Exhibit No.: ____
Issue: Policy Issues Related to Southwest Power Pool
Witness: Burton L. Crawford
Type of Exhibit: Direct Testimony
Sponsoring Party: Kansas City Power & Light Company
Case No. EO-2006-0142
Date Testimony Prepared: September 27, 2005

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

FILED
JUN 0 2 2006
Missouri Public
Service Commission

SEPTEMBER 27, 2005

Exhibit No. 3
Case No(s). EO-2006-0141
EO-2006-0142
Date 5-12-06 Rptr KF

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	)))))	Case No. EO-2006-0142

AFFIDAVIT OF BURTON L. CRAWFORD

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Burton L. Crawford, being first duly sworn on his oath, states:

1. My name is Burton L. Crawford. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Manger, Deregulation.

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 fourteen (14) 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 swear and affirm 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.

Burton L. Crawford

Subscribed and sworn before me this 27th day of September 2005.

Carol Sivils
Notary Public

CAROL SIVILS NOTARY SEAL NOTARY PUBLIC STATE OF MISSOURI

My commission expires:

CAROL SIVILS
Notary Public - Notary Seal
STATE OF MISSOURI
Clay County
My Commission Expires: June 15, 2007

DIRECT TESTIMONY

OF

BURTON L. CRAWFORD

KANSAS CITY POWER & LIGHT COMPANY

Q. Please state your name and business address.

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

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

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

Q. What is your educational background?

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

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

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

Q. Please describe your involvement with the SPP.

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

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

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

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

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

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

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

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

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

1 Order 2000, p. 423.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. The SPP EIS market is settled financially based on the differences between actual generation (or load) and that which was previously scheduled. A schedule informs SPP of a 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 the transmission system. SPP will calculate a load-weighted average LIP for financial settlement of load imbalances.

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

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

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

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

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

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}

Net Settlement = Generation Settlement + Load Settlement

= $0 + $0

= $0

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.

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

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

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

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

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

Q. How frequently are transmission schedules curtailed in SPP?

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

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

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

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

Q. Is there any prioritization to schedule curtailments?

A. Yes. Just like today, transmission service under the EIS market will have different priorities. This prioritization is based on how the transmission service was sold. Transmission service is either sold as firm or non-firm, and there are several different levels of non-firm service. For example, hourly non-firm service has a lower priority than monthly non-firm service. Under the EIS market, any needed schedule curtailment will be based on the priority of service (e.g., non-firm service will be curtailed prior to curtailing firm service).

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

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

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

The exact process varies by market.

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

A. In general, FTRs have either been allocated or auctioned on an annual basis, with monthly auctions for any remaining rights. While FTR trades occur in secondary markets and can sometimes be reconfigured (i.e., modified to a different source/sink designation), FTRs cannot be adjusted as frequently or easily as schedules can under the SPP EIS market design. The flexibility provided by SPP's scheduling process should make it easier for market participants to obtain hedges that more closely align with their real-time needs. Scheduling rights in SPP can be thought of somewhat like a flexible portfolio of FTRs.

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

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

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

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

Q. Does this conclude your direct testimony?

A. Yes.