Exhibit No.: ____
Issue: Policy Issues Related to Southwest Power Pool
Witness: Leslie E. Dillahunty
Type of Exhibit: Direct Testimony
Sponsoring Party: Southwest Power Pool, Inc
Case No.: EO-2006-0141
Date Testimony Prepared: September 30, 2005

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

DIRECT TESTIMONY OF
LESLIE E. DILLAHUNTY, VICE PRESIDENT,
REGULATORY POLICY, SOUTHWEST POWER POOL, INC.

Q. Please state your name, position, and business address.

A. My name is Leslie E. Dillahunty, Vice President, Regulatory Policy, Southwest Power Pool, 415 North McKinley, Suite 140, Plaza West, Little Rock, AR 72205-3020.

Q. What are your duties and responsibilities in your current position?

A. Organizationally, I coordinate and support activities in the regulatory affairs and engineering areas. Additionally, I am involved with a number of SPP Committee activities, regulatory and policy matters, as well as specific project assignments.

Q. Please describe your educational and professional background.

A. I am a graduate of Louisiana Tech University holding a Bachelor's and Master's degree in Mechanical Engineering. During the period 1971-2002, I held numerous positions within the Southwestern Electric Power Company; its parent company, the Central and South West Corporation; and the merged company, American Electric Power. The bulk of this experience dealt with generation, engineering, fuel procurement, system operations, and environmental affairs. I began a consulting role with Southwest Power Pool in 2002 that led to permanent employment and my present position. I am a Registered Professional Engineer in the states of Louisiana and Texas and have attended a number of advanced management courses.

Q. What is the purpose of your testimony?

A. My testimony supports the Applications of The Empire District Electric Company (Empire) and of Kansas City Power & Light Company (KCPL) to transfer functional control of certain transmission facilities to the Southwest Power Pool (SPP). I will focus on the qualifications of SPP to assume functional control over these certain transmission facilities of Empire and KCPL. I will also introduce three other witnesses in this testimony. These witnesses will provide additional evidence on why it is not detrimental to the public interest for this Commission to grant Empire's and KCPL's Applications.

HISTORY, FUNCTIONAL CONTROL AND RTO EVOLUTION

Q. Please give a brief history of SPP.

A. SPP is an Arkansas non-profit corporation with its principal place of business in Little Rock, Arkansas. SPP came into existence in 1941, when 11 companies joined together voluntarily to serve critical national defense needs during World War II. When the war ended in 1945, SPP's Executive Committee decided the organization should be retained to further the benefits of coordinated operation of their electric systems. As a result of the northeast power interruption in late 1965, a number of reliability councils were organized, and in 1968 SPP joined with 12 other entities to form the National Electric Reliability Council, now known as the North American Electric Reliability Council (NERC). SPP incorporated as a not-for-profit corporation in 1994.

SPP currently has forty-five (45) members serving more than 4 million customers in a 255,000 square mile area covering all or part of the States of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma and Texas. SPP's membership includes 13 investor-owned utilities, seven municipal systems, eight generation and transmission cooperatives, two State authorities, three independent power producers and twelve power marketers. Both Kansas City Power & Light and Empire District Electric Company were founding members of SPP.

Since 1998, SPP has administered open-access transmission service across the SPP region under the terms of SPP's open-access transmission tariff, filed with and approved by the Federal Energy Regulatory Commission ("FERC"). The transmission facilities used to provide service under the SPP tariff are comprised of the transmission facilities owned by a number of public utility and non-public utility members of SPP that are currently committed to the SPP tariff. Customers taking service under the SPP tariff now possess the ability to receive and/or deliver power throughout the SPP region with one-stop shopping, while paying only a single non-pancaked transmission charge for service under the SPP tariff.

FERC Order No. 2000[1] strongly encouraged all public utilities that own, operate or control interstate transmission facilities to participate in a Regional Transmission Organization ("RTO"). On October 15, 2003, SPP submitted a

---

[1]*Regional Transmission Organizations Order No. 2000*, III FERC Stats & Regs., Regs. Preambles ¶ 31,089 (1999), order on reh'g, *Order No. 2000-A*, III FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000).

filing pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 8244, and Section 35.34 of the FERC's regulations, to establish the SPP RTO. This filing sought recognition that the SPP RTO satisfied the requirements of Order 2000 and the FERC's regulations issued thereunder. In a series of orders issued October 1, 2004, FERC granted SPP RTO status subject to certain limited compliance issues.

