118 FERC ¶ 61,214
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Jon Wellinghoff.

Bluegrass Generation Company, L.L.C. Docket No. ER05-522-001

ORDER AFFIRMING INITIAL DECISION

(Issued March 16, 2007)

1. This case is before us on exceptions to the April 19, 2006 *Initial Decision*[1] issued in this proceeding. The central issue in this case is whether Bluegrass Generation Company, L.L.C.'s (Bluegrass) proposed rate schedule[2] for Reactive Supply and Voltage Control from Generation Sources Service (reactive power) is just and reasonable under section 205 of the Federal Power Act (FPA).[3] In this order, we affirm the *Initial Decision* in its entirety.

Background

A. History of Reactive Power Pricing

2. The modern history of reactive power pricing begins with Order No. 888.[4] In Order No. 888, the Commission decided that reactive power was one of six ancillary

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[1] *Bluegrass Generation Company, L.L.C.*, 115 FERC ¶ 63,015 (2006) (*Initial Decision*).

[2] Bluegrass Generation Company, L.L.C., Rate Schedule FERC No. 2.

[3] 16 U.S.C. § 824d(a) (2000).

[4] *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. Regulations Preambles January 1991-June 1996 ¶ 31,036 at 31,705-06 and 31,716-17 (1996) (Order No. 888), Order No. 888-A, FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

services transmission providers must include in their Open Access Transmission Tariffs (OATT).[5] The Commission stated that there are two methods of supplying reactive power and controlling voltage: (1) installing facilities as part of the transmission system and (2) using generation facilities. The Commission concluded that the costs of the first method would be recovered as part of the cost of basic transmission service and thus, would not be a separate ancillary service.[6] The second method (using generation facilities) would be considered a separate ancillary service, and must be unbundled from basic transmission service. The Commission stated that, in the absence of proof that the generation seller lacks market power in providing reactive power, rates for this ancillary service should be cost-based and established as price caps, from which transmission providers may offer a discount.[7]

3. The next stage in the development of modern reactive power pricing is Opinion No. 440.[8] In Opinion No. 440, the Commission approved a method presented by American Electric Power Service Corp. (AEP) for generators to recover costs for reactive power. AEP identified three components of a generation plant related to the production of reactive power: (1) the generator and its exciter, (2) accessory electric equipment that supports the operation of the generator-exciter, and (3) the remaining total production investment required to provide real power and operate the exciter. Because these plant items produce both real and reactive power, AEP developed an allocation factor to sort the annual revenue requirements of these components between real and reactive power production.[9] Subsequently, the Commission indicated that all generators that have actual cost data should use this *AEP* method in seeking reactive power recovery.[10]

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[5] Order No. 888 at 31,705. The *pro forma* OATT includes six schedules that set forth the details pertaining to each ancillary service. The details concerning reactive power are included in Schedule 2 of the pro forma OATT. *Id*. at 31,960.

[6] Supplying reactive power and voltage control by installing facilities as part of the transmission system is not at issue in this proceeding.

[7] Order No. 888 at 31,720-21.

[8] *American Electric Power Service Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) (*AEP*) (Opinion No. 440).

[9] The factor for allocating to reactive power, developed by AEP, is $MVAR^2/MVA^2$, where MVAR is megavolt amperes reactive capability and MVA is megavolt amperes capability at a power factor of 1.

[10] *WPS Westwood Generation, L.L.C.*, 101 FERC ¶ 61,290 at 62,167 (2002) (*WPS Westwood*).

4. After Opinion No. 440, the Commission accepted a proposal by PJM Interconnection, LLC (PJM)[11] that revenue requirements of generation owners that are not also transmission owners be included in the charges for reactive power. Subsequently, the Commission concluded that a generator need not be compensated further for providing reactive power within its power factor range.[12] The Commission also concluded that a transmission owner need not provide compensation to generators for reactive power if the generator is not under the control of the control area operator.[13] However, the Commission explained that a transmission owner must compensate a non-affiliated generator for providing reactive power to the extent that the transmission owner compensates an affiliated generator for providing reactive power.[14]

5. In Order No. 2003,[15] the Commission concluded that an interconnection customer should not be compensated for reactive power when operating within its established power factor range. Under Order No. 2003, the required power factor range is 0.95 leading (consuming) and 0.95 lagging (supplying), but the transmission provider may establish a different power factor range. However, the Commission determined that the transmission provider must compensate the interconnection customer for reactive power during an emergency where the interconnection customer provides reactive power outside the power factor range. In Order No. 2003-A, the Commission clarified that if a transmission provider pays its own or its affiliated generators for reactive power within the established range, it must also pay the interconnection customer.[16]

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[11] *PJM Interconnection LLC*, Docket No. ER00-3327-000, (September 25, 2000) (unpublished letter order).

[12] *Michigan Electric Transmission Co.*, 96 FERC ¶ 61,214 at 61,906 (2001) (citing *Consumers Energy Company*, 93 FERC ¶ 61,339 at 62,154 (2001), *order on reh'g*, 94 FERC ¶ 61,230 at 61,834 (2001)).

[13] *Otter Tail Power Co.*, 99 FERC ¶ 61,019 at 61,092 (2002).

[14] *Michigan Electric Transmission Co.*, 97 FERC ¶ 61,187 at 61,853 (2001) (*METC*).

[15] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,146 at P 21 (2003) (Order No. 2003), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,160 (2004) (Order No. 2003-A), *order on reh'g*, 109 FERC ¶ 61,287 (2004) (Order No. 2003-B), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005) (Order No. 2003-C), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, No. 04-1148, 2007 U.S. App. LEXIS 626 (D.C. Cir. Jan. 12, 2007).

[16] Order No. 2003-A at P 416.

B. Midwest ISO's Schedule 2

6. Schedule 2 of the Midwest Independent Transmission System Operator, Inc.'s (Midwest ISO) OATT, which is similar to Schedule 2 of the Commission's *pro forma* OATT, states that reactive power service will be provided by the control area operator within Midwest ISO where the load is located. In the past, Midwest ISO's Schedule 2 only compensated the transmission owners' own generators for reactive power service; it had no mechanism to compensate independent power producers (IPPs) like Bluegrass for reactive power service. On June 25, 2004, Midwest ISO proposed Schedule 21 to supplement its existing Schedule 2 by providing a mechanism to compensate generators not covered under Schedule 2, namely IPPs.

7. In an order issued on October 1, 2004,[17] the Commission rejected Schedule 21 as unduly discriminatory because of the substantial differences between how transmission owners' own generators were compensated under existing Schedule 2 and how IPPs would be compensated under proposed Schedule 21. In the *October 2004 Order*, the Commission also held that Schedule 2 was unjust, unreasonable, and unduly discriminatory under section 206 of the FPA because it did not compensate non-transmission owners or IPPs for providing reactive power service. Accordingly, the Commission directed Midwest ISO to revise Schedule 2 to compensate all generators, and ordered Midwest ISO to include language requiring IPPs to file cost-based revenue requirements with the Commission before receiving reactive power compensation. The Commission conditionally accepted Midwest ISO's compliance filings in *MISO I* and *MISO II*, and ordered further revisions to Schedule 2 in both orders. Finally, the Commission accepted revised Schedule 2 for filing in *MISO III*.

C. Relationship between Bluegrass, LG&E, and Midwest ISO

8. Bluegrass, a wholly-owned subsidiary of Dynegy Inc., is an exempt wholesale generator[18] authorized by the Commission to make wholesale sales of power at market-based rates.[19] Bluegrass leases a natural gas-fired peaking generating facility from Oldham County, Kentucky. This facility is interconnected with Louisville Gas and

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[17] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,005 (2004) (*October 2004 Order*), *order on reh'g*, 110 FERC ¶ 61,267 (2005), *order on compliance filing*, 113 FERC ¶ 61,046 (2005) (*MISO I*), *order on reh'g and compliance filing*, 114 FERC ¶ 61,192 (2006) (*MISO II*), *order on reh'g and compliance filing*, 116 FERC ¶ 61,283 (2006) (*MISO III*).

[18] *See Bluegrass Generation Company, L.L.C.*, 97 FERC ¶ 62,279 (2001).

[19] *See Bluegrass Generation Company, L.L.C.*, Docket No. ER02-506-000 (February 1, 2002) (unpublished letter order).

Electric Company's (LG&E) transmission system.[20] LG&E was, until recently, a transmission-owning member and control area operator of Midwest ISO. LG&E withdrew from Midwest ISO effective September 1, 2006.[21] Prior to LG&E's withdrawal from Midwest ISO, Bluegrass provided LG&E with reactive power service according to the terms of a Generator Interconnection and Operating Agreement (Interconnection Agreement) approved by the Commission in August 2001.[22]

D. Procedural History

9. Bluegrass submitted the instant rate schedule on January 31, 2005. At the time Bluegrass submitted its rate schedule and requested its cost-based yearly revenue requirement, the Commission had received, but not yet acted upon, Midwest ISO's compliance filing in response to the *October 2004 Order*. LG&E protested Bluegrass' filing, and Midwest ISO and Midwest ISO Transmission Owners filed timely motions to intervene. On March 25, 2005, the Commission conditionally accepted Bluegrass's rate schedule, made it effective March 1, 2005, subject to refund, and set the case for hearing to determine the justness and reasonableness of Bluegrass's proposed rate schedule.[23] The Commission held the hearing in abeyance to allow for settlement discussions, but these discussions failed and were terminated on May 26, 2005. The Presiding Judge issued the *Initial Decision* on April 19, 2006

Discussion

10. As discussed more fully below, we deny the exceptions raised by LG&E, Commission Trial Staff (Staff), and Bluegrass, and affirm the Presiding Judge on each issue.

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[20] LG&E is now known as E.ON U.S. LLC (E.ON). Following E.ON's lead, we will continue to refer to it as LG&E for consistency with this case's prior proceedings. *See* Brief on Exceptions of E.ON U.S. LLC at n.1 (LG&E's Brief on Exceptions).

[21] *See Louisville Gas and Electric Co.*, 114 FERC ¶ 61,282, *order on reh'g sub nom. E.ON U.S. LLC*, 116 FERC ¶ 61,020 (2006).

[22] *See LG&E Operating Companies*, Docket No. ER01-2579-000 (Aug. 16, 2001) (unpublished letter order).

[23] *See Bluegrass Generation Company, LLC*, 110 FERC ¶ 61,349 at P 1 (2005).

