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BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

DIRECT TESTIMONY

OF

DOUGLAS R. STERBENZ

WESTAR ENERGY

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Douglas R. Sterbenz, 818 South Kansas Avenue, Topeka, Kansas 66612.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. Westar Energy, Inc. (Westar). I am Executive Vice President and Chief Operating Officer.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received my B.S. degree in mechanical engineering from Kansas State University in 1985 and an M.B.A. degree from the University of Texas at Tyler in 1995.

I began my career in 1986 with Texas Utilities Generating Company, where I spent over 10 years working in power plants.

Before joining Westar, I was the director of power marketing for Questar Energy Trading. I began my career with Westar in 1997. After holding several positions in energy trading and bulk power marketing, including director of the department, I was promoted to Senior Vice President, Generation and Marketing in 2001. I was promoted to my current position in 2007.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I will discuss our generation operations, including generation plant performance and actions we have taken to improve the efficiency of our overall operations. I will also discuss the recent refueling outage at Wolf Creek Nuclear Generating Station (Wolf Creek) and our plans to shut down and decommission some of our older generating stations. Finally, I will illustrate examples of cost savings measures we have undertaken to be more efficient and to offset some of the unavoidable cost increases stemming from such things as commodity price increases and more stringent regulation.

II. GENERATION OPERATIONS

A. *Generating Capacity*

Q. PLEASE DESCRIBE WESTAR'S GENERATING UNITS.

A. Westar's generating fleet includes a mix of baseload, intermediate load and peaking units fueled with uranium, coal, natural gas, fuel oil, diesel fuel and renewables. We own 47% of Wolf Creek. Our coal units are composed of the Lawrence Energy Center (LEC), the Tecumseh Energy Center (TEC), a 92% ownership/leasehold interest in the Jeffrey Energy Center (JEC), and a 50% interest in the La Cygne Station (La Cygne). We own 40% of a combined cycle natural gas unit called State Line Combined Cycle Plant (State Line). We also have three gas-fired combustion turbines at Gordon Evans Energy Center, a number of smaller, mostly older, natural gas and oil-fired intermediate and peaking units, the 300 MW Spring Creek natural gas-fired combustion turbines in Oklahoma and natural gas peaking turbines near Emporia, Kansas. We also receive the output of 295 MW of wind generation at three sites in Kansas through a combination of ownership and purchased power agreements and 6 MW of landfill gas generation from the Rolling Meadows Recycling and Disposal Facility near Topeka under a purchased power agreement.

Q. ARE SOME OF THE UNITS IN WHICH WESTAR HAS AN INTEREST RUN BY ANOTHER ENTITY?

A. Yes. The units in which we own an interest but do not operate are Wolf Creek, which is operated by Wolf Creek Nuclear Operating Corporation (WCNOC); La Cygne, which is operated by our co-owner Kansas City Power & Light Company; State Line, which is operated by The Empire District Electric Company; and our wind generation.

Q. HOW ARE THE OUTPUT AND COST RELATED TO THE JOINTLY OWNED PLANTS ALLOCATED BETWEEN OWNERS?

A. For the plants we do not own, but in which we have an ownership interest, our share of the output and our responsibility for operating and capital expenditures is equal to our ownership interest. We have Westar "owner-representatives" at Wolf Creek and La Cygne to monitor those plants' performance and expenditures and to advise the operators.

B. *Generating Plant Performance*

Q. HOW DOES WESTAR MEASURE THE RELIABILITY OF ITS GENERATING FLEET?

A. Principally, we use a measure called the equivalent unplanned outage rate (EUOR). Though certainly not the only measure of performance, I believe EUOR provides the best single measure for evaluating the reliability of our generating fleet. This measure compares the time a unit is either partially or totally out of service, due to forced or unplanned maintenance outages, to the total time the unit would have operated without such outages. EUOR captures unplanned outages, as well as those periods of time when a plant is operating, but at something less than full capacity due to unit problems, a situation referred to as a "de-rate." Consequently, the lower the EUOR, the better.

Q. HOW HAS WESTAR'S GENERATING FLEET PERFORMED IN RECENT YEARS?

A. For the most recent five-year period (2006-2010), for which comparable data are available, Westar's system EUOR was 9.0%.

This system EUOR includes both the units that Westar operates and the units in which it owns an interest but does not operate.[1] This EUOR rate is slightly better than the five-year North American Electricity Reliability Corporation (NERC)-calculated industry average EUOR of 9.3% for similar system composition.

The industry average EUOR rate for plants similar to those Westar operates – that is, excluding Wolf Creek and La Cygne – is 11.3%. By contrast, however, the EUOR for plants we operate is far better, achieving the same 9.0% as our fleet as a whole. Table 1 below shows Westar's actual EUOR by year from 2006 through 2010 for the plants we operate and the plants in which we own a share but do not operate.

TABLE 1
EUOR RATES (2006-2010)

	Westar operated	Westar owns but does not operate	Total System
2006	8.7	5.2	7.7
2007	9.1	5.5	8.1
2008	10.5	11.8	10.8
2009	9.4	11.2	9.9
2010	7.3	11.7	8.5
2006-2010 Average	9.0	9.1	9.0

Q. HOW HAS THE COST OF OPERATING AND MAINTAINING YOUR PLANTS CHANGED OVER RECENT YEARS?

A. As Table 2 below shows, the cost of operating and maintaining our plants has increased at an average rate of about 5% per year.

[1] This calculation excludes State Line, because it is treated as purchased power.

Table 2 below shows our annual non-fuel O&M for the period 2005 through 2010 and the 2011 budget, exclusive of our share of State Line and our wind generation.

TABLE 2
(DOLLARS IN MILLIONS)

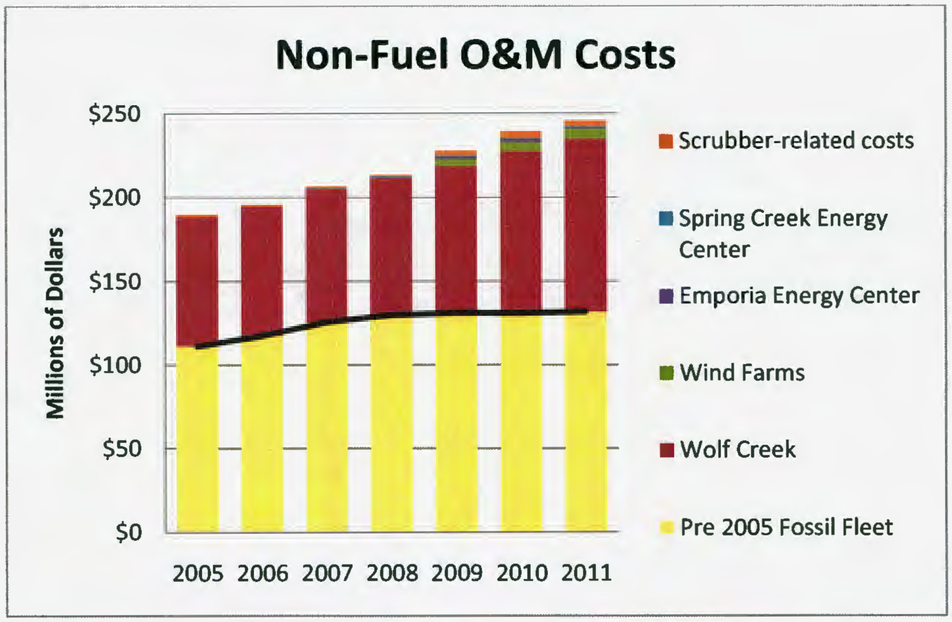
Year	2005	2006	2007	2008	2009	2010	2011
Non-fuel O&M costs*	187.7	195.7	206.6	213.5	223.7	233.7	243.8
*All EC's except State Line; JEC @ share; *O&M cost in millions*							

Our average non-fuel O&M cost for 2005 through 2010 was $7.67/MWh.