Q. Are there additional organizational or functional details concerning SPP's history that may be of value in evaluating the Applications?

A. Yes. There are at least three other functions that are worthy of comment. First, in 1991, SPP began to administer a reserve-sharing program among its members that allows the combined resources of the participating members to be used to meet the NERC criteria for the maintenance of reserve generation, which is equal the largest unit scheduled for operation in a given period on the SPP system plus ½ of the second largest unit scheduled.. Absent this program, individual members would have to maintain a higher level of reserves than that which is available in a joint approach.

Second, SPP began providing security coordination in a more formal manner in 1997. This included monitoring the reliability needs of the members in both real time and forward-looking scenarios. Because of the nature of interstate and inter-control area transactions, the regionalization of the security coordination function has provided much greater reliability to the electric transmission grid within SPP's footprint.

Third, in 2001, SPP began providing regional scheduling that allowed SPP to be the scheduling entity for all agreements and transactions. This consolidation not only eased the administrative burden for market participants, but also ensured that SPP was responsible to monitor and record each transaction. These three factors show SPP's contribution to the public interest in supporting the reliable transmission of electricity through innovation and functional control of utility assets and will assist the Commission's evaluation of this request.

Q. What did you mean above when you said that SPP "will assume functional control over certain facilities?"

A. Although the term, "functional control," is not defined in the governing documents of SPP, the SPP Membership Agreement (SPP MA) provides a concise definition of SPP's authority to control the transmission system. Section 2.1.1(k) of the SPP MA states, "SPP shall have the authority to direct the day-to-day operations of the Tariff Facilities in order to carry out its responsibilities as a Transmission Provider and Reliability Coordinator as described in SPP's Operational Authority Reference document..." Section 1.17 defines Tariff Facilities as "[t]he Electric Transmission system and the Distribution Facilities subject to SPP's tariff administration." Finally, the Operational Authority Reference document lists the functions that are included in SPP's authority and that involve functional control. These functions are as follows:

- Scheduling authority over tariff facilities,
- Determining the Available Transmission Capacity under the SPP OATT,
- Coordinating with other regions,

- Directing transmission construction under coordinated planning criteria or under the SPP OATT,
- Acting as a reliability coordinator,
- Directing control areas to maintain adequate reserves,
- Coordinating reliability with other regions,
- Directing the emergency response of any of SPP's members, including the shedding of firm load,
- Monitoring and coordinating voltage schedules,
- Directing redispatch of generation in accordance with the SPP OATT,
- Reviewing and coordinating transmission and generation maintenance schedules, and
- Redirecting maintenance outage schedules for reliability reasons and providing compensation.

Q. Should SPP's position as a FERC-approved RTO weigh into the assessment of the Applications?

A. Yes. The numerous FERC orders and decisions regulating the formation of RTOs should assure the Commission that SPP's functional control of the transmission facilities of Empire and KCPL will enhance the reliable and economic provision of electricity to their customers.

Q. What are the characteristics for a Regional Transmission Organization (RTO) and how has SPP complied?

A. According to FERC Order 2000, the four RTO characteristics are the following:

1. <u>Independence</u> – the first characteristic for an RTO is independence; i.e., the RTO must be independent of any market participant. SPP is governed by a seven member independent Board of Directors. Board of Directors' meetings includes the Members Committee and a representative from the Regional State Committee (as defined in Section 7.2 of the SPP Bylaws) for all meetings except

when in executive session. SPP employees and directors cannot have financial interest in any market participant. SPP is a not-for-profit organization and has no financial interests in any market participant. SPP's decision-making processes are independent of control by any market participant or class of participants. SPP possesses the right to file rates, terms and conditions related to its Tariff with the FERC as directed by the Board of Directors, while SPP transmission owners retain their full rights to seek recovery of their specific wholesale transmission revenue requirements from FERC under provisions of the Federal Power Act.

