NP

FILED[3]

SEP 2 9 2006

Missouri Public Service Commission

Exhibit No.:
Issue: Energy Cost Recovery, Fuel and Purchased Power Expense
Witness: Todd W. Tarter
Type of Exhibit: Direct Testimony
Sponsoring Party: Empire District
Case No.
Date Testimony Prepared: February 2006

Before the Public Service Commission
Of the State of Missouri

Direct Testimony

of

Todd W. Tarter

February 2006

Empire Exhibit No. 15 NP
Case No(s). ER-2006-0315
Date 9-05-06 Rptr DF

NP

TABLE OF CONTENTS
OF
TODD W. TARTER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

NP

DIRECT TESTIMONY
OF
TODD W. TARTER
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Todd W. Tarter. My business address is 602 Joplin Street, Joplin, Missouri.

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

A. The Empire District Electric Company ("Empire" or "Company"). My title is Manager of Strategic Planning.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND FOR THE COMMISSION.

A. I graduated from Pittsburg State University in 1986 with a Bachelor of Science Degree in Computer Science. After graduation I received a mathematics education certification and became a mathematics teacher for Columbus Kansas Unified School District # 493. In May 1989, I joined Empire as a Planning Analyst. In 1994 I was promoted to Senior Planner. My primary functions at that time were coordinating the Company's construction budget, fuel and purchased power projections and financial forecasts. In August 1998, I became a Systems Analyst in the Information Technology Department. In November 2000, I left Empire to become a Senior Ecommerce Programmer Analyst with Leggett and Platt, Inc. In June 2001 I rejoined Empire as a Lead Systems Analyst in the Information Technology Department. I moved to the Planning and Regulatory Department in June 2002, where my primary duties were the preparation of the demand and energy and sales and revenue forecasts. In September 2004, I was promoted to my current position where I work on fuel and purchased power cost projections and resource planning.

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

A. My direct testimony addresses the appropriate consideration of fuel and purchased power expense. First, I will explain why the Company is requesting what I will generally refer to as an Energy Cost Recovery Rider ("ECR"). This request is designed to coincide with and utilize recent Missouri legislation allowing such an approach. I will also discuss how Empire's fuel and purchased power expenses have dramatically increased since its last Missouri rate proceeding and the reasons why. In addition, I will also present figures for an annualized and normalized fuel and purchased power expense developed with a production cost computer model. In connection with that, I will describe the modeling process and discuss the key data inputs to the model. This annualized and normalized approach represents an alternative, although less desirable, approach to setting a fuel and purchased power amount for ratemaking purposes if an ECR is not approved in this case.

II. ENERGY COST RECOVERY

Q. WHY IS EMPIRE PROPOSING AN ECR IN THIS RATE CASE?

A. Fuel and purchased power expense is the largest expense category Empire experiences in providing electric service to customers. During the test year of the 12 months ended (TME) September 30, 2005 that Empire has presented in this case, total fuel and purchased power expenses were about 50% of total electric expenses. As the Commission is no doubt aware, we are currently in a period of significant volatility in fuel and purchased power costs since energy costs are making regular headlines. The combination of (1) fuel and purchase power costs being the largest of Empire's expenses, and (2) the magnitude of increases in their costs since Empire's last Missouri rate proceeding has meant that the Company has not been able to recover its fuel and purchased power costs. The Company seeks an ECR in this case in order for it to have the opportunity to recover all of its prudently incurred fuel and purchased power expense attributable to its Missouri retail electric customers.

Q. ARE THERE ENERGY COST RECOVERY MECHANISMS IN OTHER JURISDICTIONS?

A. Yes. Missouri is the only jurisdiction of Empire's five jurisdictions where there is not some type of ECR. These energy adjustment clauses generally operate to enable the Company to recover its prudently incurred fuel and purchased power energy costs on a timely basis.

In Missouri, Empire was given permission to utilize an interim energy charge (IEC) in its last rate case, Case No. ER-2004-0570. The Missouri IEC became effective March 27, 2005, and is set to expire in March 2008.

Q. PLEASE EXPLAIN THE PARAMETERS OF THE CURRENT EMPIRE IEC IN MISSOURI.

A. The IEC is based on variable fuel and purchased power (energy) costs for Missouri on-system retail customers. It does not apply to demand costs associated with purchased power or to fixed natural gas reservation charges. The IEC approach recognizes that energy costs can fluctuate. Instead of having just one number as the assumed energy cost in the customer's base rate, it establishes a band or range with a top and a bottom that I will refer to as a "floor" and a "ceiling." A portion of the energy expense is built into "base" rates. A base rate would be one that does not vary. This represents the IEC floor. To deal with the potential for the expenses being volatile, customers are charged a separate and additional IEC rate of .002131 \$/KWh. The IEC charge, which is separate and subject to a possible refund at a later date, is based on the actual fuel and purchased power costs during the IEC period. This IEC rate, which is not a part of the base rates, creates the IEC ceiling in the Company's Missouri electric rates. In a scenario where Empire's actual energy costs are exactly equal to the IEC floor, then base rates will cover the cost of energy and the Company will be required to refund all of the IEC revenue it recovers, plus interest. In another scenario where actual energy costs are exactly equal to the IEC ceiling during the IEC period, then the base rates plus the IEC rate will perfectly cover the cost of energy for Empire's Missouri retail customers and the Company will keep all of the IEC revenue collected during the IEC period.

Q. ARE THERE OTHER POSSIBLE OUTCOMES DURING AN IEC PERIOD?

A. Yes. There are three other possible outcomes. Actual energy costs could be higher than the IEC ceiling, lower than the IEC floor, or be somewhere within the IEC band. If the actual energy cost ends up somewhere within the IEC band, the Company would keep a portion of the IEC revenue equal to the amount necessary to fully recover the energy costs and then it would refund the remainder with interest back to its Missouri retail customers. If the actual energy cost is below the IEC floor, then the Company would be required to refund all of the IEC revenue collected with interest. If the actual energy cost is above the IEC ceiling, then the Company would keep all of the IEC revenue collected and absorb the remainder of the energy costs. As you can see, Empire can be at significant financial risk if the actual fuel and purchased power expenses it incurs is higher than the IEC ceiling.

Q. PLEASE DESCRIBE THE PARTICULAR IEC FLOOR AND CEILING ESTABLISHED IN THE LAST RATE CASE.

A. Empire's current IEC floor (without demand charges) is 21.97 dollars per megawatt hour ($/MWh) and the IEC ceiling is 24.11 $/MWh. If purchase demand charges and natural gas firm transportation are included this would make the IEC floor 24.68 $/MWh and the IEC ceiling 26.66 $/MWh. This is shown in Schedule TWT-1 attached to my testimony.

Q. WHAT HAS HAPPENED TO EMPIRE'S ACTUAL MISSOURI FUEL AND PURCHASED POWER COSTS SINCE THIS IEC BEGAN NEAR THE END OF MARCH 2005?

A. During the IEC period of March 27, 2005 through December 31, 2005, actual Missouri variable fuel and purchased power expense has averaged *----* $/MWh, well above the IEC ceiling of 24.11 $/MWh. During this time, Empire's Missouri retail sales were *-----------* MWh. Since actual energy costs have been *---* $/MWh greater than the IEC ceiling, the Company has been forced to absorb roughly *--------------* in increased energy costs since the IEC began just nine months ago. These figures are from an IEC Report which is included as Schedule TWT-2 to my testimony.

Q. IS THE IEC THAT STARTED IN MARCH OF 2005 THE ONLY IEC THAT EMPIRE HAS HAD IN MISSOURI?

A. No. Empire had one other IEC. It was established in Case No. ER-2001-299 and became effective on October 2, 2001.

Q. WHAT WAS THE RESULT OF THAT 2001 IEC?

A. In that situation, fuel and energy costs dropped subsequent to the implementation of the IEC. The Company sought and received permission to reduce the IEC effective June 14, 2002. The 2001 IEC ended early as of December 1, 2002, and all of the IEC revenue that was collected was refunded to customers with interest.

Q. WHAT IS EMPIRE RECOMMENDING REGARDING FUEL AND PURCHASED POWER RECOVERY IN THIS CASE?

A. Empire is requesting, or making an "application" within the context of this rate case since no application rules are in place at this time, that the Commission approves the implementation of a procedure allowing periodic rate adjustments for its Missouri retail customers outside of general rate proceedings. While the IEC concept has been a definite improvement over the previous approach of trying to guess one correct number for future costs and collecting only that amount in Missouri retail base rates, recent experience demonstrates that this still is not the best solution. Empire seeks the implementation of a more traditional and robust ECR in Missouri—an ECR that has more flexibility than the current IEC process. The ECR mechanism requested by Empire in this proceeding would enable Empire to request periodic rate adjustments outside of a general rate proceeding to reflect the actual changes, both increases and decreases, in its prudently incurred fuel and purchased power costs.

Q. IS THERE AN UNDERLYING PREMISE FOR EMPIRE'S REQUEST?

A. It is based upon Missouri Senate Bill 179, which was signed by the governor in July 2005 and I understand has been codified as section 386.266 RSMo. This new law, and the accompanying rules which the legislation directs the Commission to adopt to implement the changes, is designed to enable Missouri's electric utilities to utilize periodic rate adjustments to recover the cost of fuel and purchased power used to provide service to retail electric customers in Missouri. This approach should include features that provide incentives to improve the efficiency and cost-effectiveness of the utility's fuel and purchased power procurement and provide the utility with a sufficient opportunity to earn a fair return on equity. It is Empire's belief that section 386.266 allows it to apply for the ECR adjustment mechanism prior to the implementation of the rules governing the ECR process; however, the statute directs the Commission to have these ECR rules in place prior to making any

NP

decisions with regard to such an application.

Q. ARE YOU PROVIDING ANY SUPPORTING INFORMATION FOR YOUR REQUEST OF AN ECR?

A. Yes. The following supporting information is attached to my testimony: Schedule TWT-3 is the supply side and demand side resources that the Company expects to use to meet its load for the next four years; Schedule TWT-4 is the expected dispatch of those resources (generation levels) for the next four years; Schedule TWT-5 is the expected heat rates for each supply side resource for the next 4 years; Schedule TWT-6 shows the fuel types for each supply side resource; and Schedule TWT-7 provides information about the long-term resource planning process.

III. FUEL AND PURCHASED POWER COST HISTORY

Q. PLEASE PROVIDE SOME HISTORY OF EMPIRE'S FUEL AND PURCHASED POWER COSTS.

A. The table below shows the recent history of Empire's total company (meaning all of its five jurisdictions, not just Missouri) on-system fuel and purchased power costs, including purchased power demand charges and fixed natural gas reservation charges.

TOTAL COMPANY ON-SYSTEM FUEL AND PURCHASED POWER COSTS INCLUDING PURCHASE & NATURAL GAS DEMAND CHARGES

______	*____________* *____________*	*______*	*______*
______	*____________*	*______*	
______	*____________*	*______*	*____*
______	*____________*	*______*	
______	*____________*	*______*	*______________________________________*
______	*____________*	*______*	
______	*____________*	*______*	
______	*____________*	*______*	
______		*______*	*____*
______	*____________*	*______*	*__________________________*

____

NP

As indicated, total on-system fuel and purchased power costs in 2003, the test year utilized by Empire in the previous Missouri rate case, was $104,714,009 or an average of 21.15 $/MWh. By the twelve months ending (TME) September 2005, the test year utilized by Empire in this case, this same expense had grown to $138,482,415 or an average of 26.59 $/MWh, an increase of 25.7 % per MWh. For calendar year 2005 this same expense was *-------------* or *-----* $/MWh. On a $/MWh basis, the year of 2005 is the largest one year percentage increase in fuel and purchased power expense for the Company in at least the last fifteen years. Part of this increase is due to the differences in weather in 2004 versus 2005, but most of the increase is due to rising fuel and purchased power costs.

The following graph which I prepared shows the trend in fuel and purchased power costs in recent twelve-month ending periods from TME Dec-03 to TME Dec-05.

Twelve-Month Ending Fuel and Purchased Power Costs with Demand

____

Q. WHAT ARE SOME OF THE KEY FACTORS IN THIS INCREASE IN FUEL AND PURCHASED POWER COSTS?

NP

A. The costs of nearly all forms of fuel used by Empire, including fuel oil and coal, have been rising recently, but the key drivers are certainly the rapid increases in natural gas and purchased power prices.

Q. PLEASE PROVIDE SOME HISTORY OF NATURAL GAS PRICES.

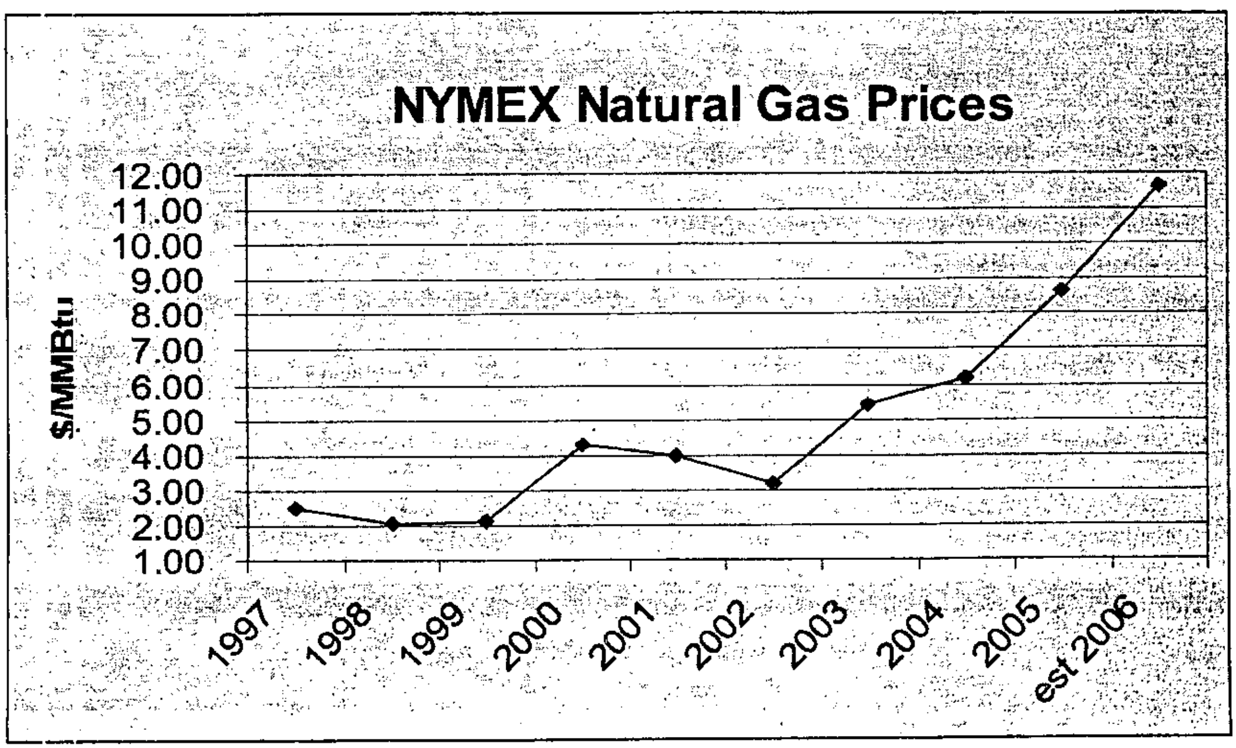
A. The following table that I prepared shows a historical comparison of reported natural gas prices based on NYMEX (the New York Mercantile Exchange) prices. The historical periods are based on the monthly NYMEX futures expired (settled) prices, and the future periods are based on NYMEX futures as of December 16, 2005. NYMEX is the world's largest physical commodity futures exchange and the preeminent trading forum for energy, and is commonly considered the most liquid and price transparent pricing point for natural gas in the United States. The standard contract point is at the Henry Hub which is physically located in Louisiana. The natural gas prices are expressed in dollars per one million British thermal units ($/MMBtu). One million British thermal units (one MMBtu) of natural gas is roughly equivalent to one thousand cubic feet (mcf) or one dekatherm (Dth) of natural gas.

