BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT TESTIMONY

OF

WILLIAM STEVEN SEELYE

WESTAR ENERGY

DOCKET NO. _______________

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6435 West Highway 146, Crestwood, Kentucky, 40014.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am a senior consultant and principal for The Prime Group, LLC, a firm located in Crestwood, Kentucky, providing consulting and educational services in the areas of utility marketing, regulatory analysis, cost of service, rate design and fuel and power procurement.

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

A. The purpose of my testimony is to discuss the accounting adjustments that are necessary to reflect the implementation of the Transmission Delivery Charge proposed by Westar; to discuss the accounting adjustments necessary to reflect the fuel normalization adjustment; to describe the Energy Cost Adjustment being proposed by Westar; and to sponsor the fully allocated class cost of service studies for Westar North and Westar South.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Westar is proposing to implement a Transmission Delivery Charge to recover its revenue requirement associated with transmission service provided to its retail customers. The Transmission Delivery

Charge will reflect revenue requirements determined by the application of a formula rate filed with the Federal Energy Regulatory Commission. Westar will recover or “flow through” on a dollar-per-dollar basis the transmission revenue requirements assigned to retail customers from the formula rate. Essentially, transmission revenue requirements will be unbundled from base rates and recovered through the Transmission Delivery Charge. Since these transmission revenue requirements will no longer be included in base rates and will be tracked through a separate set of charges, it is necessary to remove transmission-related items from Westar’s cost of service. In my testimony, I will describe how this is done and how Westar’s transmission revenue requirements determined from the formula rate are allocated to Westar North and South and to the rate classes within each utility.

A pro-forma adjustment was made to test year operating results to reflect the impact on fuel and other energy-related expenses due to the weather normalization adjustment, the customer annualization adjustment, annualization of the Wolf Creek Generating Station (Wolf Creek) refueling outage and the addition of a large industrial customer early in 2005. This standard adjustment, referred to as “Fuel Normalization,” reflects the incremental expenses that correspond to these four adjustments. In performing this adjustment, changes in energy costs between base case and normalized production cost scenarios were identified.

Westar is also proposing to implement Retail Energy Cost Adjustments (RECAs) for Westar North and South. The RECAs will operate as monthly adjustment clauses and will provide monthly charges or credits to reflect differences between fuel and other energy-related costs during the month and base energy costs during the test year. The RECAs are modeled after the ECA used by Aquila that was reviewed by the Commission in a recent rate case. They are also similar to other fuel adjustment clauses and energy cost adjustment clauses used by utilities around the country. The proposed RECAs also incorporate a mechanism for sharing off-system sales margins with customers.

The Prime Group prepared fully allocated, embedded class cost of service studies ("class cost of service studies") for Westar North and South using standard cost of service methodologies. The purpose of the class cost of service studies is to determine the contribution that each customer class is making towards the utility's overall rate of return. Rates of return are computed for each rate class. Westar was guided by the class cost of service studies in allocating the proposed revenue increase to the classes of service and is proposing rates in this proceeding that move closer to the cost of providing service.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is divided into the following sections: (I) Introduction, (II) Qualifications, (III) Accounting Adjustments to Reflect the Implementation of the Transmission Delivery Charge, (IV) Fuel Normalization, (V) Retail Energy Cost Adjustment (RECA), and (VI) Class Cost of Service Studies.

II. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE?

A. I received a B.S. degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. I have been performing revenue requirement studies, statistical and economic studies, embedded and marginal cost of service studies, and rate design studies on behalf of utilities for more than 26 years. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E. A more detailed description of my qualifications is included in Exhibit___(WSS-1).

Q. HAVE YOU TESTIFIED ON BEHALF OF UTILITIES THAT HAVE MERGED?

A. Yes. I have testified on behalf of Louisville Gas and Electric Company and Kentucky Utilities Company that merged to form LG&E Energy, and on behalf of Sierra Pacific Power and Nevada Power Company, that merged as Sierra Pacific Resources. These merged entities continued to operate their units as separate utilities, but both were moving in the direction of consolidating their operations and their service rates for the two units. I also assisted Vectren Energy, which was formed from the merger of Indiana Gas and Southern Indiana Gas and Electric Company, in developing revenue requirements and performing cost of service studies for its gas utility units in Indiana. Based on my experience in working with these merged utilities, the transition periods for integrating the service rates for the individual utilities have proven to be lengthy, in spite of concerted efforts to move in the direction of consolidation. None of the other merged companies I have worked with have fully consolidated the service rates for the individual utilities.

Q. HAVE YOU WORKED WITH FUEL ADJUSTMENT CLAUSES OR ENERGY COST ADJUSTMENT MECHANISMS FOR ELECTRIC UTILITIES?

A. Yes. While employed by LG&E, I had management responsibility for the preparation of the utility's monthly fuel adjustment clause (FAC) filings. I also testified in numerous FAC review proceedings. Since leaving LG&E, I have developed or supervised the development of energy cost adjustment clauses for numerous electric utilities.

Q. DO YOU HAVE ANY EXPERIENCE WITH RATE UNBUNDLING?

A. Yes. I have developed unbundled rates for a number of electric and gas utilities and have performed unbundling studies for even more utilities. The model that was used by The Prime Group to prepare Westar's class cost of service study discussed later in my testimony was developed to facilitate the functional unbundling of costs for ratemaking purposes. This model was used to develop the unbundled transmission rates in this proceeding.

III. ADJUSTMENTS TO REFLECT THE TRANSMISSION DELIVERY CHARGE

Q. ARE YOU SPONSORING THE ACCOUNTING ADJUSTMENTS TO REFLECT THE IMPLEMENTATION OF THE TRANSMISSION DELIVERY CHARGE?

A. Yes. These adjustments are identified as Adjustment Nos. 4 in Section 4, No. 4 in Section 5, No. 5 in Section 6, No. 5 in Section 10, and No. 28 in Section 9 of the Minimum Filing Requirements MFRs.

Q. PLEASE EXPLAIN WHY AN ACCOUNTING ADJUSTMENT IS REQUIRED TO IMPLEMENT THE TRANSMISSION DELIVERY CHARGE.

A. Westar is proposing to implement a Transmission Delivery Charge ("TDC") that will track the annual revenue requirement determined from the application of the formula rate filed with the Federal Energy Regulatory Commission ("FERC"). Essentially, transmission costs will be unbundled from Westar base rates and will be set out separately in a Transmission Delivery Charge that will be adjusted annually to reflect changes in the application of the FERC formula rate. Therefore, we are removing test-year transmission costs from Westar's cost of service and adding back the transmission revenue requirements determined from the application of the FERC formula rate. The Transmission Delivery Charge tariff is described in Mr. Rohlfs' testimony, and the FERC formula rate is described in Mr. Oakes' testimony.

Q. WHAT ELEMENTS FROM WESTAR'S COST OF SERVICE WERE REMOVED?

A. In general, any cost element that would be recovered through the application of the FERC formula rate was removed from test-year cost of service. More specifically, all operation and maintenance expenses, depreciation and amortization expenses, revenue credits, plant in service, and accumulated depreciation directly identified as transmission costs in Westar's accounting records were removed. Additionally, joint costs such as administrative and general expenses, depreciation of general plant, taxes other than income taxes, general plant, general plant accumulated depreciation, accumulated deferred income taxes, and working capital (including materials and supplies and prepayments) were removed using the same direct assignment or allocation percentages as used in the application of the formula rate. Because Westar's rate base has been adjusted to remove all transmission-related costs, the operating income and associated income taxes shown in Westar's cost of service (e.g. Westar's MFRs, Section 3, Schedules 3-A and 3-C) do not include a return on transmission rate base and associated income taxes. The return on transmission rate base and associated income taxes are included in the revenue requirement determined by application of the FERC formula rate and are added back to cost of service.

Q. WHAT COSTS WERE ADDED BACK TO WESTAR'S COST OF SERVICE?

A. The revenue requirement for the Transmission Delivery Charge includes (i) the revenue requirement determined from the application of the formula rate and (ii) the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT) administrative fees, including Schedule 1 fees and monthly assessment charges.

