UNITED STATES OF AMERICA 115 FERC ¶63,015
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL DECISION

(Issued April 19, 2006)

APPEARANCES

Gunnar Birgisson, Betsy R.Carr, and *Joe Lakshmanan* on behalf of Bluegrass Generation Company, L.L.C.

Andrea J. Chambers, Jennifer Keisling, Mark E. Nagle, Stephen D. Philips, and *Rebecca Roback* on behalf of E.ON U.S. (formerly "LG&E Energy")

Jennifer D. Cook and *Stephen L. Teichler* on behalf of the Midwest Independent Transmission System Operator, Inc.

David S. Berman, Wendy N. Reed, Matthew Segers, and *Michael E. Small* on behalf of the Midwest ISO Transmission Owners

Derek Anderson and *Irene Szopo* on behalf of the Federal Energy Regulatory Commission

Charlotte J. Hardnett, Presiding Administrative Law Judge

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INTRODUCTION

1. Bluegrass Generation, Inc. ("Bluegrass") is a natural gas-fired peaking generating facility located near Oldham, Kentucky.[1] Bluegrass went into service in June 2002.[2] Bluegrass is an exempt wholesale generator (or non-utility generator not generally subject to traditional rate regulation) that is authorized by the Commission to make wholesale sales of power at market-based rates.[3] Bluegrass sells power generated at the facility to wholesale customers at market-based rates. Bluegrass also provides reactive power support for which it is compensated separately. The appropriate amount of compensation or revenue for that reactive power support is at issue in this case.

2. Bluegrass is interconnected with the transmission system of Louisville Gas and Electric Company ("LG&E").[4] LG&E is a transmission-owning member of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"),[5] which makes arrangements with control area operators, such as LG&E, to obtain ancillary service, including reactive power, from generation sources.[6]

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[1] Ex. BGC-1 at 2.

[2] Bluegrass Transmittal Letter, January 31, 2005 at 5.

[3] *Bluegrass Generation Co., L.L.C.*, 97 FERC ¶ 62,279 (2001); *Bluegrass Generation Co., L.L.C.*, Docket No. ER02-506-000, February 2, 2002, unpublished letter order and *Bluegrass Transmittal Letter*, January 31, 2005 at 4.

[4] *Bluegrass Transmittal Letter*, January 31, 2005, at 1. LG&E is a registered public utility holding company with two operating subsidiaries, Louisville Gas and Electric Company and Kentucky Utilities Company.

[5] On March 17, 2006, the Commission issued an order in *Louisville Gas and Electric Co.*, 114 FERC ¶ 61,282 (2006), conditionally approving LG&E's request to withdraw from Midwest ISO and to join Southwest Power Pool, Inc. LG&E has made compliance filings pursuant to the Commission's March 17, 2006, Order asking, among other things, that it be allowed to withdraw from Midwest ISO by June 1, 2006.

[6] *See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles January 1991-June 1996 31,036 (1996), *aff'd*, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), 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

PROCEDURAL HISTORY

3. On January 31, 2005, Bluegrass filed its Rate Schedule FERC No. 2, under which it requested a cost-based yearly revenue requirement for Reactive Support and Voltage Control Reactive Power[7] from the Bluegrass Facility. The tariff being superseded is an interconnection agreement ("IA") filed with the Commission on July 13, 2001, under which Bluegrass was to be paid for reactive power support.[8]

4. Bluegrass originally filed a proposed reactive power tariff for annual compensation of $1,086,509,[9] for providing reactive power support. The filing was protested by LG&E.[10] Midwest ISO and the Midwest ISO Transmission Owners ("Midwest ISO TO")[11] filed timely motions to intervene. On March 25, 2005, the Commission conditionally accepted Bluegrass's Rate Schedule, subject to refund, and set this proceeding for hearing "concerning the justness and reasonableness of Bluegrass's proposed rate schedule."[12] The Commission held the hearing in abeyance to allow for settlement discussions.

5. The settlement efforts were unsuccessful and were terminated on May 26, 2005. A prehearing conference was convened by Presiding Administrative Law Judge Hardnett on June 13, 2005 and the procedural schedule was issued. Bluegrass filed supplemental direct testimony in support of its Rate Schedule on August 3, 2005, which incorporated

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(2002) ("Order No. 888").

[7] Bluegrass Transmittal Letter, January 31, 2005, at 1.

[8] Ex. LGE-1, Attachment A, § 8.4.4(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(ii)).

[9] *Bluegrass Generation Co., L.L.C.*, Rate Schedule FERC No. 2, issued on January 31, 2005.

[10] Motion of LG&E Energy, L.L.C. for Leave to Intervene and Protest and Hearing Procedures, filed February 22, 2005.

[11] The Midwest ISO TO is a group of vertically integrated transmission owners, cooperatives and municipals that are load serving entities in the Midwest ISO. *Motion to Intervene of the Midwest ISO Transmission Owners* at 2. They represent approximately two thirds of the load within the Midwest ISO. *Request for Clarification and/or Rehearing of the Midwest ISO Transmission Owners*, Midwest ISO, Docket Nos. ER04-961-002, ER04-961-003, filed November 16, 2005 at 2.

[12] *Bluegrass Generation Company, LLC*, 110 FERC ¶ 61,349 at 62,398 (2005).

the January 31, 2005 pre-filed direct testimony while substituting a new witness. The Midwest ISO TO and LG&E, the two active intervenors in this proceeding, filed direct and answering testimony on September 15, 2005, while Staff filed direct and answering testimony on October 6, 2005. LG&E filed cross-answering testimony on October 27, 2005. Bluegrass filed rebuttal testimony on November 17, 2005. Staff filed surrebuttal testimony on January 5, 2006. LG&E submitted corrected testimony on January 6, 2006. The hearing commenced on January 9, 2006, and concluded on January 10, 2006. On January 26, 2006, LG&E filed further testimony.

6. On April 18, 2006, the Presiding Administrative Law Judge, denied LG&E's [13] April 12, 2006, Motion to Lodge the Commission's order conditionally approving LG&E's request to withdraw from Midwest ISO in this proceeding.

BACKGROUND

7. **Reactive Power and VARS.** There are two components of electrical power. One is referred to as real power, which is the electrical power measured in megawatts (MW), the second is reactive power (often referred to as VARs or VAr) which is measured in Mega Volt Amperes Reactive or MVARs (also called megavars). Reactive power is responsible for creating the magnetic fields needed to operate transformers, transmission lines and electric motors. Reactive power ordinarily can be supplied by electric generators (as in the instant proceeding) or by placing static devices such as inductors and capacitors on the transmission and distribution systems.

8. Reactive power provides support to maintain adequate voltage at all points in the power system, from the generating station through the transmission system and into the distribution system to the load and is therefore an inherent and necessary component in the operation of an AC power system. Reactive power is directly related to the maintenance of proper voltage levels in the electric system. If too much reactive power is produced, an over-voltage situation can occur and the protective equipment which monitors system voltage levels can cause breakers to trip and take transmission lines out of service. Excessive reactive power can also damage equipment by producing voltage levels greater than the design rating of that equipment. If too little reactive power is supplied to the system, voltage levels will decrease and may lead to a total system collapse. Furthermore, decreased voltage levels can lead to equipment malfunction. Reactive power is quickly used up by transmission system components and therefore cannot be transported over long distances.[14]

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[13] E.ON U.S. actually filed the motion. As noted, E.ON U.S. was formerly LG&E. For the sake of simplicity, we will continue to refer to E.ON U.S. as LG&E.

[14] Staff Initial Brief ("Staff IB") at 4-5 and Ex. S-1 at 3-5.

9. **Commission Decisions Regarding Compensation for Reactive Power.** In 1990, in *Northern States Power*, the Commission found for the first time that a separate charge for reactive power was not inherently unjust and unreasonable.[15] Before that, the cost of providing reactive power was generally included in the charge for wholesale power, or for transmission service, without being separately stated or calculated.[16] In a subsequent case, again involving Northern States Power, the Commission set procedures by which utilities were to set wholesale prices for reactive power support.[17] Specifically, the Commission stated that the utility would be required to identify the actual costs of the portion of the generator used in the production of reactive power. The Commission concluded by stating that "[a]s always, the burden of proof will be on the utility to justify its proposed rate."[18]

10. In Order No. 888,[19] issued in 1996, the Commission made reactive power support from generation sources one of six separate ancillary services to be provided by transmission owners filing open access transmission tariffs ("OATTs"). The Commission's pro forma OATT includes schedules that were to be used for providing and pricing each of the ancillary services. Schedule 2 of the OATT describes Reactive Supply and Voltage Control from Generation Sources Service and indicates the service must be provided for each transmission transaction on the transmission provider's facilities. Order No. 888 did not specify a particular method of pricing reactive service.[20]

11. After issuance of Order No. 888, the Commission was called on to address the issue of how to calculate a reactive power charge in *Southern Company Services, Inc.* (*Southern Company*) [21] and in *American Electric Power Service Corp*. (*"AEP")*.[22] In *Southern Company*, the Commission found that a reactive power charge is appropriate in a situation in which the transmitting utility delivers power from generation located on its

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[15] *Northern States Power Co.*, 53 FERC ¶ 61,027 at 61,107, *reh'g denied*, 53 FERC ¶ 61,306 (1990).

[16] Order No. 888 at 31,703-07.

[17] *Northern States Power Co*., 64 FERC ¶ 61,324 (1993), *reh'g denied*, 74 FERC ¶ 61,106 (1996).

[18] *Id*.

[19] Order No. 888 at 31,705-06 and 31,716-17.

[20] Order No. 888 at 31,720 (Commission will consider ancillary service rate proposals on a case-by-case basis.)

[21] *Southern Company Services, Inc.*, 80 FERC ¶ 61,318 (1997), *aff'd*, 82 FERC ¶ 61,168 (1998).

[22] *American Electric Power Service Corp*, 88 FERC ¶ 61,141 (1999).

own system.[23] In *AEP*, the issue was what portion of the generation plant should be charged to transmission customers in order to reflect the reactive power that the AEP plant provided. In that case, AEP identified three components of a generation plant that are directly related to the production of VARs: (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. The Commission added generator step-up transformers ("GSU") as a fourth component. Because these plant items produce both real and reactive power, AEP developed an allocation factor to segregate the reactive production component from the real power production component. AEP based this allocation factor on the capability of a generator to produce VARs, where this capability is measured at the generator terminals. This allocator is based on the ratio of $MVAR^2$ to MVA^2 ("reactive allocator").[24]

12. The final step in the *AEP* methodology is to allocate some portion of the total production plant cost to the production of reactive power. This is done by subtracting the generator step-up transformer, accessory equipment and generator-exciter costs from the total production plant cost, to avoid double counting, and then allocating the remaining production plant costs based on an allocator which is the product of two ratios. Once the plant investment associated with reactive power production is determined, *AEP* applied an annual carrying charge to these costs to determine an annual revenue requirement.[25]

13. Subsequently, in *WPS Westwood Generation LLC*, the Commission standardized the methodology for reactive power compensation by indicating that all generators seeking reactive power recovery that have actual cost data and support should use the *AEP* methodology.[26] *AEP* opened the door for independent power producers ("IPP") to file to recover a cost-based rate for reactive power.

14. More recently, in *Midwest Independent Transmission System Operator, Inc.* ("*MISO I*"),[27] the Commission held that Midwest ISO had complied with an earlier Commission order in its Schedule 2 of its OATT in providing that Qualified Generators were entitled to compensation for reactive power service. In an earlier filing supplement to Schedule 2, Midwest ISO had not provided a mechanism for compensating IPPs and the Commission had rejected that Schedule 2 iteration as being unjust, unreasonable, and

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[23] *Southern Company*, 80 FERC at 62,082.

[24] *AEP*, 88 FERC at 61, 141 and 61,461 and Ex. S-1 at 6.

[25] *Id*. at 7.

[26] *WPS Westwood Generation LLC,* 101 FERC ¶ 61,290 at 62,167 (2002).

[27] *Midwest Independent Transmission Operator, Inc.*, 113 FERC ¶ 61,046 (2005).

unduly discriminating under Section 206 of the Federal Power Act ("FPA").[28] The Commission approved of the Midwest ISO definition of "Qualifying Generator" contained in § II.A of Schedule 2.[29] The Commission also in *MISO I* restated its policy that a generator was to be compensated for its capacity to provide reactive power without regard to whether or not the generator has to be on-line and that a needs test was contrary to Order No. 2003.[30] On rehearing (*MISO II*), the Commission emphasized that a needs test (or "used and useful" determination) would violate the "comparability principle" of Order No. 2003-A. The Commission also clarified that a generator could be precluded from rate recovery due to the terms of an interconnection agreement, or some other agreement.[31]

POSITIONS OF THE PARTIES

15. **BLUEGRASS.** The position of Bluegrass is that it has shown that its proposed reactive power tariff and revised revenue requirement ("proposed reactive power tariff" or "revenue requirement") produces just and reasonable rates. Bluegrass maintains that its proposed reactive power tariff is consistent with the LG&E-Bluegrass IA, Order No. 2003, and Midwest ISO Schedule 2. Bluegrass argues that due to the Commission holdings in *MISO I*, and affirmed in *MISO II*,[32] the positions of LG&E, Staff, and the Midwest ISO TO in this proceeding must be rejected as not consistent with Commission reactive power support precedent. According to Bluegrass, Commission policy, as articulated in Order No. 2003 and its progeny (most recently *MISO I* and *MISO II*) , settle the issue that a generator is to be compensated based on its capacity or capability to

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[28] 16 U.S.C. § 824(e) (2004).