A. ***AEP* Method/Hours of Operation**

1. **Presiding Judge's Findings**

11. The Presiding Judge held that Bluegrass was required to use the *AEP* method to calculate its reactive power compensation.[24]

2. **Exceptions**

12. LG&E argues that the Presiding Judge incorrectly relied on the *AEP* method as a substitute for an independent determination that Bluegrass' proposal is just and reasonable. LG&E claims that "merely following the *AEP* [m]ethod does not provide sufficient evidence that the rates produced in this case are just and reasonable for the service provided."[25] LG&E faults the Presiding Judge for failing to distinguish this case from *AEP*,[26] and as a consequence, claims that the result here "is unjust and unreasonable on its face."[27]

13. LG&E argues that there are three distinctions between *AEP* and the instant case that make the *AEP* method inapplicable here. First, because the reactive power facility in *AEP* was owned and completely controlled by the utility, LG&E concludes that ownership is essential to the *AEP* method.[28] LG&E argues that since Bluegrass leases its reactive power facility it cannot demonstrate a capital investment, and therefore cannot compare this case to *AEP*. Second, LG&E asserts that in *AEP* there was no interconnection agreement limiting when AEP could call on the facility for reactive power. LG&E states that here, however, Bluegrass' reactive power obligations are carefully spelled out in the Bluegrass-LG&E Interconnection Agreement. Lastly, LG&E contends that the *AEP* method was developed for utilities that follow the Commission's Uniform System of Accounts (USofA) because, it asserts, the *AEP* method "relies on the uniform and pre-approved classification of costs to fairly and justly allocate specific costs to the production of reactive power."[29] LG&E states that Bluegrass does not use the

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[24] *Initial Decision*, 115 FERC ¶ 63,015 at P 140.

[25] LG&E's Brief on Exceptions at 20.

[26] *Id*. at 17-18.

[27] *Id*. at 12.

[28] *Id*. at 18.

[29] *Id*. at 11-12.

USofA, and argues that relying on inputs that are not kept under the USofA frustrates the purpose of the *AEP* method because there is no way to determine whether Bluegrass has accurately stated its reactive power costs.

14. LG&E also faults the Presiding Judge for failing to explain why Bluegrass' rate is just and reasonable given its limited necessity and operations. According to LG&E, Bluegrass's facility ran only 1.8 percent of the time from June 2002 through June 2005, did not produce MVARs in 2004, and received only three reactive power requests in 2005. LG&E argues that Bluegrass should be compensated under an "as-available" or 100 percent load factor rate because that would limit its remuneration to occasions when it is actually producing reactive power.

15. Staff agrees with LG&E that "simply following the *AEP* methodology does not automatically establish that Bluegrass' proposed rates are just and reasonable or that Bluegrass is entitled to collect a fixed charge each year."[30] Staff believes that "a capacity-based payment based on the *AEP* method is not appropriate in this case"[31] because it "grossly overstates" the value of Bluegrass' reactive power service.[32] Staff opposes allowing Bluegrass to receive a fixed yearly payment because Bluegrass infrequently operates its facilities, rarely provides reactive power service, and is virtually unneeded as a reactive power service provider. Staff contends that an as-available charge is appropriate because Bluegrass is served under an interruptible fuel supply contract and can only provide non-firm reactive power support.[33]

16. Staff offers a compensation scheme that "uses the *AEP* revenue requirement methodology but develops and implements a specific rate based on service provided."[34] Staff's rate is based on the MVAR capability of Bluegrass' facility (which Staff sets at 360.33 MVARs) and a charge based on the MVAR hours (MVARh) Bluegrass actually produces. Staff's rate is $0.1831 per MVARh for Bluegrass' as-available reactive power service. This rate equals Staff's recommended annual revenue requirement for reactive power of $577,862 (derived in accordance with *AEP*) divided by Bluegrass' reactive power capability of 360.33 MVARs divided by 8,760 hours per year.[35]

[30] Staff's Brief on Exceptions at 24.

[31] *Id*. at 27.

[32] *Id*. at 31.

[33] *Id*. at 24.

[34] *Id*. at 29.

[35] *Id*. at 28.

17. Staff cites *Cottonwood Energy I* [36] as an example of a case where the Commission "expressed the possibility of compensation based on a methodology other than the *AEP* methodology" when setting the case for hearing.[37] Although Staff acknowledges that in *Cottonwood Energy II* the Commission clarified that it did not intend to make the propriety of the *AEP* method an issue at hearing, Staff argues that the Commission nevertheless left room for alternative methods of charging the ratepayer, such as Staff presents here.[38] Staff finds further support for departing from the *AEP* methodology in the Commission Staff Report on Reactive Power,[39] which Staff claims recognizes that paying in real time for actual reactive power production is one way to compensate reactive power providers.

3. <u>Opposing Exceptions</u>

18. Bluegrass argues that Staff's and LG&E's arguments collaterally attack established Commission precedent requiring generators to use the *AEP* method to calculate reactive power compensation.[40] Bluegrass disagrees that the Presiding Judge abandoned her duty to ensure that Bluegrass' rate schedule is just and reasonable by following the *AEP* method. Bluegrass claims that "the Commission has already determined that utilization of the *AEP* [m]ethodology produces a just and reasonable result."[41]

19. Although Staff purports to follow the *AEP* method, Bluegrass characterizes Staff's proposal as "flat-out inconsistent" with the Commission's requirement that generators be compensated based on their capability, rather than on hours of operation.[42] Bluegrass further argues that the Presiding Judge correctly rejected Staff's and LG&E's proposed 100 percent Load Factor or "as-available" rate. Bluegrass claims that the sole basis for

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[36] *Cottonwood Energy Co., LP*, 110 FERC ¶ 61,303 (2005) (*Cottonwood Energy I*), *order on reh'g*, 111 FERC ¶ 61,369 (2005) (*Cottonwood Energy II*), *order granting clarification*, 112 FERC ¶ 61,317 (2005) (*Cottonwood Energy III*).

[37] Staff's Brief on Exceptions at 29.

[38] *Id*.

[39] Principles for Efficient and Reliable Power Supply and Consumption, Federal Energy Regulatory Commission Staff Report (Commission Staff Report on Reactive Power) in Docket No. AD05-1-000, issued February 4, 2005 at 104.

[40] Bluegrass' Brief Opposing Exceptions at 8.

[41] *Id*. at 9.

[42] *Id*.

Staff's recommendation of a 100 percent load factor rate is that natural gas pipelines utilize rate designs based on a 100 percent load factor for interruptible transportation.[43] In Bluegrass' view, a 100 percent load factor rate is unduly discriminatory because it would not compensate Bluegrass in the same manner and to the same extent as the fixed capacity charges the Commission has approved for other generators under Midwest ISO's Schedule 2.[44]

4. Commission Determination

20. We deny the exceptions raised by Staff and LG&E and affirm the Presiding Judge. First, we note that while LG&E may be correct to state that there are three differences between the facts in *AEP* and the facts here, nothing in *AEP* or our subsequent cases indicates that these differences should be accorded any substantive weight in determining whether a generator may use the *AEP* method to calculate its reactive power compensation. In fact, our cases clearly indicate that the distinctions LG&E raises do not factor into the decision whether to use the *AEP* methodology. In *Marcus Hook I*, for example, Exelon Corporation (Exelon) questioned whether it was appropriate for FPL Energy Marcus Hook, L.P. (Marcus Hook) to use the *AEP* method to determine its reactive power compensation, given the type of facility at issue.[45] Marcus Hook's facility was a new 744 MW gas fired cogeneration facility with exempt wholesale generator status and market based rate authority.[46] Exelon further argued that the *AEP* method should not apply because Marcus Hook's filing relied on unexplained totals for Operations Expense, Maintenance Expense, and Administrative and General Expenses, and failed to include cost data in conformance with the USofA.[47] The Commission rejected Exelon's USofA argument, and although the ownership and interconnection issues LG&E raises here were not present in *Marcus Hook I*, the Commission's rejection of Exelon's USofA argument clearly indicates that these considerations have no bearing on whether it is appropriate for generators to use the *AEP* method. Specifically, the Commission stated that "*all* generators seeking to recover a Reactive Power Service revenue requirement based on actual cost data are required to use the [*AEP*] methodology."[48] The Commission affirmed this position in *Marcus Hook II*, where it

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[43] *Id*. at 14.

[44] *Id*. at 15.

[45] *FPL Energy Marcus Hook, L.P.*, 110 FERC ¶ 61, 087 at P 9 (2005) (*Marcus Hook I*), *order on reh'g*, 111 FERC ¶ 61,168 (2005) (*Marcus Hook II*).

[46] *Marcus Hook I*, 110 FERC ¶ 61, 087 at P 2 & n.1.

[47] *Id*. at P 11.

[48] *Id*. at P 16. Emphasis original.

denied Exelon Corporation's request for rehearing, and specifically stated that *Marcus Hook I* clarified the Commission's policy on this issue.[49] As we have previously explained in other proceedings, Midwest ISO may seek to revise its criteria, including an availability or necessity test, to be applied comparably and prospectively, that would determine which generators would receive reactive power compensation and how that compensation would be paid.[50]

21. Next, we reject LG&E's and Staff's argument that it is inappropriate to allow Bluegrass to use the *AEP* method because of its limited necessity and operations. We note that under Midwest ISO's Schedule 2 IPPs like Bluegrass are compensated based on their reactive power capability.[51] The Commission has repeatedly stated that the *AEP* method is based on the capability of a given generator, not on the generator's actual operations.[52] The Commission has also rejected similar arguments in the past. In *Rolling Hills*, for example, AEP argued that Rolling Hills should not receive a fixed capacity payment because it operated too infrequently to merit such compensation.[53] The Commission rejected AEP's argument, reiterated that the *AEP* method compensates generators for their capability, and pointed out that the Commission did not require AEP to justify its allocation factors on its generators' hours of operation in *AEP*.[54] The Commission also stated that Rolling Hills' revenue requirement was intended to recover the embedded, investment cost of reactive power, and that this embedded cost remained constant regardless of Rolling Hills' hours of operation. This statement is true for Bluegrass and its revenue requirement as well. As we have previously explained in other proceedings, Midwest ISO may seek to revise its tariff to reflect criteria, including an

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[49] *Marcus Hook II*, 111 FERC ¶ 61,168 at P 10.

[50] *See Calpine Oneta*, 116 FERC ¶ 61,282 at P 50; *MISO III*, 116 FERC ¶ 61,283 at P 23.

[51] *See MISO I*, 113 FERC ¶ 61,046 at P 17, P 27.

[52] *See, e.g., Calpine Oneta Power, L.P.*, 116 FERC ¶ 61,282 at PP 49-50 & n.59 (2006) (*Calpine Oneta)*; *MISO II*, 114 FERC ¶ 61,192 at n.5; *MISO III*, 116 FERC ¶ 61,283 at P 20.

[53] *Rolling Hills Generating, L.L.C.*, 109 FERC ¶ 61,069 at P 10-11 (2004) (*Rolling Hills*).

