111,532	6,243
Underground Lines	584	2,230,678	22,121	864,450	0	0	0	0	0	266	95,286	5,333
Street Lighting & Signal Systems	585	1,560,715	0	0	0	0	0	0	0	0	0	0
Meters	586	2,502,945	2,385	360,711	2,105	1,143	566	5,661	3,963	133	139,465	22,204
Customer Installations	587	1,370,050	1,305	197,444	1,152	626	310	3,099	2,169	73	76,340	12,154
Miscellaneous Distribution	588	2,359,603	13,833	632,788	60,383	10,057	195	1,952	1,366	202	104,123	10,792
Rents	589	40,375	237	10,828	1,033	172	3	33	23	3	1,782	185
Operation Supervision & Engineering	590	1,096,456	6,428	294,043	28,059	4,673	91	907	635	94	48,384	5,015
Structures	591	1,140	9	350	202	33	0	0	0	0	39	2
Station Expenses	592	1,182,531	9,289	363,015	209,315	33,904	0	0	0	112	40,014	2,240
Overhead Lines	593	7,716,233	76,520	2,990,254	0	0	0	0	0	920	329,608	18,449
Underground Lines	594	1,569,479	15,564	608,217	0	0	0	0	0	187	67,042	3,752
Line Transfomers	595	860,700	820	124,039	724	393	195	1,947	1,363	46	47,959	7,636
Street Lighting & Signal Systems	596	126,500	0	0	0	0	0	0	0	0	0	0
Meters	597	1,060,993	1,011	152,904	892	484	240	2,400	1,680	56	59,119	9,412
Miscellaneous Distribution	598	0	0	0	0	0	0	0	0	0	0	0
Subtotal - DISTRIBUTION EXPENSES	870-894	30,507,788	205,738	8,887,305	537,707	89,635	1,793	17,934	12,554	2,804	1,295,459	118,119
Total - OPERATION & MAINTENANCE EXPENSES		346,811,278	350,964	145,003,373	3,816,951	16,484,445	107,483	7,726,596	451,622	3,328	5,820,453	371,389
			350,964	14,574,416	3,816,951	630,693	107,483	313,509	14,409	3,328	1,483,503	128,644
II. CUSTOMER ACCOUNTS EXPENSES												
Supervision	901	0	0	0	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,367,170	1,082	149,169	14,105	5,735	419	3,003	1,560	20	11,052	3,754
Customer Records & Collection Expense	903	6,446,558	5,101	703,370	66,509	27,040	1,975	14,160	7,356	96	52,111	17,699
Uncollectible Accounts Expense	904	1,451,223	8,024	373,457	33,084	5,884	148	1,350	885	116	58,492	6,209
Miscellaneous Customer Accts	905	4,093	3	447	42	17	1	9	5	0	33	11
Total - CUSTOMER ACCOUNTS EXPENSES	901-905	9,269,045	14,210	1,226,443	113,741	38,676	2,543	18,522	9,805	232	121,687	27,672
III. CUSTOMER SERVICE & INFORMATIONAL EXPI												
Customer Assistance Expenses	908	2,805,448	2,220	306,096	28,944	11,767	859	6,162	3,201	42	22,678	7,702
Inform. & Instruct Advertising	909	618,281	489	67,459	6,379	2,593	189	1,358	705	9	4,998	1,697
Misc. Customer Service & Info	910	730,537	2,778	143,596	59,361	10,905	1,902	5,915	539	15	6,743	1,399
Subtotal - CUSTOMER SERVICE	907-910	4,154,266	5,487	517,152	94,683	25,266	2,950	13,435	4,446	66	34,418	10,799
IV. SALES EXPENSES												
Supervision	911	0	0	0	0	0	0	0	0	0	0	0
Demonstration and Selling Expense	912	205,805	163	22,455	2,123	863	63	452	235	3	1,664	565
Advertising Expense	913	0	0	0	0	0	0	0	0	0	0	0
Misc Sales Promo Expense	916	0	0	0	0	0	0	0	0	0	0	0
Total - SALES EXPENSES	911-919	205,805	163	22,455	2,123	863	63	452	235	3	1,664	565

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Account Description	Account Code	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
Subtotal - TRANSMISSION EXPENSES	560-573	17,060,515	6,966	89,893	3,019	2,374
C. DISTRIBUTION EXPENSES						
Operation Supervision & Engineering	580	2,338,810	15,061	115,367	708	1,092
Load Dispatching	581	896,607	1,130	11,007	370	291
Station Expenses	582	982,966	982	9,559	321	252
Overhead Lines	583	2,611,008	3,292	32,053	1,077	847
Underground Lines	584	2,230,678	2,812	27,384	920	723
Street Lighting & Signal Systems	585	1,560,715	131,676	1,327,215	1,669	100,155
Meters	586	2,502,945	0	0	0	0
Customer Installations	587	1,370,050	0	0	0	0
Miscellaneous Distribution	588	2,359,603	15,195	116,393	714	1,102
Rents	589	40,375	260	1,992	12	19
Operation Supervision & Engineering	590	1,096,456	7,061	54,085	332	512
Structures	591	1,140	1	11	0	0
Station Expenses	592	1,182,531	1,181	11,499	386	304
Overhead Lines	593	7,716,233	9,728	94,724	3,181	2,502
Underground Lines	594	1,569,479	1,979	19,267	647	509
Line Transfomers	595	860,700	0	0	0	0
Street Lighting & Signal Systems	596	126,500	10,673	107,574	135	8,118
Meters	597	1,060,993	0	0	0	0
Miscellaneous Distribution	598	0	0	0	0	0
Subtotal - DISTRIBUTION EXPENSES	870-894	30,507,788	201,029	1,928,129	10,472	116,426
Total - OPERATION & MAINTENANCE EXPENSES		346,811,278	207,995	4,916,266	110,849	195,362
			207,995	2,018,022	13,491	118,800
II. CUSTOMER ACCOUNTS EXPENSES						
Supervision	901	0	0	0	0	0
Meter Reading Expenses	902	1,367,170	901	76,459	337	1,267
Customer Records & Collection Expense	903	6,446,558	4,249	360,523	1,590	5,975
Uncollectible Accounts Expense	904	1,451,223	8,110	69,996	438	737
Miscellaneous Customer Accts	905	4,093	3	229	1	4
Total - CUSTOMER ACCOUNTS EXPENSES	901-905	9,269,045	13,264	507,207	2,366	7,983
III. CUSTOMER SERVICE & INFORMATIONAL EXPI						
Customer Assistance Expenses	908	2,805,448	1,849	156,895	692	2,600
Inform. & Instruct Advertising	909	618,281	408	34,577	152	573
Misc. Customer Service & Info	910	730,537	410	26,423	160	453
Subtotal - CUSTOMER SERVICE	907-910	4,154,266	2,667	217,895	1,005	3,626
IV. SALES EXPENSES						
Supervision	911	0	0	0	0	0
Demonstration and Selling Expense	912	205,805	136	11,510	51	191
Advertising Expense	913	0	0	0	0	0
Misc Sales Promo Expense	916	0	0	0	0	0
Total - SALES EXPENSES	911-919	205,805	136	11,510	51	191

