129 FERC ¶ 61,041
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Suedeen G. Kelly, Marc Spitzer,
and Philip D. Moeller.

Midwest ISO Transmission Owners | Docket No. ER08-15-002

ORDER DENYING REHEARING

(Issued October 15, 2009)

1. Several parties[1] request rehearing of the Commission's March 31, 2008 order[2] accepting Schedule 2-A for filing. Schedule 2-A revised the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) Open Access Transmission and Energy Markets Tariff (Tariff) to institute zone-based[3] compensation for Reactive Supply and Voltage Control from Generation or Other Sources Service (reactive power). For the reasons discussed below, we deny rehearing.

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[1] The parties seeking rehearing are: Dynegy Midwest Generation, Inc. and Renaissance Power, LLC (Dynegy), Exelon Corporation (Exelon), FirstEnergy Solutions Corp. (FirstEnergy), Michigan Public Power Agency (Michigan Public Power), and Reliant Energy, Inc. (Reliant).

[2] *Midwest ISO Transmission Owners*, 122 FERC ¶ 61,305 (2008) (March 2008 Order).

[3] Under the license-plate rate design that exists in the Midwest ISO, the Midwest ISO's footprint is divided into a number of transmission pricing zones, typically based on the boundaries of individual transmission owners or groups of transmission owners. Customers taking transmission service for delivery to load within the Midwest ISO pay a rate based on the embedded cost of the transmission facilities in the transmission pricing zone where the load is located. The zonal boundaries used for the license-plate rate design are also used for reactive power compensation under the Tariff.

I. **Background**

2. Schedule 2-A allows transmission owners to choose which reactive power compensation provisions in the Tariff—those in Schedule 2 or those in Schedule 2-A—will apply in their zones.[4] In a zone governed by Schedule 2, reactive power compensation will be paid on a capability basis; that is, each Qualified Generator can collect a cost-based revenue requirement that reflects its capability to provide reactive power, including its capability to provide reactive power inside the deadband. In contrast, in a zone governed by Schedule 2-A, reactive power compensation will be paid on a per MVar basis; each Qualified Generator will be paid only for the reactive power it provides outside the deadband.[5] Prior to the March 2008 Order, Schedule 2 was the only option in the Tariff.

3. Schedule 2-A was submitted for filing under section 205 of the Federal Power Act[6] by a subset of Midwest ISO transmission owners (Filing Transmission Owners).[7] Several protesters argued that only Midwest ISO, as the independent Regional Transmission Organization (RTO), could propose to modify the Tariff. The protesters

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[4] Details about the events leading up to the filing of Schedule 2-A are described more fully in the March 2008 Order.

[5] This compensation is fixed at the higher of their lost opportunity costs or $2.20 per MVarh. Under Schedule 2-A, a single deadband applies to all Qualified Generators within a given zone unless that deadband conflicts with an individual Qualified Generator's interconnection agreement, in which case the deadband specified in the interconnection agreement would apply to that Qualified Generator.

[6] 16 U.S.C. § 824d(a) (2006). Midwest ISO joined the filing as the administrator of the Tariff but it took no position on the merits of Schedule 2-A.

[7] This subset consists of: Ameren Services Company, as agent for Union Electric Company, Central Illinois Public Service Company, Central Illinois Light Company, and Illinois Power Company; American Transmission Company, LLC; City of Columbia Water and Light Department (Columbia, MO); City Water, Light & Power (Springfield, IL); Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indianapolis Power & Light Company; Minnesota Power (and its subsidiary Superior Water, Light & Power Co.); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; and Southern Minnesota Municipal Power Agency.

also argued, inter alia, that the Filing Transmission Owners should have submitted Schedule 2-A under section 206 of the Federal Power Act[8] rather than under section 205, that Schedule 2-A fails to meet Commission imposed criteria for amendments to Schedule 2, and that zone-based reactive power compensation conflicts with Commission precedent, specifically Order Nos. 2003 and 2003-A.[9] In the March 2008 Order, the Commission rejected these arguments and accepted Schedule 2-A for filing.

II. <u>Rehearing Requests</u>

A. <u>Filing Rights under Section 3.9 of the Filing Rights Settlement</u>

1. <u>March 2008 Order</u>

4. The Filing Transmission Owners relied on section 3.9 of the Filing Rights Settlement between Midwest ISO and the Midwest ISO transmission owners for the authority to submit Schedule 2-A.[10] The Filing Rights Settlement allocates section 205 filing rights between Midwest ISO and the transmission owners. Section 3.9 allocates to both transmission owners and Midwest ISO the right to submit section 205 filings to govern the rates, terms, and conditions applicable to the provision of ancillary services:

> Both [t]ransmission [o]wners that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff]) and the Midwest ISO shall have the right to submit filings under [Federal Power Act] section 205 to govern the rates, terms, and conditions applicable to the provision of ancillary services. A [t]ransmission [o]wner shall not be required to

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[8] 16 U.S.C. § 824e (2006).

[9] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007).

[10] Settlement Agreement between Transmission Owners and Midwest ISO on Filing Rights, Docket No. RT01-87-010 (Filing Rights Settlement); *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,380 (2005) (accepting the Filing Rights Settlement for filing) (Filing Rights Order).

> follow the governance and coordination provisions of [s]ections 4 and 5 of this [Filing Rights Settlement] to exercise the filing right provided for in this [s]ection 3.9; provided, however, that any ancillary service proposal that has regional impacts shall be subject to the governance and coordination provisions of [s]ections 4 and 5 of this [Filing Rights Settlement].

5. Several parties challenged the Filing Transmission Owners' reliance on section 3.9. For example, Dynegy argued that section 3.9 allocates to transmission owners the right to make section 205 filings that modify only their individual reactive power rates, not filings that modify the Tariff.[11] Dynegy pointed to language in section 3.9 that appears to allocate filing rights only to transmission owners "that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff])," and asserted that because transmission owners in this subset share the incentive to recover costs associated with providing ancillary services, the purpose of section 3.9 must be to protect the rights of these transmission owners to make filings that pertain to their individual rates. Dynegy also argued that the Filing Transmission Owners violated section 3.9 by allowing transmission owners that do not own or control generation or other resources capable of providing ancillary services to join in filing Schedule 2-A.

6. Although it found that section 3.9 is ambiguous, the Commission also found that when read in its entirety, and in the context of section 3 of the Filing Rights Settlement, section 3.9 allocates to transmission owners the right to make section 205 filings that modify the Tariff. The Commission rejected Dynegy's alternative interpretation, explaining that section 3.9 allocates to transmission owners and to Midwest ISO the same section 205 filing right:

> Section 3.9 states that "*[b]oth* [t]ransmission [o]wners . . . *and* the Midwest ISO *shall have the right* to submit filings under [Federal Power Act] section 205 to *govern* the rates, terms, and conditions applicable to the *provision of ancillary services*." This language indicates that transmission owners and the Midwest ISO share the same section 205 filing right, which is "the right to submit filings under [Federal Power Act] section 205 to govern the rates, terms, and conditions

[11] New Covert Generating Company, LLC and Reliant also challenged the Filing Transmission Owners' interpretation of section 3.9. However, the Commission rejected their arguments in the March 2008 Order, and they have not sought rehearing.