[54] *See AEP*, 88 FERC ¶ 61,141 at 61,457 (1999) ("[T]he allocation factor should be based on the *capability* [emphasis added] of the generators to produce VARS and that this capability should be measured at the generator terminals . . . [and] a generating plant must be capable of producing reactive power in excess of that which ultimately reaches the transmission system in order to have enough reactive power remaining to provide adequate voltage support on the transmission system.").

operations test, to be applied comparably and prospectively, that would determine which generators would receive reactive power compensation and how that compensation would be paid.[55]

22. Finally, we reject Staff's recommendation that a rate be developed for Bluegrass that addresses the "needs" issue and pays Bluegrass a stated rate for each hour in which it provides reactive power support. Bluegrass filed its proposed rate schedule pursuant to the terms and conditions of Midwest ISO's Schedule 2, which provides that IPPs may seek compensation based on a capability basis consistent with the approach taken by Midwest ISO to compensate the generators of its transmission owners. To provide that Bluegrass should be compensated on a use basis would be contrary to Midwest ISO's Schedule 2, would be a collateral attack on the Commission's order accepting Midwest ISO's Schedule 2, and would result in Bluegrass not being treated comparably to Midwest ISO's own transmission owners. As we have previously explained in other proceedings, Midwest ISO may seek to revise its tariff to reflect criteria, including a "needs" test, to be applied comparably and prospectively, that would determine which generators would receive reactive power compensation.[56] However, applying a "needs" test to a single generator is inappropriate and would result in noncomparable service and unduly discriminatory rates.[57]

B. "Needs" Test & Commission Precedent

1. Presiding Judge's Findings

23. The Presiding Judge held that using a "needs," "value," or "used and useful" test to determine whether Bluegrass should receive reactive power compensation is inconsistent with Order No. 2003 and contrary to Commission precedent.[58] The Presiding Judge found that Order No. 2003 only requires generators to be capable of responding to requests for reactive power within a specified range to be eligible for compensation.[59] The Presiding Judge stated that recent Commission precedent forecloses recourse to a "needs," "value," or "used and useful" test to determine whether compensation is warranted, that a generator is "used and useful" under Commission

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[55] *See Calpine Oneta*, 116 FERC ¶ 61,282 at P 50; *MISO III*, 116 FERC ¶ 61,283 at P 23.

[56] *See Calpine Oneta*, 116 FERC ¶ 61,282 at P 50; *MISO III*, 116 FERC ¶ 61,283 at P 23.

[57] *See Calpine Oneta*, 116 FERC ¶ 61,282 at P 50 & n.59.

[58] *Initial Decision*, 115 FERC ¶ 63,015 at P 135.

[59] *Id*. at P 136.

precedent if it is capable of providing reactive power, and that generators in the Midwest ISO footprint are to be compensated for their reactive power capacity under Midwest ISO's Schedule 2.[60]

2. Exceptions

24. Staff faults the Presiding Judge for basing her decision on a "narrow view of Commission precedent."[61] According to Staff, "the cases cannot fairly be read to preclude any inquiry whatsoever into the need for reactive power."[62] Staff points to *Cottonwood Energy II* and *Duke Lee*[63] as examples. Staff cites *Cottonwood Energy II* as a case where the Commission failed to explicitly reject a "needs" test "although it had ample opportunity to do so."[64] Staff cites *Duke Lee* to show that there the Commission rejected a "needs" test because of PJM's OATT, not Commission policy. Staff also finds it meaningful that here the Commission noted, but did not dismiss, LG&E's "needs" test arguments when setting this case for hearing.[65]

25. Staff acknowledges that in *MISO I* the Commission held that generators may receive compensation for their capability to provide reactive power, and that generators are capable of providing reactive power even though they are not on-line or available at any given moment.[66] Staff maintains, however, that *MISO I* is distinguishable from the instant case because *MISO I* did not present the Commission "with the factors that make the availability of the Bluegrass units a critical consideration."[67] Specifically, Staff points to the fact that Bluegrass' units are not staffed around the clock and cannot be operated remotely. Staff also claims that the reactive power in *MISO I* was requested,

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[60] *Id*.

[61] Staff's Brief on Exceptions at 15.

[62] *Id*. at 18.

[63] *Duke Energy Lee, LLC*, 107 FERC ¶ 61,200 (2004) (*Duke Lee*).

[64] Staff's Brief on Exceptions at 19.

[65] *Id*.

[66] *Id*. at 17.

[67] *Id*.

making a “needs” test unnecessary. In Staff’s view, *MISO I* presumes that a need for reactive power service has already been established.[68] Staff argues that the instant case “couldn’t be more opposite.”[69]

26. Staff further argues that Bluegrass’ reactive power is unnecessary. Staff supports its claim by pointing to the Bluegrass-LG&E Interconnection Agreement, which obliges Bluegrass to produce or absorb VARS only during system emergencies and only when Bluegrass is synchronized to the grid. Next, Staff notes that Bluegrass’ units operated only 5 or 6 times in 2005 and 0 times in 2004, that there was adequate reactive capacity in the area when the Interconnection Agreement was negotiated, and that Bluegrass’ units were on line an average of 1.8 percent of 2928 hours in the first four months of operation while LG&E’s five units operated 84.8 percent of the time during the same period.

27. Staff also doubts that Bluegrass can produce reactive power upon request, making availability “even more of an issue than needs.”[70] According to Staff, Bluegrass has a firm fuel supply in the summer, but receives the rest of its fuel on an interruptible basis. Staff maintains that Bluegrass’ facility is only staffed 5 days a week from 6:00 a.m. until 4:00 p.m., and does not have remote start up capability. Finally, Staff argues that “the price ratepayers pay for a service should have at least some relation to its value” because “value is an appropriate consideration in determining reactive power compensation.”[71] Staff concludes that Bluegrass is less valuable then other generators.

28. Staff likened this case to the proceeding in Docket No. ER03-765-001.[72] Staff stated that a major issue in that proceeding was whether Southwest Power Pool (SPP) should have to compensate Calpine Oneta Power, L.P (Oneta) for reactive power regardless of whether SPP actually needs, or Oneta can actually supply, reactive power service. Staff viewed Oneta’s proposed rate as unjust and unreasonable “because Oneta failed to demonstrate why it should be compensated for providing reactive power service at all.”[73] Staff offered its opinion that the reactive power Oneta proposed to provide was not needed and would not be used or useful.

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[68] *Id*. at 18.

[69] *Id*.

[70] *Id*. at 22.

[71] *Id*.

[72] At the time Staff made this argument, the initial decision in Docket No. ER03-765-001 was pending before the Commission. The Commission subsequently decided the case in *Calpine Oneta*.

[73] *Id*. at 21.

29. LG&E argues that the Presiding Judge should not have considered Commission precedent dispositive in this case because the facts here fundamentally differ from the facts underlying previous "needs" cases.[74] LG&E's argument is based on the distinction between providing reactive power inside and outside the bandwidth. LG&E asserts that Order No. 2003 only requires that reactive power suppliers receive compensation *when they respond to requests for reactive power outside the bandwidth*.[75] LG&E states that there is no "needs" test under Order No. 2003 because transmission providers only call on the reactive power suppliers when they are needed for reactive power support.[76] LG&E maintains that the situation here is very different because Bluegrass' proposed rate schedule will compensate it based on its reactive power capability, thereby making the distinction between reactive power produced inside and outside the bandwidth irrelevant. LG&E asserts, therefore, that since Bluegrass "is requesting compensation of almost three-quarters of a million dollars *for providing reactive power both inside and outside the bandwidth*,"[77] its request falls outside Order No. 2003, and should be subject to a "needs" test.

30. Finally, LG&E faults the Presiding Judge for failing to recognize what LG&E and Staff claim is an important difference between PJM's Schedule 2 and Midwest ISO's Schedule 2. LG&E explains that PJM's Schedule 2 includes language specifically expressing a need for reactive power service, but Midwest ISO's Schedule 2 does not. LG&E concludes that this difference shows that "needs" may be considered in determining reactive power compensation.[78]

3. <u>Opposing Exceptions</u>

31. Bluegrass claims that the arguments put forth by Staff and LG&E ignore Commission policy. Bluegrass cites *MISO I* to show that the Commission expressed concern over "needs" language in Midwest ISO's revised Schedule 2 and directed Midwest ISO to remove the contested language in a compliance filing.[79] Bluegrass argues that since the Commission has rejected a "needs" test both generally and

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[74] LG&E's Brief on Exceptions at 32-33.

[75] *Id*. at 32-33.

[76] *Id*. at 33.

[77] *Id*. at 33. Emphasis added.

[78] *Id*.

[79] Bluegrass' Brief Opposing Exceptions at 10.

specifically as to generators located within Midwest ISO's footprint, the arguments advanced by LG&E and Staff amount to collateral attacks on Commission precedent. Bluegrass argues that the Presiding Judge correctly rejected them.

32. Bluegrass also argues that the Presiding Judge properly rejected the "used and useful" and "value" tests. Bluegrass asserts that these "other iterations" of the "needs" test are inconsistent with Commission policy. Bluegrass characterizes the arguments made by Staff and LG&E about its value as incorrectly insinuating that it seeks to recover more than the embedded investment cost of reactive power, and as demonstrating a lack of understanding of the importance of peaking generating units to the market. According to Bluegrass, "the Commission's policy is clear—because generators are to be compensated for capability, plant operating hours are not relevant."[80] In support of this assertion, Bluegrass cites *MISO II* to show that reactive power rates based on capability are not rendered unjust or unreasonable because the reactive power the generator is capable of producing is not used at some particular time. Bluegrass also cites *MISO II* to show that Order No. 2003 requires generators to be capable of providing reactive power within a specified range when so requested, that generators are compensated for capability under Midwest ISO's Schedule 2, and that a generator is "used and useful" if it is capable of providing reactive power.[81]

4. <u>Commission Determination</u>

33. We deny the exceptions filed by Staff and LG&E and affirm the Presiding Judge. As we have explained, Midwest ISO's Schedule 2, which the Commission has found to be just and reasonable, compensates IPPs based on their reactive power capability; it does not contain a "needs" test.[82] Bluegrass, therefore, must receive compensation based on its capability of providing reactive power. Applying a "needs" test to Bluegrass' reactive power capability that is not also applied to all other generators under Midwest ISO's Schedule 2 would deny Bluegrass comparable treatment and constitute undue discrimination.[83] Further, Staff's and LG&E's arguments are improper collateral attacks on the Commission's orders accepting Midwest ISO's Schedule 2, which provides that IPPs are to be compensated for reactive power on a capability and not a "needs" basis.

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[80] *Id*. at 11.

[81] *Id*.

[82] *See supra* P 21. *See also*, *MISO II*, 114 FERC ¶ 61,192 at P 15; *MISO III*, 116 FERC ¶ 61,283 at PP 15-20. We also note that Midwest ISO has strongly opposed a "needs" test since its initial filing in response to the Commission's *October 2004 Order* directing it to revise its Schedule 2. *See MISO II*, 114 FERC ¶ 61,192 at P 15 & n.9; *MISO III*, 116 FERC ¶ 61,283 at PP 15-20.

[83] *See Calpine Oneta*, 116 FERC ¶ 61,282 at P 35.

