generation, transmission constraints, proposed new transmission construction, demand response and new generation projects as they relate to PJM's current and forecasted reliability needs. The Commission further requests that PJM summarize the main components of RPM. (A representative of PJM will be present during each subsequent panel to answer questions, but PJM will not make any further independent presentation.)

PJM Interconnection, LLC: Audrey A. Zibelman, Executive Vice President & Chief Operating Officer, and Andrew L. Ott, Vice President—Markets.

Panel 1:

10:45 a.m.–1 p.m.

Whether the current capacity obligation construct within PJM's market design provides for just and reasonable wholesale power prices in the PJM footprint, at levels that provide adequate assurance that necessary resources will be provided to assure reliability, or whether changes must be made to that capacity obligation construct.

Dayton Power and Light Company: Gary Stephenson, Vice President, Commercial Operations.

Edison Mission Companies: Reem Fahey, Vice President, Market Policy.

Exelon Corporation: John F. Young, Executive Vice President, Finance and Markets and Chief Financial Officer.

FirstEnergy Service Company: Michael R. Beiting, Associate General Counsel.

Public Utilities Commission of Ohio: Hon. Alan R. Schriber, Chair.

Pennsylvania Public Utility Commission: Andrew S. Tubbs, Counsel.

Maryland Office of People's Counsel: William Fields, Senior Assistant People's Counsel.

Lunch

1 p.m.–2 p.m.

Panel 2:

2 p.m.–3:30 p.m.

Whether PJM's RPM proposal would provide for just and reasonable wholesale power prices in the PJM footprint, at levels that provide adequate reliability, or whether changes must be made to the proposal to meet those goals.

PSEG Companies: Gary R. Sorenson, Managing Director, Energy Operations, PSEG Power LLC.

Reliant Energy, Inc.: Neal A. Fitch, Senior Regulatory Specialist.

Mirant Parties/NRG Companies/ Williams: Robert B. Stoddard, Vice President, Charles River Associates, International.

Constellation Energy Group: Marjorie R. Philips, Vice President, Regulatory Affairs.

National Grid USA: Mary Ellen Paravalos, Director of Regulatory Policy.

PJM Industrial Customer Coalition: Robert A. Weishaar, McNees, Wallace and Nurick, LLC.

New Jersey Board of Public Utilities: Hon. Frederick T. Butler, Commissioner.

Virginia Office of the Attorney General: Seth W. Brown, Manager of Transmission Services, GDS Associates, Inc.

Panel 3:

3:30 p.m.–4:45 p.m.

Whether an alternative approach to RPM is necessary to ensure just and reasonable wholesale power prices in the PJM footprint.

American Electric Power Service Co.: J. Craig Baker, Senior Vice President, Regulatory Services.

Morgan Stanley Capital Group Inc.: James Sheffield, Vice President.

Coalition of Consumers for Reliability: Edward D. Tatum, Jr., Assistant Vice President, Rates and Regulation, Old Dominion Electric Cooperative (ODEC).

PPL Parties: Thomas Hyzinski, Manager, ISO Markets Development and Regulatory Policy.

Delaware Public Service Commission: Hon. Arnetta McRae, Chair.

Closing remarks by Chairman Joseph T. Kelliher:

4:45 p.m.–5 p.m.

Each panelist should provide a presentation of no more than five minutes, and the Commissioners may ask questions at the conclusion of each presentation. If time permits, the audience may also ask questions of the panelists at the conclusion of the Commissioners' questions. Panelists wishing to distribute copies of their presentation should bring 100 or more hard copies to the conference for distribution. Any such presentation will be placed into the record for these dockets. Any panelist requiring particular software or other technical facilities for a presentation should contact FERC staff no later than January 27, 2006. All parties to this proceeding may file comments on the technical conference by close of business on February 23, 2006.

[FR Doc. E6–953 Filed 1–25–06; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PL02–6–001]

Before Commissioners: Joseph T. Kelliher, Chairman; Nora Mead Brownell, and Suedeen G. Kelly; Natural Gas Pipeline Negotiated Rate Policies and Practices; Order on Rehearing and Clarification

Issued January 19, 2006.

1. Several parties [1] request rehearing and or clarification of the Commission's July 9, 2003 Order in the captioned docket.[2] In that order, the Commission modified its negotiated rate policies so that pipelines would no longer be permitted to enter into negotiated rate agreements that utilize basis differentials as a transportation pricing mechanism.