> applicable to the provision of ancillary services." There is no language in section 3.9 that distinguishes the section 205 filing right granted to the transmission owners from the section 205 filing right granted to the Midwest ISO.[[12]]

7. The Commission further explained that because section 3.9 allocates to transmission owners and to Midwest ISO the same section 205 filing right, Dynegy's claim that the filing right granted in section 3.9 relates only to a transmission owner's individual rates would render section 3.9 meaningless with respect to Midwest ISO. Midwest ISO itself does not own or control generation capable of providing ancillary services and therefore could not make a section 205 filing related to those services.[13]

8. The Commission also found that Dynegy's interpretation of section 3.9 was inconsistent with language in section 3.9 that subjects all ancillary service proposals that have regional impacts to the governance and coordination provisions of sections 4 and 5 of the Filing Rights Settlement. The Commission explained that there was no reason why section 3.9 would contemplate transmission owners submitting section 205 filings that have "regional impacts" if it merely authorized transmission owners to make section 205 filings that pertain only to their individual ancillary service rates.[14]

9. The Commission did agree with Dynegy that section 3.9 allocates filing rights only to the subset of transmission owners that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff]). However, the Commission found that this restriction did not affect its conclusion that, when read as a whole, section 3.9 allocates to transmission owners in the subset the section 205 filing rights necessary to file Schedule 2-A. The Commission also determined that because Schedule 2-A provides all transmission owners, including those that do not have filing rights under section 3.9, with the option of continuing under Schedule 2 or switching to Schedule 2-A, there was no practical consequence to the possibility that transmission owners without filing rights may have joined in filing Schedule 2-A.[15]

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[12] March 2008 Order, 122 FERC ¶ 61,305 at P 24 (emphasis in original) (footnotes omitted).

[13] *Id*. P 24.

[14] *Id*. P 25.

[15] *Id*. P 27.

2. Arguments on Rehearing

10. On rehearing, Dynegy argues that the Commission acknowledged, but then ignored, language in section 3.9 that limits the reservation of section 205 filing rights to transmission owners "that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff])." Dynegy claims that this language has a direct bearing on section 3.9's scope, and asserts that while both Midwest ISO and transmission owners with filing rights can file rate schedules with the Commission, section 3.9 provides that transmission owners can file only to establish the rates, terms, and conditions for their own recovery of non-Schedule 1 ancillary services.[16] Dynegy contends that the Commission erred by failing to give effect to section 3.9's plain language, and by expanding the scope of permitted filings and the class of transmission owners permitted to file.[17]

11. Exelon argues that the Commission should have rejected Schedule 2-A as inconsistent with section 3.9, regardless of the Filing Transmission Owners' filing rights, because non-uniform reactive power compensation inside Midwest ISO is inherently unjust and unreasonable. Exelon maintains that if section 3.9 grants transmission owners and Midwest ISO the same filing rights, then it follows that the Filing Transmission Owners here do not have greater filing rights than Midwest ISO and cannot successfully file a reactive power rate design that would be rejected if filed by Midwest ISO. Exelon argues that the Commission would have rejected Schedule 2-A if it had been filed by Midwest ISO because it discriminates between similarly situated generators.

3. Commission Determination

12. We deny rehearing of our finding that section 3.9 allows a subset of transmission owners to submit section 205 filings that amend the reactive power compensation provisions in the Tariff. We also reiterate our previous conclusion that Dynegy's interpretation would render section 3.9 internally inconsistent.

13. Dynegy argues that the words "that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff])" have a direct bearing on section 3.9's scope because they specify which transmission owners have filing rights and what kind of filing rights they have.

14. We disagree. As the Commission stated in the March 2008 Order, the language at issue defines the class of transmission owners eligible to submit filings pursuant to

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[16] Dynegy Rehearing Request at 22.

[17] *Id*.

section 3.9 (i.e., those "that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff]));"[18] it does not limit the filing rights of those transmission owners. To reach that conclusion, one must read into the language intent that is not suggested from either the language itself or section 3.9.

15. In its initial protest, Dynegy made clear that its interpretation lacks a textual basis when it asserted that to understand section 3.9, the Commission needed to understand "language that ha[d] not been included."[19] Dynegy claimed that the "language that ha[d] not been included" was an explanation that section 3.9 permits eligible transmission owners to file individual rate schedules because all eligible transmission owners share the incentive to protect this right.[20] On rehearing, however, Dynegy suggests that the text of section 3.9 unambiguously expresses the parties' intent.[21]

16. We highlight this difference between Dynegy's characterization of section 3.9 on rehearing and its characterization of section 3.9 in its initial protest to underscore that if Dynegy's interpretation of section 3.9 is plausible, it is only because Dynegy supplies "language that has not been included." Nothing in section 3.9 suggests a relationship between the language that defines the class of transmission owners eligible to make section 205 filings and the nature of the right allocated in section 3.9. The assumption of such a relationship, without which Dynegy's interpretation cannot work, rests entirely on speculation that has no support in section 3.9 or the Filing Rights Settlement.

17. Moreover, even if we were to assume that Dynegy is correct and that there is some relationship between the language that defines the class of transmission owners eligible to make section 205 filings and the nature of the right allocated in section 3.9, we could not conclude anything about the substance of that relationship from either section 3.9 or the Filing Rights Settlement. Contrary to Dynegy's implication, the fact that section 3.9 allocates filing rights to transmission owners "that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the [Tariff])" does not entail the conclusion that the filing rights of these transmission owners are limited by their shared incentive to retain their individual filing rights only to establish the rates, terms, and conditions for their own provision of non-Schedule 1

[18] March 2008 Order, 122 FERC ¶ 61,305 at P 27.

[19] Dynegy Protest at 10 ("To understand the language in [s]ection 3.9, it is necessary to understand language that has not been included.").

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

[21] Dynegy Rehearing Request at 22.

ancillary services. These transmission owners might share this incentive, but they might also share the incentive to retain the right to submit filings that modify the Tariff provisions under which they and others recover their ancillary services costs. Nothing in section 3.9 or the Filing Rights Settlement indicates which shared incentive, if either, should govern the assumed relationship.

18. Dynegy's interpretation of section 3.9 is implausible for another reason. As the Commission explained in the March 2008 Order, Dynegy's interpretation would render section 3.9 internally inconsistent and meaningless with respect to Midwest ISO. Section 3.9 provides that both transmission owners and Midwest ISO shall have the right to submit section 205 filings to govern the rates, terms, and conditions applicable to the provision of ancillary services; it does not distinguish between the right granted to transmission owners and the right granted to Midwest ISO. Dynegy's interpretation, which reads section 3.9 as a reservation of transmission owners' rights to file individual ancillary services rate schedules, is an empty letter with respect to Midwest ISO because Midwest ISO is an independent RTO that does not own or control generation capable of providing ancillary services and therefore cannot make a section 205 filing related to those services.

19. On rehearing, Dynegy makes no effort to reconcile its interpretation of section 3.9 with this analysis, except to recognize that section 3.9 allocates filing rights to both transmission owners and Midwest ISO. Dynegy does not attempt to explain the substance of the filing right that Midwest ISO has under its interpretation of section 3.9; it merely states that Midwest ISO "can file rate schedules with the Commission."[22] Dynegy also fails to point out where section 3.9 makes a distinction between the right allocated to transmission owners and the right allocated to Midwest ISO, and it does not address our finding that section 3.9 allocates to transmission owners and to Midwest ISO the same filing right. Dynegy merely reasserts its initial arguments, as if making them for the first time.

20. Moreover, Dynegy's interpretation of section 3.9 cannot be squared with the language in section 3.9 that subjects ancillary services filings that have regional impacts to the governance and coordination provisions of sections 4 and 5 of the Filing Rights Settlement. The general rule in section 3.9 is that transmission owners are not required to follow the governance and coordination provisions of sections 4 and 5 of the Filing Rights Settlement. There is a specific exception, however, for ancillary service proposals that have regional impacts:

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[22] *Id.*

> A [t]ransmission [o]wner shall not be required to follow the governance and coordination provisions of [s]ections 4 and 5 of this [Filing Rights Settlement] to exercise the filing right provided for in this [s]ection 3.9; provided, however, that any ancillary service proposal that has regional impacts shall be subject to the governance and coordination provisions of [s]ections 4 and 5 of this [Filing Rights Settlement].

The logical implication of this sentence is that transmission owners can submit filings that have regional impacts.[23] As the Commission explained in the March 2008 Order, this implication is inconsistent with Dynegy's claim that transmission owners can submit filings that pertain only to their individual ancillary services rates. On rehearing, Dynegy does not address this aspect of the March 2008 Order.