Natural Gas Prices

	Annual Average Based on NYMEX Monthly Settle Prices $/MMBtu	Annual Average Based on NYMEX Futures Dec 16, 2005 $/MMBtu
1997	2.472	
1998	2.081	
1999	2.143	
2000	4.307	
2001	3.963	
2002	3.167	
2003	5.417	
2004	6.138	
2005	8.616	
2006		11.637
2007		10.046
2008		8.884
2009		7.989
2010		7.356

NP

This table is presented to illustrate the recent increase in market natural gas prices from a common pricing point and does not necessarily represent the price that Empire has paid for natural gas that it has burned or procured. As I will explain later, Empire has hedged a substantial portion of its natural gas requirements in recent years. The term hedging that I used refers to various mechanisms, both physical and financial, which are employed to contractually fix or stabilize the price of the commodity. However, the substantial increase in natural gas prices depicted in the table is a major reason for the increase in Empire's fuel and purchased power costs. In addition, we at Empire believe the substantial increase in natural gas prices is a major cause of the dramatic increase we have seen in spot purchased power prices. There are a number of variables that impact the price and availability of spot market energy such as generating unit availability, transmission issues, weather and certainly, fuel costs including the price of natural gas.



 NP

Q. PLEASE PROVIDE SOME HISTORY OF EMPIRE'S WHOLESALE MARKET PURCHASED POWER PRICES.

A. Empire does purchase power from the wholesale market from time to time. The prices are not fixed in the sense that they are set by a tariff sheet approved by a regulatory agency. The following table shows the amount of energy purchased by Empire on the wholesale power market, and the average price paid per megawatt hour. The data represents total company (all five jurisdictions) on-system non-contract purchases, meaning these purchases were made in the open market and were not the subject of a pre-existing contract.

NON-CONTRACT PURCHASED POWER ENERGY AND AVERAGE PRICE

-------	*-------* *-------*	*---------* *---------*	*-------*
-------	*-------*	*---------*	
-------	*-------*	*---------*	*--*
-------	*-------*	*---------*	
-------	*-------*	*---------*	*---------------------------------*
-------	*-------*	*---------*	
-------	*-------*	*---------*	
-------	*-------*	*---------*	
-------		*---------*	*---*

As you can see, during the year 2003, the test year utilized by Empire in the last Missouri rate case, the average non-contract purchase price was 35.76 $/MWh. By TME Sep-05, the test year utilized by Empire in this case, the average price paid had increased to *-----------------* *-----------------*. During the current IEC period, the average price of non-contract purchase has been *----* $/MWh. *---* which reflects the prevailing prices at about the time that the current IEC was established.

Q. ARE THERE OTHER FACTORS THAT ARE CONTRIBUTING TO RECENT HIGH ENERGY COSTS?

 NP

A. Yes. While natural gas prices and wholesale purchased power prices are the key drivers to Empire's increase in fuel and purchased power costs, there are other factors that contribute to increased fuel and energy costs. Other fuel costs, such as fuel oil and coal have increased over time. Various circumstances, including the May 2005 train derailments in Wyoming, have constrained the movement of coal out of the Powder River Basin. Recently coal conservation has begun in the Midwest region due to these rail transportation issues. This coal conservation has negatively impacted the Company's Jeffrey Energy Center contract purchase from Westar (the Jeffrey Energy Center is a generating station located in Kansas) and Empire's share of the Iatan Plant (located near St. Joseph, Missouri) output to some extent. At this point, coal conservation has not lowered the output from the Company's Riverton and Asbury coal units, but coal inventory levels at both of these sites are lower than normal. Coal is the fuel source for some of the lowest cost energy produced in the region, so coal conservation may also have some impact on the wholesale power market prices that Empire is seeing. Uncontrollable events such as coal supply disruptions, and the recent hurricanes in the Gulf Coast, can all have an impact on fuel and purchased power costs.

Q. WHAT IS THE OUTLOOK FOR FUTURE ENERGY COSTS?

A. In today's environment, it is difficult if not impossible to say what the future will hold for energy costs. At the time that Empire's current rates were implemented in Missouri during the last rate proceeding (rates were effective March 27, 2005), I do not think that anyone involved in that case would have anticipated that natural gas prices or wholesale market prices would be at the recent levels that I have described in this testimony. On page 8 beginning at line 10 of Staff witness John P. Cassidy's direct testimony in Empire's last case, he says: "The Staff believes that given the current volatile state of natural gas prices no one can predict, with a reasonable degree of certainty, the natural gas prices that Empire will pay in the future to fuel their generating facilities….The uncertainty surrounding natural gas prices also impacts the cost of purchased power obtained on the market."

According to a news article from November 22, 2005, Joseph Kelliher, chairman of the Federal Energy Regulatory Commission, stated that progress is being made in restoring offshore natural gas facilities shut down by the 2005 hurricanes, but predicted that gas prices will remain high as demand outpaces supply. Recovery of operations are progressing along the Gulf Coast, but the chairman added, "I don't think they'll go back to the level they were a few years ago."

If NYMEX gas futures are indicative of future natural gas prices, the next few years may still reflect prices near historically high levels. At December 16, 2005, future prices from the Henry Hub for the next 36 months averaged 10.189 \$/MMBtu, ranging from a low of 8.052 to a high of 13.880 \$/MMBtu. Over the next 60 months the average was 9.215 \$/MMBtu.

Basically, I share the sentiment in the quote from Staff witness Cassidy that I mentioned before. I do not think it is possible to accurately predict future energy costs, but it appears to me from all of the objective evidence that the trend of high energy costs will continue in the near term, and given that Empire has significantly under collected its fuel and purchased power costs since the IEC began, there certainly appears to be a very low probability of Empire's energy costs getting back into the band of the current IEC anytime soon (i.e., from the period beginning March 27, 2005).

Q. WHAT HAS EMPIRE DONE TO TRY TO ALLEVIATE THE VOLATILITY ASSOCIATED WITH ITS FUEL AND PURCHASED POWER COSTS?

A. The Company has several measures in place to help manage the costs of energy.

- We have a natural gas hedging program that has been in place since 2001 that is designed to mitigate energy price volatility. A portion of Empire's expected needs for natural gas are hedged financially or physically in advance—in effect dollar cost averaging the price of natural gas to remove volatility for both Empire and Empire's customers.
- During periods of volatile prices, short energy supply or extreme weather, Empire's wholesale energy trading desk is staffed to cover extended hours. The energy traders contact other energy providers in an effort to find the most economical power available on an hourly basis. They also use various analytical tools to help with economic generating unit dispatch decisions while maintaining reliability.
- During the summer of 2005, Empire burned fuel oil instead of natural gas in some of the dual fuel units whenever the fuel oil in inventory was less expensive than natural gas.
- In mid-October 2005, Empire began receiving wind energy from the new 150 MW Elk River Wind Farm. This wind-generated energy is displacing higher-cost energy and providing more price stability.
- In the longer-term view, to help reduce natural gas exposure, Empire has signed a letter of intent to be a partner in the proposed Iatan 2 coal unit, issued an RFP (Request for Proposals) for additional baseload capacity in the 2010 timeframe, and begun a Customer Programs Collaborative with other parties which will focus on demand side management as well as other customer programs.

Q. COULD YOU BRIEFLY EXPLAIN EMPIRE'S NATURAL GAS HEDGING PROGRAM?

A. The Company's natural gas hedging program has been very successful in that it allowed Empire to acquire its natural gas at an average cost below what it could have purchased on the spot market. Empire implemented its current Energy Risk Management Policy in 2001, and added personnel who focus specifically on the purchasing and hedging of power and natural gas. The Energy Risk Management Policy sets targets related to the levels of natural gas Empire must have hedged at any point in time. In general, the Risk Management Policy brings more sophistication, consistency and discipline to the fuel procurement process. The risk management policy is attached to my testimony as Schedule TWT-8.

Hedging is a strategy used to offset investment or price risk, specifically to protect against price movements. Empire's Risk Management Policy allows the utilization of traditional physical purchases and the utilization of financial tools such as call options, collars, swaps, and futures contracts to protect against adverse price movements.

Q. WHAT DETERMINES HOW MUCH NATURAL GAS IS HEDGED BY EMPIRE AND WHEN SUCH NATURAL GAS IS HEDGED?

A. The Risk Management Policy targets for hedging natural gas are:

- A minimum of 10% of year four expected gas burn
- A minimum of 20% of year three expected gas burn
- A minimum of 40% of year two expected gas burn
- A minimum of 60% of year one expected gas burn

Up to 80% of any years expected requirement can be hedged if appropriate, given the associated volume risk.

Q. WAS EMPIRE'S NATURAL GAS HEDGING PROGRAM REVIEWED IN THE

COMPANY'S LAST MISSOURI RATE CASE?

A. Yes. In Case No. ER-2004-0570 Empire's natural gas hedging program and the Risk Management Policy were presented in the direct testimony of Empire witness Brad P. Beecher. Empire's hedging program was cited in the direct testimony of Staff witness John P. Cassidy; Office of Public Counsel witness James Busch; and Explorer Pipeline/Praxair Inc. witness Maurice Brubaker.

On page 10 line 17 of Mr. Cassidy's direct testimony, the question was posed, "Has this [natural gas hedging] program been successful for Empire?" and his answer beginning at line 18 states, "Yes. Through the use of effective hedging strategies, Empire experienced overall natural gas costs of $2.70 / MMBTU during 2002 and $3.02 / MMBTU during 2003 compared to an average NYMEX close price of $3.22 during 2002 and $5.39 during 2003."

IV. PROPOSED LEVEL OF FUEL AND PURCHASED POWER EXPENSE

Q. WHAT LEVEL OF FUEL AND PURCHASED POWER EXPENSE IS EMPIRE PROPOSING IF AN ECR IS NOT IMPLEMENTED IN THIS CASE?

A. As stated earlier, Empire's first preference is an ECR. If an ECR is not used, Empire recommends that a total company on-system fuel and purchased power expense, including demand charges, of $162,888,204 be used to establish its base electric rates. This is based on a projected energy requirement of 5,294,800 MWh. On an average basis, this is $30.76/MWh. A summary of the output from a computer simulation I performed which supports this number is attached as Schedule TWT-9.

Q. HOW WAS THIS LEVEL OF FUEL AND PURCHASED POWER EXPENSE DEVELOPED?

A. This ongoing level of fuel and purchased power expense was developed by running the hourly production cost computer model known as PROSYM using normalized sales levels, growth and weather, and projected fuel and purchased power costs.

Q. COULD YOU BRIEFLY DESCRIBE THE PROSYM MODEL?

A. The PROSYM model is a chronological computer model that dispatches resources to meet demand requirements on an hourly basis. The model commits resources based on fuel costs, unit start-up costs, and variable operation and maintenance ("O&M") costs after accounting for operational characteristics of a utility system that may override economic dispatch.

The PROSYM simulation engine is described by its developer, Global Energy Decisions (formerly Henwood Energy), as providing the most accurate generation unit commitment logic in the world. PROSYM is used by well over 100 energy organizations around the world in both control room dispatch environments as well as in market analytic groups. Empire has been using chronological production costing models for projection purposes since 1991. Empire's four previous rate case filings in Missouri, and most recent rate case in Kansas, have utilized the PROSYM model.

Q. BRIEFLY DESCRIBE THE REASONS THE PROPOSED LEVEL OF FUEL AND PURCHASE POWER EXPENSE IS HIGHER THAN THE TEST YEAR (TME SEP-05)?

A. The actual total on-system fuel and purchased power expense during the test year (TME Sep-05) was $138,482,415. The adjusted level included in this case is $162,888,204, an increase of $24.4 million or 17.6%. During the test year, Empire was able to lower fuel expense by over $5 million by unwinding a forward natural gas contract it had entered into as a result of its Risk Management Policy. Had this not been done, actual test year expense would have been over $143 million. This test year also includes fuel and purchased power costs from 2004, which do not reflect the recent surge in natural gas and wholesale market prices. Empire's fuel and purchased power expense for calendar year 2005 was *----------------*. Had the unwinding of a forward natural gas contract not occurred, the 2005 expense would have been approximately *---* million. In addition, even though 2005 was a warm year relative to 30 year NOAA normals (National Oceanic and Atmospheric Administration normal temperatures), the adjusted level of fuel and purchased power expense in this case is based on an increased energy requirement due to customer growth. Generating unit availability was also very good in the test year, and a normalized outage schedule has been used in the computer simulation. This change raises the overall energy costs. The other factors taken into consideration that increase the cost of fuel and purchased power are the expected increases coming in fuel and wholesale power costs in 2006. Finally, adjusted fuel and purchased power costs reflect a full year of the new wind purchase. The wind purchase was not in the test year that Empire is using in this filing.

V. UNIT DATA USED IN THE MODEL

Q. PLEASE PROVIDE AN OVERVIEW OF THE DATA USED FOR MODELING EMPIRE'S GENERATING UNITS.

A. Data for Empire's generating units are shown in Schedule TWT-10. These data include each unit's rated capacity, maximum capacity, minimum capacity, heat rate curve information, ramp rate, forced outage rate information, mean repair time, minimum down time, minimum up time, fuel ratio, start-up fuel requirements and associated cost, and variable O&M. The normalized outage schedule is provided in Schedule TWT-11.

Q. ARE THERE ANY SPECIAL CONSIDERATIONS THAT NEED TO BE MADE WHEN MODELING EMPIRE'S GENERATING UNITS?

A. Yes. There are special considerations that need to be made for modeling (1) Asbury Unit 1 and Asbury Unit 2; (2) Riverton Unit 7 and Riverton Unit 8; and (3) the State Line Combined Cycle (SLCC).

Q. BRIEFLY EXPLAIN THE OPERATING CHARACTERISTICS FOR EMPIRE'S ASBURY UNITS THAT NEED SPECIAL CONSIDERATION.

A. The Asbury coal plant is comprised of one boiler and two turbines. The Asbury Unit 1 turbine is rated at 193 MW and Asbury Unit 2 is rated at 17 MW. Asbury Unit 2 cannot operate while Asbury Unit 1 is off line. In addition, Asbury is not able to run on a continuous basis at 210 MW due to operational issues. Specifically, the upper convection passes in the furnace tend to plug with ash. These operational limitations have been taken into consideration in the PROSYM model.

Q. ASBURY UNIT 2 DOES NOT APPEAR TO RUN VERY MANY HOURS IN THE MODEL RUN. COULD YOU PLEASE EXPLAIN WHY?

A. Running Asbury Unit 2 increases the total cycle heat rate of the Asbury plant which decreases the plants efficiency. It also contributes to plugging the furnace, which could lead to more forced outages. As a result Empire generally operates Asbury Unit 2 as a peaking unit. In the computer model run Asbury Unit 2 generates 3,900 MWh. In the test year (TME Sep-05) Asbury Unit 2 generated 2,270 MWh and in 2004 it generated 5,167 MWh.

Q. BRIEFLY EXPLAIN THE OPERATING CHARACTERISTICS FOR EMPIRE'S RIVERTON COAL UNITS THAT NEED SPECIAL CONSIDERATION.

A. Since the last Missouri rate case, the Riverton coal units have recently been burning petroleum coke as a blend fuel. Riverton Unit 7 can operate to approximately 23 MW out of its 38 MW of rated capacity on a blend of coal and petroleum coke. The remainder of the Riverton Unit 7 capacity can only be obtained by over-firing natural gas. Likewise, Riverton Unit 8 can operate to approximately 45 MW out of its 54 MW rated capacity on a blend of coal and petroleum coke with the remainder of the capacity obtained by over-firing natural gas. These operational constraints were modeled in PROSYM.