Background

2. In 1996, the Commission permitted pipelines the opportunity to use negotiated rates as an alternative to cost-of-service ratemaking.[3] Under the negotiated rate program, the pipeline and a shipper may negotiate rates that vary from a pipeline's otherwise applicable cost-of-service tariff rate. However, a cost-based recourse rate must be maintained by the pipeline for customers that prefer traditional cost-of-service rates and to mitigate market power if the pipeline unilaterally demands excess prices or withholds service. The Commission determined that the availability of the recourse rate would prevent pipelines from exercising market power by assuring that the customer always has the option of purchasing capacity at the just and reasonable tariff rate if the pipeline unilaterally demands excessive prices.[4]

[1] Parties requesting rehearing or clarification are: Illinois Municipal Gas Agency; Natural Gas Pipeline Company of America and Kinder Morgan Interstate Gas Transmission, LLC; CenterPoint Energy Gas Transmission Company; Northern Natural Gas Company; MidAmerican Energy Company; BP America Production Company and BP Energy Company; American Public Gas Association; Williston Basin Interstate Pipeline Company; ANR Pipeline Company and Tennessee Gas Pipeline Company; American Gas Association; and Interstate Natural Gas Association of America.

[2] *Natural Gas Pipeline Negotiated Rates Policies and Practices*, 104 FERC ¶ 61,134 (2003)(July 2003 Order).

[3] The Commission's negotiated rate policies were originally established in Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, Regulation of Negotiated Transportation Services, 74 FERC ¶ 61,076, order on clarification, 74 FERC ¶ 61,194, order on reh'g, 75 FERC ¶ 61,024 (1996).

[4] Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines, 74 FERC ¶

In order to implement a negotiated rate transaction, a pipeline must file either the negotiated rate agreement itself or a tariff sheet describing the agreement, since, unlike a discount, a negotiated rate is a material deviation from the pipeline's tariff.[5] Until the issuance of the modification of the policy statement, the Commission permitted pipelines to use price indices in pricing their negotiated rate transactions.[6] However, on July 9, 2003, the Commission issued a policy statement, revising its negotiated rate policies so that the use of gas basis differentials would no longer be permitted.[7]

3. In its modification of the original negotiated rate policy statement, the Commission stated that it was concerned that the use of basis differentials could provide pipelines with an incentive to withhold capacity in an attempt to manipulate the gas commodity market to widen the differences between the relevant price indices. The Commission explained that the manner in which it regulated transportation rates would ordinarily minimize any incentive for a pipeline to withhold capacity. That was because even if a pipeline created scarcity, it could not charge rates above the maximum just and reasonable rate based upon the pipeline's cost of service. Therefore, if a pipeline withheld capacity, its revenues would not increase.[8] However, because the negotiated rate policy permits a pipeline to charge a rate above the maximum cost of service rate, a pipeline charging negotiated rates tied to basis differentials could increase its revenues by withholding capacity in order to increase the relevant basis differentials.[9] The Commission concluded that pricing mechanisms that invest pipelines with an incentive to use market power to manipulate the commodity price of gas would hinder the Commission's attempt to maintain and improve the competitive natural gas market. Therefore, the Commission prohibited the use of natural gas indices in pricing negotiated rate transactions.[10]

4. In reaching this determination, the Commission recognized that these basis differential pricing mechanisms are useful in permitting parties to the negotiated agreement to engage in various hedging programs and gas supply cost-management programs, but the Commission found that such flexibility could not justify the increased risk of market manipulation faced by market participants. The Commission determined that this limitation of flexibility was offset by the fact that negotiated rates may still be based upon a virtually unlimited number of indices or other mechanisms that have no relationship with the commodity price of gas, and are, therefore, not as subject to manipulation through the withholding of pipeline capacity.

5. Subsequent to its modification of the negotiated rate policy statement, the Commission modified its selective discounting policies which had prohibited the use of formulas in discounted rates. On remand from the court in *Northern Natural Gas Company,* the Commission determined that it would permit the use of formulas, including those tied to basis differentials in discounted rate transactions.[11] In reaching this determination, the Commission stated that its concerns about the use of basis differentials in negotiated rates were not present to the same degree in the context of discounted rates. The Commission reasoned that because discounted rates, unlike negotiated rates, were capped by the pipeline's maximum cost-of-service rate, use of pricing differentials in discounted rates did not present the pipeline with an incentive to withhold capacity in order to achieve higher revenues. Given this fact, the Commission found that the benefits of allowing the use of basis differentials to price transportation service in discounted rate agreements outweighed any potential harm.

Discussion

6. A number of parties have filed requests for rehearing of the revised policy statement, objecting not only to the revised policy concerning the use of pricing differentials in negotiated rates but also to other aspects of the revised policy statement. The revised policy statement is not a final action of the Commission but an expression of policy intent. As the U.S. Court of Appeals for the District of Columbia Circuit has held, a statement of policy ''is not finally determinative of the issues or rights to which it is addressed''; rather, it only ''announces the agency's tentative intentions for the future.'' [12] Therefore, the parties are not aggrieved by the revised policy statement, and rehearing does not lie.[13] The Commission accordingly dismisses the requests for rehearing.