21. Additionally, after further review of the Filing Rights Settlement, we find that the Commission's interpretation of section 3.9 in the March 2008 Order is further supported by a definite and discernable pattern in the Filing Rights Settlement. There are several instances where the Filing Rights Settlement allocates to transmission owners the exclusive right to submit a section 205 filing[24] and several instances where it allocates filing rights to transmission owners and to Midwest ISO.[25] In both cases, the Filing Rights Settlement employs consistent language. For example, when the Filing Rights Settlement allocates rights exclusively to transmission owners, it states that the transmission owners "shall possess the full and exclusive right" to submit the filing. In contrast, when the Filing Rights Settlement allocates rights to both transmission owners and to Midwest ISO it states that "both the [t]ransmission [o]wners and the Midwest ISO shall possess the right." Since section 3.9 is ambiguous, we find that its use of the "both shall possess" rather than the "full and exclusive right" language confirms our finding that it allocates the same filing right both to transmission owners and to Midwest ISO and, thus, supports our reading of its provisions.

22. We also disagree with Dynegy's claim that the Commission ignored language in section 3.9 that describes the class of transmission owners eligible to submit a filing pursuant to section 3.9 by allowing non-eligible transmission owners to join the filing. The Commission interpreted the language as specifying which transmission owners are

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[23] In their initial filing, the Filing Transmission Owners stated that they complied with sections 4.1 and 5.1 of the Filing Rights Settlement. Filing Transmission Owners Initial Filing at 5. No party has alleged otherwise.

[24] *See*, *e.g*. sections 3.1, 3.3(a), 3.4, 3.5, 3.7, and 3.8.

[25] *See*, *e.g*. sections 3.5(iii)(b) and 3.6.

eligible to file pursuant to section 3.9, but found that the mix of eligible and ineligible transmission owners in the group that submitted Schedule 2-A did not have any practical consequence. This is because Schedule 2-A could have been filed by the eligible transmission owners alone and would still have applied to all transmission owners.[26] Moreover, whether ineligible transmission owners joined the group that filed Schedule 2-A is irrelevant to whether eligible transmission owners could file Schedule 2-A. On rehearing, Dynegy has not challenged any of these conclusions.

23. Like Dynegy, Exelon has offered no arguments that address the Commission's actual interpretation of section 3.9. Instead, Exelon contends that the Commission's interpretation of section 3.9 must be wrong because it allows the Filing Transmission Owners to file a rate schedule that unduly discriminates between similarly situated generators. This argument rests on the premise that non-uniform reactive power compensation inside Midwest ISO is inherently unjust and unreasonable. We rejected this argument and explained our reasoning in the March 2008 Order. We reject it again in this order and explain our reasoning once more below.[27]

B. Schedule 2-A and Sections 205 and 206 of the Federal Power Act

1. March 2008 Order

24. The Filing Transmission Owners submitted Schedule 2-A under section 205 of the Federal Power Act rather than under section 206. In its protest, Dynegy argued that Schedule 2-A was not a valid section 205 filing because it would revise the filed rates of non-filing utilities by eliminating their reactive power compensation. Dynegy argued that the Filing Transmission Owners should have followed what it described as the two-step process employed in similar cases—first making a section 205 filing to eliminate reactive power compensation under their respective tariffs, then filing a separate section 206 proceeding to address the rates of unaffiliated generators.

25. The Commission rejected Dynegy's argument and found that Schedule 2-A was a valid section 205 filing.[28] The Commission also found that because Schedule 2-A was appropriately filed under section 205, the Filing Transmission Owners needed only to demonstrate that Schedule 2-A was just and reasonable and did not need to show that

[26] If the *only* transmission owners that submitted Schedule 2-A were from among those ineligible to file pursuant to section 3.9, then we would have a different situation and potentially a different outcome.

[27] *See infra* P 70-83.

[28] March 2008 Order, 122 FERC ¶ 61,305 at P 31.

Schedule 2 or any rates filed under Schedule 2 were unjust, unreasonable, or unduly discriminatory.[29]

26. The Commission further explained that Schedule 2-A was, in fact, the first step in the two-step process described by Dynegy, and that the only material difference between Schedule 2-A and the section 205 filings made in similar cases was that Schedule 2-A gives transmission owners the choice, on a zone-by-zone basis, of eliminating or maintaining reactive power compensation inside the deadband.[30] The Commission also explained that because Schedule 2-A was a section 205 filing, it did not abrogate or eliminate any filed rate schedule, and therefore, transmission owners that switch to Schedule 2-A remain obligated to compensate generators in their zones pursuant to the generators' filed rate schedules unless and until those rate schedules are successfully challenged under section 206.[31] Consequently, the Commission directed the Filing Transmission Owners to remove from Schedule 2-A a prohibition on Qualified Generators maintaining rate schedules that require compensation for reactive power inside the deadband.[32]

2. Arguments on Rehearing

27. On rehearing, Dynegy challenges the Commission's decision to accept Schedule 2-A as a section 205 filing. Dynegy argues that the Commission should have found that the Filing Transmission Owners were required to submit Schedule 2-A as a section 206 filing and to prove that Schedule 2 is unjust, unreasonable, and unduly discriminatory. Dynegy also argues that the Commission's interpretation of section 3.9 violates the Federal Power Act because it allows the Filing Transmission Owners to use section 205 to revise the rates of non-filing utilities.

28. Dynegy contends that *PJM Interconnection, L.L.C.*[33] supports its argument. In *PJM*, the Commission rejected an attempt by Virginia Electric and Power Company to unilaterally change a transmission rate charged jointly with other transmission owners. Dynegy claims that in rejecting the attempt, the Commission relied on the basic principle that utilities can change only their own rates under section 205, and that any attempt to

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[29] *Id*. P 37.

[30] *Id*. P 31.

[31] *Id*. P 38.

[32] *Id*.

[33] 110 FERC ¶ 61,234 (2005) (*PJM*).

change another utility's rates must be made pursuant to section 206. Dynegy notes that in *PJM* the Commission acknowledged that utilities may voluntarily relinquish their section 205 filing rights, but argues that the Commission lacks authority to enhance or eliminate section 205 filing rights. Dynegy claims that the Commission erroneously enhanced the Filing Transmission Owners' section 205 filing rights by allowing them to use section 205 to change the rates of non-filing utilities.

3. Commission Determination

29. We deny rehearing. Dynegy's assertion that Schedule 2-A revises the rates of non-filing generators ignores critical aspects of the March 2008 Order.

30. In the March 2008 Order, the Commission stated that because Schedule 2-A was a section 205 filing, it did not, and could not, abrogate, eliminate, or revise any existing rate schedule.[34] The Commission also explained specifically that transmission owners that switch to Schedule 2-A remain obligated to compensate generators in their zones pursuant to the generators' filed rate schedules unless and until those rate schedules are successfully challenged under section 206.[35] Moreover, precisely because it would inappropriately require revisions to the rates of non-filing utilities, the Commission directed the Filing Transmission Owners to remove from Schedule 2-A a prohibition on Qualified Generators maintaining rate schedules that require compensation for reactive power inside the deadband.[36] Thus, there are no grounds for Dynegy's claim that Schedule 2-A revises the rates of non-filing generators, or its assertions that the Commission expanded the scope of section 205 or allowed section 205 to be used to accomplish section 206's purposes.

C. Schedule 2-A and the Midwest ISO Schedule 2 Orders

1. March 2008 Order

31. In its protest, Dynegy argued that Schedule 2-A directly conflicts with *MISO I* and *MISO IV*, two of the Commission's Schedule 2 Orders.[37] In *MISO I*, the Commission

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[34] March 2008 Order, 122 FERC ¶ 61,305 at P 38.

[35] *Id*.

[36] *Id*.

[37] Schedule 2 formerly authorized reactive power compensation only for generators that were either owned by or affiliated with transmission owners; it had no mechanism to compensate non-affiliated generators. The Commission found under section 206 of the Federal Power Act that this discrepancy was unjust, unreasonable, and

(continued…)

found that "only a Schedule 2 that includes all generators, including [independent power producers], is just and reasonable and not unduly discriminatory or preferential." [38] Dynegy argued that this finding requires Midwest ISO to apply Schedule 2 to all generators, and that Schedule 2-A undermines this requirement because it permits transmission owners to decide that Schedule 2 will not apply to generators in their zones.