Q. BRIEFLY EXPLAIN THE OPERATING CHARACTERISTICS FOR EMPIRE'S STATE LINE COMBINED CYCLE THAT NEED SPECIAL CONSIDERATION.

A. Empire owns 300 MW or 60% of the 500-MW combined cycle unit at State Line (SLCC). The combined cycle consists of three electrical generating units—two combustion turbines (CTs) and one steam turbine. The CTs have heat recovery steam generators (HRSGs) on the exhaust end which utilize the high temperature exhaust gases to generate steam for use in the steam turbine. Steam can be used from one or both HRSGs to operate the steam turbine. This allows the combined cycle to be operated in one of two modes. Mode one, which I will call 1x1 mode, consists of one CT operating in conjunction with the steam turbine. Mode two, which I will call 2x1 mode, consists of both CTs operating in conjunction with the steam turbine. For this rate case filing, SLCC was modeled as two separate units. The first unit represents 1x1 mode and the second unit represents the 2x1 mode configuration. For the 2x1 mode unit to run in the model, the 1x1 mode unit must be running. Multi-step heat rates were input for each unit with the overall heat rate of the units comparing favorably to SLCC's average heat rate of approximately 7,500 Btu/kWh.

Q. HOW WAS THE OZARK BEACH HYDRO UNIT MODELED?

A. Ozark Beach was modeled close to the 30-year average of the historical generation of the unit from 1975 to 2004. Hydro generation accounts for less than 1.25 percent of net system input in this normalized model run. Historical data for Ozark Beach are shown as Schedule TWT-12.

VI. FUEL DATA USED IN THE MODEL

Q. BRIEFLY EXPLAIN THE BASIS FOR THE SOLID FUEL COSTS INCLUDED IN THE PRODUCTION COST MODEL.

A. All coal and petroleum coke prices are based on expected 2006 delivered cost. Other costs associated with solid fuel, including handling and unit train costs are not included in the solid fuel costs in the model. These fuel related costs will be discussed in Section VIII, Other Fuel Related Costs. The following solid fuel types were modeled: (1) Asbury western coal; (2) Asbury blend coal; (3) Riverton western coal; (4) Riverton petroleum coke; and (5) Iatan western coal.

Q. WHAT FUEL BLEND RATES ARE USED IN THE MODEL?

A. In the model on an MMBtu basis, Asbury burns 75% western coal and 25% blend coal; Riverton Unit 7 and Riverton Unit 8 burn 71% western coal and 29% petroleum coke; and Iatan burns 100% western coal.

Q. PLEASE EXPLAIN HOW THE NATURAL GAS PRICES WERE DEVELOPED FOR THE MODEL.

A. In the computer model, the gas-fired units can burn natural gas from two sources—from hedged natural gas and from spot market natural gas. The hedged gas represents Empire's current hedged position for 2006 (as of November, 2005). The hedged natural gas is a limited fuel type. Gas-fired generating units can burn this fuel until a specified MMBtu level is reached. After the limit is reached, the computer models the generating units as if they must operate on spot market gas.

Q. WHAT IS THE 2006 HEDGED NATURAL GAS POSITION THAT WAS USED IN THE MODEL?

A. The following table summarizes the 2006 hedged natural gas position that was used in the model. As of November, 2005, *---------* MMBtu of natural gas are hedged for 2006, at an average price of about *------* $/MMBtu.

2006 Natural Gas Hedged Position
As of November, 2005

------	*------*	*---------* *---------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
------	*---------*	*------*
	---------	*------*

Q. HOW WERE THE SPOT MARKET NATURAL GAS PRICES DEVELOPED FOR THE MODEL RUN?

A. The spot market natural gas prices in the model are based on NYMEX gas futures for 2006 as of November 1, 2005, with a basis adjustment. The data is summarized in the following table.

2006 Estimated Spot Natural Gas Prices
November 1, 2005 NYMEX with Basis Adjustment

Month	NYMEX $/MMBtu	Basis Adj	Spot Gas Modeled $/MMBtu
Jan	12.641	2.449	10.192
Feb	12.611	2.441	10.170
Mar	12.336	2.361	9.975
Apr	10.466	1.821	8.645
May	10.226	1.752	8.474
Jun	10.256	1.760	8.496
Jul	10.304	1.774	8.530
Aug	10.349	1.787	8.562
Sep	10.331	1.782	8.549
Oct	10.376	1.795	8.581
Nov	10.836	1.928	8.908
Dec	11.276	2.055	9.221
	11.001	1.976	9.025

Q. COULD YOU BRIEFLY EXPLAIN HOW THE NATURAL GAS BASIS ADJUSTMENT WAS DETERMINED?

A. NYMEX natural gas prices are based on a standard contract point at the Henry Hub in Louisiana. Since Empire takes gas delivery from the Southern Star Central Gas Pipeline (Southern Star), formerly known as Williams Gas Pipeline, NYMEX prices have been adjusted to reflect the cost from Southern Star. This basis adjustment was calculated with the FUTRAK software tool. FUTRAK is a leading risk and hedge management tool that uses regression analysis based on comparing three years of natural gas settlement data from NYMEX versus Southern Star. From this analysis, the software predicts the difference in Southern Star prices given NYMEX prices. The NYMEX prices adjusted for Southern Star delivery point were used in the model.

Q. WHAT WAS THE WEIGHTED AVERAGE NATURAL GAS PRICE FROM THE MODEL RUN?

A. In the PROSYM run for this case, with the model utilizing the hedged and spot market natural gas fuel types, the weighted average of the natural gas consumed was about 7.18

NP

$/MMBtu.

Q. HOW MUCH NATURAL GAS WAS BURNED IN THE MODEL RUN, AND HOW DOES THIS COMPARE TO HISTORY?

A. In the model run, 8,688,300 MMBtu of natural gas was used. In 2004, a mild weather year, Empire burned 7,778,910 MMBtu. In the filed test year (TME Sep-05), which contains a warm summer, Empire burned *-----------* MMBtu. In 2005, Empire burned *-------------* MMBtu. The primary reason that the model run reflects a lower natural gas burn than the calendar year 2005 level is due to the new wind purchase.

VII. PURCHASED POWER DATA IN THE MODEL

Q. BRIEFLY OUTLINE THE PURCHASES THAT WERE MODELED.

A. In the model, purchased power can be grouped into three categories: (1) 162 MW Westar – Jeffrey contract purchase; (2) 150 MW Elk River Wind Farm contract purchase; and (3) the wholesale power market also referred to as non-contract purchases.

Q. PLEASE DESCRIBE HOW THE WESTAR - JEFFREY PURCHASE WAS MODELED.

A. The energy and capacity for this 162 MW contract purchase comes from the three different coal units at the Jeffrey Energy Center (54 MW each). The purchase is represented as three units in PROSYM, all with the same energy costs, but each with separate scheduled maintenance outages. The test year average energy price with losses from this purchase was *----* $/MWh. In 2005, the average energy price with losses was *----* $/MWh. In the model, the filed test year (TME Sep-05) average of *----* $/MWh was used. This purchase also has a fixed demand charge which will be discussed in Section VIII, Other Fuel Related Costs.

NP

Q. WAS THE ELK RIVER WIND FARM PURCHASE INCLUDED IN THIS RATE CASE COMPUTER SIMULATION EVEN THOUGH IT WAS NOT OPERATING IN THE TEST YEAR?

A. Yes. This was done to be consistent with using 2006 natural gas prices and other 2006 fuel costs. The wind purchase began full commercial operation on December 15, 2005. In fact, the Company began receiving some energy from this site beginning in October 2005. This purchase is expected to save the Company several million dollars per year in fuel and purchased power costs depending on the prices of and amount of natural gas and purchased power that it offsets.

Q. PLEASE DESCRIBE THE ELK RIVER WIND CONTRACT.

A. Empire has signed a 20-year contract with PPM Energy, a US subsidiary of Scottish Power, to purchase the energy generated at the 150-megawatt Elk River Windfarm located in Butler County, Kansas near the town of Beaumont. Empire recently received Green-e™ certification from the Green-e™ Program of the Center for Resource Solutions. Green-e™ is the leading renewable energy certification and verification program in the United States. This program provides independent, third party certification to ensure certified renewable energy meets strict environmental and consumer protection standards.

Q. PLEASE DESCRIBE HOW THE ELK RIVER WIND FARM PURCHASE WAS MODELED.

A. Based on wind data collected at the wind farm site, this purchase was modeled as a must take purchase with an hourly load profile. In the model run, the annual energy purchased was 565,100 MWh or about a 43% capacity factor. The energy price used in the model is based on the agreed to contract price for 2006.

Q. WHAT PRICE WAS USED FOR THE NON-CONTRACT PURCHASED ENERGY?

A. The non-contract purchase data in the model represents the wholesale power market. The data is comprised of 8,760 hourly prices. The prices were developed by Global Energy Decisions using regional models for the Southwest Power Pool North region. The prices are forecasted for year 2006, utilizing the same spot natural gas forecast with basis adjustments described in this testimony. The average non-contract purchase price in the model run is 60.42 $/MWh. The test year average (TME Sep-05) was *----* $/MWh. In 2005, the average price was *----* $/MWh. Since the IEC period began on March 27, 2005 through December 2005, the average price has been *----* $/MWh.

VIII. OTHER FUEL RELATED COSTS

Q. BRIEFLY OUTLINE THE OTHER FUEL RELATED COSTS THAT ARE INCLUDED IN THE TOTAL COMPANY ON-SYSTEM FUEL AND PURCHASED POWER EXPENSES OF $162,888,204.

A. The other fuel related costs are: (1) Purchased power demand charge; (2) natural gas demand charges; and (3) unit train and undistributed and other costs.

Q. PLEASE DESCRIBE THE PURCHASED POWER DEMAND CHARGE.

A. There is a monthly demand charge for the 162 MW Westar – Jeffrey purchase. By contract this is 8.33 $/Kw/month which is $1,349,460 monthly and $16,193,520 annually. This contract expires May 31, 2010.

Q. PLEASE DESCRIBE THE NATURAL GAS DEMAND CHARGES.

A. The natural gas demand charges are based on three components (1) fixed cost for firm transportation service; (2) commodity charge; and (3) losses.

The contract fixed costs for firm transportation service is *---------* (2006 expected level).

The commodity charge is based on *------* $/MMBtu for a total of *-------------------------- --*. The losses are based on a natural gas loss rate of *----* for a total of *-- ---*. These three components result in a total gas demand cost of *-----------*.

Q. PLEASE DESCRIBE THE OTHER FUEL RELATED EXPENSES.

A. The Other fuel related expenses include undistributed and other costs, unit train lease, unit train maintenance, unit train depreciation and unit train property taxes. A five-year average (adjusted for nonrecurring expenses and *--* of approximately $1,454,344 was used in this rate filing. These are shown in Schedule TWT-13.

Q. HAVE YOU DESCRIBED IN GENERAL, THE OPERATIONS OF THE COMPUTER MODEL AND THE DATA INPUTS FOR THE SIMULATION THAT WAS PERFORMED?

A. Yes. And I have reviewed all of the inputs and outputs and compared them to actual situations such that I am confident that the result is accurate and reasonable for the use to which we are putting it in this case.

IX. SUMMARY

Q. PLEASE PROVIDE A SUMMARY OF YOUR DIRECT TESTIMONY.

A. When determining the proper amount of fuel and purchased power expense for Empire, the natural gas price is a significant variable. Because of natural gas price volatility, natural gas prices can not be predicted with any degree of certainty. Non-contract purchase power prices, which have some correlation to natural gas prices, are also very difficult if not impossible to predict with great accuracy. Fuel and purchased power costs have risen dramatically recently, seriously challenging—if not completely decimating—Empire's ability to recover all of its prudently incurred fuel and purchased power costs. An electric utility needs a realistic, timely and reasonable opportunity to recover prudently incurred fuel and purchased power costs in order to remain financially stable, a topic that will be addressed by other Empire witnesses. For these reasons, Empire has requested the authority to implement an ECR in this case as permitted by section 386.266 RSMo.

If an ECR is not approved, Empire requests that an annual total company fuel and purchased power expense including demand charges of $162,888,204 to be used to establish its base electric rates in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, at this time.

	Total Company	Allocator	MO Jurisdictional
Total On-System F&PP	$ 135,000,000		
Purchase Demand (Fixed)	$ 16,193,520		
Gas Demand (Fixed)	$ 5,685,044		
Variable F&PP	$ 113,121,436	82.49%	$ 93,313,873
Sales MWH			3,871,067.822
$/MWH			24.11

	Total Company	Allocator	MO Jurisdictional
Total On-System F&PP	$ 125,000,000		
Purchase Demand (Fixed)	$ 16,193,520		
Gas Demand (Fixed)	$ 5,685,044		
Variable F&PP	$ 103,121,436	82.49%	$ 85,064,873
Sales MWH			3,871,067.822
$/MWH			21.97

	$ 135,000,000	$ 93,313,873
	$ 125,000,000	$ 85,064,873
	$ 10,000,000	$ 8,249,000

Appendix A
Page 1 of 2

Total Company	125,000,000 Base	135,000,000 Forecast	Incremental
Variable F&PP Price $/MWH - NSI	20.36	22.34	
MWH - NSI	5,064,657	5,064,657	
Variable Charge	103,121,436	113,121,436	10,000,000
Purchased Power Demand (Fixed)	16,193,520	16,193,520	
Natural Gas Reservation Charges (Fixed)	5,685,044	5,685,044	
Total F&PP Expense for NSI	125,000,000	135,000,000	10,000,000
Total F&PP Price $/MWH	24.68	26.66	
Allocation Factor Missouri Retail			
.8249 Variable Fuel & PP	85,064,873	93,313,873	8,249,000
.8195 Fixed Fuel & PP	17,929,483	17,929,483	
Total MO Fuel & PP	102,994,356	111,243,356	8,249,000
Total MO Retail kWh Sales $/kWh	0.026606	0.028737	0.002131
MO Retail kWh Sales	3,871,067,822	3,871,067,822	
Variable MO Retail kWh Sales $/kWh	0.021975	0.024105	0.002131

Proof	
.8249 Variable Fuel & PP IEC Range (10,000,000 *.8249)	8,249,000
MO Retail kWh Sales	3,871,067,822
	0.0021

Appendix A
Page 2 of 2

The Empire District Electric Company

Revenue Recognition for Interim Energy Charge (IEC) Subject to Refund

___ *___*
___ *___*

		Current Period					To Date									
		MO Retail Calendar Sales MWh	MO Variable F&PP Cost $	MO Variable F&PP Cost $/MWh	MO Retail Calendar IEC $	Mo Retail Act Billed Rev $	MO Retail Calendar Sales MWh	MO Variable F&PP Cost $	MO Variable F&PP Cost $/MWh	MO Retail Calendar IEC $	Mo Retail Act Billed Rev $	IEC To Keep $	Provision For Refund $	Provision For Interest $	Provision For Int + Refund	
0	Mar-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
1	Apr-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	*___*	*___*	*___*	*___*
2	May-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
3	Jun-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
4	Jul-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
5	Aug-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
6	Sep-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
7	Oct-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
8	Nov-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
9	Dec-05	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	*___*	-	-	-	*___*
10	Jan-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
11	Feb-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	Mar-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
13	Apr-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	May-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	Jun-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
16	Jul-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	Aug-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	Sep-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	Oct-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	Nov-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Dec-06	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
22	Jan-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
23	Feb-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
24	Mar-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
25	Apr-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
26	May-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
27	Jun-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
28	Jul-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
29	Aug-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
30	Sep-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
31	Oct-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
32	Nov-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
33	Dec-07	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
34	Jan-08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
35	Feb-08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
36	Mar-08	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

NP

Interim Energy Charge (IEC)

