

Exhibit No.: **KCP&L-10(NP)**
Issue: Fuel Prices, Fuel Hedging,
Fuel Related Commodities, Future
Fuel and Fuel Related Commodities,
Inventory, and Emission Allowances
including SO2
Witness: Wm Edward Blunk
Type of Exhibit: Direct Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No.: ER-2010-____
Date Testimony Prepared: June 4, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2010-____

DIRECT TESTIMONY

OF

WM. EDWARD BLUNK

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

**Kansas City, Missouri
June 2010**

***** [REDACTED] *** Designates "Highly Confidential" Information
Has Been Removed.
Certain Schedules Attached To This Testimony Designated "(HC)"
Have Been Removed
Pursuant To 4 CSR 240-2.135.**

Zobrist Exhibit No. 10-NP
Date 1/31/11 Reporter NS
File No. ER-2010-0355

TABLE OF CONTENTS

I.	CHANGES IN FUEL MARKETS and FUEL COSTS	2
A.	Energy Commodities (Coal and Natural Gas)	3
B.	Rail Rates	6
II.	HEDGING FUEL MARKET RISK	9
A.	Natural Gas Price Hedging	9
B.	Coal Price Hedging	11
III.	FUEL IN COST OF SERVICE	13
A.	Fuel Price Forecast.....	13
B.	Fuel Adders and Fuel Additives	16
IV.	FUTURE FUEL AND RELATED COMMODITIES	23
A.	Fuel Price Forecast.....	23
B.	Fuel Adders and Fuel Additives	24
C.	Rate Volatility Mitigation Features	25
D.	Emission Allowance Purchases and Sales	25
V.	FUEL INVENTORY	26
VI.	SO ₂ EMISSION ALLOWANCE MANAGEMENT PROGRAM	35

DIRECT TESTIMONY

OF

WM. EDWARD BLUNK

Case No. ER-2010-_____

1 **Q: Please state your name and business address.**

2 A: My name is Wm. Edward Blunk. My business address is 1200 Main Street, Kansas City,
3 Missouri 64105.

4 **Q: By whom and in what capacity are you employed?**

5 A: I am employed by Kansas City Power & Light Company ("KCP&L" or the "Company")
6 as Supply Planning Manager.

7 **Q: What are your responsibilities?**

8 A: My primary responsibilities are to facilitate the development and implementation of fuel
9 purchase and risk management strategies.

10 **Q: Please describe your education, experience and employment history.**

11 A: In 1978, I was awarded the degree of Bachelor of Science in Agriculture Cum Laude,
12 Honors Scholar in Agricultural Economics by the University of Missouri at Columbia.
13 The University of Missouri awarded the Master of Business Administration degree to me
14 in 1980. I have also completed additional graduate courses in forecasting theory and
15 applications.

16 Before graduating from the University of Missouri, I joined the John Deere
17 Company in 1977 and through 1981 performed various marketing, marketing research,
18 and dealer management tasks. In 1981, I joined KCP&L as Transportation/Special

1 Projects Analyst. My responsibilities included fuel price forecasting, fuel planning and
2 other analyses relevant to negotiation and/or litigation with railroads and coal companies.
3 I was promoted to the position of Supervisor, Fuel Planning in 1984. In 2007, my
4 position was upgraded to Manager, Fuel Planning. In 2009 my position was changed to
5 Supply Planning Manager.

6 **Q: Have you previously testified in a proceeding at the Missouri Public Service
7 Commission or before any other utility regulatory agency?**

8 A: I have previously testified before both the Missouri Public Service Commission
9 (“MPSC”) and the Kansas Corporation Commission (“KCC”) in multiple cases on
10 multiple issues regarding KCP&L’s fuel prices, fuel price forecasts, strategies for
11 managing fuel price risk, fuel-related costs, fuel inventory, and the management of
12 KCP&L’s SO₂ emission allowance inventory.

13 **Q: On what subjects will you be testifying?**

14 A: I will be testifying on changes in the fuel markets, fuel and fuel-related costs, fuel
15 inventory, and KCP&L’s SO₂ Emission Allowance Management Program. I will explain
16 how KCP&L forecasts the fuel prices and fuel related costs used in the Cost of Service
17 (“COS”). I will also discuss KCP&L’s expectations regarding new rail transportation
18 arrangements that will take effect between now and the time rates established by this
19 proceeding will be effective.

20 **I. CHANGES IN FUEL MARKETS and FUEL COSTS**

21 **Q: What is the purpose of this portion of your testimony?**

22 A: The purpose of this portion of my testimony is to discuss historical changes in coal and
23 natural gas fuel markets and the impact of those changes on KCP&L’s COS.

1 **Q: How do changes in fuel markets affect KCP&L's COS?**

2 A: Changes in fuel markets affect KCP&L's COS in multiple ways. The first and most
3 obvious impact is the effect of changes in fuel prices and their direct effect on fuel
4 expense. Changes in fuel prices also affect off-system sales prices. KCP&L witness
5 Michael M. Schnitzer discusses the impact of gas price uncertainty on off-system sales in
6 his direct testimony.

7 **A. Energy Commodities**

8 **Q: How have fuel prices changed since the Regulatory Plan Stipulation and Agreement**
9 **was approved by the Commission in Case No. EO-2005-0329?**

10 A: Schedule WEB2010-1 shows how fuel prices have changed dramatically over the past
11 few years. While much attention has been focused on oil's dramatic rise, natural gas and
12 coal have also been demonstrating significant price movement. Natural gas in December
13 2004 was about \$6.83/MMBtu. In December 2005 it reached a peak of \$15.38 then
14 dropped to \$4.20 in September 2006. Those moves represented a climb of 125%
15 followed by a decline of 73%. By July 2008 natural gas had returned to \$13.58 but then
16 dropped 82% to \$2.51, a price level it had not seen since March 2002. By the end of
17 March 2010 natural gas was trading near \$4.00.

18 Coal has generally followed a pattern similar to natural gas until earlier this year.
19 From December 2004 to December 2005 the mine price for Powder River Basin ("PRB")
20 coal increased 258% from \$0.34/MMBtu to \$1.23/MMBtu. By January 2007 it dropped
21 72% to \$0.34. Over the next 13 months it climbed 192% before dropping 55% to \$0.44
22 in September 2009. By the end of March 2010 it had returned to about \$0.71 which
23 represents another 60% run up.

1 Q: What changes have you seen in gas price basis differentials over this time period?

2 A: Basis differentials are the difference between one pricing point and another. Since Henry
3 Hub is the most liquid natural gas point, basis differentials are often in comparison to it.
4 Natural gas basis differentials from Henry Hub to Mid-Continent for 2005 and 2006
5 averaged about minus \$1.25/MMBtu. It tightened to minus \$0.80 in 2007, then more
6 than doubled to minus \$1.80 in 2008 before retracting to minus \$0.70 in 2009. Now we
7 are expecting basis for 2010 to be about minus \$0.20-0.25. This reduction in basis has
8 been primarily driven by three factors.

9 The foreseen factor was construction of the Rockies Express Pipeline ("REX").
10 REX is a 1,679 mile long natural gas pipeline system from the Rocky Mountains,
11 Colorado to eastern Ohio. REX began service to Missouri in May 2008. That combined
12 with high natural gas prices in summer 2008 stretched the Mid-Continent basis to its
13 widest sustained spread. The basis narrowed as the price of natural gas declined from
14 \$13 to \$4/MMBtu. In November 2009, REX extended its service to eastern Ohio and the
15 Rocky Mountain gas that was depressing our regional price started moving farther east.