32. Dynegy also argued that in *MISO IV* the Commission created an exception to the "all generators" rule. In *MISO IV*, the Commission stated that "[g]oing forward, parties may propose a rate for all generators that compensates them comparably for the level of reactive power actually needed and used," and that it expected that "reliability would be factored into any proposal that may be made."[39] Dynegy read this statement to mean that the only exception to the requirement to apply Schedule 2 to all generators is if Midwest ISO adopts a "needs" test that factors in reliability and applies comparably to all generators.[40] Dynegy argued that Schedule 2-A does not qualify as a needs test or factor in reliability.

33. In the March 2008 Order, the Commission found that Dynegy read *MISO I* and *MISO IV* out of context. The Commission explained that these orders discuss potential revisions to Schedule 2, which does not permit transmission owners to choose whether or not to pay compensation for reactive power inside the deadband. The Commission stated that the considerations outlined in these orders apply differently in the context of Schedule 2-A, which does permit transmission owners to make this choice. The Commission also noted that Schedule 2-A complies with the comparability requirement, which it stated was behind the considerations discussed in *MISO I* and *MISO IV*.[41]

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unduly discriminatory and directed the Midwest ISO to revise Schedule 2 to compensate all generators on a comparable basis. Subsequently, the Midwest ISO filed, and the Commission accepted, a revised Schedule 2. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,005 (2004), *order on reh'g*, 110 FERC ¶ 61,267 (2005) (*MISO I*), *order on compliance filing*, 113 FERC ¶ 61,046 (2005) (*MISO II*), *order on reh'g and compliance filing*, 114 FERC ¶ 61,192 (2006) (*MISO III*), *order on reh'g and compliance filing*, 116 FERC ¶ 61,283 (2006) (*MISO IV*) (collectively, Schedule 2 Orders).

[38] Dynegy Rehearing Request at 9-10 (citing *MISO I*, 109 FERC ¶ 61,005 at P 40 (emphasis added)).

[39] *Id*. at 10 (citing *MISO IV*, 116 FERC ¶ 61,283 at P 23).

[40] Dynegy Protest at 26 -34.

[41] March 2008 Order, 122 FERC ¶ 61,305 at P 73.

2. **Arguments on Rehearing**

34. On rehearing, Dynegy renews its claim that *MISO I* and *MISO IV* require all generators to collect reactive power compensation pursuant to Schedule 2, unless a suitable needs test is developed.[42] Dynegy argues that Schedule 2-A does not qualify as a needs test, but that Schedule 2-A will nevertheless allow transmission owners to unilaterally abandon the requirement that Schedule 2 apply to all generators.[43]

35. Dynegy further argues that Schedule 2-A effectively gives transmission owners the ability to determine which generators can collect compensation for providing reactive power inside the deadband,[44] and that the testimony of the Filing Transmission Owners' own witness demonstrates that they regard Schedule 2-A as an effort to eliminate such compensation.[45] Dynegy concludes from this testimony and from the text of Schedule 2-A[46] that Schedule 2-A's "true purpose" is to amend Schedule 2 to give transmission owners the discretion to eliminate compensation for reactive power inside the deadband.[47]

36. Dynegy also argues that the Commission erroneously treated Schedule 2-A as a discrete schedule under the Tariff rather than as an amendment to Schedule 2. As a consequence, Dynegy argues that the Commission failed to recognize that Schedule 2-A is a collateral attack on *MISO I* and *MISO IV*.[48]

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[42] Dynegy Rehearing Request at 9-12; 18-19.

[43] *Id*. at 19.

[44] *Id*. at 16-17.

[45] *Id*. at 17.

[46] Dynegy emphasizes the sentence: "No Qualified Generator shall maintain a service schedule or tariff provision pertaining to the production of reactive power that imposes or may impose charges associated with the supply of reactive power within the [d]eadband." The Commission, however, ordered this language to be removed. March 2008 Order, 122 FERC ¶ 61,305 at P 38.

[47] Dynegy Rehearing Request at 18.

[48] *Id*. at 16.

3. Commission Determination

37. We deny rehearing. As the Commission explained in the March 2008 Order, Dynegy reads *MISO I* and *MISO IV* out of context.

38. Dynegy argues that *MISO I* and *MISO IV* require Schedule 2 to apply to all generators unless a suitable needs test is developed, and that Schedule 2-A is a collateral attack on this requirement because it is not a needs test, but nevertheless allows transmission owners to abandon Schedule 2. The essential element of this argument is the premise that *MISO I* requires Schedule 2 to apply to all generators, which Dynegy attempts to support by citing the Commission's finding in *MISO I* that only a Schedule 2 that includes all generators is just and reasonable. Dynegy reads this finding to establish the categorical rule that, barring a needs test, every generator must collect reactive power compensation pursuant to Schedule 2 and no generator can collect compensation pursuant to a different schedule. On the surface, this appears to be a reasonable reading of a seemingly unequivocal Commission finding; however, a closer look at *MISO I* reveals that Dynegy's reading is an inaccurate and misleadingly broad interpretation of a decision that is properly understood only in light of the dispute then before the Commission.

39. The Commission did not rule on Schedule 2 in a vacuum; in *MISO I*, the Commission examined it in the context of a controversy over reactive power compensation for unaffiliated generators. Previously, Schedule 2 authorized reactive power compensation only for affiliated generators. Midwest ISO proposed to remedy this discrepancy and provide compensation for unaffiliated generators by adding Schedule 21 to the Tariff. Schedule 21, however, would have compensated unaffiliated generators on substantially different terms than Schedule 2 compensated affiliated generators. Consequently, in *MISO I* the Commission rejected Schedule 21 as unduly discriminatory.

40. The Commission did not stop there. Because Schedule 2 compensated only affiliated generators, the Commission exercised its authority under section 206 of the Federal Power Act and found that Schedule 2 was unjust, unreasonable, and unduly discriminatory.[49] The Commission explained that "only a Schedule 2 that includes all generators, including [independent power producers], is just and reasonable and not unduly discriminatory or preferential," and directed Midwest ISO to revise Schedule 2 to compensate all generators—affiliated and unaffiliated—on a comparable basis.[50]

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[49] *MISO I*, 109 FERC ¶ 61,005 at P 39.

[50] *Id*. P 40.

41. Thus, while *MISO I* requires that Schedule 2 apply to all generators, it does not establish the kind of categorical requirement envisioned by Dynegy. When the Commission stated that Schedule 2 must compensate all generators, it was in the specific context of rejecting a Schedule 2 that unduly discriminated *on the basis of affiliation*. The purpose of the Commission's directive to compensate all generators was to erase the distinction between affiliated and unaffiliated generators; it was not to forbid a zone-based approach that compensates affiliated and unaffiliated generators in the same zone comparably but allows for different zones to employ different schedules. *MISO I* was not a universal mandate that every generator must, for all time, collect reactive power compensation pursuant to Schedule 2, and it was not a blanket prohibition on generators ever collecting compensation pursuant to a different schedule; it was a specific rejection of discrimination on the basis of affiliation.

42. A brief comparison between proposed Schedule 21 and Schedule 2-A illustrates the point. Schedule 21 would have applied only to unaffiliated generators; thus, if the Commission had accepted Schedule 21 and left the then-existing Schedule 2 in place, affiliated and unaffiliated generators would still receive compensation under different schedules. Discrimination on the basis of affiliation would continue to exist. Moreover, if the Commission had rejected Schedule 21, but left Schedule 2 intact, undue discrimination would have continued to exist because Schedule 2 would still have applied only to affiliated generators. These are the outcomes that the Commission rejected in *MISO I*.

43. In contrast to Schedule 21, Schedule 2-A does not create or perpetuate undue discrimination on the basis of affiliation; instead, it applies equally to both affiliated and unaffiliated generators. Under Schedule 2-A, all generators in the same zone—affiliated and unaffiliated—collect reactive power compensation on the same basis. There is no discrimination based on affiliation because whether a generator collects reactive power compensation pursuant to Schedule 2 or Schedule 2-A is independent of its affiliation.