34. Moreover, contrary to LG&E's and Staff's contentions, the fact that the reactive power that a generator is capable of producing is not used at some particular given time does not render the generator's filed rates based on reactive power capability unjust or unreasonable.[84] In addition, we note that the Commission explicitly rejected the same arguments made by Staff in this proceeding in another proceeding (Docket No. ER03-765-001).[85] The Commission explicitly found in that proceeding, which was decided by the Commission after Staff filed its Brief on Exceptions here, that the *AEP* methodology does not include a "needs" test. Instead, the Commission explained that the *AEP* method measures a generator's maximum capability to produce reactive power.[86] The Commission also repeated that a generator is "used and useful" if the generator is *capable* of providing reactive power.[87] Here, the record indicates that Bluegrass is capable of providing reactive power and thus is "used and useful."

C. Order No. 2003 and the Interconnection Agreement

1. Presiding Judge's Findings

35. The Presiding Judge made two findings related to Bluegrass' Interconnection Agreement with LG&E. First, the Presiding Judge held that the Interconnection Agreement did not preclude Bluegrass from filing the instant rate schedule.[88] Second, the Presiding Judge concluded that even though the Interconnection Agreement preceded Order No. 2003, it was not abrogated by applying the principles of comparability articulated in Order No. 2003 to the instant rate schedule.[89]

36. The Presiding Judge interpreted sections 8.4.4(i) and 8.4.4(ii) of the Interconnection Agreement to give Bluegrass a contractual right to file a rate schedule with the Commission. Section 8.4.4 provides that:

> (i) In the event that FERC, or any other applicable Governmental Authority, issues an order or approves a tariff establishing specific compensation to be paid to Applicant for reactive power support service, [LG&E] shall pay Applicant pursuant to such order or tariff; or

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[84] *See Id* at P 28; *MISO II*, 114 FERC ¶ 61,192 at P 19.

[85] *See Calpine Oneta*, 116 FERC ¶ 61,282 at P 26-P 28.

[86] *Id*. at P 28.

[87] *Id*.; *See also, MISO II*, 114 FERC ¶ 61,192 at P 19.

[88] *Initial Decision*, 115 FERC ¶ 63,015 at P 121.

[89] *Id*. at P 129.

> (ii) In the absence of such an order or tariff, and subject to any applicable rules and regulations of FERC, [LG&E] shall pay Applicant for the reactive power absorbed by the Applicant Facilities and the reactive power produced by the Applicant Facilities on a per MVARh basis for the total MVARh for the hours operated under 8.4.2(ii) and 8.4.3 above at a rate of $0.50 per MVARh; provided, however, if [LG&E], its successors or assigns pay, under any agreement with any other similarly situated generator, for reactive power and voltage control at a rate that is higher than $0.50 per MVARh, Applicant shall be compensated for providing such reactive support at a rate that is equal to the highest rate [LG&E], its successors or assigns pay for reactive power and voltage control to any other similarly situated generator. The total MVARh for a given month shall be equal to the sum of the absolute value of the reactive power absorbed or the reactive power produced, as the case may be, by the Applicant Facilities in each hour of the month during which reactive power was absorbed or produced by Applicant under 8.4.2(ii) or 8.4.3.[90]

Reading these sections together, the Presiding Judge concluded that the language created a contractual right for Bluegrass to file reactive power rate schedules with the Commission.[91] The presiding Judge explained that "[t]he argument of Bluegrass that § 8.4.4 expressly contemplates that the Commission may approve a rate tariff for it on its application, is well-taken. The plain language of that section is that the fifty-cents-per-MVARh compensation provision applies when there is no Commission order providing for reactive power support compensation for Bluegrass."[92] The Presiding Judge also found nothing in the Interconnection Agreement to support LG&E's claim that section 8.4.4(i) requires the Commission to act *sua sponte* to establish new compensation. The Presiding Judge added that "if we were to consider the intention of the parties, it is difficult to believe that LG&E was unaware that the Commission does not instigate all rate changes; proposed rate schedules are filed by utilities for Commission approval all the time."[93] The Presiding Judge cited *IMPA*[94] to show that LG&E has made, and the Commission has rejected, similar arguments in the past.

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[90] Ex. LGE-1, Attachment A, § 8.4.4(i) and (ii) (Interconnection and Operating Agreement between Bluegrass Generation Company, L.L.C., and Louisville Gas and Electric Company and Kentucky Utilities Company, effective as of February 13, 2001, FERC Tariff Volume 1, Service Agreement No. 255 § 8.4.4

[91] *Initial Decision*, 115 FERC ¶ 63,015 at P 126.

[92] *Id*.

[93] *Id*.

[94] *Indiana Municipal Power Agency*, 114 FERC ¶ 61,008 at 61,021 (2006).

37. The Presiding Judge also acknowledged that Order No. 2003 does not abrogate pre-existing reactive power compensation agreements, and that the Interconnection Agreement here pre-exists Order No. 2003.[95] The Presiding Judge concluded however that because the Interconnection Agreement gave Bluegrass the right to file a rate schedule, the Interconnection Agreement was not abrogated by applying the principles of comparability articulated in Order No. 2003 to the instant rate schedule.[96] The Presiding Judge stated that the Commission definitively settled this question in *Rolling Hills*, where it held that Order No. 2003 applied to a pre-existing Interconnection Agreement with the same compensation language as the Interconnection Agreement here.[97]

2. **Exceptions**

38. LG&E disagrees with both conclusions. First, LG&E argues that nothing in the Interconnection Agreement grants Bluegrass the right to file a rate schedule with the Commission. LG&E claims that to establish new compensation under section 8.4.4(i) either LG&E has to file to amend the rate under section 205 of the FPA or the Commission has to act *sua sponte*.[98] LG&E argues that Bluegrass failed to preserve "a unilateral filing right."[99] LG&E claims that Bluegrass cannot rely on Midwest ISO's revised Schedule 2 to establish a right to file for new reactive power compensation. LG&E states that Schedule 2 is merely a pass through mechanism which indicates by its own terms that it does not set specific compensation levels for reactive power suppliers.[100] LG&E also faults the Presiding Judge for citing *IMPA* to support her decision. LG&E states that in *IMPA* it argued that an existing non-jurisdictional agreement precluded compensation for reactive power, while here it acknowledges Bluegrass' right to reactive power compensation, but denies its ability to unilaterally file for new compensation with the Commission.[101]

39. Second, LG&E argues that Order No. 2003 should not apply to the instant rate schedule. LG&E points out that Order No. 2003's own terms limit its application to interconnection agreements entered into after its effective date. LG&E points to

[95] *Initial Decision*, 115 FERC ¶ 63,015 at P 130.

[96] *Id*.

[97] *Id*.

[98] LG&E's Brief on Exceptions at 25.

[99] *Id*. at 24.

[100] *Id*. at 26.

[101] *Id*. at 25-26.

language in Order No. 2003 and Order No. 2003-C explicitly stating that Order No. 2003 neither abrogates pre-existing reactive power compensation agreements, nor requires retroactive application of its principles to pre-existing agreements.[102] LG&E also claims the Presiding Judge was "blatantly wrong" to cite *Rolling Hills* as support for her decision.[103] According to LG&E, the entire discussion of Order No. 2003 in Rolling Hills consisted of the following: "[w]e also deny AEP's request that Rolling Hills be required to show a need for reactive power service. We find this request to be contrary to Order No. 2003."[104] LG&E maintains that there was no finding in *Rolling Hills* that Order No. 2003 applies to existing interconnection agreements, and that the Presiding Judge erred by disproportionately emphasizing a single sentence.[105]

40. In the alternative, LG&E argues that Order No. 2003 does not require that Bluegrass receive compensation for reactive power it provides within the dead band. LG&E cites Order No. 2003 to show that Bluegrass should only be compensated for reactive power when it operates outside the bandwidth. LG&E claims that Order No. 2003 does not establish a rate for compensation for reactive power, and points out that Bluegrass is already being compensated for reactive power outside the bandwidth at the rate set forth in the Interconnection Agreement.

41. Finally, LG&E argues that Bluegrass has not demonstrated any lack of comparability under Order No. 2003-A.[106] LG&E acknowledges that Order No. 2003-A and its progeny command transmission providers to compensate non-affiliated generators for reactive power within the established range if they compensate their own or affiliated generators for such power. LG&E notes, however, that it is not the transmission provider in this case. LG&E also claims that it does not receive any compensation for reactive power produced at its Trimble County Generating Unit (Trimble Unit), which LG&E claims to be comparable to Bluegrass. LG&E maintains that since Bluegrass has made no comparability argument, LG&E should not be required to compensate Bluegrass if Bluegrass is operating within the bandwidth.[107]

[102] *Id*. at 26-27.

[103] *Id*. at 27.

[104] *Id*. (quoting *Rolling Hills*, 109 FERC ¶ 61,069 at P 13) (internal quotations omitted).

[105] *Id*.

[106] *Id*. at 29.

[107] *Id*. at 30.

3. Opposing Exceptions

42. Bluegrass maintains that the Interconnection Agreement expressly recognizes its right to file a rate schedule. Bluegrass agrees with the Presiding Judge that *IMPA* is relevant here. Bluegrass argues that it, like the Indiana Municipal Power Agency (Indiana Municipal) in *IMPA*, is simply filing its reactive power revenue requirement for Commission approval.[108] Bluegrass claims that it has a contractual right to a revenue requirement following the *AEP* methodology and that, in filing the instant tariff, it has exercised that right.[109] Bluegrass also agrees with the Presiding Judge that Order No. 2003 applies to the instant rate schedule.[110]

43. Bluegrass states that bandwidth is not an issue here.[111] Bluegrass claims that LG&E has missed that the intention behind the Commission's reactive power compensation policy is comparability.[112] Bluegrass acknowledges that, absent contrary contract provisions, reactive power compensation may be unavailable within the dead band if the transmission provider does not compensate its own or affiliated generators within the dead band. Bluegrass argues, however, that its revenue requirement applies under Midwest ISO's Schedule 2, and that under Schedule 2, generators are compensated for their reactive power capability.[113]

4. Commission Determination

44. We deny the exceptions filed by LG&E and affirm the Presiding Judge on both issues. First, we affirm the Presiding Judge's conclusion that the Interconnection Agreement recognizes Bluegrass' right to file for reactive power compensation with the Commission. LG&E's argument that under section 8.4.4(i) only LG&E or the Commission may act to amend the rate is untenable. Section 8.4.4(i) does not distinguish who is or is not eligible to seek compensation for reactive power support service. Rather, the section has been drafted in the inverse, that is, upon the Commission's issuance of an order or approval of a tariff establishing specific compensation to be paid to Bluegrass, LG&E shall pay Bluegrass pursuant to such order or tariff. Thus, the question must be, how can the issue be brought before the Commission so that the Commission can issue an order or approve a tariff. LG&E seeks to limit the ways the issue can be brought to the

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[108] Bluegrass' Brief Opposing Exceptions at 19.

[109] *Id*.

[110] *Id*. at 16.

[111] *Id*. at 17.

[112] *Id*.

[113] *Id*.