16 At the same time REX was under construction, the Marcellus Shale field in the
17 Appalachians began producing natural gas. That put significant downward pressure on
18 eastern gas prices.

19 The third factor which is squeezing Mid-Continent basis is the overall lower price
20 of natural gas which is a function of lower demand due to the decline in the economy and
21 increased production from shale.

1 **Q: How has shale changed the fundamental outlook for natural gas?**

2 A: The main change has been the tremendous increase in natural gas reserves that are now
3 perceived as economically recoverable. Natural gas proved reserves increased 12.6%
4 from 2006 to 2007. Since 1950, that is double the next largest year over year increase of
5 6.3% in 1956. From 2004 to 2007 natural gas proved reserves increased 23.5%. That
6 compares to the next largest 3 year increase since 1950 of only 16.5% set from 1954 to
7 1957.

8 As recently as 2002, the United States Geological Survey in its Assessment of
9 Undiscovered Oil and Gas Resources of the Appalachian Basin Province calculated that
10 the Marcellus Shale field contained an estimated undiscovered resource of about 1.9
11 trillion cubic feet of gas. In early 2008, Terry Englander, a geoscience professor at
12 Pennsylvania State University, and Gary Lash, a geology professor at the State University
13 of New York at Fredonia, estimated that the Marcellus Shale field might contain more
14 than 500 trillion cubic feet of natural gas. That is 250 times the 2002 estimate!

15 In June 2009 the Potential Gas Committee, a widely recognized and
16 knowledgeable non-profit organization affiliated with the Colorado School of Mines,
17 released the results of its latest biennial assessment of the nation's natural gas resources,
18 indicating that the United States possesses a total resource base of 1,836 trillion cubic
19 feet. That is a 39% increase over the 2006 assessment and is the highest resource
20 evaluation in the Committee's 44-year history. Most of the increase from the previous
21 assessment arose from re-evaluation of shale-gas plays in the Appalachian basin and in
22 the Mid-Continent, Gulf Coast and Rocky Mountain areas. Shale now accounts for about
23 33% of the total resource base.

1 **B. Rail Rates**

2 **Q: How have rail rates changed in the past few years?**

3 A: In the past few years the railroads serving the Powder River Basin ("PRB") have adopted
4 new pricing policies. Those new pricing policies have significantly increased the cost of
5 shipping coal.

6 **Q: What are the railroads' new pricing policies?**

7 A: The new pricing policies are best described in the railroads' own words. Union Pacific
8 Corporation Chairman and Chief Executive Officer Dick Davidson stated the following
9 in his letter to shareholders in the company's 2004 Annual Report:

10 Unprecedented levels of demand have created a very strong pricing environment
11 that we are working diligently to convert into higher returns on investment.
12 Across all business groups, **we are obtaining solid price increases** in the
13 marketplace. At the same time, we are working to reduce the complexity and
14 inflexibility of long-term contracts so that we can respond more quickly to
15 changing market conditions. One clear example is in our coal business where we
16 have instituted **new coal pricing mechanisms for all shipments from the**
17 **Southern Powder River Basin (SPRB) in Wyoming**, as well as spot movements
18 out of Colorado and Utah. We have simplified the way we do business with our
19 customers by clearly communicating the revenue we need in order to reinvest in
20 our coal business, while sharply reducing the administrative burden of dozens of
21 separate contracts. In total, 322 million tons of coal moved out of the SPRB
22 [South Gillette and Wright areas] in 2004, and that is expected to grow to over
23 500 million tons by 2013. Our goal is to participate in meeting that growing
24 demand, **but only if the financial returns are sufficient to justify the necessary**
25 **investment.** (Emphasis added)
26

27 **Q: What do those "new coal pricing mechanisms" look like in practice?**

28 A: Union Pacific ("UP") instituted "Circulars" and Burlington Northern Sante Fe ("BNSF")
29 instituted "Pricing Authorities." To avoid antitrust violation from public price disclosure,
30 both railroads argued that those pricing mechanisms were tariffs subject to review by the
31 Surface Transportation Board ("STB"). Since about 2006 the railroads have shifted to
32 using contracts which incorporate tariffs.

1 **Q. How have the rates changed?**

2 A. New western rail rates are much higher today than they were even just a few years ago.
3 Prior to the railroad's shift to these new coal pricing mechanisms, they were bidding 8 to
4 9 mills/ton-mile for typical SPRB moves. Now they are charging rates that are more than
5 double those levels and adding a fuel surcharge on top of that.

6 **Q: Why are the railroads charging such higher rates?**

7 A: The April 2010 issue of *Trains* magazine had an interesting article discussing changes in
8 the market for coal freight that addresses that question. It summarized the situation as
9 follows:

10 On August 25, 1984, the Chicago & North Western railroad moved its first load
11 of coal out of the Powder River Basin changing the Burlington Northern
12 monopoly into a duopoly. With the entry of the North Western and UP into the
13 market, BN cut its rates 40 percent. ...

14 For roughly two decades after 1984, those utilities that could played BN off
15 against North Western (and later BNSF Railway against Union Pacific). As
16 contracts came up for renegotiations, it wasn't whether the utility would get a
17 lower rate from one or another of the railroads, but how much lower a rate.
18 Finally, half a dozen years ago, Jack Koraleski, UP's executive vice president of
19 marketing and sales, remarked that so little profit was left in the coal business that
20 given the choice of running a grain train or coal train over his capacity-
21 constrained railroad, he'd choose the grain.

22 Starting in 2004, as their networks filled up, railroads regained some of their
23 pricing power. They briefly toyed with abandoning long-term contracts and
24 instead publishing tariffs – here's what we charge between X and Y, take it or
25 leave it. And they ceased to reflexively try to steal each other's business at every
26 opportunity.

27 **Q: Are these rate increases unprecedented?**

28 A: No. For example, Arkansas Power & Light in 1979 was charged a rate of \$12.78/ton to
29 White Bluff, Arkansas. In 1982 it was charged \$22.62 for a similar distance move to
30 Newark, Arkansas. That was a 77% increase.

1 Q: Will KCP&L know the new freight rates for its moves by the true-up date in this
2 proceeding?

3 A: Yes. We are currently in negotiations with the BNSF, Kansas City Southern Railway
4 ("KCS"), and UP and expect to complete those negotiations by early fourth quarter this
5 year. The new rates will be effective in fourth quarter 2010 and we will begin shipping
6 under those new rates after our existing contract is exhausted or it expires on
7 December 31, 2010, which ever is earlier.

8 Q: When do you expect the existing contract to be exhausted?

9 A: KCP&L's current contract provides for the annual shipment of up to ** [REDACTED]
10 [REDACTED]**. We currently expect to exhaust that shipment volume in ** [REDACTED]
11 [REDACTED]**

12 Q: Besides these much higher freight rates, are the railroads assessing other charges
13 that increase the total cost of rail transportation?

14 A: Yes. We have observed two other major changes in the market for rail services. The
15 first change has been the addition of a fuel surcharge on top of the major rate increases I
16 discussed earlier. The fuel surcharges are not only a significant increase in the cost of
17 rail transportation, but they also add a significant measure of uncertainty to the cost of
18 rail transportation. Since the current fuel surcharge rules went into effect February 2006,
19 BNSF's fuel surcharge has ranged from \$0.15 to \$0.58/loaded car-mile. From PRB to
20 Kansas City is about 800 miles. KCP&L's railcars carry 120 tons of coal which means
21 that if BNSF's fuel surcharge had been assessed against KCP&L's traffic it would have
22 ranged from about \$1.00/ton to almost \$3.90/ton. That would amount to \$11 - \$42
23 million per year if we include tonnage for Iatan 2.