Q. WHY HAS NON-FUEL O&M EXPENSE INCREASED SINCE 2005?

A. As Figure 1 below shows, the majority of the increase in non-fuel O&M expense is a result of increasing O&M expense as Wolf Creek ages and related to required new equipment in our system; namely, the additions of EEC, wind generation and the significant new air quality equipment additions to JEC. Although the costs to build EEC and install air quality equipment additions are capital costs, there are also increased costs associated with operating and maintaining the new equipment, which is reflected in the increased O&M expense.

FIGURE 1



Q. WOULD YOUR RELIABILITY COMPARE AS WELL IF YOU USED A MEASURE OTHER THAN EUOR?

A. In most cases, yes. While I believe EUOR is the best single measure with which to compare reliability, our relative advantage would generally also hold if one looked at less robust measures such as capacity factor or unit availability. While we generally do not compare as well using heat rates, a common measure of thermal efficiency, that is largely due to the original design of our plants –decisions made decades ago, and related to our access to low-cost fuel – and not a result of how we operate them.

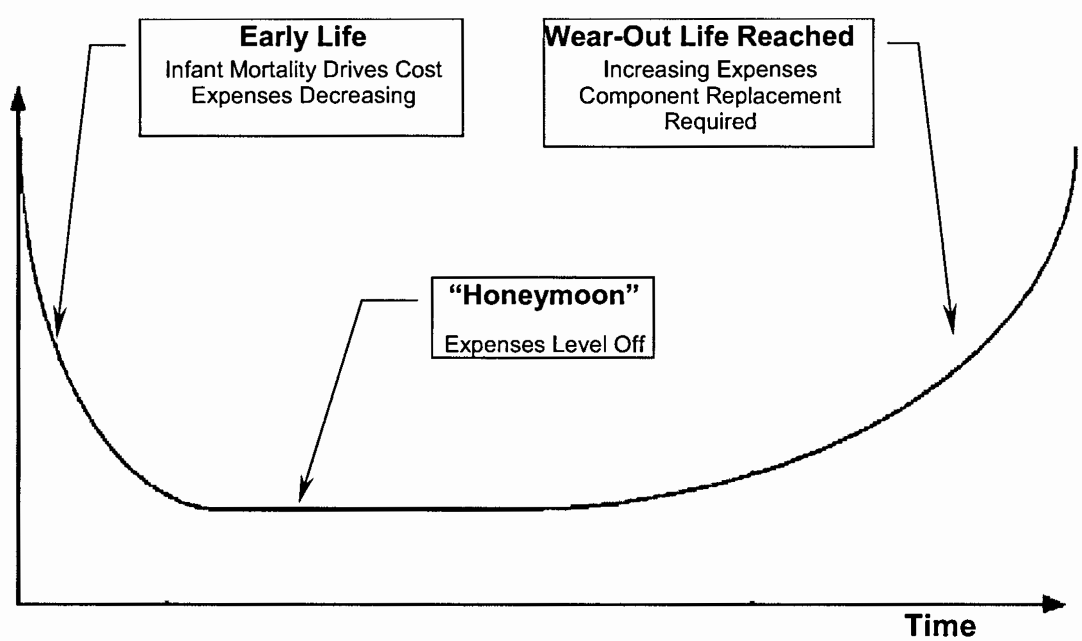
Q. HOW DOES THE AGE OF WESTAR'S GENERATING FLEET AFFECT O&M EXPENSES?

A. The average age of our base load coal units is 42 years. Our baseload coal plants were placed in service between 1954 and 1983. We also have several very old gas-powered steam units, which I address later in my testimony when I discuss our decommissioning plans. The average age for those steam units is 53 years. As with most complex machines, our power plants generally follow the familiar saddle-shaped maintenance curve associated with machine failures. Although this curve is specific to machine and system reliability, in our opinion, it reasonably represents in aggregate a power generating plant comprised of a large number of systems and components.

The three distinct periods of a typical maintenance curve are illustrated in Figure 2. In the classical failure analysis methodology, the curve actually plots failure rates over time. There is obviously a strong correlation between failure rates on equipment and the associated cost to either prevent or repair the failures. Thus, for the purposes of this discussion, we have shown the plot as maintenance expenses including capital maintenance over time.

The first period is known as burn in or "infant mortality." This is the period immediately following the unit first going into service. It is characterized by higher failure rates and costs as bugs are worked out of new equipment. The second period is the honeymoon. This is where the unit has its bugs worked out and is still new enough so that long-term life extension maintenance is not yet required. It is characterized by decreased and stable operating costs. Eventually the honeymoon is over, and costs start to rise with the age of the equipment. A significant component of cost incurred during this third phase is represented by life extension projects that involve the replacement of major components to extend the life of the unit and assure a reasonable level of reliability. At some point the cost of repairs exceeds the worth of the asset and it is retired from service. This is similar to what might occur with a family car. At some point repair costs to keep an aging car running will exceed its value. At that point, the car is likely to be replaced.

FIGURE 2
TYPICAL MAINTENANCE CURVE



Q. WHERE WOULD YOU PLACE YOUR BASELOAD UNITS ON SUCH A CURVE?

A. The average age of our baseload coal units – 42 years – actually exceeds the original design life of those plants of 40 years. Consequently, I would have to say that our baseload units are somewhere along the third stage of the curve. However, through our maintenance practices, we have been able to postpone the time at which operating costs begin to escalate quickly enough to force retirement.

Q. WHAT IS THE RESULT OF WESTAR'S MAINTENANCE PROGRAM?

A. We have prolonged the economic life of our plants. In essence, we have extended the flatter portion of the second stage of the maintenance curve in Figure 2 above. The benefit of this is that we have been able to avoid the much higher cost and rate shocks associated with replacing older plants with new, more expensive capacity. The negative effect is that we continue to operate in the portion of the curve where our maintenance costs are increasing. As a result, we must spend incrementally more in capital and O&M dollars to obtain or maintain a given amount of reliability. We believe it is in our customers' interests to continue this approach. But true to the adage, there is no free lunch. At some point in the future, our customers may see sharp rate increases as we are forced to retire and replace power plants. In the meantime, it is likely our customers will see increasing maintenance costs related to those aging plants.