These revenue requirement items were added back as an operation and maintenance expenses to Westar's cost of service. Because Westar has a single OATT and a single set of transmission rates applicable to both Westar North and South, under the FERC formula rate transmission revenue requirements are determined for Westar as a whole and not for Westar North and South individually.

The revenue requirement that was added back to cost of service in this proceeding reflected computations from the formula rate that were current late in the day on April 27, 2005, five days prior to submitting the transmission formula rate filing with the FERC. In order to file the Minimum Filing Requirements with the KCC in this proceeding on May 2, 2005, we had to move forward with the development of the Transmission Delivery Charge revenue requirement using the April 27th values, which were the most current costs available at the time. Subsequent to April 27, 2005, minor changes to the figures that feed into the FERC formula rate resulted in a slightly different revenue requirement being filed with the FERC. Because these changes occurred so late in the process of developing the cost of service and unit charges and preparing the Minimum Filing Requirements in the KCC proceeding, we were unable to update all of the interconnected cost and revenue items that would be affected by the revisions to the FERC transmission formula revenue requirement. As a practical matter, however, the revenue requirement in the FERC filing may ultimately change as it is reviewed by the FERC and ultimately approved in that proceeding. Irrespective of what is filed in the FERC proceeding or in the KCC rate review, it is Westar's intention to collect through the Transmission Delivery Charge an amount that properly tracks the revenue requirement ultimately authorized by the FERC. During the pendency of the proceeding before the KCC, if the FERC proceeding is resolved and the revenue requirement from the formula rate becomes known, Westar will submit an update to the Commission as to its impact on the Transmission Delivery Charge.

The revenue requirement that was added back to cost of service in this proceeding, which included the revenue requirement from the application of the FERC formula rate using information available April 27, 2005, and the test-year level of SPP administrative fees, is $81,571,102 for the 12 months ended December 31, 2004, which corresponds to a $71,676,527 Kansas-jurisdictional amount. This revenue requirement was allocated to Westar North and South on the basis of each utility's transmission rate base, which is used to determine the return and income tax components of revenue requirements in the formula rate and is thus one of the principal cost drivers in the formula rate. This methodology results in $45,251,842 of the revenue requirement (or

$39,762,794 on a Kansas-jurisdictional basis) allocated to Westar North and $36,319,260 (or $31,913,734 on a Kansas-jurisdictional basis) allocated to Westar South. This allocation is shown on Exhibit___(WSS-2). These amounts were added back as operation and maintenance expenses to each utility's cost of service.

Q. WHAT IS THE DIFFERENCE BETWEEN THE REVENUE REQUIREMENT INCLUDED IN COST OF SERVICE IN THIS PROCEEDING AND THE AMOUNT REFLECTED IN THE FORMULA RATE ACTUALLY FILED WITH THE FERC?

A. They are virtually the same. The difference between the revenue requirement in the FERC formula rate and the value included in the TDC is only $30,907, which would not likely affect unit charges when spread over the billing determinants for all customer classes. However, it is important to keep in mind that this amount could change as the formula rate proceeding is reviewed by the FERC.

Q. HOW WERE THE REVENUE REQUIREMENTS TO BE RECOVERED THROUGH THE TRANSMISSION DELIVERY CHARGE ALLOCATED TO THE CLASSES OF SERVICE?

A. As will be discussed in the context of the class cost of service studies later in my testimony, the Kansas-jurisdictional revenue requirement to be recovered through the Transmission Delivery Charge was allocated to the customer classes on the basis of each class's contribution to the 12 monthly coincident peaks. This is consistent with the load ratio share methodology that is used to determine the revenue requirement allocation for network transmission service in Westar's OATT. Exhibit___(WSS-3) shows the results of this allocation. The transmission revenue requirements for Westar North allocated to each customer class are shown in Table 1.

TABLE 1
TDC Revenue Requirement
Westar North (WEN)

Customer Class	**Transmission Revenue Requirement From Formula Rate**	**Percentage Of Total**
Residential	$ 16,597,474	41.74%
Small General Service	$ 7,788,937	19.59%
Churches and Schools	$ 943,549	2.37%
Medium General Service	$ 6,586,152	16.56%
High Load Factor Service	$ 7,596,744	19.11%
Lighting Service	$ 249,937	0.63%
Total System	**$ 39,762,794**	**100.00%**

Table 2 shows the allocation of transmission revenue requirements to each customer class for Westar South.

TABLE 2 TDC Revenue Requirement Westar South (WES)		
Customer Class	**Transmission Revenue Requirement From Formula Rate**	**Percentage Of Total**
Residential	$ 12,409,670	38.89%
Small General Service	$ 5,714,405	17.91%
Medium General Service	$ 2,765,368	8.67%
High Load Factor Service	$ 5,293,694	16.59%
Lighting Service	$ 100,966	0.32%
Public Schools	$ 1,144,320	3.59%
Churches	$ 101,970	0.32%
Demand Side Management	$ 102,237	0.32%
Special Contracts	$ 4,281,105	13.41%
Total System	**$ 31,913,734**	**100.00%**

IV. FUEL NORMALIZATION

Q. PLEASE EXPLAIN WHY ADJUSTMENT NO. 10 IN SECTION 9, FUEL NORMALIZATION, IS NEEDED.

A. This adjustment normalizes fuel expense for the effects of Wolf Creek Generating Station's 18-month refueling cycle, adjusts normal weather, year-end customers and the addition of a large industrial customer.

Q. PLEASE EXPLAIN HOW THE FUEL NORMALIZATION ADJUSTMENTS WERE DETERMINED FOR WESTAR NORTH AND SOUTH.

A. The fuel normalization adjustments for Westar North and South were determined by computing the difference between (i) a production cost model scenario that reconstructed the base case energy-related expenses and revenues, based on the test-year actual results, and (ii) a production cost model scenario based on normalized energy-related expenses and revenues. The normalized scenario reflected the weather normalization adjustment, customer annualization adjustment, and the addition of a new large industrial customer early in 2005. Differences between the base case and normalization scenarios were calculated for fuel expenses, purchased power expenses, off-system sales revenues, and third-party transmission expenses related to the off-system sales revenues. Mr. Olsen discusses the PROSYM® model that was used to perform the fuel normalization adjustment in his testimony.

Q. HAS THIS METHODOLOGY BEEN USED IN THE PAST BEFORE THIS COMMISSION?

A. It is my understanding that these are standard types of adjustments that have been made in previous rate cases.

Q. WHY DON'T YOU JUST USE ACTUAL TEST YEAR RESULTS?

A. If unadjusted test-year results were used, we would set rates that are biased and not reflective of conditions we can reasonably expect to exist in the future. It is standard practice in rate cases to normalize conditions for weather and other factors that Mr. Oakes and I have testified to, so that we are establishing just and reasonable rates for the future, not for the past.

Q. WHAT IS THE RESULT OF THE FUEL NORMALIZATION ADJUSTMENT?

A. Operating income decreased $8,709,893 for Westar North and $6,380,141 for Westar South. For Westar North, this decrease results from an $8,073,927 reduction in off-system sales revenue (Account 447.1), a $2,591,000 increase in fuel expenses (Account 501), a $1,080,467 increase in interchange received (Account 555), an increase of $3,719,030 in economy purchases (Account 555), a reduction of $1,006,450 in transmission expenses (Account 565), and a reduction of $5,751,021 in income taxes. For Westar South, this decrease results from a $6,845,706 reduction in off-system sales revenue (Account 447.1), a $1,314,000 increase in fuel expenses (Accounts 501 and 518), an increase of $3,287,921 in economy purchases (Account 555), a reduction of $853,346 in transmission expenses (Account 565), and a reduction of $6,380,141 in income taxes.