1 the hedge benefiting the Company. This is balanced with a price protection strategy
2 oriented toward avoiding high prices.

3 The approach in this program is to identify statistically favorable points at which
4 to hedge. The strategy can be thought of as a three-zone strategy comprised of high
5 price, normal price and low price zones. The high price zone identifies prices that are
6 threatening to move upward. In this price zone actions are taken to protect against
7 unfavorable high price levels, mostly through the use of options-related tactics. The
8 normal price zone identifies prices that are in a "normal" range, neither high enough to
9 warrant protecting price, nor low enough to be considered "opportunities." No action is
10 taken whenever prices are deemed to be in the normal price range. The low price zone
11 identifies prices that are statistically low. In this zone, actions are taken to capture
12 favorable forward prices as those prices move into a range where the probability of prices
13 remaining at or below these levels is decreasing. While the main focus in the high price
14 zone is defensive, to set a maximum or ceiling on prices, in the low price zone the focus
15 is on capturing attractive prices.

16 **Q: How does KCP&L determine the amount of natural gas to hedge under its price
17 risk management program?**

18 **A:** Within the context of our hedge program, we refer to the sum of natural gas requirements
19 for the Missouri jurisdictional share of native load, firm wholesale sales, and fuel loss
20 reimbursement as the projected usage. ** [REDACTED]

21 [REDACTED]
22 [REDACTED]

1

[REDACTED]

2

[REDACTED]**

3

Q: How often does KCP&L use the HedgeModel?

4

A: KCP&L monitors the HedgeModel daily. ** [REDACTED]

5

[REDACTED]**

6

Q: How well has this program performed for KCP&L?

7

A: ** [REDACTED]

8

[REDACTED]

9

[REDACTED]

10

[REDACTED]

11

[REDACTED]

12

[REDACTED]

13

[REDACTED]

14

[REDACTED]

15

[REDACTED]

16

[REDACTED]

17

[REDACTED]

18

[REDACTED]

19

[REDACTED]**

20

B. Coal Price Hedging

21

Q: Does KCP&L have a program for managing the price risk of coal?

22

A: Yes, it does.

1 Q: Please describe KCP&L's coal price hedging program.

2 A: ** [REDACTED]
3 [REDACTED]
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]
7 [REDACTED]
8 [REDACTED]
9 [REDACTED]
10 [REDACTED]
11 [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]**

18 Q: How has this strategy performed for KCP&L?

19 A: This strategy has helped us avoid much of the coal market's volatility. It has also helped
20 us avoid locking in to the market highs. Using this strategy we have achieved weighted
21 average prices that are below what we would have had to pay if all of our coal had been
22 purchased on the spot market. ** [REDACTED]
23 [REDACTED]

1

2

3

4

III. FUEL IN COST OF SERVICE

5

Q: What is the purpose of this portion of your testimony?

6

A: The purpose of this part of my testimony is to explain how prices for fuel and fuel related commodities were forecast to project fuel expense for the COS.

7

8

A. Fuel Price Forecast

9

Q: What fuel prices did KCP&L use to develop its COS?

10

A: I provided KCP&L witness Burton Crawford projected fuel prices that he used to develop the annualized fuel expense included in COS that resulted in adjustment CS-24, "Annualize Fuel Expense at contract prices for net system input normalized for weather and annualized for customer growth" included in Schedule JPW2010-2 of the direct testimony of KCP&L witness John P. Weisensee. We expect to true-up these projected prices to actual prices during the course of this proceeding.

11

12

13

14

15

16

Q: How did you forecast the natural gas prices?

17

A: Natural gas prices for the 12 months from January 2010 through December 2010 were used to develop the cost of natural gas in the COS. Natural gas prices for January 2010 through March 2010 were based on the first of the month index price published in Platt's *Inside FERC*. Monthly natural gas prices for April 2010 through December 2010 were based on the average of the six (6) business days from March 9 through March 16, 2010, for the NYMEX closing prices for the April 2010 through December 2010 Henry Hub natural gas futures contracts. These monthly Henry Hub prices were then adjusted for

18

19

20

21

22

23

1 basis using the CME Group's ClearPort Panhandle Basis Swap futures contracts. These
2 basis-adjusted values for April 2010 through December 2010 and the *Inside FERC* first
3 of the month index prices for January 2010 through March 2010 were used to develop the
4 cost of natural gas in the COS. We expect to true-up the 2010 natural gas prices for the
5 COS to actual during the course of this proceeding.

6 **Q: How did you forecast the oil prices?**

7 A: Oil prices are handled differently than natural gas because KCP&L uses oil differently.
8 Oil is used primarily for flame stability and start-up at our Iatan, LaCygne, and Montrose
9 coal units. The price of oil used for flame stability and start-up was based on the average
10 of the six (6) business days from March 9 through March 16, 2010, for the NYMEX
11 closing prices for the December 2010 heating oil futures contract. The heating oil futures
12 contract price was adjusted-for basis and transportation to determine the station specific
13 delivered cost. KCP&L's Northeast unit, on the other hand, uses oil as a primary fuel.
14 For modeling purposes, Northeast was dispatched using replacement fuel prices like
15 those used for flame stability and start-up, however, fuel expense was determined using
16 Northeast's projected average inventory value. We expect to true-up oil prices for the
17 COS to actual during the course of this proceeding.

18 **Q: How did you forecast the coal prices?**

19 A: The January 2011 delivered prices of PRB coal were forecast as the sum of mine price
20 and transportation rate. ** [REDACTED]

21 [REDACTED]

22 [REDACTED]

1

[REDACTED]

2

[REDACTED]

3

[REDACTED]

4

[REDACTED]

5

[REDACTED]

6

[REDACTED]**

7

The contracts that construct their price from a market index were forecast following the contractually defined mechanism and the average of the six (6) business days from March 9 through March 16, 2010 of Evolution Markets Inc.'s settlement price for 8800 PRB coal for calendar 2011 for the COS.

8

9

10

11

For 2011 about seventy-five (75) percent of KCP&L's expected coal requirements have been committed. The price for that twenty-five (25) percent of those expected coal purchases that are not currently under contract was simply forecast to equal the price of the market-based contract I described earlier.

12

13

14

15

The January 2011 price for KCP&L's long-term bituminous coal contract was the contractually specified price for 2011. I used that 2011 base price as the forecast value for 2011.

16

17

18

We expect to true-up coal prices and freight rates to actual during the course of this proceeding.

19

20 Q:

How did you develop projections of the freight rates that will replace the existing contracts?

21

22 A:

** [REDACTED]

23

[REDACTED]

1
2
3
4
5
6
7
8

[REDACTED]

B. Fuel Adders and Fuel Additives

10 **Q: Are there costs related to fuel and included in adjustment CS-24 that are not**
11 **included in the price of fuel?**

12 **A:** Yes. Generally those costs fall into two categories: "fuel adders" and "fuel additives."
13 The fuel adders include unit train lease expense, unit train maintenance, unit train
14 property tax, unit train depreciation, coal dust mitigation, natural gas hedging costs, and
15 costs associated with transporting natural gas. Fuel additives include ammonia, lime,
16 limestone, powder activated carbon ("PAC"), and sulfur which are used to control
17 emissions. We expect to true-up these costs during the course of this proceeding.