2. Scope and Configuration – The February 10, 2004 FERC Order granting SPP conditional RTO status considered scope and configuration and determined that (with the exception of one Available Transmission Capacity (ATC) matter that SPP clarified within the requisite 60 days) SPP met the scope and configuration requirements for RTO status.

3. Operational Authority – FERC Order No. 2000 requires RTOs to have functional authority over the operations for all transmission facilities under its control. In SPP's case, FERC in its Order on Compliance issued on October 1, 2004 found that SPP had provided a list clearly identifying facilities under its functional control, had clarified in its Membership Agreement its authority to exercise this control, and had adopted the NERC functional model to describe the RTO's responsibilities. Those elements, combined with the inclusion of the Operational Authority Reference Document in the Membership Agreement

caused FERC to find that SPP had met the third RTO characteristic, Operational Authority.

4. Short-term Reliability – FERC Order No. 2000 also requires that an RTO must have exclusive authority for: (1) receiving, confirming and implementing all interchange schedules; (2) ordering redispatch of any generator connected to transmission facilities it exercises functional control of if necessary for the reliable operation of these facilities; (3) approving or disapproving all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards; and (4) if reliability standards are established by another entity, reporting to the FERC its ability to provide reliable, non-discriminatory and efficiently-priced transmission service. FERC's February 2004 Order found that "SPP meets the Order No. 2000 requirements for Short-Term Reliability".

Q. Briefly enumerate and explain the required functions of a Regional Transmission Organization.

A. 1. The RTO is to be the sole administrator and provider of transmission service. SPP meets this required function. This is a continuation of services that SPP has performed over an extended period of time. These services affect facilities covered by SPP's Open Access Transmission Tariff (OATT) and other facilities subject to SPP's control with regard to non-grandfathered, non-bundled load transmission.

2. FERC Order 2000 contained certain requirements with regard to congestion management that is the responsibility of SPP as an RTO. SPP has managed real-time congestion pursuant to its Tariff through transmission line loading relief (TLR). Beyond the existing procedure for the control of congestion, the February 10, 2004 RTO Order assigned to the SPP Regional State Committee "primary responsibility" for the determination of the timing and methodology of a replacement for the TLR approach.

3. As an RTO, SPP must also have procedures in place to address parallel path flows within its region and other regions. SPP has a long history in this area of responsibility as the regional security coordinator and has met this requirement.

4. The RTO must be the provider of last resort for ancillary services. While market participants have the right to self-supply ancillary services, the SPP Tariff contains provisions for SPP (through its members) to provide these services. This fulfills the ancillary services requirement.

5. An RTO must be the single administrator of the OATT, and SPP has met this requirement.

6. The RTO must engage in market monitoring. SPP has engaged Boston Pacific as an Independent Market Monitor (IMM). This function has been fulfilled

and the first required annual report was released and submitted to the RSC and SPP Board on May 31, 2005. Internally, SPP has also established an Independent Market Monitoring Unit that is in the initial stages of formation in parallel with the scheduled implementation of an imbalance energy market in on May 1, 2006.

7. The RTO must be responsible for planning and expansion of the transmission system. SPP has developed a regional planning process and an associated transmission expansion plan. SPP also has a FERC-approved cost allocation plan that was developed by the SPP Regional State Committee.

8. Finally, the RTO must be responsible for interregional coordination. SPP is a NERC regional reliability council and has a joint operation agreement with the Midwest Independent Transmission System Operator. SPP continues to fulfill its commitment to interregional coordination.

Q. Please describe SPP's Regional State Committee ("RSC") and the RSC's role in SPP.

A. The SPP RTO Bylaws provide for the creation of a Regional State Committee ("RSC") to be comprised of one designated commissioner from each State regulatory commission having jurisdiction over an SPP member. This organization was formed April 26, 2004, and this Commission, through its designated representative, is a member of the RSC. The RSC has primary responsibility for determining regional proposals and the transition process in the following areas:

(a) Whether and to what extent participant funding will be used for transmission enhancements;

(b) Whether license plate or postage stamp rates will be used for the regional access charge;

(c) Financial Transmission Rights ("FTRs" allocation, where a locational price methodology is used; and

(d) The transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights.