Q. HAS WESTAR'S APPROACH TO GENERATING PLANT MAINTENANCE CHANGED OVER TIME?

A. Yes. Along with the industry, our approach has evolved. Advances in technology and maintenance practices have allowed a transition from conventional time-based maintenance, to a preventive maintenance philosophy, to a modern reliability-centered maintenance (RMC) strategy. RCM provides a formal structured framework for analyzing the functions and potential failures for physical assets in order to develop a specific maintenance strategy for each individual component that will provide an acceptable level of operability, with an acceptable level of risk, in an efficient and cost effective manner. This new approach has decreased the rate of growth for operating and maintenance expense and has improved the reliability of our generating plants.

C. *Operating expense associated with SCR catalysts at La Cygne*

Q. IS WESTAR PROPOSING AN ADJUSTMENT RELATED TO THE OPERATING AND MAINTENANCE EXPENSE ASSOCIATED WITH THE SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM AT LA CYGNE?

A. Yes. As Mr. Kongs discusses in his testimony, Westar is proposing an adjustment to reflect Westar's share of a full year's cost associated with the maintenance and replacement of the catalysts in the SCR at La Cygne.

Q. WHAT IS A CATALYST?

A. In the selective catalytic reduction process used in utility boilers, the catalyst is similar to a stack of boxes which are full of materials that aid the reaction of ammonia with oxides of nitrogen in boiler exit gases. These boxes are stacked inside the SCR in layers. As the combustion gasses flow over the catalyst, the reaction takes place on the surface of the catalyst material. The catalyst can be of differing materials and configurations. Most often the catalyst comes in a layered or honeycomb pattern designed to provide as much surface area as possible to maximize reaction sites.

While the catalyst is not consumed in the process, over time, however, the surface of it becomes fouled and ineffective. The catalyst must then be replaced or regenerated. The life of the catalyst is determined by the conditions to which it is exposed in the boiler, the design of the SCR system, and the design of the catalyst. The effective life of the catalyst used at La Cygne is two years.

Q. WHY IS THE ADJUSTMENT PROPOSED BY MR. KONGS NECESSARY?

A. The adjustment proposed by Mr. Kongs ensures that the annual cost of maintaining and operating the SCR is reflected in Westar's rates. During the test year, Westar incurred only a portion of the expense associated with the maintenance and replacement of the catalysts. Additional refurbishment and/or replacement costs will be incurred during 2012. If, in a given test year, there is or is not a replacement scheduled, the costs in that year would either overstate or understate the actual operating costs. In order to capture a fully normalized level of these costs, we need to increase the actual level of costs incurred during the test year.

The expense for the replacement or refurbishment of the catalysts will be a recurring expense because the catalysts at La Cygne only have a two-year life and will be refurbished or replaced every two years.

Q. IS THIS APPROACH CONSISTENT WITH RATEMAKING PRINCIPLES THE COMMISSION USES ELSEWHERE?

A. Yes. It is very similar to how refueling and outage expense are handled at Wolf Creek.

III. FUEL SUPPLY AND COST OF FUEL

A. *Wolf Creek*

Q. HOW IS FUEL FOR WOLF CREEK ACQUIRED?

A. WCNOC, acting as agent for the three owner companies, arranges acquisition of the fuel supply for Wolf Creek. As a Wolf Creek owner, Westar is a party to the uranium supply and fuel fabrication contracts, along with the other Wolf Creek owners.

Q. WHAT HAS BEEN THE HISTORY OF FUEL COSTS AND FUEL SUPPLY AT WOLF CREEK?

A. During the last ten years, Wolf Creek enjoyed relatively stable fuel costs, ranging from 4.55 mils ($0.00455)/kWh in 2001 to a low of 4.04 mils ($0.00404)/kWh in 2004, then increasing to 4.86 mils ($0.00486)/kWh in 2009. In 2010, fuel costs took a rather steep increase to 6.49 mils ($0.00649)/kWh. Such increases can be attributed to several factors, including higher market prices for uranium and higher enrichment contract prices. There was also the need to purchase more uranium on the spot market due to a partial supply interruption, due to flooding of a mine for which force majeure conditions were applicable, under Wolf Creek's lower-priced, long-term uranium contract.

Q. DO YOU EXPECT THIS TREND TO CONTINUE?

A. We expect the price for nuclear fuel to continue to increase. Previous global surpluses of already mined uranium have been consumed by increased plant capacity factors. Existing mine production and new mine development has not kept pace with such increased demand and demand from new plant construction worldwide, much of which is occurring in China. Supply reliability issues have taken on greater significance in parallel with the tighter supply/demand balance. The above changes suggest that prices that have been low and stable will now become more expensive and potentially volatile.

Other areas of the global fuel supply chain, namely conversion and enrichment services, continue to experience significant cost pressures as a result of increased demand, the need to replace aging facilities, and to build additional capacity. Consequently, new contracts demand higher prices than experienced by utilities just a few years ago.

Q. HOW HAS WESTAR RESPONDED TO THESE CHANGES IN THE MARKET?

A. As a result of consultations with our co-owners and WCNOC management, and in further to reduce risk, we modified our nuclear fuel acquisition strategy a few years ago. We acquired additional inventory and increased the lead times for purchase of uranium, conversion and enrichment services, and fuel fabrication. If we do experience delays in scheduled fuel delivery, it is unlikely that we will have to reduce production.

To address increasing market prices, we negotiated several supply contracts during a more favorable price environment and for longer-term supply. Fortunately, this has allowed Wolf Creek to avoid the full brunt of market price increases which occurred following those negotiations and helped to insulate our customers from the full impact of market uncertainty.

B. *Coal plants*

Q. WHAT IS THE SOURCE OF GENERATING FUEL FOR YOUR BASELOAD COAL PLANTS?

A. All three of the coal-fired plants we operate are fueled with low sulfur coal mined in the Powder River Basin (PRB) of Wyoming. The coal is delivered to the plants under rail contracts with the BNSF Railway Company (BNSF) and the Union Pacific Railroad Company (UP). La Cygne, operated by KCP&L, is also fueled primarily with PRB coal from Wyoming. Due to the boiler configuration of the plant, La Cygne Unit 1 burns a small amount of coal mined locally that is hauled to the plant by truck.

Q. WHAT ARE THE CONTRACTUAL ARRANGEMENTS RELATED TO THE COAL?

A. Applying the principles of diversity, we fuel JEC under a long-term contract that contains provisions for periodic price adjustments. LEC and TEC utilize a mid-term (typically one – three years) contract for fixed price purchases from a single mine source. La Cygne PRB coal is based on short-term market based purchases and the cost per ton will vary depending on the timing and duration of coal purchase agreements.

Q. HAS WESTAR ALWAYS BURNED LOW-SULFUR PRB COAL IN ITS PLANTS?

A. No. Only JEC was designed to burn low-sulfur PRB coal. Given our favorable experience with that coal, during the late 1990's, our engineers studied the possibility of converting LEC and TEC to this lower-cost alternative. After careful study and testing, we switched to low-sulfur PRB coal.

Q. HAS THIS CHANGE FROM HIGHER BTU COAL TO PRB 8800 BTU/LB COAL BENEFITED WESTAR AND ITS CUSTOMERS?

A. Yes. The transition from the more expensive bituminous Colorado sourced coal to Wyoming PRB 8800 Btu/lb coal has reduced our fuel costs and eliminated our exposure to the price volatility of higher Btu coal.