18 **Q: Please describe the unit train-related expenses.**

19 **A:** Unit-train related expenses included in adjustment CS-24 are as follows:

- 20 • Unit train lease expense which is disaggregated into two components:
 - 21 Long-term unit train lease expense; and
 - 22 Short-term unit train lease expense.
- 23 • Unit train maintenance expense consisting of:

1 Foreign car repair;
2 Shared expenses; and
3 Maintenance and repair of KCP&L's railcar fleet.

4 *Long-Term Unit Train Lease Expense:* The amount presented here for unit train lease
5 expense reflects KCP&L's share of the long-term lease payments that will be made for
6 unit trains that will be in KCP&L's service in 2010.

7 *Short-Term Unit Train Lease Expense:* Short-term unit train lease expense has two
8 subcomponents. The first reflects our estimate of KCP&L's net lease expense under our
9 unit train exchange agreement. That agreement allows us to exchange trainsets among
10 the different plants within our system, recognizing that ownership interests in the Iatan
11 and LaCygne units are different from those of Hawthorn and Montrose. The other
12 subcomponent is our estimate of railcar capacity that will be acquired through-the short-
13 term railcar lease market to move KCP&L's coal requirements.

14 *Foreign Car Repair:* This represents the cost of repairing railcars that are running in
15 service for KCP&L but are not owned by or under a long-term lease to KCP&L.

16 *Shared Expenses:* These are costs for things like Association of American Railroads
17 publications, Universal Machine Language Equipment Register fees, and railcar
18 management software fees that cannot be assigned to an individual car.

19 *Maintenance and Repair of KCP&L's Railcar Fleet:* These repair values reflect
20 KCP&L's projection for 2010 given the age and makeup of the railcar fleet.

21 **Q: Are there unit train-related expenses that are not equipment related?**

22 A: Yes. In May 2009 BNSF issued new loading rules (Publication 6041-B) to be effective
23 November 1, 2009. Those rules set limits on the volume of coal dust that may come off a

1 coal train over certain units of track. ** [REDACTED]

2 [REDACTED]
3 [REDACTED] ** I used that estimate under the
4 assumption we will replace it with actual prices at true-up.

5 **Q: What is the status of BNSF's coal dust rule?**

6 A: On October 22, 2009, a coal shipper petitioned the STB to open a declaratory order
7 proceeding regarding BNSF's coal dust rules. This request was supported by WCTL, of
8 which KCP&L is a member. On December 1, 2009, the STB granted the request. BNSF
9 suspended the effectiveness of its coal dust tariff until August 1, 2010.

10 **Q: Are there unit train-related expenses that are not included in adjustment CS-24?**

11 A: Yes, unit-train related expenses for ad valorem private car line taxes and railcar
12 depreciation are not included in adjustment CS-24. Ad valorem private car line taxes are
13 included in adjustment CS-126. Depreciation for railcars is included in adjustment CS-
14 120.

15 **Q: How did you determine the natural gas hedging costs?**

16 A: The natural gas hedging costs are the actual premium costs incurred to hedge natural gas
17 for summer 2010.

18 **Q: How did you determine the settlement values for the natural gas hedge program?**

19 A: The natural gas hedge program settlement values were calculated assuming our existing
20 natural gas hedge portfolio had settled in early April.

21 **Q: What are the costs associated with transporting natural gas?**

22 A: The costs for transporting natural gas fall into two categories. The first category is those
23 costs which are relatively fixed. That includes reservation or demand charges, meter

1 charges, and access charges. The second category of transportation costs is those which
2 are volumetric. They include: commodity costs, commodity balancing fees,
3 transportation charges, mileage charges, fuel and loss reimbursement, Federal Energy
4 Regulatory Commission ("FERC") annual charge adjustment, storage fees, and parking
5 fees.

6 **Q: How did you determine the costs associated with transporting natural gas?**

7 A: I disaggregated the costs of transporting natural gas into its various components. For
8 those items specifically defined by tariff or contract, I used the defined mechanism. I
9 estimated parking fees based on prior period actuals. Those subcomponents were then
10 aggregated and added to the specific tariff costs to determine the total cost of
11 transportation. These costs are included in KCP&L's COS as fuel adders.

12 **Q: What are fuel additives?**

13 A: Fuel additives, which include pollution control reagents, are commodities that are
14 consumed in addition to the fuel either through combustion or chemical reaction. For
15 example, ammonia is added to a stream of flue gas where it reacts with NOx as the gases
16 pass through a catalyst chamber. Lime or limestone is added to the flue gas stream in a
17 flue gas desulfurization ("FGD") module to "scrub" SO₂. Sulfur is added to the flue gas
18 stream to act as a conditioning agent which reduces the resistivity of the fly ash enabling
19 electrostatic precipitators to operate at higher power levels enhancing collection of the fly
20 ash and reduction of opacity.

1 **Q: With the addition of new environmental controls at Iatan, are there new fuel**
2 **additives?**

3 A: Yes. The new environmental controls at Iatan use ammonia and limestone which are
4 already being used in our system. They also use PAC as a sorbent for controlling
5 mercury emissions. The use of PAC for controlling mercury emissions is new to
6 KCP&L.

7 **Q: How is PAC used to control mercury?**

8 A: It is injected into the flue gas upstream of the particulate control system to act as a
9 sorbent. The gas phase mercury in the flue gas contacts the activated carbon and attaches
10 to its surface. The activated carbon with the mercury attached is then collected by the
11 particulate control system. While this process enhances the capture of mercury, the
12 activated carbon that is now mixed with the fly ash interferes with chemicals used in
13 making concrete which is the primary market for beneficial reuse of fly ash.
14 Consequently, the fly ash is no longer salable for use in concrete. We have adjusted the
15 test period revenue from fly ash sales to zero to reflect this change.

16 **Q: How did you determine the cost of the fuel additives?**

17 A: The cost was determined as the quantity times price where price was the value projected
18 for the true-up and quantity was normalized based on historical usage. For additives that
19 lack historical data we estimated normal usage. We expect to true-up these costs to
20 actual during the course of this proceeding.

1 Q: What is “adjustment CS-103 STB Litigation” as shown in the Summary of
2 Adjustments in Schedule JPW2010-2, attached to the direct testimony of KCP&L
3 witness John P. Weisensee?

4 A: The Company filed a rate complaint case on October 12, 2005, with the STB. In that rate
5 complaint, KCP&L charged that UP’s rates for the movement of coal from origins in the
6 PRB of Wyoming to KCP&L’s Montrose Generating Station were unreasonably high.
7 KCP&L witness John P. Weisensee discusses the operating income effects included in
8 adjustment CS-103 in his direct testimony.

9 Q: Why did KCP&L file a rate complaint with the STB?

10 A: KCP&L’s Montrose Station is captive to UP; that is, UP is the only railroad that can
11 provide coal delivery service from the SPRB to the Montrose Station. In anticipation of
12 the need for unit train coal service to Montrose Station after 2005, KCP&L expressed to
13 UP its desire to negotiate an extension of the 1995-2005 contract or a new contract.
14 Consistent with the public pronouncements made at the unveiling of its Circular 111
15 (tariff) program in March 2004, UP insisted that it would only transport SPRB coal to
16 Montrose Station after December 31, 2005, under rates and terms set forth in
17 Circular 111. According to UP’s 2004 Annual Report, this tariff was intended to be a
18 “new coal pricing mechanism for all shipments from SPRB in Wyoming” In the
19 absence of a successor agreement to its existing contract, KCP&L had no means to
20 procure SPRB coal delivery service to the Montrose Station other than under the terms of
21 UP’s Circular 111, even though KCP&L did not consider the rates and service terms in
22 the Circular to be equitable or reasonable. KCP&L accepted the terms of UP’s Circular

1 111 under duress and subsequently filed a rate complaint with the STB, the federal
2 agency that governs captive shipper rail rates.