V. RETAIL ENERGY COST ADJUSTMENT (RECA)

Q. IS WESTAR PROPOSING AN RETAIL ENERGY COST ADJUSTMENT OR "RECA" IN THIS PROCEEDING?

A. Yes. Westar is proposing RECAs for both Westar North and South. The RECAs will provide for the recovery or refund of changes in the cost of fuel and will incorporate a sharing mechanism for margins on off-system sales ("market based margins"). In tariffs for Westar North and South, the schedule is entitled "Retail Energy Cost Adjustment Clause." The RECA will operate as a monthly adjustment consisting of two factors – (i) a Fuel Adjustment Clause (FAC) factor that accounts for changes in fuel costs, and (ii) an Off-System Sales Adjustment (OSSA) factor that provides for a sharing between the utility and customers of margins on off-system sales. As will be discussed in greater detail later in my testimony, the sharing of market based margins is a critical element of the RECA designed to align the interests of Westar and its customers in encouraging the utility to optimize the utilization of its production assets by maximizing the off-system sales that can be made from its generating resources.

Q. PLEASE DESCRIBE HOW THE MONTHLY RECA FACTOR WILL BE COMPUTED?

A. As I've stated, the monthly RECA factor will consist of an FAC and OSSA as follows:

RECA = FAC + OSSA

The FAC will be determined based on a standard formula used by other utilities in Kansas and by both KPL and KG&E prior to the merger. The formula is essentially the same as the monthly adjustment factors used in fuel adjustment clauses of many other utilities with which I have worked. The purpose of the FAC component is to reflect differences between current fuel costs and the level reflected in base rates. The following formula is used to compute the monthly FCA component of the RECA:

$$FAC = \frac{(F + P + NI + C)}{(.01) \times S} - FAC_b$$

Where:

F represents the estimated cost of nuclear and fossil fuel burned during the current month;

P represents the estimated cost of purchased power during the current month

NI represents the estimated net dollar cost of interchange received less interchange sales (including all short-term opportunity sales and interchange related to participation agreements) during the current month;

S represents the estimated kWh delivered to all requirements customers during the current month; S is multiplied by a factor of .01 so that the FCA will be stated on a ¢/kWh basis rather than on a $/kwh basis.

C represents the correction to dollar cost that is calculated as:

Actual (F + P + E + NI + C^1) less estimated (F + P + NI + C^1) x (Actual S ÷ Estimated S) for the month preceding the current month

E represents the actual cost of emission credit expenses

C1 represents the correction dollars used originally in the FAC calculation for the month preceding the current month

FAB_b represents the base cost of energy in cents per kWh sold determined from the application of the FAC formula to adjusted data for the twelve month period ended December 31, 2004.

Q. WHAT IS THE BASE COST OF ENERGY FOR THE TWO UTILITIES?

A. The base cost of energy (FAC_b) for Westar North is 1.423 ¢/kWh and the base cost of energy (FAC_b) for Westar South is 1.142 ¢/kWh. These two figures were determined by computing the fuel cost component of the FAC (i.e. Fuel Cost = F + P + NI) for the twelve months ended December 31, 2004, corresponding to the test year of the rate case, adjusted to reflect the fuel normalization adjustments for Westar and South in this proceeding. Exhibit___(WSS-4) shows the derivation of the base costs of energy for the two utilities.

Q. IF THE COMMISSION WERE TO REJECT WESTAR'S PROPOSAL TO IMPLEMENT AN RECA, SHOULD TEST-YEAR OPERATING EXPENSES BE ADJUSTED IN ANY WAY?

A. Yes. Westar considered only four key normalization factors in computing the fuel normalization adjustment in this proceeding. Specifically, the fuel normalization adjustment only considered the impact on energy costs related to increased sales volumes due to normal weather, year-end customers, the addition of a new, very large high load factor industrial customer and to a refueling of the Wolf Creek.

Because Westar is proposing a RECA, it is not critical that the utility adjust test-year energy costs to reflect every possible adjustment. Without an RECA it would be appropriate to also adjust the price of coal, gas and oil to reflect an appropriate level of cost on a going-forward basis. Therefore, if the Commission rejects Westar's RECA proposal, then fuel expenses should be further adjusted to more accurately reflect prospective fuel commodity costs. For example, in the Westar's last rate review, fuel expenses were adjusted to reflect a 36-month forward strip of gas prices. Without an ECA it would be essential to reflect in cost of service a going-forward level of fuel costs using a 36-month strip of commodity prices for coal, natural gas, and fuel oil consistent with the fuel normalization principles followed in Westar's last rate case.

Q. DO ANY OTHER ELECTRIC UTILITIES IN KANSAS HAVE AN ECA?

A. Yes, Aquila (WestPlains), Midwest Energy, Sunflower Electric Cooperative, and Kansas Electric Power Cooperative have ECAs. The sharing of off-system sales margins on a 75/25 basis through the ECA was considered in Aquila's most recent rate case and the

Commission allowed the utility to continue to use its current ECA. See Order dated January 28, 2005, in Docket No. 04-AQLE-1065-RTS. Westar's RECA is modeled after Aquila's ECA. It is also important to note that gas distribution utilities ("LDCs") in Kansas use a cost recovery mechanism to account for changes in gas supply costs.

Q. DO ELECTRIC UTILITIES IN THE NEIGHBORING STATES OF OKLAHOMA, COLORADO, MISSOURI, AND NEBRASKA HAVE SOME FORM OF ECA?

A. Yes. Although ECAs are common throughout the US, the neighboring states of Oklahoma, Colorado, Missouri and Nebraska all permit the use of some type of mechanism to recover the difference between the fuel and purchased power included in base rates and the actual cost of fuel and purchased power.

Q. DOES THE FEDERAL ENERGY REGULATORY COMMISSION (FERC) PERMIT UTILITIES TO USE AN ECA?

A. Yes. Most wholesale requirements contracts approved by the FERC include provisions for an ECA. In fact, Westar North and South use an ECA to provide recovery of fuel and purchased power costs for service to their wholesale requirements sales subject to FERC regulation.

Q. WHY IS IT APPROPRIATE FOR A UTILITY TO HAVE AN ECA?

A. There are a number of reasons why it is appropriate for utilities to be allowed to recover the differences between the fuel and purchased power cost included in base rates and their actual cost of fuel and purchased power. It is a fundamental regulatory principle that utilities should be afforded an opportunity to recover the cost of providing service. Setting rates in a general rate case based on test-year costs, adjusted for known and measurable changes, will generally provide a utility a reasonable opportunity to recover its costs. However, for cost components that are more volatile – especially those components of cost that represent a significant portion of a utility's overall costs – it is appropriate to implement a recovery mechanism that will provide the utility with a reasonable opportunity to recover its costs while at the same time protecting customers from cost over-recoveries.

Fuel and purchased power are large cost components whose fluctuation alone could trigger a rate increase or decrease. An ECA would thus eliminate the cost and resources required to have potentially frequent rate cases, but at the same time, allow adequate regulatory oversight of these expenditures. An ECA is a traditional ratemaking tool used by electric utilities to provide for the recovery of fuel and other energy-related costs outside of a general rate case.

Additionally, fuel and purchased power are expense items on which the utility earns no return or margin. Under the current regulatory framework, utilities are allowed to recover their prudently incurred expenses. An ECA simply provides a mechanism for the recovery of this volatile variable cost component. Utility margins serve not only as a return to shareholders, but also as a pool of internal resources to finance contingencies until they can be recovered in subsequent rate case proceedings. A cost component as volatile as fuel can quickly erode liquidity, resulting in undue financial stress and preventing shareholders from having the opportunity to earn a fair, just and reasonable return.

An ECA is a traditional mechanism that recovers the cost of fuel and purchased power on a dollar for dollar basis with no markup. Under an ECA, customers are asked to pay neither more nor less than the actual cost of providing the fuel and purchased power cost to provide electric service. In a business environment characterized by volatile fuel prices, an ECA is an essential component of a regulatory framework that helps provide shareholders a reasonable opportunity to earn a fair, just and reasonable return.