Period	0 Current Mar-05	1 Current Apr-05	2 Current May-05	3 Current Jun-05	4 Current Jul-05	5 Current Aug-05	6 Current Sep-05	7 Current Oct-05	8 Current Nov-05	9 Current Dec-05
IEC Ceiling $/MWh										
IEC Floor $/MWh										
Prime Interest Rate (Annual)										
MO Residential Calendar Sales KWh										
MO Commercial Calendar Sales KWh										
MO Other Ind Calendar Sales KWh										
MO Praxair Calendar Sales KWh										
MO OPP Calendar Sales KWh										
MO Public Auth Calendar Sales KWh										
MO S&H Lighting Calendar Sales KWh										
MO Interdepart. Calendar Sales KWh										
MO Retail Calendar Sales KWh										
MO Ceiling $										
MO Floor $										
IEC Possible $										
Total On-System F&PP $										
Purchase Demand (Fixed) $										
Gas Demand (Fixed) $										
Variable F&PP $										
MO Jurisdictional Allocator										
MO Variable F&PP $										
MO Variable F&PP $/MWh										
IEC Rate $/KWh										
Calendar IEC $										
IEC Actual Revenue Booked $										
Current Period										

	To Date Mar-05	To Date Apr-05	To Date May-05	To Date Jun-05	To Date Jul-05	To Date Aug-05	To Date Sep-05	To Date Oct-05	To Date Nov-05	To Date Dec-05
IEC Ceiling $/MWh										
IEC Floor $/MWh										
MO Retail Calendar Sales KWh										
MO Ceiling $										
MO Floor $										
IEC Possible $										
Total On-System F&PP $										
Purchase Demand (Fixed) $										
Gas Demand (Fixed) $										
Variable F&PP $										
MO Jurisdictional Allocator										
MO Variable F&PP $										
MO Variable F&PP $/MWh										
IEC Rate $/KWh										
Calendar IEC $										
IEC Actual Revenue Booked $										
Provision for Refund	-		-	-	-	-	-	-	-	-
Provision for Interest	-		-	-	-	-	-	-	-	-
Total Provision for Refund with Interest	-		-	-	-	-	-	-	-	-
IEC to Keep		-								
To Date										
Under Recover To Date										
Over Recover To Date										

NP

The Empire District Electric Company
Load and Capability Forecast
Based on Load Forecast 2006-2009

Year	2006	2007	2008	2009

---------------	*--------*	*--------*	*--------*	*--------*
---------------	*--------*	*--------*	*--------*	*--------*
Net Peak	*--------*	*--------*	*--------*	*--------*
Total Asbury	210	210	210	210
Iatan	80	80	80	80
Riverton 7	38	38	38	38
Riverton 8	54	54	54	54
Riverton 9	12	12	12	12
Riverton 10	16	16	16	16
Riverton 11	16	16	16	16
Riverton 12		155	155	155
Energy Center 1	86	86	86	86
Energy Center 2	85	85	85	85
Energy Center 3	50	50	50	50
Energy Center 4	50	50	50	50
State Line 1	89	89	89	89
State Line Combined Cycle	300	300	300	300
Ozark Beach (hydro unit)	16	16	16	16
WRI Jeffrey contract purchase	162	162	162	162
Total Capacity	1,264	1,419	1,419	1,419
Capacity Resp. (12%)	1,254	1,282	1,312	1,340
-------------------	*--------*	*--------*	*--------*	*--------*
-------------------	*--------*	*--------*	*--------*	*--------*

12% Capacity Responsibility
Current Capacity Ratings

150 MW Elk River Wind Purchase is not counted as firm capacity in this report
Riverton 12 is a 155 MW V84 combustion turbine scheduled to be on-line in 2007

NP

Expected Generation (MWh)
2006-2009

	2006	2007	2008	2009
ASBURY 1	*-------------*	*-------------*	*-------------*	*-------------*
ASBURY 2	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL ASBURY	*-------------*	*-------------*	*-------------*	*-------------*
IATAN	*-------------*	*-------------*	*-------------*	*-------------*
RIVERTON 7	*-------------*	*-------------*	*-------------*	*-------------*
RIVERTON 8	*-------------*	*-------------*	*-------------*	*-------------*
RIVERTON 9	*-------------*	*-------------*	-	-
RIVERTON 10	*-------------*	*-------------*	-	*-------------*
RIVERTON 11	*-------------*	*-------------*	-	-
RIVERTON 12	-	*-------------*	*-------------*	*-------------*
TOTAL RIVERTON	*-------------*	*-------------*	*-------------*	*-------------*
ENERGY CENTER 1	*-------------*	*-------------*	*-------------*	*-------------*
ENERGY CENTER 2	*-------------*	*-------------*	*-------------*	*-------------*
ENERGY CENTER 3	*-------------*	*-------------*	*-------------*	*-------------*
ENERGY CENTER 4	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL ENERGY CENTER	*-------------*	*-------------*	*-------------*	*-------------*
STATELINE 1	*-------------*	*-------------*	*-------------*	*-------------*
SLCC 1X1	*-------------*	*-------------*	*-------------*	*-------------*
SLCC 2X1	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL STATE LINE	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL THERMAL	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL COMBUSTION TURBINE	*-------------*	*-------------*	*-------------*	*-------------*
OZARK BEACH	*-------------*	*-------------*	*-------------*	*-------------*
PURCHASES:				
WRI (JEFFREY) PURCHASE	*-------------*	*-------------*	*-------------*	*-------------*
SPOT PURCHASE	*-------------*	*-------------*	*-------------*	*-------------*
WIND PURCHASE	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL PURCHASE	*-------------*	*-------------*	*-------------*	*-------------*
TOTAL NSI	*-------------*	*-------------*	*-------------*	*-------------*

--
--
--
--

NP

Expected Heat Rates (Btu/KWh)
2006-2009

	2006	2007	2008	2009
ASBURY 1	*----------*	*----------*	*----------*	*----------*
ASBURY 2	*----------*	*----------*	*----------*	*----------*
TOT ASBURY	*----------*	*----------*	*----------*	*----------*
IATAN	*----------*	*----------*	*----------*	*----------*
RIVERTON 7	*----------*	*----------*	*----------*	*----------*
RIVERTON 8	*----------*	*----------*	*----------*	*----------*
RIVERTON 9	*----------*	*----------*		
RIVERTON 10	*----------*	*----------*		*----------*
RIVERTON 11	*----------*	*----------*		
RIVERTON 12		*----------*	*----------*	*----------*
TOT RIVERTON	*----------*	*----------*	*----------*	*----------*
ENERGY CENTER 1	*----------*	*----------*	*----------*	*----------*
ENERGY CENTER 2	*----------*	*----------*	*----------*	*----------*
ENERGY CENTER 3	*----------*	*----------*	*----------*	*----------*
ENERGY CENTER 4	*----------*	*----------*	*----------*	*----------*
TOTAL ENERGY CENTER	*----------*	*----------*	*----------*	*----------*
STATELINE 1	*----------*	*----------*	*----------*	*----------*
SLCC 1X1	*----------*	*----------*	*----------*	*----------*
SLCC 2X1	*----------*	*----------*	*----------*	*----------*
TOT SLCC	*----------*	*----------*	*----------*	*----------*
TOT STATE LINE	*----------*	*----------*	*----------*	*----------*
TOTAL THERMAL	*----------*	*----------*	*----------*	*----------*

--

NP

Fuel Types For Each Supply Side Resource

	Primary Fuel	Secondary Fuel	Start Fuel	Additional Fuel
Asbury 1	Asbury PRB Coal (~75%)	Asbury Blend Coal (~25%)	Oil	Tire derived Fuel
Asbury 2	Asbury PRB Coal (~75%)	Asbury Blend Coal (~25%)	-	Tire derived Fuel
Iatan	Iatan Western Coal		Oil	
Riverton 7	Riverton PRB Coal (~71%)	Riverton Petroleum Coke (~29%)	Natural Gas	Natural Gas *
Riverton 8	Riverton PRB Coal (~71%)	Riverton Petroleum Coke (~29%)	Natural Gas	Natural Gas **
Riverton 9	Natural Gas		Natural Gas	Oil
Riverton 10	Natural Gas		Natural Gas	
Riverton 11	Natural Gas		Natural Gas	
Riverton 12	Natural Gas		Natural Gas	
Energy Center 1	Natural Gas		Natural Gas	Oil
Energy Center 2	Natural Gas		Natural Gas	Oil
Energy Center 3	Natural Gas		-	Oil
Energy Center 4	Natural Gas		-	Oil
State Line 1	Natural Gas		Natural Gas	Oil
SLCC 1x1	Natural Gas		Natural Gas	
SLCC 2x1	Natural Gas		Natural Gas	

Approximate % blends are on an MMBtu basis

PRB is an abbreviation for Powder River Basin

* Riverton 7 has a rated capacity of 38 MW but a modeled max of 23 MW on coal & petroleum coke. Over firing with natural gas needed to reach 38 MW.

** Riverton 8 has a rated capacity of 54 MW but a modeled max of 45 MW on coal & petroleum coke. Over firing with natural gas needed to reach 54 MW.

CTs with oil as an additional fuel can burn oil if natural gas is unavailable or if oil is more economical

Long-Term Resource Planning Process in Missouri

Since October 1999 Empire has been meeting with the Missouri Commission Staff (Staff), Missouri Office of Public Counsel (OPC) and Missouri Department of Natural Resources (MDNR) twice each year as an alternative to electric utility resource plan filings. Empire hired Black and Veatch to perform a generation expansion plan in September 2003 which was presented at a semiannual meeting. As part of the stipulation and agreement (S&A) in the experimental regulatory plan Case No. EO-2005-0263, Empire is required to file a new resource plan in Missouri in July 2006. The details of this filing can be found in the S&A. The S&A states that Empire will continue to hold Integrated Resource Plan (IRP) presentations semiannually, and invite all interested non-IOU Signatory Parties (Parties). Empire issued a request for proposal (RFP) for baseload capacity and energy for the 2010 timeframe. In accordance with the S&A, the proposals were evaluated with the MIDAS capacity expansion module and the MIDAS Gold integrated resource planning tool. Empire hired the consulting firm that developed and maintains the models—Global Energy Decisions—to assist with the evaluation. The results of this RFP evaluation were presented to the Parties in September 2005. Empire has recently issued an additional RFP for electric generation resources that would be put in service after June 2014. The evaluation of these RFP responses will be included in the July 2006 resource plan filing. The S&A also established the Empire Customer Programs Collaborative (CPC). This group comprised of the Parties, will serve as a collaborative that will make decisions pertaining to the development, implementation, monitoring and evaluation of Empire's Affordability, Energy Efficiency and Demand Response Programs.

Schedule TWT-8

THE EMPIRE DISTRICT ELECTRIC COMPANY

ENERGY RISK MANAGEMENT POLICY

December 6, 2005

Services You Count On

THE EMPIRE DISTRICT ELECTRIC COMPANY
ENERGY RISK MANAGEMENT POLICY

TABLE OF CONTENTS

1 STANDARDS OF OVERALL COMPANY PROGRAM

INTRODUCTION

The purpose of the Energy Risk Management Policy (RMP) document is to define the approach and internal rules that The Empire District Electric Company (EDE) will utilize to manage its power and natural gas commodity risk. The content of this document establishes and describes the EDE policy in assuming, assessing, and controlling the level of natural gas commodity risk exposure involved in the normal course of serving EDE's native load energy requirements.

OBJECTIVES

It is the policy of EDE NOT to engage in financial or commodity transactions unless they are related to underlying exposures related to supplying EDE's native load or to hedge back-to-back off-system transactions. It is the express intention of EDE to prohibit financial or physical commodity transactions that would reasonably be considered outside of EDE's core business activities.

The following are specific RMP objectives for EDE that represent a balanced financial and operational focus:

OBJECTIVE #1

Provide an organizational structure to support management goals and budget performance by mitigating energy price volatility and; hence, limiting fluctuations in the cost of supplying power to retail customers.

The RMP provides an organizational structure for effectively assessing and managing risk associated with EDE's natural gas supply and wholesale power activities. It provides a framework for effective control, audit, and reporting. The procedures set forth allow for the management of operational risks without placing undue restrictions on the operations of EDE.

OBJECTIVE #2

Allow utilization of physical and financial tools to provide a predictably priced reasonable cost gas-supply.

EDE's cost to generate, purchase, and supply power is greatly impacted by fluctuations in the market price of energy sources such as coal, natural gas, oil, and wholesale electricity. This RMP outlines procedures on how hedge positions will be employed to limit these market fluctuations in the price of natural gas and; hence, provide EDE with tools to manage expenses to generate, purchase, and supply power for its customer base.

2. RESPONSIBILITY FOR ENERGY RISK MANAGEMENT POLICY

The Officer Group as listed below is responsible for maintaining and overseeing the RMP:

The Officer Group is comprised as follows:

President and CEO
Vice President - Finance and CFO
Vice President - Energy Supply
Vice President - Regulatory and General Services
Vice President - Strategic Development
Vice President - Commercial Operations

From time to time, the Officer Group will report to the Board of Directors on the risk management activities surrounding natural gas risk. Officer Group activities shall include:

- Providing the Risk Management Oversight Committee (RMOC) authorization to engage in those activities consistent with prudent risk management and related trading practices which correlate with the native load requirements of EDE;
- Recognizing financial instruments such as futures, swaps, options, as well as physical market position management, can be effective transaction tools; and
- Providing sufficient management involvement, financial controls, and systems to monitor, report, and ensure the integrity of the RMP at all levels.

RISK MANAGEMENT OVERSIGHT COMMITTEE

The RMOC is charged to monitor aggregate risks and ensure they are managed in accordance with the RMP. The RMOC will meet periodically to assess aggregate risks and review EDE's market positions and exposures and strategy.

The RMOC is comprised as follows:

Chairman
Vice President - Finance and CFO

Members:
Vice President - Energy Supply
Vice President - Regulatory and General Services
Vice President - Strategic Development
Controller and Assistant Treasurer and Secretary
Director of System Operations

Non-Voting Internal Control Members:
President and CEO (see exceptions at Appendix 12)
Director of Internal Audit
Fuel Accounting Manager
Wholesale Energy Trader(s)

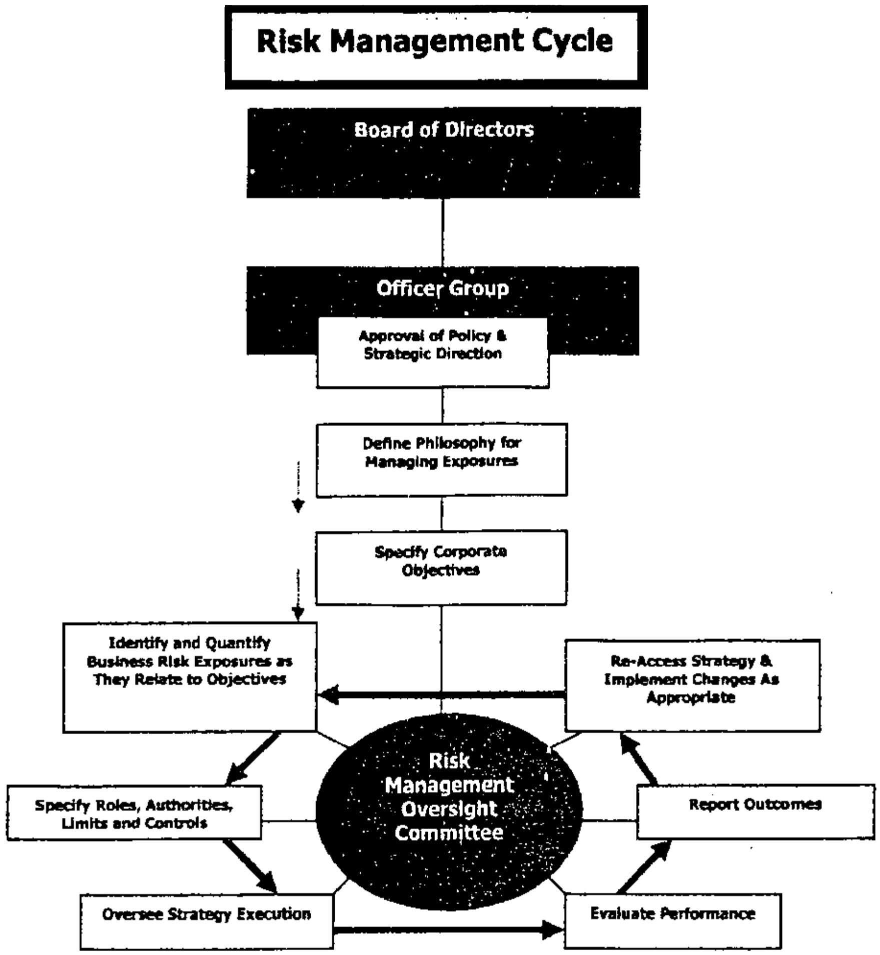
RMOC RESPONSIBILITIES

- **Approve Hedging Strategies** - Develop and approve strategies that achieve risk management objectives.
- **Individual Trading Authorization** - Approve a list of individuals authorized to establish trading relationships and execute trades. The hierarchy of oversight will include opening futures accounts, executing International Swap Dealer Association (ISDA) master agreements, placing futures orders, and entering into transactions per a master swap agreement.
- **Set Transaction Exposure Limits** - Approve limits on volumes and length of coverage of all outstanding physical, futures, options, and Over-the-Counter (OTC) positions.
- **Ensure Credit Approval and Documentation** - The credit approval / monitoring process is described in Appendix 12: Trader Authorization and Appendix 1: Credit Risk / Procedures Policy.
- **Establish Procedures and Develop Reporting Systems** - Ascertain appropriate checks and balances are in place and financial reporting is correct.
- **Establish Approved Counterparty List** - Establish an approved counterparty trading checklist to be used by the Wholesale Energy Group.