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Account Description	Account Code	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
Total - CUSTOMER ACCOUNTS, SERVICES & SALES	901-919	13,629,116	8,646,578	19,777	440,926	20,480	162,566	61	2,540	4,717	1,252,751
V. ADMINISTRATIVE & GENERAL EXPENSES											
1. Labor-Related:											
Administrative & General Salaries	920	16,515,054	6,951,289	16,450	337,372	119,467	644,832	120	2,524	4,504	1,240,892
Office and Supplies Expense	921	4,924,573	2,072,783	4,905	100,600	35,623	192,281	36	753	1,343	370,018
Admin. Expense Transferred	922	(4,958,580)	(2,087,097)	(4,939)	(101,295)	(35,869)	(193,608)	(36)	(758)	(1,352)	(372,573)
Outside Services Employed	923	6,853,416	2,884,645	6,826	140,003	49,576	267,592	50	1,047	1,869	514,945
Injuries & Damages	925	3,957,178	1,665,601	3,942	80,838	28,625	154,509	29	605	1,079	297,330
Employee Pensions & Benefits	926	8,575,680	3,609,557	8,542	175,185	62,035	334,839	62	1,311	2,339	644,351
General Plant - Maintenace	935	2,896,456	1,219,136	2,885	59,169	20,952	113,092	21	443	790	217,631
Property Insurance											
Subtotal - O&M Accounts 920-926		38,763,776	16,315,914	38,611	791,873	280,410	1,513,537	281	5,924	10,571	2,912,594
2. Other-Related:											
Property Insurance	924	510,696	193,536	462	9,257	4,181	21,692	4	74	132	36,630
Franchise Requirements	927	0	0	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	898,532	378,198	895	18,355	6,500	35,083	7	137	245	67,513
Duplicate Charges	929	0	0	0	0	0	0	0	0	0	0
Miscellaneous General Expenses	930	862,286	362,942	859	17,615	6,238	33,668	6	132	235	64,790
Rents	931	2,191,252	922,312	2,183	44,763	15,851	85,558	16	335	598	164,644
Subtotal - O&M Accounts 927-935		4,462,767	1,856,987	4,399	89,990	32,770	176,001	33	678	1,210	333,576
Total - ADMINISTRATIVE & GENERAL EXPENSES	920-935	43,226,543	18,172,901	43,010	881,863	313,180	1,689,538	314	6,602	11,780	3,246,170
TOTAL - OPERATING EXPENSES (X Depr. & Supply)		104,423,962	44,018,810	104,355	2,134,582	760,102	4,113,908	748	15,405	27,240	7,526,701
VI. DEPRECIATION EXPENSE											
Depreciaton Exp - Int	403	234,178	76,466	187	3,561	2,324	8,652	1	21	40	11,610
Depreciation Exp-Production	403	0	0	0	0	0	0	0	0	0	0
Depreciation Exp- Transmission	403	14,010,590	4,087,758	10,210	186,105	153,036	505,255	40	915	1,870	559,848
Depreciation Exp - Substations	403	2,423,314	729,140	1,817	33,158	23,508	160,125	26	263	333	99,359
Depreciation Exp - Poles	403	15,564,172	5,911,773	14,732	268,843	185,149	1,261,157	209	2,069	2,697	805,588
Depreciation Exp - Onsite	404	11,511,896	6,723,744	14,838	348,430	2,213	31,263	80	3,603	7,264	1,904,468
Depreciation Exp - Dist Lighting	404	2,454,107	1,042,463	2,448	50,733	16,502	113,668	25	463	803	219,095
Depreciation Exp-General/Common	404	8,413,711	3,541,383	8,381	171,877	60,863	328,514	61	1,286	2,294	632,181
Depreciation Exp-Other	404-406	94,914	35,605	85	1,704	770	3,918	1	13	24	6,700
Amort Regulatory Debits	407	12,563,810	4,713,020	11,258	225,514	101,910	518,591	90	1,782	3,193	886,868
Total - DEPRECIATION EXPENSE		67,270,692	26,861,353	63,956	1,289,923	546,275	2,931,143	533	10,416	18,518	5,125,716
VII. TAXES OTHER THAN INCOME TAXES											
A. General Taxes											
Tax Other Than Inc Util Ops- Labor	408Lab	0	0	0	0	0	0	0	0	0	0
Tax Other Than Inc Util Ops- Property	408Plant	64,213,246	24,334,535	58,132	1,163,930	525,757	2,727,472	479	9,301	16,582	4,605,706
General Taxes	408Oth	0	0	0	0	0	0	0	0	0	0
Subtotal - General Taxes		64,213,246	24,334,535	58,132	1,163,930	525,757	2,727,472	479	9,301	16,582	4,605,706

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Account Description	Account Code	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
Total - CUSTOMER ACCOUNTS, SERVICES & SALES	901-919	13,629,116	19,860	1,766,049	210,548	64,805	5,556	32,409	14,486	302	157,769	39,036
V. ADMINISTRATIVE & GENERAL EXPENSES												
1. Labor-Related:												
Administrative & General Salaries	920	16,515,054	99,714	4,436,764	1,110,760	189,547	30,550	93,962	8,423	1,014	491,787	51,986
Office and Supplies Expense	921	4,924,573	29,734	1,322,985	331,214	56,520	9,110	28,018	2,512	302	146,644	15,502
Admin. Expense Transferred	922	(4,958,580)	(29,939)	(1,332,121)	(333,501)	(56,911)	(9,172)	(28,212)	(2,529)	(304)	(147,657)	(15,609)
Outside Services Employed	923	6,853,416	41,380	1,841,168	460,943	78,658	12,678	38,992	3,495	421	204,082	21,573
Injuries & Damages	925	3,957,178	23,893	1,063,095	266,150	45,417	7,320	22,514	2,018	243	117,837	12,456
Employee Pensions & Benefits	926	8,575,680	51,778	2,303,854	576,778	98,425	15,863	48,791	4,374	526	255,367	26,995
General Plant - Maintenace	935	2,896,456	17,488	778,132	194,808	33,243	5,358	16,479	1,477	178	86,251	9,117
Property Insurance												
Subtotal - O&M Accounts 920-926		38,763,776	234,048	10,413,877	2,607,153	444,901	71,706	220,546	19,770	2,379	1,154,312	122,021
2. Other-Related:												
Property Insurance	924	510,696	3,462	148,388	43,214	7,151	1,153	3,424	212	34	16,409	1,610
Franchise Requirements	927	0	0	0	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	898,532	5,425	241,390	60,433	10,313	1,662	5,112	458	55	26,757	2,828
Duplicate Charges	929	0	0	0	0	0	0	0	0	0	0	0
Miscellaneous General Expenses	930	862,286	5,206	231,653	57,995	9,897	1,595	4,906	440	53	25,677	2,714
Rents	931	2,191,252	13,230	588,679	147,378	25,150	4,053	12,467	1,118	134	65,251	6,898
Subtotal - O&M Accounts 927-935		4,462,767	27,324	1,210,111	309,020	52,510	8,464	25,909	2,227	276	134,094	14,050
Total - ADMINISTRATIVE & GENERAL EXPENSES	920-935	43,226,543	261,372	11,623,988	2,916,173	497,411	80,170	246,455	21,998	2,655	1,288,405	136,071
TOTAL - OPERATING EXPENSES (X Depr. & Supply)		104,423,962	632,195	27,964,453	6,943,671	1,192,909	193,209	592,373	50,893	6,285	2,929,678	303,751
VI. DEPRECIATION EXPENSE												
Depreciaton Exp - Int	403	234,178	1,837	73,988	37,034	6,133	1,172	3,312	51	9	3,800	308
Depreciation Exp-Production	403	0	0	0	0	0	0	0	0	0	0	0
Depreciation Exp- Transmission	403	14,010,590	119,263	4,670,420	2,693,010	444,333	86,796	242,735	1,524	430	154,427	8,644
Depreciation Exp - Substations	403	2,423,314	19,037	743,913	428,940	69,477	0	0	0	229	82,000	4,590
Depreciation Exp - Poles	403	15,564,172	154,346	6,031,549	0	0	0	0	0	1,856	664,842	37,212
Depreciation Exp - Onsite	404	11,511,896	10,967	1,659,031	9,683	5,257	2,604	26,039	18,227	611	641,448	102,126
Depreciation Exp - Dist Lighting	404	2,454,107	14,387	658,132	62,801	10,460	203	2,030	1,421	210	108,294	11,224
Depreciation Exp-General/Common	404	8,413,711	50,800	2,260,341	565,885	96,566	15,564	47,870	4,291	516	250,544	26,485
Depreciation Exp-Other	404-406	94,914	635	27,229	9,003	1,489	225	666	39	6	2,937	290
Amort Regulatory Debits	407	12,563,810	84,078	3,604,292	1,191,730	197,069	29,776	88,103	5,180	793	388,750	38,426
Total - DEPRECIATION EXPENSE		67,270,692	455,350	19,728,894	4,998,086	830,784	136,339	410,754	30,733	4,661	2,297,041	229,304
VII. TAXES OTHER THAN INCOME TAXES												
A. General Taxes												
Tax Other Than Inc Util Ops- Labor	408Lab	0	0	0	0	0	0	0	0	0	0	0
Tax Other Than Inc Util Ops- Property	408Plant	64,213,246	435,334	18,657,872	5,433,596	899,168	145,036	430,515	26,621	4,222	2,063,164	202,431
General Taxes	408Oth	0	0	0	0	0	0	0	0	0	0	0
Subtotal - General Taxes		64,213,246	435,334	18,657,872	5,433,596	899,168	145,036	430,515	26,621	4,222	2,063,164	202,431

