REBUTTAL TESTIMONY OF DAVID A. SPAINHOWARD

Q1. Please state your name.

Response: My name is David A. Spainhoward.

Q2. Are you the same David A. Spainhoward who has filed direct testimony in this case?

Response: Yes.

Q3. Please explain the purpose of your rebuttal testimony.

Response: The purpose of my rebuttal testimony is to correct the erroneous implications contained in certain statements made in the direct testimony of Thoroughbred's witnesses

Q4. Are you familiar with the meetings that Thoroughbred witness Jacob Williams says in his testimony that he participated in with Rivers regarding expansion of the generating facilities at the Big Rivers' Wilson Generating Station site?

Response: Yes. I participated on behalf of Big Rivers in most of those meetings.

Q5. Mr. Williams states on page 4 of his testimony that "[o]n or about February 23, 2001, a Confidentiality Agreement was executed between Thoroughbred's parent and BREC to share information on the Thoroughbred Energy Campus as well as other generation opportunities in the area." Are you familiar with this confidentiality agreement?

Response: Yes. I have attached a copy of that confidentiality agreement to this testimony as Exhibit DAS-2.

Q6. In its response to Big Rivers' Data Request No. 1, Thoroughbred states that one of the reasons its application in this matter does not mention the meetings between its parent and Big Rivers regarding locating the Thoroughbred facility at the Wilson site is the existence of a confidentiality agreement. Did Big Rivers expect that this confidentiality agreement would prevent Thoroughbred from mentioning those meetings in its application?

Response: No. The confidentiality agreement, which Thoroughbred correctly notes is dated February 23, 2001, expired after two years. So the agreement has not been in effect since February of this year, and was certainly not in effect on the date that Thoroughbred filed its application.

Q7. Mr. Williams states on page 2 of his testimony that Big Rivers has discussed a plant expansion at Wilson for "many years without taking any affirmative steps to do so . . . ." Is this statement accurate?

Response: No. Big Rivers has stated publically that it believes it has value at the Wilson site that it should try to extract, even if its system power requirements do not require addition of generation. Mr. Williams' statement is quite odd, since he admits in his testimony, and Thoroughbred admits in data request responses and in its response to Big Rivers' motion to deny participating in several meetings with Big Rivers on that exact subject. Attached to my testimony as Exhibit DAS-3 is a copy of a presentation Mr. Williams made outlining the proposed extent of his company's participation in any expansion project. The investigation of this project is quite serious, and the participants are at the stage of contributing the funds necessary to conduct monitoring and initial permitting activities. Another meeting of the participants is scheduled for this month. Prior to this effort, and since Big Rivers reorganized, Big Rivers has also engaged a developer to market the Wilson site to any party interested in developing another generating unit at Wilson. That developer met with representatives of Mr. Williams' employer, including Mr. Williams. To represent that Big Rivers has taken no affirmative steps to develop the Wilson site is simply erroneous.

Q8. Mr. Williams also says that Big Rivers is an "inappropriate partner" for the Thoroughbred project. During the meetings concerning development of the Wilson site, to your knowledge, did Mr. Williams or any representative of his employer ever say that his employer was unwilling to participate in a project to expand Wilson

because Big Rivers was an inappropriate business partner for his employer?

Response: No. I do not understand why Mr. Williams would participate in the number of meetings with Big Rivers that he did if his employer had such grave reservations about doing business with Big Rivers.

Q9. Is there adequate space available at the Wilson site to accommodate the Thoroughbred project?

Response: Yes.

Q10. Does Big Rivers have any remaining concerns about Thoroughbred's commitment to pay the costs of transmission additions Big Rivers may be required to make as a result of the load created by Thoroughbred's project?

Response: Yes. Thoroughbred's position that it will pay the up-front costs of those transmission additions and improvements, but expects reimbursement through some kind of crediting mechanism. Mr. Housley outlines in his direct and rebuttal testimony the risks associated with crediting mechanisms, and the potential for Big Rivers to find itself paying for some of the costs of these additions and improvements.

Big Rivers notes that Thoroughbred has not stated in its application, its responses to data requests or in its testimony that it will "comply fully" with the sections of Kentucky law listed in KRS 278.710(2). One of those sections listed is the Kentucky law regarding responsibility for transmission costs incurred as the result of the load of a merchant generator. In fact, in referring to the law applicable to transmission costs, Thoroughbred always refers to federal requirements. We also know that Thoroughbred's position on federal transmission policy is at odds with the position of the Kentucky Public Service Commission, as is shown in the comments of each in the FERC standard market design docket, No. RM01-12-000, which are attached to this testimony as Exhibits DAS-4 and DAS-5, respectively. As noted in Mr. Housley's testimony, these facts increase Big Rivers' concern about the ultimate cost to Big Rivers' members if Big Rivers gets caught in a conflict between state and federal jurisdictions over transmission policy on participant funding. Big Rivers believes that Thoroughbred, not Big Rivers, should shoulder that risk, or that a construction certificate should not be issued until this serious problem can be resolved.

Q11. Does this conclude your rebuttal testimony?

Response: Yes.

VERIFICATION

I verify, state, and affirm that the foregoing rebuttal testimony is true and correct to the best of my knowledge and belief.

David A Spainhoward
David A. Spainhoward

STATE OF KENTUCKY

COUNTY OF HENDERSON

Subscribed and sworn to before me by David A. Spainhoward on this the 13th day of October, 2003.

Paula Mitchell
Notary Public, Kentucky State at Large
My Commission Expires 1-12-05

CONFIDENTIALITY AGREEMENT

THIS **CONFIDENTIALITY AGREEMENT** ("Agreement") is made and entered into as of February 23, 2001 ("Agreement Date"), **BIG RIVERS ELECTRIC CORPORATION**, with a principal business located in Henderson, Kentucky ("Big Rivers") and **PEABODY HOLDING COMPANY, INC.** and all its subsidiaries, affiliates and parent companies ("PHC"), with an address of 701 Market Street, Suite 900, St. Louis, Missouri 63101.