Furthermore, ECAs provide better price signals to customers. Fuel and purchased power prices can be reflected to customers on a continuum that runs from real-time pricing on one end to reflecting these prices in the next rate case on the other end. Customers cannot respond to price changes that they cannot see. If fuel and purchased power prices are only reflected in rate cases, customers cannot see the fuel and purchased power volatility that is occurring in the marketplace. This takes away demand response as a tool that can be used for balancing customer needs with utility resources. Enabling demand response as a part of the solution requires that customers be provided with price information on as timely a basis as possible. Reflecting price signals to customers on a timely basis is the most effective means of encouraging energy conservation as part of the energy solution. With an ECA, as energy costs go up or down, customers will quickly be able to see the impact of increased or decreased energy costs on their bills and customers will be more inclined to take measures to modify their energy consumption than if they only see price changes when there is a rate case. Indeed, if prices are only changed in a rate case, it is possible that the price signal sent to customers will not only fail to encourage conservation but actually signal customers to purchase more energy at a time when energy commodity prices are increasing.

Q. HAS THE COST OF FUEL BECOME MORE VOLATILE IN RECENT YEARS?

A. Yes. Oil, natural gas and coal prices have become more volatile over the last several years. Exhibit___(WSS-5) shows the average cost per ton of coal to electric utilities in the US during 2002 through 2004 based on information published by the Energy Information Administration (EIA). The average price of coal has varied from a low of $23.64 per ton to a high of $28.55 per ton. Exhibit____(WSS-6) shows the volatility of Westar's delivered coal costs during the period 2000 through 2004. From 2000 to 2004, coal costs varied from a low of about $17.39 per ton to a high of about $20.08 per ton, or a swing of approximately 15.5%.

The commodity prices of oil and gas have exhibited considerably greater volatility. Exhibit___(WSS-7) shows the average cost per barrel of oil (petroleum liquids) to electric utilities in the US during 2002 through 2004 based on EIA data. During this period, the average price of oil has ranged from a low of $17.36 per barrel to a high of $36.77 per barrel. The price therefore fluctuated by approximately 112% during this period. Exhibit___(WSS-8) shows the volatility of Westar's delivered cost of oil (principally #6 fuel oil) during the period 2001 through 2003. An alternative perspective on the volatility of oil prices can be obtained from examining the daily NYMEX future prices for crude oil settled in June 2005. Exhibit___(WSS-9) shows the daily futures price during the calendar year 2004. Somewhat typical of a futures price based on a fixed settlement date, the price exhibits greater volatility as it moves towards the settlement point.

Exhibit___(WSS-10) shows the average cost per MMBtu of natural gas to electric utilities in the US during 2002 through 2004 as published by EIA. The average price of natural gas from 2002 through 2004 has ranged from a low of $2.97 per MMBtu to a high of $6.85 per MMBtu. This represents a swing of 131%. Exhibit___(WSS-11) shows the volatility of Westar's delivered cost of natural gas in dollars per Mcf for the period 2001 through 2003. Exhibit___(WSS-12) shows the daily futures prices in 2004 reflecting a June 2005 settlement. The most striking perspective of volatility, however, is seen in Exhibit___(WSS-13), which depicts daily prices at Henry Hub as reported by Platts *Gas Daily*, a trade publication. During this period, natural gas prices spiked at $18.60 per MMBtu on February 26, 2003, compared to an average of $5.68 per MMBtu.

These price volatilities, especially for natural gas, carry over into the prices of electric power in the marketplace. Natural gas prices are noted for having a significant effect on prices in the power market. Market participants closely monitor the "spark spread" that is created by the difference between natural gas and electric power prices. Given the lag inherent in the regulatory process, without an ECA, fuel price volatilities of these magnitudes can result in serious financial harm to a utility. In a business environment with such fuel price volatility, the use of an ECA is essential.

Q. IS THE USE OF AN ECA CONSISTENT WITH WESTAR'S EFFORT TO GET BACK TO BASICS?

A. Yes. An ECA is a traditional approach that has been used in the industry for years and is consistent with Westar's effort to get back to basics. The use of ECAs was particularly important starting in the mid-1970's as fuel prices became more volatile. Starting in the mid-1990's, some utilities and regulatory commissions moved away from ECAs because fuel price volatility had moderated significantly and because of the prospect of retail competition in the electric industry. The anticipation of retail competition led some utilities and commissions to eliminate ECAs. The reasoning was that, since the generation component would become a competitive service if a state adopted retail competition, the price of electric power would be determined in the marketplace and ECAs would no longer be needed. According to economic theory, in an efficient market environment the market itself would automatically flow through marginal fuel costs to customers, just as increases in oil costs, for example, are automatically passed along to customers at the pumps.

Q. DO THESE REASONS FOR ELIMINATING FUEL ADJUSTMENT CLAUSES CURRENTLY APPLY IN THE STATE OF KANSAS?

A. No. It appears unlikely that electric retail competition will be adopted in Kansas in the foreseeable future. It is therefore likely that cost of service ratemaking and rate of return regulation will continue in Kansas. Consequently, the price of the generation component will continue to be set in the regulatory process. Under traditional regulation, a utility is allowed to recover the cost of its prudently incurred expenses and earn a fair and reasonable return on its investment. In the traditional regulatory framework, fuel and purchased power are expense items on which there is no investment, and therefore no return is earned. The justification for eliminating ECAs due to decreased fuel and purchased power price volatility is also no longer valid. In recent years, fuel price volatility has increased significantly making fuel adjustment clauses necessary mechanisms for protecting the financial integrity of utilities.

Q. WHY IS IT APPROPRIATE TO SHARE MARGINS ON OFF-SYSTEM SALES WITH CUSTOMERS?

A. Off-system sales sharing aligns the interests of the utility and its retail customers and represents a different kind of sharing than exists today. There is a sharing of the benefits of off-system sales under the current regulatory framework that takes place over time.

Under the current regulatory framework, the utility retains all of the incremental benefits of off-system sales until the next rate case. In the next rate case, the level of off-system sales enters as a credit against the revenue requirement and customers receive all the benefit of off-system sales that occurred during the test year.

An alternative approach is for both the utility and customers to benefit from incremental off-system sales on an ongoing and timely basis. With Westar's proposal to share margins on off-system sales, the timing of sharing the benefits changes from a sharing over an extended period of time to a sharing on a more concurrent basis.

Q. IN THE CONTEXT OF THE ECA, WHAT ARE "OFF-SYSTEM SALES"?

A. Off-system sales are short-term asset-based power sales made to other utilities from Westar's generating resources. These transactions, which are often referred to as "opportunity sales" or "sales made in the opportunity market," are transactions with a term of less than one year. Most of Westar's short-term opportunity sales are transactions with a term of less than one month. Westar also makes long- and intermediate-term power sales to other utilities, including requirement sales to municipal utilities and electric cooperatives. Only short-term opportunity sales will be considered to be "off-system sales" in the off-system sales sharing component of the RECA. Long-term and intermediate power sales, which have a term greater than one year, will continue to be handled in the traditional manner for purposes of determining Westar's Kansas-jurisdictional cost of service. Specifically, in retail rate cases intermediate and long-term requirements transactions will continue to be fully allocated (jurisdictionalized) between KCC and FERC jurisdictions, and short-term power sales will be treated as a revenue credits for purposes of determining retail cost of service.

Q. PLEASE DESCRIBE HOW OFF-SYSTEM SALES SHARING WILL WORK.

A. Any off-system sales margins above an annual base level per kWh of $24 million would be shared between the customers and Westar according to the following sliding scale:

(i) Customers will be guaranteed 100% of the benefits of the first $24 million in annual off-system margins, irrespective of whether Westar can achieve this level of margins or not. In this proceeding, Westar is proposing to include $24 million of off-system sales margins (as a revenue credit to cost of service) in base rates.

(ii) For annual off-system sales margins per kWh between an equivalent of $24 and $32 million, margins will be shared on a 50/50 basis, with the customers receiving a credit for 50% of the margins and Westar retaining 50% of the margins;

(iii) For annual off-system sales margins per kWh greater than an equivalent of $32 million, the margins will be shared on a 25/75 basis, with the customers receiving a credit for 25% of annual margins greater than an equivalent of $32 million and Westar retaining 75% of the margins, after reflecting a 50/50 sharing of margins between an equivalent of $24 and 32 million, as described in (i), above.