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Account Description	Account Code	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
Total - CUSTOMER ACCOUNTS, SERVICES & SALES	901-919	13,629,116	16,066	736,612	3,422	11,799
V. ADMINISTRATIVE & GENERAL EXPENSES						
1. Labor-Related:						
Administrative & General Salaries	920	16,515,054	62,651	608,902	4,346	7,199
Office and Supplies Expense	921	4,924,573	18,682	181,567	1,296	2,147
Admin. Expense Transferred	922	(4,958,580)	(18,811)	(182,820)	(1,305)	(2,161)
Outside Services Employed	923	6,853,416	25,999	252,682	1,803	2,987
Injuries & Damages	925	3,957,178	15,012	145,899	1,041	1,725
Employee Pensions & Benefits	926	8,575,680	32,532	316,181	2,256	3,738
General Plant - Maintenace	935	2,896,456	10,988	106,791	762	1,263
Property Insurance						
Subtotal - O&M Accounts 920-926		38,763,776	147,053	1,429,202	10,200	16,897
2. Other-Related:						
Property Insurance	924	510,696	2,172	17,188	132	180
Franchise Requirements	927	0	0	0	0	0
Regulatory Commission Expenses	928	898,532	3,409	33,128	236	392
Duplicate Charges	929	0	0	0	0	0
Miscellaneous General Expenses	930	862,286	3,271	31,792	227	376
Rents	931	2,191,252	8,313	80,790	577	955
Subtotal - O&M Accounts 927-935		4,462,767	17,164	162,899	1,172	1,903
Total - ADMINISTRATIVE & GENERAL EXPENSES	920-935	43,226,543	164,217	1,592,100	11,371	18,800
TOTAL - OPERATING EXPENSES (X Depr. & Supply)		104,423,962	388,278	4,346,734	28,285	149,399
VI. DEPRECIATION EXPENSE						
Depreciaton Exp - Int	403	234,178	316	3,257	47	51
Depreciation Exp-Production	403	0	0	0	0	0
Depreciation Exp- Transmission	403	14,010,590	5,720	73,823	2,479	1,950
Depreciation Exp - Substations	403	2,423,314	2,420	23,565	791	622
Depreciation Exp - Poles	403	15,564,172	19,622	191,065	6,417	5,047
Depreciation Exp - Onsite	404	11,511,896	0	0	0	0
Depreciation Exp - Dist Lighting	404	2,454,107	15,803	121,055	743	1,146
Depreciation Exp-General/Common	404	8,413,711	31,918	310,209	2,214	3,667
Depreciation Exp-Other	404-406	94,914	391	3,129	24	33
Amort Regulatory Debits	407	12,563,810	51,730	414,127	3,155	4,374
Total - DEPRECIATION EXPENSE		67,270,692	127,921	1,140,229	15,871	16,891
VII. TAXES OTHER THAN INCOME TAXES						
A. General Taxes						
Tax Other Than Inc Util Ops- Labor	408Lab	0	0	0	0	0
Tax Other Than Inc Util Ops- Property	408Plant	64,213,246	273,057	2,161,112	16,550	22,675
General Taxes	408Oth	0	0	0	0	0
Subtotal - General Taxes		64,213,246	273,057	2,161,112	16,550	22,675

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Account Description	Account Code	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
TOTAL EXPENSES (excl. Gross Receipts Taxes & Supply)	408.1	235,907,900	95,214,698	226,443	4,588,435	1,832,133	9,772,523	1,759	35,122	62,341	17,258,123
B. Revenue Taxes: (GRT)											
State Gross Earnings	408.11	0	0	0	0	0	0	0	0	0	0
Other	408	0	0	0	0	0	0	0	0	0	0
Subtotal - Revenue Taxes (GRT)		0	0	0	0	0	0	0	0	0	0
C. INCOME TAXES											
Subtotal - Income Taxes		14,648,265	5,447,813	13,020	260,525	118,670	602,344	104	2,051	3,672	1,020,569
TOTAL TAXES (Excl. General Taxes)		14,648,265	5,447,813	13,020	260,525	118,670	602,344	104	2,051	3,672	1,020,569
TOTAL EXPENSES		549,799,140	202,927,480	494,896	9,509,213	1,950,804	25,870,624	1,863	70,318	66,012	33,027,240
VIII. OPERATING REVENUES											
Residential	440	203,363,552	193,852,812	573,645	8,937,095	0	0	0	0	0	0
Comm & Industrial	442	335,390,739	0	0	0	2,183,864	23,890,058	888	53,781	60,492	31,949,143
Lighting	444	15,209,629	0	0	0	0	0	0	0	0	0
Employee Revenue Allocation	450	(229,458)	(56,933)	(142)	(2,594)	(2,700)	(8,907)	(1)	(19)	(27)	(8,211)
Miscellaneous Service Revenue	451	0	0	0	0	0	0	0	0	0	0
Rent From Electric Property	454	2,551,536	889,203	2,460	40,780	19,759	109,719	6	227	332	136,183
Transmission	456	34,865,450	10,172,414	25,407	463,123	380,830	1,257,330	100	2,276	4,654	1,393,186
Other Misc. Revenues	456	0	0	0	0	0	0	0	0	0	0
TOTAL REVENUE		591,151,448	204,857,495	601,370	9,438,404	2,581,753	25,248,201	993	56,264	65,450	33,470,301
NET INCOME	Marginal	41,352,309	1,930,015	106,474	(70,809)	630,949	(622,423)	(871)	(14,054)	(562)	443,061
Return	Marginal	5.9%	0.7%	17.1%	-0.6%	11.1%	-2.2%	-17.5%	-14.4%	-0.3%	0.9%