[29] Staff IB at 1 and 4-6. .

[30] *Id*. at 8 and *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs., Regulations Preambles 2001-2005 ¶ 31,146 (2003),*order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. & Regs., Regulations Preambles 2001-2005 ¶ 31,160 (2004), *order on reh'g*, Order No. 2003-B, 70 *Fed. Reg.* 265 January 4, 2005), FERC Stats. & Regs., Regulations Preambles 2001-2005) ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, 70 *Fed. Reg.* ¶ 37,661 (June 30, 2005), FERC Stats. & Regs, Regulations Preambles 2001-2005 ("Order No. 2003"); *accord Rolling Hills Generating, L.L.C.,* 109 FERC ¶ 61,069 (2004).

[31] *Midwest Independent Transmission System Operator, Inc*., 114 FERC ¶ 61,192 at 61,648 (2006) ("*MISO II*").

[32] *Midwest Independent Transmission System Operator, Inc., order on reh'g*, 114 FERC ¶ 61,192 (*"MISO")* at 2-4.

provide reactive power without regard to "needs"/"value"/"used and useful," hours of operation, requirements for twenty-four hour staffing, remote start-up of the units and firm fuel supply assessments.[33]

16. Bluegrass presented the testimony of William L. Carr, Jason Cox, and Daniel E. Roethemeyer.

17. Mr. Carr is Senior Director of Transmission Analysis for Dynegy. He is responsible for transmission analysis activities for Dynegy assets in North America. His duties include negotiation of interconnection agreements, directing technical and market assessments for both new and existing generating assets, and supporting the filing of applicable FERC tariffs. Mr. Carr testified as to the justness and reasonableness of Bluegrass's proposed reactive power tariff for the capability of providing reactive power support.[34]

18. Mr. Carr testified that the IA provides that Bluegrass will supply, and be compensated for providing reactive power to, or absorbing reactive power from LG&E's system. Mr. Carr stated that Order No. 2003 requires that if a transmission provider compensates its own or its affiliated generators for reactive power within the established framework, it must also pay the interconnection customer.[35]

19. Mr. Carr testified that the proposed reactive power tariff for the Bluegrass facility consists of a fixed capability component that is designed to recover the portion of plant costs attributable to the reactive power capability of Bluegrass's generators and represents the portion of the plant investment in Bluegrass that is attributable to the production of reactive power. Mr. Carr explained that the fixed capability component has been calculated by analyzing the reactive portion of Bluegrass's generator/excitation system and GSU investments. Since the GSU contribute to the provision of both reactive and real power, the amount of investment in the generator/exciter and GSU is multiplied by an allocation factor to determine the reactive power portion of this investment.[36]

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[33] Bluegrass Initial Brief ("Bluegrass IB") at 8-12 and Bluegrass Reply Brief ("Bluegrass RB") at 1-2 and 14-15 (**NOTE**: Citations to briefs and exhibits in this Initial Decision will not include noting the sources cited in the briefs and exhibits although the sources were considered).

[34] Ex. BGC-1 at 1.

[35] Ex. BGC-1 at 2-3.

[36] *Id*. at 4-5.

20. Mr. Carr testified that the reactive power allocation factor is the percentage of the facility necessary to provide reactive power. Bluegrass calculated the level of investment in the Bluegrass generator/exciter in a manner consistent with that used in *AEP*, using accounting detail based on the Commission's Uniform System of Accounts ("USOA"). The *AEP* methodology requires that portions of select sub-accounts that are specific to the generator/exciter be isolated from production plant amounts associated with the turbine generators. Bluegrass's accounting practices, however, do not treat the generator/exciter investment as a separate property cost, therefore, production plant amounts associated with the generator and exciter were isolated from the resulting combustion turbine generator costs utilizing information received from Siemens-Westinghouse. Using this information, Mr. Carr determined that 15% of its turbine generator costs are attributable to the generator itself and 1% is attributable to the associated exciter. Mr. Carr explained that those percentages, when applied to the direct total turbine generator costs, yield the corresponding direct generator and exciter cost components.[37]

21. Mr. Carr testified that after identifying the direct generator and exciter costs components, indirect costs components, such as development, legal, interconnection and startup costs were then allocated to direct combustion turbine generator costs in the same percentages as the ratios of respective turbine generator costs to overall direct equipment costs. He explained that since the generator/excitation system performs functions associated with both real and reactive power, an allocator is necessary to calculate the portion of plant investment properly assigned to the production of reactive power.[38]

22. Mr. Carr proposes a 27.8% allocator, which represents the percentage of the total installed generating unit MVARs for Bluegrass that is directly associated with the total installed MVAR capability of the Bluegrass units, based on the power factor for the units. When the allocator is applied, the resulting cost of associated reactive power production facilities is calculated to be approximately $4.8 million. Mr. Carr contends that this method of determining the cost allocation is the same as that used in *AEP* and has also been previously accepted in other recent reactive power tariff filings approved by the Commission.[39]

23. Mr. Carr testified that Bluegrass included a 16.17% accessory electric equipment allocator in its calculation of investment allocated to reactive power production, because the accessory electric equipment performs functions associated with both the generator/exciter and the entire production plant. Since the accessory electric equipment

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[37] *Id*. at 5-7.

[38] *Id*. at 8.

[39] *Id*. at 8-10.

performs functions associated with both real and reactive power, that value is multiplied by the reactive power allocation factor and the resulting cost of associated reactive power production facilities is calculated to be approximately $124,000.[40]

24. Mr. Carr stated that GSU transformer costs were included in the calculation of investment allocated to reactive power production for Bluegrass. The resulting cost of associated reactive power production facilities is calculated to be approximately $1.48 million, when the reactive power allocation factor of 27.8% is applied to the GSU investment. Mr. Carr further explained that the *AEP* methodology subtracts the total costs of the generator, exciter, GSU and accessory electric equipment that supports the generator/exciter from the total production plant. The net amount is then multiplied by 0.203%, and the resulting amount of production plant investment necessary to support reactive power production totals approximately $363,000. Mr. Carr testified that the total resulting investment attributable to reactive power production equals approximately $6.77 million.[41]

25. Mr. Carr testified that Midwest ISO TO witness Mr. Kirby, and LG&E witness Mr. Becher do not understand the value of peaking units in energy markets that utilize locational marginal pricing. Mr. Carr explained that in both PJM and Midwest ISO's day-ahead markets, the generator bids (*i.e.*, a generator's willingness to sell power) are matched with load offers (i.e., a load's willingness to buy power). In most markets the offers and bids do not match the regional transmission organization ("RTO") load and ancillary service requirements and when this occurs, the RTO is required to commit additional units to meet those needs. These additional units are typically peaking units and even though peaking units are not run most of the time, as baseload units are, they still provide products that are just as valuable to the market. Peaking units are usually required to operate only during the peak hours of the day, when need is greatest and their ability to start up and shutdown multiple times a day makes them a reliable and flexible source of energy and reactive power support.[42]

26. Mr. Carr testified that about 360 MVARs is the total reactive capability of the Bluegrass plant, which is obtained by multiplying the reactive capability of each unit times the number of units at Bluegrass. Mr. Carr disagrees with LG&E's position that Bluegrass's estimated reactive capability is 183 MVARs for several reasons. First, a reactive capability test conducted in accordance with East Central Area Reliability Coordination ("ECAR") requirements is the correct method for verifying the reactive

[40] *Id*. at 9-10.

[41] *Id*. at 10-12.

[42] Ex. BGC-4 at 2-4.

capability of the Bluegrass units.[43] According to ECAR testing requirements, Bluegrass is responsible for determining when the test will be conducted. Further, although Bluegrass was limited in its ability to generate MVARs on August 11, 2005, it is not uncommon for plants to experience problems with equipment that may limit a unit's output from time-to-time. (Bluegrass, as discussed below, was only able to produce 183 of 200 requested MVARs of power.) Mr. Carr claims that the arbitrary selection by Mr. Seelye of one day's operating experience is inconsistent with the method used to establish the reactive capability of other units in ECAR. Bluegrass has provided reactive power as requested on June 8, 2005, and August 2, 2005, as acknowledged by the Midwest ISO.[44]

27. Mr. Carr testified that the August 11, 2005, request by LG&E for power violated the terms of the IA, and it is, therefore, inappropriate to draw any conclusions about Bluegrass's reactive capability based on that date. Mr. Carr testified that LG&E violated the terms of the IA because there was no system emergency on August 11, 2005. Also, LG&E failed to request additional VAR support from nearby generators on that date. LG&E's allegations that Bluegrass was the only unit in the area without automatic voltage control turned on was false, as Bluegrass was operating in that mode on August 11. Finally, Mr. Carr testified that its reactive capability test completed on November 3, 2005, demonstrated that Bluegrass's actual reactive capability is 360.33 MVARs. Mr. Carr also asserts that Staff witness Mr. Clark's reactive capability values incorrectly incorporate a data point and, therefore, also require adjustment.[45]

28. Mr. Carr claims that Mr. Clark is incorrect in his claim that Bluegrass neglected to include the second ratio used in the calculation of the remaining power plant investment allocator in its application of the *AEP* methodology. According to Mr. Carr, Bluegrass did not, in fact, omit this second ratio. Rather, based on the results of the Midwest ISO Available Flow Capacity ("AFC") models, the numerator is the same as the denominator.[46]

29. At the hearing, Mr. Carr testified that, to his knowledge, Bluegrass has no remote start-up capability. He testified that reactive power, generally, needs to be introduced into the system near the place needed. He testified that the need for reactive power can arise fairly quickly. Bluegrass units are tied into LG&E on a 345-kilovolt line that runs

[43] Also, Section II.B of the Midwest ISO's Schedule 2 approved October 17, 2005 provides that a Qualified Generator must meet the regional reliability council's testing requirements within the last five years; s*ee MISO.* 113 FERC ¶ 61,046 at 61,114.

[44] *Id*. at 8-10.

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

[46] *Id*. at 13-14.

along a corridor about seventy miles long. Other generating plants are along that kilovolt line any of which would also be able to produce reactive power, as well as real power.[47]

30. Mr. Carr testified that § 8.4.3 of the IA states the basic obligation of Bluegrass, under the agreement, to produce or absorb MVA arises only during system emergencies that occur when Bluegrass is synchronized to the grid. Mr. Carr testified that, even if Bluegrass units only operated five to six times in 2005 and did not run at all in 2004, he still believed Bluegrass was entitled to the $750,000 to $800,000 it was requesting in this rate case because Bluegrass remained ready to supply reactive power if called on to do so.[48]

31. Mr. Carr testified that the Bluegrass IA provides for about a fifty-cent compensation rate per MVARh; however, the IA also provided that Bluegrass could apply for a tariff if it were not satisfied with the fifty-cent rate. Bluegrass officials determined that it could use Opinion 440 (i.e., the reactive power compensation formula approved in *AEP*) to improve its compensation situation. He testified that fifty cents per MVARh when Bluegrass was actually producing reactive power, did not cover its costs of production.[49]

32. Mr. Cox is Director of Regulatory Affairs with Dynegy, Inc. Bluegrass is a subsidiary of Dyengy, through which Dynegy leases and operates the Bluegrass plant. His work background includes positions as a journeyman power plant operator, system operator, and power trader and asset manager. In his current position at Dynegy, Mr. Cox focuses on RTO markets and is active in stakeholder processes through which new tariffs and market rules are developed and implemented. Mr. Cox offers rebuttal testimony to challenges to Bluegrass's claimed capacity or capability.[50]

33. Mr. Cox concluded that LG&E's and Staff's recommendations for as-available or interruptible-type compensation for the Bluegrass's reactive power tariff are contrary to Commission precedent and their conclusions regarding Bluegrass reactive power support are not supported by the facts. He testified that as-available/interruptible/100% load factor proposals are contrary to *AEP* methodology, which dictates that the revenue requirements for reactive power tariffs should be based on the capability/capacity of the unit. Mr. Cox testified that LG&E and Staff are misguided in their claims that Bluegrass does not have the capacity it claims it has. Contrary to the testimony of Mr. Seelye and Mr. Clark, Bluegrass does have firm service and also buys gas from third parties.

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[47] Tr. 67-78.

[48] Tr. 75-77.

[49] Tr. 121-126.

[50] Ex. BGC-6 at 2.