WHEREAS, PHC is in the business of providing fuel, power, and financing to it's clients;

WHEREAS, Big Rivers is in the business of providing the wholesale power requirements of its member distribution cooperatives; and

WHEREAS, the parties are interested in evaluating the permitting and design of a power generating facility on Peabody property; and

WHEREAS, to properly conduct the analyses requested and required by each party, each party must have access to and consider certain information which the other party considers to be confidential and/or proprietary in nature, or which the other party is under an obligation to maintain as confidential; and

WHEREAS, each party is willing to make such information available to the other party and to those employees, consultants and legal counsel of the other party who have reason to be so informed, providing the same is held on a confidential basis as specified in this Agreement.

NOW. THEREFORE, in consideration of the premises and promises contained herein, the parties agree as follows:

1. <u>Information</u>. Each party shall provide to the other party all information reasonably requested by the requesting party, available to such party, and which such party considers reasonable and necessary. All such information, including any and all budgets, models, designs, details, cost estimates, cost summaries, financial statements, term sheets proposals, offers, correspondence and letters relating to a power generating facility ("Confidential Materials"), whether provided by PHC to Big Rivers, or by Big Rivers to PHC, and whether written, oral or provided on recorded media, thereafter shall be considered confidential under the terms of this Agreement, unless, and then only to the extent that, such information includes:

    (a) information now in the public domain;

    (b) information known to the other party on the Agreement Date;

(c) information disclosed to a party by any third party not thereby breaching an obligation to the other party hereto, about which obligation by such party has knowledge, or

(d) information required by law to be disclosed or reported

In addition, any and all notes, reports, analyses, memoranda, studies, and other materials prepared by a party, based upon Confidential Materials received from the other party, shall also be considered Confidential Materials for purposes of this Agreement.

2. Commitment. For two (2) years commencing on the Agreement Date, each party shall keep in confidence all of the Confidential materials received by it. Each party shall use the Confidential Materials which it receives from the other party only for purposes related to the analysis required or proved for herein.

Each party shall return to the other party all Confidential Materials which it has received from the other party within thirty (30) days following the receipt of written notice from the other party to return the same. Each party agrees not to copy the Confidential Materials except upon the basis of written authorization from the other party. Unless otherwise agreed to in writing, each party shall, upon the direction of the other party, promptly destroy all copies so made, as well as all notes, studies, or analyses made by it, or its employees relating to the Confidential Materials which had been provided hereunder.

Each party shall only communicate the Confidential Materials to those of its employees, consultants and legal counsel, whose knowledge of the same is required for the purposes stated herein. Any and all such employees, consultants and legal counsel to whom the Confidential Materials have been communicated shall have read and understood the obligations of confidentiality created hereunder. Each party shall not use any of the Confidential Materials provided to it by the other party to the detriment of the other party.

The parties hereby agree that both injunctive relief and monetary damages, alone or in combination, are appropriate remedies for any breach of this Agreement by the other party, its partners, parents, subsidiaries or affiliates, or the employees, agents or consultants of any of them.

Each party shall not, without the express written consent of the other party, disclose to any person the fact that this Agreement exists, or that either party is involved in discussions concerning developing, permitting and construction of a power generating facility, or any of the terms, conditions, or facts with respect to any possible relationship between PHC and Big Rivers, including the status thereof; provided, that either party may make such disclosure if it has receive the written opinion of its attorney that such disclosure must be made by it in order that it does not commit a violation of law, in which case the disclosing party shall notify the other party and its attorney with a reasonable time prior to any disclosure it proposes to make concerning the reasons for, and nature of, such proposed disclosure

In the event that either party or any of its representatives are requested in any proceeding to disclose any of the Confidential Materials, the disclosing party shall give the other party prompt notice of such request, so that such party may seek an appropriate protective order. If, in the absence of a protective order, the disclosing party or any of its representatives are nonetheless compelled to disclose any of the Confidential Materials, the disclosing party or its representative, as the case may be, may disclose such information in the proceeding without liability hereunder; provided, however, that the disclosing party shall give the other party written notice of the information to be disclosed as far in advance of its disclosure as is practicable and, upon written request of the other party, and at the other party's expense, the disclosing party shall use reasonable efforts to obtain assurances that confidential treatment will be accorded to such information.

3. No Waiver. No failure or delay by either party, or any of its representatives, in exercising any right, power or privilege under this Agreement shall operate as a waiver thereof, nor shall any single or partial exercise thereof preclude any other or future exercise of any right, power, or privilege hereunder.

4. Invalidity. In the event any provision of this Agreement shall be held to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions of this Agreement shall not, in any way, be affected or impaired thereby.

5. Operative Provisions of Agreement. This Agreement constitutes the entire agreement between the parties concerning the subject matter hereof, supersedes all other agreements and understandings, and shall be interpreted under the laws of the Commonwealth of Kentucky. No amendment hereof shall be binding unless made by written instrument signed by both parties hereto. Time is of the essence in this Agreement. This Agreement may not be assigned by either party without the prior written consent of the other party.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the date set forth herein, by their duly authorized representatives, each of which, by signing this Agreement, personally represents and guarantees his/her authority to sign for the party indicated.