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Account Description	Account Code	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
TOTAL EXPENSES (excl. Gross Receipts Taxes & Supply)	408.1	235,907,900	1,522,879	66,351,218	17,375,354	2,922,860	474,585	1,433,643	108,247	15,168	7,289,883	735,485
B. Revenue Taxes: (GRT)												
State Gross Earnings	408.11	0	0	0	0	0	0	0	0	0	0	0
Other	408	0	0	0	0	0	0	0	0	0	0	0
Subtotal - Revenue Taxes (GRT)		0	0	0	0	0	0	0	0	0	0	0
C. INCOME TAXES												
Subtotal - Income Taxes		14,648,265	97,808	4,185,857	1,407,315	232,680	34,895	103,103	5,926	917	447,311	44,023
TOTAL TAXES (Excl. General Taxes)		14,648,265	97,808	4,185,857	1,407,315	232,680	34,895	103,103	5,926	917	447,311	44,023
TOTAL EXPENSES		549,799,140	1,620,687	200,966,032	18,782,669	19,009,292	509,480	8,949,834	551,386	16,085	12,074,143	1,022,254
VIII. OPERATING REVENUES												
Residential	440	203,363,552	0	0	0	0	0	0	0	0	0	0
Comm & Industrial	442	335,390,739	1,879,478	214,993,316	19,601,546	20,371,878	370,398	9,553,576	679,318	33,715	9,298,097	471,194
Lighting	444	15,209,629	0	0	0	0	0	0	0	0	0	0
Employee Revenue Allocation	450	(229,458)	(1,854)	(72,613)	(55,732)	(9,200)	(1,545)	(4,330)	(255)	(7)	(2,414)	(135)
Miscellaneous Service Revenue	451	0	0	0	0	0	0	0	0	0	0	0
Rent From Electric Property	454	2,551,536	15,872	998,638	245,219	40,460	7,903	22,103	139	39	14,062	787
Transmission	456	34,865,450	296,788	11,622,372	6,701,574	1,105,725	215,992	604,048	3,791	1,070	384,293	21,509
Other Misc. Revenues	456	0	0	0	0	0	0	0	0	0	0	0
TOTAL REVENUE		591,151,448	2,190,283	227,541,713	26,492,607	21,508,862	592,748	10,175,396	682,992	34,817	9,694,037	493,356
NET INCOME	Marginal	41,352,309	569,596	26,575,680	7,709,938	2,499,570	83,269	1,225,562	131,606	18,733	(2,380,105)	(528,898)
Return	Marginal	5.9%	12.2%	13.3%	11.6%	22.7%	5.0%	25.0%	46.6%	42.7%	-11.1%	-25.2%

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Account Description	Account Code	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
TOTAL EXPENSES (excl. Gross Receipts Taxes & Supply)	408.1	235,907,900	789,255	7,648,075	60,706	188,965
B. Revenue Taxes: (GRT)						
State Gross Earnings	408.11	0	0	0	0	0
Other	408	0	0	0	0	0
Subtotal - Revenue Taxes (GRT)		0	0	0	0	0
C. INCOME TAXES						
Subtotal - Income Taxes		14,648,265	51,164	529,916	3,549	35,035
TOTAL TAXES (Excl. General Taxes)		14,648,265	51,164	529,916	3,549	35,035
TOTAL EXPENSES		549,799,140	840,419	11,076,235	161,612	300,562
VIII. OPERATING REVENUES						
Residential	440	203,363,552	0	0	0	0
Comm & Industrial	442	335,390,739	0	0	0	0
Lighting	444	15,209,629	1,141,599	13,705,744	126,143	236,143
Employee Revenue Allocation	450	(229,458)	(126)	(1,614)	(54)	(43)
Miscellaneous Service Revenue	451	0	0	0	0	0
Rent From Electric Property	454	2,551,536	521	6,722	226	178
Transmission	456	34,865,450	14,235	183,709	6,170	4,852
Other Misc. Revenues	456	0	0	0	0	0
TOTAL REVENUE		591,151,448	1,156,229	13,894,561	132,485	241,130
NET INCOME	Marginal	41,352,309	315,810	2,818,326	(29,127)	(59,432)
Return	Marginal	5.9%	12.8%	10.9%	-17.1%	-3.4%

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Summary Reports

Account Description	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
SUMMARY	TOTAL									
OPERATING REVENUES										
Total Operating Revenues	591,151,448	204,857,495	601,370	9,438,404	2,581,753	25,248,201	993	56,264	65,450	33,470,301
OPERATING EXPENSES										
Production Expenses	299,242,974	102,264,970	255,432	4,660,253	0	15,495,758	0	33,145	0	14,748,548
Transmission Expenses	17,060,515	4,977,610	12,432	226,617	186,349	615,242	49	1,114	2,277	681,720
Distribution Expenses	30,507,788	12,221,721	29,136	585,175	240,093	1,646,562	324	5,148	8,466	2,346,059
Total Operating Expenses	346,811,278	119,464,300	297,000	5,472,046	426,442	17,757,562	373	39,407	10,743	17,776,328
CUSTOMER ACCOUNTS, SERVICES, & SALES EXPI	13,629,116	8,646,578	19,777	440,926	20,480	162,566	61	2,540	4,717	1,252,751
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	18,172,901	43,010	881,863	313,180	1,689,538	314	6,602	11,780	3,246,170
DEPRECIATION EXPENSE	67,270,692	26,861,353	63,956	1,289,923	546,275	2,931,143	533	10,416	18,518	5,125,716
TAXES OTHER THAN INCOME TAXES	64,213,246	24,334,535	58,132	1,163,930	525,757	2,727,472	479	9,301	16,582	4,605,706
INCOME BEFORE INCOME TAXES	56,000,574	7,377,827	119,494	189,716	749,620	(20,079)	(766)	(12,003)	3,109	1,463,630
INCOME TAXES	14,648,265	5,447,813	13,020	260,525	118,670	602,344	104	2,051	3,672	1,020,569
Effective Tax Rate- Actual	26.16%	73.84%	10.90%	137.32%	15.83%	-2999.82%	-13.57%	-17.09%	118.09%	69.73%
NET OPERATING INCOME	41,352,309	1,930,015	106,474	(70,809)	630,949	(622,423)	(871)	(14,054)	(562)	443,061
RATE BASE	699,172,944	259,963,525	621,376	12,430,361	5,668,698	28,820,636	4,979	97,926	175,178	48,697,117
RATE OF RETURN	5.91%	0.74%	17.14%	-0.57%	11.13%	-2.16%	-17.48%	-14.35%	-0.32%	0.91%
	1.00	0.13	2.90	(0.10)	1.88	(0.37)	(2.96)	(2.43)	(0.05)	0.15
ELECTRIC PLANT IN SERVICE										
Intangible Plant	1,197,944	391,165	959	18,217	11,890	44,259	5	107	205	59,390
Production Plant	0	0	0	0	0	0	0	0	0	0
Transmission Plant	489,223,045	142,736,701	356,506	6,498,425	5,343,708	17,642,539	1,399	31,937	65,303	19,548,835
Distribution Plant.										
Substations	124,933,785	37,590,769	93,676	1,709,470	1,211,943	8,255,254	1,365	13,546	17,147	5,122,436
Poles & Wires	387,369,346	147,135,332	366,661	6,691,094	4,608,081	31,388,347	5,192	51,507	67,114	20,049,905
Onsite	305,866,483	178,647,210	394,235	9,257,639	58,806	830,632	2,128	95,743	193,009	50,600,951
Other Distribution Plant	56,497,926	0	0	0	0	0	0	0	0	0
General Plant	63,142,251	26,576,966	62,893	1,289,880	456,759	2,465,397	458	9,650	17,219	4,744,319
TOTAL PLANT IN SERVICE	1,428,230,779	533,078,143	1,274,931	25,464,726	11,691,187	60,626,428	10,548	202,490	359,997	100,125,836
COMMON PLANT	36,871,939	15,519,628	36,727	753,226	266,725	1,439,670	268	5,635	10,055	2,770,447
DEPRECIATION RESERVE	676,713,524	255,323,048	610,373	12,201,726	5,530,147	29,303,815	5,164	97,718	172,864	48,055,196
OTHER RATE BASE ITEMS										
Accelerated Depreciation	(76,376,404)	(28,943,940)	(69,143)	(1,384,400)	(625,344)	(3,244,105)	(569)	(11,063)	(19,723)	(5,478,110)
Materials and Supplies	5,749,950	2,179,026	5,205	104,224	47,079	244,230	43	833	1,485	412,416
Working Capital Requirement	(23,785,344)	(9,013,799)	(21,533)	(431,133)	(194,746)	(1,010,288)	(177)	(3,445)	(6,142)	(1,706,008)
Customer Advances for Construction	3,549,626	1,830,017	4,038	94,833	602	8,509	22	981	1,977	518,343
All other, net	1,645,923	637,497	1,523	30,611	13,343	60,007	9	213	393	109,389
SubTotal Other Rate Base Items	(89,216,250)	(33,311,198)	(79,908)	(1,585,865)	(759,067)	(3,941,647)	(672)	(12,481)	(22,011)	(6,143,969)
RATE BASE	699,172,944	259,963,525	621,376	12,430,361	5,668,698	28,820,636	4,979	97,926	175,178	48,697,117