Additionally, according to Mr. Cox, Bluegrass had not had issues with gas availability to date. Mr. Cox explained that while firm natural gas service pursuant to a Texas Gas Firm Transportation ("FT") service could be procured, it probably would not be an appropriate way to manage fuel arrangement for a peaking unit like Bluegrass. Mr. Cox explained that FT service would likely increase the revenue requirement of the reactive power tariff and increase the potential for imbalances. Mr. Cox maintains that there is no authority, contractual or otherwise, that mandates that Bluegrass have FT service in order to provide, or be compensated for provision of reactive power support.[51]

34. At the hearing, Mr. Cox testified that while he was not responsible for procuring gas for the Bluegrass units, he was aware that natural gas came to the Bluegrass plant over the Texas Gas Pipeline. He testified that the Texas Gas Pipeline was the only pipeline serving the Bluegrass plant. He testified that Bluegrass has no on-site gas storage facilities. However, Bluegrass had 1000 MMBtus a day in firm summer, no-notice service and 60,000 MMBtus per day virtual storage, or through "park and loan" arrangements. Bluegrass has an interruptible rate transportation agreement and also buys gas on a "delivered basis" (i.e., buying gas from Texas Gas Pipeline's firm transmission customers). Mr. Cox testified that Bluegrass would like to arrange firm gas delivery contracts for its plant, but could only do so if it could recover the cost in its rate schedule.[52]

35. Mr. Roethemeyer is a Senior Business Analyst for Dynegy. He has been employed by Dynegy since 1996 and has been in his current position since 2002. Mr. Roethemeyer has responsibility for, among other things, Dynegy's acquisition and divestiture activities. Mr. Roethemeyer testified about the overall revenue requirement for reactive supply and voltage control from generation sources under the Midwest ISO OATT and about the basis for Bluegrass's proposed level of operations and maintenance ("O&M") expense, and administration and general ("A&G") expense to be considered in the total proposed reactive power tariff.[53]

36. Mr. Roethemeyer testified that although he had not done so in his original cost-of-service calculations in employing the *AEP* methodology, in his rebuttal testimony he had used a levelized carrying charge in the calculations. LG&E and Staff had urged the use of a levelized carrying charge.[54] Use of a levelized carrying charge resulted in a

[51] *Id.* at 3-5.

[52] Tr. 155-170.

[53] Ex. BGC-2 at 1-2.

[54] *See Calpine Fox, LLC,* 113 FERC ¶ 61,047 at 61,124-26 (2005) ("*Calpine Fox*") (use of levelized annual carrying cost approach to develop annual revenue requirement appropriate in applying *AEP* methodology).

reduction to the originally-filed proposed reactive power tariff by $205,958 for a total of $880,551. In his rebuttal testimony, Mr. Roethemeyer further explained that Bluegrass's revised proposed reactive power tariff totals $762,135 and is based on three revisions to the filed proposed reactive power tariff: 1) carrying charge methodology, 2) rate of return, and 3) accumulated deferred income taxes.[55]

37. Mr. Roethemeyer testified that the level of reactive production plant determines the earnings base, or rate base on which the overall cost of capital is computed. The ratios of both fixed O&M and fixed A&G to the total Bluegrass production plant are multiplied by the reactive production plant in order to allocate a portion of fixed O&M and A&G to the reactive power support. The reactive production plant serves as the basis for the depreciation expense included in the total proposed reactive power tariff. [56]

38. Mr. Roethemeyer testified that the amount of demand O&M expense only included fixed costs. He stated that a ratio of those costs to the total Bluegrass production plant is calculated, then the ratio is multiplied by the reactive production plant to yield a fixed O&M expense allocated to reactive power support. Mr. Roethemeyer indicated that the O&M included in the total proposed reactive power tariff is $30,601. Mr. Roethemeyer explained that the amount of demand A&G expense is calculated by applying the ratio of fixed and variable direct O&M costs to A&G costs to determine total fixed A&G costs for Bluegrass. A&G costs are divided by total Bluegrass production plant, in the same manner as O&M expenses, which results in a ratio that is multiplied by the reactive production plant. The A&G included in the total proposed reactive power tariff is $12,248. [57]

39. Mr. Roethemeyer testified that he revised the rate of return in order to limit the areas that continue to divide the parties, and to simplify the issue. He explained that Bluegrass would follow the approach of other generators filing reactive power tariffs that the Commission has accepted, and use the authorized rate of return of the interconnected utility. This adjusts the overall rate of return from 9.52% to 8.54%, and as adjusted for the levelized carrying charge methodology, is a reduction of $6,847 to $873,704.[58]

40. Mr. Roethemeyer testified that an overall rate of return of 8.54% compares favorably with the calculated overall rate of return of 8.71% using Dynegy's capital costs. He testified that it is more appropriate to base the Bluegrass reactive power tariff on this value since that is the approach used in most reactive power cases. Mr.

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[55] *Id.* at 2-3.

[56] Ex. BGC-5 at 3-4.

[57] *Id*. at 4-5.

[58] *Id*. at 3-5

Roethemeyer also stated that the Dynegy capital structure used by Mr. Seelye does not take into account the sale of Dynegy's midstream business unit and the fact that only Dynegy's generation business unit remains.[59]

41. Mr. Roethemeyer testified that the recommendation of Staff witness Mr. Green is not consistent with Commission precedent because the Commission has accepted rates of return and capital structures based on those authorized for the interconnected utility in the development of reactive power rates in a number of recent cases. In fact, in the cases cited by Mr. Green, and in nearly every other proceeding establishing a merchant generation reactive power revenue requirement, the Commission accepted the use of the interconnected utility's Commission-authorized return and capital structure. According to Mr. Roethemeyer, the Commission has recognized that non-utility generators, like Bluegrass, with no guaranteed customers face greater risk than regulated utilities like LG&E and so use of regulated utilities' capital costs for establishing reactive power tariffs is appropriate. Given that Mr. Green's recommendation of 7.01% is far below the interconnected utility's overall authorized rate of return, the Commission should reject it.[60]

42. Mr. Roethemeyer testified that Bluegrass did not overstate its reactive power capability for purposes of calculating the revenue requirement; he agreed with the testimony of Mr. Carr about Bluegrass's reactive power capacity. Mr. Seelye erred in using the total MVARs Bluegrass supplied on August 11, 2005 in his estimate of Bluegrass's reactive capability. Mr. Roethemeyer concedes that Mr. Seelye had a justifiable point as to the reduced relative capability of the plant, but claims Mr. Seelye failed to account for the location of his reduced and MVA values; simply accounting for the proper location would result in a 230 MVAR values and a 545.8 MVA value. Mr. Roethemeyer also testified that Mr. Clark's reactive capability values required adjustment for the same reason. Further, Bluegrass's proposed reactive power tariff incorporated the proper Remaining Power Plant Investment Allocator. Mr. Roethemeyer explained that if Mr. Seelye's calculated revenue requirement is revised with the correct values, it results in a revised proposed reactive power tariff of $437,466. Additionally, if Mr. Clark's calculated total power plant cost of reactive power is recalculated using the correct values, the change results in an increase of $46,800, for a total of $6,561,428. Also, if Staff witness Mr. Mill's revenue requirement calculations are recalculated using the corrected values, the change results in an increase of $4,022 for a total of $577,862.[61]

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[59] *Id.*at 4.

[60] *Id.* at 5 and Ex. S-12 at 7 & 33; *see Calpine Fox*, 113 FERC ¶ 61,047 at 61,125-26 (appropriate for Calpine Fox to adopt ROE and overall return based on proxy derived from the capital structure and ROE of the transmission system to which connected.).

[61] *Id.* at 7-9.

43. Mr. Roethemeyer concluded based on testimony provided in this case: (1) Bluegrass's revised proposed reactive power tariff totaled $762,135; and, (2) the impact of an incorrect reactive power capability, used by both LG&E and Staff, which resulted in revised revenue requirements totaling $437,466 and $581,884, respectively.[62]

44. At the hearing, Mr. Roethemeyer testified that Dynegy leases the Bluegrass plant. He testified that LG&E's capital structure was used for the rate of return calculations and that lease payments were not reflected in the calculations. Mr. Roethemeyer testified that in addition to now relying on a levelized carrying charge methodology, he was also including accumulated deferred income taxes ("ADIT") in his calculations and that the inclusion of ADIT had the effect of a downward revision in the revenue requirement. He testified that the latest capital structure data available to him was through September 30, 2005.[63]

45. Bluegrass argues in briefs that it has met all Commission requirements necessary to recover annual reactive service compensation because it: 1) used the *AEP* methodology which must be used to calculate rates for the service; 2) filed for compensation consistent with MISO Schedule 2; and, 3) used the *AEP* methodology.[64]

46. According to Bluegrass, § 8.4.4 of the IA expressly allows Bluegrass to file a tariff for compensation for reactive power support. The fifty-cents-per-MVARh charge was only intended as an alternative provision to compensate Bluegrass if there were no specific order or tariff providing for reactive power compensation. Bluegrass argues that LG&E's contrary view was found wanting by the Commission in *Indiana Municipal Power Agency* ("*IMPA*").[65] Although the IA between Bluegrass and LG&E predates Order No. 2003, Bluegrass maintains that the IA is subject to that policy, which is applicable to all generators. According to Bluegrass, the Commission decided the applicability of Order No. 2003 to pre-Order No. 2003 agreements in *Rolling Hills*

[62] *Id*.

[63] Tr. 135-37, 140-42, and 148-49.

[64] Bluegrass IB at 2 and 31-32.

[65] *Indiana Municipal Power Agency*, 114 FERC ¶ 61,008 at 61,021 (2006) (Commission found that pre-Order No. 2003 agreement did not preclude Indiana Municipal Power Agency's ("IMPA") filing a proposed reactive power tariff for Commission approval).

Generating, L.L.C. (*"Rolling Hills"*)[66] in the manner that Bluegrass urges here. As to the requirements of MISO's Schedule 2, Bluegrass maintains that it met them.[67]

47. The Bluegrass proposed rate schedule explains that a fixed monthly charge will be assessed to LG&E until MISO's Schedule 2 is accepted and that thereafter the charge will be assessed under MISO's Schedule 2. The fact that the Bluegrass proposed rate schedule does not identify a penalty for not providing the service when required is not determinative of the issue of whether the Bluegrass filing can be used as a stand-alone tariff. The Commission has accepted other such reactive service tariffs. Moreover, according to Bluegrass, under MISO's Schedule 2, effective January 1, 2005, there is a potential penalty for not providing service. Schedule 2 was made effective January 1, 2005, before the March 1, 2005, effective date of the Bluegrass proposed rate schedule. Bluegrass argues that if the Commission grants LG&E's application to withdraw from the MISO in *LG&E LLC*, Docket No. EC06-4, the Bluegrass proposed reactive power tariff should be found to be a stand-alone tariff and the compensation due should be recovered directly from LG&E.[68]

48. Bluegrass claims it is able to produce the amount of VAR support indicated in its filing. A reactive capability test conducted in accordance with ECAR requirements on November 3, 2005, as required by MISO Schedule 2, supports the filed reactive capability of 360.33 MVARs. The LG&E and Staff contention that the Bluegrass proposed reactive power tariff should be based on the amount of VAR support provided by Bluegrass on August 11, 2005, should be discredited, according to Bluegrass. Bluegrass states it fully complied with LG&E's request for reactive support of 100 MVARs made about 10:00 a.m. on August 11, 2005. However, Bluegrass admits it was only able to provide an additional eighty-three when LG&E made a second request for another 100 MVARs about noon. Under § 8.4.3 of the IA, according to Bluegrass, LG&E is only allowed to make a request for Bluegrass to dispatch the unit during a system emergency and only when all such redispatch requests are made on a non-discriminatory basis. No system emergency existed on August 11, 2005, and LG&E did not dispatch other units. Bluegrass claims that LG&E's explanation that other units would have automatic voltage control turned on, contrary to the situation with Bluegrass, and would have automatically responded, is not true. The voltage regulators at Bluegrass are always operated in automatic mode.[69]

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[66] *Rolling Hills*, 109 FERC ¶ 61,069 at 61,272-73 (2004).

[67] *Id*. at 61,272.

[68] Bluegrass IB at 9-11 and Bluegrass RB at 7-104.

[69] Bluegrass IB at 18-19 and 40-42 and Bluegrass RB at 11-13.

49. Bluegrass asserts that Staff's argument that operating a generation facility under an interruptible fuel transportation contract indicates that the service provided by the generator is non-firm, is without merit, as is LG&E's criticism of Bluegrass's fuel supply arrangements. There is no support for an argument that use of interruptible fuel supply impairs the ability of a generating unit to operate reliably. Bluegrass plant manager, James Eiseman, testified that Bluegrass had never run out of gas. Moreover, the allegation that Bluegrass does not have firm fuel supply or firm pipeline transportation, is not factually correct as Bluegrass's summer no-notice service is a firm transportation service. In any event, Bluegrass maintains, the *AEP* methodology looks to the capability of the unit in determining revenue requirements, and not to its fuel supply arrangements.[70]

50. Bluegrass contends that LG&E's and Staff's proposals to base Bluegrass's reactive service revenue requirement on anything other than the *AEP* methodology, which is based on the capability of the unit, are contrary to Opinion No. 440 and MISO Schedule 2, are a collateral attack on the Commission's orders in *MISO I and MISO II*, and are beyond the scope of this proceeding.[71] Bluegrass argues that the 100% load factor proposed by Staff and LG&E is inadequate and unduly discriminatory. The 100% load factor methodology for reactive power would not provide increased incentives for Bluegrass to run the plant more often. Generation plants run when economics justify energy production. Baseload units run more because they are more economical while peakers run during peak hours of the day, usually when either all baseload units that were committed are at maximum or are not available to run.[72]

51. Bluegrass argues that its final proposed overall rate of return of 8.54%, which is the authorized rate of return for LG&E, is the appropriate rate of return for Bluegrass. Bluegrass maintains also that 12.38% rate of return on equity ("ROE") is also appropriate for it as the Commission has authorized that rate for all transmission owners in Midwest ISO, including LG&E. Bluegrass points out that the Commission has routinely accepted proposed reactive power tariff filings of non-utility generators using host zone transmission owners' cost-of-capital rates. Bluegrass further argues that use of the capital structure of LG&E (i.e., 41% debt, 3% preferred stock, and 56% equity) is appropriate for Bluegrass for the same reasons that apply to Bluegrass using LG&E's overall rate of return and ROE.[73]

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[70] Bluegrass IB at 19-21, Ex. BGC-6 at 3-5, and Tr. 184, 223-26, 246, 247, and 259.