The RSC also will determine the approach for resource adequacy across the entire region. In addition, with respect to transmission planning, the RSC will determine whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process. As the RSC reaches decisions on the methodology that will be used to address any of these issues, SPP will file this methodology pursuant to Section 205 of the Federal Power Act. SPP also can file its own related proposals pursuant to Section 205 of the Federal Power Act.

Q. Has the RSC approved a cost allocation methodology for recovering costs associated with new transmission facilities constructed within the SPP region?

A. Yes. On November 16, 2004, the RSC unanimously approved a cost allocation methodology for allocating the costs associated with new transmission facilities constructed within the SPP region on November 16, 2004. Subsequently, SPP submitted this allocation methodology as part of a Section 205 filing to the FERC on February 28, 2005. FERC conditionally accepted this methodology on April 22, 2005, to be effective May 5, 2005.

Q. Please describe how this cost allocation methodology impacts transmission owners' revenue requirements within the region.

A. As new facilities are constructed, SPP will assign the costs associated with these new facilities to the transmission owners (and other transmission customers) in accordance with the recently approved cost allocation methodology. Hence, these represent additional costs to the transmission owners that they will seek to recover under the appropriate retail tariffs. These costs will arise through a two-year SPP planning process with opportunities for stakeholder input, including the RSC. The independent SPP Board of Directors will then approve the Plan. The costs resulting from the Plan will be allocated according to the FERC-accepted cost allocation methodology.

SPP believes the transmission owners should be permitted to recover these additional costs given they will be incurred to support the reliability of the SPP region and are necessary to meet the SPP regional reliability criteria. Transmission Owners have a responsibility to maintain the reliability of the electrical grid. Given the open, public process associated with the implementation and approval of important recent changes involving reliability assessments, aggregate studies, cost allocation methodologies and the Energy Imbalance Services (EIS) market coupled with the sizable effort and financial commitment made by Empire, KCPL, the State(s) and other stakeholders, I encourage this Commission to provide the necessary element of cost recovery certainty to ensure that the desired benefits can be achieved. Cost Recovery is the second side of the two-sided coin of cost incurrence and cost recovery. To facilitate a successful transmission upgrade process, both sides of the coin must be in place. The revised SPP OATT sheets and the FERC order approving this tariff change are attached to this testimony as Schedules 1 and 2, respectively.

COST-BENEFIT ANALYSIS

Q. Please give a general overview of the Cost-Benefit Analysis Performed for the SPP Regional State Committee.

A. The SPP Regional State Committee retained CRA International, formerly Charles Rivers Associates (CRAI) to perform a Cost-Benefit Analysis to (1) analyze the probable costs and benefits that accrue from the consolidation and utilization of the services and functions provided by SPP and (2) the costs and benefits of SPP's implementation of an Energy Imbalance Service market. The *Cost Benefit Analysis Performed for the SPP Regional State Committee Final Report*, hereinafter referred to as "Study" or "Report," was released on April 25, 2005 and presented to the Regional State Committee and the SPP Board of Directors. The Study was subsequently revised on July 27, 2005.

Q. What has been your role in the Study and its follow-up during the time period following the Study's release on April 25, 2005?

A. I served as an Associate Member of the Cost Benefits Task Force (CBTF) that was comprised of SPP stakeholders, including participants from the Staff of the respective state commissions participating in the RSC. The CBTF, chaired by Sam Loudenslager of the Arkansas Public Service Commission, prepared the scope of work for the Study; solicited and evaluated proposals for the performance of the Study; selected the firm (CRAI) to conduct the study; provided the requisite policy, input data, and review functions that enabled CRAI to complete the analysis. I attended the April 25, 2005 meeting of the RSC where the Study was initially presented. Subsequently, I have served as a liaison with CRAI, SPP Staff, members and regulators as each has progressed in their respective review of the Study results.

Q. During the period since the Study was completed and released, what has been the general tone of the feedback concerning the Study?