7. Nevertheless, the Commission has further considered the basis differential issue, and has determined to modify its negotiated rate policy to again permit the use of gas commodity basis differentials in negotiated rate transactions without regard to the existence of a revenue cap. The Commission finds that a generic policy against the use of gas basis differentials in negotiated rate transactions is overly restrictive, given the benefits such pricing mechanisms yield and the fact that there are other less restrictive means to ensure that the pipelines do not utilize market power to influence the gas commodity market.

8. The Commission has long recognized that the ''commodity and transportation markets are closely interdependent in the natural gas business with changes in one market affecting the other.'' [14] Further, the Commission itself has stated that the market conditions it has fostered create a ''market-driven value for transportation * * * the implicit value of transportation between two such points is the spot price of gas at the delivery point minus the spot price of gas at the receipt point.'' [15] Thus, the

61,076 at 61,238–242, order on clarification, 74 FERC ¶ 61,194, order on reh'g, 75 FERC ¶ 61,024 (1996).

[5] NorAm Gas Transmission Co., 75 FERC ¶ 61,091 at 61,309, order on reh'g, 77 FERC ¶ 61,011 at 61,037 (1996).

[6] Before the modification of the Commission's negotiated rate policies, pipelines were permitted to negotiate pricing mechanisms for transportation based upon the difference between gas commodity price indices at different points (referred to here as the ''basis differential''). These gas commodity price indices, when used as a negotiated pricing mechanism, usually reflect gas prices at different points such as at gas basins or certain receipt and delivery points and citygates. The pricing mechanism is based upon the difference between the gas price indices at the two points. The foundation for this pricing mechanism is that the difference in price between two points, as shown by the respective price indices, reflects the value of transportation between the two points.

[7] In its July 9, 2003 Order, the Commission also clarified its filing requirements for negotiated rates, particularly where the negotiated agreement contained material deviations from the form of service agreement. July 2003 Order, 104 FERC at P 31–34.

[8] *Id.* at P 17–18.

[9] *Id.* at P 19–20.

[10] *Id.* at P 23–24.

[11] *Northern Natural Gas Co.,* 105 FERC ¶ 61,299 (2003).

[12] *Pacific Gas & Electric Co.* v. *FPC*, 506 F.2d 33, 38 (D.C. Cir. 1974).

[13] *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines*, 75 FERC ¶ 61,024 at 61,076, *citing, American Gas Association* v. *FERC*, 888 F.2d 136 (1989); *Interstate Natural Gas Pipeline Rate Design*, 47 FERC ¶ 61,295 (1985), *order on reh'g*, 48 FERC ¶ 61,122 at 61,442 (1989).

[14] Order No. 637 at 31,258.

[15] *Id.* at 33,436. In this vein, the Commission also added that, ''The implicit price for transportation represents the most any shipper purchasing delivered gas at a downstream market would pay to move gas from the lower priced market to the higher priced market. For instance, the implicit value of transportation between the Henry Hub and

Continued

use of basis differentials to price transportation services enables the pipeline to negotiate market sensitive transportation rates, consistent with the Commission's goal of encouraging competition in the transportation capacity market. Such market sensitive rates provide greater efficiency in the production and distribution of gas across the pipeline grid. For example, such rates minimize the distorting effect of transportation costs on producer decisions concerning exploration and production. They also help the pipeline to more accurately assess when new construction is needed, because a high basis differential indicates a need for more capacity between the points.[16]

9. In implementing its policy against the use of gas basis differentials, the Commission recognized that the use of basis differential pricing mechanisms yielded significant benefits, but stated that such increased flexibility could not justify the increased risk that the pipelines may utilize their market power over transportation service to manipulate the commodity market to increase basis differentials.[17]

10. However, in the Commission's view, the ability of pipelines to manipulate the gas commodity market is tempered by several factors. First, part 284 of the Commission's regulations and its policies provide that pipelines must sell capacity to maximum rate bidders.[18] Therefore, pipelines may not hoard desired capacity in an attempt to widen basis differential without violating the Commission's existing regulations.

Second, pipelines must file all negotiated rate agreements with the Commission for approval. Those filing negotiated rate contracts are noticed for comments giving all interested parties an opportunity to raise whatever concerns they have with the agreement. Moreover, the Commission has access to information regarding available pipeline capacity and daily gas basis differentials. This allows it to monitor the transactions to determine if the pipeline is withholding capacity in order to increase the gas commodity basis differential. Moreover, subsequent to the modification of the negotiated rate policy statement, Congress enacted new legislation designed to prohibit manipulation of the gas transportation markets. Concurrently with the issuance of this order, the Commission is approving a final rule in Docket No. RM06–3–000 implementing new section 4A of the Natural Gas Act.[19]

11. Given these facts and the benefits of the use of basis differential pricing mechanisms, the Commission finds that it is not necessary to ban the use of such mechanisms in order to mitigate the potential for manipulation of the market for either transportation or gas sales. Rather, the Commission will permit the use of gas commodity basis differentials and will continue to investigate, on a case by case basis, allegations of market manipulation or attempted market manipulation by pipelines. In this manner, the flexibility benefits of this pricing mechanism may be retained while the Commission maintains the integrity of the marketplace.