3 **Q: What is the status of the STB case?**

4 **A:** On May 19, 2008, the STB found that the rates for Montrose exceeded 180% of the
5 variable cost of providing service, which is the statutory floor for regulatory relief set
6 forth in 49 U.S.C. 10707. Upon finding that the challenged rates exceeded the regulatory
7 floor, the STB prescribed the rate where the revenue-to-variable-cost ratio ("R/VC ratio")
8 equals 180% until the end of 2015. In addition, UP was ordered to reimburse KCP&L for
9 amounts previously collected above that level, plus interest.

10 **Q:** ** [REDACTED] **

11 **A:** ** [REDACTED]
12 [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED] **

1 Q: ** [REDACTED]

2 [REDACTED] **

3 A: ** [REDACTED]

4 [REDACTED] **

5 Q: Do you expect to true-up all emission allowance, fuel, fuel additive, fuel adder and
6 transportation related costs during the course of this proceeding?

7 A: Yes.

8 IV. FUTURE FUEL and FUEL RELATED COMMODITIES

9 Q: What is the purpose of this portion of your testimony?

10 A: The purpose of this part of my testimony is to explain how prices for fuel and fuel related
11 commodities were forecast to project fuel expense beyond the test period that may be
12 addressed, if an Interim Energy Charge ("IEC") were determined to be an appropriate
13 vehicle to recover fuel and fuel related commodities in this case after the anticipated
14 effective date of tariffs. This also gives the Commission insight into what direction fuel
15 and fuel related commodities are expected to move.

16 A. Fuel Price Forecast

17 Q: How did you forecast the natural gas prices that could be used to develop an IEC?

18 A: Natural gas prices for the 12 months from January 2011 through December 2011 were
19 used to develop the cost of natural gas. Monthly natural gas prices for January 2011
20 through December 2011 were based on the average of the six (6) business days from
21 March 9 through March 16, 2010, for the NYMEX closing prices for the January 2011
22 through December 2011 Henry Hub natural gas futures contracts. These monthly Henry
23 Hub prices were then adjusted for basis using the CME Group's ClearPort Panhandle

1 Basis Swap futures contracts. These basis-adjusted values were used to develop the cost
2 of natural gas.

3 **Q: How did you forecast the oil prices?**

4 A: The price of oil used for flame stability and start-up was based on the average of the six
5 (6) business days from March 9 through March 16, 2010, for the NYMEX closing prices
6 for the December 2011 heating oil futures contract. The heating oil futures contract price
7 was adjusted for basis and transportation to determine the station specific delivered cost
8 for the units that use oil for these purposes. Northeast, on the other hand, uses oil as a
9 primary fuel. For modeling purposes, Northeast was dispatched using replacement fuel
10 prices like those used for flame stability and start-up. Northeast fuel expense, however,
11 was determined using Northeast's projected average inventory value.

12 **Q: How did you forecast the coal prices?**

13 A: The January 2012 delivered prices of PRB coal were forecast as the sum of mine price
14 and transportation rate. About half of KCP&L's expected coal requirements for 2012
15 currently are under contract. I forecast the 2012 contract prices like the 2011 contract
16 prices I described earlier. The prices for the half of expected coal purchases that are not
17 currently under contract were simply forecast to equal the price of the market-based
18 contract I described earlier for the 2011 prices. The January 2012 price for KCP&L's
19 long-term bituminous coal contract was assumed to equal the contractually specified
20 price for 2011.

21 **Q: How did you develop projections of the freight rates?**

22 A: For the January 2012 freight rates, ** [REDACTED]
23 [REDACTED]**

1 For those shipments under a contract that extends beyond 2011, I used the mechanism
2 defined in that contract. Where those contracts or proposals called for an index, I
3 constructed the index from data forecast by Moody's Analytics.

4 **B. Fuel Adders and Fuel Additives**

5 **Q: How did you develop projections of fuel adders and additives?**

6 A: We included those adders and additives that are volumetric in nature or have price
7 uncertainty. That included coal dust mitigation, natural gas hedging costs, volumetric
8 costs associated with transporting natural gas, ammonia, lime, limestone, PAC, and
9 sulfur.

10 **C. Rate Volatility Mitigation Features**

11 **Q: What rate volatility mitigation features are designed in the proposed IEC?**

12 A: As discussed above, KCP&L uses hedging programs for coal and natural gas to mitigate
13 the impacts of market price volatility.

14 **D. Emission Allowance Purchases and Sales**

15 **Q: Would emissions allowance costs or sales margins be included in an IEC?**

16 A: Yes, but as discussed above, KCP&L has enough "free" emission allowances to cover its
17 native load. Generation for off-system sales will require the purchase of NOx
18 allowances. The cost for those NOx allowances is being recognized as a variable cost of
19 providing off-system sales and is reflected in KCP&L witness Michael M. Schnitzer's
20 off-system contribution margin calculations.

21 **Q: What are KCP&L's forecasted allowance purchases and sales?**

22 A: ** [REDACTED]
23 [REDACTED]

1 [REDACTED]** This position may change with changes in the laws, rules, or regulations
2 governing emission allowances.

3 **Q: Based on this analysis, what is the expected annual increase in fuel and fuel related**
4 **expenses for KCP&L Missouri Operations that would be reflected in an IEC?**

5 A: **** [REDACTED] ****

6 **V. FUEL INVENTORY**

7 **Q: What is the purpose of this portion of your testimony?**

8 A: The purpose of this portion of my testimony is to explain the process by which KCP&L
9 determines the amount of fuel inventory to keep on hand and how the level of fuel
10 inventory impacts KCP&L's COS.

11 **Q: Why does KCP&L hold fuel inventory?**

12 A: KCP&L holds fuel inventory because of the uncertainty inherent in both fuel
13 requirements and fuel deliveries. Both fuel requirements and deliveries can be impacted
14 by weather. Fuel requirements can also be impacted by unit availability, both the
15 availability of the unit holding the inventory and the availability of other units in
16 KCP&L's system. Fuel deliveries can also be impacted by breakdowns at a mine or in
17 the transportation system. Events like the flood of 1993 and the 2005 joint line
18 derailments in the SPRB interrupt the delivery of coal to KCP&L's plants. Fuel
19 inventories are insurance against events that interrupt the delivery of fuel or unexpectedly
20 increase the demand for fuel. All of these factors vary randomly. Fuel inventories act
21 like a "shock absorber" when fuel deliveries do not exactly match fuel requirements.
22 They are the working stock that enables KCP&L to continue generating electricity
23 between fuel shipments.

1 **Q: How does KCP&L manage its fuel inventory?**

2 A: Managing fuel inventory involves ordering fuel, receiving fuel into inventory, and
3 burning fuel out of inventory. KCP&L controls inventory levels primarily through our
4 fuel ordering policy. That is, we set fuel inventory targets and then order fuel to achieve
5 those targets. We define inventory targets as the inventory level that we aim to maintain
6 on average during "normal" times. In addition to fuel ordering policy, plant dispatch
7 policy can be used to control inventories. For example, KCP&L might reduce the
8 operation of a plant that is low on fuel to conserve inventory. Of course, this might
9 require other plants in the system to operate more and to use more fuel than they
10 normally would, or it might require either curtailing generation or purchasing power in
11 the market. One can view this as a transfer of fuel "by wire" to the plant with low
12 inventory. To determine the best inventory level, KCP&L balances the cost of holding
13 fuel against the expected cost of running out of fuel.