Commission to a filing under section 205 by LG&E or an action by the Commission under section 206. Without explanation, LG&E simply concludes that Bluegrass is somehow ineligible to make a filing upon which the Commission could act. We do not disagree that LG&E, pursuant to section 8.4.4(i), could make a filing pursuant to section 205. Nor do we disagree with LG&E that the Commission *sua sponte* could act pursuant to section 206 and issue an order. However, we disagree with LG&E that section 8.4.4(i) prevents Bluegrass from filing. Because of the approach the parties took to drafting section 8.4.4(i), either the language of section 8.4.4(i) is read as preventing both LG&E, Bluegrass and the Commission from initiating a proceeding and seeking an order from the Commission, or as allowing LG&E, Bluegrass and the Commission to initiate a proceeding and seek an order from the Commission. The former interpretation would render section 8.4.4(i) meaningless, as the Commission would never be able to issue an order or approve a tariff as contemplated by section 8.4.4(i). Thus, under the facts of this case, we interpret section 8.4.4(i) as allowing all eligible entities, including Bluegrass, to initiate a proceeding that would lead to the Commission issuing an order or approving a tariff.

45. Moreover, we note that we have previously recognized that language like section 8.4.4(i) allows generators to file rate schedules with the Commission. In *Rolling Hills*, for example, the interconnection agreement between Rolling Hills Generating, L.L.C. (Rolling Hills) and AEP (on behalf of Ohio Power Company) contained language nearly identical to section 8.4.4(i).[114] Rolling Hills filed a rate schedule for reactive power compensation under the language, and the Commission described the language as "indicating compensation for reactive power support."[115] The Commission accepted Rolling Hills' rate schedule for filing, and established hearing and settlement judge procedures on unrelated matters.[116] In other words, the Commission did not interpret this language to mean that only AEP or the Commission could initiate a change in Rolling Hills' rates.

46. Similarly, the Presiding Judge was correct to cite *IMPA* to support her decision. In *IMPA*, LG&E argued that nothing in its preexisting agreements with Indiana Municipal permitted Indiana Municipal to seek reactive power compensation after Midwest ISO revised Schedule 2 to compensate IPPs. We held that LG&E's argument was misplaced, as LG&E made no showing that Indiana Municipal was precluded from receiving reactive power compensation.[117] Here, LG&E acknowledges that Bluegrass has a right to reactive power compensation under the Interconnection Agreement, but argues that

[114] *Rolling Hills*, 109 FERC ¶ 61,069 at P 2.

[115] *Id*.

[116] *Id*. at P 14.

[117] *IMPA*, 114 FERC ¶ 61,008 at P 18.

nothing in the Interconnection Agreement allows Bluegrass to seek new compensation by filing with the Commission. Again, we find LG&E's argument to be misplaced. As in *IMPA*, LG&E has made no showing that the Interconnection Agreement here precludes Bluegrass from seeking new compensation from the Commission. On the contrary, we find that the Interconnection Agreement affirmatively authorizes Bluegrass to make such a filing.

47. Second, we agree with the Presiding Judge's conclusion that Bluegrass' proposed rate schedule must be evaluated in light of the principle of comparability articulated in Order No. 2003. As explained, the Commission evaluated Midwest ISO's Schedule 2, pursuant to which Bluegrass filed its rate schedule, on a comparability basis and found that Midwest ISO must compensate IPPs on the same basis as Midwest ISO's transmission owners' generators. In this regard, the Commission accepted Midwest ISO's proposal to compensate all generators on its system on a capability basis, thus assuring comparable treatment. Accordingly, in order for Bluegrass to receive comparable treatment and to be treated in a not unduly discriminatory manner, it must receive compensation based on its capability of providing reactive power.[118] We also find that whether LG&E is the transmission provider or not is irrelevant to the matter at issue. The only relevant matter is Bluegrass' status and, as we find below, Bluegrass meets Midwest ISO's OATT requirements for obtaining reactive power compensation. We are also not persuaded by LG&E's argument regarding the compensation it receives for reactive power produced at its Trimble Unit. According to its witness, LG&E's current Schedule 2 rates were originally filed in 1996, before the gas-fired combustion turbines at the Trimble Unit were built, and do not include compensation for reactive power produced by these combustion turbines.[119] Whether LG&E has updated its Schedule 2 rates to reflect recent plant additions is not at issue. The critical issue is whether LG&E's Schedule 2 rates were designed to provide compensation for reactive power produced within the established range to its own generators that were in-service during the relevant test period used to establish those rates. While LG&E's existing Schedule 2 rates resulted from a settlement in Docket No. ER98-114, LG&E does not argue that those rates were not designed to compensate its own generators for reactive power produced within the established range.

[118] *See MISO II*, 114 FERC ¶ 61,192 at P 18; *Calpine Oneta*, 116 FERC ¶ 61,282 at P 35. *See also METC*, 97 FERC ¶ 61,187 at 61,852-53 (2001) ("the need to treat all generation interconnection customers comparably underlies the need for a *pro forma* tariff. To that end, it is hardly consistent to allow an affiliate to have different and/or superior terms and conditions for interconnection than non-affiliates . . . we direct Michigan Electric to compensate Generators for providing reactive power to the same degree that it will compensate its affiliate, Consumers, for providing reactive power."). *See also* Order No. 2003-A at P 416 (comparability of compensation); *accord* Order No. 2003-B at P 113, 119; October 14, 2005 Order, 113 FERC ¶ 61,040 at P 22-24, 38-39.

[119] Ex. LGE-2 at 20.

D. Qualified Generator Requirements Of MISO Schedule II

1. Presiding Judge's Findings

48. The Presiding Judge held that Bluegrass met Midwest ISO's Qualified Generator Requirements.[120] The Presiding Judge cited evidence showing that Midwest ISO approved Bluegrass as a Qualified Generator on November 21, 2005.[121] The Presiding Judge rejected LG&E's argument that Bluegrass was ineligible for reactive power compensation prior to November 21, 2005. In rejecting LG&E's argument, the Presiding Judge noted that Bluegrass' reactive power tariff was made effective March 1, 2005, the Commission made Midwest ISO's revised Schedule 2 effective January 1, 2005, and the Commission rejected Midwest ISO's request for a 60-day review period after generators submit their Qualified Generator certification paperwork.[122]

2. Exceptions

49. LG&E claims that Bluegrass did not meet Midwest ISO's compensation eligibility requirements before November 21, 2005. LG&E states that Schedule 2 requires generators to receive Commission approval for their cost-based revenue requirements and submit self-certifications of compliance with other Midwest ISO provisions before they are eligible for Qualified Generator status.[123] LG&E argues that Bluegrass could not have completed its required self-certification until November 21, 2005 because its facility's first test for reactive power capability was on November 3, 2005.[124] LG&E claims that the Presiding Judge's decision lacks rationale and disregards Schedule 2's plain language.[125] In LG&E's view, the Presiding Judge's decision permits generators with accepted revenue requirements to delay or ignore certification and testing, submit self-certifications at a later date, and receive compensation back to their tariff's effective date.[126]

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[120] *Initial Decision*, 115 FERC ¶ 63,015 at P 132.

[121] *Id*. at P 133.

[122] *Id*.

[123] LG&E's Brief on Exceptions at 29.

[124] *Id*. at 29-30.

[125] *Id*. at 30.

[126] *Id*.

3. Opposing Exceptions

50. Bluegrass argues that its compensation should begin March 1, 2005, the effective date of its rate schedule.[127] Bluegrass claims Schedule 2 was in a state of flux until the Commission accepted it in *MISO I*, and that until the Commission issued *MISO I*, Bluegrass did not know what was necessary to obtain Qualified Generator Status.[128] Bluegrass acknowledges that the Commission made Schedule 2 effective January 1, 2005, but points out that *MISO I* was not issued until October 17, 2005.[129] Bluegrass states that it submitted its certification soon thereafter. Bluegrass maintains that it should not be penalized for the lapse in time that occurred between Midwest ISO's submission of its compliance tariff and the Commission's ultimate approval of same, "particularly since Bluegrass otherwise satisfies the criteria for Qualified Generator status."[130] Finally, Bluegrass argues that a March 1, 2005 effective date is consistent with *MISO I*. Bluegrass cites the same language the Presiding Judge cited to show that the Commission rejected Midwest ISO's proposal that generators with Commission approved revenue requirements provide uncompensated service during a 60-day review period.

4. Commission Determination

51. We deny LG&E's exceptions and affirm the Presiding Judge. The Presiding Judge concluded that permitting Bluegrass to receive compensation before November 21, 2005 was consistent with the Commission's rejection of Midwest ISO's proposed 60-day review period in *MISO I*. We agree. In *MISO I*, we held that Midwest ISO had no rational basis for requiring generators with revenue requirements already accepted by the Commission to provide uncompensated service for 60 days while Midwest ISO reviewed their certifications.[131] We also stated that we interpreted Commission acceptance of a revenue requirement to mean initial, not final acceptance.[132]

52. We are persuaded to apply similar reasoning here, given the circumstances of this case. The Commission initially accepted Bluegrass' rate schedule on March 25, 2005, making it effective March 1, 2005.[133] While the Commission did not accept Midwest

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[127] Bluegrass' Brief Opposing Exceptions at 22.

[128] *Id*. at 21-22.

[129] *Id*. at 21.

[130] *Id*. at 22.

[131] *MISO I*, 113 FERC ¶ 61,046 at P 43.

[132] *Id*.

[133] *See Bluegrass Generation Company, L.L.C.*, 110 FERC ¶ 61,349 at P 1 (2005).

ISO's Schedule 2 until October 17, 2005 (*MISO I*), it would be unreasonable not to allow Bluegrass to begin receiving compensation on March 1, 2005, the effective date of its proposed rate schedule. The fact that the later accepted Midwest ISO Schedule 2 contained technical requirements for a generator to obtain Qualified Generator Status as a prerequisite to obtaining compensation should not be held against Bluegrass under these circumstances. Bluegrass knew from prior Commission orders that it would be able to seek compensation for its reactive power capability and accordingly filed its rate schedule. Upon the issuance of *MISO I*, Bluegrass promptly completed the certification process. Just as we found no reason to require generators with revenue requirements accepted by the Commission to provide uncompensated service for a 60-day review period in *MISO I*, we find no reason that Bluegrass should not receive compensation for the service it has provided since we accepted and made its rate schedule effective. To do otherwise would exalt form over substance.