44. Thus, Dynegy's insistence on classifying Schedule 2-A as an amendment to Schedule 2 misses the mark. Whether Schedule 2-A "amends" Schedule 2 is relevant for Dynegy only insofar as it supports the premise that *MISO I* creates a categorical requirement that, absent a needs test, every generator must receive compensation under Schedule 2. If *MISO I* created such a requirement, then Schedule 2-A would, in fact, amend Schedule 2. However, *MISO I* does not create such a requirement; it merely establishes that Schedule 2 cannot discriminate on the basis of affiliation. Consequently, there is no significance to whether Schedule 2-A is understood as an amendment to

Schedule 2, an independent rate schedule, or both because the fundamental predicate that would give the designation any substantive meaning does not exist.[51]

45. Additionally, the nonexistence of the type of categorical requirement envisioned by Dynegy undermines Dynegy's interpretation of *MISO IV*. Dynegy claims that in *MISO IV* the Commission created a needs test exception to the general rule that Schedule 2 must apply to all generators; the Commission cannot, however, create an exception to a non-existent rule. Dynegy's reading of *MISO IV* also misleadingly implies that the Commission raised the possibility of a needs test in relation to Schedule 2 as part of a speculative evaluation of permissible modifications to Schedule 2. In fact, the Commission discussed the possibility of a needs test only in response to repeated attempts by transmission owners to include one in Schedule 2.

46. The Schedule 2 submitted to comply with the Commission's directive in *MISO I* provided compensation for affiliated and unaffiliated generators on a capability basis, but it also contained language that required generators to demonstrate that their reactive power was needed. In *MISO II*, the Commission ordered Midwest ISO to remove this language.[52] Several transmission owners sought rehearing, arguing that there should be no automatic entitlement to compensation where reactive power is not needed, or used and useful to ratepayers. In *MISO III*, the Commission denied rehearing and explained that the imposition of a needs test would violate the principle of comparability because it would be applied only to new generation, while existing generation, most of which was owned by or affiliated with transmission owners, would collect compensation on a capability basis.[53] The Commission further explained that Schedule 2 compensates generators on a capability basis, and that a generator is "used and useful" if it is capable

[51] Nevertheless, it is worth noting that in light of the predicate that does exist—the elimination of discrimination on the basis of affiliation—Schedule 2-A is not properly characterized as an amendment to Schedule 2, at least in the sense "amendment" is used by Dynegy. Dynegy uses the concept of an "amendment" to Schedule 2 to convey more than a simple revision; for Dynegy, it conveys a fundamental departure from Schedule 2's rationale and substantive core. Because Schedule 2 was revised to eliminate discrimination on the basis of affiliation, Schedule 2-A could not be an amendment in Dynegy's sense, unless it undermined the prohibition of discrimination on the basis of affiliation. Schedule 2-A does not do this. It merely revises Schedule 2 to give transmission owners the ability to choose which schedule will apply in their zones. Moreover, it does not change how compensation is paid under Schedule 2; that is, it does not alter the capability approach.

[52] *MISO II*, 113 FERC ¶ 61,046 at P 42.

[53] *MISO III*, 114 FERC ¶ 61,192 at P 18.

of providing reactive power.[54] The transmission owners again sought rehearing, pressing the needs test issue. In *MISO IV*, the Commission denied rehearing, and observed that the transmission owners had failed to formulate a needs test proposal that could be applied comparably to all generators while addressing Midwest ISO's reliability concerns.[55] Despite these failures, the Commission stated that, going forward, parties could propose a needs test that compensated all generators comparably, and factored in reliability.

47. Thus, while *MISO IV* indicates the possibility of a needs test, it is not in the context of creating the sole exception to a general rule. Rather, it is in the context of a response to the transmission owners' arguments. Had transmission owners or other parties advanced proposals other than a needs test—such as the approach in Schedule 2-A—the Commission would have considered and discussed them as well. Dynegy makes the mistake of assuming that a needs test is the only possible alternative to Schedule 2 based solely on what the transmission owners happened to argue in the Schedule 2 Orders.

48. Finally, we want to make explicit our implicit rejection of two elements in Dynegy's reasoning. First, Dynegy criticizes Schedule 2-A because it permits transmission owners to choose which schedule will apply in their zones, and therefore which generators will collect reactive power compensation on a capability basis and which will not.[56] Although this critique essentially reformulates the assertion that the Commission should reject Schedule 2-A because it prevents Schedule 2 from applying to all generators, this particular articulation of the argument emphasizes the transmission owners' discretion and appears to suggest that this aspect of Schedule 2-A is suspect. We clarify that vesting transmission owners with discretion to choose whether affiliated and unaffiliated generators will collect compensation on a capability basis does not violate Commission policy. In fact, the Commission's reactive power compensation policy entitles transmission owners to make the decision whether or not to compensate generators (affiliated and unaffiliated) for reactive power inside the deadband.[57] Similarly, Dynegy portrays the Filing Transmission Owners' desire to curb or eliminate

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[54] *Id*. P 19.

[55] *MISO IV*, 116 FERC ¶ 61,283 at P 23.

[56] Dynegy Rehearing Request at 17.

[57] *See Bonneville Power Administration*, 125 FERC ¶ 61,273, at P 25 (2008) (*BPA*).

reactive power compensation inside the deadband as if it is some nefarious motive.[58] We reject this implication and observe that the Commission's default reactive power compensation policy is that generators should not collect compensation for providing reactive power inside the deadband, and that a transmission owner is only required to compensate a generator for reactive power inside the deadband if it so compensates its own or affiliated generators.[59]

D. Basis for Distinctions in Reactive Power Compensation

1. Arguments on Rehearing

49. FirstEnergy argues that paragraph 37 of *MISO I* requires distinctions in reactive power compensation to be based on a generator's type or size (including what quantity of reactive power it can produce or when), location, or other physical characteristic, but that in this case the only rationale for the disparity in reactive power compensation is the Filing Transmission Owners' desire to cease compensating generators for reactive power inside the deadband.[60] FirstEnergy argues that there is no legitimate distinction justifying Schedule 2-A, and no rational basis for distinguishing between the generators compensated pursuant to Schedule 2 and those compensated pursuant to Schedule 2-A.

2. Commission Determination

50. We deny rehearing. In paragraph 37 of *MISO I*, the Commission did not find that distinctions in reactive power compensation must be based on a generator's type or size (including what quantity of reactive power it can produce or when), location, or other physical characteristic.[61] In that proceeding, the only basis advanced by Midwest ISO for

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[58] Dynegy Rehearing Request at 17.

[59] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546 (stating that an interconnecting generator "should *not* be compensated for reactive power when operating its Generating Facility *within* the established power factor range, since it is *only* meeting its obligation."); Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416.

[60] FirstEnergy Rehearing Request at 10.

[61] *MISO I*, 109 FERC ¶ 61,005 at P 37 states:

> Further, Midwest ISO's only stated distinction between generators who may receive compensation under section 2 and those who may receive compensation under Schedule 21 is based on whether they were being compensated or not under Schedule 2 as of June 25, 2004 (the date of the instant

(continued…)

its proposal to compensate some generators under Schedule 2 and some generators under Schedule 21 was whether the generator had been compensated under Schedule 2 at the time that Schedule 21 was filed—which is to say, whether it was an affiliated generator.[62] In paragraph 37, the Commission cited other potential grounds for a distinction merely to highlight the inadequacy of Midwest ISO's rationale, not to require future distinctions to be based on one of these factors.

E. Stakeholder Process

1. March 2008 Order

51. In its protest, Dynegy argued that paragraph 23 of *MISO IV* established a requirement that any revisions to Schedule 2 be developed through a stakeholder process. Dynegy maintained that the Commission established this requirement by referring to "parties" when it stated that "'[g]oing forward, parties may propose a rate for all generators that compensates them comparably for the level of reactive power actually needed and used.'" Dynegy also observed that the Commission rejected without prejudice Midwest ISO's revisions to Attachment N of the Tariff because they had not been submitted through a stakeholder process.[63]

52. In the March 2008 Order, the Commission rejected Dynegy's interpretation of "parties." The Commission found that in paragraph 23 of *MISO IV* the Commission did not mention the term "stakeholder process," much less require a stakeholder process as a prerequisite for future filings related to reactive power compensation. The Commission stated that the process for filing Schedule 2-A was governed by the Filing Rights Settlement, which does not require a stakeholder process. Consequently, the Commission determined that its reasoning in the Attachment N Order was not relevant to this case.[64]

> filing). There is no distinction based on the type or size of generators (and what quantity of reactive power it can produce or when), its location, or any other physical characteristic. This distinction is simply an inadequate basis in this context to distinguish between generators.