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Account Description	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
SUMMARY	TOTAL										
OPERATING REVENUES											
Total Operating Revenues	591,151,448	2,190,283	227,541,713	26,492,607	21,508,862	592,748	10,175,396	682,992	34,817	9,694,037	493,356
OPERATING EXPENSES											
Production Expenses	299,242,974	0	130,428,957	0	15,853,752	0	7,413,087	437,214	0	4,336,949	242,746
Transmission Expenses	17,060,515	145,226	5,687,110	3,279,244	541,058	105,690	295,575	1,855	524	188,044	10,525
Distribution Expenses	30,507,788	205,738	8,887,305	537,707	89,635	1,793	17,934	12,554	2,804	1,295,459	118,119
Total Operating Expenses	346,811,278	350,964	145,003,373	3,816,951	16,484,445	107,483	7,726,596	451,622	3,328	5,820,453	371,389
CUSTOMER ACCOUNTS, SERVICES, & SALES EXPI	13,629,116	19,860	1,766,049	210,548	64,805	5,556	32,409	14,486	302	157,769	39,036
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	261,372	11,623,988	2,916,173	497,411	80,170	246,455	21,998	2,655	1,288,405	136,071
DEPRECIATION EXPENSE	67,270,692	455,350	19,728,894	4,998,086	830,784	136,339	410,754	30,733	4,661	2,297,041	229,304
TAXES OTHER THAN INCOME TAXES	64,213,246	435,334	18,657,872	5,433,596	899,168	145,036	430,515	26,621	4,222	2,063,164	202,431
INCOME BEFORE INCOME TAXES	56,000,574	667,404	30,761,538	9,117,253	2,732,250	118,164	1,328,666	137,532	19,649	(1,932,795)	(484,876)
INCOME TAXES	14,648,265	97,808	4,185,857	1,407,315	232,680	34,895	103,103	5,926	917	447,311	44,023
Effective Tax Rate- Actual	26.16%	14.65%	13.61%	15.44%	8.52%	29.53%	7.76%	4.31%	4.67%	-23.14%	-9.08%
NET OPERATING INCOME	41,352,309	569,596	26,575,680	7,709,938	2,499,570	83,269	1,225,562	131,606	18,733	(2,380,105)	(528,898)
RATE BASE	699,172,944	4,673,188	199,941,740	66,559,734	11,005,151	1,658,797	4,901,651	282,189	43,885	21,393,448	2,102,383
RATE OF RETURN	5.91%	12.19%	13.29%	11.58%	22.71%	5.02%	25.00%	46.64%	42.69%	-11.13%	-25.16%
	1.00	2.06	2.25	1.96	3.84	0.85	4.23	7.89	7.22	(1.88)	(4.25)
ELECTRIC PLANT IN SERVICE											
Intangible Plant	1,197,944	9,398	378,487	189,449	31,376	5,998	16,941	260	47	19,439	1,573
Production Plant	0	0	0	0	0	0	0	0	0	0	0
Transmission Plant	489,223,045	4,164,450	163,082,146	94,034,767	15,515,250	3,030,738	8,475,847	53,201	15,019	5,392,299	301,815
Distribution Plant:											
Substations	124,933,785	981,429	38,352,378	22,113,987	3,581,906	0	0	0	11,802	4,227,481	236,619
Poles & Wires	387,369,346	3,841,446	150,116,370	0	0	0	0	0	46,194	16,546,932	926,158
Onsite	305,866,483	291,400	44,079,782	257,275	139,664	69,185	691,845	484,292	16,231	17,043,013	2,713,442
Other Distribution Plant	56,497,926	0	0	0	0	0	0	0	0	0	0
General Plant	63,142,251	381,240	16,963,146	4,246,787	724,698	116,801	359,246	32,204	3,875	1,880,256	198,759
TOTAL PLANT IN SERVICE	1,428,230,779	9,669,364	412,972,309	120,842,266	19,992,894	3,222,722	9,543,880	569,957	93,168	45,109,420	4,378,367
COMMON PLANT	36,871,939	222,625	9,905,635	2,479,913	423,188	68,206	209,782	18,805	2,263	1,097,976	116,066
DEPRECIATION RESERVE	676,713,524	4,592,583	196,421,179	48,945,330	8,118,733	1,424,832	4,241,409	273,085	45,587	21,994,603	2,126,288
OTHER RATE BASE ITEMS											
Accelerated Depreciation	(76,376,404)	(517,794)	(22,192,013)	(6,462,819)	(1,069,486)	(172,508)	(512,063)	(31,664)	(5,022)	(2,453,965)	(240,775)
Materials and Supplies	5,749,950	38,982	1,670,712	486,549	80,516	12,987	38,550	2,384	378	184,745	18,127
Working Capital Requirement	(23,785,344)	(161,253)	(6,911,096)	(2,012,668)	(333,062)	(53,723)	(159,468)	(9,861)	(1,564)	(764,220)	(74,983)
Customer Advances for Construction	3,549,626	2,985	451,542	2,635	1,431	709	7,087	4,961	166	174,584	27,796
All other, net	1,645,923	10,862	465,829	169,188	28,405	5,237	15,293	691	83	39,510	4,074
SubTotal Other Rate Base Items	(89,216,250)	(626,218)	(26,515,025)	(7,817,114)	(1,292,197)	(207,299)	(610,601)	(33,488)	(5,959)	(2,819,345)	(265,762)
RATE BASE	699,172,944	4,673,188	199,941,740	66,559,734	11,005,151	1,658,797	4,901,651	282,189	43,885	21,393,448	2,102,383

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Account Description	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
SUMMARY	TOTAL				
OPERATING REVENUES					
Total Operating Revenues	591,151,448	1,156,229	13,894,561	132,485	241,130
OPERATING EXPENSES					
Production Expenses	299,242,974	0	2,898,244	97,357	76,562
Transmission Expenses	17,060,515	6,966	89,893	3,019	2,374
Distribution Expenses	30,507,788	201,029	1,928,129	10,472	116,426
Total Operating Expenses	346,811,278	207,995	4,916,266	110,849	195,362
CUSTOMER ACCOUNTS, SERVICES, & SALES EXPI	13,629,116	16,066	736,612	3,422	11,799
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	164,217	1,592,100	11,371	18,800
DEPRECIATION EXPENSE	67,270,692	127,921	1,140,229	15,871	16,891
TAXES OTHER THAN INCOME TAXES	64,213,246	273,057	2,161,112	16,550	22,675
INCOME BEFORE INCOME TAXES	56,000,574	366,974	3,348,242	(25,578)	(24,397)
INCOME TAXES	14,648,265	51,164	529,916	3,549	35,035
Effective Tax Rate- Actual	26.16%	13.94%	15.83%	-13.87%	-143.61%
NET OPERATING INCOME	41,352,309	315,810	2,818,326	(29,127)	(59,432)
RATE BASE	699,172,944	2,468,989	25,746,188	170,010	1,745,793
RATE OF RETURN	5.91%	12.79%	10.95%	-17.13%	-3.40%
	1.00	2.16	1.85	(2.90)	(0.58)
ELECTRIC PLANT IN SERVICE					
Intangible Plant	1,197,944	1,615	16,659	240	263
Production Plant	0	0	0	0	0
Transmission Plant	489,223,045	199,742	2,577,753	86,579	68,085
Distribution Plant:					
Substations	124,933,785	124,770	1,214,912	40,805	32,089
Poles & Wires	387,369,346	488,365	4,755,330	159,717	125,601
Onsite	305,866,483	0	0	0	0
Other Distribution Plant	56,497,926	4,766,667	48,045,223	60,409	3,625,627
General Plant	63,142,251	239,534	2,328,024	16,614	27,523
TOTAL PLANT IN SERVICE	1,428,230,779	5,820,693	58,937,901	364,364	3,879,188
COMMON PLANT	36,871,939	139,876	1,359,450	9,702	16,072
DEPRECIATION RESERVE	676,713,524	3,144,157	31,785,780	180,734	2,119,173
OTHER RATE BASE ITEMS					
Accelerated Depreciation	(76,376,404)	(324,779)	(2,570,466)	(19,685)	(26,970)
Materials and Supplies	5,749,950	24,451	193,516	1,482	2,030
Working Capital Requirement	(23,785,344)	(101,143)	(800,501)	(6,130)	(8,399)
Customer Advances for Construction	3,549,626	49,168	364,154	628	2,457
All other, net	1,645,923	4,881	47,913	383	588
SubTotal Other Rate Base Items	(89,216,250)	(347,423)	(2,765,384)	(23,322)	(30,294)
RATE BASE	699,172,944	2,468,989	25,746,188	170,010	1,745,793