Therefore, under Westar's proposed margin sharing mechanism, customers will be guaranteed the first $24 million in off-system sales margins, 50% of the next $8 million in off-system sales margins (i.e., $32 million minus $24 million), and 25% of all additional off-system sale margins, as follows:

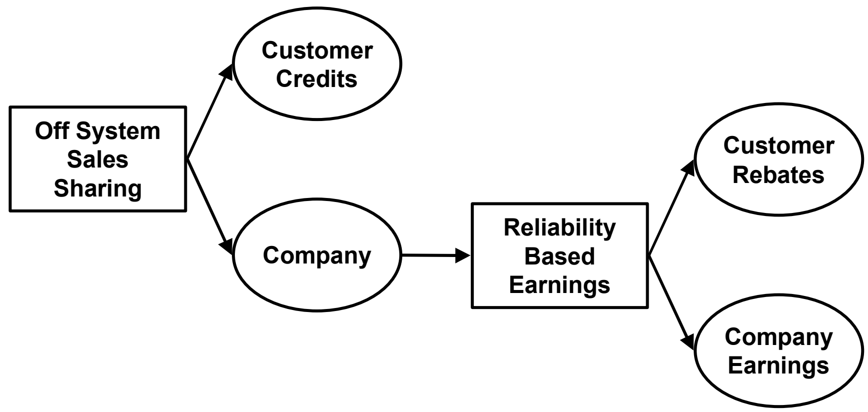
Off-System Margins	Customer Share	Company Share
$24 Million Guaranteed	100%	0%
$24 to $32 Million	50%	50%
Greater than $32 Million	25%	75%

Q. WILL WESTAR'S SHARE OF THE OFF-SYSTEM SALES MARGINS WORK INTO THE RELIABILITY BASED SHARING PROPOSAL DESCRIBED BY MR. HARRISON?

A. Absolutely. The off-system sales margins retained by Westar will flow directly into the Reliability-Based Sharing Proposal (RBSP), increasing the potential for customer rebates under the RBSP. It is extremely important to consider the Off-System Sharing and the Reliability- Based Sharing Proposal as an integrated package. Together, these two proposals provide an integrated framework for aligning the interests of Westar and its customers to improve operational performance and increase off-system sales and thereby lowering rates through rebates and improving the financial integrity of the utility. Figure 1 depicts this integrated framework:

FIGURE 1

Integration of Off-System Sharing With Reliability Based Sharing in Providing Customer Rebates



Q. HOW WILL CUSTOMERS RECEIVE THEIR SHARE OF THE OFF-SYSTEM SALES MARGINS?

A. The monthly RECA will include an OSSA factor that will provide a credit in the RECA for the sharing of off-system sales. The OSSA, which will be re-computed every 12 months, will be calculated by determining whether the off-system sales margins (OSSM) per kWh is greater than 0.121 cents per kWh (equivalent to margins of $24 million) or is greater than 0.162 cents per kWh (equivalent to margins of $32 million). OSSM will be calculated by dividing off-system sales margins for the 12 month period by the estimated sales to all requirements customers served by <u>*both*</u> Westar North and South for the upcoming 12-month period. If OSSM is less than or equal to

0.121 cents per kWh, then the OSSA for the 12-month period will be zero. If OSSM is greater than 0.121 cents per kWh but less than or equal to 0.162 per kWh, then the OSSA for the 12-month period will be equal to 50% of the difference between OSSM and 0.121 cents per kWh. If OSSM is greater than 0.162 cents per kWh, then the OSSA will be equal to 0.021 cents per kWh (calculated as 50% x [0.162 – 0.121]) plus 25% of the difference between OSSM and 0.162 cents per kWh. Because the OSSA will be determined by dividing Westar's ***total*** off-system sales by the requirement sales for both Westar North and South, the same OSSA factor will be used in the ECAs for both the North and South. Exhibit____(WSS-14) shows the derivation of the unit charges used in the sharing proposal. The following table shows the sharing percentages and the charges per kWh.

Q. WHY IS WESTAR PROPOSING TO BEGIN SHARING OFF-SYSTEM SALES MARGINS AT A LEVEL OF $24 MILLION?

A. For two reasons. First, $24 million is the level of off-system sales margins currently reflected in rates. Second, $24 million represents a reasonable – but certainly not assured – level of off-system sales margins that will likely be achieved on a going-forward basis during the period in which the rates will likely be in effect. On a pro-forma basis, after reflecting fuel normalization, Westar's off-system sales margins for the test year were approximately $32 million.

With less capacity available to make off-system sales because of system growth and with falling margins, it is unlikely that Westar can sustain off-system sales margins of $32 million or greater. As discussed by Mr. Sterbenz, Westar does not anticipate that it will maintain $32 million in margins. For these reasons, we are proposing to continue the $24 million of margins that are reflected in Westar's current base rates (as a revenue credit to Westar's cost of service) and to begin sharing 50 percent of the margins between $24 and $32 million. For margins of $32 million and greater, a 25/75 percent sharing would be used. Again, it is important to consider that off-system sales margins retained by Westar will flow directly into the Reliability-Based Sharing Proposal, thus providing customers a second opportunity to share in any margins retained by the company (potentially another 50% of the margins).

Q. DOES ANY OTHER ELECTRIC UTILITY IN KANSAS SHARE ITS OFF-SYSTEM SALES MARGINS WITH CUSTOMERS?

A. Yes. Aquila's ECA includes a mechanism for sharing off-system sales margins. Aquila's ECA provides for a 25/75 percent sharing of off-system sales margins above a base level. Westar is proposing to use the same 25/75 percent sharing percentages for margins above the pro-forma test-year level of approximately $32 million, and 50/50 percent sharing of margins between $24 and $32 million. Other than the use of a sliding scale and unitizing the sharing break points (i.e., the $24 and $32 million levels) on a cents per kWh basis, the methodology proposed by Westar is essentially the same as the one approved by the Commission for Aquila. Because Westar is proposing to begin sharing margins at a level lower than the test-year level of $32 million, a more favorable sharing percentage to customers of 50/50 is being proposed for margins between the $24 and $32 million.

Q. ARE OFF-SYSTEM SALES SHARING MECHANISMS USED BY UTILITIES OUTSIDE OF KANSAS?

A. Yes, they are becoming more and more common for both electric and gas utilities. Off-system sales sharing mechanisms are a form of "performance based ratemaking" and regulatory commissions are recognizing the importance of providing the utilities with financial incentives to improve performance. Several of the utilities I have worked with, including those in Alabama and Kentucky, have performance-based ratemaking mechanisms. Notably, I helped design and the Kentucky Public Service Commission approved a gas off-system sales mechanism for Louisville Gas and Electric Company, which provided for a sharing of off-system sales margins above a base level of zero.

Q. WHY IS IT APPROPRIATE TO INCORPORATE AN OFF-SYSTEM SHARING MECHANISM IN THE RECA FOR WESTAR?

A. There is simply no substitute for proper incentives, whether one is dealing with individuals or an organization. By providing tangible incentives, Westar will be encouraged to find creative ways to pursue opportunities that will benefit both customers and shareholders. Off-system sharing will encourage Westar to use its generating assets to make off-system sales when those assets are not being used to serve firm retail and wholesale requirements customers (firm native load customers).

Westar must have sufficient generating capacity to serve its firm native load customers at all times, including during peak conditions. However, at times during the year, for example, during off-peak periods, Westar's generating capacity can be utilized to make opportunity sales outside the system. Margins on these off-system sales can be used to defray the fixed costs of owning and operating power plants, which must stand ready to serve Westar's firm native load customers.

However, there are risks involved in making such sales. Indeed, some companies choose not to even pursue off-system sales for that reason. If Westar has an incentive that it believes exceeds the costs and risks of pursuing off-system sales transactions, then it will be encouraged to take reasonable steps to maximize off-system sales into the wholesale market, thereby reducing the net cost of providing service to its native load customers. Therefore, it is in the interest of retail customers for Westar to have a sharing component in the RECA that will balance the risks and rewards of making off-system sales in a manner that will encourage Westar to find innovative ways to take full advantage of those opportunities.