14 **Q: What are the costs associated with holding fuel inventory?**

15 A: Holding costs reflect cost of capital and operating costs. Holding inventories requires an
16 investment in working capital, which requires providing investors and lenders those
17 returns that meet their expectations. It also includes the income taxes associated with
18 providing the cost of capital. The operating costs of holding inventory include costs
19 other than the cost of the capital tied up in the inventories. For example, we treat
20 property tax as an operating cost.

21 **Q: Please explain what you mean by the expected cost of running out of fuel?**

22 A: The cost of running out of fuel at a power plant is the additional cost incurred when
23 KCP&L must use replacement power instead of operating the plant. If the plant runs out

1 of fuel and replacement power is unavailable, KCP&L could fail to meet customer
2 demand for electricity. The cost of replacement power depends on the circumstances
3 under which the power is obtained. We would expect replacement power (and the
4 opportunity cost of forgone sales) to cost less at night than during the day and less on
5 weekends than during the week. In other words, replacement power costs (and
6 opportunity costs of forgone sales) are cyclical. A varying replacement power cost (or
7 opportunity cost of forgone sales) translates directly into a varying shortage cost. As a
8 result, if KCP&L was running low on fuel, it could mitigate the shortage cost by
9 selectively reducing burn when the cost of replacement power is lowest. During any
10 significant period of disruption, we would expect many replacement power cost cycles.

11 **Q: How does KCP&L determine the best inventory level, i.e., the level that balances the**
12 **cost of holding fuel against the expected cost of running out?**

13 A: KCP&L uses the Electric Power Research Institute's ("EPRI") Utility Fuel Inventory
14 Model ("UFIM") to identify those inventory levels with the lowest expected cost. UFIM
15 identifies an inventory target as a concise way to express the following fuel ordering rule:

$$\begin{aligned} \text{Current Month Order} &= (\text{Inventory Target} - \text{Current Inventory}) \\ &+ \text{Expected Burn this Month} \\ &+ \text{Expected Supply Shortfall.} \end{aligned}$$

19 That is, UFIM's target assumes all fuel on hand is available to meet expected burn.
20 "Basemat" is added to the available target developed with UFIM to determine KCP&L's
21 inventory target. Generally, and in the rest of my testimony, references to inventory
22 targets mean the sum of fuel readily available to meet burn plus basemat.

1 **Q: What is basemat?**

2 A: Basemat is the quantity of coal occupying the bottom eighteen inches of our coal
3 stockpiles footprint. It may or may not be useable due to contamination from water, soil,
4 clay, or fill material on which the coal is placed. Because of this uncertainty about the
5 quality of the coal, basemat is not considered readily available. However, because it is
6 dynamic and it can be burned (although with difficulty), it is not written off or considered
7 sunk. Eighteen inches was identified in previous KCP&L cases as being the error range
8 for placement of a dozer blade or scraper on a coal pile and the appropriate depth for
9 basemat. To determine basemat under our compacted stockpiles, we only consider the
10 area of a pile that is thicker than nine inches. The area of the coal piles that covers either
11 a hopper or concrete slab is not included in the calculation of basemat. The basemat
12 values presented here for all inventory locations except Iatan Unit 2 are premised on
13 work performed by MIKON Corporation, a consulting engineering firm that specializes
14 in coal stockpile inventories and related services for utilities nationwide.

15 **Q: How were the basemat values determined for Iatan Unit 2?**

16 A: Much like the Iatan Unit 2 plant still under construction, the coal inventory designated for
17 the unit is being accumulated to bring it up to the target level. The Iatan Unit 2 basemat
18 values were calculated from the available target identified by UFIM and applying the
19 ratio of basemat to available target for Iatan Unit 1.

20 **Q: How does the UFIM model work?**

21 A: The fundamental purpose of UFIM is to develop least-cost ordering policies, *i.e.*, targets,
22 for fuel inventory. UFIM does this by dividing time into "normal" periods and
23 "disruption" periods where a disruption is an event of limited duration with an uncertain

1 occurrence. It develops inventory targets for normal times and disruption management
2 policies. The inventory target that UFIM develops is that level of inventory that balances
3 the cost of holding inventory with the cost of running out of fuel.

4 **Q: What are the primary inputs to UFIM?**

5 A: The key inputs are: holding costs, fuel supply cost curves, costs of running out of fuel,
6 fuel requirement distributions, "normal" supply uncertainty distributions, and disruption
7 characteristics.

8 **Q: What are the holding costs you used to develop coal inventory levels for this case?**

9 A: KCP&L based the holding costs it used to develop fuel inventory levels for this case on
10 the cost of capital proposed and described in the direct testimony of KCP&L witness Dr.
11 Samuel C. Hadaway.

12 **Q: What do you mean by "fuel supply cost curves"?**

13 A: A fuel supply cost curve recognizes that the delivered cost of fuel may vary depending on
14 the quantity of fuel purchased in a given month. For example, our fuel supply cost curves
15 for PRB coal recognize that when monthly purchases exceed normal levels, we may need
16 to lease additional train sets. Those lease costs cause the marginal cost of fuel above
17 normal levels to be slightly higher than the normal cost of fuel.

18 **Q: What was the normal cost of fuel?**

19 A: The normal fuel prices underlying all of the fuel supply cost curves were the
20 January 1, 2011 delivered fuel prices used to develop the Company's cost of service for
21 this filing.

1 **Q: What did you use for the costs of running out of fuel?**

2 A: There are several components to the cost of running out of fuel. The first cost is the
3 opportunity cost of forgone non-firm off-system power sales. I developed that cost by
4 constructing a price duration curve derived from the distribution of monthly non-firm
5 off-system megawatt-hour ("MWh") transactions for January 2006 through December
6 2009. I supplemented those points with estimates for purchasing additional energy and
7 using oil-fired generation. The last point on the price duration curve is the socio-
8 economic cost of failing to meet load for which I used KCP&L's assumed cost for
9 unserved load. These price duration curves are referred to in UFIM as burn reduction
10 cost curves. These burn reduction cost curves can vary by inventory, location and
11 disruption.

12 **Q: What fuel requirement distributions did you use?**

13 A: For all units except Iatan Unit 2, I used distributions based on historical fuel requirements
14 from January 2006 through December 2009. The Iatan Unit 2 requirements were based
15 on projected requirements for 2011 through 2014. All of these distributions included fuel
16 to serve off-system sales.

17 **Q: What do you mean by "normal" supply uncertainty?**

18 A: We normally experience random variations between fuel burned and fuel received in any
19 given month. These supply shortfalls or overages are assumed to be independent from
20 period to period and are not expected to significantly affect inventory policy. To
21 determine these normal variations, I developed probability distributions of receipt
22 uncertainty based on the difference between historical burn and receipts.

1 **Q: What are disruptions?**

2 A: A disruption is any change in circumstances that persists for a finite duration and
3 significantly affects inventory policy. A supply disruption might entail a complete cut-
4 off of fuel deliveries, a reduction in deliveries, or an increase in the variability of receipts.
5 A demand disruption might consist of an increase in expected burn or an increase in the
6 variability of burn. Other disruptions might involve temporary increases in the cost of
7 fuel or the cost of replacement power. Different disruptions have different probabilities
8 of occurring and different expected durations.

9 **Q: What disruptions did KCP&L use in developing its inventory targets?**

10 A: KCP&L recognized three types of disruptions in development of its inventory targets:

- 11 • PRB capacity constraints;
- 12 • Fuel yard failures; and
- 13 • Major floods.