[62] Since only affiliated generators were compensated under Schedule 2 when Schedule 21 was filed, this was undue discrimination on the basis of affiliation.

[63] Dynegy Protest at 33-34 (citing *Midwest Indep. Transmission Sys. Operator, Inc*., 98 FERC ¶ 61,064, *reh'g denied*, 98 FERC ¶ 61,356 (2002) (Attachment N Order)).

[64] March 2008 Order, 122 FERC ¶ 61,305 at P 47-48.

2. Arguments on Rehearing

53. Dynegy continues to argue that paragraph 23 of *MISO IV* establishes a requirement for a stakeholder process. Dynegy acknowledges that the term "stakeholder process" does not appear in paragraph 23; however, it continues to maintain that paragraph 23's "plain language" requires a stakeholder process because it refers to "the parties" (and not transmission owners acting alone) when discussing proposals to revise Schedule 2.[65] Dynegy also cites the Attachment N Order and *Midwest ISO*[66] to show that the Commission has previously required a stakeholder processes before accepting revisions to the Tariff.

3. Commission Determination

54. We deny rehearing and reject Dynegy's claim that the Commission's single use of the word "parties" in paragraph 23 of *MISO IV* establishes a requirement for a stakeholder process. Dynegy's interpretation has no support in either the sentence in which the word "parties" appears or paragraph 23 generally.[67]

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[65] Dynegy Rehearing Request at 25.

[66] *Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 61,009, at P 10 (2006) (*Midwest ISO*).

[67] *MISO IV*, 116 FERC ¶ 61,283 at P 23 states:

> While we have denied the Midwest ISO TOs' rehearing request on this matter, the very exercise of doing so highlights the Midwest ISO TOs' difficulty in supporting their position. Indeed, the Midwest ISO TOs have never made a proposal as to how a needs test might be formulated and applied to all generators on a comparable basis. Moreover, the Midwest ISO TOs have failed, throughout this long proceeding, to demonstrate that the Midwest ISO's proposed Schedule 2 is unjust and unreasonable or otherwise unduly discriminatory or preferential. The Midwest ISO TOs have only speculated that the capability approach favored by and filed by the Midwest ISO could result in excessive charges being paid to generators. Significantly, they have never attempted to address the Midwest ISO's reliability concerns that led it, at least in part, to its decision to file a Schedule 2 based on capability and comparability for all generators. Going forward, parties may propose a rate for all generators that

(continued…)

55. Dynegy's claim that *MISO IV* establishes a requirement for a stakeholder process is connected to its argument that *MISO I* and *MISO IV* require all generators to be compensated pursuant to Schedule 2 unless a needs test that factors in reliability is developed. Dynegy's argument rests on the assumption that *MISO IV* creates rules that the Commission must follow in order to deviate from the general rule established in *MISO I*—in this case, that it must convene a stakeholder process. As we have explained, however, this is a misreading of *MISO I* and *MISO IV*.[68]

56. In any event, Dynegy's interpretation of paragraph 23 is not plausible. There is nothing in either paragraph 23 or the Commission's use of "parties" that suggests that "parties" has any meaning other than its natural and normal meaning as the plural of "party." Thus, the Commission's use of "parties" merely indicates that the ability to propose needs-based criteria is not the exclusive possession of a single entity.

57. Equally as important, there is nothing in paragraph 23 that can reasonably be interpreted as establishing a requirement for a stakeholder process. The words "stakeholder process" do not appear anywhere in paragraph 23, and there is no mention of consultation or coordination among transmission owners, generators, and Midwest ISO. Likewise, there are no citations to previous cases where the Commission required a stakeholder process, and no mention of a stakeholder process in conjunction with the admonition that any needs-based proposal should be advanced in a separate section 205 proceeding. Thus, to accept Dynegy's claim that in paragraph 23 the Commission established a requirement for a stakeholder process, one must assume that the Commission did so in the most discrete and unnoticeable way possible—without mentioning, describing, or in any way calling attention to it.

58. Finally, our decision is unaffected by Dynegy's observation that the Commission required a stakeholder process in the Attachment N Order and *Midwest ISO*. In the first place, neither of these cases involved the Filing Rights Settlement which, as we explained in the March 2008 Order, is the relevant authority governing the Filing Transmission Owners' right to submit section 205 filings that revise the rates, terms, and conditions

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> compensates them comparably for the level of reactive power actually needed and used, so as to avoid remuneration in excess of those levels. Therefore, criteria may be developed, applied comparably and prospectively, that would determine which generators would receive reactive power compensation. We would also expect that reliability would be factored into any proposal. Any such proposal should be advanced in a separate section 205 proceeding.[]

[68] *See supra* P 38-47.

applicable to the provision of ancillary services and which does not require a stakeholder process. More to the point, however, the fact that the Commission required a stakeholder process in those proceedings is not evidence that the Commission established a requirement for a stakeholder process in paragraph 23 of *MISO IV* or that Dynegy's reading of *MISO I* and *MISO IV* is correct. As we have explained, Dynegy's interpretation of paragraph 23 of *MISO IV* is without any plausible textual basis, and its assumption that *MISO IV* creates rules that the Commission must follow in order to deviate from the general rule established in *MISO I* rests on a misreading of the Schedule 2 Orders.[69]

F. Consistency with Order Nos. 2003 and 2003-A and Status as a Transmission Provider

1. March 2008 Order

59. Several protesters argued that Schedule 2-A violates the Commission's comparability policy as set forth in Order No. 2003-A and subsequent precedent because it permits similarly situated generators in different zones in the same RTO to receive different compensation for providing the same service. These protesters claimed that comparability requires that Midwest ISO, as the RTO and Transmission Provider, maintain a single compensation policy that applies to all zones.

60. The Commission rejected this argument and found that Schedule 2-A complied with the comparability policy.[70] The Commission observed that Order Nos. 2003 and 2003-A were written to apply generically to traditional utilities outside of an RTO, and stated that in order to apply the principle of comparability to zone-based compensation within an RTO, it had to distinguish between how "Transmission Provider" is used in Order Nos. 2003 and 2003-A and how "transmission provider" is used in the context of RTOs and Order No. 2000.[71]

61. The Commission explained that in Order Nos. 2003 and 2003-A the definition of "Transmission Provider" includes *both* the entity that provides transmission service and,

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[69] *See supra* P 38-47.

[70] March 2008 Order, 122 FERC ¶ 61,305 at P 55.

[71] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

if separate, the entity that actually owns the transmission facilities.[72] In contrast, the Commission explained that when it refers to an RTO as the "transmission provider" it is generally in the context of Order No. 2000 and section 35.34(k) of the Commission's regulations, which require the RTO to "be the sole provider of transmission service and sole administrator of its own open access tariff."[73] Consequently, the Commission found *that when used in the context of an RTO*, "transmission provider" (i.e., the RTO) has a narrow meaning and describes an entity that is separate and distinct from the entity that is the transmission owner (i.e., the RTO member(s) that has (have) turned over operational control of the transmission facilities it owns to the RTO).[74]

62. The Commission also observed that an RTO is a transmission provider that by design does not have any affiliated generation. Consequently, although the definition of "Transmission Provider" in Order Nos. 2003 and 2003-A includes both transmission providers and transmission owners, the Commission found that in the context of reactive power compensation within an RTO, the concern addressed by the Commission's comparability policy – that affiliated and unaffiliated generators collect compensation on the same basis – is adequately addressed when transmission owners are required to compensate affiliated and unaffiliated generators on the same basis.[75] Accordingly, the Commission determined that Schedule 2-A complies with the comparability requirement because even though it permits different reactive power compensation policies for different zones within Midwest ISO, all generators in the same zone – affiliated and unaffiliated –receive compensation on the same basis.