E. Bluegrass' Capability

1. Presiding Judge's Findings

53. The Presiding Judge held that Bluegrass is capable of providing 360.33 MVARs of reactive power.[134] The Presiding Judge based her conclusion on the results of the November 3, 2005 test conducted in accordance with the requirements of the East Central Area Reliability Coordination Agreement (now Reliability*First*) (ECAR). The Presiding Judge found that the ECAR test verified Bluegrass' ability to produce 360.33 MVARs of reactive power. In support of her conclusion, the Presiding Judge noted that Midwest ISO certified Bluegrass as a Qualified Generator after considering the test's results, that Bluegrass uses the MVAR and MVA capability at the generator terminals in conformity with the *AEP* methodology, and that Staff accepts Bluegrass' ability to produce 360.33 MVARs.[135]

2. Exceptions

54. LG&E claims the only time Bluegrass has ever produced 360.33 MVARs was during the ECAR test, which was conducted in a controlled environment while Bluegrass was fully staffed.[136] LG&E argues that "this does not demonstrate the capability of the plant in actual operating circumstances."[137] LG&E points to Bluegrass' failure to meet its request for 200 MVARs on August 11, 2005 as an example.[138] LG&E faults the

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[134] *Initial Decision*, 115 FERC ¶ 63,015 at P 138.

[135] *Id*. at P 139.

[136] LG&E's Brief on Exceptions at 31.

[137] *Id*.

[138] *Id*.

Presiding Judge for dismissing this example because it emphasizes Bluegrass' performance on a single day, but then relying on the single day of ECAR testing to hold that Bluegrass is capable of producing 360.33 MVARs.[139]

55. LG&E also makes the general argument that Bluegrass cannot provide reactive power according to Schedule 2's requirements. LG&E maintains that even if the Commission finds that the single day of ECAR testing accurately represents Bluegrass' capability, the Presiding Judge erred by summarily dismissing the plant's minimal operation, lack of full-time staff, and lack of remote start-up capability.[140] LG&E also faults the Presiding Judge for failing to address whether Bluegrass can immediately respond to reactive power requests as required by Schedule 2.

3. Opposing Exceptions

56. Bluegrass claims that its performance on August 11, 2005 unfairly represents its capability. Bluegrass states that LG&E requested 100 MVARs of reactive power support directly from Bluegrass at 10:00 a.m. EDT on August 11, 2005. Bluegrass states that LG&E made a second request for an additional 100 MVARs two hours later, after Bluegrass re-dispatched its unit to fully respond to the first request.[141]

57. Bluegrass acknowledges that it only produced an additional 83 MVARs, but claims that LG&E was violating the Interconnection Agreement. Bluegrass states that section 8.4.3 of the Interconnection Agreement permits LG&E to make such requests during a System Emergency and only when re-dispatch requests are made on a nondiscriminatory basis. Bluegrass states that no System Emergency existed on August 11, 2005 and that no other units were requested to provide reactive power that day. In Bluegrass' view, LG&E's inappropriate and unduly discriminatory behavior makes it "especially inappropriate" to cite test data from August 11, 2005 as evidence of Bluegrass' capability.[142]

58. Bluegrass characterizes LG&E's other concerns about its ability to produce reactive power as attempts to impose extra-tariff obligations. Bluegrass states that Schedule 2 does not require it to have full-time staff, remote start-up capability, or a firm fuel supply. Bluegrass argues that imposing these requirements on its facility would be unduly discriminatory.[143]

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[139] *Id*.

[140] *Id*.

[141] Bluegrass' Brief Opposing Exceptions at 23-24.

[142] *Id*. at 24.

[143] *Id*. at 22.

4. Commission Determination

59. We deny LG&E's exception and affirm the Presiding Judge. The ECAR test is performed by a neutral party and Midwest ISO recognizes it as a reliable indicator of a generator's reactive power capability. In fact, Midwest ISO requires such testing and certified Bluegrass as a Qualified Generator after evaluating the ECAR results. We also agree with Bluegrass' characterization that the events of August 11, 2005 are extraordinary and not an appropriate basis upon which to determine its reactive power capability.

60. Finally, we note that the fact that Bluegrass *actually produced* 360.33 MVARs during the ECAR test necessarily shows that it is *capable* of producing 360.33 MVARs. Even LG&E admits that Bluegrass produced 360.33 MVARs; its challenge therefore is not to Bluegrass' capability, but to its ability to meet its capability under unpredictable circumstances. We agree with Bluegrass that this challenge is actually an attempt to impose extra-tariff obligations on Bluegrass. Therefore, we affirm the Presiding Judge in rejecting these conditions.

F. Rate of Return/ Capital Structure

1. Presiding Judge's Findings

61. The Presiding Judge held that Bluegrass' proposed capital structure and proposed overall return of 8.54 percent are just and reasonable.[144] The Presiding Judge accepted Bluegrass' proposal to use the authorized rate of return of the interconnected utility, LG&E, as a proxy. In accepting Bluegrass' proposal, the Presiding Judge rejected alternatives proposed by LG&E and Staff.[145]

62. LG&E argued that Bluegrass' return should be predicated on Dynegy's actual capital structure and not the hypothetical structure Bluegrass proposed. LG&E noted that Bluegrass is a wholly-owned subsidiary of Dynegy, and Dynegy has publicly-traded stock.[146] LG&E maintained that it is incorrect to use its capital structure because it is owned by a German non-publicly traded corporation with business operations in Europe and a very different risk profile. LG&E also pointed to Commission precedent stating that the rate of return of the transmission provider is not presumptively the appropriate model for reactive power compensation computations.[147]

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[144] *Initial Decision*, 115 FERC ¶ 63,015 at P 149.

[145] *Id*. at P 153.

[146] *Id*. at P 151.

[147] *Id*.

63. The Presiding Judge rejected LG&E's recommendation of using Dynegy's actual capital costs as unjust, unreasonable, and suffering from "several infirmities."[148] The Presiding Judge found the fact that Dynegy's S&P bond rating is 'BBB-' to be "a determinative factor."[149] According to the Presiding Judge, the Commission has rejected the use of a parent company's 37 percent common equity ratio as unrepresentative of utility business after noting the below-investment-grade status of that parent company.[150] The Presiding Judge stated that Dynegy's common equity ratio of 25.20 percent is also unrepresentative and, therefore, not appropriate for use in this case.[151]

64. Staff agreed with Bluegrass that LG&E is an appropriate company to look to for developing Bluegrass' return on capital, but argued that Bluegrass should not use LG&E's specific capital structure and cost rates because LG&E does not have a market-driven capital structure and because its parent company is not in the United States.[152] Staff recommended using companies comparable to LG&E as a proxy group.[153]

65. The Presiding Judge rejected Staff's use of a group of four companies as a proxy for Bluegrass as inappropriate, notwithstanding the fact that LG&E does not issue publicly-traded stock.[154] The Presiding Judge stated that, because LG&E does not have its own independent, market-driven capital structure, Staff determined a capital structure and overall rate of return for Bluegrass based on a four-member proxy group citing to an old, non-reactive power case for the proposition that the Commission prefers a market-driven capital structure.[155] The Presiding Judge rejected Staff's recommendation, finding that the Commission has been accepting reactive power revenue requirement filings of non-utility generators using the interconnected transmission's owner's cost-of-capital rates.[156] The Presiding Judge found that the Commission used the same LG&E cost of capital components that Bluegrass advocated using here as a proxy for Indiana

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[148] *Id*. at P 154.

[149] *Id*.

[150] *Id*.

[151] *Id*.

[152] *Id*. at P 152.

[153] *Id*.

[154] *Id*. at P 155.

[155] *Id*.

[156] *Id*. at P 156.

Municipal, also a non-public utility generator, in *IMPA*.[157] The Presiding Judge stated that LG&E made similar arguments against use of its capital structure in *IMPA*, which the Commission rejected.[158]

2. **Exceptions**

66. LG&E claims that the Presiding Judge erred by accepting Bluegrass' overall rate of return and capital structure. As a threshold issue, LG&E maintains that Bluegrass failed to demonstrate any investment in the facility for which it requests a return, and as such, is not entitled to a return.[159] LG&E also asserts that Bluegrass has not shown that LG&E is an appropriate proxy, or that Bluegrass faces more risks than a utility providing transmission services. According to LG&E, Bluegrass will have no risk in collecting its proposed revenue requirement because it does not have to produce a single MVAR to collect the capability payment under its proposal.[160] LG&E also maintains that Bluegrass failed to meet is burden of showing that its rates are just and reasonable under section 205 of the FPA,[161] and that section 206 of the FPA required the Presiding Judge to find that the existing Interconnection Agreement is unjust and unreasonable.[162]

67. LG&E argues that Bluegrass is not entitled to reactive power compensation because it leases its generating station from the County of Oldham, Kentucky. According to LG&E, "the return on equity should be commensurate with the return on investments of businesses with similar risks; thus, to be entitled to a return on investment, the entity must be an equity owner, *i.e.*, an owner of the asset on which it is attempting to secure an approved rate of return."[163] In LG&E's view, *AEP* "manifestly presupposes ownership of the plant assets for which cost recovery is being sought."[164] LG&E faults the Presiding Judge for failing to address this argument, and incorrectly finding that Bluegrass is entitled to a return on equity on property that it does not own. Similarly, LG&E argues that Bluegrass should not be allowed to recover an income tax component related to an equity return on property that it does not own.

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[157] *Id*.

[158] *Id*.

[159] LG&E's Brief on Exceptions at 36-38.

[160] *Id*. at 35.

[161] *Id*. at 15-16.

[162] *Id*. at 16-17

[163] *Id*. at 36.

[164] *Id*. at 36-37.

68. LG&E further argues that Bluegrass has not met its burden of proving that its lease is a capital lease, which might entitle Bluegrass to a return on equity.[165] LG&E notes that Staff has pointed out that while operating leases do not afford the lessee the right to receive a return on equity on property that it does not own, the same is not true with capital leases.[166] LG&E asserts, however, that the terms of Bluegrass' lease do not indicate whether the lease is an operating or a capital lease. In LG&E's view, Bluegrass has failed to demonstrate an ownership interest supporting its request for a return on equity and therefore is not entitled to receive one.[167]

69. Next, LG&E faults the Presiding Judge for failing to follow *Detroit Edison*[168] and *Pacific Gas*.[169] LG&E claims that *Pacific Gas* requires Bluegrass to establish the necessity and suitability of its chosen proxy.[170] This includes, LG&E notes, showing that Dynegy and LG&E bear comparable risks.[171] LG&E asserts that Bluegrass has not met this burden. LG&E further claims that Bluegrass has never addressed LG&E's argument that Bluegrass' and LG&E's capital structures and costs are completely different, and has never explained why Dynegy's capital structure is not a more appropriate model.[172] LG&E states that Bluegrass has also failed to respond to its point that LG&E is an integrated utility that must meet a broader array of obligations and supply a wider array of services than Bluegrass. LG&E also points to its foreign ownership and the fact that it is no longer publicly-traded as reasons why it is unsuited as a model for reactive power rate-setting for an American merchant power producer.

70. LG&E asserts that if Bluegrass is entitled to a rate of return it should be based on Dynegy's capital structure. LG&E states that because Bluegrass is a wholly-owned subsidiary of Dynegy and has no publicly-traded stock, its capital structure does not

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[165] *Id*. at 37.

[166] *Id*.

[167] *Id*.

[168] *Detroit Edison Co.*, 105 FERC ¶ 61,264 (2003), *reh'g denied*, 106 FERC ¶ 61,244 (2004) (*Detroit Edison*).