A. 1. I have observed many detailed discussions of the specific values quantified by the Study, but I continually remind myself, and others, that the Study is only one important piece of information and not the only factor that should be considered in any evaluation of the benefit of membership in SPP.

2. There are many specific questions about the CRAI model assumptions. However, one must remember that the Study was conducted at the direction of the CBTF with credible, agreed upon inputs. The Study is a complex analysis, with strong interdependencies. The evaluation of a single change and an assessment of its impact are not possible without actually re-running the economic model used to develop the values in the Study. CRAI should be valued for their independence and professionalism. I believe the results presented in the Report to be indicative and not definitive for both the costs and benefits associated with membership in SPP.

3. CRAI states in the Report that "the Study results are subject to a margin of error due to various abstractions that must be made in any modeling exercise such as this...CRAI has not had the opportunity to develop a formal margin of error for this Study, but CRAI experience in modeling exercises of this type suggest that a change of less than $10 million over the Study period for individual companies is likely to be within the Study's margin of error". The production cost modeling that produced the quantitative impacts in the Study was designed to produce "some high-level, region-wide wholesale market metrics related to the three cases simulated." CRAI has urged caution in interpreting the results of the Study because, as these region-wide values were allocated to individual States and Companies, the Study accuracy was diminished due to this "slice and dice" effect.

4. The Study applied 2003 historical average distribution percentages to allocate the wheeling impacts to individual SPP companies. This modeling accommodation continues to be a topic for discussion. The SPP Tariff allocates 50% of point-to-point revenue to members based upon their pro-rata portion of overall revenue requirements and 50% based upon the megawatt-mile usage associated with transactions. CRAI considered the use of a high-level analysis method that simulated the SPP Tariff; however, initial indications from this method showed that loop flow effects are important within this compact region. This complicated the successful application of an expedient, cost effective modeling approach that mimicked the SPP Tariff provisions. Instead of continuing to pursue this method, CRAI chose the historical average approach.

5. If SPP and other RTOs are effective in securing some downward adjustment in the FERC fees and if SPP were to commence the provision of Entergy ICT services, the impact of the reduced fees should drive the costs of RTO membership down and increase the positive results of this Study.

6. The Study includes no representation of demand side response to price signals. The SPP Energy Imbalance market will explicitly provide these price signals; however the quantitative modeling of the impacts of such demand "elasticity" significantly complicates a study effort and was not attempted by CRAI. A representation of the demand side price response could potentially impact the results.

7. The study only reflects the addition of 30 MW of the Sunflower Wind farm in 2005 and 800 MW of the Iatan 2 coal fired facility scheduled for 2010. No generating unit retirements were modeled. The Study stated that overall projected capacity balance indicated that existing installed capacity, coupled with these additions, will be more than sufficient to meet SPP reliability requirements through the Study period. Unit commitments or retirements beyond those modeled would impact the Study.

8. Finally, and of great significance, FERC Order 2000 states, "We conclude that control area operators should face the same costs and price signals as other transmission customers and, therefore, also should be required to clear system imbalances through a real-time balancing market." This leads to the conclusion that SPP must move forward to an imbalance energy market. Implementation of that market will provide a substantial improvement in transparency. Once this market is implemented, it will provide another important evolutionary step for SPP to possibly move forward into another phase of the market such as congestion management or ancillary services.

Q. Please summarize your testimony.

A. SPP has a rich history of supporting the reliable transmission of electricity in its role as a NERC regional reliability coordinator and through such initiatives as its reserve sharing program, security coordination and regional scheduling. By successfully satisfying the FERC's rigorous requirements for RTO status, SPP has established that it has the independence, scope and configuration, operational authority and short-term reliability attributes that would enhance the reliable, economic and non-discriminatory provision of transmission service to its members, to market participants and their customers. For these reasons, as well as other reasons discussed by the other witnesses I will introduce, SPP respectfully submits that it is well qualified to assume functional control over certain transmission facilities of Empire and KCPL.