2. **Arguments on Rehearing**

63. In general, Dynegy, First Energy, and Reliant, argue that the March 2008 Order departs from the Commission's comparability precedent, which they claim requires that

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[72] March 2008 Order, 122 FERC ¶ 61,305 at P 58 & n.46.

[73] Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,108; *See also* 18 C.F.R. § 35.34(k)(1)(i) ("The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The Regional Transmission Organization must have the authority to review and approve requests for new interconnections.").

[74] March 2008 Order, 122 FERC ¶ 61,305 at P 58.

[75] *Id*. P 59.

Midwest ISO, as the Order No. 2003-A Transmission Provider, maintain a single compensation policy that applies to all zones.

64. Dynegy agrees with the Commission's characterization of the differences between Order Nos. 2000 and 2003-A, but claims that the distinctions are unsurprising and of little value because the Commission first developed its reactive power comparability policy almost two years after Order No. 2000.[76] Dynegy suggests that the Commission should have focused on Order No. 2003-A and subsequent precedent rather than look back to Order No. 2000. Dynegy contends that Order No. 2003-A and subsequent precedent require that the Commission reject Schedule 2-A.

65. FirstEnergy contends that the Commission excluded RTOs from the Order Nos. 2003 and 2003-A definition of "Transmission Provider." FirstEnergy agrees with the Commission's observation that Order Nos. 2003 and 2003-A apply to traditional utilities outside of an RTO, but maintains that they also apply to RTOs. FirstEnergy states that Order No. 2003 explicitly provides for RTOs to submit compliance filings related to reactive power compensation,[77] Midwest ISO's *pro forma* large generator interconnection agreement, Schedule 2, and Schedule 2-A all designate Midwest ISO (or its successors) as the Transmission Provider, and Transmission Customers purchase reactive power from, and make reactive power payments to, Midwest ISO rather than to individual transmission owners. FirstEnergy describes the Commission's reasoning as an effort to circumscribe the definition of "Transmission Provider" to include only transmission owners and to exclude Midwest ISO,[78] which it claims is in marked contrast to *SPP*,[79] where the Commission accepted a region-wide proposal for reactive power compensation by an RTO on the sole ground that it treated all generators in the RTO, regardless of zone, on a comparable basis.

66. In contrast to FirstEnergy, which reads the Commission as excluding RTOs from the Order No. 2003-A definition of Transmission Provider, Reliant reads the March 2008 Order as finding that, for the purposes of applying the comparability policy, the Commission may consider both Midwest ISO and individual transmission owners as the

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[76] Dynegy Rehearing Request at 8 (referring to *Michigan Electric Transmission Co.*, 97 FERC ¶ 61,187 (2001), *reh'g denied*, 98 FERC ¶ 61,104 (2002)).

[77] FirstEnergy Rehearing Request at 13 (citing Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 548).

[78] *Id*.

[79] *Southwest Power Pool*, *Inc*., 119 FERC ¶ 61,199 (2007) (*SPP I*), *reh'g denied*, 121 FERC ¶ 61,196 (2007) (*SPP II*) (collectively, *SPP*).

Order No. 2003-A Transmission Provider.[80] Reliant also reads the March 2008 Order as concluding that the concern underlying the Commission's comparability policy is adequately addressed when transmission owners are required to compensate generators within their zones on the same basis. However, Reliant rejects these conclusions and agrees with FirstEnergy that permitting multiple reactive power compensation policies within a single RTO is a reversal of *SPP*.

67. Reliant argues that in substituting transmission owners for Midwest ISO as the Order No. 2003-A "Transmission Provider," and endorsing Schedule 2-A's zone-based compensation rules, the Commission wrongly presumed that unaffiliated generators provide reactive power only within the pre-RTO boundaries of the particular transmission owner with which they are interconnected. Reliant states that generators do not provide zonal reactive power service, but provide reactive power to Midwest ISO for the benefit of the entire Midwest ISO grid. Reliant asserts that nothing in the Midwest ISO large generator interconnection agreement limits a generator's obligation to providing reactive power solely for the benefit of an individual transmission owner, or for a subset of Midwest ISO customers subject to a particular zonal transmission price; instead, the agreement requires generators to provide reactive power at Midwest ISO's direction, and for the benefit of all Midwest ISO transmission users. Reliant argues that the Commission cannot require generators to provide reactive power to Midwest ISO as a whole while allowing compensation to be determined on a zonal basis.

68. In Reliant's view, Midwest ISO's use of zonal (license-plate) transmission rates does not justify granting transmission owners the discretion to deprive generators of reactive power compensation because the rationale for license plate rates has no operational significance. Reliant also rejects any analogy between zonal transmission rates and zonal reactive power compensation because, according to Reliant, unlike zonal transmission rates, Schedule 2-A will not assure all generators full cost recovery for reactive power.

3. Commission Determination

69. We deny rehearing. None of the arguments made by Dynegy, FirstEnergy, and Reliant cast doubt on our finding that Schedule 2-A treats affiliated and unaffiliated generators comparably; nor do they persuade us to revisit the Commission's closely related conclusion that Midwest ISO may maintain two reactive power compensation policies that both require compensation on a comparable basis. Instead, the arguments on rehearing tend to misunderstand the issue presented by Schedule 2-A and avoid addressing the Commission's reasoning.

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[80] Reliant Rehearing Request at 9.

70. For example, Dynegy's argument that the Commission should have focused on Order No. 2003-A and subsequent precedent rather than look back to Order No. 2000 illustrates a fundamental misunderstanding of the issue presented by Schedule 2-A.

71. Schedule 2-A raises the question of whether an RTO with different zones must maintain a single reactive power compensation policy applicable to all zones, or whether it may allow each zone to choose between two different compensation policies, provided that both policies compensate affiliated and unaffiliated generators on a comparable basis. In previous cases, the Commission has only confronted tariff provisions or proposed tariff provisions that established reactive power compensation for all generators on an RTO-wide basis; some provided that affiliated and unaffiliated generators would receive compensation on a comparable basis, others did not. In any event, prior to this case, the Commission has never evaluated a proposed tariff provision that allows all generators within a particular zone in an RTO—affiliated and unaffiliated—to collect reactive power compensation on one basis, while all generators in a different zone in the same RTO collect reactive power compensation on a different basis. Thus, Dynegy's claim that the Commission could have resolved this case by focusing on recent precedent wrongly implies that recent precedent addresses how the comparability requirement applies to a proposal for zone-based reactive power compensation within an RTO. More to the point, it suggests that Dynegy failed to recognize that a proposal for zone-based compensation in an RTO presents an entirely different dynamic than the proposals the Commission has previously examined.

72. Dynegy's argument also betrays a fundamental misunderstanding of what the Commission actually did in the March 2008 Order. Contrary to Dynegy's assertion, the Commission did not reach its decision on Schedule 2-A by looking backward to Order No. 2000; rather, it used Order No. 2000 to demonstrate by way of comparison the scope of the Commission's definition of Transmission Provider in Order No. 2003-A.

73. Since the Commission had not previously determined how the comparability requirement applies to a proposal for zone-based compensation in an RTO, it began its analysis in the March 2008 Order by referring back to the source of the comparability requirement—Order No. 2003-A. Order No. 2003-A requires the Transmission Provider to compensate affiliated and unaffiliated generators on a comparable basis.[81] However,

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[81] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416 (emphasis added); *accord* Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 at P 113, 119; Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 at P 34, 42-43; *Entergy*, 113 FERC ¶ 61,040 at P 22-24, 38-39. Section 9.6.3 of the Commission's Order No. 2003-A *pro forma* Large Generator Interconnection Agreement (which was reaffirmed in relevant respects in Order Nos. 2003-B and 2003-C) reflects this policy, providing that as a general rule, payment for reactive power is only for reactive power "outside the agreed upon deadband" but also (continued…)

Order No. 2003-A was written to apply generically to traditional utilities outside an RTO. Consequently, the Commission's task in the March 2008 Order was to look closely at how Order No. 2003-A's comparability requirement applies in the context of an RTO, and more particularly, how it applies in the context of a proposal for zone-based reactive power compensation in an RTO. When considered in light of this task, the central question posed by Schedule 2-A is whether comparability requires an RTO with different zones to maintain a single reactive power compensation policy applicable to all zones. This question can appropriately be restated as which entity, in the context of an RTO, is the Transmission Provider *for the purposes of the comparability requirement*. This gives rise to the second, more specific question of whether the comparability requirement can be satisfied if the transmission owners in each zone compensate all the generators in their zone on a comparable basis, even if that basis differs between zones.