[71] Bluegrass IB at 22-24 and Bluegrass RB at 15-17.

[72] Bluegrass IB at 24-25 and Bluegrass RB at 12-13, Tr. 114-15, 258, 260, and 265-60.

[73] Bluegrass IB at 32-38.

52. Bluegrass states that remaining reactive power production plant investment totals about $363,000. Bluegrass also maintains that it did not omit the second ratio in the Remaining Power Plant Investment Allocator. Based on results on Midwest ISO AFC models for March, June, and August 2005 and projected for March and August 2006, which show Bluegrass units generating at maximum collective output, the numerator and denominator are the same. The Midwest ISO AFC load flow models for those months show projected peak conditions for those months. Staff erred in relying on LG&E data showing one day's operating experience as the basis for the second ratio numerator. The *AEP* methodology subtracts the total cost of the generator, exciter, GSU, and accessory electric equipment that supports the generator/exciter from the total production plant in accounts 310 through 316 on the USOAs. The net amount is then multiplied by 0.203%, the percentage ratio of the exciter rating (MW) to the generator's rating (MW) to estimate the associated part of production plant investment other than the generator, exciter, GSU, and accessory electric equipment necessary to support reactive power productions. Bluegrass maintains that its Remaining Power Plant Investment Allocator is consistent with the *AEP* methodology, which used a summer peak load flow model.[74]

53. Bluegrass argues that it satisfies the Qualified Generator Status technical qualifications under Midwest ISO's Schedule 2 and is able to immediately respond to a request for reactive power as required by that Schedule despite lack of twenty-four/seven onsite staff. Bluegrass maintains that LG&E is not accurate in its claim that Bluegrass is not able to respond immediately and that it does not satisfy the technical qualifications of Midwest ISO Schedule 2 due to lack of on-site staff and firm fuel supply. Bluegrass explains that employees can get to the facility in an hour or less, it takes about nine minutes for start-up, and there is usually a few hours lead-time before the plant is actually required to start up. Further, there no legal or contractual requirement for twenty-four hour staffing or for firm fuel supply. Moreover, the immediate-response requirement in Midwest ISO's November 16, 2005, pending Schedule 2 compliance filing takes into account individual generator characteristics.[75]

54. Bluegrass argues that the *Mobile-Sierra*[76] doctrine argument made by LG&E is factually and legally incorrect. Bluegrass states that it is trying to implement the terms of the IA, not seeking to change them. Also, the IA has no *Mobile-Sierra* clause in which it waived its statutory right to file a rate schedule. Bluegrass, therefore, did not bargain away statutory rights to Commission review of future changes under the "just and reasonable" standard. And, although the "public interest" standard may apply in the case

[74] Bluegrass IB at 38-39.

[75] Bluegrass IB at 43-46 and Bluegrass RB at 22-23.

[76] *United Gas Pipe Line Co. v. Mobile Gas Service Corp*, 350 U.S. 332 (1956) and *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 at 355 (1956) ("*Mobile/Sierra*").

of contractual silence, the IA is not silent. Section 8.4.4(i) specifically contemplates Commission approval of a tariff-setting compensation to be paid to Bluegrass for reactive power support. Section 8.4.4 provides that the per MVARh charge only applies in the absence of an order establishing specific compensation to Bluegrass for reactive support.[77]

55. LG&E -- The position of LG&E is that Bluegrass's proposed reactive power tariff will not result in just and reasonable rates. A 100% load factor rate is the appropriate rate design for the as-available reactive power support Bluegrass provides, and Bluegrass should be paid on an as-available basis consistent with the IA. LG&E maintains that: 1) Bluegrass does not have the unilateral right to change the IA (*i.e. Mobile/Sierra* doctrine); 2) Order No. 2003 does not provide the right to change the compensation provision of the IA; 3) the IA was entered into before the effective date of Order No. 2003; 4) Midwest ISO Schedule 2 does not entitle Bluegrass to such payments; 5) the rate increase would be "exorbitant;" 6) and, the Commission in *MISO II* reaffirmed that Order No. 2003-B allows excluding a generator from rate recovery due to an interconnection, or other agreement. If it is found that Bluegrass should be allowed a fixed payment, then Bluegrass should be allowed $262,386 a year for reactive power support.[78]

56. LG&E presented the testimony of Daniel D. Becher, Martin J. Blake, Mark S. Johnson, William Seelye, and James Eiseman.

57. Mr. Becher is the Managing Member and Principal of DB Consulting, LLC, and is also an Associate Consultant with The Prime Group, LLC. Before forming DB Consulting, Mr. Becher spent thirty-three years at LG&E and predecessor companies in various engineering, operations, and management positions in the LG&E electric system. Mr. Becher's last position with LG&E was Director of Transmission. In that position, he was responsible for the engineering, operations, construction and maintenance of the combined LG&E and Kentucky Utilities transmission system. Additionally, he managed the reorganization of electric transmission under FERC Order No. 889 and helped develop the OATT under FERC Order No. 888. He managed the reorganization of electric transmission through two mergers. He served as Chairman of the ECAR Operations Panel represented ECAR on the North American Electric Reliability Council (NERC) Operating Committee. Mr. Becher was involved in the negotiation of the IA between Bluegrass and LG& E Energy. Mr. Becher explains the basis for the compensation provided for in the IA.[79]

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[77] Bluegrass RB at 2-3 and 9-10.

[78] LG&E Reply Brief ("LG&E RB") at 1-4, 8, and 14-16.

[79] Ex. LGE-3 at 2-3.

58. Mr. Becher testified that there was adequate reactive capacity in the area when the IA was negotiated. So, the IA called for Bluegrass to regulate to zero reactive output (within +/- 10 MVAR) when the units were online. When Bluegrass is operating in that bandwidth, there is no compensation for reactive power. The IA allows LG&E to request reactive power in emergency situations from Bluegrass, with compensation of fifty cents per MVARh supplied or absorbed when the Bluegrass units are already on line and synchronized to the system and provides for additional compensation if the requested reactive power limits Bluegrass's output of real power. Mr. Becher testified that Dynegy suggested the compensation of fifty cents-per-MVARh-supplied based on an interconnection agreement in the Commonwealth Edison system.[80]

59. Mr. Becher explained that the Midwest ISO dispatches the five coal-fired LG&E and the Bluegrass generating units. The Midwest Market determines which generating units are placed on line based on offers submitted by the generator to produce energy. He testified that Bluegrass's units had been on line an average of 1.8% of 2928 hours, in the first four months of market operation, while the five LG&E units were on line an average of 84.8% of the hours in the same period, with at least some combination of the five-base load units on line 100% of the time.[81]

60. Mr. Becher testified that a reactive resource that is only available to support voltage about 2% of the time is of much less value in ensuring effective delivery of real power than are resources that are almost continually available. Mr. Becher's view is that providing identical compensation to all generators for reactive capacity regardless of location, removes any incentive to consider the need for the reactive power in determining where to build plants. It results in increased costs to customers without resulting benefit. According to Mr. Becher, some recognition of the ability to provide reactive power when needed should be reflected in compensation for reactive capacity. This method, according to Mr. Becher, better reflects the fact that one unit is only on line 2% of the time while another unit is on line supplying reactive power 84% of the time.[82]

61. Dr. Blake is a Member and Principal of The Prime Group, LLC. He has professional experience as an economist and a professor of economics and has testified in other proceedings before FERC and various state regulatory bodies. Before joining the Prime Group, LLC, Dr. Blake was employed as Director, Marketing, Planning and Regulatory Affairs at LG&E. He was responsible for coordinating LG&E's retail gas and electric marketing, strategic planning, and state and federal regulatory efforts.[83]

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[80] *Id*. 6-8.

[81] *Id*.at 8.

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

[83] Ex. LGE-2 at 1-6.

62. Dr. Blake testified that Bluegrass's proposed increased charge for providing support under the IA was not just and reasonable and that because Bluegrass had not met all the requirements of Midwest ISO's Schedule 2, it could not be compensated under the provisions of that schedule. Dr. Blake testified that the IA provides for compensation for reactive power Bluegrass might provide pursuant to an LG&E request for emergency reactive power support. LG&E does not need reactive power supply capability from Bluegrass, as indicated by § 8.4.1 of the IA which states that Bluegrass must regulate the reactive power output of its generators so that the reactive power output remains within a range of between +/-10 MVAR at the point of interconnection, except when LG&E requests reactive power support. Dr. Blake testified that the emergency service Bluegrass supplies is an as-available service since Bluegrass is not required to provide reactive power if it is not already operating.[84]

63. Dr. Blake observed that the IA does not indicate a consistent need for reactive power from Bluegrass in the area where Bluegrass is located. He testified that his review of Midwest ISO data requests responses shows that Midwest ISO believes that because Bluegrass does not meet the requirements of Schedule 2, the only agreement between LG&E and Bluegrass that applies is the IA. If Bluegrass met the requirements of Schedule 2, it would be entitled to compensation pursuant to that schedule. Since it does not, comparability is not an issue, according to Dr. Blake. It does not violate the principle of comparability for Bluegrass to continue to receive the compensation that is currently specified in the IA for the as-available service that Bluegrass is currently providing.[85]

64. Dr. Blake testified that the Bluegrass filings cannot be used as a stand-alone tariff to collect for reactive power support. According to Dr. Blake, the rate schedule contained in Bluegrass's filing can only be used as an input in the Midwest ISO's Schedule 2, which would then provide the tariff mechanism for collecting any reactive supply service that Bluegrass might provide. Dr. Blake argues that even though it is labeled as a rate schedule, Bluegrass's Attachment A does not identify to whom the charge is assessed, how the charge is assessed, what service is being provided to justify this charge, or what the consequences are for not providing the service when required.[86]

65. Dr. Blake testified that it was his opinion that if the Commission were to accept a fixed reservation charge, the rate schedule should be modified to require Bluegrass to provide reactive power whenever requested by LG&E, with no limitations and also to

[84] *Id*. at 6-10 and 18-19.

[85] *Id*. at 19-21.

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

provide for penalties, specifically those contained in Schedule 2, if Bluegrass fails to perform. Dr. Blake believes that a reservation charge would not provide the proper incentives for Bluegrass to provide reactive power support absent significant penalty provisions. According to him, once a reservation charge for reactive power support is received, the incentive would be to supply as little reactive power as possible while maximizing the real power output for the market. He argues that in order to avoid this, penalty provisions are essential.[87]

66. Dr. Blake testified that in order to receive compensation, § II.A of Schedule 2 requires that Midwest ISO determine that a generation resource is a Qualified Generator. Dr. Blake noted that Bluegrass had not filed an application for Qualified Generator Status as required by § IIB Schedule 2. Dr. Blake further testified that Bluegrass had not met the testing requirements for voltage control capability required by ECAR. Additionally, Bluegrass may not even be able to meet the requirements of § II.B.3, according to Dr. Blake, because of the nature of the natural gas supply contracts that it had in place. Dr. Blake concluded that since Bluegrass had not complied with at least two of the four provisions of § II.B, and may not be able comply with a third provision, it did not meet the requirements to be designated as a Qualified Generator by the Midwest ISO.[88]

67. Mr. Johnson is the Director of Transmission for LG& E Energy. Mr. Johnson is responsible for the design, engineering, planning, operations and maintenance of the transmission system. He is also responsible for contractual agreements related to transmission service. Mr. Johnson has twenty-four years of experience in the utility industry and has held leadership positions for seventeen of those years. Mr. Johnson provided testimony about the circumstances under which LG&E, as the Control Area Operator, requests reactive power from Bluegrass. Mr. Johnson testified about an occasion on which Bluegrass was called on to provide reactive support, but was not able or willing to provide the amount of reactive power requested.[89]

68. Mr. Johnson testified that the Midwest ISO has over thirty separate control areas within its geographical area and that Midwest ISO transmission owners, for the most part, operate their control areas for Midwest ISO. Therefore, LG&E control area operators perform NERC-required “balancing-area functions,” which are intended to ensure the reliability of the transmission system. The Midwest ISO, as the transmission provider, determines the amount of reactive power support necessary to maintain transmission voltages within generally accepted ranges, but makes reactive supply and voltage control available through arrangements with the control area operators. As a control area

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[87] *Id*. at 22-24.

[88] *Id*. at 12-13.

[89] Ex. LGE-4 at 1-2.

operator, LG&E acquires reactive power from generation in its control area, including its own generation units. Mr. Johnson testified that LG&E does not usually require Bluegrass to produce reactive power, but that Bluegrass was obliged to provide reactive power in certain emergency circumstances on request from LG&E.[90]

69. Mr. Johnson testified that on August 11, 2005, LG&E requested VAR support from Bluegrass, but Bluegrass was not able to supply the requested amount. When the LG&E control area operator asked Bluegrass for an additional 100 MVARs, Bluegrass was running and producing 100 MVARs and it agreed to produce the additional 100 MVARs. However, Bluegrass later reneged claiming that it could only supply seventy-five MVARs, because of a concern about tripping the units. Ultimately, according to Mr. Johnson, Bluegrass was able to supply an additional eighty-three MVARs, for a total of 183 MVARs. Mr. Johnson indicated that, to his knowledge, Bluegrass has never provided 360 MVARs of reactive power, even though Bluegrass bases its fixed demand charge on that amount.[91]

70. Mr. Seelye is a Senior Consultant and Principal for the Prime Group, LLC. Previously Mr. Seelye was Manager of Market Management and Rates at LG&E. Mr. Seelye has a long utility industry work history.[92] Mr. Seelye provided testimony on Bluegrass's proposed reactive power tariff.

