

Exhibit No.: _____

Issue: Policy Issues Related to Southwest Power Pool

Witness: Burton L. Crawford

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Sponsoring Party: Kansas City Power & Light Company

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DIRECT TESTIMONY

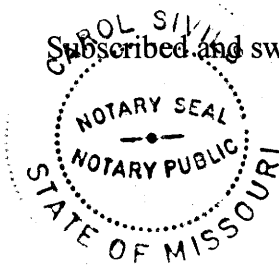
OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

SEPTEMBER 27, 2005



1 DIRECT TESTIMONY
2 OF
3 BURTON L. CRAWFORD
4 KANSAS CITY POWER & LIGHT COMPANY
5

6 **Q. Please state your name and business address.**

7 A. Burton L. Crawford, 1201 Walnut, Kansas City, Missouri, 64106-2124.

8 **Q. What is your position and experience with the Kansas City Power & Light**
9 **Company ("KCPL" or "Company")?**

10 A. I am currently Manager, Deregulation. I have previously served in various other
11 areas including regulatory, economic research, and power engineering starting in 1988.

12 **Q. What is your educational background?**

13 A. I hold a Master of Business Administration from Rockhurst College and a
14 Bachelor of Science in Mechanical Engineering from the University of Missouri.

15 **Q. What is the purpose of your testimony in this case?**

16 A. The purpose of my testimony is to present information in support of the
17 Company's request to transfer functional control of KCPL's transmission network to the
18 Southwest Power Pool Regional Transmission Organization (SPP RTO). My testimony
19 describes the proposed SPP Energy Imbalance Service (EIS) market and the differences in
20 congestion cost hedging mechanisms between the SPP EIS market and those in other regions
21 such as the Midwest Independent Transmission System Operator (MISO) market.

22 **Q. Please describe your involvement with the SPP.**

23 A. Starting in January 2000, I became directly involved with SPP's efforts to design
24 and implement an energy imbalance market per the requirements of FERC Order 2000. These
25 efforts continued until July 2001 when the Federal Energy Regulatory Commission (FERC)
26 rejected SPP's efforts to become an RTO. At that point, I became directly involved with the
27 efforts to design and implement an energy market for the area covered by the proposed merger of

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1 SPP and MISO. Once the merger efforts failed in Spring 2003, I once again became directly
2 involved in the efforts to design and implement an energy imbalance market for SPP. Currently,
3 I am a member of the SPP Market Working Group (MWG). This group is responsible for the
4 SPP EIS market design.

5 **Q. When is the proposed SPP EIS market scheduled to start?**

6 A. The market is currently scheduled to start May 1, 2006.

7 **Q. Please describe the purpose of an energy imbalance market.**

8 A. In general, energy imbalance markets allow a load-serving entity to buy and sell
9 energy in real time to make up for any difference (i.e., imbalance) between their actual generation
10 output and actual load requirements. RTOs are required to provide access to an energy
11 imbalance market per FERC Order 2000. In Order 2000, FERC determined that “real-time
12 balancing markets are necessary to ensure non-discriminatory access to the grid and to support
13 emerging competitive energy markets.”¹

14 **Q. What happens in the absence of an energy imbalance market?**

15 A. Today, an imbalance between a load-serving entity’s actual load and generation
16 can be accounted for in different ways. If the load-serving entity is a control area, such as KCPL,
17 the differences are tracked for later settlement on a physical basis. For example, if KCPL over-
18 generates relative to KCPL’s load requirements during one time period, KCPL will under-
19 generate relative to its load requirements at some later time. This over and under generation is
20 termed “inadvertent energy” and is closely tracked.

21 If a load-serving entity is not a control area, differences are tracked and may be settled
22 financially based on FERC approved tariffs. For example, a municipal utility that does not fully
23 meet their load obligations during an hour may be subject to paying for the amount under-
24 generated. This payment is made to the control area where the municipal utility is located for

¹ Order 2000, p. 423.

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1 supplying the difference. The control area may also make a payment to the municipal utility if
2 the municipal utility exceeds its load obligation.