Any member of the RMOC has authority to call committee meetings and the responsibility to ensure that all activities are in accordance with this program. The committee may meet in person, through telephone conference calls, and/or electronic mail. The RMOC secretary (who is not a member of the RMOC) will keep regular minutes and records of meetings and actions.

At any time a RMOC member believes the committee has failed to adequately address a situation in which the member believes price or credit speculation is taking place, that member shall submit a written statement describing the concern to the President and CEO or the Director of Internal Audit.

RMOC CYCLE



3 RISK

COMPANY EXPOSURE

EDE's exposure spans activity in both the physical fuels market and the financial derivative markets that have developed to accommodate natural gas and power. Without risk management, EDE will be subject to cost and pricing uncertainty, as well as uncertainty in meeting budgeted earnings and cash flow.

The primary components of EDE's risk exposure are operations risk, market risk, and credit risk. The RMP is designed to address the management of these risks in the aggregate.

OPERATIONS RISK

Involves the potential increased cost for items such as providing replacement power to serve customers due to the unscheduled outage of generation plants, interruptions of power purchases from other parties, or interruption of gas supply.

MARKET RISK

Involves the potential change in value of a commodity contract, liability, or cash flow caused by adverse fluctuations in market factors over a pre-defined holding period. Types of market risk include:

- **Price Risk** - Uncertainty associated with changes in the price level of commodity fuel costs.
- **Liquidity Risk** - Risk associated with the diminished market activity of a fuel commodity.
- **Volume Risk** - Supply or demand deviation from forecast (for example, the risk of not having enough or having too much natural gas to meet forecasted obligations). Volume risk is highly correlated with price risk because availability of wholesale electricity is high and price low when the weather is mild causing reduced volume need. Conversely, when weather is extreme causing an increase in our underlying needs, the price of wholesale electricity may increase exponentially.
- **Calendar Risk** - Exposure due to time differential in commodity value between actual physical delivery and financial position expiration.
- **Basis Risk** - Exposure due to a difference in commodity value between different delivery points or between cash market prices and the pricing points used in the financial markets.

COUNTERPARTIES/CREDIT RISK

A component of the overall RMP is the management of credit exposure. EDE's exposure is different when transacting on the New York Mercantile Exchange (NYMEX) versus when transacting OTC.

The creditworthiness of trading partners or clearinghouses is a function of both qualitative and quantitative factors. Such factors are centered on the credit rating assigned to a company by major credit rating services and an evaluation of the company's ability to financially meet its obligations to EDE. Typical sources of credit-related information are credit rating reports (published by one or more of the commonly recognized rating agencies, such as Dunn & Bradstreet, Standard & Poor's, or Moody's), general market intelligence, electronic news releases, and other public information sources. Based on these resources, the RMOC will provide oversight as to each approved counterparty's credit exposure limit.

Credit risk associated with maintaining an account with a futures clearinghouse is considerably less than that with OTC counterparts. This distinction exists because the collective clearinghouse members of NYMEX, which includes virtually every major energy company and financial institution in the country, guarantee the performance on all positions placed on the exchange. Requiring margin deposits and daily mark-to-market by clearinghouse members allows for incremental monitoring and control of transactions and eliminates the potential for sudden defaults on contracts.

ESTABLISHING CREDIT RESPONSIBILITIES

As defined in Appendix 1 - Credit Risk / Procedures Policy, establishing limits and creditworthiness monitoring will be done independent of the trading function and will be performed by the Fuel Accounting Manager in Finance (with oversight by the RMOC), in order to guarantee appropriate segregation of duties within EDE. All trading activity with a particular counterpart who no longer meets EDE's credit standards will be halted. A Counterparty Credit Exposure Report will be included as part of the weekly Position Report described later. The report will summarize the total amount of exposure by counterparty by hedging instrument based on current mark-to-market amounts.

4. HEDGE STRATEGY

EDE's Missouri retail rates are not subject to a fuel cost adjustment clause. Missouri legislators did pass a fuel adjustment clause in the summer of 2005. However, at this time EDE is stipulated to operating under a three year Interim Energy Credit mechanism that began March 27, 2005. As such, the only time EDE's rates are adjusted for changes in fuel costs is during a rate proceeding. The regulatory schedule for a rate proceeding in Missouri requires 11 months from the date of filing before new rates come into effect. Adding preparation time for a rate case, this period could stretch to 12 or 13 months. This regulatory schedule combined with the volatility of natural gas necessitates that EDE focus on procuring fuel over periods longer than 18 months to help prevent EDE's revenues from lagging its costs. The Kansas Corporation Commission has approved a fuel adjustment clause that will become effective January 1, 2006.
EDE's strategic focus addresses both the regulatory structure and volatility by attempting to protect against volatile natural gas costs for EDE plants. To best utilize the economic trade-offs between generating with on-system resources versus buying non-firm wholesale power, EDE will apply risk management strategies. EDE will attempt to lessen the risks associated with variances in the volume of fuel consumed relative to budgeted fuel consumption volume.

EDE's specific hedge strategy goals are to provide for predictable fuel and purchased power costs over a multi-year period and to provide a framework to allow EDE to manage its risk positions.

EDE's RMP is designed to provide the Wholesale Energy Group with a more comprehensive set of tools to mitigate the adverse impacts associated with changing natural gas or wholesale electricity prices.

EDE's risk management strategies involve an active and continual "mark-to-market" assessment of market conditions to match its supply portfolio to its portfolio of retail and wholesale obligations.

In effect, these strategies set out to determine how much market risk is reasonable to best minimize costs and volatility, while still providing EDE's customers with reasonable fuel costs.

An overview of the hedging targets for natural gas is outlined below.

NATURAL GAS

At least yearly, EDE will model its electric system with a production cost model to establish an expected gas burn for retail load for each of the next four years. This budgeted gas burn will be the same as that utilized in EDE's financial projections.

From time to time as conditions change (i.e. unit outages, gas commitments, purchase power commitments), the Wholesale Energy Group shall re-model EDE's system to establish a new "expected" gas burn for native load.

EDE will utilize the following procurement guidelines:

- Hedge a minimum of 10% of year four expected gas burn
- Hedge a minimum of 20% of year three expected gas burn
- Hedge a minimum of 40% of year two expected gas burn
- Hedge a minimum of 60% of year one expected gas burn

The Wholesale Energy Group will have the flexibility to hedge up to 80% of any year's expected requirements while being cognizant of volume risk. For years beyond year four, additional factors of long term uncertainty in required volumes, counterparty credit, etc. should also be considered.

(By December 31 of current year we should have a minimum of 60% of the next years projected gas burn hedged.)

This progressive dollar cost averaging approach is intended to protect our customers and shareholders from volatility in the marketplace. In addition, the progressive approach allows for increasing uncertainty of gas needs inherent in forecasting events occurring further in the future.

If changes in expected gas burns occur that make us more than 100% hedged in any given month, immediate steps will be taken to reduce our hedged position to 100% or less.

5. INTERNAL CONTROLS

Internal controls are essential in ensuring adherence to the RMP and include the authorization of acceptable instruments, limits, and credit standards. Additional checks and balances including segregation of departmental duties, market position monitoring, and a management reporting structure should be in place to verify and reconcile the integrity of EDE's risk management activity results. EDE's accounting policies and key controls relating to our hedging program are detailed in the Power & Fuel Cycle section of our Sarbanes/Oxley documentation.

SEGREGATION OF DEPARTMENTAL RESPONSIBILITIES

An appropriate segregation of duties is fundamental in controlling EDE's risk management operations and includes activities such as approvals, verifications, and reconciliations. A clear separation between transacting, credit review and approval, margining and cash settlements, and accounting has been established with respect to the RMP.

Wholesale Energy Group, Finance, and Internal Audit are the departments most directly impacted by energy supply risk management activities.

AUTHORIZATION PARAMETERS

INSTRUMENTS

A primary responsibility of the RMOC is the review and approval of tools acceptable for implementation of the risk management strategy.

The various hedging instruments that EDE is authorized to use by this RMP is described as follows:

- **Physical Forward Contract** - Contract for future physical delivery of a designated quantity of a fuel source or power supply at a designated price, time, and location. Physical forward contracts obligate both the buyer and seller to accept the agreed-upon price, regardless of the market price when the delivery takes place.
- **Futures Contract** - Standardized binding agreement to buy or sell a specified quantity or grade of a commodity at a later date. Futures contracts are freely transferable, can be traded exclusively on regulated exchanges, and are settled daily based on their current value in the marketplace.
- **Put Option / Call Option** - Contract giving the holder the right, but not the obligation, to purchase or sell the underlying futures contract at a specified price within a specified period of time in exchange for a one-time premium payment. The contract also requires the writer, who receives the premium, to meet these obligations. (Use of these instruments in a manner that precludes them from falling under hedge accounting treatment is prohibited.)
- **OTC Instrument** - Any financial or physical instrument that is customized and created by a counterpart to replicate the risk profile associated with a commodity. The OTC swap is a contractual agreement between two parties to

exchange a series of cash flows, for a stipulated period of time, based on agreed-upon parameters and price fluctuations in some underlying commodity or market index. There is a monthly settlement price, which is the difference between the fixed price of the contract and the index price in the publication for that month's date. If the index price for the delivery period is higher than the fixed price of the OTC contract, then the seller pays the buyer the difference. If the index price is lower, the buyer pays the seller the difference. This policy approves the use of OTC forwards and options for natural gas and power. Power examples include: 5x16, 7x24, 5x8, 2x24, 7x8, 1x16, etc. (Use of these instruments in a manner that precludes them from falling under hedge accounting treatment is prohibited.)

LIMITS

AUTHORIZED TRADERS AND TRADING LIMITS

- **"Round Trip" Trades Prohibited** - "Round trip" transactions shall be strictly prohibited. Round trip transactions, as used herein, refer to simultaneous (or nearly simultaneous) energy purchases and sales of equal duration, price and volume. Employees engaging in such transaction shall be subject to progressive discipline up to and including termination of employment.

- **Off-Premise Trading** - Off-premise trading is not allowed. One-time trades may be done with the approval of a senior officer.

Authorized traders, along with approval and transaction limits, are listed in Appendix 12.

6. **REPORTING POSITION REPORT**

The Position Report contains a list of all open and recently closed transactions for EDE trade-based activity and serves as a crucial element of RMP control and management. The Position Report has multiple applications for risk management review that includes account transaction tracking and evaluation as well as overall performance evaluation.

The Position Report is updated as transactions occur and distributed weekly by the Wholesale Energy Group (WEG). Its primary objectives are:

- Allow for marking individual transactions to market;
- Provide data for transactions as well as portfolio analysis; and
- Simplify accounting and program results evaluation through analysis of the closed positions list.

MARK-TO-MARKET

All positions will be mark-to-market (using the appropriate NYMEX prices or other suitable market indicator as defined by the underlying contract) weekly or as determined by the RMOC on the Position Report by Wholesale Energy Group. This analysis is performed to appropriately reflect the current value and cash flows associated with open positions and to provide timely information regarding EDE's market risk and exposure.

The Wholesale Energy Group is responsible for verifying the validity of the market data used in mark-to-market calculations through the Position Report, with Finance performing a subsequent review as a check on this report's accuracy. On certain OTC positions, it may be difficult to obtain an accurate mark-to-market value. In these instances, Wholesale Energy Group will provide the most precise estimate of values and will identify the source and reliability of the data.

ADDITIONAL MANAGEMENT REPORTING

Management reports are to be based on the principles of adequate compliance limit monitoring, accuracy of data sources, and frequency and quality of information. All reports should communicate the price risks assumed by EDE. Information pertaining to performance measurement and program evaluation will be included in required reports and will be used as a basis for RMOC discussions and future strategy setting.

MINIMUM REPORTING REQUIREMENTS

The following table identifies the various reports to be generated by different departments or management levels, the normal regularity, and circulation of the document.

Report	Distribution	Normal Frequency	Originator
Position Report	WEG Fuel Accounting Manager RMOC	Weekly and Quarter-End	WEG
Man Financial Account Statements via email	WEG Fuel Accounting Manager.	Daily – Others	RMI
Minutes of RMOC Meetings	RMOC	As soon as possible after RMOC meeting (5-7 business days)	RMOC Secretary
Counterparty Credit Exposure Report	RMOC WEG Fuel Accounting Manager	Weekly	WEG (as reviewed by Fuel AccountingMgr.)

DISCIPLINE

Any violation by an employee of the RMP will be subject to the Progressive Discipline Policy as outlined in the Personnel Policy Manual of EDE.

7. POLICY REVIEW

On a periodic basis, the RMOC will review and mutually make a recommendation to the Officer Group on the adequacy of the RMP and any necessary changes.

8. CONFLICTS OF INTEREST

Personnel responsible for executing and managing EDE's trading activity will not be authorized to enter into energy-related commodity transactions on behalf of others or themselves unless specifically approved by the RMOC.

9. DUTIES AND WORK FLOW

Appendices are listed as follows:

- **Credit Risk and Procedures Policy - Appendix 1**
- **Duties for Wholesale Energy Group - Appendix 2**
- **Duties for Finance - Appendix 3**
- **Duties for Auditing - Appendix 4**
- **Work Flow to Execute Trade - Appendix 5**
- **Procedure for Hedge Transactions and Reconciliation - Appendix 6**
- **Trade Ticket - Appendix 7**
- **Confirmation Procedure - Appendix 8**
- **Position Report - Appendix 9**
- **Mark to Market Report - Appendix 10**
- **Broker Account Statement - Appendix 11**
- **Authorized Traders - Appendix 12**
- **Wholesale Energy Group – Purchase and/or Sale Pre-Approval Form – Appendix 13**

APPENDIX 1

THE EMPIRE DISTRICT ELECTRIC COMPANY

CREDIT RISK/PROCEDURES POLICY

January 11, 2005

Services You Count On

I: INTRODUCTION

The purpose of this policy is to establish a consistent process whereby the credit risk of future financial loss due to counterparty physical or financial non-performance is significantly diminished for energy purchases and / or sales. This Credit Risk/Procedures Policy will govern any energy transactions relating to natural gas and / or purchased power conducted by Empire District Electric Company.

II: POLICY OVERVIEW

In general, all energy suppliers and / or purchasers will be subject to a financial review in accordance with Empire District Electric standards for determination of creditworthiness. Evaluation of a company's financial strength and its ability to deliver its product or to pay is crucial.