The current prompt month market price for Colorado 11,700 Btu/lb coal FOB the mine is approximately $39 per ton or $1.67 per MMBtu vs. PRB 8800 Btu/lb coal's current prompt month market price FOB the mine of approximately $13.00 per ton or $0.74 per MMBtu. In other words, on a per Btu basis, the price of PRB 8800 Btu/lb is less than half the price of Colorado 11,700 Btu/lb coal.

Q. WHAT ARE YOUR ARRANGEMENTS WITH YOUR RAIL SUPPLIERS?

A. For JEC, we have contracts with the BNSF and UP railroads. The term of these contracts runs through 2013. For LEC and TEC, we have a contract with the BNSF railroad. This contract also expires at the end of 2013. The cost of transportation is a significant portion of the delivered cost of coal and is currently more expensive than the cost of coal at the mine. The railroads provide no service guarantees for either quantities or cycle time performance. This requires us to control our inventory levels carefully to ensure we have sufficient reserves.

Q. WHAT IS YOUR RECENT EXPERIENCE WITH THE COST OF RAIL DELIVERIES?

A. The cost of rail transportation to JEC has increased an average of 3.5% since 2002, due in large part to the increased cost of diesel fuel for the train locomotives. Other items that drive the costs of rail transportation include the cost of materials such as steel which have also seen significant cost increases, labor, and other related costs of providing rail service.

Q. WHAT DETERMINES YOUR COAL INVENTORY LEVELS?

A. A host of factors. They include such things as rail delivery cycle times (the time for a round trip from the mine to the plant and back), risk and consequence of natural or man-made disasters (e.g., floods and work stoppages), plant operations, the amount of real estate we have available for coal storage at the plants, the safe working level of inventory, the capacity of rail siding at the plants, capacity of unloading equipment and the cost of carrying inventory.

We contracted with Black and Veatch to perform an inventory study and Monte Carlo-based analysis to determine the appropriate coal inventory levels at our power plants and shared the study with Commission Staff. Based on the results of this study, we believe it is prudent to target a coal inventory equal to approximately two months worth of coal burn or maximum practical storage levels at the plants, whichever is less. The actual amount of inventory varies around that target for a host of reasons.

Q. WHY DOES WESTAR TARGET AN INVENTORY LEVEL OF APPROXIMATELY TWO MONTHS OF COAL BURN?

A. Coal mine operations and rail transportation are subject to a variety of disruptions that can curtail production and delay deliveries. Rail transportation is highly subject to interruptions and delays. Transportation of coal to our power plants requires a coordinated effort of the loading and delivering railroads. Problems on either of the railroads that serve the coal-fired plants we own can result in congestion that affects the other's operations. Even in the case of LEC and TEC where only one railroad is involved, congestion on other railroads can affect delivery times.

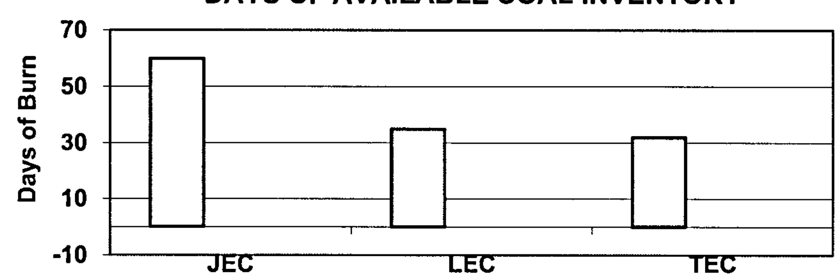
Rail deliveries are affected by severe summer or winter weather and both localized and wide-ranging weather-related natural disasters, which may cause track and bridge washouts and equipment and crew shortages, resulting in increased congestion. In addition, the increased short and long term demand for delivery of other products (intermodal shipping containers, grain, etc.) by rail may create a shortage of track and siding availability, labor and equipment necessary to deliver the coal required by Westar in a timely manner.

Mines are also subject to operational problems and weather-related production problems, particularly flooding, which may disrupt production at one or more mines for several weeks.

Q. WHAT ARE THE MARCH 31, 2011 COAL INVENTORY LEVELS AT YOUR POWER PLANTS?

A. Figure 3 below provides the days of coal inventory as of March 31, 2011, at our coal-fired facilities.

FIGURE 3
DAYS OF AVAILABLE COAL INVENTORY



Q. DO THESE DAYS OF INVENTORY DIFFER FROM THE FINDINGS OF THE BLACK AND VEATCH STUDY?

A. Yes, they do. Inventory will vary depending on the time of year, whether the plant has completed an outage recently, allowing the inventory to temporarily increase, as well as the variables discussed in the previous response.

In addition to the factors that normally affect inventory levels, LEC's maximum inventory storage is temporarily reduced from 60 days to 50 days. LEC is in the process of a significant environmental upgrade and part of the coal inventory storage area was used to create space required for construction materials, temporarily reducing its maximum available storage from 60 days to approximately 50 days. There is not enough unoccupied space at the LEC site to avoid temporarily using some of the coal storage area for construction activity.

Q. DO YOU EXPECT THE INVENTORY LEVELS AT LEC AND TEC TO INCREASE?

A. Yes. An outage planned at TEC for later in 2011 and completion of construction at LEC in fall 2012 will allow us the opportunity to increase the coal inventories at these plants.

Q. WHAT HAS BEEN YOUR RECENT EXPERIENCE WITH RAIL DELIVERIES SINCE 2002?

A. Generally, cycle times are longer than they were eight years ago and they have become more volatile. JEC, our largest coal-fired facility, has seen a 29% increase in cycle time since 2002; LEC and TEC have seen an increase in cycle times of 15% over the same time period.

The volatility of railroad performance continues to be of concern, with a differential of 32% and 22% between the fastest and slowest months for JEC and LEC/TEC, respectively during the test period. This performance volatility is one of the drivers in our inventory level decisions.

Q. HAS THE RECENT FLOODING ON THE MISSOURI RIVER NEGATIVELY AFFECTED YOUR COAL DELIVERIES?

A. Yes. The flooding has affected much of the BNSF track that serves LEC, TEC, and other BNSF customers. These closures have required BNSF to re-route many of its customers' trains – including our LEC and TEC trains – on routes that are less efficient and more congested than their normal routes. Additionally, the train length for LEC and TEC trains was reduced from 135 cars to 120 cars to accommodate shorter sidings on the alternate routes. The shorter trains and longer cycle times has resulted in less coal delivered to the plants.

Q. HAVE JEC DELIVERIES ALSO BEEN NEGATIVELY IMPACTED?

A. Yes, though not as dramatically. In fact, due to good planning, we were able to grow the JEC coal pile in anticipation of reduced coal inventories at LEC and TEC due to longer cycle times to those plants and the reduced area for the LEC coal pile due to our construction at that plant. There has been some congestion-related slowdown of our trains and our train set count has been reduced by one set until railroad fluidity returns but overall the cycle times for

JEC are still close to typical. Thus, our production at JEC has not been limited.