3 **Q. Are there any other purposes for an energy imbalance market other than**
4 **buying and selling energy?**

5 A. Yes. As designed, the SPP EIS market will provide a mechanism to efficiently
6 dispatch generation within the SPP footprint. Market participants with generation resources can
7 provide information to the RTO expressing their desire to provide energy at a given offer price.
8 The RTO then uses this information to determine the lowest priced generation dispatch that will
9 meet the RTO's load requirements. The RTO will dispatch just enough generation to meet the
10 load requirements by dispatching the lowest priced generation first.

11 In addition to considering the offer price of each participating generating resource, the
12 RTO must also consider if the transmission system is capable of reliably dispatching the lowest
13 priced generation available. When transmission limitations prevent the lowest priced generation
14 from being dispatched, the RTO will re-dispatch higher priced generation.

15 This process of dispatching resources in the most economic manner while taking
16 transmission system limitations into consideration is known as a "security constrained economic
17 dispatch".

18 **Q. How are energy prices determined for the energy imbalance market?**

19 A. SPP, like many other regions of the country, is implementing an energy market
20 based on Locational Marginal Pricing (LMP). Under an LMP methodology, energy prices for
21 any given physical location on the transmission system are calculated based on the cost to
22 provide one additional MW of energy at that location. The LMP is based on offers to provide
23 energy, taking into consideration any available transmission capacity to move the energy offered,
24 to that location.

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1 Since available transmission capacity determines what energy can or cannot be delivered
2 to any particular location, LMPs can vary between locations on the transmission system during
3 any given hour. When the transmission system is constrained (i.e., fully loaded at one or more
4 locations), LMPs will differ from location to location. When the transmission system is
5 unconstrained, LMPs can be the same at every location in the RTO market.

6 When purchases or sales are made through an energy imbalance market based on LMP,
7 the price paid or received is based on the specific location where the purchase or sale was made.

8 While SPP calls their pricing methodology "Locational Imbalance Pricing" (LIP), it is the
9 same in theory as LMP.

10 **Q. Why do you state that LMPs "can be" the same in every location when the**
11 **transmission system is unconstrained?**

12 A. Depending on how LMP is implemented, LMPs may differ by location even in an
13 unconstrained case due to the treatment of transmission system losses. Under an LMP market,
14 transmission system losses can be accounted for in at least two different ways - average losses or
15 marginal losses. When the transmission system is unconstrained and an average loss
16 methodology is employed, LMPs will be the same at all locations within the RTO market. When
17 the transmission system is unconstrained and a marginal loss methodology is employed, LMPs
18 may differ at all locations within the RTO market. These differences reflect the incremental cost
19 of transmission system losses.

20 SPP's proposed EIS market is based on an average loss methodology. Therefore, for any
21 given hour when the transmission system is unconstrained, LIPs will be the same at all locations
22 within the SPP EIS market.

23 **Q. Please describe how the SPP energy imbalance market is settled financially.**

24 A. The SPP EIS market is settled financially based on the differences between actual
25 generation (or load) and that which was previously scheduled. A schedule informs SPP of a

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market participant's desire to move energy from a specific generation resource location to a specified load. In general, schedules are submitted prior to real-time operations.

The following describes the financial settlement for four possible imbalance scenarios:

- Actual generation is greater than scheduled generation. When actual generation output exceeds that which was scheduled by the market participant for that generator, SPP will pay the market participant for the energy produced above the scheduled level at the LIP for that specific generator location.
- Actual generation is less than scheduled generation. When actual generation output is less than the amount scheduled by the market participant for that generator, SPP will charge the market participant for the energy not produced (i.e., the difference between actual output and scheduled output) at the LIP for that specific generator location.
- Actual load is greater than scheduled load. When actual load exceeds that which was scheduled by the market participant for that load, SPP will charge the market participant for the energy consumed above the scheduled level at the LIP for that specific load location.
- Actual load is less than scheduled load. When actual load is less than the amount scheduled by the market participant for that load, SPP will pay the market participant for the energy not consumed (i.e., the difference between actual load and scheduled load) at the LIP for that specific load location.