A credit review cannot be viewed as the mechanism to prevent any and all losses, but it can help identify those companies where performance has been a problem in the past or may present a problem in the future. Established limits combined with proper monitoring oversight will help Empire District Electric to effectively mitigate possible losses due to counterparty insolvency.

III: RESPONSIBILTIES

Risk Management Oversight Committee

The Risk Management Oversight Committee (RMOC) shall give final approval for all credit policies and procedures. In today's business environment, a formularized credit rating approach for rating counterparties may not be practical. The RMOC will provide oversight by reviewing weekly Position Reports produced by the Wholesale Energy Group (WEG) and by formal discussions of counterparty credit limits, credit risk, credit exposure, etc. at the RMOC meetings. The Fuel Accounting Manager will provide monthly credit rating status reports of counterparties. WEG will report on credit exposure by counterparties in the weekly Position Report.

RMOC Committee Members

This group is defined in the Energy Risk Management Policy.

Fuel Accounting Manager

The Fuel Accounting Manager shall monitor the credit exposures created through the trading of energy and derivative products, and ensure that the RMOC is aware of any inappropriate credit exposure.

Primary Responsibilities include the following:

- On-going monitoring of existing counterparty credit/financial strength, see On-Going Financial/Credit Strength Monitoring Procedures section below
- Monitor credit exposures created by the trading of energy and / or derivative products, see On-Going Financial/Credit Strength Monitoring Procedures section below
- Oversee the development and administration of systems necessary to support the above activities
- Monitoring trade activity with each counterparty

Wholesale Energy Group

The Wholesale Energy Group optimizes the use of generation, purchased power and natural gas as outlined in the Energy Risk Management Policy.

Primary Responsibilities include the following:

- Keeping abreast of market trade talk and communicate knowledge to the Fuel Accounting Manager
- Coordination of legal documentation appropriate for each counterparty such as Master Agreements, International Swaps Derivative Agreements (ISDA), etc.
- Monitoring trade activity with each counterparty

Legal Services

An outsourced legal services group shall be used by the Wholesale Energy Group in counterparty agreement negotiations. While it is not always possible to achieve, the Wholesale Energy Group will work with legal services to seek netting and/or set-off agreements with counterparties on all contracts.

Netting provisions allow counterparties to settle with each other the net of all transactions for a given period rather than gross amounts involved in a series of transactions. If a company buys power from a counterparty and also sells them power, the final transaction will take both aspects into consideration and pay the difference between the two. The non-defaulting party may also perform a closeout of any existing positions and include this balance in the netting calculation. This provision can eliminate a large amount of downside potential associated with counterparties that default.

Set-Off can be viewed in simple terms as netting among different governing agreements. For instance, Empire District Electric may be transacting both electricity and natural gas with the same counterparty under two different governing agreements. Set-Offs allow for amounts owed or received under both agreements to be netted against each other.

On-Going Financial/Credit Strength Monitoring Procedures

The Fuel Accounting Manager shall be responsible for reviewing on an on-going basis the credit rating status of counterparties. In addition, the Fuel Accounting Manager will follow business news reports on counterparties for any potential information that may indicate a change in creditworthiness. The Fuel Accounting Manager will also work in close contact with WEG to stay abreast of any current negative supplemental information gained from direct contact within the energy industry.

If any declining creditworthiness information develops on a counterparty, such as their credit rating is downgraded by Moody's or Standard and Poor's, the Fuel Accounting Manager will notify the RMOC of such development by email.

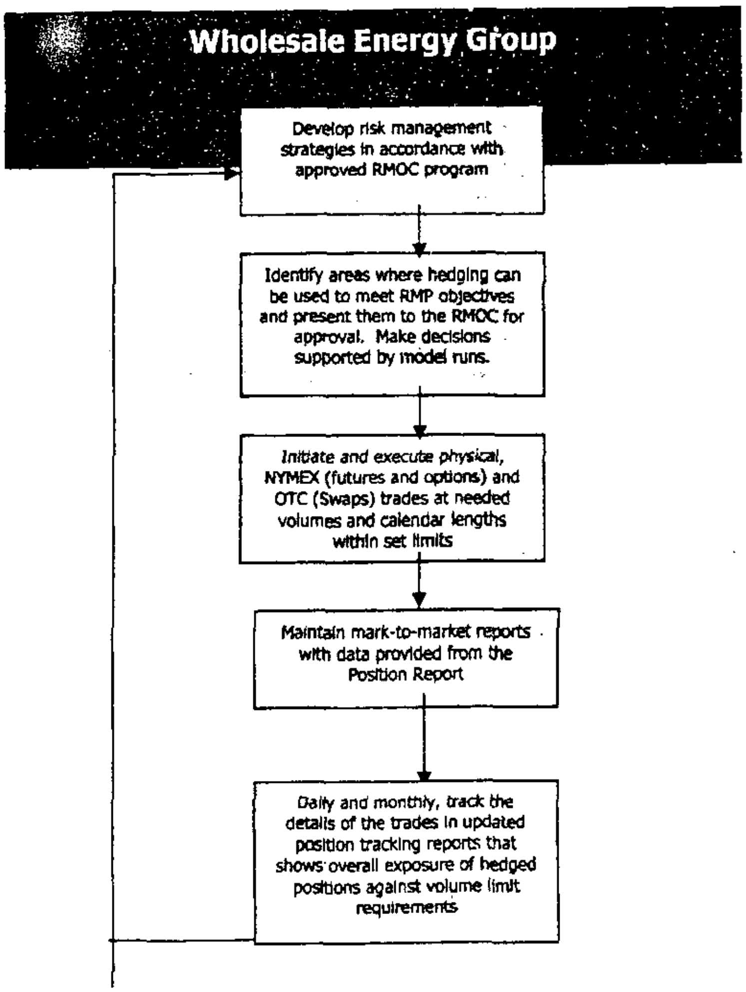
Furthermore, if a counterparty's credit rating is downgraded to below investment grade (Ba by Moody's, BB by Standard and Poor's) or below, the Fuel Accounting Manager will additionally notify the Chief Financial Officer, Controller and Vice-President of Energy Supply by phone of the downgrade. The Fuel Accounting Manager would also notify the Wholesale Energy Group to halt any further trades with this counterparty until further notice. Any member of the RMOC could then call a special meeting of the RMOC for discussion or add this information to the agenda of the next regularly scheduled RMOC meeting.

APPENDIX 2

WHOLESALE ENERGY GROUP

Responsible for analyzing the market and developing appropriate strategies and tactics in line with the RMP.

Responsibilities include the following:



APPENDIX 3

FINANCE

Responsible for the provision of financing Wholesale Energy Group hedge transactions. In addition, Finance will crosscheck hedge positions placed by Wholesale Energy Group in physicals, swaps, futures, and options for accuracy and accordance with EDE's RMP. Accountable for review of account balances for any associated margin requirements with day-to-day activity and also responsible for the following:

Finance

Perform credit analysis, approval, and limit monitoring *(On-going)*

↓

Reconcile daily activity reports from Wholesale Energy Group and daily statements from brokers and banks independent of the Position report

↓

Approve, send, and verify wire transfers in or out of trading accounts

↓

Decide whether or not to put trading funds into interest bearing treasury bills or cash

↓

Review accuracy of monthly account statements from broker pertaining to margin account balances

↓

Alert RMOC when transactions taken exceed the limits and standards of the RMP on any discrepancies from this policy as well as any other irregularity, which could expose EDE to financial or legal liability

↓

Develop and apply accounting policies to financial transactions (compliant with FASB 80 or FASB 133 (as amended by FASB 149) to the extent applicable)

APPENDIX 4

INTERNAL AUDIT

Review documentation as needed to verify the RMP defined limits of EDE hedge transactions and operations and will periodically confirm the internal controls in place are effective in protecting the objectives of EDE's risk management program.

APPENDIX 5

FOR ANY HEDGE TRANSACTION

(Physical, Exchange-Traded or OTC)
**Please reference Appendix 6 for a graphical representation of this process*

DAILY

1. **Monitor Market Prices/Identify Need for a Hedge in line with Hedging Strategy Objectives**

✓ Wholesale Energy Group will monitor prices for opportunities to meet RMP hedge goals and objectives.

2. **Determine Best Strategy within Limits to Achieve Hedging Objective**

✓ Within the RMOC approved limits, Wholesale Energy Group will determine the best hedge strategies to implement in line with objectives.

✓ For any chosen strategies that exceed a specified time period or dollar limit, the Vice President – Energy Supply must verify that the chosen hedge transaction meets objectives.

3. **Confirm Counterparty Meets Credit Requirements**

✓ For an OTC transaction, the prospective counterparty must be crosschecked with the Approved Counterparty Credit List for credit verification.

4. **Implement Transaction**

✓ Wholesale Energy Group prepares internal documentation for current order.

5. **Communicate Order**

✓ Wholesale Energy Group executes a hedge with broker and/or counterpart by picking up the phone and calling in information that is simultaneously recorded via a trading ticket (*reference example in Appendix 7 in next section*) which is date/time stamped and entered into a position tracking report and FUTRAK software.

6. **Broker Documents and Executes Transaction**

✓ In addition, the broker and the NYMEX floor representatives keep their own trading tickets to document the transaction.

7. **Verify Transaction (Verbal and Written)**

✓ Broker and/or counterpart verifies hedge fill via phone initially to Wholesale Energy Group.

✓ Written confirmations will be sent to Wholesale Energy Group and Finance the following business day via e-mail or fax. The confirmation/contract is examined by the WEG Energy Trader for accuracy by crosschecking to the input on the trading ticket. If everything is in agreement, the appropriate WEG representative (as defined in Appendix 12, Trading Authorities) will sign the confirmation/contract and fax back to the counterparty. If there are disagreements, these will be resolved and then the confirmation/contract will be signed and faxed to the counterparty. A copy of the trading ticket is sent to the Fuel Accounting Manager to be matched up with the confirmation/contract.

8. Confirm Accuracy of Transaction

✓ Wholesale Energy Group crosschecks daily broker Account Statement confirmations against internal Position Report for accuracy

✓ Wholesale Energy Group provides mark-to-market reports that tracks the value of the hedge based on current market price.

9. Track Positions

✓ This Wholesale Energy Group Position Report is forwarded to Finance as a check for accuracy on market value and is compared to the broker daily Account Statement report.

10. Reconcile Positions Daily with Broker via Finance

✓ On a daily basis, Finance will determine and verify cash flow receipts and obligations. If EDE is on margin call, funds will be wired to the broker to keep the hedge account equity in line with the current market value.

MONTHLY AND ON-GOING

1. Reconcile Monthly Account Statements

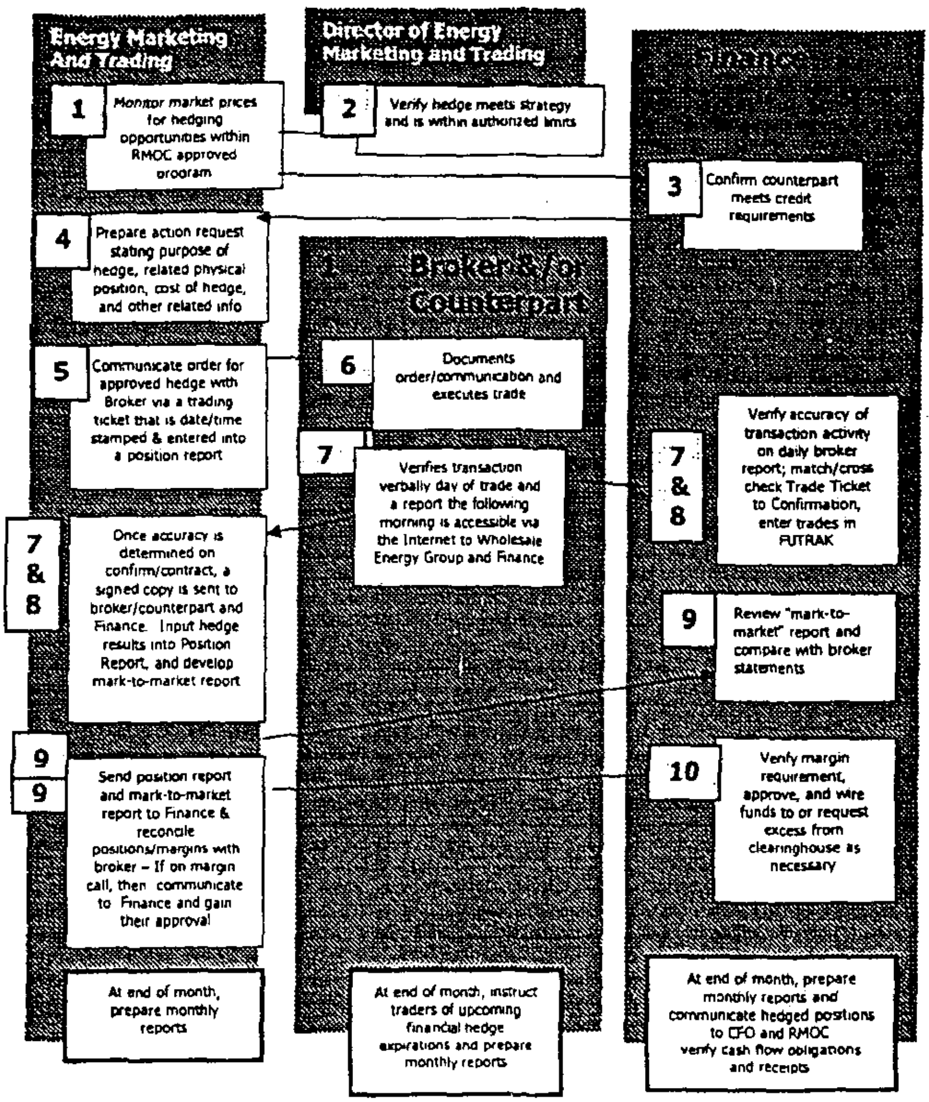
✓ Finance reconciles broker and/or counterpart statements with internal Position Report and FUTRAK software.

2. Review of Transaction/Reporting

✓ On a monthly basis, Wholesale Energy Group will review with the RMOC the strategy and positions taken. On at least a semi-annual basis, the results of the RMP hedge strategy will be reported to the Board of Directors by the RMOC.

APPENDIX 6

PROCEDURAL FLOW FOR HEDGE TRANSACTIONS & RECONCILIATION



Internal Audit will periodically review process to verify accuracy and compliance

APPENDIX 7

TRADE TICKET

The ability to internally track hedge transactions is crucial to providing an audit trail whereby all parties involved in the decision-making process are notified of a hedge position. This notification of a transaction is also the primary document in tracking a hedge and providing information for the Position Report. Included in the document will be the volumes hedged, the price or instrument used, the length of time for the hedge, and the counterpart to the transaction. Internal Trade Transaction Ticket(s) are included on the following pages.