14 **Q: Please explain what you mean by disruptions related to PRB capacity constraints.**

15 A: Supply capacity is the ultimate quantity of coal that can be produced, loaded, and shipped
16 out of the PRB in a given time period. Constraints to supply capacity can come from
17 either the railroads or from the mines, but regardless of which of these is the constraint
18 source, the quantity of coal that can be delivered is restricted. A constrained supply
19 caused by railroad capacity constraints can come from an inability of the railroad to ship
20 a greater volume of coal from the PRB. A scenario such as this can arise from not having
21 enough slack capacity to place more trains in service. It can also come from an
22 infrastructure failure such as the May 2005 derailments on the joint line in the SPRB. A
23 variety of mine issues can constrain supply, such as there not being enough available

1 load-outs, not enough space to stage empty trains, reaching the productive limits of
2 equipment such as shovels, draglines, conveyors, and trucks, or the mine reaching the
3 production limits specified in its environmental quality permits.

4 **Q: Please explain what you mean by disruptions related to fuel yard failures.**

5 A: KCP&L and other utilities have experienced major failures in the equipment used to
6 receive fuel. Perhaps KCP&L's most significant fuel yard failure occurred in 1986 when
7 a conveyor belt caught fire at Hawthorn. The ensuing fire destroyed Hawthorn's normal
8 facilities for unloading coal received by train. As used here, "disruption" is designed to
9 cover a variety of circumstances that could result in a significant constraint on a plant's
10 ability to receive fuel.

11 **Q: Please explain what you mean by "major flood" disruptions.**

12 A: This disruption was modeled after the 1993 flood which affected the entire Missouri
13 River Valley. Such a large flood can lengthen railroad cycle times and curtail the
14 deliveries of coal to generating stations. For example, at Iatan Station the average
15 standard deviation in cycle time for the flood year is nearly double the standard deviation
16 for the year before or after the flood, and during the months most affected by flooding,
17 the differences are even more substantial.

18 **Q: How does KCP&L manage disruptions?**

19 A: The target inventory levels presented here assume KCP&L will actively manage its fuel
20 inventory. That is, the Company would take whatever actions were deemed appropriate
21 to ensure an adequate supply of fuel was kept on hand for generating energy necessary to
22 serve native load. If KCP&L runs low on fuel, it might choose to curtail generation and
23 reduce burn. KCP&L would manage the cost of any such disruption to take advantage of

1 replacement power cost cycles. This assumption allows us to operate with lower
2 inventory targets.

3 **Q: What are the coal inventory targets used in this case?**

4 A: The coal inventory targets resulting from application of UFIM and their associated value
5 for incorporation into rate base are shown in the attached Schedule WEB2010-2 (**Highly**
6 **Confidential**) and are the values used to determine adjustment RB-74, "Adjust Fossil
7 Fuel Inventories to required levels" included in the Summary of Adjustments in Schedule
8 JPW2010-2 of the direct testimony of KCP&L witness John P. Weisensee. Since these
9 coal inventory targets are a function of fuel prices, cost of capital and other factors that
10 may be adjusted in the course of this proceeding, we would expect to adjust the coal
11 inventory targets as necessary.

12 **Q: Does that mean it would be appropriate to update coal inventory levels included in**
13 **rate base to reflect information known at true-up?**

14 A: Yes. It would be appropriate to update the coal inventory levels for changes in fuel
15 prices and cost of capital. A change in either the delivered cost of coal or cost of capital
16 may result in different coal inventory levels. For example, lower fuel prices or a lower
17 rate of return than the Company has requested would result in higher inventory
18 requirements.

19 **Q: How were the inventory values for activated carbon, ammonia, lime, and limestone,**
20 **determined?**

21 A: With the exception of activated carbon for Iatan Units 1 and 2, inventory values for
22 ammonia, lime and limestone were calculated as the average month-end quantity on hand
23 for the 13-month period March 2009 through March 2010 multiplied by the projected

1 January 2011 per unit value. November 2009 was the first month activated carbon was
2 used at Iatan so I used the average month-end quantity on hand from November 2009
3 through March 2010 multiplied by the projected January 2011 per unit value to determine
4 its value. The inventory values for activated carbon, ammonia, lime, and limestone are
5 shown in Schedule WEB2010-2 (**Highly Confidential**) and were included in the
6 derivation of adjustment RB-74.

7 **Q: How were the inventory values for oil determined?**

8 A: Inventory values for oil were calculated as the average month-end quantity on hand for
9 the 13-month period March 2009 through March 2010 multiplied by the projected
10 December 2010 per unit value. The inventory values for oil are shown in Schedule
11 WEB2010-2 (**Highly Confidential**) and were included in the derivation of adjustment
12 RB-74.

13 **VI. SO₂ EMISSION ALLOWANCE MANAGEMENT PROGRAM**

14 **Q: What is the purpose of this portion of your testimony?**

15 A: The purpose of this portion of my testimony is to describe how KCP&L's SO₂ Emission
16 Allowance Management Program impacts KCP&L's COS and rate base, to review the
17 actions KCP&L has taken under its SO₂ Plan, and to describe KCP&L's SO₂ Plan for
18 2010.

19 **Q: How does this program impact KCP&L's COS and rate base?**

20 A: KCP&L was first authorized to manage its SO₂ emission allowance inventory, including
21 the sales of such allowances, under the Stipulation and Agreement in Case
22 No. EO-95-184. That Stipulation and Agreement and a similar Stipulation and
23 Agreement under Case No. EO-2000-357, allowed KCP&L to record all SO₂ emission

1 allowance sales proceeds as a regulatory liability in Account 254, Other Regulatory
2 Liabilities. The Stipulation and Agreement concerning KCP&L's Regulatory Plan,
3 which was approved in 2005 by the Commission in Case No. EO-2005-0329
4 ("Regulatory Plan Stipulation and Agreement") included a SO₂ Emission Allowance
5 Management Policy ("SEAMP"), which provided for KCP&L to sell SO₂ emission
6 allowances in accordance with the initial SO₂ Plan submitted to the Commission Staff,
7 the Office of the Public Counsel ("OPC") and other parties in January 2005. While the
8 Regulatory Plan Stipulation and Agreement also requires KCP&L to record all SO₂
9 emission allowance sales proceeds as a regulatory liability in Account 254, it further
10 provides that KCP&L may recommend an appropriate amortization period for SO₂
11 emission allowance sales proceeds that have been booked to Account 254 to be included
12 in the 2009 rate case revenue requirement. Company witness John Weisensee discusses
13 the Company's proposed amortization method in his direct testimony in his discussion of
14 adjustment CS-22.

15 **Q: In the SEAMP included in the Regulatory Plan Stipulation and Agreement,**
16 **KCP&L agreed to provide Staff and OPC an SO₂ Plan by December 31 each year.**
17 **Did KCP&L submit a new SO₂ Plan prior to December 31, 2009?**

18 A: Yes, we did. We submitted a "SO₂ Plan for 2010" to Staff and OPC in December 2009.

19 **Q: Describe how you developed the SO₂ Plan for 2010 that KCP&L submitted in**
20 **December 2009.**

21 A: To determine the optimal number of allowances to sell and the timing of those sales,
22 KCP&L developed a decision and risk model to explicitly consider the various
23 uncertainties discussed in the report. The SO₂ Plan considered those uncertainties in the

1 identification of transactions intended to minimize the expected present value of long-run
2 utility revenue requirements, while ensuring that the operation of KCP&L generators
3 would not be restricted due to a deficiency of available SO₂ emission allowances. Those
4 risk considerations included:

- 5 ▪ changes in the price of allowances,
- 6 ▪ cost and/or effectiveness of emission control technologies,
- 7 ▪ changes in environmental regulations or proposed environmental regulations,
- 8 ▪ changes in other energy market conditions, and
- 9 ▪ market opportunities.