PEABODY HOLDING COMPANY, INC.
("PHC")

By: [illegible]
Name: [illegible]
Title: [illegible]

BIG RIVERS ELECTRIC
CORPORATION ("Big Rivers")

By: [illegible]
Name: Michael Core
Title: CEO

Peabody

Peabody's Potential Participation in

DB Wilson II

June 6, 2003

Exhibit DAS-3

Peabody

Peabody Interest in DB Wilson II

- Desires to participate in ways to enable projects like this to be able to get financing and therefore get built
- Participation can come in the form of:
  - Long term coal supply agreements which take the fuel price risk and credit worthiness of the coal supplies out of the project
  - Contribute coal reserves and potentially equity to help the overall project economics and ensure financing
- Continue its industry leader role to build and facilitate the building of the next generation of new coal generation

Peabody

Peabody's Value to DB Wilson II Effort

- Lock down fuel price assumptions in development effort
- Lend relevant new coal experience, from the 3 ongoing projects
  - New air regulations implemented since 1990 including
    - FLAG and Class 1 visibility
    - Best Available Control Technology (BACT)
    - Mercury, MACT, analysis
  - Current technology and vendor capabilities to meet the above criteria
  - Actual negotiated costs of projects versus consultants estimates
  - Public relations experience from the permitting processes of the three projects

Peabody

Conditions for Peabody Participation

- Peabody would cost share with other 4 participants with two conditions:
  - If project successfully goes forward, Peabody must be the fuel provider/coal reserve provider, or all fund contributed must be refunded to Peabody
  - All 4 participants, including their affiliates, cannot negatively intervene in the siting process of Thoroughbred Energy Campus. If parties intervene, all fund contributed by Peabody must be refunded to Peabody

ORIGINAL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design	)))	Docket No. RM01-12-000

ADDITIONAL COMMENTS ON JANUARY 10 ISSUES OF PEABODY ENERGY CORPORATION

On November 15, 2002 the Peabody Energy Corporation (Peabody Energy) filed comments in this proceeding regarding the Federal Energy Regulatory Commission's (Commission) proposed Standard Market Design (SMD). In light of the Commission's October 2, 2002 Notice of Conferences and Revisions to Public Comment Schedule, Peabody Energy welcomes this opportunity to file additional comments on issues identified in that Notice. Those issues include: (1) transmission planing and pricing, including participant funding issues; (2) Regional State Advisory Committees and state participation; and (3) Congestion Revenue Rights (CRRs) and transition issues.

I. INTRODUCTION AND OVERVIEW

In its November 15 comments, Peabody Energy largely endorsed the Commission's SMD initiative and urged the adoption of a Final Rule, with certain critical modifications, as soon as possible. However, the issues identified for this second round of comments are some of the more difficult and controversial in the development of the SMD. These are the areas where details matter, where consensus is difficult and where the Commission must develop both transition and "end state" rules that may vary. Recognizing these difficulties, Peabody Energy urges the Commission to stay the course on its SMD initiative and to make the critical decisions necessary to achieve the seamless regional wholesale markets needed to bring the benefits of reliable and affordable electricity to consumers. Peabody Energy also urges the Commission to view these policies from a multi-fuel perspective versus the essentially gas only new generation push during the last ten years. The low variable cost baseload generation assets are the backbone of the electric grid today and the reason the U.S. has affordable electricity. The industry is beginning the next wave of development of clean coal plants to meet the growing electric requirements as well as replace some of the smaller, older, inefficient plants that are still operating.

With respect to the issue of transmission planning, regional and interregional long-term transmission planning is critical to resolving "National Interest Transmission Bottlenecks" as well as other less interregional transmission problems. Solving National Interest Transmission Bottlenecks will benefit large regions of customers by reducing electric prices in the wholesale markets, and the cost of achieving those benefits would be shared over one or more regions. We cannot afford to wait for Locational Marginal Pricing (LMP) markets to develop over the next two to three years to identify well-known National Interest Transmission Bottlenecks. Waiting will unnecessarily cost electricity customers a significant amount of money by causing underutilization of existing low-cost resources and siting of inefficient new generation in sub optimal locations.

Peabody Energy is also concerned with the Commission's interconnection policies. While extensive and important progress was made in the rulemaking proceeding last year, Peabody Energy still awaits a Final Rule resolving critical outstanding issues.[1] Needless to say, pricing issues, including the current debate about participant funding, remain at the core of the current controversy.

With respect to participant funding, Peabody Energy will pay hundreds of millions of dollars to upgrade and expand the nation's transmission grid in conjunction with just two 1,500 MW projects it is developing. This investment will be made possible by the Commission's current policy on crediting. While other forms of participant funding may be equally equitable and allow for similar investment, it is critical that an independent transmission operator be in place and make the key decisions about participant funding. An Independent Transmission Provider (ITP)/Regional Transmission Organization (RTO) must be in place to evaluate congestion costs fairly and to ensure that the assignment of benefits and costs associated with infrastructure upgrades are assessed and allocated in an unbiased manner.

On the issues of the role of states in this process, Peabody Energy applauds the Commission's efforts to develop a meaningful role for state participation in achieving regional solutions to the problems facing today's developing markets. However, it is important that the role of Regional State Advisory Committees (RSACs) be clearly defined, that governance and structure be fairly uniform and that RSACs not become new, bureaucratic entities, slowing rather than speeding the process of infrastructure development.

---

[1] Of specific concern is that certain issues that appeared to be resolved in the Standardization of Generator Interconnection Agreements and Procedures NOPR process last year, such as the effect of studying generators as network resources, now appear to be the topic of discussion at the January 21 technical conference in this proceeding (Docket No. RM01-12-000), the Generator Interconnection NOPR (Docket No. RM02-1-000) and the Small Generator Interconnection NOPR (Docket No. RM02-12-000).

On Congestion Revenue Rights (CRRs), Peabody Energy believes that a system based on uniform financial rights that allows parties to hedge congestion risk in a non-discriminatory manner is a key to the success of a fully implemented SMD. Peabody Energy addresses two overriding concerns in these comments. First, the system of congestion rights should be purely financial, without an overlay of physical rights that perpetuates undue discrimination. Second, based on experiences to date, Peabody Energy endorses a prompt transition from CRR allocations to auctions.

II. TRANSMISSION PLANNING AND PRICING

A. Introduction

The issue of transmission planning is a complex one and is of great concern to Peabody Energy. It is well documented that investment in transmission infrastructure is lagging.[2] As a supplier of fuel for over 9% of the electricity produced in the U.S., Peabody Energy has an interest in a robust, efficient transmission system that will provide all consumers with reliable and affordable electricity.