Energy Trade Confirmation Sheet

Trader: Greg
Trade Ticket Number G082203SA
Date 8/22/2003

A
PSE: EDE
Path: EDE/WRI

Sale

HE	MW	$/MWH	$	Cost $/MWH	Cost $
0100			0		0.00
0200			0		0.00
0300			0		0.00
0400			0		0.00
0500			0		0.00
0600			0		0.00
0700			0		0.00
0800			0		0.00
0900			0		0.00
1000			0		0.00
1100			0		0.00
1200			0		0.00
1300			0		0.00
1400			0		0.00
1500			0		0.00
1600			0		0.00
1700	30	75.00	2250	64.73	1,941.90
1800	50	70.00	3500	64.73	3,236.50
1900			0		0.00
2000			0		0.00
2100			0		0.00
2200			0		0.00
2300			0		0.00
2400			0		0.00
02AA					
Totals	80		5,750.00		5,178.40

Comments: Net Margin: 571.60
Sold to Westar.
Avg cost 64.73
Avg revenue 71.88
Deal type:
WSPP
Economy Sale

Fax or Voice Confirmation voice

Margin: 7.15

Source Unit: EC unit 2

Source Unit Cost: $/MWH 64.73

Incentive amount:

Supervisor's initials:

Schedule TWT-8

Empire District Electric Company
Internal Trade Transaction Ticket

Trade G22
Trade Date 9-Sep-
Trade Time 11:50

Buy/Sell	Instrument	Type	Strike Price	Market
Buy	Futures	Normal		NYMEX
			Premium	

Location	Quality	Delivery Start Date	Exercise
Henry Hub	Firm	01-Jul-05	
		Delivery End Date	Settlement Date
		31-Aug-05	01-Jul-05
			01-Aug-05

Price Type: Fixed

Price Differential /
4.58 Jul-05
4.58 Aug-05

Volumetric Quantity
Rate
Total Qty 200,000 Jul-05
200,000 Aug-05

Transmission/Transport Charges

Scheduling

Counter Party: NYMEX

Mark-to-Market: Henry Hub

Broker Commission

General

Energy Trader: Greg

Energy Trader's ________

Transaction Objective Based on Empire's Risk Management Policy

Purchased gas futures to financially lock in a portion of Calendar 2005 gas

Middle Office - Risk Management ______ Doug Gallemore

Back Office - Accounting ______ Doug Gallemore

Back Office - Tax Accounting ______ Jay Williams

This Transaction complies with:
Ordinary Property Obligations
(IRC Section 1221

Identification
(Treas. Regs. Section 1.1221-2(e))

Distribution:
Energy Trading
Risk Management
Tax Accounting
Treasury

CONFIRMATION PROCEDURE

Exchange Traded Confirmations

Wholesale Energy Group will verbally confirm every transaction with broker and/or counterpart on the trade date. Trade confirmations on the daily open position statements will be sent by the broker (on the following business day) to Wholesale Energy Group and Finance. Wholesale Energy Group must check for accuracy on the following business day, input updates into the position report, maintain a mark-to-market report, and forward said report to Finance. Finance is responsible for verifying the confirmation against the transacting records and entering the transaction into FUTRAK.

Physical and OTC Financial Confirmations

Wholesale Energy Group must verbally confirm every transaction with the broker/counterpart on the trade date. For physical and financially settled OTC transactions, written or email confirmations of the applicable business terms and conditions will be completed by Wholesale Energy Group and forwarded to Finance by the end of the second business day following the trade day. Finance is responsible for verifying the confirmation against the transacting records.

The following procedures will be adhered to at all times:

- The trader will review a copy of the confirmation for completeness and initial the confirmation.
- The trader will enter the trade into the Position Report. The Fuel Accounting Manager will enter the trade into FUTRAK.
- Confirmations will be completed, signed, and sent to the counterpart by WEG within two business days.
- Original trade tickets and confirmations will be kept by Finance until after the transaction has settled. Once the transactions have settled, the confirmations and tickets will be maintained.

APPENDIX 9

POSITION REPORT

EXAMPLE

The Empire District Electric Company

Gas Position Summary as of October 6, 2003

	November 2003	December 2003	Nov-Dec 2003	Year 2004 60% min	Year 2005 40% min	Year 2006 20% min	Year 2007 10% min	Net All Years
Budget DTh	394,656	882,590	1,277,246	10,492,844	11,261,182	12,232,134	12,884,706	48,148,111
Expected DTh	510,900	877,800	1,388,700	10,492,844	11,261,182	12,232,134	12,884,705	48,259,565
Policy minimum hedged DTh (2)	408,720	702,240	1,110,960	6,295,706	4,504,473	2,446,427	0	14,357,566
Policy maximum hedged DTh	510,900	877,800	1,388,700	8,394,275	6,756,709	4,892,854	2,576,941	24,009,479
Amount Hedged from Upside Volatility	395,000	675,000	1,070,000	6,620,000	3,800,000	1,300,000	600,000	13,390,000
percentage	77%	77%	77%	63%	34%	11%	5%	28%
Amount Hedged from Downside Volatility	395,000	675,000	1,070,000	6,620,000	3,800,000	1,300,000	600,000	13,390,000
percentage	77%	77%	77%	63%	34%	11%	5%	28%
Bookout per physical Dth, all positions	-3.659	-4.716	-4.188	-10.091	3.949	3.988	4.203	1.870
Average Cost per Dth hedged	2.288	3.388	2.981	3.312	4.119	4.188	4.203	3.613
Net All Positions Market to Market $ (1)	818,435	950,095	1,768,530	8,844,225	1,478,350	211,600	45,600	12,348,305
PHYSICAL HEDGES								
Purchased Dth	100,000	100,000	200,000	600,000	2,400,000	1,000,000	600,000	4,800,000
Purchased $	325,500	325,500	651,000	2,256,000	9,636,000	4,050,000	2,521,500	19,114,500
Purchased $/DTh	3.255	3.255	3.255	3.760	4.015	4.050	4.203	3.982
Market $	452,500	478,500	931,000	2,789,475	10,955,400	4,199,500	2,567,100	21,442,475
Market $/Dth (on Williams Pipeline)	4.525	4.785	4.655	4.649	4.565	4.200	4.279	4.467
Gain/(Loss) versus current market	127,000	153,000	280,000	533,475	1,319,400	149,500	45,600	2,327,975
FINANCIAL HEDGES								
Swap/Futures Dth Purchased	375,000	375,000	750,000	6,300,000	1,400,000	300,000	0	8,750,000
Net Cost, $/Dth	3.093	3.093	3.093	3.307	4.298	4.648	0.000	
Market $/Dth (at Henry Hub or Swap	4.396	4.652	4.524	4.652	4.411	4.855	0.000	
Swap Settlement - Receipt / (Payment)	488,475	584,575		8,474,550	158,950	62,100	-	9,768,650
Swap/Futures Dth Sold or Settle	280,000	0	280,000	280,000	0	0	0	560,000
Net Cost, $/Dth	4.935	0.000	4.935	4.150	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap	4.767	0.000	4.767	4.735	0.000	0.000	0.000	
Swap Settlement - Receipt / (Payment)	47,040	-	47,040	(163,800)	-	-	-	(116,760)
Call Dth (Buy a Call)	0	0	0	0	0	0	0	0
Call Strike $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Cost of Call $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Value $ of Call Position	-	-	-	-	-	-	-	0
(Cost) $ of Call Position	-	-	-	-	-	-	-	0
Collar Dth	200,000	200,000	400,000	-	-	-	-	400,000
Floor $/Dth	3.350	3.350	3.350	0.000	0.000	0.000	0.000	
Ceiling $/Dth	4.000	4.000	4.000	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap	4.767	5.034	4.901	0.000	0.000	0.000	0.000	
Cost of Floor $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Value of Ceiling $/Dth	0.780	1.063	0.921	0.000	0.000	0.000	0.000	
(Cost) / Value $ of Collar Position	155,920	212,520	368,440	-	-	-	-	368,440
Put Dth (Sell a Put)	0	0	0	0	0	0	0	0
Put Strike $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Revenue from Put $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Value $ of Put Position	-	-	-	-	-	-	-	0
(Cost) $ of Put Position	-	-	-	-	-	-	-	0

Note 1: Market data using NYMEX Close Prices as of October 3, 2003.

Note 2: Policy minimums and maximums are 12/31/2003 targets

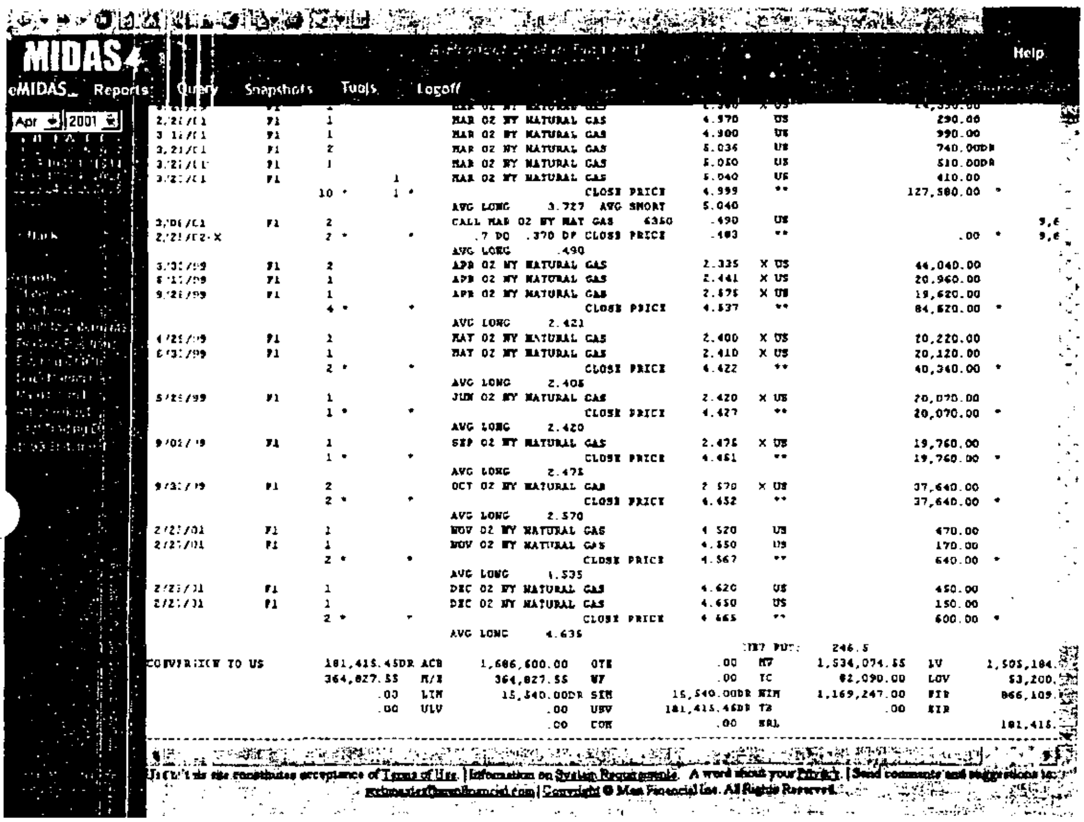
APPENDIX 10

MARK-TO-MARKET REPORTING

As mentioned previously, all positions will be "mark-to-market" (using the appropriate NYMEX prices as defined by the underlying contract) weekly. This analysis is performed by Wholesale Energy Group to appropriately reflect the current value and cash flows associated with open positions and to provide timely information regarding EDE market risk and exposure. Wholesale Energy Group is responsible for verifying the validity and accuracy of the market data used in mark-to-market calculations through the position report on a weekly basis. All positions will be "marked-to-market" (using the appropriate NYMEX prices as defined by the underlying contract) at the end of each month using FUTRAK accounting software by the Fuel Accounting Manager. The resulting entries will then be recorded in EDE's general ledger.

DAILY BROKER ACCOUNT STATEMENT

The RMI Account Statement shown below is an illustration of the daily report that Wholesale Energy Group and Finance can access on the Internet daily to confirm the previous day's trading activities:



2/27/01	F1	1		MAR 02 NY NATURAL GAS	4.970	US	290.00	
3/12/01	F1	1		MAR 02 NY NATURAL GAS	4.900	US	990.00	
3/21/01	F1	2		MAR 02 NY NATURAL GAS	5.036	US	740.00DR	
3/27/01	F1	1		MAR 02 NY NATURAL GAS	5.050	US	510.00DR	
3/27/01	F1		1	MAR 02 NY NATURAL GAS	5.040	US	410.00	
		10 *	1 *	CLOSE PRICE	4.999	**	127,580.00 *	
				AVG LONG 3.727 AVG SHORT	5.040			
3/06/01	F1	2		CALL MAR 02 NY NAT GAS 6350	.490	US		9,6
2/27/02-X		2 *	*	.7 DO .370 DP CLOSE PRICE	.483	**	.00 *	9,6
				AVG LONG .490				
3/31/99	F1	2		APR 02 NY NATURAL GAS	2.335	X US	44,040.00	
6/17/99	F1	1		APR 02 NY NATURAL GAS	2.441	X US	20,960.00	
9/21/99	F1	1		APR 02 NY NATURAL GAS	2.575	X US	19,620.00	
		4 *	*	CLOSE PRICE	4.537	**	84,620.00 *	
				AVG LONG 2.421				
4/21/99	F1	1		MAY 02 NY NATURAL GAS	2.400	X US	20,220.00	
6/31/99	F1	1		MAY 02 NY NATURAL GAS	2.410	X US	20,120.00	
		2 *	*	CLOSE PRICE	4.422	**	40,340.00 *	
				AVG LONG 2.405				
5/25/99	F1	1		JUN 02 NY NATURAL GAS	2.420	X US	20,070.00	
		1 *	*	CLOSE PRICE	4.427	**	20,070.00 *	
				AVG LONG 2.420				
9/01/99	F1	1		SEP 02 NY NATURAL GAS	2.475	X US	19,760.00	
		1 *	*	CLOSE PRICE	4.461	**	19,760.00 *	
				AVG LONG 2.475				
9/31/99	F1	2		OCT 02 NY NATURAL GAS	2.570	X US	37,640.00	
		2 *	*	CLOSE PRICE	4.452	**	37,640.00 *	
				AVG LONG 2.570				
2/27/01	F1	1		NOV 02 NY NATURAL GAS	4.520	US	470.00	
2/27/01	F1	1		NOV 02 NY NATURAL GAS	4.550	US	170.00	
		2 *	*	CLOSE PRICE	4.567	**	640.00 *	
				AVG LONG 4.535				
2/27/01	F1	1		DEC 02 NY NATURAL GAS	4.620	US	450.00	
2/27/01	F1	1		DEC 02 NY NATURAL GAS	4.650	US	150.00	
		2 *	*	CLOSE PRICE	4.665	**	600.00 *	
				AVG LONG 4.635				

						NET PUT:	246.5			
CONVERSION TO US	181,415.45DR	ACB	1,686,600.00	OTE	.00	MV	1,534,074.55	LV	1,505,184.	
	364,827.55	M/E	364,827.55	NF	.00	TC	82,090.00	LOV	53,200.	
	.00	LIN	15,540.00DR	SIN	15,540.00DR	NIN	1,169,247.00	FIR	866,109.	
	.00	ULV	.00	USV	181,415.46DR	TB	.00	EIR		
			.00	CON	.00	BAL			181,415.	

APPENDIX 12

TRADING AUTHORIZATION

	Physical Power Purchases and Sales	Other Physical and Financial Transactions
Rick McCord	Up to $5 million	Up to $5 million
Brian Berkstresser	Up to $5 million	*Up to $5 million
Katie Barton	Next 7 days and up to $1 million	*Next 7 days and up to $1 million
Greg Sweet	Next 7 days and up to $1 million	*Next 7 days and up to $1 million
Jay Haralson	Next 7 days and up to $1 million	*Next 7 days and up to $1 million
Matthew Howard	Next 7 days and up to $1 million	*Next 7 days and up to $1 million
Michael Kidwell	Next 7 days and up to $1 million	*Next 7 days and up to $1 million
Tim Wilson	Next 7 days and up to $1 million	*Next 7 days and up to $1 million
Kristy Tackett	Next 7 days and up to $1 million	*Next 7 day s and up to $1 million
Brad Beecher	Up to $10 million	Up to $10 Million
John Deffenbaugh	Next 3 days	None
Jim Graham	Next 3 days	None
Denny Fales	Next 3 days	None
Kenny Myers	Next 3 days	None
Todd Murray	Next 3 days	None
Don Kimrey	Next 3 days	None

*Denotes only physical transactions trading authorization

- The persons listed above are authorized only to engage in the types of transactions specifically approved by the RMOC and the Energy Risk Management Policy.

- Although system dispatchers should do whatever is necessary to ensure system reliability, they should immediately notify the Director of System Operations or a Senior Officer in the event they enter into a single transaction exceeding $250,000 in a calendar day

- Transactions greater than $5 million must be pre-approved by at least two-thirds (2/3) of the Senior Officers appointed to the RMOC by completing a Wholesale Energy Group Purchase and/or Sale Pre-Approval Form (see attached). If 2/3 of the Senior Officers appointed to the RMOC are not available, the President and CEO will pre-approve in their place.