This financial settlement process occurs for each generator location and each load location in the SPP EIS market. For settlement purposes, load can be aggregated across several different locations. For example, KCPL can combine its entire retail load into one settlement location for scheduling and settlement purposes. This helps simplify the scheduling and settlement process since schedules would not have to be submitted for each location where KCPL takes energy from

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1 the transmission system. SPP will calculate a load-weighted average LIP for financial settlement
2 of load imbalances.

3 In contrast to load, generation cannot be combined across multiple physical locations and is
4 therefore scheduled and settled separately for each specific generator location.

5 **Q. Please describe how a market participant can benefit from the energy**
6 **imbalance market.**

7 A. A market participant can directly benefit from the energy imbalance market in two
8 primary ways – either through energy purchases or energy sales.

9 Energy purchases can be made when the EIS market price is lower than a generator's cost
10 of production. For example, a generator serving 100 MW of load with 100 MW of owned
11 generation can schedule its generation output to its load and at the same time offer the 100 MW
12 of generating capacity into the SPP EIS market. Let's assume that the market participant offers
13 its generation at its cost of \$30/MWh. If the LIP at the generator's location is lower than its
14 offer, say \$20/MWh, it will not be dispatched by the RTO. As a result, the generator must pay
15 for the 100 MW of scheduled generation that was not actually produced; however, it is purchased
16 at a price lower (in this case \$20/MWh) than the generator's offer price (\$30/MWh). Therefore,
17 the market participant's cost to serve its load has been reduced by \$10/MWh.

18 Energy sales can be made when the EIS market price is equal to or above a generator's
19 cost of production. For example, a generator with 100 MW of load and 200 MW of owned
20 generation can schedule 100 MW of its generation output to its load and at the same time offer
21 the 200 MW of capacity into the SPP EIS market. Let's assume that the market participant offers
22 its generation at its cost of \$30/MWh. If the LIP at the generator's location is above its offer, say
23 \$40/MWh, it will be dispatched by the RTO. As a result, the generator will get paid for the
24 excess above its schedule at a price higher (in this case \$40/MWh) than the generator's offer

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price (\$30/MWh). The EIS market provides a ready outlet for the market participant's excess energy.

Q. While the EIS market provides a ready outlet for energy purchases and sales, are there any new risks from participating in this type of market?

A. Yes. Differences in LIPs between generation and load can result in an additional cost to market participants if they have not scheduled appropriately. Consider the following example for a single market participant during one hour:

Actual Generation = 100 MW LIP at Generator = \$20/MWh

Actual Load = 100 MW LIP at Load = \$30/MWh

Schedule (generation to load) = 0 MW

Given the above assumptions concerning generation, load, schedule and LIPs, the financial settlement would be:

Generation Settlement = LIP at Generator * (Scheduled Generation – Actual Generation)

= \$20 * (0 MW – 100 MW)

= -\$2,000 {negative sign indicates a payment from the RTO}

Load Settlement = LIP at Load * (Actual Load – Scheduled Load)

= \$30 * (100 MW – 0 MW)

= +\$3,000 {positive sign indicates a payment to the RTO}

Net Settlement = Generation Settlement + Load Settlement

= -\$2,000 + \$3,000

= +\$1,000 {positive sign indicates a payment to the RTO}

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In this example, the market participant generated 100 MW to meet its 100 MW of load. However, the market participant had to make a payment of \$1,000 to the RTO. This \$1,000 payment reflects the cost of transmission congestion between the market participant's generation and load.

These costs are known in other locational-based markets as "congestion charges".

Q. Can a market participant avoid paying congestion charges in the SPP EIS market?

A. Yes. Congestion charges can generally be avoided by scheduling appropriately. If the market participant in the previous example had scheduled 100 MW of generation to its load, it would have avoided paying these charges.