B. Regional and Interregional Long Term Transmission Planning Is Critical To Resolving "National Interest Transmission Bottlenecks"

Regional and interregional long-term transmission planning is critical to resolving National Interest Transmission Bottlenecks as well as other less interregional transmission problems. Resolving these bottlenecks will benefit large regions of consumers by reducing electric prices across the wholesale markets, and the cost of achieving these benefits would be shared over one or more regions. The identification of the National Interest Transmission Bottlenecks, the development of mechanisms to facilitate their resolution and the cost/benefit analysis of doing so, must happen rapidly given that transmission solutions may take five to ten years to implement. In the interim, we will be left to deal with these systemic bottlenecks and their debilitating costs to an otherwise efficient electricity delivery system for the next five to ten years. We cannot afford to wait for LMP markets to develop over the next two to three years to identify well-known National Interest Transmission Bottlenecks.

Implementing transmission solutions/upgrades can take up to ten years, therefore, the planning process should include consideration of various scenarios of generation mixes, relative fuel pricing, load growth and environmental requirements ten years in advance. This generic review should identify, on a regional basis, the projects that will provide consumer benefits under a robust set of scenarios. This independent cost/benefit analysis will provide policy decision makers at the local, state and federal level with much of the needed support data to defend regional and interregional projects in the public domain. Finally, given the physics and associated financial implications of the electricity market, the planning of the transmission system should err on the side of adequate transmission reserves versus inadequate reserves. The experience from the West should remind us that inadequate transmission reserves enables market manipulation and consumer price harm far more than when transmission reserves are at the high end of the acceptable range.

[2] Eric Hirst and Brendan Kirby, "Transmission Planning for a Restructuring U.S. Electricity Industry," June 2001 located at http://www.ehirst.com/PDF/TransPlanning.pdf.

C. LMP Pricing Is Useful in Identifying Long-Term Transmission Solutions, But It Does Not Directly Enable Market Solutions

A spot market for electricity, including LMP pricing, is useful in terms of providing appropriate price signals for short-term market responses and identifying long-term areas of concern. However, LMP pricing alone does not directly lead to resolution of long-term transmission bottlenecks that inhibit low-cost generation from reaching load areas with higher costs. More direct incentives, better planning and market stability will be needed for transmission providers to act to resolve these bottlenecks for the benefit of all consumers.

FERC must take into account the inadequate transmission system today and not solely rely on spot market price signal of LMP to identify the problems. Doing so would be akin to implementing the "New California Spot Market" five years ago, without recognizing there was a lack of generation and transmission infrastructure to survive market events outside the normal load growth, fuel price, weather pattern and environmental regulations. Unfortunately, we all witnessed the outcome of a failure to recognize the current infrastructure situation and implement rules assuming all was well.

D. There is a Need for Clarity About the Commission's Transmission Expansion Pricing Policy in the Generator Interconnection NOPR and the SMD NOPR

Peabody Energy is concerned that aspects of the SMD could conflict with the forthcoming generator interconnection rule being developed in Docket No. RM02-1-000. Peabody Energy encourages the Commission to honor the consensus work achieved in the interconnection process and not create policies in this rulemaking that will undermine or negate that process.

In the Generator Interconnection NOPR the Commission states that the "rolled in" approach is the pricing policy of the interconnection rule, yet the SMD process suggests that participant funding will be the Commission's pricing policy going forward. The cross currents of these two proposed rules and their different implementation transition schedules will be problematic unless the Commission is able to articulate its system expansion pricing policy in a clear way and includes a fair transition for all market participants.

One area of concern is that in P 193 of the SMD Preamble it states that, "whether for reliability or economic reasons," the Commission historically uses "rolled in" pricing to administratively determine how users will pay for system expansions. However, in several existing markets such as the New England ISO and PJM,[3] the Commission has approved "participant funding mechanisms" that do not directly follow the "rolled in" pricing approach described in the SMD NOPR. Under these current pricing policies, the costs associated with interconnecting to the grid have been largely paid for by generators. Where network upgrades were required that benefited all transmission system users, generators then received transmission credits.

Yet, in Appendix F of the SMD NOPR, "Access Charges and Congestion Revenue Rights," the Commission signals a change in direction regarding its pricing policy, leaning toward participant funding, while continuing with the policy that generators receive transmission credits for transmission system upgrades:

> If participant funding is adopted, the customer would receive the Congestion Revenue Rights associated with the additional transfer capability made possible by the transmission

[3] See ISO New England, Inc., 91 FERC ¶ 61,311 (2000); order on reh'g, 95 FERC ¶ 61,384 (2001) and PJM Interconnection, L.L.C., 87 FERC ¶ 61,299 (1999), reh'g denied, 92 FERC ¶ 61,186 (2000).

expansion. This pricing is subject to the outcome of the Generator Interconnection rule in Docket No. RM02-1-000.

Peabody Energy's concern is not with the philosophy of participant funding, discussed further below, but with the details by which it will work. Peabody Energy is more concerned about how an evolving participant funding policy will be balanced against existing policies for pricing for transmission system upgrades. Since any fair approach to participant funding requires that independent transmission administrators and LMP be in place existing policies should not be changed until the transition to and implementation of the SMD in complete.

Therefore, Peabody Energy strongly urges the Commission to offer more clarity regarding its pricing policies for transmission system network upgrades under the SMD. In addition, the Commission must clarify the rules that will apply during the transition from existing policies to the SMD. Moreover, consensus reached in the Generator Interconnection NOPR must be reflected in the SMD Final Rule.

E. Participant Funding

1. Implementation of Participant Funding Must Keep Interconnection and Transmission Upgrade Cost Allocation Reasonable and Equitable

Generators have paid significant amounts to interconnect to the transmission grid in order to competitively serve demand growth and provide needed infrastructure. They have been able to do this, largely in part, because of the Commission's current transmission crediting policy for the funding of network upgrades. As long as the methods for funding network upgrades remain reasonable and equitable among traditional utilities, merchant generators and merchant transmission entities, and generators are able to internalize upgrade costs in their bilateral contracts and spot bids, competitive generators will continue to be able to supply the nation's need for reliable, efficient and competitively-priced power.