- In Rick McCord's absence, any single VP on the RMOC can approve any transaction up to $5 million.

- Transactions beyond the limits set forth above require the completion of a Pre-Approval Form (see APPENDIX 13) prior to the execution of the sale and/or purchase.

- In the event a market opportunity arises and no other approved trader is available, the VP-Energy Supply has the authority to execute the trade. In this situation, if the trade is less than $5 million, one additional Senior Officer appointed to the RMOC must approve the trade. If the trade is greater than $5 million, then the two additional Senior Officers appointed to the RMOC or the President and CEO must pre-approve the trade as defined in Appendix 13 of this policy.

Wholesale Energy Group
Purchase and/or Sale Pre-Approval Form

This form is to convey pre-approval of the Officers or RMOC for purchases and/or sales that are beyond the approval limits of the members of the Wholesale Energy Group as set forth in *Appendix 12 - Trading Authorization* of the Energy Risk Management Policy.

	(circle one)	(circle one)
Approval for:	Purchase	Nat Gas
	Sale	Power

Quantity
Minimum ______________
Maximum ______________

Price
Minimum ______________
Maximum ______________

Timeframe
Months ______________
Years ______________

Total $ Value
Minimum $ -
Maximum $ -

Other Comments:

Approval is valid until:
Filled ______________
Date ______________

Signatures

Name:	Name:
Title:	Title:
Date:	Date:

Schedule TWT-9

On-System F&PP Summary
2006 MO Rate Case Run

	GWH	CF	F &PP Cost ($000) Incl Start	$/MWH		Starts	Hours	GBTU	Avg HR	
Asbury 1	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Asbury 2	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Total Asbury	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Iatan	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Riverton 7	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Riverton 8	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Riverton 9	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Riverton 10	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Riverton 11	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Total Riverton	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Energy Center 1	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Energy Center 2	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Energy Center 3	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Energy Center 4	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Total EC	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
State Line 1	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
State Line CC	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
tal SL	*-------*	-------*	*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Gas Turbines	*-------*		*-------*	*-------*		*-------*	*-------*	*-------*	*-------*	
Total Thermal	*-------*		*-------*	*-------*				*-------*	*-------*	
Ozark Beach	*-------*	-------*								
Total EDE (less fixed)	*-------*		*-------*	*-------*						
WR-JP	*-------*	-------*	*-------*	*-------*						
Spot Purch	*-------*		*-------*	*-------*					*-------*	*-------*
Total Purch less Wind	*-------*		*-------*	*-------*	-----*	*-------*				
								-------	*-------*	*-------*
Wind Energy	*-------*	-------*	*-------*	*-------*	-----*	*-------*	*-------*	*-------*	*-------*	*-------*
									-------	*-------*
Total Model	*-------*	-------*	*-------*	*-------*						
								-------	*-------*	
Purch Power Demand Charge			*-------*					*-------*	*-------*	
								-------	*-------*	
Undist-Oth-Train			*-------*					*-------*	*-------*	*-------*
Gas Fixed FT			*-------*							
Gas Dmd Commodity Chg			*-------*							
Gas Dmd Losses Chg			*-------*	*-------*	-----*					
Total Gas DMD			*-------*							
;al FPP NSI	*-------*		162,888.20	*-------*						

--

NP

Thermal Unit Model Inputs

	Rated Capacity (MW)	Modeld Max Capacity (MW)	Modeld Min Capacity (MW)	Heat Rate Curve Capacity (MW)	Heat Rate Curve Heat Rate (Btu/kWh)	Ramp Rate (MW/hr)	Normalized Outage (Days)	Forced Outage Rate (%)	Mean Repair Time (Hours)	Min Down Time (Hours)	Min Up Time (Hours)	Fuel Ratio (MMBtu)	Start Fuel (MMBtu)	Start Cost ($)	Variable O&M ($/MWh)
Asbury 1	193	183	105	110 140 162 188 191	11485 11230 11135 11180 11210	90	30	7%	60	90		75% / 25%	1200 (oil)	2500	0.60
Asbury 2	17	16	4	4 20	18300 18200	8	30	20%	60	60		75% / 25%	0	0	5.00
Iatan	80	80	40	70 80	10100 10025		30	8%	60	60		100%	1200 (oil)	2500	0.60
Riverton 7	38	23	20	20 27 38	12700 12500 17000	40	25	6%	48	90		71% / 29%	600 (gas)	1000	1.00
Riverton 8	54	45	32	30 46 54	12080 11980 21610		25	6%	72	90		71% / 29%	600 (gas)	1000	1.00
Riverton 9	12	12	4	4 12	18500 17500	6	16	10%	60	24	8		50 (gas)	1500	3.75
Riverton 10	16	16	6	6 16	18500 17500	8	16	10%	60	24	8		50 (gas)	1500	3.75
Riverton 11	16	16	10	10 16	18500 18000	8	16	10%	60	24	8		50 (gas)	1500	3.75
Energy Center 1	86	76	30	30 50 70 85 90	17850 15800 14750 14200 14000	60	25	10%	72	24	12		150 (gas)	5000	3.00
Energy Center 2	85	75	30	30 50 70 85 90	17850 15800 14750 14200 14000	60	25	10%	72	24	12		150 (gas)	5000	3.00
Energy Center 3	50	50	25	25 38 50	12400 11200 10600	40	16	10%	60	2	2		0	300	3.00
Energy Center 4	50	50	25	25 38 50	12400 11200 10600	40	16	10%	60	2	2		0	300	3.00
State Line 1	89	86	80	60 85	14750 13425	60	25	10%	120	24	24		150 (gas)	5000	3.00
SLCC 1x1	250	250	150	150 175 200 225 250	8000 7700 7400 7100 6850	90	30	7%	72	36	48		300 (gas)	13,000	3.50
SLCC 2x1	500	50	10	10 20 30 40 50	7600 7250 6900 6750 6850	20	30	14%	72	36	72		300 (gas)	2500	3.00

Schedule TWT-11

THE EMPIRE DISTRICT ELECTRIC COMPANY - SCHEDULED OUTAGES FOR THERMAL UNITS

	2000	2001	2002	2003	2004	Average Hours	Average Days	GADS 1998 -2002 Days	Modeled Days
Asbury 1	808.3	2356.9	564.6	658.5	654.1	1008	42	30	**30**
Asbury 2	808.3	2356.9	654.6	658.5	449.4	986	41	30	**30**
Iatan	59.8	462.9	1897.9	826.1	223.6	694	29	32	**30**
Riverton 7	1445.8	153.7	219.1	288.1	587.8	539	22	34	**25**
Riverton 8	855.0	379.3	422.0	1084.1	567.0	661	28	34	**25**
Riverton 9	401.5	0.0	0.0	288.1	0.0	138	6	18	**16**
Riverton 10	3912.4	2.5	267.9	0.0	9.0	838	35	18	**16**
Riverton 11	149.2	2.5	2296.8	0.0	9.0	491	20	18	**16**
Energy Center 1	365.8	798.8	3546.5	35.7	848.3	1119	47	25	**25**
Energy Center 2	109.7	199.7	1090.7	55.4	439.9	379	16	25	**25**
Energy Center 3	NIS	NIS	NIS	0.0	0.0	0	0	25	**16**
Energy Center 4	NIS	NIS	NIS	0.0	0.0	0	0	25	**16**
State Line 1	460.8	616.9	925.4	116.6	422.4	508	21	25	**25**
SLCC	NIS	735.6	1473.5	798.7	387.0	849	35	28	**30**
JEC 1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32	**30**
JEC 2	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32	**30**
JEC 3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	32	**30**

NIS - NOT IN SERVICE

Normalized Outage Schedule
The Empire District Electric Company

Month	Week	Date
Jan-06	1	1
	2	8
	3	15
	4	22
	5	29
Feb-06	6	5
	7	12
	8	19
	9	26
Mar-06	10	5
	11	12
	12	19
	13	26
Apr-06	14	2
	15	9
	16	16
	17	23
May-06	18	30
	19	7
	20	14
	21	21
	22	28
Jun-06	23	4
	24	11
	25	18
	26	25
Jul-06	27	2
	28	9
	29	16
	30	23
Aug-06	31	30
	32	6
	33	13
	34	20
	35	27
Sep-06	36	3
	37	10
	38	17
	39	24
Oct-06	40	31
	41	8
	42	15
	43	22
	44	29
Nov-06	45	5
	46	12
	47	19
	48	26
Dec-06	49	3
	50	10
	51	17
	52	24
	53	31

Unit	Days	Outage
Asbury	30	30 Mar 15-Apr 13
Iatan 1	30	30 Feb 15-Mar 16
Riverton 7	25	25 Mar 29-Apr 22
Riverton 8	25	25 Apr 26-May 20
Riverton 9	16	16 Mar 15-30
Riverton 10	16	16 Apr 19-May 4
Riverton 11	16	16 Sep 20-Oct 5
Energy Center 1	25	25 Mar 8- Apr 1
Energy Center 2	25	25 Apr 5-29
Energy Center 3	16	16 May 3-18
Energy Center 4	16	16 Oct 4-19
State Line 1	25	25 Oct 25-Nov 18
SLCC	30	30 Oct 11-Nov 9
WRI JEC 1	30	30 Mar 15-Apr 13
WRI JEC 2	30	30 Apr 19-May 18
WRI JEC 3	30	30 Sep 27-Oct 26

OZARK BEACH GROSS* GENERATION HISTORY

	YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	Total	Capacity Factor
1	1975	8,266	8,548	7,608	6,938	8,455	5,139	5,899	6,233	2,635	3,029	2,322	4,154	69,226	49.4%
2	1976	4,184	2,492	2,819	6,771	8,599	6,033	8,651	4,987	2,843	3,398	6,338	6,407	63,522	45.2%
3	1977	8,481	3,139	3,265	1,661	700	2,811	3,334	1,784	4,330	4,576	6,338	6,677	47,096	33.6%
4	1978	6,309	5,939	6,177	8,495	9,359	8,385	7,473	3,800	5,270	5,959	4,413	2,927	74,506	53.2%
5	1979	5,591	3,494	7,601	6,534	3,450	850	2,095	6,284	7,179	2,865	4,702	5,988	56,633	40.4%
6	1980	2,494	3,581	6,119	4,997	5,132	7,752	8,203	5,522	3,279	1,163	3,208	1,391	52,841	37.6%
7	1981	1,530	2,182	2,046	803	1,382	2,137	2,625	2,537	1,772	1,306	2,372	3,238	23,930	17.1%
8	1982	7,881	8,784	9,468	4,486	1,695	7,036	4,775	3,950	2,759	2,912	4,459	4,770	62,975	44.9%
9	1983	1,215	8,097	9,186	9,066	7,463	4,227	7,933	7,644	3,324	1,234	4,512	9,159	73,060	52.1%
10	1984	2,689	3,187	8,764	9,338	7,725	5,286	4,203	6,326	2,720	4,402	5,816	5,065	65,521	46.6%
11	1985	352	3,270	5,781	2,831	840	516	903	2,450	5,504	4,765	5,938	8,081	41,231	29.4%
12	1986	7,537	6,842	8,644	9,923	8,226	5,732	7,756	5,463	5,126	5,484	8,602	6,143	85,478	61.0%
13	1987	2,114	5,969	11,330	10,469	6,860	3,422	3,902	3,296	2,379	1,471	6,061	10,255	67,528	48.2%
14	1988	10,605	9,533	11,647	9,268	6,440	4,306	3,283	7,010	4,375	3,429	3,360	3,847	77,103	54.9%
15	1989	4,860	7,443	7,671	8,439	6,325	6,409	4,499	4,824	3,226	5,909	3,219	1,049	63,873	45.6%
16	1990	1,526	8,451	10,173	8,770	2,966	-13	464	3,240	7,540	5,292	2,372	8,991	59,772	42.6%
17	1991	10,249	9,226	7,348	9,338	6,189	2,852	3,979	5,252	3,389	5,199	8,201	8,889	80,111	57.2%
18	1992	6,810	7,576	6,541	3,675	1,876	7,335	5,124	5,684	6,968	8,527	6,676	11,079	77,871	55.4%
19	1993	9,701	9,900	11,285	10,841	9,000	10,060	10,832	7,029	5,459	6,415	6,903	5,483	102,908	73.4%
20	1994	9,680	9,062	10,772	9,834	3,836	2,727	6,008	9,355	5,060	2,690	6,958	7,801	83,783	59.8%
21	1995*	9,981	9,716	10,582	8,692	7,149	4,545	2,743	6,208	4,834	2,934	3,077	841	71,302	50.9%
22	1996*	2,717	4,822	3,636	3,450	6,212	2,952	2,666	6,329	5,076	6,706	9,089	9,205	62,860	44.7%
23	1997*	10,149	7,255	10,246	9,531	4,351	2,856	8,387	6,731	5,869	6,031	3,406	2,766	77,578	55.3%
24	1998*	8,187	9,626	10,524	6,874	4,895	6,166	6,980	8,171	4,909	2,049	1,407	91	69,879	49.9%
25	1999*	4,032	7,854	11,966	10,694	7,729	8,210	10,769	9,442	4,815	3,489	1,928	5,427	86,355	61.6%
26	2000*	4,584	2,221	761	423	574	3,511	10,858	11,824	3,894	1,182	4,586	6,732	51,150	36.4%
27	2001*	4,372	6,707	7,578	3,024	1,486	2,520	7,267	7,001	1,788	3,174	3,932	4,861	53,710	38.3%
28	2002*	4,811	7,455	7,630	5,910	1,415	0	171	1,050	4,212	3,624	5,518	3,789	45,585	32.4%
29	2003*	6,274	5,554	4,879	2,640	4,802	4,302	7,962	9,149	3,443	2,466	2,970	3,739	58,180	41.5%
30	2004*	5,265	2,614	6,718	7,626	3,076	2,097	8,236	7,099	3,226	2,133	6,174	8,772	63,036	45.0%
	30 year Average	5,748	6,351	7,626	6,711	4,940	4,339	5,599	5,856	4,240	3,794	4,829	5,587	65,620	46.8%

*Net Generation values are presented starting in 1995.

THE EMPIRE DISTRICT ELECTRIC COMPANY
HISTORICAL UNDISTRIBUTED AND OTHER COSTS

	2000	2001	2002	2003	2004	5-YR AVERAGE
Asbury	606,120.01	585,054.74	613,783.51	569,227.05	662,735.60	607,384.18
Riverton 7 & 8	120,557.31	132,242.09	126,809.25	133,382.32	185,705.99	139,739.39
Iatan	699,058.12	788,642.06	798,278.48	497,808.64	228,060.83	602,369.63
Total Coal	1,425,735.44	1,505,938.89	1,538,871.24	1,200,418.01	1,076,502.42	1,349,493.20
SLCC	-	2,195,355.86	8,240.35	869,744.44	18,108.04	618,289.74
Riverton CT's	-	-	-	27,332.21	1,145.22	5,695.49
State Line 1 & 2	(61.80)	201.33	1,027.26	53,272.99	1,004.05	11,088.77
Energy Center CT's	(17.40)	398.42	881.13	59,300.54	1,923.67	12,497.27
Total Gas	(79.20)	2,195,955.61	10,148.74	1,009,650.18	22,180.98	647,571.26
Total	1,425,656.24	3,701,894.50	1,549,019.98	2,210,068.19	1,098,683.40	1,997,064.46
Adjustments						
Enron (Gas)				(1,000,000.00)		
SLCC Test Fuel (Gas)		(2,195,103.51)				
Adjusted Total	**1,425,656.24**	**1,506,790.99**	**1,549,019.98**	**1,210,068.19**	**1,098,683.40**	**1,358,043.76**

Total **1,454,343.76**

NP