71. Mr. Seelye's position, on behalf of LG&E, is that the IA fairly compensates Bluegrass; however, if the Commission decides to require additional compensation, then a charge for reactive power support should only be assessed whenever Bluegrass generates power that is supplied to the transmission grid. It is also Mr. Seelye's opinion that Bluegrass receive $0.0599/MWH for all energy metered at the interconnection point on the LG&E transmission system.[93]

72. Mr. Seelye testified that Bluegrass is adequately compensated under the IA in that it: 1) has infrequently operated since it began commercial operation on June 1, 2002 and has rarely been in a position to provide reactive power support; 2) does not receive firm transportation service for deliveries of natural gas to its facility, and so cannot provide firm reactive power support; 3) is located in an area with an abundance of baseload generation and, 4) consequently, the support for which Bluegrass is seeking compensation provides little or no value to LG&E. Because Bluegrass has operated only rarely, provides only a fraction of the reactive power used to determine its proposed

[90] *Id.* at 3-4.

[91] *Id*. at 5-6.

[92] Ex. LGE-1 at 1.

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

annual fixed payment, and is not able to provide service on a firm basis, its filing is an unreasonable attempt to extract a fixed payment from consumers for service that provides little or no value. Moreover, errors in Bluegrass's fixed carrying charge calculations cause those charges to be significantly overstated, according to Mr. Seelye. The reactive power schedule Bluegrass submitted does not constitute a stand-alone tariff sufficient to charge LG&E for reactive power support because Bluegrass fails to describe with any useful specificity what services are being provided, under what terms and conditions the services would be provided, or who would pay the charge specified in the schedule.[94]

73. Mr. Seelye testified that one type of revenue-requirement cost support is the "carrying charge support." The "fixed carrying charge calculation" or "fixed charge formula" is used to compute the carrying charge support. "Fixed carrying charges" are the costs incurred by a utility to carry the investment required to provide service. According to Mr. Seelye, Bluegrass has attempted to use the carrying charge approach in computing its proposed revenue requirements for reactive service; however, Bluegrass has not used a Commission-approved calculation methodology.[95]

74. Mr. Seelye further testified that using a sinking fund depreciation rate based on a forty-year service life would lower Bluegrass's annual revenue requirements from $1,0869,509 to $880,340. Deferred income taxes are a significant source of cost-free capital for Bluegrass and, therefore, the long-term impact of income taxes should not be ignored in Bluegrass's revenue requirement calculations. According to Mr. Seelye, Bluegrass has received, and continues to receive the benefits of a liberalized accelerated depreciation for income tax purposes, which has the effect of decreasing Bluegrass's revenue requirements. ADIT should be deducted from the net investment over the forty-year life of the plant. This lowers the annual levelized carrying charges from $880,340 to $772,321.[96]

75. Mr. Seelye testified that Bluegrass had not made a persuasive case for using a hypothetical capital structure. Because Bluegrass is not a regulated entity, it has no obligation to provide service to retail electric customers, and there is no basis to assume that its capital structure should resemble in any way the capital structure of a regulated utility that has an obligation to provide such service. Mr. Seelye believes that without a stronger demonstration that the pro-forma adjustment to its capital structure is warranted, the capital structure of Bluegrass's parent company, Dynegy, should be used. Using Dynegy's capital structure, applying a levelized carrying charge methodology, and

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[94] *Id*. at 9-14.

[95] *Id*. at 14-15.

[96] *Id*. at 20-25.

accounting for deferred income taxes, lowers Bluegrass's proposed reactive power tariff from $1,086,509 to $664,550.[97]

76. Mr. Seelye testified further that Bluegrass significantly overstated the amount of reactive power that its generating units can provide in calculating its annual fixed charges. Mr. Seelye said that Bluegrass assumed it could provide 360.33 MVARs in developing its carrying charges, however, the average reactive power provided by Bluegrass from June 6, 2002 to July 7, 2005 was 3.9 MVARs. Further, Mr. Seelye pointed out that, as indicated in Mr. Johnson's testimony, on August 11, 2005, LG&E requested that Bluegrass supply 200 MVARs from its three generating units that were operating that day but Bluegrass was only able to supply 183 MVAR. Therefore, according to Mr. Seelye, 183 MVARs represents the maximum amount of reactive power that the Bluegrass facility is capable of supplying. Mr. Seelye calculated the annual carrying costs using this 183 MVARs, and with the previous adjustments resulted in the carrying costs being reduced to $262,386 per year.[98]

77. Mr. Seelye testified that if it were found that Bluegrass should receive compensation beyond that provided for in the IA, the reactive power support provided by Bluegrass should be priced at a 100% load factor rate, which assumes that the customer takes service at a 100% load factor even though service may not be provided 100% of the time. Mr. Seelye said the 100% load factor charge represents a compromise in the payment amounts between the IA and what Bluegrass has requested. Mr. Seelye further represented that a 100% load factor rate is appropriate because of Bluegrass's interruptible gas transportation. It also allows Bluegrass to receive full compensation for the $262,386 in fixed carrying charges associated with reactive power, in the event that Bluegrass provides service comparable to the two utility operating units of LG&E. Mr. Seelye calculated the 100% load factor rate on a MWh basis so that it would be comparable to the billing units used in calculating and assessing the LG&E Schedule 2.[99]

78. Mr. Seelye testified that the capital structure that Staff recommends is not appropriate. His view is that Staff erred in ignoring the significant income tax implications of using a capital structure consisting of 49% common equity and 51% long term debt. Mr. Seelye recommended using a capital structure consisting of 69.4% long-term debt, 5.4% preferred stock, and 25.2% equity. He argues that Staff is allowing a larger portion of the return element to be grossed up for income taxes and that has the impact of indirectly increasing the impact of the ROE that Mr. Green is recommending. Using Staff's hypothetical capital structure is the equivalent of awarding a 15.94% ROE

[97] *Id*. at 29-31.

[98] *Id*. at 31-33.

[99] *Id*. at 44 and Ex. LGE-5 at 2.

to Dynegy. Moreover, according to Mr. Seelye, an actual, and not hypothetical capital structure should be used, as the Commission has routinely authorized gas transportation rates based on capital structures in the 25%-30% range for gas pipelines. Mr. Seelye believes that in this case, the impact of the use of a hypothetical capital structure costs consumers more than a higher ROE would when applied to Dynegy's capital structure.[100]

79. At the hearing, Mr. Seelye testified that although he had indicated in a data request that Bluegrass did not have summer no-notice service, he had subsequently learned that it did. He said that it could be argued that Order No. 2003 is not applicable because of the pre-existing rate and because Order No. 2003 does not address how compensation should be determined. In addition, according to Mr. Seelye, Order No. 2003 does not apply because Bluegrass is neither new, nor is an expansion of an existing generator and because the IA predated Order No. 2003. Additionally, Midwest ISO is the transmission provider not LG&E and, therefore, Bluegrass must meet the requirements of the Midwest ISO TEMT if it is to receive compensation under Schedule 2 for reactive power support. He continued to maintain that although the Commission cited Order No. 2003 in the *Rolling Hills* reactive power proceeding and others, those cases were fact-driven and that, in any event, the Commission did not specify the appropriate compensation in those cases.[101]

80. Mr. Seelye testified that he had used Dynegy's 2004 actual capital structure data in Bluegrass revenue requirement calculations in Exhibit LGE No. 1, as that was the latest data available at the time.[102]

81. LG&E called Bluegrass employee, James Eiseman, to testify at the hearing. Mr. Eiseman testified that he was employed as plant supervisor at the Bluegrass facility. His duties include ensuring the safe operation of the facility. He testified that the facility was staffed by eight employees five days a week (Monday through Friday) from 6:00 a.m. until 4:00 p.m. for the operators. He usually stayed until 5:00 p.m. or 6:00 p.m. The facility is in an industrial park. None of the employees live immediately adjacent to the facility site. The employee living furthest from the site lives twenty miles away. The plant does not have remote start-up ability. Mr. Eiseman testified that an employee was always on call, however. All employees can get to the facility within an hour of receiving the call from Dynegy. Power can be introduced into the grid in as few as nine minutes after the employee arrives at the plant. He testified that there had always been gas available at the facility when needed. If there were not enough gas to shut the unit down, it would trip due to low gas pressure. One trip costs about $8,000.00 in

[100] *Id*. at 30-31.

[101] Tr. 184-187.

[102] Tr. 187-188.

maintenance costs. He testified that one unit tripped in June 2005 due to low gas pressure resulting from an improperly operating fuel valve.[103]

82. LG&E maintains that *Mobile-Sierra* precludes Bluegrass from changing the IA compensation provision unilaterally as there is no public interest at stake in this case. The § 8.4.4 language that Bluegrass relies on, only indicates that the Commission's action can trigger a different compensation; it does not allow Bluegrass to make a rate filing to change the compensation.[104]

83. LG&E argues that Order No. 2003 and its progeny do not provide support for Bluegrass to file a proposed reactive power tariff. The IA was entered into on February 13, 2001. Order No. 2003 does not apply to IAs existing at the time of its adoption. In fact, Order No. 2003-C specifically excepts retroactive changes and existing agreements. Moreover, Bluegrass's argument that if a transmission provider pays its own or affiliated generators for reactive power it must also pay the interconnection customer, is unavailing because Midwest ISO is the transmission provider, not LG&E. Nor is *Rolling Hills* applicable. First, *Rolling Hills* is of no precedential value because it was a settlement. Also, Rolling Hills, while a peaking facility, was located in the PJM Interconnection, L.L.C. ("PJM") region and fell under its tariff requirements for providing reactive power. PJM's requirements are not the same as those set forth in Midwest ISO's Schedule 2. Also there was no claim in *Rolling Hills* that the facility was not able to provide reactive power.[105]

84. LG&E further argues that Bluegrass does not meet the minimal Midwest ISO Schedule 2 qualification needed in order to receive compensation for production of reactive power. According to LG&E, there is no Midwest ISO-approved document indicating Bluegrass is a Qualified Generator although it appears Bluegrass submitted a self-certification on November 21, 2005. Even if Midwest ISO approved the self-certification, that does not support finding Qualified Generator Status before that date. And, Bluegrass, in fact, does not meet the Midwest ISO Schedule 2 qualifications. The record evidence shows that Bluegrass cannot meet the requirement that it be capable of providing reactive power "immediately" as Bluegrass: 1) is not staffed twenty-four hours a day, seven days a week; 2) does not have remote start-up capability; 3) does not have natural gas available to produce power; and, 4) is not bid into the Midwest Energy Market.[106]

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[103] Tr. 214-222, 230-234, and 226-227.

[104] LG&E RB at 7-8.

[105] LG&E IB at 13 and LG&E RB at 8-9.

[106] Bluegrass IB at 13-16 and Bluegrass RB at 10-11 and 23-25.

85. LG&E emphasizes that the fixed capacity charge that Bluegrass has proposed would not result in just and reasonable rates. Compensation should be stated either as a MWh or MVARh charge based on a 100% load factor rate to compensate Bluegrass only when it is operating. The 100% load factor methodology would provide increased incentives for Bluegrass to run the plant more often, consistent with Commission policy. The reactive power tariff that Bluegrass proposes offers no incentive to provide MVARs as there are no penalties for non-production, but payment is nonetheless guaranteed.[107]

86. LG&E argues that use of the *AEP* methodology does not necessarily render Bluegrass's proposed reactive power tariff appropriate (even if Bluegrass had correctly applied it, which LG&E maintains it did not). LG&E maintains that there is uncertainty about use of the *AEP* methodology in pricing for reactive power. AEP itself has filed comments in Docket No. AD05-1-000 which contend that it is not appropriate to use the *AEP* methodology for reactive power.[108] The gist of AEP's comments, according to LG&E, is that there should not be payment for having unneeded generation power.[109]

87. LG&E argues that it would not violate the concept of comparability for Bluegrass to continue to receive the compensation allowed in the IA for the as-available service it provides. LG&E's Trimble County Generating Station is more comparable to Bluegrass than any other LG&E unit and does not receive compensation under Schedule 2 for reactive power even though the turbines at Trimble County are either staffed full time or have remote start-up capability. Nor is there provision under the Midwest ISO's Schedule 2, or LG&E's Schedule 2 in effect before the start-up of the Midwest ISO energy market, that provides for compensation for those peaking units. LG&E's baseload units on the same transmission corridor as is Bluegrass, are obligated to provide service twenty-four hours a day, seven days a week. Those units are staffed full time or have remote start-up capability and firm gas supply and/or alternate full capability. Those units are on-line over 85% of the time (compared to Bluegrass's 2%) and are available immediately during those times.[110]

88. LG&E argues that because the Bluegrass plant is leased, Bluegrass is entitled to no return. However, should Bluegrass be found entitled to a rate of return, that rate should be predicated on Dynegy's actual capital structure and not the hypothetical one Bluegrass proposed. Bluegrass, a wholly-owned subsidiary of Dynegy, has no publicly-traded

[107] Bluegrass IB at 21-23 and Bluegrass RB at 14-15.