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Account Description	Total Allocated Dollars	RES-1A Non-Demand Non-Choice RESIDENTIAL	RES-1B Non-Demand Non-Choice EMPLOYEE	RES-1C Non-Demand Non-Choice LIEAP	GS1-2A Demand Choice Primary	GS1-2B Demand Non-Choice Primary	GS1-2C Non-Demand Choice Primary	GS1-2D Non-Demand Non-Choice Primary	GS1-3A Non-Demand Choice Secondary	GS1-3B Non-Demand Non-Choice Secondary
	2	16,962,392	(87,961)	1,016,825	(373,017)	2,935,692	1,470	25,037	13,781	3,074,594
REVENUE REQUIREMENTS										
Target Average Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
RATE BASE	699,172,944	259,963,525	621,376	12,430,361	5,668,698	28,820,636	4,979	97,926	175,178	48,697,117
OPERATING EXPENSES	346,811,278	119,464,300	297,000	5,472,046	426,442	17,757,562	373	39,407	10,743	17,776,328
CUST. ACCTS., SERVICES, & SALES EXP.	13,629,116	8,646,578	19,777	440,926	20,480	162,566	61	2,540	4,717	1,252,751
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	18,172,901	43,010	881,863	313,180	1,689,538	314	6,602	11,780	3,246,170
DEPRECIATION EXPENSE	67,270,692	26,861,353	63,956	1,289,923	546,275	2,931,143	533	10,416	18,518	5,125,716
GENERAL TAXES	64,213,246	24,334,535	58,132	1,163,930	525,757	2,727,472	479	9,301	16,582	4,605,706
TOTAL	535,150,874	197,479,668	481,875	9,248,688	1,832,133	25,268,280	1,759	68,267	62,341	32,006,672
RETURN ON RATEBASE	41,352,309	15,375,440	36,751	735,189	335,273	1,704,585	294	5,792	10,361	2,880,172
FIT / State Inc tax- Actual	14,648,265	5,447,813	13,020	260,525	118,670	602,344	104	2,051	3,672	1,020,569
FIT/State Tax on Incr in Net Income	(0)	3,516,967	(18,238)	210,828	(77,341)	608,684	305	5,191	2,857	637,484
Total FIT/State Tax ON RETURN	14,648,265	8,964,779	(5,217)	471,352	41,329	1,211,028	409	7,242	6,529	1,658,052
GROSS RECEIPTS TAX	0	0	0	0	0	0	0	0	0	0
Other Utility Operating Inc (Exp)	0	0	0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT	**591,151,448**	**221,819,887**	**513,409**	**10,455,229**	**2,208,736**	**28,183,893**	**2,462**	**81,301**	**79,230**	**36,544,896**
TOTAL REVENUE REQUIREMENT - Minus Purchase Power	**291,908,474**	**119,554,918**	**257,976**	**5,794,976**	**2,208,736**	**12,688,136**	**2,462**	**48,156**	**79,230**	**21,796,347**

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Account Description	Total Allocated Dollars	GS1-3C Demand Choice Secondary	GS1-3D Demand Non-Choice Secondary	GS2-4A Demand Choice Substation	GS2-4B Demand Non-Choice Substation	GS2-5A Demand Choice Transmission	GS2-5B Demand Non-Choice Transmission	GS2-5C Demand Non-Choice TransmissionSPP	IRR-6A Demand Choice Irrigation	IRR-6B Demand Non-Choice Irrigation	IRR-6C Non-Demand Non-Choice Irrigation
	2	(369,896)	(18,608,467)	(4,760,281)	(2,332,239)	18,722	(1,180,399)	(144,975)	(20,358)	4,598,956	824,114
REVENUE REQUIREMENTS											
Target Average Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
RATE BASE	699,172,944	4,673,188	199,941,740	66,559,734	11,005,151	1,658,797	4,901,651	282,189	43,885	21,393,448	2,102,383
OPERATING EXPENSES	346,811,278	350,964	145,003,373	3,816,951	16,484,445	107,483	7,726,596	451,622	3,328	5,820,453	371,389
CUST. ACCTS., SERVICES, & SALES EXP.	13,629,116	19,860	1,766,049	210,548	64,805	5,556	32,409	14,486	302	157,769	39,036
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	261,372	11,623,988	2,916,173	497,411	80,170	246,455	21,998	2,655	1,288,405	136,071
DEPRECIATION EXPENSE	67,270,692	455,350	19,728,894	4,998,086	830,784	136,339	410,754	30,733	4,661	2,297,041	229,304
GENERAL TAXES	64,213,246	435,334	18,657,872	5,433,596	899,168	145,036	430,515	26,621	4,222	2,063,164	202,431
TOTAL	535,150,874	1,522,879	196,780,175	17,375,354	18,776,612	474,585	8,846,730	545,460	15,168	11,626,832	978,231
RETURN ON RATEBASE	41,352,309	276,394	11,825,476	3,936,649	650,895	98,109	289,906	16,690	2,596	1,265,307	124,345
FIT / State Inc tax- Actual	14,648,265	97,808	4,185,857	1,407,315	232,680	34,895	103,103	5,926	917	447,311	44,023
FIT/State Tax on Incr in Net Income	(0)	(76,694)	(3,858,263)	(986,992)	(483,564)	3,882	(244,743)	(30,059)	(4,221)	953,543	170,871
Total FIT/State Tax ON RETURN	14,648,265	21,114	327,595	420,322	(250,884)	38,777	(141,639)	(24,133)	(3,304)	1,400,854	214,894
GROSS RECEIPTS TAX	0	0	0	0	0	0	0	0	0	0	0
Other Utility Operating Inc (Exp)	0	0	0	0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT	**591,151,448**	**1,820,387**	**208,933,245**	**21,732,326**	**19,176,623**	**611,470**	**8,994,997**	**538,017**	**14,459**	**14,292,993**	**1,317,470**
TOTAL REVENUE REQUIREMENT - Minus Purchase Power	**291,908,474**	**1,820,387**	**78,504,288**	**21,732,326**	**3,322,871**	**611,470**	**1,581,910**	**100,804**	**14,459**	**9,956,044**	**1,074,724**