Generators need to be able to continue to add competitive supply infrastructure to the grid in a manner that achieves the goals of all system users. The Commission has recognized the importance of adequate infrastructure to competitive markets and, in turn, lower prices for consumers. Peabody Energy, therefore, strongly urges that the Commission keep its existing transmission crediting policy in place until independent transmission operating entities, whether ITPs or RTOs, are operational and can implement a transition to participant funding mechanisms. The Final Rule needs to retain this policy and provide details on how regional markets should transition to participant funding. Participant funding transmission projects should not be allowed to progress on a utility-by-utility basis before ITPs/RTOs are in place. The NOPR's goal of eliminating discrimination in wholesale electricity markets can only be achieved if an ITP/RTO has independent cost allocation responsibility. Otherwise, a utility's transmission expansion decisions would unduly favor themselves and their affiliates, which would severely penalize independent generators such as Peabody Energy, and limit the benefits of competitive markets.

The Commission should look to the benefits associated with participant funding to develop principles to provide adequate parameters for a successful participant funding mechanism. These benefits include equitable cost allocation, properly-sited generation, enhanced reliability and reduction in market prices regionally or interregionally. Peabody Energy cannot emphasize enough that the only way for these benefits to materialize is if there is an independent transmission operator determining the cost of and responsibility for the network transmission upgrades, as well as determining congestion price signals and the assumptions underlying power-flow analyses. Having an independent entity make these determinations is crucial to the success of any participant funding mechanism.

The benefits of transmission upgrades cover a wide variety of market participants, including load-serving entities, generators, marketers and end-use customers. All these parties need to be considered in establishing a participant funding system for the true benefits of a participant-funded cost allocation pricing mechanism to be realized. Despite its inherent complexities, all market participants that benefit from transmission system improvements must be considered in the design of such a mechanism.

This requires that the Commission be thorough in the design and detail of participant funding cost allocation mechanism in the SMD so that fair assignment of system benefits result for the various parties. The assignment of benefits and, in turn, costs for infrastructure additions or upgrades must be done in an unbiased manner for participant funding to work. Only reasoned, detailed rules and parameters for a participant funding mechanism will ensure the comparable and equitable treatment for all market participants that the Commission seeks to establish through SMD.

That said, participant funding is not the end of the discussion. As such, the Commission should not end its exploration of new pricing policies that could be used instead of, or along with, participant funding. Facilitating investment in transmission infrastructure may require additional incentives beyond that offered by participant funding.

The ITP will need to follow a carefully designed standard, with objective criteria, for allocating the costs of network upgrades between those benefiting loads and those benefiting generators. Additionally, the independent entity must consider regional impacts so that variations between markets are minimized to ensure against the creation of seams. Any allocation of costs to market participants must take into account the benefits of higher voltage upgrades that benefit more than one transmission owner's system or more than one geographic zone or region.

Issues associated with the transition from transmission credits to CRRs must be fully addressed to ensure that companies that fund network upgrades receive a value proportionate to their grid investment. While generators have participated and will continue to participate in funding network transmission upgrades, key safeguards preserving the efficiency of LMP must be in place prior to the Commission approval of any specific form of participant funding.

In regional markets run by independent transmission operating entities, interconnecting generators must have the opportunity to compete for energy and capacity sales within and into broad, regional liquid markets to help ensure system reliability. As part of this market framework, interconnecting generators must be able to be assessed as a network resource and to secure Network Access Service (NAS) regardless of whether participant funding is in place or not. They should be able to do this on the same terms as other market participants, commensurate with their investment in the transmission system and without having to pay additional transmission access charges or fees.

independent administration of the transmission system, as proposed in the NOPR, is crucial to facilitating the benefits of participant funding under the SMD, but is still not enough. In addition to an ITP/RTO, an LMP congestion management system, a resolution of transmission crediting issues and a mechanism to ensure that network upgrades costs are reasonably allocated to all parties benefiting from the upgrade are needed for participant funding to work successfully. Unless these SMD elements are in place, participant funding will obligate generators to pay for network upgrades without providing any commensurate rights associated with that investment. The Commission's goal for SMD will be undermined if it puts in place an ill-defined participant funding mechanism without the context provided by SMD.

III. REGIONAL STATE ADVISORY COMMITTEES AND STATE PARTICIPATION

A. Introduction

Peabody Energy joins the Commission in recognizing the importance of states in fostering competitive wholesale electricity markets. Peabody Energy applauds the Commission's ongoing efforts to promote a meaningful working relationship with the states, including provisions in the NOPR intended to establish a more formal process for state participation in ITP decision-making. There are many benefits to creating a common forum to discuss facility-planning, and RTOs, ITPs and the states have responsibilities for ensuring a safe, adequate and reliable power supply for consumers. Well-functioning RSACs[4] will help ensure that all parties work effectively and efficiently together toward this common goal.

[4] The word "advisory" is a misnomer in that it does not recognize the significant role states will have in the ITP process. The Commission expressly states that contact between an RSAC and an ITP governing board should be conducted "in a manner that recognizes [the RSAC's] public interest responsibilities."

In the NOPR, the Commission expressed its intention to work with the states "to seek regional solutions to issues that may fall under federal, state or shared jurisdiction."[5] This transition inevitably requires a broader application of the Commission's regulatory authority to address the interstate nature and impact of those markets. Accordingly, it is entirely necessary and appropriate for the Commission to assert their statutory authorities over any and all activities that transcend state boundaries and that otherwise reflect the interstate nature of wholesale transmission service.[6] Hence, RSACs should work in conjunction with the Commission, but the Commission must be the ultimate arbiter of issues involving wholesale markets and the interstate transmission grid.

B. Role of RSACs

The RSACs' role in ITP must be clearly defined. The ITP should seek RSAC input on the implementation and operation of wholesale market rules, including the need for market mitigation measures, recognizing the significant state interest in well-functioning FERC-jurisdictional wholesale markets.