The Commission orders:

(A) The requests for rehearing of the Commission's July 9, 2003 Order are dismissed as discussed in the body of this order.

(B) The Commission's July 9, 2003 Order is clarified as discussed in the body of this order.

By the Commission.

Magalie R. Salas,

Secretary.

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the Chicago city gate was $.07 in September 1999 (the difference between the $2.67 price for gas in Chicago and the $2.60 price at Henry Hub).'' *Id.* at 31,271. The difference between the downstream delivered gas price and the market price at upstream market centers in the production area shows the market value of transportation service between those two points. As the Commission observed in Order No. 637, ''gas commodity markets now determine the economic value of pipeline transportation services in many parts of the country. Thus, even as FERC has sought to isolate pipeline services from commodity sales, it is within the commodity markets that one can see revealed the true price for gas transportation.'' Order No. 637 at 31,274 (*quoting* M. Barcella, *How Commodity Markets Drive Gas Pipeline Values,* Public Utilities Fortnightly, February 1, 1998 at 24–25).

[16] *See Policy for Selective Discounting by Natural Gas Pipelines,* 111 FERC ¶ 61,309 at P 32–37 (2005).

[17] July 2003 Order, 104 FERC at P 23.

[18] *See Tennessee Gas Pipeline Co.*, 91 FERC ¶ 61,053 (2000), *order on reh'g,* 94 FERC ¶ 61,097 (2001), *aff'd, Process Gas Consumers Group* v. *FERC*, 292 F.3d 831 (D.C. Cir. 2002). Moreover, in Order No. 637–A, the Commission reaffirmed its position that the recourse rate effectively mitigates pipeline market power by stating that ''[T]he requirement that a pipeline sell its capacity at the regulated maximum rate prevents tacit collusion between the pipeline and the shipper to withhold capacity to raise price above the ceiling * * *'' *Id.* at 31,564.

[19] Section 315 of the Energy Policy Act of 2005 added the following provision to the Natural Gas Act:

Prohibition on Market Manipulation

SEC. 4A. It shall be unlawful for any entity, directly or indirectly, to use or employ, in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934 (15 U.S.C. 78j(b))) in contravention of such rules and regulations as the Commission may prescribe as necessary in the public interest or for the protection of natural gas ratepayers. Nothing in this section shall be construed to create a private right of action.

Energy Policy Act of 2005, Pub. L. No. 109–58, § 315, 119 Stat. 594, (2005).

ENVIRONMENTAL PROTECTION AGENCY

[FRL–8025–3]

Proposed CERCLA Administrative Settlement Agreement for the Bountiful/Woods Cross/5th South Pce Plume NPL Site, in Woods Cross, Davis County, UT

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice and request for public comment.

SUMMARY: In accordance with the requirements of section 122(h)(1) of the Comprehensive Environmental Response, Compensation, and Liability Act, as amended (''CERCLA''), 42 U.S.C. 9622(h)(1), notice is hereby given of the proposed administrative settlement under section 122(h) of CERCLA, 42 U.S.C. 9622(h), between EPA and W.S. Hatch Company and Jack B. Kelley, Inc. (''Settling Parties'') regarding the W.S. Hatch facility (the ''Facility''). The property which is the subject of this proposed Settlement Agreement is a parcel of land approximately three acres in size and is located at approximately 643 South and 800 West in Woods Cross, Davis County, Utah. The terms of the proposed Administrative Settlement Agreement, (the ''Settlement''), are intended to resolve the Settling Parties' liability at the Site for all response costs incurred and paid, or to be incurred and paid, by EPA in connection with the work performed at the Site as provided for in the Settlement.

W.S. Hatch Company, a subsidiary of Jack B. Kelley, Inc., is the owner of a parcel of land which has been impacted by business operations at the Facility and is included within the defined boundaries of the Site. The proposed Settlement will resolve the Settling Parties' liability under section 107(a)(1) of CERCLA, 42 U.S.C. 9607(a)(1). EPA has performed an ability to pay analysis of Settling Parties' financial capacity. Under the terms of the proposed Settlement, W.S. Hatch Company agrees to pay $450,000, plus interest, to EPA over five installment payments, and Jack B. Kelley, Inc. agrees to pay the principal sum of $40,000 to EPA. In exchange, the Settling Parties will settle their liability for all response costs incurred and paid, or to be incurred and