[108] *See Joint Comments of the American Public Power Association and the National Rural Electric Cooperative* Association, Dkt No. AD05-1-000, filed April 4, 2005.

[109] Bluegrass RB at 15.

[110] Bluegrass IB at 28-29.

stock, but Dynegy does. Use of Dynegy's capital structure also affords the advantage of minimizing the need to "gross up" the cost of common equity to account for the fact that the cost of equity is not deductible for income tax purposes. LG&E is not a proper proxy because Bluegrass presented no evidence that the risks of Dynegy and those of LG&E are so similar as to meet the requirements of *Pacific Gas and Electric C. v. FERC* [111] for use of a proxy. Moreover, LG&E is owned by a German non-publicly traded corporation with business operations throughout Europe and has a very different risk profile. Additionally, according to LG&E, the Commission held in *Detroit Edison* [112] that the ROE of the transmission provider is not to be presumed the appropriate model for reactive power or other ancillary service computations.[113]

89. LG&E argues that if a proxy group is proper here, the one selected by Bluegrass is not appropriate. The companies selected by Bluegrass – DTE Energy Company, First Energy Company, OGE Energy Corporation, Puget Energy, Inc., and TXU – are traditional, integrated utilities and are not, as is Bluegrass, independent power producers. Bluegrass has no obligation to provide retail customer service. In addition, the Bluegrass proxy group yields a common equity ratio of 47%, while Dynegy's is 25.2%. That high a ratio is not compatible with use of the *AEP* methodology as it artificially inflates the cost of capital component of the rate of return formula. Normally, an IPP has a high level of debt due to project financing among merchant generation power producers, resulting in usual common equity ratios for IPPs of 10% to 20%. The proxy group chosen by Staff is more appropriate. The overall rate of return should be 8.72%.[114]

90. MIDWEST ISO TO -- The position of Midwest ISO TO is that Bluegrass's proposed reactive power tariff would not result in just and reasonable rates because: 1) Bluegrass cannot be relied on to meet the reactive power needs of LG&E, or Midwest ISO and its transmission customers; and, 2) does not operate comparably to other LG&E generators. Midwest ISO TO argues that use of the *AEP* methodology does not override the statutory just and reasonable standard. The appropriate compensation for Bluegrass would be based on a 100% load factor, as-available basis on a MVARh basis, as recommended by Staff, or on a MWh basis as recommended by LG&E. Midwest ISO TO takes no position on whether IA agreement payment rates should be maintained.[115]

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

[112] *Detroit Edison Co.*, 105 FERC ¶ 61,264 at 62,357-358 (2003), *reh'g denied*, 106 FERC ¶ 61,244 (2004).

[113] Bluegrass IB at 31-34 and Bluegrass RB at 17-21.

[114] Bluegrass IB at 35-37.

[115] Midwest ISO TO Initial Brief ("MTO IB") at 30 and Midwest ISO TO Reply Brief ("MTO RB") at 2, 18, and 19.

91. Midwest ISO TO argues that Bluegrass does not satisfy Qualified Generator Status technical qualifications under Midwest ISO's Schedule 2 because it is off-line about 98% of the time and could not immediately respond to a request for reactive power. Nor did Bluegrass conduct the tests necessary to establish its reactive power capability until November 3, 2005 or submit the required request for Qualified Generator Status until November 21, 2005, and would not be eligible for compensation before the latter date in any event.[116]

92. Mr. Kirby is a senior researcher at the Oak Ridge National Laboratory ("ORNL"). His duties at ORNL include working with FERC technical staff to support reliability efforts including NERC/FERC reliability readiness audits. Mr. Kirby responded to Bluegrass testimony, dealing with the need, and appropriate compensation for the supply of reactive power and voltage control from generation.[117]

93. Mr. Kirby testified that he believed the IA authors did not anticipate the need of any reactive support from Bluegrass. Infrequent operation of Bluegrass indicates that it has not served a backbone reliability purpose. Therefore, these units are in a materially different position than the LG&E units which provide backbone reactive power support. Mr. Kirby testified that Bluegrass should not be compensated with the same type of charge as units which provide backbone reactive power support.[118]

94. Staff -- The position of Staff is that the rate proposed by Bluegrass for providing reactive power support is not just and reasonable. Simply following the *AEP* methodology does not automatically establish that Bluegrass's proposed rates are just and reasonable. The rate increase would be "huge" using the capacity-based *AEP* methodology. Bluegrass should get a rate of $0.1831 per MVARh for the as-available reactive power support it provides.[119]

95. Staff presented the testimony of Charlton I. Clark, Douglas M. Green, and Edward W. Mills.

96. Mr. Clark is an Electrical Engineer in the Engineering Analysis Group, Office of Administrative Litigation, FERC. He analyzes engineering issues in cases set for hearing and assists in settlement negotiations at FERC. Mr. Clark testified about Bluegrass's

[116] *Id*. at 30 and 31 and MTO RB at 24.

[117] Ex. MTO-1 at 2-3.

[118] *Id*. at 12-13.

[119] Staff Initial Brief ("Staff IB") at 13 and 15, and Staff Reply Brief ("Staff RB") at 25-29.

application of the *AEP* methodology and about how Bluegrass's fuel supply situation relates to reactive power support.[120]

97. Mr. Clark testified that Bluegrass neglected to use the second ratio in deriving the remaining power plant investment allocator. The second ratio is that of the maximum MVARs produced by the facility to the MVAR rating of the facility. According to Mr. Clark by not including the second ratio, Bluegrass failed to adjust for the difference between the actual operation of the unit and the reactive capability of the unit in allocating the remaining costs of the production plant. This is important because, as in the instant case, a generator is not typically operated at its full reactive capability, but instead is operated to provide as much reactive power as is needed to maintain a predetermined voltage schedule. Mr. Clark explains that this correction will bring the Bluegrass filing in accord with the *AEP* methodology. Mr. Clark obtained the first ratio in the calculation from Schedule 1.3 of the Bluegrass filing and obtained the second ratio in the calculation from the information contained in Attachment C to Ex. LGE-4. The correction results in a total power plant cost of reactive power production of $6,561,428. This creates a downward adjustment of $178,049.[121]

98. Mr. Clark noted that the Commission had expressed the possibility of compensation based on a methodology other than the *AEP* methodology. He explains that in an Order Granting Clarification in *Cottonwood Energy Company, L.P.*, the Commission stated that: "... parties are not precluded from developing a record on the issue of how Cottonwood is to be compensated for providing reactive power,"[122] including whether the compensation should be under the proposed rate schedule or some provision of the Cottonwood interconnection agreement.[123]

99. Mr. Clark testified that that he is not aware that any other company had requested compensation for reactive power support in a situation where the unit is fueled pursuant to an interruptible supply contract so there is no clear precedent to draw on to determine appropriate compensation. Mr. Clark stated that Bluegrass's "as-available" rate for reactive power support should be derived based on the MVAR capability of the facility (i.e., 360.33 MVAR) and levying a charge based on the MVARh produced by the Bluegrass facility. Mr. Clark testified that because Bluegrass does not provide reactive power support comparable to that provided by LG&E, and because Bluegrass is served

[120] Ex. S-1 at 1-2.

[121] *Id*. at 7-9; *see* Attachment C to Ex. LGE-4.

[122] *Cottonwood Energy Co., L.P.*, 112 FERC ¶ 61,317 at 62,413-414 (2005).

[123] Ex. S-1 at 12.

under an interruptible fuel supply contract and can only provide "non-firm" reactive power support, an as-available charge is appropriate.[124]

100. Mr. Green has been a Financial Analyst with the Office of Administrative Litigation, FERC, since 1993. His duties as Financial Analyst include determining appropriate ROE for electric utilities, and gas and oil pipelines. Mr. Green provided testimony as to the appropriate ROE, capital structure, and cost of long-term debt. Mr. Green concluded that the reasonable ROE for Bluegrass is 7.7% to 10.6%. His recommended ROE is 8.2%.[125]

101. Mr. Green testified that long-term interest rates were at a near forty-year low, having generally declined over the past fifteen years. He testified that a reasonable inference is that equity costs are likely also at about a forty-year low.[126] Mr. Green, cited *Southern California Edison Co.* ("*SoCal*"),[127] for the proposition that the Commission prefers using current market data to develop an appropriate ROE for electric utility companies. He testified that ROE was a forward-looking concept, not dependent on past required or earned ROE. He testified that, in making ROE determinations, regulators must look to data investors consider when determining the appropriate ROE for a company, and use that data as inputs in their analytical exercises. Mr. Green testified that there were no Commission decisions regarding the appropriate development of the ROE for reactive power rates.[128]

102. Mr. Green testified that he used the Discounted Cash Flow ("DCF") method to determine the cost of common equity financing and resulting ROE. According to Mr. Green, the DCF method uses a market-oriented approach to show the ROE required to attract equity financing. According to Mr. Green, use of the DCF method ensures that investor-perceived risks, reflected in stock price, are taken into account in making the cost-of-common-equity determination.[129]

103. Mr. Green testified that the ROE that he calculated was based on application of the DCF method to the LG&E system because Bluegrass does not have publicly-traded stock and Dynegy, the parent company of Bluegrass, does not pay dividends. Therefore,

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[124] *Id.* at 10-11.

[125] Ex. S-12 at 1-2 and Appendix A.

[126] *Id*. at 2-3; *see* Staff Ex. S-13 Schedule Nos. 1 and 2.

[127] *Southern California Edison Co.*, 92 FERC ¶ 61,070 (2000), *reh'g denied* 111 FERC ¶ 61,085 (2004).

[128] Ex. S-12 at 3-5.

[129] *Id*. at 6.

neither Bluegrass nor Dynegy is a suitable company on which to apply the DCF method. Mr. Green testified that it was appropriate to use the ROE of LG&E because LG&E is the owner of the transmission company to which Bluegrass is interconnected. He testified that reactive power is provided by both generators and such static devices as inductors and capacitors, which are connected to the transmission system. Therefore, Mr. Green selected a proxy group of companies with risk characteristics that were similar to LG&E's.[130] Mr. Green cited several Commission decisions he claims support the proposition that the Commission approves of using the ROE for the interconnected transmission owner in the development of reactive power rates.[131]

104. Mr. Green testified that he did not perform a DCF analysis on LG&E because LG&E is a wholly-owned subsidiary of E.ON AG, a German-based industrial company. LG&E, therefore, does not have publicly-traded shares of common stock and does not pay a dividend to shareholders. However, since E. ON AG has considerable business operations in Europe and in other business operations besides electric utilities, Mr. Green did not consider E.ON AG a suitable proxy for estimating investors' required ROE for Bluegrass. Mr. Green selected four electric utility companies he found met DCF model requirements and with an aggregate risk profile most similar to LG&E's. Mr. Green chose: (1) Allete, Inc.; (2) OGE Energy Corporation; (3) Pepco Holdings, Inc.; and, (4) Wisconsin Energy Corporation. He testified that his four-company proxy group was suitable. If he had increased the number of companies, it would have resulted in inclusion of companies with inapt risk profiles.[132] He testified that Commission precedent supports using a proxy group of four or fewer companies.[133]

105. Mr. Green testified that in conducting the DCF analysis, he used the five-year earnings-per-share estimates published by IBES and computed estimates of sustainable growth using *Value Line* and *S&P* company-specific data about growth. Mr. Green explained how he developed growth rates for the proxy companies he used. He testified that he calculated the sustainable growth rates of the proxy-group companies by adding their internal growth rate to their external growth rate to obtain the following growth

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[130] *Id*. at 6-7.

[131] *Energy Marcus Hook. L.P.*, 100 FERC ¶ 61,087, *reh'g denied* 111 FERC ¶ 61,168 (2005); *Tenaska Virginia Partners*, 107 FERC ¶61,207 (2004); *Duke Energy Lee, L.L.C.*, 107 FERC ¶ 61,200 (2004); and, *Duke Energy Fayette, L.L.C.*, 104 FERC ¶ 61,090 (2003).

[132] Ex. S-12 at 7-9; *see* Ex. S-12 at 10-21 for specific criteria used by this witness to select proxy companies.

[133] *See* So*Cal*, 92 FERC ¶ 61,070 and *Consumers Energy Co*., 85 FERC ¶ 61,100 (1998).

rates: Allete - 5.35%; OGD Energy - 3.47%; Pepco Holdings - 3.79%; and Wisconsin Energy – 6.29%.[134]

106. Mr. Green testified that he used a DCF model that assumes dividends are paid quarterly. The formula Mr. Green used to develop the adjustment factor for application to the current dividend yield to account for quarterly payment of dividends is: (1+.5g), where "g" is the estimate of investors' expected growth rate. The adjustment factors were multiplied by each company's six-month low and high dividend yields to arrive at adjusted low and high dividend yields. The reasonable range for the proxy group was 7.7% to 10.6% using the lowest and highest DCF results for the proxy-group companies.[135]

107. Mr. Green testified that he found Bluegrass to be in the median of the proxy group DCF returns. He testified that he did not violate *MISO*[136] in using the "median" instead of the "midpoint" because since the rate determined in that case would apply to all of the Midwest ISO TOs, the *MISO* case was unique. The Commission had so stated in its decision by specifically noting that Midwest ISO was not an average-risk single utility.[137]

108. Mr. Green testified that he used the average capital structure for the proxy group of 49% common equity and 51% long-term debt. His recommended overall, after-tax return on capital for Bluegrass was 7.01%.[138]

109. Mr. Green testified that his average capital structure represented actual capital structures used to finance regulated electric utilities. It represents the fact that capital structure and required ROE for investors are interrelated. Mr. Green testified that Commission guidelines for determining the appropriate capital structure to be used in utility company rate cases are in Opinion No. 414-A[139] and that he followed those guidelines. He testified that it was important that the capital structure for Bluegrass be based on a "market-driven" capital structure. That was because a "market-driven" capital structure is one in which an entity is publicly owned and has financial autonomy, such

[134] Exs. S-12 at 22-25 and S-12 Schedule No. 9; *see also* Ex. S-12 Schedule Nos.1-8 and 11-15.