Q. HAS THIS FLOODING-RELATED RAIL SERVICE DISRUPTION NEGATIVELY AFFECTED YOUR INVENTORIES?

A. Yes, our current inventory in early August at LEC and TEC is approximately 16 days of available coal at maximum daily burn rates for LEC and approximately 14 days for TEC. At JEC, we were able to increase the coal inventory above the target level during the last planned maintenance outage resulting in JEC currently at or near its target inventory level.

Q. ARE YOU ABLE TO PUT ADDITIONAL TRAIN SETS IN SERVICE TO BRING MORE COAL TO LEC AND TEC?

A. Not at this time. Due to the re-routing of trains for their customers, many BNSF routes are congested. This congestion and the resulting longer cycle times have resulted in a shortage of BNSF crews and locomotive power. Even if the BNSF were to permit additional train sets into service for LEC and TEC, history has demonstrated that the effectiveness of additional train sets is limited because of the additional congestion caused by more train sets in service.

Q. WHAT MEASURES IS WESTAR TAKING TO PROVIDE YOUR CUSTOMERS THE LOWEST COST ENERGY POSSIBLE DURING THIS SITUATION?

A. We always work to minimize the cost of fuel to our customers and manage our coal inventory to protect our customers from the risks associated with potential inventory shortages. To help manage our coal inventory, we have reduced our off-system sales from coal generation. One way we have accomplished this by is by increasing the price at which we are willing to sell power off our coal units to customers outside our service territory during off-peak periods, when market prices are lowest. Our increased offer price results in fewer sales off our coal units and allows us to use the coal we save to generate electricity when the market price of power is higher. This is an example of "coal banking" and is an effective tool to manage our coal inventory while deriving the maximum value from our generation and the power market.

Q. WILL THESE CONSERVATION MEASURES BE ADEQUATE?

A. Much will depend on the demand for electricity and how quickly the BNSF is able to complete its plan for extensive track rebuilding and replacement in the Missouri river flood area. Should additional conservation measures become necessary, we are prepared to supplement our coal generation at LEC and TEC with generation from natural gas units and purchased power. We have reduced production at LEC and TEC on weekends and week nights and will continue to do so. And finally, it could become necessary to turn off the less efficient LEC and TEC units, saving coal for the largest and more efficient LEC and TEC units.

Q. WILL WESTAR STILL BE ABLE TO MEET CUSTOMERS' DEMAND FOR ELECTRICITY SHOULD YOU NEED TO IMPLEMENT THESE MEASURES?

A. Yes. Our generating system is healthy and, by managing our coal inventory and generating fleet as I have previously discussed, we expect to have adequate generation to meet our customers demand for electricity until the railroad is able to return its flooded tracks to service.

Q. WHAT HAVE YOU DONE AND WHAT ARE YOU DOING TO IMPROVE DELIVERIES INTO YOUR POWER PLANTS?

A. Westar has taken significant steps to improve deliveries over the years. We increased the amount of siding several years ago to accommodate longer trains at LEC and, in cooperation with the BNSF and UP, we have been running longer trains – 123 car trains rather than 119 car trains – into JEC.

We lease train sets under both long-term and short-term lease agreements. These leases provide flexibility to maintain the appropriate set count necessary to provide coal to our power plants under varying levels of railroad performance. Westar continues to meet and work with both the UP and BNSF to explore other solutions to expedite the delivery process into JEC, LEC and TEC.

We also performed a study to determine what changes would be needed to increase the capacity of the unloading facilities at TEC and LEC that would have allowed them to unload faster and therefore decrease cycle times. However, the study showed that the cost of the projects was prohibitive.

C. *Natural gas plants*

Q. WHAT PLANTS USE NATURAL GAS AS THEIR PRIMARY FUEL?

A. The plants that use natural gas are Murray Gill, Gordon Evans, Hutchinson, Abilene, State Line, Spring Creek, Emporia, and Neosho.

Q. CAN THESE PLANTS BURN BOTH NATURAL GAS AND FUEL OIL?

A. Historically, the steam plants, with the exception of State Line, have burned both natural gas and fuel oil. However, due to environmental restrictions, we now only burn fuel oil at these plants under emergency conditions.

IV. GENERATING PLANT DISMANTLING

Q. HAS WESTAR STUDIED THE COST TO DISMANTLE ANY OF ITS GENERATING FACILITIES?

A. Yes. We recently commissioned a study of the costs to dismantle a number of our older and smaller generating plants. Table 3 below lists the units that we included in the study together with their currently anticipated retirement dates.

TABLE 3

Unit	MWs	In-service date	Anticipated Retirement date
Abilene GT 1	77.4	1973	2013
Hutchinson GT 4	85.5	1975	2015
Murray Gill 1	48.0	1952	2015
Murray Gill 2	66.0	1954	2015
Neosho 3	66.0	1954	2012
Tecumseh GT 1	28.8	1972	2012
Tecumseh GT 2	28.8	1972	2012
TOTAL	**401**		

Q. WHY DID WESTAR INCLUDE THESE SEVEN PLANTS IN ITS DISMANTLING STUDY?

A. The plants included in the study are among the oldest in our fleet. They are generally in or approaching the point in the maintenance curve of rapidly increasing maintenance costs shown on Figure 2. As a result, we know that these plants are approaching the ends of their useful lives. Additionally, because of their size, they are not economic to retrofit for emission controls.

Q. WHAT FACTORS DID WESTAR CONSIDER IN SETTING RETIREMENT DATES FOR THESE PLANTS?

A. They included:

- the condition of the unit (to determine remaining useful life),
- on-going operations and maintenance costs,
- capital needed to keep the unit operational or extend the life,
- the fuel cost to produce electricity from the unit,
- the capacity factor of the unit,

- whether the unit is needed for transmission or distribution system reliability, and
- the cost to retrofit a unit to meet environmental rules.

Additionally, we considered the capacity plan for the system and attempted to synchronize the retirement dates seamlessly with construction of new generation and load forecasts.

The fundamental question that needs to be answered when evaluating each generating unit is, "Does continuing to operate this unit most economically and reliably meet the needs to serve our customers, or is there a better alternative?"

Q. WHY IS THERE A NEED TO SET A DATE FOR RETIREMENT?

A. First and foremost, the utility must have a date so that it can perform essential capacity planning.

Second, a date must be established so that all life extension projects and other maintenance are appropriate to the age and expected remaining life of the facility. It would not be a good idea for us to invest large amounts of capital in a plant and then retire it. In order to make well-informed decisions concerning investments in our generating plants, we must have a reasonable idea of how much longer they can be expected to provide service.

Third, a retirement date must be established so that the asset can be depreciated at a reasonable rate.

Q. ONCE THE PLANTS ARE RETIRED, DOES WESTAR PLAN TO DISMANTLE THEM?

A. Yes. As the study shows, some amount of work and expense will be required at each site to partially dismantle the retired plants.

Q. HOW IS THE PUBLIC INTEREST SERVED BY DISMANTLEMENT?

A. The number one reason for dismantling these plants – as opposed to merely closing them up and walking away – is safety. If we merely close these plants and take no further action, they will deteriorate over time due to the effects of weather and gravity. At a minimum, they would become unsafe eyesores. In some cases, they may become environmental hazards.