Q. EARLIER, YOU INDICATED THAT $24 MILLION OF OFF-SYSTEM SALES MARGINS WOULD BE REFLECTED IN BASE RATES IN THIS PROCEEDING. PLEASE EXPLAIN HOW THIS WILL BE ACCOMPLISHED.

A. Westar's pro-forma test-year margins during the test year were $32,234,726. Therefore, it was necessary to make a pro-forma adjustment to operating income to reflect a reduction in off-system sales margins from $32,234,726 to $24,000,000. This was accomplished by reducing off-system sales revenues and the cost to achieve those revenues (which includes fuel and third-party transmission expenses) by a net amount of $8,234,726 (or $32,234,726 - $24,000,000). To reflect this reduction, off-system sales revenues were reduced by $30,422,765 ($16,463,622 for Westar North and $13,959,143 for Westar South), and fuel and third-party transmission expenses were reduced by $22,188,039 ($12,007,307 for Westar North and $10,180,732 for Westar South). These pro-forma adjustments are shown in Section 9, Adjustment Nos. 27, of Westar North's and South's MFRs.

VI. CLASS COST OF SERVICE STUDIES

Q. DID YOU PREPARE CLASS COST OF SERVICE STUDIES FOR WESTAR NORTH AND WESTAR SOUTH BASED ON FINANCIAL AND OPERATING RESULTS FOR THE 12 MONTHS ENDED DECEMBER 31, 2004?

A. Yes. I supervised the preparation of fully allocated, embedded class cost of service studies based on jurisdictionally allocated costs for the test year. The class cost of service studies correspond to the pro-forma financial exhibits included in Schedules 3 through 14 of the MFRs. The objective in performing the class cost of service studies is to determine the rate of return on rate base that Westar North and South are earning from each customer class, which provides an indication as to whether the electric service rates reflect the cost of providing service to each customer class.

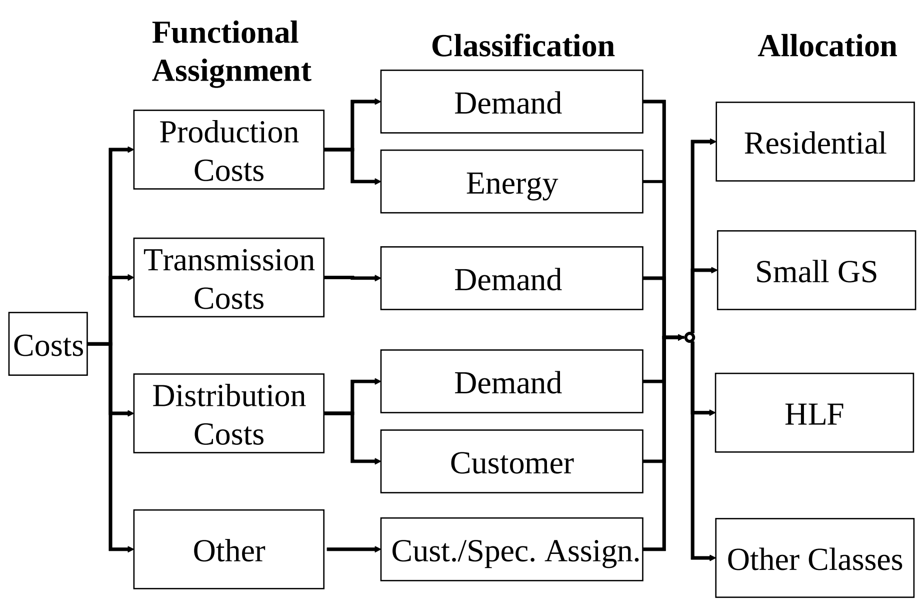
Q. DID YOU DEVELOP THE MODEL USED TO PERFORM THE CLASS COST OF SERVICE STUDIES?

A. Yes. In addition to being a traditional class cost of service model, it was designed specifically to help facilitate the functional unbundling of costs, such as the unbundling of transmission costs in this proceeding.

Q. WHAT PROCEDURE WAS USED IN PERFORMING THE CLASS COST OF SERVICE STUDIES?

A. The three traditional steps of an embedded cost of service study were used – functional assignment, classification, and class allocation. The class cost of service studies were therefore prepared using the following procedure: (1) costs were functionally assigned (*functionalized*) to the major functional groups; (2) costs were then *classified* as commodity-related, demand-related, or customer-related; and then (3) costs were allocated to the rate classes. hese steps are depicted in the following diagram (Figure 2).

FIGURE 2



The following functional groups were identified in the class cost of service studies: (1) Production, (2) Transmission, (3) Distribution

Substation (4) Distribution Primary Lines, (5) Distribution Secondary Lines (6) Distribution Line Transformers, (7) Distribution Services, (8) Distribution Meters, (9) Distribution Street and Customer Lighting, (10) Customer Accounts Expense, (11) Customer Service and Information, and (12) Sales Expense.

Q. HOW WERE COSTS CLASSIFIED AS ENERGY RELATED, DEMAND RELATED OR CUSTOMER RELATED?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary most directly with the amount of kilowatt-hours consumed. Fuel and purchased power expenses are examples of costs typically classified as energy costs.

Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet a customer's maximum demands at particular points in time. Production plant and the cost of transmission lines are examples of costs typically classified as demand costs. Those assets are sized to meet the maximum demands customers place on the system at a given time.

Costs classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy they purchase or the peak demands they place on the system. These costs include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to Distribution Primary Lines, Distribution Secondary Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Customer Accounts Expense, Customer Service and Information and Sales Expense were classified as customer-related.

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE FUNCTIONAL ASSIGNMENT AND CLASSIFICATION STEPS OF THE CLASS COST OF SERVICE STUDIES?

A. Yes. Exhibit____(WSS-15) and Exhibit____(WSS-16) show the results of the first two steps of the class cost of service studies – functional assignment and classification – for Westar North and South, respectively.

Q. PLEASE DESCRIBE THE ALLOCATION FACTORS USED IN THE CLASS COST OF SERVICE STUDIES.

A. The following allocation factors were used in the class cost of service studies:

- **E01** – The energy cost component of purchased power costs was allocated on the basis of the kWh sales to each class of customers during the test year.
- **PPBDA** – The demand cost components of production fixed costs were allocated on the basis of the average of each class's contribution to the 4 monthly summer coincident peak demands.
- **TDEM** – Transmission costs were allocated on the basis of the average of each class's contribution to the 12 monthly coincident peak demands. This methodology is consistent with the load ratio share methodology that is used to determine the revenue requirement allocation for network transmission service in Westar's OATT
- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customer.
- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of

meters to the class of customers for whom these meters were installed.

- **YECust04** – Costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **Cust05** – The customer cost component is allocated on the basis of the average number of customers for the test year.
- **YECust07** – The customer cost component is allocated on the basis of the year-end number of customers using line transformers and secondary voltage conductor.
- **YECust08** – The customer cost component is allocated on the basis of the year-end number of customers using primary voltage conductor.