[135] Ex. S-12 at 25-27 and Ex. S-12 Schedule 10.

[136] *Midwest Independent System Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *aff'd in part & rev'd in part PSC of Kentucky v. FERC*, 397 F.3d 1004 (2005).

[137] Ex. S-12 at 28-30 and 48-51.

[138] Ex. S-12 at 30 and 36.

[139] *Transcontinental Gas Pipe Line Corp.*, 84 FERC ¶ 61,084 at 61,413, *aff'd* 85 FERC ¶ 61,323 (1998).

that the entity is shaped by market forces. In contrast, wholly-owned subsidiaries are affected by non-market forces exerted by parent entities. Mr. Green testified that Opinion No. 414-A makes clear that the Commission prefers use of a market-driven capital structure.[140]

110. Mr. Green testified that he calculated the cost of long-term debt for Bluegrass of 5.86% using the most recent six-month average yield on *Moody's* "Baa" public utility bonds. Each of the proxy-group companies had a "Baa"-equivalent rating. According to Mr. Green, Dynegy's actual cost of long-term debt was used because Dynegy's cost of 8.08% reflects compensation to investors for the high level of financial risk inherent in its highly-leveraged capital structure of about 75% long-term debt. Bluegrass, on the other hand, has a much greater percentage of higher cost common equity and, therefore, has less financial risk.[141]

111. Mr. Green testified that LG&E is incorrect in its view that Bluegrass is a non-traditional independent power producer or non-utility generator, and not a regulated utility with an obligation to service retail customers, such that Dynegy's capital structure should be used for Bluegrass and not the capital structure that reflects a regulated utility. The rates at issue in this proceeding concern Bluegrass's reactive power and that reactive power is a regulated electric utility service.[142]

112. Mr. Green testified that he agreed with Bluegrass that LG&E is an appropriate company to look to for developing the return on capital for Bluegrass; however, he does not agree with Mr. Roethemeyer's use of LG&E's specific capital structure and cost rates because LG&E does not have a stand-alone, market-driven capital structure. In addition, the parent company of LG&E is not located in the United States and has considerable non-electric business operations. Nor does Mr. Green agree with Bluegrass that it should use LG&E's cost of long-term debt and preferred stock.[143]

113. Mr. Green testified that he did not agree with Bluegrass's use of a 12.38% ROE because the Commission rejected that same rate of return in *Detroit Edison Co*.[144] Mr. Green noted, among other things, that a ROE of 12.38% is more than three times

[140] Ex. S-12 at 31-35.

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

[142] *Id*. at 55-56.

[143] Ex. S-15 at 1-6.

[144] *Detroit Edison Co.*, 106 FERC ¶ 61,244 (2004).

LG&E's current cost of long-term debt, which indicates that that rate does not reflect investor requirements in a low capital cost environment.[145]

114. Mr. Green testified that Bluegrass was not correct in claiming that the Commission has recognized that merchant generators are riskier than regulated utilities, such that use of capital costs of regulated utilities for determining reactive power tariffs is conservative. According to Mr. Green, the case on which Bluegrass relies[146] addresses appropriate "capital structure," not "cost rates."[147]

115. At the hearing, Mr. Green testified that his ROE, return on capital structure, and cost of capital recommendations apply regardless of the ultimate revenue requirement or rate design adopted. He testified that he was not aware of penalties under Midwest ISO Schedule 2 if reactive power is not provided on request, but if that were the case, it might have some impact on his recommended ROE. Mr. Green testified that his opinion is that a ROE that is three multiples the cost of debt was highly irregular. He said he had never even seen a company propose a risk premium of 900 basis points.[148]

116. Mr. Mills has twenty years of work experience in the energy industry. He has been employed as an economist in the Office of Administrative Litigation, FERC, since 1998. His current duties involve preparing for, and testifying in electric utilities and oil and natural gas pipeline rate, merger, and complaint proceedings. Mr. Mills testified as to some adjustments to Bluegrass's proposed reactive power tariff and Staff's proposed rate design. He concluded that the levelized approach should be used in calculating Bluegrass's annual revenue requirements for reactive power and that deferred income taxes should be reflected in the determination of Bluegrass's cost-based rates. Mr. Mills testified further that Staff's revised plant allocator and cost of capital should be adopted. He also supported a flat-rate MVARh charge for non-firm reactive power, and not a dollar per MWh. [149]

117. Staff argues that Bluegrass is only entitled to as-available, or 100% load factor compensation because its natural gas supply is interruptible or non-firm. Staff maintains that reactive power is measured in MVAR. The amount of MWs supplied is not typically related to the amount of MVARs supplied. Therefore, the rate should be derived based on the MVAR capability of Bluegrass (360.33 MVAR) and by levying a charge based on

[145] Ex. S-15 at 6-10.

[146] *Calpine Fox*, 113 FERC ¶ 61,047.

[147] Ex. S-12 at 10-12.

[148] Tr. 269-72.

[149] Exs. S-6 at 1-7 and S-7- S-12.

the MVARh actually produced by Bluegrass. That charge should be, according to Staff, $0.1831 per MVARh for as-available reactive power service. That result is Staff's recommended annual revenue requirement for reactive power of $577,862 divided by 360.33 MVARs, divided by 8760 hours per year.[150]

118. Further positions taken by Staff are that it does not object to LG&E's proposal that Bluegrass compensation should be maintained at the rate in the existing IA. However, Staff has proposed the above-noted alternative eighteen-cent rate it believes is appropriate. The Commission has not held that use of methodologies other than the *AEP* methodology were precluded and Staff used a modified *AEP* methodology. Staff observed that other LG&E stations do not receive compensation under Schedule 2 for providing reactive power support.[151]

BURDEN OF PROOF

119. Bluegrass filed its proposed Rate Schedule FERC No. 2 under Section 205 of the Federal Power Act ("FPA")and Part 35 of the Commission's regulations. Under the statute and the regulations, the entity filing for a rate change has the burden of proving that the proposed rates are just and reasonable.[152]

ISSUES/CONCLUSIONS/RATIONALES

120. ISSUE -- Does the IA preclude Bluegrass from filing a rate schedule for reactive power revenue?

121. CONCLUSION -- Bluegrass may, consistent with the IA, file a rate schedule for reactive power revenue.

122. RATIONALE -- Section 8.4.4(i) of the IA provides that LG&E will pay Bluegrass consistent with any FERC order or FERC-approved tariff for reactive power support. Section 8.4.4(ii) provides that absent such order or tariff, LG&E will pay Bluegrass at a rate of at least $0.50 per MVARh for reactive power absorbed or produced per month. Section 8.4.4(ii), or the fifty-cents-per-MVARh section, had been the compensation provision used by LG&E and Bluegrass until the Commission accepted the Bluegrass rate schedule, subject to refund.[153]

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[150] Staff IB at 24-25; Exs. S-1 at 10-11, S-6 at 7.

[151] *Id*.

[152] 16 U.S.C. § 824d(e) and 18 C.F.R. § 35.13(e)(3)(2005).

[153] Initial Decision at ¶¶ 3-4 (**NOTE:** "Initial Decision" refers to this decision.

123. LG&E argues that Bluegrass's filing is no more than its effort to unilaterally change a contract provision in violation of *Mobile/Sierra*.[154] LG&E argues that the IA was entered into before the effective date of Order No. 2003 and the Commission made clear that Order No. 2003 did not alter the terms of existing interconnection or other agreements. [155] However, Bluegrass correctly argues that *Mobile/Sierra* does not apply. Bluegrass seeks to implement, not change, a provision of the IA, specifically § 8.4.4(i). The question is, does § 8.4.4(i) allow Bluegrass to file a proposed rate schedule in order to obtain a FERC order or FERC-approved tariff.

124 Mr. Beecher, testifying for LG&E, said that he had been involved in the negotiation of the IA and that the intent had been to "do no harm" as there had been adequate reactive power on the line when the IA was negotiated. He said that Dynegy had recommended the fifty-cent figure based on another interconnection agreement. Dr. Blake, also testifying for LG&E, similarly argued that the IA did not show a consistent need for reactive power support from Bluegrass.[156]

125 The Court of Appeals for the D.C. Circuit has held that the issue of intent of the parties regarding revised rates in federal power contract provisions is to be determined by the plain language of the contract provisions absent ambiguity in the language.[157] Further, "the subjective, unexpressed and uncommunicated thoughts of a party are irrelevant to the material issue of the parties' intent."[158] Contract interpretation is required when the language of an agreement is susceptible to different interpretations.[159]

Citations to the various paragraphs incorporates sources cited, or referred to in the paragraphs, or in their source documents).

[154] The *Mobile/Sierra* rule is that a utility cannot unilaterally change a contract provision by filing a rate schedule, although the Commission does reserve authority to modify contract provisions it determines are not in the public interest.

[155] Initial Decision at ¶ 55.

[156] Initial Decision ¶¶ 58 and 62-63.

[157] *Papago Tribal Utility Authority v. FERC,* 723 F.2d 950 at 955 (1983) ("*Papago*").

[158] *Amerada Hess Pipeline Corp.*, 74 FERC ¶ 61,318 at 62,007 (1996), *aff'd* 75 FERC ¶ 61,302 (1996).

[159] *Papago*, 723 F.2d at 955.

126 There is nothing to be found in the language of the IA which would limit Bluegrass's right to file a tariff to determine compensation LG&E should pay it for reactive power support. The 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. LG&E's argument that § 8.4.4(i) requires the Commission to act *sua sponte* is not borne out by the language of that section, or any other language in the IA. And, 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.

127 LG&E made similar arguments in *IMPA*; however, the Commission found that LG&E had not shown that existing agreements precluded IMPA from being compensated for reactive power and IMPA could file a proposed reactive power tariff for Commission approval.[160] That reasoning applies here; Bluegrass simply filed a proposed rate schedule as permitted by law and not precluded by the IA.

128 ISSUE -- Does Order No. 2003 apply to the proposed reactive power tariff filed by Bluegrass when the Bluegrass/LG&E IA pre-dates Order No. 2003?

129 CONCLUSION -- Order No. 2003 is applicable to the Bluegrass proposed reactive power tariff filing at issue in this case.

130 RATIONALE -- There is no dispute that the Bluegrass/LG&E IA was entered into before the effective date of Order No. 2003. And, Order No. 2003 by its express terms, does not abrogate existing agreements for reactive power compensation.[161] However, as discussed above, Bluegrass has the right under its IA to file a rate schedule; therefore, the Bluegrass/LG&E IA is not abrogated. As Bluegrass pointed out, the Commission settled this question in *Rolling Hills* with its finding that Order No. 2003 applied to a pre-existing IA which contains the same compensation language as appears in IA § 8.4.4(ii).[162]

131 ISSUE -- Does the Bluegrass meet the Qualified Generator requirements of Midwest ISO Schedule 2?

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[160] FERC ¶ 61,008 at 61,021.

[161] Order No. 2003-C at 45.

[162] *Rolling Hills*, 109 FERC at 61,271-73.

132 CONCLUSION -- The Bluegrass proposed reactive power tariff does meet Qualified Generator requirements of Midwest ISO Schedule 2.

133 RATIONALE -- Exhibit MTO-4 is Midwest ISO's response to a Bluegrass data request in which Midwest ISO states that it had received a request from Bluegrass for Qualified Generator Status under Schedule 2 of the Midwest ISO Transmission and Energy Markets Tariff and had certified Bluegrass pursuant thereto. Bluegrass sought the Qualified Generator Status on November 8, 2005, and the request was apparently approved by Midwest ISO on November 21, 2005.[163] The LG&E and Midwest ISO TO argument that Bluegrass may not receive revenues under Schedule 2 before November 21, 2005[164] also fails. The Commission conditionally accepted Bluegrass's proposed reactive power tariff effective March 1, 2005, the MISO Schedule 2 was accepted and made effective January 1, 2005, and the Commission rejected a proposed sixty-day response period.[165]

134. ISSUE -- Should "needs," "value," or "used and useful" be considered in determining appropriate reactive power support compensation for Bluegrass or is such consideration not consistent with Order No. 2003.

135 CONCLUSION -- Consideration of "needs," "value," or "used and useful," in determining appropriate reactive power support compensation for Bluegrass is not consistent with Order No. 2003.

136 RATIONALE -- LG&E, MISO ISO and Staff argue that the reactive power support of Bluegrass is not needed, not of value, and not used and useful. The Commission has held as recently as February 2006, that "needs," "value," or "used and useful," may not be considered. Under Order No. 2003, generators must simply be capable of providing reactive power within a specified range when called on to do so. Generators in the Midwest ISO footprint are to be compensated under Midwest ISO's Schedule 2[166] for their reactive power capacity. A generator is presumed "used and

[163] Ex. MTO-4 and Tr. 108-09.

[164] *See* LG&E IB at 13 and Midwest ISO TO IB at 22.