All of the plant sites contain hazardous chemicals and some contain asbestos. These materials need to be remediated and there is equipment that can be salvaged and resold, partially mitigating the dismantling expense. As a matter of public safety, we must secure these plants, remove hazardous materials, demolish facilities that might otherwise fall down on their own over time, and salvage those portions of the facility that can be reused or sold.

Q. HAS WESTAR INCURRED COSTS TO RETIRE PLANTS IN THE PAST?

A. Yes. Westar and its predecessors have a history of dismantling retired equipment that ranges from partial to complete removal of facilities. Table 4 below summarizes dismantling activities since the mid 1980's.

TABLE 4

Plant	Unit	Capacity kW	Initial Service	Retirement	Comments
ABILENE	1	15,000	1940	03/1987	Oil tanks were removed in the 1990's. The turbine generators and auxiliaries were removed in the early 2000's. Asbestos was also removed from the remaining equipment in the early 2000's. The 2 boilers and a small number of auxiliaries are still in place on site.
	2	15,000	1947	03/1987	
	1CT	77,750	6/1/1973	-	
HUTCH (NEW)	1	20,000	5/15/1950	3/31/2007	Units 1, 2, and 3 turbine generator sets and auxiliaries were removed in 2010.
	2	20,000	4/29/1950	3/31/2007	
	3	30,000	8/1/1951	3/31/2007	
	4	160,000	4/11/1965	-	
	1CT	71,100	4/1/1974	-	
	2CT	71,100	4/1/1974	-	
	3CT	71,100	4/1/1974	-	
	4CT	85,500	5/1/1975	-	
	D	2,750	1/12/1983	-	
KINSLEY	1	136	1918	1949	Kinsley plant

	2	269.5	1924	1978	has undergone various dismantling activities since 1986. Removal of the 4 diesel generator sets was performed by local staff until their departure in the 1990's. The remaining plant at Kinsley was completely removed during summer 2011.
	3	376	1929	1972	
	4	676	xfer JC 1948	1978	
LAWRENCE	1	10,000	1938	06/1993	Unit 1 turbine generator and boiler were removed in 1993. The Unit 2 turbine generator was removed in the early 2000's. Unit 2 boiler is still in place.
	2	37,500	1952	11/30/2000	
	3	56,000	12/16/1954	-	
	4	115,000	2/1/1960	-	
	5	385,000	3/16/1971	-	
NEOSHO	1	15,000	1/28/1924	05/1979	Units 1 and 2 were removed in their entirety in 1985 and 1986.
	2	25,000	10/11/1927	05/1979	
	3	66,000	10/30/1954	-	
RIPLEY	1	23,000	7/18/1938	12/1985	Unit 1 and 2 turbines and auxiliaries were removed in 1992 and
	2	25,000	9/25/1948	12/1985	
	3	33,000	9/12/1949	12/1985	

					1993. The asbestos was removed from the remaining equipment in the early 2000's. Two boilers, some auxiliary equipment, and the yard equipment are still at the site.
TECUMSEH	1	6,000	1925	1955	Units 1, 2, removed for installation unit 3. Unit 4 removed in late 1980's. Units 5 and 6 removed in 1992 and 1993. The old boilers are still in place including the coal handling equipment and bunkers. The bottom ash hoppers and lower headers on units 7 and 8 boilers were removed in 1992 and 1993.
	2	6,000	1925	1955	
	AUX	800	1925	1954	
	3	15,000	1927	1979	
	4	25,000	1930	1979	
	5	37,500	1949	05/1983	
	6	37,500	1955	05/1983	
	7/9	75,000	7/1/1957	-	
	8/10	125,000	2/1/1962	-	
	1CT	28,800	5/1/1972	-	
	2CT	28,800	5/1/1972	-	
WICHITA	3	10,000	4/15/1918	06/1986	The turbines were removed in the early 1990's. Two

					marine boilers remain at the site.

In addition to the plants identified in Table 4 above, Westar has also recently incurred costs to dismantle and retire a warehouse in Hiawatha, Kansas that was damaged beyond repair during a wind storm in 2010. The cost to dismantle and retire the Hiawatha warehouse was $80,000. And, in August 2011, Westar performed a final dismantling of an old power plant at Kinsley, KS. The cost for this final dismantling was approximately $120,000.

Q. DO THESE SITES HAVE SIGNIFICANT VALUE AS POWER PLANT SITES?

A. No. The sites addressed by the dismantling study contain small, older plants. Any new plant that might be contemplated for construction would require substantially more land, more water rights, and better access to natural gas transportation and electric power transmission facilities than are available at the location.

Q. COULD THESE PROPERTIES BE SOLD AT A PROFIT FOR A USE OTHER THAN POWER PRODUCTION?

A. No. In order to sell the property for an industrial use, we would have to bring the land up to at least a brownfield condition. For commercial use, the land would need to be brought to greenfield conditions. We believe that the additional cost to rehabilitate the land even to brownfield conditions would be significantly more than the additional proceeds we could obtain from selling the land.

Q. DO YOU HAVE ANY RECENT EXPERIENCE THAT FORMS THE BASIS FOR YOUR BELIEF?

A. Yes. We have attempted to dispose of our Abilene facility and have made inquiries concerning others' potential interest in acquiring the property. We have been unable even to give the land away without making a substantial commitment to remove facilities and rehabilitate the real estate.

Q. HOW DID WESTAR DETERMINE THE COST TO DISMANTLE THE PLANTS UNDER DISCUSSION IN THIS FILING?

A. We hired the firm of TLG Services, Inc. (TLG) to develop a dismantling study addressing the cost to decommission the plants in today's dollars. TLG is familiar to the Commission because it is the firm that develops decommissioning studies related to Wolf Creek. TLG is very experienced in conducting studies concerning the cost to retire power plants and performed its study of these plants in a manner similar to the method it uses to develop the Wolf Creek decommissioning studies. Francis Seymore, an Engineering Manager at TLG, provides testimony regarding the decommissioning study performed by TLG.

Q. WHAT COSTS WILL WESTAR INCUR TO DISMANTLE THESE PLANTS?

A. As the study reflects, the cost to retire each plant will be dependent on a number of factors unique to each plant. For instance, if a unit is retired at a site where other units will continue to operate, there may be common systems that will remain in service. Therefore, the dismantling cost will be lower because those systems will not be removed. Dismantling of some equipment may jeopardize the operation of existing units so that equipment may be left in place until the entire site is retired. We are also likely to realize salvage on some of the equipment.

When retirement will be done in conjunction with a site closing, the dismantling costs will likely be higher because the unit will be fully dismantled.

Environmental regulations will determine to what degree a site should be remediated when a site closes, but safety must also be a consideration in dismantling a unit. Structures must be secured or removed to prevent them from deteriorating and causing a safety hazard.

Q. HOW DOES WESTAR PROPOSE TO RECOVER THE COSTS ASSOCIATED WITH DISMANTLING THESE PLANTS?

A. We propose to recover the costs estimated by TLG escalated for inflation to the anticipated retirement dates over the remaining lives of the plants as indicated by our depreciation study.