C. RSACs Should Not Create an Additional, Unnecessary Level of Bureaucracy

While supportive of the creation of RSACs, Peabody Energy is concerned that, unless properly structured, the RSACs will create overlapping jurisdictions and confuse

---

(SMD NOPR at P 552). Further, in large part, the Commission bases its description of the critical role states will play under the SMD in transmission planning and siting on a report by the National Governors' Association, and specifically notes the "valuable regional perspective" and role states will have with respect to rate design and revenue requirements. (SMD NOPR at P 555).

[5] SMD NOPR at P 554.

[6] A more extensive legal analysis of the Commission's authority to enact a Final Rule was set forth in Attachment A to the Competitive Supplier's November 15 comments in this proceeding.

the responsibilities of federal and state agencies. The establishment of RSACs should not result in a new level of bureaucracy by delegating regulatory authority over FERC jurisdictional wholesale electricity markets to a state-dominated body.

D. Governance and Staffing of RSACs

While the Commission has, understandably, avoided being overly proscriptive with respect to the structure, governance and staffing of RSACs, some additional guidance is warranted to avoid a long, protracted political debate that may delay the formation and creation of RSACs. To achieve a fairly uniform approach, Peabody Energy recommend that the Commission endorse the resolution approved by the National Association of Regulatory Utility Commissioners' Board of Directors on July 31, 2002, that endorsed the National Governors' Association's concept of Multi-State Entities. Peabody Energy concurs with the National Governors' Association that an RSAC be composed of no more than two representatives, appointed by the governor, from each state that is represented in the RSAC. The RSACs should consist of public utility commissioners or their staff, or a representative of the state siting authority for resource adequacy.

E. Boundaries Should Be Same as RTOs/ISOs/ITPs

Peabody Energy recommends that RSACs be formed following closely along the lines of RTOs and/or the occurrence of the given regional electricity market. However, due to uncertainties currently surrounding RTO formation, states should also have the option to develop RSACs that correspond to an area that is larger than a single RTO. The Commission may also want to consider allowing states to coordinate on an interconnection-wide basis that could encompass more than one (proposed) RTO.

While it may be difficult to establish initial RSAC boundaries, the Commission must avoid subjecting ITPs/RTOs to competing RSAC processes.

IV. CONGESTION REVENUE RIGHTS

A. Introduction

Peabody Energy earnestly supports the Commission's initiative to establish seamless competitive wholesale electricity markets. Ensuring that market participants can hedge transmission congestion in a non-discriminatory manner will be a key to the success of a fully implemented SMD. Peabody Energy supports much of what the Commission has proposed to transition to the use of CRRs, as well as the CRR principles developed at the Commission's technical conference on December 3, 2002. Peabody Energy is concerned about how CRRs influence other aspects of the SMD and herein offer comments and seek clarity on specifics in the NOPR.

The linkage between CRRs and the overall SMD framework is critical to ultimately realizing an efficient, standardized national power marketplace that brings the benefits of reliable and affordable electricity to all consumers. The details and protocols associated with CRRs are crucial to the successful adoption and implementation of SMD. Consequently, it is critical that the Commission consider, during the transition to and implementation of CRRs, how each feature is intertwined and, therefore, influences the success or failure of each aspect of a fully implemented SMD. Additionally, the Commission needs to ensure that in its CRR rules, when an entity makes infrastructure investments that are rolled in, the entity receives commensurate value equal to the transfer capability created by the investment.

B. Fully Financial Transmission Rights Lead to Efficient Scheduling and Dispatch of Generation and the Efficient Use of Transmission Capacity

The rules associated with and the definition of CRRs as financial rights impact the success of several key SMD elements, including the single NAS tariff, the LMP congestion management system and comparable scheduling practices. Moreover, CRRs must be financial rights in order to transition from CRR allocation to CRR auctions as quickly as possible. The overall success of a fully implemented SMD may be dependent on cohesive, well-reasoned CRR rules that make transmission rights financial rights in all instances.[7]

Finally, the NOPR correctly asserts that CRRs should be based on a system of point-to-point financial transmission rights in the form of obligations that can be aggregated into trading zones and hubs. Moreover, the NOPR correctly recognizes that, going forward, markets will need other products to ensure the viability of transmission rights, such as financial flowgate rights and options. These should be offered as the market requires once the foundation of CRRs is in place. The anticipated evolution of transmission rights will require that the Commission remain proactive during the implementation of CRRs.[8]

C. A Transition to Purely Financial Rights Within RTOs is Essential to Achieving the Commission's Goal of Comparability

Converting pre-existing physical rights to financial rights will facilitate an orderly transition from allocation to auction of CRRs in each regional market. The Commission's policy in this regard must seek to clearly define any interim periods for

[7] Competitive Suppliers commented on the beneficial aspects of the proposed Network Access Service (NAS) tariff and CRRs in their November 15 comments in this proceeding.

existing and forming markets. This policy needs to consider existing ISOs and RTOs that are further along with their respective transmission rights programs. The timing of the CRR transition for existing markets must be balanced against those markets that are still forming in an effort to ensure that all markets get the benefits of financial rights.

Peabody Energy believes the only way to allocate financial transmission rights fairly would be to allocate them initially to existing users of the system. Thus, CRRs initially would be allocated in a manner consistent with existing rights for firm use of the grid. The financial nature of the CRRs allows a party that receives the rights to ensure that it can realize the greater of either the congestion revenues associated with its own use of the rights as a hedging instrument, or the value placed by an alternative party on the congestion revenues. This means that a full transition to financial rights will replicate the minimum value of existing physical rights, while ensuring that all uses of the system are compatible with an efficient LMP-based market. As was recognized at the December 3, 2002, technical conference, a supplementary auction of allocated rights should be in place immediately following an initial allocation of CRRs.