[165] Bluegrass RB at 6; *MISO I*, 113 FERC at 61,111 and 61,116.

[166] As previously indicated, the Commission conditionally approved LG&E's withdrawal from Midwest ISO on March 17, 2006, and allowed LG&E to join the Southwest Power Pool RTO. On LG&E's withdrawal, if it occurs, from whom and how Bluegrass is compensated may be expected to change.

useful" if capable of providing reactive power.[167]

137 ISSUE -- Is Bluegrass capable of providing reactive power and if so, how much?

138 CONCLUSION -- Bluegrass is capable of providing 360.33 MVARs of reactive power.

139 RATIONALE -- The results of a reactive capability test Bluegrass conducted on November 3, 2005, in accord with ECAR requirements and as required by Midwest ISO Schedule 2, verified Bluegrass's 360.33 MVAR capacity. Midwest ISO certified Bluegrass as a Qualified Generator after considering the ECAR results. Bluegrass uses the MVAR and MVA capability at the generator terminals in conformance with the *AEP* methodology. Staff accepts the 360.33 MVAR figure.[168]

140. On the other hand, LG&E and Midwest ISO TO challenge Bluegrass's claim of having 360.33 MVAR capacity. LG&E points out that Bluegrass only provided 3.9 MVARs between June 6, 2002, through July 7, 2005. LG&E and Midwest ISO TO also point out that Bluegrass was only able to produce 183 MVARs reactive power on August 11, 2005. LG&E notes that Bluegrass has never produced as much as 360 MVARs. However, the ECAR testing results are more persuasive than the subjective views of LG&E and Midwest ISO TO. Bluegrass has the better argument about why its inability to produce over 183 MVARs on one day should not be determinative of its capability. Bluegrass pointed out that a plant could experience problems with equipment from time-to-time that may impact its ability to produce power at a specific moment in time.[169]

141. ISSUE -- What is the appropriate method for determining reactive power compensation for Bluegrass?

140. CONCLUSION -- The appropriate method for determining reactive power compensation for Bluegrass is the *AEP* methodology.

141. RATIONALE -- The Commission has ordered that the *AEP* methodology is to be employed in determining compensation for reactive power.[170] The Commission

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[167] *MISO II*, 114 FERC at 61,649.

[168] Initial Decision at ¶¶ 26, 28, 69, 76, and 117.

[169] Exs. BGC-4 at 12-13, S-1 at 8-9, and MTO-4; Tr. 110.

[170] *FPL Energy Marcus Hook, L.P.*, 111 FERC ¶ 61,268 at 61,838 (2005) ("*Marcus Hook II*").

recognized that parties have concerns with that methodology, but stated the issue was not factual and, therefore, not amenable to case-by-case litigation. Changes have to be implemented on a "generic basis," according to the Commission, and the Commission is reviewing the possible need for changes in Docket No. AD05-1-000.[171] Until, or if such change is forthcoming, we are bound by the Commission's policy on the issue. "The *AEP* methodology relies on an allocation factor to segregate the reactive power function from the real power production function and is based on the capability of a given generator (as opposed to its hours of operation)."[172]

142. ISSUE -- What is the appropriate plant allocator?

143. CONCLUSION -- The appropriate plant allocator is 188.48 MVARs.

144. RATIONALE -- In order to conform to the *AEP* methodology, the product of two ratios is necessary to allocate remaining plant investment. This composite allocator is derived by taking the ratio of the plant's exciter rating to the plant's real power rating (a result of 0.00203 in this case), and then multiplying it by a second ratio, namely, the Maximum MVAR/Nameplate MVAR. Staff claims Bluegrass did not properly include the second ratio. Bluegrass replies that the second ratio was not omitted but instead was estimated as 1.0 (i.e., the numerator and denominator are the same).[173]

145. Mr. Carr, testifying for Bluegrass, explained that he followed the *AEP* methodology by utilizing the Midwest ISO AFC load flow models for March, June, and August 2005, and March and August 2006, which show the Bluegrass units generating at their collective maximum MVAR output. The numerator of this ratio, according to Mr. Carr, is the MVAR output of the Bluegrass units and is the same as the denominator (the reactive capability of the Bluegrass units).[174]

146. In contrast, Mr. Clark, testifying for Staff, examined the operational history of the Bluegrass facility on August 11, 2005, in addition to the operational information from June 2, 2002 through July 21, 2005. From this, he extracted the maximum amount of

[171] *Id*. at 61,838.

[172] *Id*. at 61,838, fn.1, *citing*, *AEP*, 88 FERC ¶ 61,141 and *Principles for Efficient and Reliable Reactive Power Supply and Consumption,* Staff Report, Dkt. No. AD05-1-000 (February 4, 2005).

[173] Initial Decision at ¶¶ 28, 52, and 97.

[174] Exs. BGC-4 at 7, 14, and Attachment B and BGC-4 at 14; Bluegrass IB at 39.

reactive power actually produced (188.48 MVARs) by the Bluegrass facility.[175] Since the reactive power capability of the facility is 360.33 MVARs, the second ratio is 0.509 (188.48 MVAR/360.33 MVAR) instead of 1.0.

147. Staff's argument is persuasive. The Midwest ISO AFC models apparently are used to demonstrate how much reactive power is usually supplied or absorbed at maximum real power capability. As Staff pointed out, "the Midwest ISO AFC models are monthly models used by market participants to determine whether or not there is sufficient transmission capacity to allow participants to sell MWs, and they are not intended or appropriate for reactive power considerations."[176]

148. ISSUE: What is the appropriate overall return and capital structure for Bluegrass?

149. CONCLUSION: The Bluegrass overall return of 8.54% and the capital structure proposed by Bluegrass results in just and reasonable rates.

150. RATIONALE: Bluegrass explained that it believed it appropriate to follow the approach of other generators filing reactive power tariffs accepted by the Commission and use the authorized rate of return of the interconnected utility. That would result in an overall rate of return of 8.54%. Bluegrass explained that an overall rate of return of 8.54% compared favorably with the calculated overall rate of return of 8.71% using Dynegy's capital costs. Testifying for Bluegrass, Mr. Roethemeyer averred that the capital structure used by LG&E did not take into account the sale of Dynegy's midstream business unit and the fact that only Dynegy's generation business unit remained. Mr. Roethemeyer further opined that non-utility customers, like Bluegrass, with no guaranteed customers, had more risk than regulated utilities like LG&E and, therefore, use of a regulated utility's capital structure for establishing reactive power tariffs is appropriate. Bluegrass advocated the Commission-authorized LG&E capital structure for rate of return calculations without reflecting the lease payments Dynegy paid to lease the Bluegrass plant.[177]

151. LG&E stated that if Bluegrass is found entitled to a return (as has been found), the rate should be predicated on Dynegy's actual capital structure and not the hypothetical one that Bluegrass proposed. Dynegy has publicly-traded stock. Bluegrass is a wholly-owned subsidiary of Dynegy. Using LG&E's capital structure is not proper because it is owned by a German non-publicly traded corporation with business operations in Europe

[175] Ex S-1 at 8-9.

[176] Staff RB at 23.

[177] Initial Decision at ¶¶ 39-41.

and a very different risk profile. And, the Commission has held that the rate of return of the transmission provider is not presumptively the appropriate model for reactive power compensation computations.[178]

152. Staff disagreed with LG&E that Bluegrass was a non-utility generator. Mr. Green, testifying for Staff, stated that the rates at issue concerned reactive power and reactive power is a regulated electric utility service. He agreed with Bluegrass that LG&E is an appropriate company to look to for developing the return on capital for Bluegrass, but did not agree that LG&E's specific capital structure and cost rates should be used because LG&E does not have a market-driven capital structure and, in addition, because its parent company is not in the United States. Staff recommends using companies comparable to LG&E as a proxy group.[179]

153. However, Bluegrass has established that its proposed 8.54% overall rate of return is just and reasonable. Neither LG&E nor Staff have shown that the use of the 8.54% overall rate of return of the interconnecting transmission owner, LG&E, as a proxy for Bluegrass is unjust and unreasonable.

154. LG&E's recommendation regarding overall rate of return is not just and reasonable. For one thing, reliance on Dynegy's capital structure suffers from several infirmities. A determinative factor, is the fact that Dynegy's S&P bond rating is 'BBB-'. The Commission has rejected the use of a parent company's 37% common equity ratios as not being representative of utility business after noting the below-investment-grade status of that parent company.[180] Dynegy's common equity ratio of 25.20%[181] is also not representative and, therefore, not appropriate for use in this case.

155. Staff's use of a group of four companies as a proxy for Bluegrass is not appropriate, notwithstanding the fact that LG&E does not issue publicly-traded stock. Staff, as well as does Bluegrass, recognizes that the Commission has accepted a return and capital structure for reactive power generators based on that of the interconnected transmission owner.[182] Bluegrass is interconnected to LG&E, which Staff acknowledges is a subsidiary entity that does not issue publicly-traded stock. Because LG&E does not

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[178] Initial Decision at ¶¶ 88-89.

[179] Initial Decision at ¶¶ 111-14.

[180] *High Island Offshore System, LLC*, 111 FERC 61,043 at 61,158 (2005).

[181] Ex. S-12 at 32.

[182] Ex. S-12 at 32.

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[183] for the proposition that the Commission prefers a market-driven capital structure.

156. Staff's recommendation fails because 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. In fact, the Commission has used the same LG&E cost of capital components, as those advocated here by Bluegrass, as a proxy for IMPA, also a non-public utility generator. LG&E made similar arguments against use of its capital structure in the *IMPA* case, which the Commission rejecting stating that: "[t]he Commission has accepted the use of proxies by non-public utility generators like IMPA that are not subject to traditional rate regulations."[184]

FINDINGS AND CONCLUSIONS

157. This FPA proceeding is subject to the jurisdiction of the Commission.

158. Bluegrass is a natural gas-fired peaking generating facility located near Oldham, Kentucky. Bluegrass, an exempt wholesale generator (or non-utility generator not generally subject to traditional rate regulation), began service in June 2002. Bluegrass sells power generated at its facility to wholesale customers at market-based rates. Bluegrass also provides reactive power support for which it is compensated separately under an IA between it and LG&E filed with the Commission on July 13, 2001.

159. Bluegrass filed Rate Schedule FERC No. 2 on January 31, 2005, under which it requested a cost-based yearly revenue requirement for Reactive Support and Voltage Control Reactive Power. The tariff to be superseded is the July 13, 2001, Bluegrass/LG&E IA.

160. Bluegrass is interconnected with the LG&E transmission system. LG&E Is a transmission-owning member of Midwest ISO. Midwest ISO makes arrangements with control area operators, like LG&E, to obtain reactive power from generation sources, like Bluegrass.

161. LG&E protested the Bluegrass filing. Midwest ISO and the Midwest ISO TO filed timely motions to intervene. On March 25, 2005, the Commission conditionally

[183] *Kentucky-West Virginia Gas Co.*, 2 FERC ¶ 61,139 *reh'g* 3 FERC ¶ 61,051 (1978).

[184] *IMPA*, 114 FERC ¶ 61,008 at 61021.

accepted Bluegrass's rate schedule, subject to refund, and set this proceeding for evidentiary hearing for a determination of the justness and reasonableness of Bluegrass's proposed rate schedule. The Commission held the hearing in abeyance to allow for settlement discussions.

162. The settlement efforts were unsuccessful and were terminated on May 26, 2005, and the matter proceeded to hearing to hearing as stated in detail in the "Procedural History" section of this Initial Decision and incorporated in these "Further Conclusions."

163. The two components of electrical power are: real power, which is the electrical power measured in megawatts (MW); and reactive power (often referred to as VARs or VAr) which is measured in Mega Volt Amperes Reactive or MVARs (also called megavars). Reactive power is responsible for creating the magnetic fields needed to operate transformers, transmission lines and electric motors. Reactive power ordinarily can be supplied by electric generators (as in the instant proceeding) or by placing static devices such as inductors and capacitors on the transmission and distribution systems.

164. Reactive power provides support to maintain adequate voltage at all points in the power system. It is an inherent and necessary component in the operation of an AC power system. Reactive power helps maintain proper voltage levels so that equipment does not malfunction or is not damaged and systems do not collapse. Reactive power cannot be transported over long distances as it is quickly used up by transmission system components.

165. Bluegrass properly filed Rate Schedule FERC No. 2 with the Commission under § 8.4.4(i) of the IA, and LG&E is obliged under § 8.4.4(i) to pay Bluegrass consistent with a Commission-approved tariff for Bluegrass reactive power support.

166. Issues raised but not discussed, were considered and found to be without merit.

167. Findings and conclusions stated in the "Issues/Conclusions/Rationale" section of this Initial Decision are incorporated in this "Findings and Conclusions" section, even if not restated in this section.

168. With the exception of the proposed plant allocator, Bluegrass has met its burden of proof supporting its proposed reactive power support cost.

169. Rates that are consistent with the findings and conclusions of this Initial Decision will be just and reasonable.

ORDER

170. IT IS ORDERED, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that:

(a) within thirty (30) days from the issuance of the final order of the Commission in this proceeding, Bluegrass shall conform its rate filing to the CONCLUSIONS of this Initial Decision; and

(b) within sixty (60) days from the issuance of the final order shall refund amounts that exceed rates found just and reasonable with interest at rates found appropriate by the Commission.

Charlotte J. Hardnett
Presiding Administrative Law Judge