Q. Who are the other witnesses you would like to introduce and what is the purpose of their testimony?

A. <u>Ellen Wolfe, Senior Consultant, Charles Rivers Associates International (CRAI)</u> – Mrs. Wolfe has been involved with numerous cost benefit studies of RTOs and was the project manager for CRAI in the *Cost Benefit Analysis Performed for the SPP Regional State Committee Final Report* that was presented to the RSC on April 25, 2005 and revised on July 27, 2005. She has extensive knowledge of the outcome of the Study and will provide the wholesale market modeling and resulting impacts. The Study is provided as Schedule 1 of this testimony.

<u>Ralph Luciani, Vice President, Charles Rivers Associates International (CRAI)</u> – Mr. Luciani oversaw the financial evaluation of costs and benefits contained in the Study, and he oversaw the financial and rate analyses presented in the SEARUC and Dominion Power RTO cost-benefit studies. Mr. Luciani will testify to the cost and allocation methods applied in the study and the resulting impacts.

Richard A. Wodyka, Senior Vice President of Energy and Utility Services, Gestalt, LLC – Mr. Wodyka is currently serving as Senior Vice President for Gestalt, LLC in their Energy and Utility Practice primarily responsible for regulatory and financial services activities including international projects. Mr. Wodyka has extensive experience in electric power system planning, real-time system operations, and the new energy markets associated with electric energy deregulation which was attained while working for over 31 years at PJM Interconnection as well as his work as an independent electric utility consultant. His testimony will provide an independent assessment of the *Cost Benefit Analysis Performed for the SPP Regional State Committee Final Report* completed by CRAI.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of The Empire District Electric Company for Authority to Transfer Functional Control of Certain Transmission Assets to the Southwest Power Pool, Inc.	)))))	Case No. EO-2006-0141

AFFIDAVIT OF LESLIE E. DILLAHUNTY

State of Arkansas)
) ss
County of Pulaski)

Leslie E. Dillahunty, being first duly sworn on his oath, states:

1. My name is Leslie E. Dillahunty, Vice President, Regulatory Policy, Southwest Power Pool, 415 North McKinley, Suite 140, Plaza West, Little Rock, AR 72205-3020.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Southwest Power Pool, Inc., consisting of nineteen (19) pages, having been prepared in written form for introduction into evidence in the above-captioned case.

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.

Leslie E. Dillahunty
Leslie E. Dillahunty

Subscribed and sworn before me this 30th day of September 2005.

Laurie Ann Guinn
Notary Public

My commission expires: June 20, 2014

OFFICIAL SEAL
LAURIE ANN GUINN
NOTARY PUBLIC-STATE OF ARKANSAS
PULASKI COUNTY
My Commission Expires 06-20-14

Southwest Power Pool
FERC Electric Tariff
Fourth Revised Volume No. 1

Third Revised Sheet No. 1
Superseding Second Revised Sheet No. 1

TABLE OF CONTENTS

Dillahunty Testimony Schedule 1

Dillahunty Testimony Schedule 1

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Aggregate Transmission Study: Transmission system impact and facilities studies that aggregate Transmission Service requests received over a 120-day period. These requests are evaluated simultaneously to provide for optimization of transmission expansion.

1.1a Ancillary Services: Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's and Transmission Owner's(s) Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Cost: The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3 Application: A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.3a Attachment Facilities: Facilities that serve to interconnect a generating unit with a Transmission Owner's transmission facilities.

1.3b Base Plan Avoided Revenue Requirement: The revenue requirement associated with previously approved Base Plan Upgrades that have been deferred or displaced due to a subsequently identified transmission upgrade.

1.3c Base Plan Charge: Charge assessed by SPP in accordance with Schedule 11 to recover the revenue requirement of facilities classified as Base Plan Upgrades.

1.3d Base Plan Region-wide Annual Transmission Revenue Requirement: The sum of the annual transmission revenue requirement for each Base Plan Upgrade and of the Base Plan Avoided Revenue Requirement(s), if any, that are allocated to the SPP Region in accordance with Attachment J to this Tariff.

1.3e Base Plan Region-wide Charge: Regional component of the charge assessed by SPP in accordance with Schedule 11 to recover the revenue requirement of facilities classified as Base Plan Upgrades.