Actual Generation	= 100 MW	LIP at Generator	= \$20/MWh
Actual Load	= 100 MW	LIP at Load	= \$30/MWh
Schedule (generation to load) = 100 MW			

Given the above assumptions concerning generation, load, schedule and LIPs, the financial settlement would be:

Generation Settlement	= LIP at Generator * (Scheduled Generation – Actual Generation)
	= \$20 * (100 MW – 100 MW)
	= \$0 {therefore no charge or credit for generation}
Load Settlement	= LIP at Load * (Actual Load – Scheduled Load)
	= \$30 * (100 MW – 100 MW)
	= \$0 {therefore no charge or credit for load}

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$$\begin{aligned}\text{Net Settlement} &= \text{Generation Settlement} + \text{Load Settlement} \\ &= \$0 + \$0 \\ &= \$0\end{aligned}$$

In this revised example, the market participant generated 100 MW to meet its 100 MW of load just like the first example. However, since the market participant submitted a schedule for 100 MW, it avoided paying any congestion charges to the RTO.

Schedules effectively protect market participants from paying congestion charges, but at the same time allow the flexibility to make economy energy purchases and sales through the EIS market. It is at this point that a market participant can benefit from the EIS market as I previously explained.

Q. How much flexibility does a market participant have in submitting schedules?

A. The flexibility that a market participant has in submitting schedules is equivalent to the flexibility that exists today for scheduling transmission service.

In order for a market participant to submit a schedule, they must first have reserved transmission service. For market participants that have reserved SPP network service, this entitles them to submit schedules from any of their designated network resources to their load. For market participants that have reserved point-to-point transmission service, schedules can be submitted from the generation specified in the point-to-point reservation to the load specified in the point-to-point reservation. All new transmission service must be reserved through the SPP.

Market participants have up until 20 minutes prior to the schedule start time to submit their schedules. This provides significant flexibility for market participants to adjust schedules to match their congestion hedge needs.

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1 **Q. Are there any situations where a market participant's right to schedule is**
2 **limited even though they have a reservation?**

3 A. Yes. There are two primary situations where the right to schedule may be limited;
4 (1) when the desired use of the transmission system exceeds its capacity, and (2) in some cases
5 when a market participant submits schedules that exceed the market participant's actual load by
6 more than 4%.

7 In the first situation, actual transmission system use has reached an operating limit. This
8 limit prevents SPP from dispatching purely on an economic basis. Instead, SPP must now reduce
9 the output from lower priced generation while increasing higher priced generation output to
10 ensure that the transmission system operating limit is not violated. In addition, when an
11 operating limit is reached, SPP must ensure that the impact of scheduled transactions (whether
12 physical or financial) on the transmission system does not exceed the operating limits. SPP will
13 have a process in place to review the scheduled impacts, and will adjust schedules downward to
14 match the transmission system operating limit. This is known as schedule curtailment.

15 When schedules are curtailed by SPP, this potentially exposes generation and load to EIS
16 market prices. To the extent a market participant can schedule from another location, exposure
17 to EIS market prices is limited or eliminated.

18 In the second situation, a market participant has submitted schedules that exceed the
19 market participant's actual load. Under certain conditions, this results in the market participant
20 collecting money from the RTO for doing nothing more than submitting excessive schedules. To
21 prevent this type of gaming, the EIS market rules contain provisions for recovering any gains a
22 market participant may have made by submitting these excessive schedules.

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1 **Q. How frequently are transmission schedules curtailed in SPP?**

2 A. From January 1, 2005 through August 31, 2005, SPP curtailed firm transmission
3 use on four occasions, covering about 52 hours. Schedules for non-firm transmission service
4 were cut on 193 occasions.

5 **Q. Why is it necessary to curtail schedules that exceed the transmission system's**
6 **capacity?**

7 A. There are two primary reasons to curtail schedules. First, in order to ensure that
8 SPP collects sufficient revenue from those purchasing energy from the EIS market to pay the
9 generators providing energy to the EIS market, the impact of schedules on the transmission
10 network must not exceed the transmission system capacity during times of transmission
11 constraints. SPP ensures that schedules do not exceed the system capacity through what is called
12 a "simultaneous feasibility test" (SFT). If schedules are allowed to exceed the transmission
13 system capacity, SPP may end up short of revenue to pay the generators. This shortfall would
14 then need to be uplifted to all market participants.