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Account Description	Total Allocated Dollars	LT-7A Non-Demand Choice Lighting	LT-7B Non-Demand Non-Choice Lighting	LT-7C Non-Demand Non-Choice MT Lighting	LT-7D Non-Demand Non-Choice Flat Lighting
	2	(214,193)	(1,634,467)	49,431	205,241
REVENUE REQUIREMENTS					
Target Average Rate of Return	5.91%	5.91%	5.91%	5.91%	5.91%
RATE BASE	699,172,944	2,468,989	25,746,188	170,010	1,745,793
OPERATING EXPENSES	346,811,278	207,995	4,916,266	110,849	195,362
CUST. ACCTS., SERVICES, & SALES EXP.	13,629,116	16,066	736,612	3,422	11,799
ADMINISTRATIVE & GENERAL EXPENSES	43,226,543	164,217	1,592,100	11,371	18,800
DEPRECIATION EXPENSE	67,270,692	127,921	1,140,229	15,871	16,891
GENERAL TAXES	64,213,246	273,057	2,161,112	16,550	22,675
TOTAL	535,150,874	789,255	10,546,319	158,063	265,527
RETURN ON RATEBASE	41,352,309	146,027	1,522,748	10,055	103,254
FIT / State Inc tax- Actual	14,648,265	51,164	529,916	3,549	35,035
FIT/State Tax on Incr in Net Income	(0)	(44,411)	(338,889)	10,249	42,554
Total FIT/State Tax ON RETURN	14,648,265	6,753	191,027	13,798	77,590
GROSS RECEIPTS TAX	0	0	0	0	0
Other Utility Operating Inc (Exp)	0	0	0	0	0
TOTAL REVENUE REQUIREMENT	**591,151,448**	**942,036**	**12,260,094**	**181,916**	**446,371**
TOTAL REVENUE REQUIREMENT - Minus Purchase Power	**291,908,474**	**942,036**	**9,361,850**	**84,559**	**369,809**

NorthWestern Energy
Electric Utility
Statement M

Due to the nature of the complete report produced by RJ Rudden for NWE, Statement M is partially presented within the body of the Electric Utility Cost Allocation Study (Study) contained under Statement L. Therefore, rather than repeat this information here, note that the discussion of the basic principles and objectives of rate design are contained at the end of Section III of the Study while Section IV of the Study presents overall recommendations and conclusions that also embody rate design.

The Study uses NWE's projection of customer numbers, loads, general expenses, revenues and marginal costs for the year 2009, in accordance with the guidelines established in ARM 38.5.176. In Statement M, NWE then reconciled the Study results to the revenues presented in the September 29, 2006 (Phase I) filing, moderated the reconciled revenues to buffer rate impact, and derived corresponding illustrative rate designs. The revenue reconciliation, moderation, and the subsequent rate designs and proof of revenue are discussed in the following:

Revenue Reconciliation

While the Montana Public Service Commission practice for determining revenue requirements is based on historic test year information, the marginal cost allocation analysis is forward-looking, and escalates customers, loads, expenses and revenues two years beyond the filing date. To account for this timing difference, the ACOS results must be scaled back, or reconciled, to equal the allowed revenue requirement. Therefore, the Study results have been reconciled to the revenue requirement presented in Phase I.

Page 3 of Statement M is derived from the Phase I filing Statement H (column H). The revenues presented in Statement H are shown here in column D, with the results of the Study shown in column E. Consistent with past practice, the Total Equal Proportional Reconciliation method was used, as follows:

> *The marginal revenue for each customer class was calculated as a percentage of total marginal revenue (row 33, column E). The resulting relationships (column F) were applied to the proposed revenue (row 33, column D) to produce reshaped customer class revenues (column G), reconciled to proposed revenue.*

The impact of the reconciliation is shown in column I. It suggests that some classes are paying more than they should, while other classes are not covering their full cost responsibility.

Moderation

The marginal cost shapes suggest shifts of cost responsibility among some classes that are substantial. Developing rates simply on the marginal shapes would violate numerous principles of sound rate design, so the marginal shapes were moderated so that no class incurred more than a 10% increase or a 10% decrease in cost responsibility. The results of the moderation are shown in column I, with corresponding moderated impacts shown in column J.

Rate Design and Proof of Revenue

Pages 4 and 5 of Statement M show the derivation of rates as well as the proof of revenue for the Electric utility based on the reconciled and moderated cost responsibility. The rate design presented here is for purposes of illustration only. First, the current delivery rate structures fom the base rates of the Phase I filing were used as the starting point. Second, the current unbundled transmission and distribution rate components were rebundled, resulting in a single delivery energy rate and/or single demand rate. Finally, the base rates from the Phase 1 filing were adjusted proportionally to collect the moderated class revenue amount.

The derivation of rates begins with column B, which is comprised of the rates developed to calculate the revenues presented in Phase I. Column C shows the rates in column B adjusted for changes due to reconciliation and moderation. Column D calculates the impact of the rate adjustment on a rate component basis.

The proof of revenue is calculated in column F, by multiplying the reconciled and moderated rates in column C by the 2005 test period billing determinants in column E.

NorthWestern Energy Electric Utility
Statement M
Reconciliation and Moderation of Marginal Cost Allocation to Proposed Revenue Requirement

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
			Presented Revenue Req.		Marginal Revenue Req.		Reconciled Revenue Req.		Moderated Revenue Req.	
Line No.	Customer Class	Avg # Cust	(mWh)	Revenues @ Presented Base Rates	ACOS Results (2009)	Proportional Share by Class	Reconciled Revenues	Raw Impact	Moderated Revenues	Class Impacts
1	***Residential***									
2	Res Non Choice	240,754	1,975,289	$ 90,759,595	$ 119,554,918	41.0%	$ 99,765,068		$ 99,530,180	
3	Emp NonChoice	615	4,930	$ 136,444	$ 257,976	0.1%	$ 215,274		$ 214,767	
4	Low Inc NonChoice	11,591	89,799	$ 4,166,959	$ 5,794,976	2.0%	$ 4,835,737		$ 4,824,352	
5	Res Choice	-	-	$ -		0.0%	$ -		$ -	
6		252,960	2,070,017	$ 95,062,999	$ 125,607,870	43.0%	$ 104,816,079	10.3%	$ 104,569,299	10.0%
7	***General Service 1***									
8	GS1 Sec NonDmd NonCh	38,850	262,767	$ 16,172,569	$ 22,166,156	7.6%	$ 18,497,006		$ 18,891,440	
9	GS1 Sec Dmd NonCh	16,285	2,324,414	$ 79,183,834	$ 78,504,288	26.9%	$ 65,509,523		$ 66,906,462	
10	GS1 Sec NonDmd Choice	154	673	$ 46,570	$ 79,230	0.0%	$ 66,115		$ 67,525	
11	GS1 Sec Dmd Choice	114	59,307	$ 1,729,218	$ 1,820,387	0.6%	$ 1,519,060		$ 1,551,452	
12	GS1 Pri NonDmd NonCh	42	639	$ 21,398	$ 48,156	0.0%	$ 40,185		$ 41,042	
13	GS1 Pri Dmd NonCh	112	302,184	$ 7,794,860	$ 12,688,136	4.3%	$ 10,587,877		$ 10,813,655	
14	GS1 Pri NonDmd Choice	1	31	$ 938	$ 2,462	0.0%	$ 2,055		$ 2,098	
15	GS1 Pri Dmd Choice	8	94,331	$ 2,188,044	$ 2,208,736	0.8%	$ 1,843,125		$ 1,882,428	
16		55,566	3,044,346	$ 107,137,432	$ 117,517,551	40.3%	$ 98,064,945	-8.5%	$ 100,156,102	-6.5%
17	***General Service 2***		-							
18	GS2 Sub NonCh	18	267,944	$ 3,235,630	$ 3,322,871	1.1%	$ 2,772,839		$ 2,831,967	
19	GS2 Sub Choice	35	1,911,104	$ 19,610,805	$ 21,732,326	7.4%	$ 18,134,987		$ 18,521,702	
20	GS2 Tran NonCh	13	160,387	$ 1,870,244	$ 1,682,714	0.6%	$ 1,404,175		$ 1,434,118	
21	GS2 Tran Choice	1	53,224	$ 366,467	$ 611,470	0.2%	$ 510,254		$ 521,135	
22		67	2,392,660	$ 25,083,147	$ 27,349,381	9.4%	$ 22,822,255	-9.0%	$ 23,308,922	-7.1%
23	***Irrigation***									
24	Irrig NonDmd NonCh	439	4,808	$ 233,458	$ 1,074,724	0.4%	$ 896,825		$ 470,836	
25	Irrig Dmd NonCh	820	83,855	$ 4,154,187	$ 9,956,044	3.4%	$ 8,308,026		$ 4,361,739	
26	Irrig Dmd Choice	2	239	$ 11,364	$ 14,459	0.0%	$ 12,066		$ 6,335	
27		1,261	88,903	$ 4,399,009	$ 11,045,227	3.8%	$ 9,216,917	109.5%	$ 4,838,910	10.0%
28	***Lighting***									
29	Lighting NonCh	3,702	59,238	$ 11,756,737	$ 9,446,409	3.2%	$ 7,882,751		$ 9,744,094	
30	Lighting Choice	108	4,394	$ 149,725	$ 942,036	0.3%	$ 786,101		$ 971,722	
31		3,810	63,632	$ 11,906,462	$ 10,388,445	3.6%	$ 8,668,852	-27.2%	$ 10,715,816	-10.0%
32										
33	**Total Rate Schedule**	**313,664**	**7,659,557**	**$ 243,589,049**	**$ 291,908,474**	**100.0%**	**$ 243,589,049**	0.0%	**$ 243,589,049**	0.0%
34										
35					sum of +/- 10% moderation for Residential/Irrigation/Lighting Classes:				$ 2,577,824	