The NOPR correctly asserts that an ITP/RTO with responsibility for a day-ahead scheduling process and an LMP-based congestion management system will result in appropriate price signals for market participants. However, to ensure the efficiency gains of the LMP market, the Commission must move quickly to empower these independent entities to convert all transmission rights to a single, uniform and fully financial set of transmission rights for all service. The initial allocation of CRRs that replicates use under existing physical rights and the right to receive the revenues of

[8] For example, to the extent the ability to implement both options and obligations is available, they should both be included in the Independent Transmission Provider's (ITP) software, even if options are "switched

subsequent auctions of such CRRs will ease the conversion process for the transition to a system of financial-based CRRs. Financial rights allow a party who receives an initial allocation of transmission rights that equate to its prior physical rights to receive the economic value of congestion associated with those rights, regardless of changes in the party's use of the system. Additionally, financial-based transmission rights in the form of CRRs allow the Commission to create incentives to convert from existing physical rights contracts that do not facilitate efficient congestion management. At the same time, the Commission will not abrogate existing contracts.

The financial nature of CRRs makes it crucial that they have flexible characteristics and timing. Fully funded or revenue-adequate CRRs may be desirable and consistent for these instruments. However, alternative approaches such as PJM's Allocated Revenue Rights should be allowed in the interim instead of allocating for shortfalls. This will allow for a best practice to evolve that can be implemented on a wide-spread basis. Flexibility is also appropriate on the timing of CRRs. Monthly, annual and multi-year CRRs should be made available to market participants so that they can utilize hedging tools of adequate duration to manage risk. The quantity of multi-year CRRs that are made available may be phased in to allow the market to gain experience.

Development of regional allocation methods can include state participation. However, once allocation methods are implemented, through whatever process, they must be free of regulatory manipulation.

Efficient and competitive use of the grid requires that the right to hedge congestion be allocated to those that place the highest value on such rights or enter into

---

off" in the beginning.

bilateral contracts for hedging protection. By determining the economic value of CRRs through an auction process, market participants can ensure that they get either the greater of congestion revenues associated with their own use of the rights as a hedging instrument or the value placed on the rights by another market participant. For example, transmission customers would have the ability to be price-takers (their revenues equal to the auction clearing price) in an auction as a means to acquire CRRs for their load.

Peabody Energy recognizes that in developing the NOPR, the Commission was faced with competing goals: ensuring that existing customers receive the same level and quality of service they have always had (and paid for), and promoting an efficient marketplace that allocates transmission to those who value it most.

D. When an Entity Pays for Upgrades That Are Not Rolled In, the Entity Should be Awarded CRRs or Their Auction Value for Enhancing the Transmission Grid

When an entity pays for the construction of new generation or transmission facilities that adds transmission transfer capability and the costs for the upgrade are not rolled in, that entity should receive the CRRs that are associated with the new transfer capability created for the transmission grid. However, it is not clear in the NOPR if the Commission intended for the entity to receive CRRs for construction of generation or just for the construction of transmission facilities associated with the new generation being added. The Final Rule needs to offer more clarity.

The Commission must be cognizant that investment to alleviate congestion will create new CRRs that may likely not have sufficient value to compensate for the investment even though the investment is in the public good by reducing power prices throughout the region. In addition, some transmission investments, such as a replacement circuit breaker, do not increase transmission capability and thus do not create any CRRs to allocate. It is also unclear how the investment community will view CRRs in the financing of new generation and transmission. Generators that pay for grid upgrades should receive CRRs that reflect all additional transfer capacity value in the system resulting from the transmission upgrades. The CRRs awarded or their auction value should equal the value of the congestion is eliminated.

E. Customers of Long-Term Firm Point-To-Point (PTP) Service Should Have Flexibility Regarding Embedded Cost Payment and CRRs

The Commission seeks comments on options concerning CRR allocation to customers currently paying for long-term firm PTP service and, in this regard, Peabody Energy supports flexibility for transmission customers. Customers with long-term firm PTP service should have the option of either continuing to pay the embedded cost and receive CRRs, or to not pay the embedded cost and not receive the CRRs. Customers should not be locked into a specific choice, but should have the ability to weigh options in the context of the market and their strategic objectives.

IV. CONCLUSION

To maintain an adequate supply of low-cost reliable electric energy will require the development and interconnection of new generation plants over the next five to ten years which, in turn, must be supported by the necessary transmission infrastructure. An important component of the final SMD rule must include methods to identify National Interest Transmission Bottlenecks prior to the development of LMP markets, to carefully develop an appropriate policy regarding participant funding of transmission upgrades, to clearly define the role of Regional State Advisory Committees, and to ensure that CRRs are fully financial transmission rights. Overall, the Commission should take this opportunity to ensure it develops standards that will facilitate and ensure the development of necessary transmission.

WHEREFORE, Peabody Energy respectfully urges the Commission to incorporate the above-described recommendations in its final Standard Electricity Market Design Rule.

Respectfully Submitted

Frederick Palmer /jr

Frederick D. Palmer
Jacob Williams
PEABODY ENERGY
701 Market Street, Suite 900
St. Louis, Missouri 63101
(314) 342-7624

Dated this 31st day of January, 2003

Sent via electronic filing

July 24, 2003

Hon. Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE, Room 1-A
Washington, DC 20426

Re: Remedying Undue Discrimination
Through Open Access Transmission Service
And Standard Electricity Market Design
Docket No. RM01-12-000

Dear Ms. Salas:

For filing in the above referenced docket, please find attached comments regarding the White Paper on Wholesale Power Market Platform on behalf of the Kentucky Public Service Commission.