Q. ARE THE RETIREMENT AND DISMANTLING DATES CERTAIN?

A. No. The dates are current estimates. If future events suggest a need to change any of the dates, the effect of such changes will be incorporated into subsequent depreciation studies.

Q. WHY IS IT APPROPRIATE FOR CURRENT CUSTOMERS TO PAY THE COSTS FOR DISMANTLING THESE PLANTS?

A. The dismantling costs reflected in our study are directly related to the ownership and operation of the plants to benefit current customers. Therefore, it is appropriate to include in current depreciation rates the net cost of making each plant site safe at the end of its operating life. Because those costs are directly related to the benefits that come from the plant – that is, the energy it produces to serve customers – it is appropriate for current customers to bear such costs. Similarly, if those costs are not recovered from the current customers who are receiving the benefits from those plants, then the dismantling cost would have to be paid for by future customers who did not receive any benefit from those plants. The customers who receive the benefits from the plants should be the customers who pay for the cost associated with the dismantling of those plants. This is a well-established principal in utility ratemaking and in other industries as well. For example, part of the cost of the coal we use is the cost that the mining companies know they must ultimately expend to reclaim the land when the mine is closed.

V. WOLF CREEK OPERATIONS

Q. WHAT IS THE CONDITION OF THE WOLF CREEK NUCLEAR PLANT?

A. Wolf Creek continues to be a reliable workhorse in our generating fleet. Between the last three refueling cycles the plant has operated at a net capacity factor of 98.5%. Despite that record of excellent performance, however, after having operated for 26 years, Wolf Creek is beginning to show the effects of becoming a middle aged plant. In the 18-month period between its most recent refueling outage, which has just ended, and the previous outage in the fall 2009, the plant operated at a net capacity factor slightly lower: 95.7%.

Q. HOW HAS THE AGING OF WOLF CREEK BEEN MANIFESTED?

A. There has been an increase in the number of de-rates and forced outages and an increase in the duration of refueling outages as plant components and systems age and require repair or replacement. Many times the scope and duration of these repairs are unknown until the commencement of the refueling outage and that adds to the duration of our planned outages.

Q. WHAT HAS BEEN THE HISTORY OF WOLF CREEK REFUELING OUTAGES?

A. After averaging 38 days for refueling outages between 1999 and 2006, the average refueling outage has increased significantly, reflecting necessarily larger planned scope of work (e.g., replacing and upgrading the turbine or other major components, such as large pumps or valves) as well as unplanned scope to repair aging equipment, some, as revealed only by the opportunity for more through inspections during outages.

Q. DID OTHER NEEDED WORK CONTRIBUTE TO THE LENGTH OF THE SPRING 2011 OUTAGE?

A. Yes. In the spring 2011 outage, 14 additional days were incurred when inspections and tests required unplanned work on the Essential Service Water system, equipment used to unload and reload fuel, repairs to heat exchangers used to cool plant components, and substation cable repairs. All of these are examples of mid-life maintenance – something that in the early days and "honeymoon" phase of the plant's life was not necessary.

In addition to these issues, during start-up at the conclusion of the spring 2011 outage, we discovered a ground in a generator rotor.

Q. HOW DID THE GROUND IN THE GENERATOR ROTOR AFFECT THE RESTART?

A. It further delayed restart.

Q. IS THE NEED TO REPAIR A GENERATOR GROUND UNIQUE TO NUCLEAR PLANTS?

A. No. The component that was repaired is part of the generating equipment that is common to fossil-fueled and nuclear power plants. In the past we have had similar required repairs at our fossil units, although each of these is a smaller machine than Wolf Creek.

Q. ARE THESE THE TYPES OF FAILURES THAT ARE REASONABLY AVOIDABLE?

A. No. This kind of failure can happen to any generator rotor. We go to great lengths to minimize the chance of experiencing a generator rotor ground, but despite our best efforts, sometimes they occur. What is important is that we take the appropriate amount of time to make the repairs in a quality manner so as to have a lasting repair. The last thing we would want to do, particularly on such a critical asset as Wolf Creek, would be to rush a repair, only to have the failure reoccur, perhaps at a much worse time.

Q. HAVE OTHER REPAIRS BEEN REQUIRED IN RECENT OUTAGES?

A. Yes. The 2009 outage was delayed eight days due to unplanned maintenance that was required on an Essential Service Water pump and motor replacement. In the 2008 outage, there was additional outage time resulting from the unplanned diesel generator work that was determined to be required during the outage.

Q. HAS WOLF CREEK ALREADY RECEIVED A LICENSE EXTENSION?

A. Yes. The license term was extended from 40 years to 60 years. WCNOC was able to secure one of the earliest life-extension orders in industry history, relative to its life. It is important to remember, however, that just because the license is extended that does not mean all the equipment can last that long. In order to ensure that Wolf Creek provides service for the 60-year term of its license and its matching depreciable life, it will be necessary for us to continue to invest in significant maintenance, repair and replacement of plant components. Even with the need to invest additional money in the plant and to extend outages to perform the work, Wolf Creek provides low cost energy to our customers. Extending the life of Wolf Creek is a great value for our customers, but it will require additional expenditures to keep it in good working order.

Q. DO YOU EXPECT THE TREND OF LONGER OUTAGES TO CONTINUE?

A. Yes. In fact, the next two future outages are planned to average 49 days given all the life extension work that needs to be done, and their actual outage time will also depend on what might be discovered when components that can only be inspected during an outage are tested. It is likely that during those outages, we will discover issues that need to be addressed that will extend the outages beyond our current projections.

VI. COST SAVING PROGRAMS

Q. YOU HAVE DISCUSSED A NUMBER OF AREAS THAT ARE DRIVING UP WESTAR'S COSTS. WHAT IS WESTAR DOING TO REDUCE COSTS IN OTHER AREAS TO HELP OFFSET THE UNAVOIDABLE INCREASES?

A. As chief operating officer, and the executive responsible for the biggest budgets, my greatest responsibility is to manage the operations of the company effectively and efficiently. A major part of effectively managing the operations is to control costs. The cost of nearly everything we need to operate this utility is rising. Therefore, we work hard to combat the rising costs by controlling costs and developing new ways of doing things to reduce costs. We seek ideas from all levels of the operation, including our front line employees, because they understand our practices best and are likely to find ways in which to operate more cost-effectively.

Q. PLEASE GIVE SOME EXAMPLES OF THE WAYS IN WHICH WESTAR IS REDUCING ITS COSTS.

A. There are many examples across the company of programs we have implemented that save large and small amounts. Here are a few examples.

Generation Savings

- We implemented a boiler inspection program starting in 2005 and have saved approximately $7.4 million annually in fuel costs by avoiding about 30 tube leak failures annually across the fleet. This is part of the Reliability Centered Maintenance I mentioned earlier.
- We implemented EtaPro, a unit performance monitoring system, and produced approximately $2 million in fuel cost savings in 2010 through improved control of heat rate losses.
- Over the last couple of years, we have shared labor resources across the fleet during scheduled outages, avoiding contractor labor costs and resulting in direct O&M savings of $1.76 million.