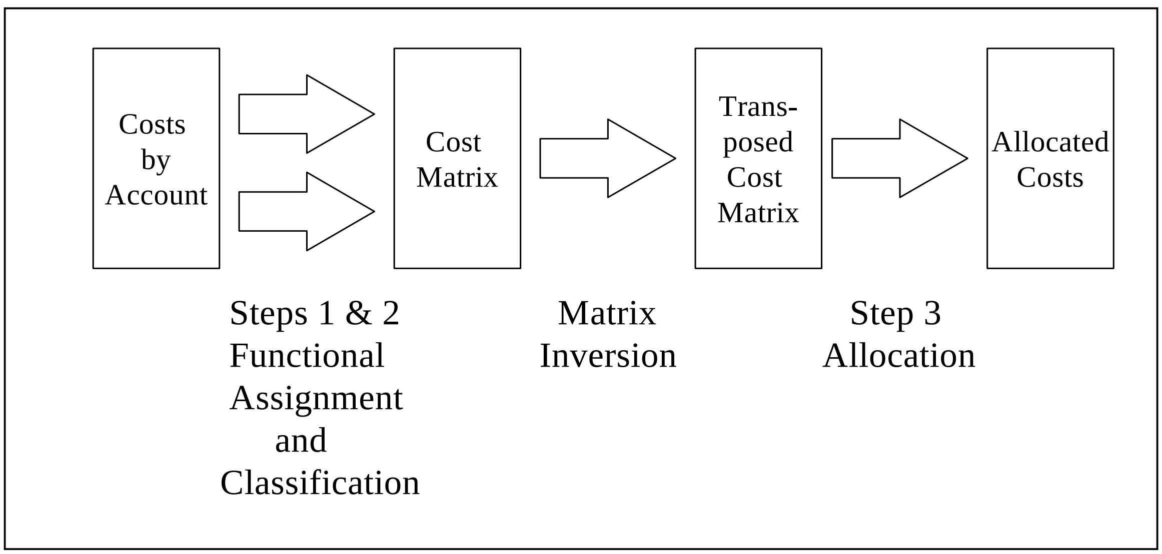
Q. IN YOUR COST OF SERVICE MODEL, ONCE COSTS ARE FUNCTIONALLY ASSIGNED AND CLASSIFIED, HOW ARE THESE COSTS ALLOCATED TO THE CUSTOMER CLASSES?

A. In the cost of service model used in this study, accounting costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using *scalar multiplication*) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the model included in Exhibit____(WSS-15) and Exhibit____(WSS-16), Westar North and South's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages 46 through 48.

Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors are also shown on pages 46 through 48 of Exhibit____(WSS-15) and Exhibit____(WSS-16). An example of this process is the use of production, transmission and distribution labor to allocate Employee Benefits – Account 926. Because employee benefits largely follow labor costs, it is reasonable to allocate these costs to the functional groups on the basis of payroll costs. (See Exhibit____(WSS-15), pages 25 through 27 for the functional assignment of Account 926 on the basis of LBSUB7 shown on pages 37 through 39.) The functional vector used to allocate a specific cost is identified by the column in the model labeled “Vector” and refers to a vector identified elsewhere in the analysis by the column labeled “Name”.

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using “allocation vectors” or “allocation factors.” This process is illustrated in Figure 3 below.

FIGURE 3



The results of the class allocation step of the class cost of service studies are included in Exhibit____(WSS-17) for Westar North and Exhibit____(WSS-18) for Westar South. The costs shown in the column labeled “Total System” in Exhibit____(WSS-17) and Exhibit____(WSS-18) were carried forward *from* the functionally assigned and classified costs shown in Exhibit____(WSS-15) and

Exhibit____(WSS-16), respectively. The column labeled "Ref" in Exhibit____(WSS-17) and Exhibit____(WSS-18) provides a reference to the results included in Exhibit____(WSS-15) and Exhibit____(WSS-16).

Q. WHAT METHODOLOGIES ARE COMMONLY USED TO CLASSIFY DISTRIBUTION PLANT?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of these minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer components of overhead conductor, underground conductor, and line transformers. Because the zero intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data is available. With the zero intercept methodology, we are not forced to choose a minimum size conductor or line transformer to determine the customer component. In the zero-intercept methodology, a zero-size conductor or line transformer is the absolute minimum system.

Q. WHAT IS THE THEORY BEHIND THE ZERO-INTERCEPT METHODOLOGY?

A. The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductor or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero intercept. The zero intercept is essentially the cost component of conductor or transformers that is invariant to the size (and load carrying capability) of the plant.

Like most electric utilities, the number of transformers on Westar's systems is not uniformly distributed over all transformer sizes. For example, Westar North has over 50,000 25 kVA transformers, but only two 367 kVA transformers. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis both types of transformers would have the same impact on the analysis, even though there are tens of thousands times more 25 kVA transformers than there are 367 kVA transformers.

Using a weighted regression analysis, the cost and size of each type of conductor or transformer is, in effect, weighted by the number of feet of installed conductor or the number of transformers. In a weighted regression analysis, the following weighted sum of squared differences

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and **ŷ** is the predicted value of the dependent variable.

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE ZERO-INTERCEPT ANALYSIS?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in Exhibit____(WSS-19) through Exhibit____(WSS-22). Sufficient cost detail was available from Westar's property records to perform a satisfactory zero-intercept analysis for line transformers. Therefore, the results from the analysis for transformers were used in the class cost of service study.

Detailed historical cost information was not available for overhead and underground conductor. A zero-intercept analysis was therefore performed using unit cost by conductor size based on engineering estimates. Although the statistical results were satisfactory based on the engineering estimates, the portion of costs identified as customer-related was outside of the norm that we have seen for electric utilities around the country. Based on my experience, the zero-intercept analysis for overhead and underground conductor classified too much cost as customer-related. Therefore, instead of relying on the results of the zero-intercept analysis included in Exhibit___(WSS-21) and Exhibit___(WSS-22), customer-related percentages on the low end of the range that we normally see for overhead and underground conductor were used in the study. For overhead conductor, 27% of the plant cost was classified as customer-related, and for underground conductor, 29% of the plant cost was classified as customer related.

Q. PLEASE SUMMARIZE THE RESULTS OF THE CLASS COST OF SERVICE STUDIES.

A. The following tables (Table 3 and Table 4) summarize the rates of return for each customer class before reflecting the rate adjustments proposed by Westar. The Actual Adjusted Rate of Return was calculated by dividing the adjusted net operating income by the adjusted net cost rate base for each customer class. The adjusted net operating income and rate base reflect the pro-forma adjustments incorporated in Sections 4 through 14 of the Applications.

TABLE 3 Class Rates of Return At Current Rates Westar North (WEN)			
Class	**Operating Income**	**Rate Base**	**Rate of Return**
Residential	$ 20,777,318	$ 544,254,460	3.82%
Small General Service	$ 15,799,917	$ 199,277,069	7.93%
Public Schools	$ 1,297,523	$ 22,142,377	5.86%
Medium General Service	$ 5,626,279	$ 129,383,985	4.35%
High Load Factor Service	$ 18,890,300	$ 137,624,151	13.73%
Lighting Service	$ 1,793,209	$ 19,853,730	9.03%
Total System	**$ 64,184,546**	**$1,052,535,773**	**6.10%**

TABLE 4 Class Rates of Return At Current Rates Westar South (WES)			
Class	**Operating Income**	**Rate Base**	**Rate of Return**
Residential	$ 26,605,142	$ 627,907,611	4.24%
Small General Service	$ 22,546,807	$ 229,919,223	9.81%
Medium General Service	$ 11,385,268	$ 90,741,432	12.55%
High Load Factor Service	$ 15,112,548	$ 155,887,187	9.69%
Lighting Service	$ 3,454,072	$ 17,581,235	19.65%
Public Schools	$ 1,120,218	$ 42,643,076	2.63%
Churches	$ 333,605	$ 4,260,723	7.83%
Demand Side Management	$ (29,834)	$ 5,688,188	(0.52%)
Special Contracts	$ 10,741,953	$ 105,930,207	10.14%
Total System	**$ 91,269,779**	**$1,280,558,881**	**7.13%**

Q. DO THE CLASS COST OF SERVICE STUDIES INDICATE A WIDE RANGE OF CLASS RATES OF RETURN?

A. Yes. For Westar North, the lowest rate of return is for the residential class at 3.82% and the highest is for the high load factor class at 13.73%. For Westar South, the lowest rate of return is for the demand side management class at (0.52%) and the highest is for the lighting class at 19.65%. At 4.24%, the rate of return for the residential class on the Westar South system is also relatively low. These rates of return suggest that measures should be taken to move Westar's rates more in the direction of the cost of providing service.