[169] *Pacific Gas & Elec. Co. v. FERC*, 306 F.3d 1112, 1120-21 (D.C. Cir. 2002) (*Pacific Gas*).

[170] LG&E's Brief on Exceptions at 38.

[171] *Id*. at 38-39, 44.

[172] *Id*. at 44.

reflect investor judgments about market-driven risks and opportunities.[173] Dynegy, in contrast, is a publicly-traded company, and its stock reflects investor judgments about potential risks and rewards. According to LG&E, Dynegy's common equity, at approximately 25 percent of total capital structure is neither overvalued nor undervalued for use as an analytical model.[174] In LG&E's view, employing Dynegy's capital structure offers the dual advantage of a real-world foundation and a minimizing of the need to "gross up" the cost of common equity to account for taxes.[175]

71. LG&E also cites *Detroit Edison* to support its argument that a transmission provider's return on equity is not *ipso facto* the proper model for reactive power or other ancillary service computations.[176] According to LG&E, this means that Bluegrass bears the burden of establishing LG&E's suitability as a proxy.[177] LG&E asserts that the instant record actually reflects no reason to employ a proxy for capital structure or rate of return. Finally, LG&E faults the Presiding Judge for relying on *IMPA*. First, LG&E states that the Presiding Judge was incorrect to rely on a decision currently pending before the Commission on rehearing.[178] Second, LG&E asserts that the instant case cannot be likened to *IMPA* because Indiana Municipal's stake in the facility at issue in *IMPA* was entirely debt financed using low-risk municipal bonds.[179]

72. Staff agrees that the Presiding Judge erred in finding that Bluegrass is entitled to a rate of return, and in permitting the return to be 8.54 percent. Staff maintains that Bluegrass has not established that it should be allowed a return for its leased facilities.[180] If a return is allowed, Staff believes that it should be 7.01 percent, based on a return on equity of 8.20 percent.[181] Staff believes that LG&E may be used as a proxy, but that the

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[173] *Id*. at 39.

[174] *Id*.

[175] LG&E states that this "grossing up" is necessary in rate of return calculations to take account of the fact that the cost of equity is not deductible for income tax purposes. *Id*. at 39-40.

[176] *Id*. at 46.

[177] *Id*.

[178] *Id*. at 42.

[179] *Id*.

[180] Staff's Brief on Exceptions at 33.

[181] *Id*. at 33.

Presiding Judge was incorrect to simply adopt LG&E's current rate. In Staff's view, the Presiding Judge failed to differentiate between the appropriateness of using a proxy and the calculation of a proper proxy result.[182]

73. First, Staff believes that Bluegrass should be denied a return because it failed to show that its lease is a capital lease. Staff recognizes that leased facilities may earn a return if a capital lease is involved, but maintains that Bluegrass did not introduce the lease or any other evidence on this point.[183] In the absence of such evidence, Staff agrees with LG&E that Bluegrass is not entitled to any return. Staff notes that the standards for classifying a lease as capital or operating are found in the USofA, and argues that these standards should be applied to the terms of Bluegrass' lease with Oldham County to determine how the lease should be classified, even though Bluegrass is not required to maintain its books according to the USofA.[184]

74. Staff argues that its proposal should be adopted if the Commission determines that Bluegrass should be allowed a rate of return. Staff claims that the preferred method for determining return on equity is the Discounted Cash Flow (DCF) Analysis, which requires careful examination of the return required to attract common equity financing as a function of the market price, dividends and growth expectations for the common stock.[185] Staff argues that the Presiding Judge incorrectly permitted Bluegrass to simply

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[182] *Id*. at 34.

[183] *Id*. at 35-36.

[184] *Id*. at 35-36. "Capital Lease" is defined as a lease of property used in utility or non-utility operations which meets one or more of the criteria stated in General Instruction 19, Criteria for classifying leases and is recorded under Acct 101.1. The Financial Accounting Standards Board (FASB), issued FASB-13 in 1976, which provides in pertinent part: If at its inception a lease meets one or more of the following four criteria, the lease shall be classified as a capital lease by the lessee. Otherwise, it shall be classified as an operating lease.

1. The lease transfers ownership of the property to the lessee by the end of the lease term

2. The lease contains a bargain purchase option.

3. The lease term is equal to 75 percent or more of the estimated economic life of the lease property

4. The present value of the rents equals or exceeds 90 percent of the fair value of the leased property

[185] Staff's Brief on Exceptions at 37-38.

adopt the general 12.38 percent return on common equity (ROE) for transmission owners (including LG&E) in the Midwest ISO.[186] Staff maintains that this generic rate of return for transmission owners is not, by definition, directly applicable to reactive power services produced by generators.[187]

75. Staff claims that in *Detroit Edison* the Commission "never purported to approve a generic ROE for all Midwest ISO members to use in formulating ancillary service rates, when it established an ROE for use in the Midwest ISO OATT, and Bluegrass has not demonstrated otherwise."[188] Staff also points out that, as a generic rate, the Midwest ISO rate does not purport to measure the actual risk of any particular company, such as LG&E.[189] Staff claims, however, that its proposed proxy group specifically mirrors LG&E's risks.[190]

76. Staff also believes that the Presiding Judge's reliance on *IMPA* is misplaced. Staff asserts that when the Commission accepted LG&E as a proxy in *IMPA* there was no critical evaluation of the elements that made up LG&E's return.[191] Staff states that no other potential proxies or proxy analysis was suggested or considered in that case.[192] Staff finds it meaningful that the decision in *IMPA* emanated from an order instituting a section 206 proceeding. Staff states that, in *IMPA*, the Commission specifically refused to set the appropriateness of using a proxy for hearing, simply accepting Indiana Municipal's uncontroverted proxy.[193] Staff notes that here, however, the issue of an appropriate proxy analysis was not similarly avoided or excluded.[194]

77. Staff also cites the Commission's language in setting this matter for hearing, asserting that it signifies that the parties and the Presiding Judge are to thoroughly analyze all aspects of Bluegrass' proposal, including whether Bluegrass used the proper

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[186] *Id*. at 38.

[187] *Id*. at 38-39.

[188] *Id*. at 39.

[189] *Id*.

[190] *Id*.

[191] *Id*. at 34.

[192] *Id*.

[193] *Id*.

[194] *Id*.

criteria to develop its rate of return.[195] Staff argues that had the development of a return on equity for Bluegrass been a simple matter of adopting the return allowed for LG&E, the Commission could have easily said as much in its order setting this case for hearing, but it did not.[196] In Staff's view, this case cannot be likened to *IMPA*, and its arguments on the appropriate proxy analysis for determining Bluegrass' rate of return and capital structure should be considered and accepted.[197]

78. Staff agrees with LG&E that the Presiding Judge erred by shifting the burden of proving that Bluegrass' proposed return is just and reasonable from Bluegrass to Staff and LG&E.[198] Staff states that as the filing entity in a section 205 proceeding, Bluegrass has the burden of demonstrating that its proposed rates are just and reasonable.[199] Staff maintains that Bluegrass has not met that burden. Staff also faults the Presiding Judge for ignoring the Commission's long-held preference for utilizing up-to-date data in the rate of return analysis.[200] Staff claims that the Commission considered the Midwest ISO generic rate, calculated in 2002, outdated for similar purposes in 2004.[201]

79. Staff states that it developed its rate of return by conducting DCF analysis on a proxy group of companies with risk factors similar to those of LG&E.[202] Staff's proxy group included Allete Inc., OGE Energy Corp., Pepco Holdings, Inc. and Wisconsin

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[195] *Id*. at 35.

[196] *Id*.

[197] *Id*.

[198] *Id*. at 37.

[199] *Id*.

[200] *Id*. at 40.

[201] *Id*.

[202] *Id*. at 41. The criteria are: (l) operation in the United States and reported on by Value Line and I/B/E/S in their respective electric utility section; (2) a Standard & Poor's (S&P) corporate credit rating (CCR) of "BBB+"; (3) a S&P utility business profile of 4 to 6; (4) are currently paying a dividend, have not cut their dividend level within the past three years, and for whom Value Line does not expect a dividend cut in its future dividend estimates for the company; (5) no announced or pending merge activity during the recent six-month data period used in the DCF analysis; (6) the DCF model growth rate cannot be higher than the proxy group's median low estimate of investors' required return on common equity; and (7) the low end DCF must exceed the Moody's six-month average yield on 'Baa' Public Utility bonds by at least 100 basis points. *Id*.

Energy Corp.[203] Staff argues that Bluegrass' appropriate capital structure is the average debt/equity ratio of this proxy group. Staff claims that by using the proxy group's average capital structure, it has assured that the level of financial risk inherent in that capital structure corresponds with the level of financial risk compensated for in Staffs' return on common equity recommendation.[204]

80. Staff points to its witness' testimony that the average equity ratio for the proxy group is 49 percent, and concludes that the appropriate capital structure for Bluegrass is 50 percent long-term debt and 40 percent common equity.[205] Applying the DCF model to all four companies in its proxy group, Staff calculated a zone of reasonableness for returns on common equity. Using the lowest and highest DCF results from the proxy companies, Staff developed a reasonable range for the entire group of 7.67 percent to 10.56 percent.[206] Taking the median of the proxy group's DCF results, Staff recommends an 8.2 percent return on equity.[207] By combining the average capital structure for the appropriate proxy group with the median return on common equity and cost of long-term debt for bonds with a similar level of risk, Staff derives an after-tax weighted average cost of capital of 7.01 percent.[208] Staff contends that this total cost of capital represents Bluegrass' appropriate rate of return.

3. <u>Opposing Exceptions</u>

81. Bluegrass disagrees with LG&E and Staff. First, Bluegrass points to *IMPA*[209] and *Calpine Fox*[210] as "clear precedent" supporting its use of LG&E's capital costs as a proxy.[211] Bluegrass points out that in *IMPA* the Commission accepted the very same LG&E capital costs for Indiana Municipal that it proposes here.[212] Similarly, Bluegrass

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[203] *Id*. at 42.

[204] *Id*. at 44-45.

[205] *Id*. at 45.

[206] *Id*. at 49.

[207] *Id*.

[208] *Id*. at 50.

[209] *IMPA*, 114 FERC ¶ 61,008 at P 20.

[210] *Calpine Fox, LLC*, 113 FERC ¶61,047 (2005) (*Calpine Fox)*.

[211] Bluegrass' Brief Opposing Exceptions at 26.

[212] *Id*. at 25.

states that the Commission accepted the use of a 50 percent debt 50 percent equity ratio and 12.20 percent ROE (overall rate of return of 9.72 percent) of American Transmission Company, LLC (ATC), the interconnected transmission owner in *Calpine Fox*.[213] Second, Bluegrass argues that the leased status of its facility should not prohibit it from receiving reactive power compensation. Bluegrass states that it identified the facility as leased in its initial filing, but neither LG&E nor Staff timely objected.[214] Bluegrass adds that neither LG&E nor Staff included the lease issue as one of their stipulated issues, or raised it in their testimony.