NorthWestern Energy Electric Utility
Statement M
Derivation of Moderated Rates and Proof of Revenue

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Class	Presented Base Rates	Proposed Rates Adjusted by Moderated Class Impacts	Rate Impact	Billing Determinants: Customers Energy Demand	Revenue Moderated by Class Impacts
1	**Residential:**					
2	*Residential:*					
3	Service Charge	$ 5.28	$ 5.81	10.0%	252,345	$ 17,587,437
4	Energy Delivery	$ 0.038225	$ 0.042048	10.0%	2,065,087,365	$ 86,831,762
5						$ 104,419,199
6	*Employee:*					
7	Service Charge	$ 3.17	$ 3.49	10.0%	615	$ 25,734
8	Energy Delivery	$ 0.022934	$ 0.025227	10.0%	4,929,769	$ 124,365
9						$ 150,099
10				*Residential Class Total*		104,569,298
11						
12	**General Service 1:**					
13	*GS 1 Secondary Non Demand:*					
14	Service Charge	$ 7.86	$ 7.35	-6.5%	39,004	$ 3,439,130
15	Energy Delivery	$ 0.047602	$ 0.04450	-6.5%	263,440,064	$ 11,723,105
16						$ 15,162,235
17	*GS 1 Secondary Demand:*					
18	Service Charge	$ 9.18	$ 8.58	-6.5%	16,399	$ 1,688,795
19	Energy Delivery	$ 0.004900	$ 0.00458	-6.5%	2,383,720,953	$ 10,919,108
20	Demand	$ 9.208208	$ 8.60817	-6.5%	7,322,414	$ 63,032,581
21						$ 75,640,484
22	*GS 1 Primary Non Demand:*					
23	Service Charge	$ 7.86	$ 7.35	-6.5%	43	$ 3,791
24	Energy Delivery	$ 0.027324	$ 0.02554	-6.5%	669,897	$ 17,111
25						$ 20,902
26	*GS 1 Primary Demand:*					
27	Service Charge	$ 26.19	$ 24.48	-6.5%	120	$ 35,256
28	Energy Delivery	$ 0.007480	$ 0.00699	-6.5%	396,514,642	$ 2,772,659
29	Demand	$ 8.158987	$ 7.62732	-6.5%	855,421	$ 6,524,566
30						$ 9,332,481
31				*GS-1 Class Total*		$ 100,156,103
32						
33	**General Service 2:**					
34	*GS 2 Substation:*					
35	Monthly Cust Charge	$ 222.75	$ 206.96	-7.1%	53	$ 131,628
36	Demand	$ 5.875247	$ 5.458825	-7.1%	3,864,403	$ 21,095,097
37						$ 21,226,725
38	*GS 2 Transmission:*					
39	Monthly Cust Charge	$ 1,441.31	$ 1,339.15	-7.1%	14	$ 224,978
40	Demand	$ 3.685572	$ 3.424348	-7.1%	542,357	$ 1,857,219
41						$ 2,082,197
42				*GS-2 Class Total*		23,308,922
43						
44	**Irrigation:**					
45	*Irrigation Non Demand:*					
46	Seasonal Cust Chg	$ 53.73	$ 59.12	10.0%	1,204	$ 71,175
47	Energy Delivery	$ 0.035100	$ 0.038618	10.0%	4,808,173	$ 185,683
48						$ 256,858
49	*Irrigation Demand:*					
50	Seasonal Cust Chg	$ 126.77	$ 139.48	10.0%	2,474	$ 345,065
51	Energy Delivery	$ 0.003914	$ 0.004306	10.0%	83,855,079	$ 361,106
52	Demand	$ 9.208207	$ 10.131176	10.0%	382,569	$ 3,875,876
53						$ 4,582,047
54				*Irrigation Class Total*		$ 4,838,905
55						

NorthWestern Energy Electric Utility
Statement M
Derivation of Moderated Rates and Proof of Revenue

	(A)	(B)	(C)	(D)	(E)	(F)
Line No.	Customer Class	Presented Base Rates	Proposed Rates Adjusted by Moderated Class Impacts	Rate Impact	Billing Determinants: Customers Energy Demand	Revenue Moderated by Class Impacts
56	**Lighting:**					
57	Utility-Owned Lighting					
58	Fixed Charge Cost Range					
59	$200 - $399	$ 2.96	$ 2.67	-10.0%	9,451	$ 302,741
60	$400 - $599	$ 6.36	$ 5.73	-10.0%	44,361	$ 3,049,008
61	$600 - $799	$ 9.88	$ 8.90	-10.0%	6,833	$ 729,586
62	$800 - $999	$ 11.85	$ 10.67	-10.0%	6,444	$ 824,890
63	$1,000 - $1,199	$ 14.26	$ 12.84	-10.0%	1,744	$ 268,567
64	$1,200 - $1,399	$ 17.30	$ 15.58	-10.0%	4,861	$ 908,708
65	$1,400 - $1,599	$ 21.09	$ 18.99	-10.0%	3,410	$ 777,102
66	$1,600 - $1,799	$ 23.74	$ 21.38	-10.0%	1,526	$ 391,551
67	$1,800 - $1,999	$ 26.76	$ 24.10	-10.0%	447	$ 129,205
68	$2,000 - $2,199	$ 28.66	$ 25.80	-10.0%	316	$ 97,806
69	$2,200 - $2,399	$ 31.40	$ 28.27	-10.0%	119	$ 40,430
70	$2,400 - $2,599	$ 34.10	$ 30.70	-10.0%	144	$ 52,893
71	$2,600 - $2,799	$ 36.85	$ 33.18	-10.0%	54	$ 21,445
72	$2,800 - $2,999	$ 39.57	$ 35.63	-10.0%	128	$ 54,547
73	Operations	$ 0.62	$ 0.56	-10.0%	81,389	$ 543,301
74	Maintenance	$ 0.61	$ 0.55	-10.0%	79,568	$ 521,307
75	Default Supply Trans Service	$ 0.003370	$ 0.003035	-10.0%	63,631,892	$ 193,097
76						$ 8,906,183
77						
78	Customer-Owned Lighting					
79	Operations	$ 0.62	$ 0.56	-10.0%	56	$ 374
80	Maintenance	$ 0.61	$ 0.55	-10.0%	1,318	$ 8,635
81	Billing	$ 0.25	$ 0.23	-10.0%	10,485	$ 28,515
82						$ 37,524
83						
84	Delivery Service Charge	$ 0.030929	$ 0.027849	-10.0%	63,631,892	$ 1,772,109
85						
86				*Lighting Class Total*		$ 10,715,816
87						
88	**Total Proof of Revenue**					**$ 243,589,044**
89	**Proposed Revenue Requirement**					**$ 243,589,049**
90	**Variance due to rounding**					**$ (5)**