15 Second, some schedules within the SPP EIS market represent transmission system use
16 from self-dispatched resources. Self-dispatched resources are those generating facilities that
17 have not been offered into the SPP EIS market and are therefore not dispatched by SPP. If a self-
18 dispatched resource is negatively impacting a constrained transmission facility and SPP
19 determines that the self-dispatched resource needs to reduce its output, its schedule (and
20 corresponding transmission system use) will be curtailed.

21 **Q. Is there any prioritization to schedule curtailments?**

22 A. Yes. Just like today, transmission service under the EIS market will have
23 different priorities. This prioritization is based on how the transmission service was sold.
24 Transmission service is either sold as firm or non-firm, and there are several different levels of
25 non-firm service. For example, hourly non-firm service has a lower priority than monthly non-

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1 firm service. Under the EIS market, any needed schedule curtailment will be based on the
2 priority of service (e.g., non-firm service will be curtailed prior to curtailing firm service).

3 **Q. Please describe the mechanism used in other LMP-style markets to protect**
4 **against paying congestion charges.**

5 A. In other LMP-style markets such as MISO, PJM Interconnection, New York ISO,
6 and ISO New England, financial instruments, sometimes call "Financial Transmission Rights"
7 (FTRs), are used to hedge congestion costs. FTR owners are paid (or charged) the difference in
8 LMP between the source and sink specified by the FTR. In theory, this is an equal and opposite
9 payment to the congestion charges assessed by the RTO for scheduled transmission service
10 between the same source/sink locations. For example, if the LMP difference between a market
11 participant's generator and their load is \$10/MW, the market participant is charged \$10/MWh to
12 move energy from their generator to their load. However, if the market participant owns the FTR
13 between the generator and the load, the market participant receives \$10/MWh from the RTO.

14 Typically in these markets, market participants that have firm transmission service are
15 allocated a portfolio of FTRs that roughly matches their transmission service. In most cases,
16 these allocations are done on an annual basis, though there are secondary markets where FTRs
17 are traded. To ensure that the RTO collects enough revenue from congestion charges to pay FTR
18 holders, the RTO must ensure that the FTRs allocated and/or sold must be simultaneously
19 feasible (i.e., if FTRs represented real transactions, the total impact on the transmission system
20 would not violate any operating limits).

21 The exact process varies by market.

22 **Q. How do FTRs differ from the scheduling process used in SPP to protect**
23 **against congestion charges?**

24 A. In general, FTRs have either been allocated or auctioned on an annual basis, with
25 monthly auctions for any remaining rights. While FTR trades occur in secondary markets and

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1 can sometimes be reconfigured (i.e., modified to a different source/sink designation), FTRs
2 cannot be adjusted as frequently or easily as schedules can under the SPP EIS market design.
3 The flexibility provided by SPP's scheduling process should make it easier for market
4 participants to obtain hedges that more closely align with their real-time needs. Scheduling
5 rights in SPP can be thought of somewhat like a flexible portfolio of FTRs.

6 The length of time covered by the hedging mechanisms also differs between FTRs and
7 the SPP scheduling rights. Typically, FTRs are limited to a one-year duration. With the
8 scheduling rights used in SPP, transmission service reservations can be made many years into the
9 future.

10 Another difference relates to the implications of a reduction in transmission capacity once
11 FTRs or scheduling rights have been granted. With FTRs, a reduction in actual transmission
12 capacity can result in the RTO having insufficient congestion charge collections to fully pay FTR
13 holders. In this case, the revenue paid to FTR holders is prorated across all FTR holders.

14 In the SPP case, a reduction in actual transmission capacity can result in schedule
15 curtailment for those that scheduled transactions across the now reduced portion of the
16 transmission network. To the extent a market participant could not schedule from an alternative
17 resource, this would place those with transmission service across the constrained path into the
18 EIS market, exposing them to congestion charges. Therefore, the reduction in transmission
19 capacity affects those that desired to use the now reduced transmission path, and does not affect
20 other market participants.

21 One last major difference between FTRs and the scheduling process used in SPP to
22 protect against congestion charges is that the SPP process avoids the lengthy and contentious
23 process of allocating FTRs. From start to finish, resolving the FTR allocation process can take
24 more than two years.

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1 **Q. Does this conclude your direct testimony?**

2 A. Yes.