82. Bluegrass maintains that had Staff or LG&E timely raised the issue, it would have submitted the lease as evidence.[215] Bluegrass claims it would have pointed to section 9.2, which provides that at the end of the lease Oldham County will convey title to Bluegrass.[216] Bluegrass asserts that this proves that the lease is a capital lease under the USofA. In any event, Bluegrass notes that it provided a copy of the lease to Staff and LG&E, so "they know or should have known that their late objection is unsubstantiated."[217] Bluegrass also argues that it is not clear under Order No. 2003-A and the Interconnection Agreement that ownership or a capital lease is required for reactive power compensation.[218]

83. Finally, Bluegrass asserts that LG&E and Staff are incorrect to assert that Bluegrass has the burden of showing that the rate under the Interconnection Agreement is unjust and unreasonable. Bluegrass states that the Presiding Judge correctly determined that Bluegrass was implementing, rather than altering, the Interconnection Agreement.[219] Bluegrass also rejects LG&E's argument that the Presiding Judge should have found that the existing Interconnection Agreement was unjust and unreasonable. Bluegrass points out that the Commission rejected the idea that there had to be a finding that the existing agreement was unjust and unreasonable before a generator with a contractual right to file

[213] *Id*. at 25-26.

[214] *Id*. at 27.

[215] *Id*.

[216] *Id*.

[217] *Id*. at 28.

[218] *Id*.

[219] *Id*. at 29.

a revenue requirement could file one in *IMPA*.[220] Bluegrass returns to its argument that it has a contractual right to a revenue requirement following the *AEP* methodology under the Interconnection Agreement.[221]

4. <u>Commission Determination</u>

84. We deny LG&E's and Staff's exceptions and affirm the Presiding Judge. We affirm the Presiding Judge's conclusion that Bluegrass is entitled to a return.[222] In its initial filing Bluegrass identified its facility as leased and asserted that it was entitled to a return.[223] Its initial testimony made the same claim.[224] Moreover, as Bluegrass explained in its brief on exceptions, section 9.2 provides that at the end of the lease Oldham County will convey title to Bluegrass.[225]

85. Next, we hold that Bluegrass does not bear the burden of showing that the existing Interconnection Agreement is unjust and unreasonable. As we have already stated, the Interconnection Agreement grants Bluegrass the right to file a reactive power rate schedule with the Commission.[226] The Presiding Judge was correct to determine that Bluegrass was implementing, rather than altering, the Interconnection Agreement.

86. Lastly, we affirm the Presiding Judge's determination that Bluegrass' proposed capital structure and proposed overall return of 8.54 percent, based on the authorized rate of return of the interconnected utility, LG&E (as a Transmission Owner of Midwest ISO) are just and reasonable.[227] Given the inherent problems of using Dynegy's capital costs, as discussed by the Presiding Judge, we find the use of a proxy in this proceeding to be just and reasonable. The Commission has generally allowed merchant generators to use

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[220] *Id*.

[221] *Id*. at 29-30.

[222] *Initial Decision*, 115 FERC ¶ 63,015 at P 151.

[223] *See* Prepared Direct Testimony of William L. Carr, Exh. No. BGC-1 at 1:5; Prepared Direct Testimony of Steven Dalhoff, Exh. No. BGC-2 at 1:5.

[224] *See* Prepared Direct Testimony of Steven Dalhoff, Exh. No. BGC-2 at 1:5, as adopted by Daniel E. Roethemeyer in Supplemental Testimony filed on August 3, 2005.

[225] Bluegrass' Brief Opposing Exceptions at 27.

[226] *See supra* P 44.

[227] *Initial Decision*, 115 FERC ¶ 63,015 at P 149.

the interconnected utility's authorized rate of return as a proxy.[228] While in *Detroit Edison* the Commission did express concern about using a Commission accepted generic return on equity without further investigation,[229] we have had a further investigation in this proceeding and find that the use of the interconnected utility's authorized rate of return is just and reasonable. Moreover, we note that since *Detroit Edison*, the Commission has continued to accept merchant generators' proposals to use the interconnected utility's rate of return as a proxy in reactive power cases.[230] Thus, it has been the Commission's general policy to allow an IPP to use the authorized rate of return and return on common equity of an interconnected utility for reactive power compensation, because as we stated in *Calpine Fox*, an interconnected utility's return is a conservative estimate of a merchant generator's return because the merchant generator faces more risk.

G. Issues Raised, Not Discussed

1. Presiding Judge's Findings

87. The Presiding Judge held that issues raised but not discussed were considered and found to be without merit.[231]

2. Exceptions

88. Staff states that the Presiding Judge erred to the extent she held that the use of a levelized carrying charge method and the adjustment for accumulated deferred income taxes (ADIT) were issues raised, considered, and found to be without merit. According to Staff, the parties have reached agreement to use the levelized approach and adjust for ADIT.[232]

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[228] *See, e.g., City of Vernon*, 93 FERC ¶ 61,103 (2000) *reh'g denied*, 94 FERC ¶ 61,148 (2001); *New England Power Pool*, 92 FERC ¶ 61,020 at 61,041 (2000).

[229] Additionally, Detroit Edison was proposing an ancillary services tariff under which many ancillary services would be provided rather than merely a reactive power service agreement which is at issue here.

[230] *See Calpine Fox*, 113 FERC 61,047 (2005); *LSP-Kendall Energy, LLC*, 116 FERC ¶ 61,136 (2006); and *Calumet Energy*, 116 FERC ¶ 61,181 (2006).

[231] *Initial Decision*, 115 FERC ¶ 63,015 at P 166.

[232] Staff's Brief on Exceptions at 31-33.

3. Opposing Exceptions

89. Bluegrass opposes this exception as unnecessary. Bluegrass acknowledges that the parties no longer disagree on these issues, but states that the Presiding Judge also acknowledged this agreement in the initial decision.[233]

4. Commission Determination

90. We affirm the Presiding Judge. We agree with Bluegrass that Staff's exception is unnecessary.

H. Numerator for Calculating Remaining Power Plant Investment Indicator

1. Presiding Judge's Findings

91. The Presiding Judge held that the appropriate numerator to use in calculating the Remaining Power Plant Investment Allocator (RPPIA or allocator) is 183.48 MVARs.[234] The Presiding Judge explained that in order to follow the *AEP* methodology the product of two ratios is necessary to allocate remaining plant investment. The Presiding Judge noted that this composite allocator is derived by taking the ratio of the plant's exciter rating to the plant's real power rating, and then multiplying it by a second ratio—the Maximum MVAR/Nameplate MVAR.[235] Staff argued that Bluegrass omitted the second ratio. Bluegrass argued that the second ratio was not omitted, but since the numerator and the denominator were both 360.33, the second ratio was estimated as 1.0.[236] Staff argued that the numerator was 183.48 MVARs. The Presiding Judge agreed with Staff's argument that Bluegrass actually produces 183.48 MVARs of reactive power. Since Bluegrass' reactive power capability is 360.33 MVARs, the Presiding Judge concluded that the second ratio is 0.509.[237]

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[233] Bluegrass' Brief Opposing Exceptions at 30.

[234] The initial decision states that the plant allocator is 188.48 MVARs. Bluegrass, Staff, and LG&E all identify the 188.48 figure as a typographical error in the initial decision.

[235] *Initial Decision,* 115 FERC ¶ 63,015 at P 144.

[236] *Id*.

[237] *Id*. at P 146-147. The RPPIA is 0.103 percent.

2. Exceptions

92. Bluegrass disagrees with the Presiding Judge's choice of numerator, and consequently, the final RPPIA.[238] Bluegrass now concedes a value of 183.48 MVARs,[239] but states that this is a net value at the high side of the Generator Step Up Transformer (GSU).[240] In Bluegrass' view, this value must be adjusted to reflect the amount of MVARs produced by the generator in order to deliver the 183.48 MVARs.[241] Bluegrass maintains that this adjustment is required to adhere to the *AEP* method, because it ensures that the numerator and the denominator of the second ratio both use gross values at the generator's terminal.[242] Bluegrass states that this adjusted numerator is 230 MVARs, and therefore the second ratio is 0.638.[243] When this second ratio is used to determine the RPPIA,[244] the cumulative effect is a decrease in Bluegrass' annual revenue requirement of $14,810.00.[245]

3. Opposing Exceptions

93. Staff argues that Bluegrass's exception is improperly raised because this issue was never before the Presiding Judge.[246] Staff points out that Bluegrass has abandoned the original argument it made before the Presiding Judge. Staff asserts that the rationale

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[238] Bluegrass' Brief on Exceptions at 7.

[239] *Id*. at 7-8. In its Brief on Exceptions, Bluegrass explains its previous reliance on Midwest ISO's Available Flow Capacity (AFC) models in determining the appropriate plant allocator, and states that the Presiding Judge erred by agreeing with Staff's argument that use of the AFC models is inappropriate here. Bluegrass further explains, however, that "for the purposes of this proceeding, Bluegrass is willing to accept use of the corrected operating data due to the difficulties associated with independent power producers such as Bluegrass obtaining meaningful access to load flow models." *Id*. at 7.

[240] *Id*. at 8.

[241] *Id*.

[242] *Id*. at 7-8.

[243] *Id*. at 8-9.

[244] Under this proposal, the RPPIA is 0.130 percent.

[245] *Id*. at 10.

[246] Staff's Brief Opposing Exceptions at 12.

behind 230 MVARs has not been examined.[247] In Staff's view, "even if the 230 MVAR figure was proved to be correct, a Brief on Exceptions is not the time to first propose using it for the numerator in the second ratio."[248]

94. LG&E states that Bluegrass still fails to faithfully replicate the *AEP* methodology. According to LG&E, the second ratio is supposed to adjust for the diversity among individual generating units by relating the maximum simultaneous MVAR output to the total reactive power capability of all of the plants in the control area. LG&E states that Bluegrass, rather than following *AEP*, picked random months when particular units at the Bluegrass plant experienced the unit's maximum output, ignoring all other months and ignoring when the system peak occurred, and appointed the sum of these months as the maximum MVAR output to be used in the numerator of the second ratio. LG&E argues that as a consequence, Bluegrass' new method ignores the diversity among individual generating units and significantly overstates the MVAR output derived under the maximum simultaneous output.[249]

4. Commission Determination

95. We deny Bluegrass' exception and affirm the Presiding Judge. We agree with Staff that Bluegrass abandoned its original argument and raised this argument for the first time in its Brief on Exceptions. Therefore, we find that this exception is improperly raised and affirm the Presiding Judge.

The Commission orders:

The Initial Decision is hereby affirmed, as discussed in the body of this order.

By the Commission. Commissioner Moeller not participating.

(S E A L)

Philis J. Posey,
Acting Secretary.

[247] *Id*. at 13.

[248] *Id*.

[249] LG&E's Brief Opposing Exceptions at 6.