Power Delivery

- We continually evaluate both upcoming O&M activities and upcoming capital projects to see how to most effectively utilize the available time of our personnel. When operationally possible, we will use our crews to complete projects. Likewise, we use our personnel to complete O&M activities where such a decision can be economically justified. By moving current employees to work on major construction projects, we have been able to reduce our need to hire contractors for such work, producing a savings of approximately $6.1 million in 2010, and keeping jobs in Kansas.

- We have consolidated our management of transmission, substation, and distribution projects so that we can utilize our crews and contractors most efficiently. For example, this approach allowed us to move existing substation maintenance personnel to work in substation construction and eliminate the need for additional contractors, for a savings of $300,000.
- Our scheduling group also collapsed roughly 45 scheduling-related processes down to 20 for greater process efficiency. In June 2011, we expanded the Scheduling System to the Customer Care field employees to provide better route-based project schedules for the Meter and Service department. The improved efficiencies attained by the scheduling group are examples of the results of leveraging IT technology across both the "wires" and customer service organizations.

<u>Environmental Services</u>

- We undertook a project to reduce the number of calibration gas bottles used in the continuous emission monitoring systems (CEMS) at JEC, LEC, and TEC during the calibration check that must be performed after every 26 hours of operation by installing new gas manifold and delivery systems, saving several thousand dollars annually as well as the man-hours required to change out the gas bottles.

Q. HAS WESTAR TAKEN ANY STEPS TO REDUCE ITS TRANSMISSION COSTS?

A. Yes. We have worked to integrate the project management for each transmission project by utilizing improved communications among the participating workgroups, more detailed schedules, and more detailed cost estimates that are based on historical experience. We ensure that our employees are accountable for the timeliness and quality of the projects by including project management in employees' performance goals. Our improved project management process has resulted in a number of benefits, including increased safety and quality and better time management for the projects. As a result of improved project management, we have been able to bid more of our transmission projects. We estimate that to date in 2011, we have saved approximately $4.43 million as a result of using a bidding process for various projects. For example, all of our transmission projects this year are on schedule and on budget.

Q. IS THERE A COST SAVING PROGRAM THAT IS OF PARTICULAR NOTE?

A. I believe that the approach we are working on for handling wastewater from our upgraded scrubbers at JEC demonstrates how we combine our cost savings efforts with our commitment to being a good environmental steward. It also manages carefully the costs that must be recovered in our ECRR and base rates.

Q. WHY IS THERE A NEED TO ADDRESS WASTEWATER FROM THE JEC SCRUBBERS?

A. A scrubber removes sulfur dioxide (SO_2) from the flue gas at a coal plant. As Mr. Harrison testifies, Westar currently has scrubbers on all three units at JEC. In the process of removing SO_2 from the flue gas, Westar's wet flue gas desulfurization process creates a liquid waste. We must dispose of the liquid waste in an environmentally permissible and responsible manner.

Q. WHAT OPTIONS DID WESTAR CONSIDER TO ADDRESS THE PROBLEM?

A. There were five primary options evaluated for handling of the scrubber wastewater at Jeffrey Energy Center. The options with estimated construction costs, estimated annual O&M costs, and 15-year net present value are shown in Table 5 below:

TABLE 5
COSTS OF ALTERNATIVE WASTEWATER OPTIONS

Option	Construction Cost ($ millions)	Annual O&M cost ($ millions)	15 year net present value ($ millions)
Discharge to Kansas River	$4.91	$0.04	$6.32
Deep Well Injection	17.75*	1.52	34.06
Constructed Wetlands	20.57	0.53	29.76
Reverse Osmosis/Crystallization	48.09	4.83	99.83
Evaporation/Crystallization	56.40	5.66	115.57
*Requires another $7.7 million for additional wells after 15 years.			

As Table 5 shows, the lowest cost option was to discharge the wastewater through a constructed pipeline to the Kansas River. While it might be technically feasible, this option was not practical from a regulatory standpoint and not a long-term solution. In order to discharge the wastewater directly to the Kansas River, Westar would have to meet stringent anti-degradation regulatory requirements. As part of the anti-degradation requirements, Westar would be required to provide compelling economic and/or social reasons justifying direct discharge of wastewater over other treatment options. Our Environmental Services group did not recommend this option due to the regulatory requirements and the availability of other treatment options.

The deep well injection and the constructed wetlands treatment systems were the next least costly treatment systems. The deep well injection has a lower initial estimated construction cost, but a higher 15-year net present value (NPV) than the constructed wetlands. The deep well injection option also requires construction of additional wells after 15 years at an estimated cost of $7.7 million and assumes that deep well injection could occur near JEC. Currently, there are no approved deep well injection permits for the geological formations under JEC giving rise to additional permitting challenges. The nearest geological formation currently permitted for deep well injection is approximately 20 to 25 miles from the plant. If that site were to be used, the construction of a pipeline to move the wastewater to the wells would increase the 15 year NPV estimate of this option to $44.0 million – an increase of approximately $10.0 million.

Treatment of FGD wastewater in a constructed wetland is a new, innovative application of the constructed wetlands treatment system. Because this is a new approach to wastewater treatment, the cost for this option includes a pilot project that constructed a small scale wetland to treat approximately 10% of the FGD wastewater. Results of the pilot project will be used to verify treatment effectiveness and improve the overall design of a full scale constructed wetland. Arguably, this is the "greenest" of all options as it allows for treatment of the water through natural biological processes, requires very little equipment or mechanical processes, potentially allows for re-use of the treated water, and has relatively low annual O&M costs.

The reverse osmosis/crystallization and evaporation/ crystallization treatment methods have significantly higher capital construction costs and the highest annual O&M costs due to the complex nature of the treatment systems and equipment.

In summary, direct discharge to the Kansas River was the lowest cost option but was not environmentally permissible. Of the remaining treatment options, the innovative approach using constructed wetlands is the most cost effective method, and also the most environmentally friendly one. The overall costs (construction and annual O&M) for the constructed wetlands will be less than the overall cost for deep well injection in as little as three years and the constructed wetlands are estimated to save $1 million in annual O&M costs over deep well injection. This non-traditional wetland treatment method does carry risks, but they are being mitigated through the use of the pilot project. The deep well injection estimated costs also carry permitting and site risks that further enhance the economic feasibility of the constructed wetlands. The potential long term savings and environmental benefits of the constructed wetlands justify thorough consideration of this treatment option.

Q. WHAT IS THE CURRENT STATUS OF WESTAR'S WETLANDS PROJECT AT JEC?

A. The pilot constructed wetland treatment system was built in late 2010 with project startup in February 2011. Our plan is to operate the pilot system for a two-year evaluation period. Performance of the pilot system is measured by the removal efficiency of seven key constituents from the influent water stream (Boron, Chloride, Fluoride, Manganese, Selenium, Mercury, and Sulfate). Early performance testing indicates the system has the potential to remove all the constituents at some level with several constituents already being removed above design level. It is expected that performance of the system will continue to improve as plant communities develop. If further testing and performance indicates success, a full scale wetland system may be constructed and in operation by June 2014.

Q. DOES THIS INCLUDE ALL THE COMPANY IS DOING TO CONTROL AND REDUCE COSTS?

A. No. We are doing much more to operate cost-effectively. These are just a few examples.

Q. THANK YOU.