Q. DO WESTAR'S PROPOSED RATES HELP MOVE RATES IN THE DIRECTION OF COST OF SERVICE?

A. Yes. As discussed by Mr. Rohlfs, Westar's goal is to move rates in the direction of cost of service, but in a way that recognizes the principles of gradualism, rate continuity and customer acceptance. As can be seen from the following Tables 5 and 6, Westar's proposed allocation of the rate increase will help close the gap in the class rates of return.

TABLE 5 Summary of Class Rates of Return At Current and Proposed Rates Westar North (WEN)		
Customer Class	**Class Rates of Return At Current Rates**	**Class Rates of Return At Proposed Rates**
Residential	3.82%	6.29%
Small General Service	7.93%	11.04%
Public Schools	5.86%	9.38%
Medium General Service	4.35%	7.21%
High Load Factor Service	13.73%	16.64%
Lighting Service	9.03%	12.33%
Total System	**6.10%**	**8.84%**

TABLE 6 Summary of Class Rates of Return At Current and Proposed Rates Westar South (WES)		
Customer Class	**Class Rates of Return At Current Rates**	**Class Rates of Return At Proposed Rates**
Residential	4.24%	6.13%
Small General Service	9.81%	11.56%
Medium General Service	12.55%	13.90%
High Load Factor Service	9.69%	11.70%
Lighting Service	19.65%	20.66%
Public Schools	2.63%	4.81%
Churches	7.83%	10.13%
Demand Side Management	(0.52%)	1.06%
Special Contracts	10.14%	10.44%
Total System	**7.13%**	**8.84%**

Q. AS A PRACTICAL MATTER, IS IT REASONABLE TO EQUALIZE THE CLASS RATES OF RETURN?

A. I don't believe that it is, at least, not all at once. Over time it is a reasonable goal and one that Westar should pursue, but doing so in this rate case would result in unreasonably large increases to certain rate classes.

Q. YOU MENTIONED THAT IT WAS WESTAR'S GOAL TO MOVE THE CLASS RATES OF RETURN CLOSER TOGETHER. IS IT ALSO APPROPRIATE TO CONSIDER INTRA-CLASS SUBSIDIES.

A. Yes. Just as there might be subsidies between one rate class and another, subsidies may also exist between customers within rate classes. What causes this is having a rate design that doesn't adequately reflect the cost of providing service. For example, having a customer charge that is significantly below the customer costs identified in the class cost of service studies will cause certain customers to pay less than the cost of service. Similarly, in rate schedules that have both and energy and demand charges, having a demand charge that is significantly less than the demand-related costs identified in the class cost of service studies will also result in intra-class subsidies.

Q. HAVE YOU CALCULATED THE CUSTOMER-RELATED COSTS FOR THE RESIDENTIAL AND SMALL GENERAL SERVICE RATE SCHEDULES?

A. Yes. Unit customer-, demand- and energy-related revenue requirements are calculated for each customer class in the class cost of service studies. For Westar North, the customer-related cost is $13.99 per customer per month for the residential class and is $19.65 per customer per month for the small general service class. For Westar South, the customer-related cost is $14.54 per customer per month for the residential class and is $20.58 per customer per month for the small general service class. These unit costs provide useful information for evaluating the appropriate level of the customer charge for these two rate classes. It is important to move the residential and general service customer charges in the direction of these unit costs. For the large power schedules (Medium General Service and High Load Factor), the demand/energy charge relationship is more critical for purposes of intra-class subsidization. Westar is moving toward collecting more of its fixed costs through demand charges rather than through energy charges.

Q. THANK YOU.

Exhibit___(WSS-1)

STATEMENT OF QUALIFICATIONS

William Steven Seelye

Overview

I received a Bachelor of Science degree in Mathematics from the University of Louisville in 1979. I have also completed 54 hours of graduate level course work in Industrial Engineering and Physics. From May 1979 until July 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). From May 1979 until December, 1990, I held various positions within the Rate Department of LG&E. In December 1990, I became Manager of Rates and Regulatory Analysis. In May 1994, I was given additional responsibilities in the marketing area and was promoted to Manager of Market Management and Rates. I left LG&E in July 1996 to form The Prime Group, LLC, with two other former employees of LG&E.

Since leaving LG&E, I have provided consulting services to numerous investor-owned utilities, rural electric cooperatives, and municipal utilities regarding utility rate and regulatory filings, cost of service and wholesale and retail rate designs. Specifically, I have prepared and filed Order No. 888 and Order No. 889 compliance filings at the Federal Energy Regulatory Commission ("FERC") for a number of electric utilities as well as Order No. 888 and Order

No. 889 waiver requests for other utilities. I have prepared market power analyses in support of market-based rate filings at FERC for utilities and their marketing affiliates, as well as assisting other utilities with their market-based rate filings. I have assisted utilities with developing strategic marketing plans and implementing these plans. I have provided utility clients with assistance regarding regulatory policy and strategy; state and federal regulatory filing development; cost of service development and support; the development of innovative rates to achieve strategic objectives; the unbundling of rates and the development of menus of rate alternatives for use with customers; and performance-based rate development. I have provided training to account executives in sales and customer negotiation, as well as providing training in ratemaking and utility finance regarding basic utility marketing. I have provided marketing, market research and marketing support services for utility clients and have assisted them in assessing their marketing capabilities and processes.

Expert Testimony

In Alabama, I testified in Docket 28101 on behalf of Mobile Gas Service Corporation concerning rate design and pro-forma revenue adjustments. In Colorado, I testified in Consolidated Docket Nos. 01F-530E and 01A-531E on behalf of Intermountain Rural Electric Association in a territory dispute case. I testified before the FERC in Docket No. EL02-25-000 et al. concerning Public Service of Colorado's fuel cost adjustment. In Florida, I testified in Docket No. 981827 on behalf of Lee County Electric Cooperative, Inc. concerning Seminole

Electric Cooperative Inc.'s wholesale rates and cost of service. In Illinois, I testified in Docket No. 01-0637 on behalf of Central Illinois Light Company ("CILCO") concerning the modification of interim supply service and the implementation of black start service in connection with providing unbundled electric service. In Indiana, I testified in Cause No. 42713 on behalf of Richmond Power & Light regarding revenue requirement, class cost of service study, revenue allocation and rate design.

In Kentucky, I testified on behalf of Louisville Gas and Electric Company ("LG&E") in Administrative Case No. 244 regarding rates for co-generators and small power producers. I testified on behalf of LG&E in Case No. 8924 regarding marginal cost of service and in numerous fuel adjustment clause ("FAC") proceedings. I testified in Case No. 96-161 and Case No. 96-362 regarding Prestonsburg City's Utilities Commission rates. I testified in Case No. 99-046 on behalf of Delta Natural Gas Company, Inc. concerning its rate stabilization plan. I testified in Case No. 99-176 on behalf of Delta Natural Gas Company, Inc. concerning cost of service, rate design and expense adjustments. In Case No. 2000-080, I testified on behalf of LG&E concerning cost of service, rate design, and pro-forma adjustments to revenues and expenses. I submitted rebuttal testimony in Case No. 2000-548 on behalf of LG&E regarding the company's prepaid metering program. I submitted testimony on behalf of LG&E in Case No. 2002-00430 and on behalf of Kentucky Utilities Company ("KU") in Case No. 2002-00429 regarding the calculation of merger savings. I submitted testimony on behalf of LG&E in Case No. 2003-00433 regarding gas and electric cost of service studies, revenue allocation, rate design, and pro-forma adjustments and on behalf of KU in Case No. 2003-00434 regarding electric cost of service studies, revenue allocation, rate design, and pro-forma adjustments. I submitted testimony on behalf of Delta Natural Gas Company in Case No. 2004-00067 concerning cost of service, temperature normalization, depreciation rates, revenue allocation, and rate design.

In Nevada, I testified before the Public Utilities Commission of Nevada on behalf of Nevada Power Company in Case No. 03-10001 regarding cash working capital. I also testified before the Public Utilities Commission of Nevada on behalf of Sierra Pacific Power Company in Case No. 03-12002 regarding cash working capital.