10 **Q: Does the methodology you used to develop the SO₂ Plan for 2010 meet the**
11 **requirements defined in the SEAMP?**

12 A: Yes, it does.

13 **Q: Describe the proposed actions to be taken in 2010 by the SO₂ Plan for 2010.**

14 A: ** [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED] **

20 **Q: When was the SO₂ Plan for 2010 effective?**

21 A: The SEAMP states that the annual SO₂ Plan will be submitted by December 31 of each
22 calendar year to be effective for the period commencing April 1 of the following year and

1 ending March 31 of the next subsequent year. Consequently, the SO₂ Plan for 2010
2 became effective April 1, 2010 and will expire March 31, 2011.

3 **Q: How were the proceeds from the SO₂ Plan for 2010 reflected in the COS?**

4 A: ** [REDACTED]

5 [REDACTED]

6 [REDACTED] ** The projected EPA auction proceeds, and the SO₂ coal

7 premium credits as authorized in Case No. EO-2005-0329 are included in adjustment

8 RB-55 "Deferred Gain on Emission Allowance Sales" in the Summary of Adjustments

9 schedule attached to KCP&L witness John P. Weisensee's direct testimony as Schedule

10 JPW2010-2.

11 **Q: Please explain how adjustment RB-55, "Deferred Gain on Emission Allowance**
12 **Sales" was determined.**

13 A: This adjustment has two components involving the roll-forward of the December 31,

14 2009 balance in Account 254, Regulatory Liability to December 31, 2010. The first

15 component, an increase in the 254 balance of ** [REDACTED] ** reflects projected total

16 company proceeds from EPA Auction sales. The second component, a decrease in the

17 254 balance of ** [REDACTED] ** reflects projected total company SO₂ coal premium costs.

18 The sum of these two components is a ** [REDACTED] ** in the 254 balance.

19 **Q: Are costs for emission allowances included in the COS calculation?**

20 A: Yes, but as it relates to native load those costs are zero. KCP&L has enough "free" SO₂

21 allowances to cover all of its needs under the current rules and enough "free" NO_x

22 allowances to cover native load. Generation for off-system sales will require the

23 purchase of NO_x allowances. The cost for those NO_x allowances is being recognized as

1 a variable cost of providing off-system sales and is reflected in KCP&L witness Michael
2 M. Schnitzer's off-system contribution margin calculations.

3 **Q: Does that conclude your testimony?**

4 **A:** Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City)
Power & Light Company to Modify Its Tariffs to) Docket No. ER-2010-____
Continue the Implementation of Its Regulatory Plan)

AFFIDAVIT OF WILLIAM EDWARD BLUNK

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

William Edward Blunk, appearing before me, affirms and states:

1. My name is William Edward Blunk. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Supply Planning Manager.

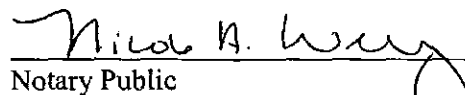
2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Kansas City Power & Light Company consisting of thirty-nine (39) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby affirm and state that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

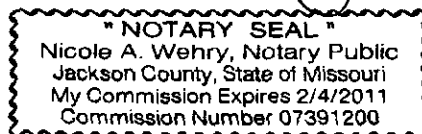


William Edward Blunk

Subscribed and affirmed before me this 28th day of May, 2010.

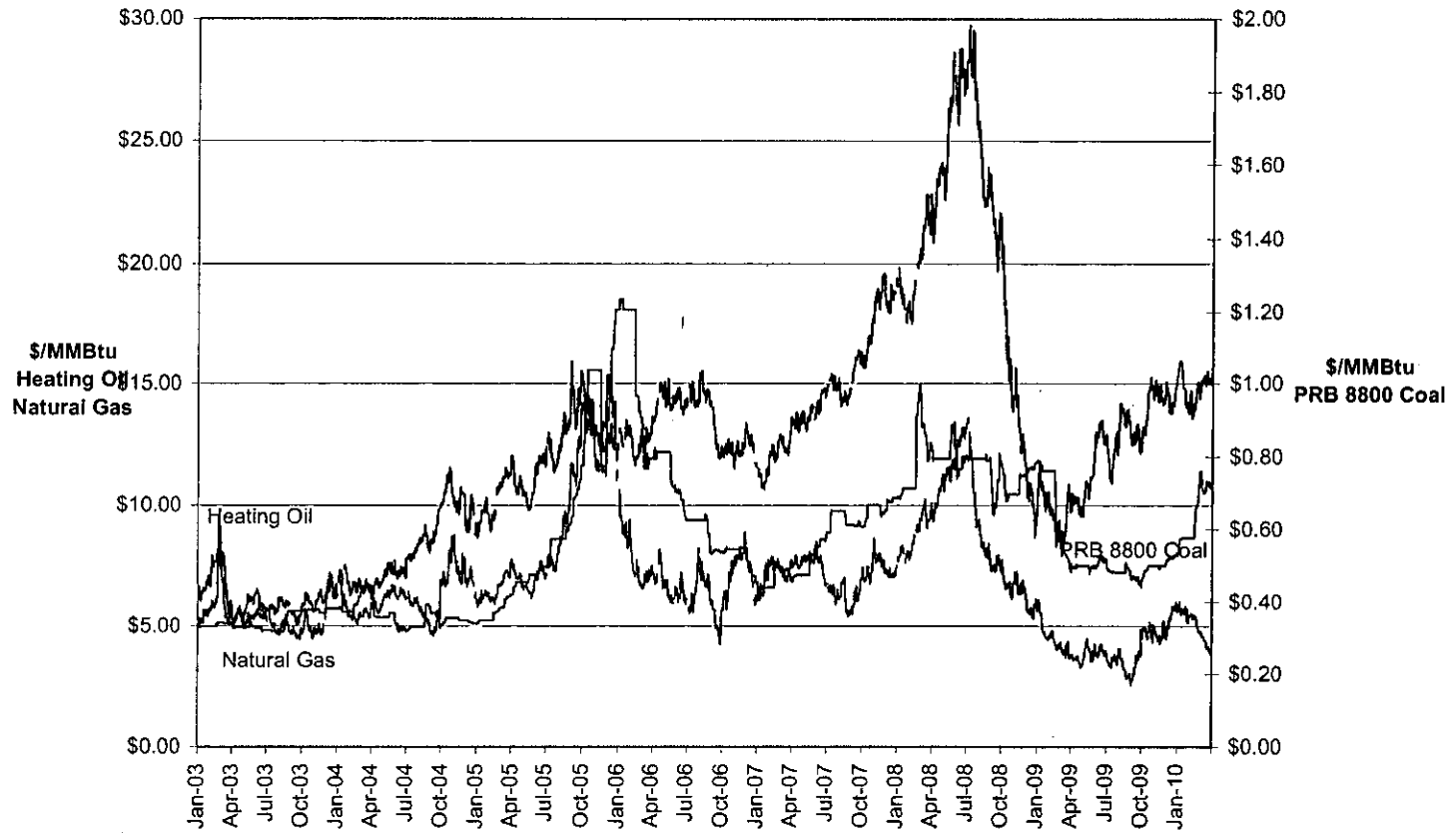

Notary Public

My commission expires: Feb. 4 2011



Schedule WEB2010-1
shows how fuel prices have changed over the past few years

Market Price of Fossil Fuels



Sources: ProphetX, Evolution Markets

SCHEDULE WEB2010-2

**THIS DOCUMENT CONTAINS
HIGHLY CONFIDENTIAL
INFORMATION NOT AVAILABLE
TO THE PUBLIC**