Sincerely,

/s/

Deborah T. Eversole, Esq.
Richard Raff, Esq.
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40601
502-564-3940

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design	)	**Docket No. RM01-12-000**

COMMENTS OF THE
KENTUCKY PUBLIC SERVICE COMMISSION
ON THE WHITE PAPER ON WHOLESALE MARKET PLATFORM

The Kentucky Public Service Commission ("Kentucky PSC") respectfully submits comments in response to the Federal Energy Regulatory Commission's ("FERC") White Paper on Wholesale Power Market Platform (the "White Paper"). We commend FERC's attempts to address serious concerns raised by multiple parties in regard to the Notice of Proposed Rulemaking to implement a standard market design for all electricity markets nationwide (the "SMD NOPR"). We must, however, state that Kentucky's major objections remain wholly unaddressed. While it is not clear what will be contained in a final rule in this docket, the White Paper indicates that FERC has not reconsidered any of the basic premises of the SMD NOPR. We repeat the general assertion that has been the central theme of all our comments in this docket: that retail ratepayers must be held harmless under any standard market rules. Nothing in the White Paper alleviates our concerns. FERC continues to assert jurisdiction over retail bundled transmission. Though it says it will oversee only terms and conditions, it thereby implicitly asserts jurisdiction over rates. As we, and others, have explained in prior pleadings in this docket, FERC has no authority to assert jurisdiction over any portion of retail bundled transmission.

Next, we continue to object to FERC's emphasis on the role for groups of states as a replacement for the actual legal authority of individual states. The White Paper gives the illusion of a larger role for state regulators; however, in reality, it merely gives states an advisory role to FERC through regional entities that are not politically answerable to anyone. These regional entities have no jurisdiction and can merely seek to advise FERC. The real power will remain at FERC. FERC has stated that it will place a great deal of weight on the majority opinion of a group of states. It is unclear what this would mean for the minority opinion, particularly when one or more unrestructured state is grouped with restructured states. It is, however, clear that states would be forced to expend scarce resources in multiple forums including the RTO, the regional state entity, FERC and most likely courts. Further, the lack of alignment between state boundaries and RTO boundaries would result in many states being located within multiple RTO boundaries and multiple regional state entities, necessitating additional expense.

We see benefits to the sharing of information on a regional basis. In fact, the Kentucky PSC is a founding member of the "Organization of MISO States" ("OMS"), and is fully prepared to participate in that organization to ensure that any regional planning includes the Kentucky perspective. However, Kentucky statutes do not allow the Kentucky PSC to cede its regulatory authority.

We continue to have serious concerns about the scope and responsibility of the regional entity as outlined in the White Paper. FERC implies this entity will have more than an advisory role, having some decision making ability in areas including the allocation of firm transmission rights, setting and enforcing resource adequacy requirements, transmission planning and expansion, and the allocation of the costs of congestion.

Presently, the Kentucky PSC and the Kentucky Siting Board have jurisdiction over generation and transmission planning. States that do not have, or have given up, planning authority will not gain that authority through this group. A voluntary organization can not have decision-making authority. Unless the organization evolves into a regional compact (which would have to be ratified by each state's legislature) or unless FERC delegates its authority through Section 209 of the Federal Power Act, this entity cannot have decision-making authority. Even in case of a Section 209 delegation, FERC could not cede authority that it does not have.

Further, we continue to object to the ever-escalating cost of RTOs, which have been largely unchecked by FERC. There is no prudency review of these costs and there seems to be a misalignment of those who pay and those who receive benefits. We object to ratepayers, such as those in Kentucky who receive fully regulated services and have adequate transmission and generation to meet their needs, paying for an energy market from which they will see little or no benefit. We object to allowing those companies which were part of the failed Alliance RTO effort to recover their costs through administrative adders in their present RTO. These objections are now compounded with the formation of the OMS, which is funded through the RTO cost adder. We are concerned with this additional and expensive layer of bureaucracy.

The White Paper is premised on the erroneous assumption that FERC has authority to mandate RTO membership. The D.C. Circuit Court of Appeals held in *Atlantic City Elec. Co. v. Federal Energy Regulatory Comm'n*, 295 F.3d 1 (D.C. Cir. 2002) that FERC has no such authority. The Court granted a petition to enforce its mandate in this case on May 20, 2003.[1] The court's holding is now clear and unequivocal. We would assume that, based on the Court's most recent order, FERC will not now attempt to mandate RTO participation.

The Department of Energy ("DOE), in its "Report to Congress: Impacts of the Federal Energy Regulatory Commission's Proposal for Standard Market Design", which was released April 30, 2003, showed that the ECAR, the NERC Reliability Region (comprised of Lower Michigan, Ohio, Indiana, Western Pennsylvania and Kentucky) would see a 1-2% benefit in the form of reduced power costs, as a result of the policies in the Standard Market Design NOPR. There were no state specific analyses in the study, but it is unlikely that Kentucky would see lower power costs, as our power costs are the lowest in the region and in the country. Even on a regional basis, it would seem that this benefit is not large in light of the many unknown and potentially negative consequences of such radical changes in the electricity market. Further, the RTO costs associated with the MISO seem to be underestimated in the model. The expected benefits would be lower if the model were updated to include the cost of new initiatives such as the MISO's Midwest Market Initiative. As a result of the concerns we continue to have, Kentucky sees many reasons to keep the status quo and few reasons to change its existing regulated structure.

Moreover, under the competitive standards that FERC continues to espouse, our laws requiring exclusivity of retail supplier and priority of Kentucky consumers are deemed to be "discriminatory." While we are willing to cooperate reasonably with states who have decided to do things differently, and while we sympathize with FERC's efforts to bring effective organization to the wholesale market, that market must succeed or fail

[1] *Atlantic City Elec. Co. v. Federal Energy Regulatory Comm'n* (D.C. Cir., No. 97-1097, May 20, 2003).

on its own merits. Captive retail customers in low cost states must not be forced to subsidize competitive markets.

In brief, our objections to the SMD remain. We urge FERC to abandon the SMD initiative and to limit the implementation of such policies in individual RTO dockets. States that have chosen to retain regulation must continue to be able to protect their ratepayers; and free market competitors are not entitled to captive customer subsidization.

All comments or communications concerning these comments should be addressed to:

Deborah T. Eversole, Esq.
Richard Raff, Esq.
Kentucky Public Service Commission
P.O. Box 615
Frankfort, Kentucky 40601
(502) 564-3940