74. The Commission approached these questions by contrasting the use of "Transmission Provider" in Order Nos. 2003 and 2003-A with the use of "transmission provider" in Order No. 2000 and RTOs in general. The Commission noted that in Order Nos. 2003 and 2003-A the definition of Transmission Provider includes both the *entity that provides transmission service and, if separate, the entity that actually owns the transmission facilities*; thus, for the purpose of Order No. 2003-A and the comparability requirement, both the RTO and its transmission owning members may appropriately be considered to be the Transmission Provider, even (and especially) when these are separate and distinct entities.[82]

75. In contrast, the Commission noted that "transmission provider" has a narrower meaning when used in Order No. 2000 and RTOs in general. In this context, "transmission provider" refers exclusively to the entity that provides transmission service—an entity that is deliberately separate and distinct from the transmission owners. Thus, "transmission provider" in the context of Order No. 2000 and general RTO parlance (i.e., the RTO itself) is not synonymous with "Transmission Provider" in the context of Order No. 2003-A and the comparability requirement because, in the Order No. 2003-A context, the Transmission Provider may be either the RTO or one of the transmission owning members of the RTO.

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providing for payment for reactive power within the deadband *if, and only if*, the Transmission Provider pays its own or affiliated generators for reactive power within the deadband.

[82] FirstEnergy and Dynegy agree with the Commission that the definition of "Transmission Provider" includes Regional Transmission Organizations and Transmission Owners; Reliant is silent on the issue.

76. This analysis demonstrates why FirstEnergy's rehearing argument is without merit. FirstEnergy asserts that the March 2008 Order excluded RTOs from the Order No. 2003-A definition of "Transmission Provider." This is not a plausible reading of the March 2008 Order. Nowhere in its discussion did the Commission suggest that RTOs are excluded from the Order No. 2003-A definition of Transmission Provider. As we have explained, the Commission did the exact opposite and determined that the definition includes both the RTO and its transmission owning members.[83]

77. Reliant's rehearing argument cannot withstand scrutiny for similar reasons. Reliant asserts that the Commission erred by treating the Filing Transmission Owners as the "Transmission Provider" and by endorsing Schedule 2-A's zone-based approach because these decisions wrongly presume that unaffiliated generators provide zonal reactive power service when in fact they provide reactive power to Midwest ISO for the benefit of the entire Midwest ISO grid. While it is true that generators provide reactive power for the benefit of the entire Midwest ISO grid, Reliant assumes that this fact necessitates that the Commission treat Midwest ISO as the Transmission Provider for the purposes of the comparability requirement. The premise behind this argument appears to be that Midwest ISO must be the Transmission Provider for the purpose of Order No. 2003-A and the comparability requirement because, as the RTO, it is the central authority operating the transmission system. This premise must be rejected in light of our discussion above, which makes clear that "transmission provider" in the context of Order No. 2000 and general RTO parlance is not synonymous with "Transmission Provider" in the context of Order No. 2003-A and the comparability requirement. Thus, for the purposes of the comparability requirement, no special force is attached to the fact that generators provide reactive power to Midwest ISO in its capacity as a transmission provider in the Order No. 2000 and general RTO context.

78. After determining that both the RTO and the transmission owning members can be considered the Transmission Provider for the purposes of the comparability requirement, the Commission addressed whether the comparability requirement can be satisfied if the transmission owners in each zone compensate all the generators in their zone on a comparable basis, even if that basis differs between zones. The Commission looked to the concern underlying the comparability requirement—that affiliated and unaffiliated generators receive reactive power compensation on a comparable basis—and noted that

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[83] March 2008 Order, 122 FERC ¶ 61,305 at P 58-59. Moreover, the Commission noted that in Order Nos. 2003 and 2003-A, "Transmission Provider" describes the entity with which the generator is interconnecting, and should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

an RTO is a transmission provider without affiliated generation. Since the comparability requirement is designed to place affiliated and unaffiliated generators on comparable footing, the Commission found that in the context of an RTO its purpose could be achieved if the transmission owners in each zone (which are considered Transmission Providers for purposes of Order No. 2003-A) compensate all the generators in their zone—affiliated and unaffiliated—on a comparable basis.

79. This finding is closely connected to the definition of "Transmission Provider" in Order No. 2003-A. Because both the RTO and the transmission owning members of the RTO are considered the Transmission Provider under Order No. 2003-A, there is no conceptual or textual difficulty in finding that transmission owners are the entities subject to the comparability requirement. Similarly, this finding bears directly on our conclusion that Midwest ISO is not required to maintain a single compensation policy for all zones. If Order No. 2003-A placed the obligation to afford comparable treatment always and exclusively on the RTO because it was the only entity eligible to be the "Transmission Provider," then we could not find that the obligation could be satisfied by individual transmission owners. Instead, we would have had to conclude that Midwest ISO, as the RTO, had to maintain a single compensation policy for all zones. However, since that is not the case, because transmission owners are also included in the definition of Transmission Provider, there is no basis for finding that the comparability requirement is violated by Midwest ISO maintaining two reactive power compensation policies that both require transmission owners to treat the affiliated and non-affiliated generators in their zones comparably.

80. We must briefly explain the importance of context in understanding the Commission's observation that an RTO is a transmission provider without affiliated generation. Since the Commission found that both the RTO and the transmission owners may be the Transmission Provider for the purposes of the comparability requirement, this observation is relevant to determining whether in this case the concern underlying the comparability policy could be adequately addressed by transmission owners or whether it had to be addressed by the RTO. Because Schedule 2-A proposes zone-based compensation that treats all generators in each zone comparably, and because Midwest ISO has no affiliated or unaffiliated generation, the Commission found that the concern could be adequately addressed by the transmission owners. In the typical case involving an RTO's reactive power compensation provisions, however, we are not faced with the choice of determining whether zone-based compensation satisfies the comparability requirement. Instead, we are presented with RTO-wide compensation provisions. In those cases, the fact that the RTO does not have affiliated or unaffiliated generation does not factor into the decision because the RTO is the only entity at issue.

81. Additionally, we reject Reliant's claim that there is no analogy between license plate transmission rates and license plate reactive power compensation. As Reliant correctly explains, the Commission allows RTOs, including Midwest ISO, to charge

transmission rates that vary by zone, subject to the requirement that customers pay only a single zonal rate (i.e., no pancaked rates) to use the entire RTO system.[84] Contrary to Reliant's assertion, there is an analogy between this approach and the zonal reactive power compensation proposed in Schedule 2-A—in both cases, customers are obligated to pay only one zonal rate. Under Schedule 2-A, customers pay a single reactive power rate to serve load in a particular zone, regardless of whether their load is located in a zone covered by Schedule 2 or Schedule 2-A.

82. We also reject Reliant's assertion that the Commission should reject a license plate reactive power compensation structure because the rationale for license plate rates has no operational significance with respect to reactive power supply in Midwest ISO. The ability for transmission owners to choose the reactive power compensation under either Schedule 2 or Schedule 2-A is consistent with the existing license plate structure for transmission service within Midwest ISO. To the extent that Reliant is challenging the concept of license plate rates in general, we reject its argument as outside the scope of this proceeding.

83. Finally, we reject Reliant's claim that the proposed license plate reactive power compensation is discriminatory because it does not guarantee full cost recovery for reactive power that is provided for the benefit of the entire Midwest ISO system. This argument implies that Reliant is entitled to compensation for providing reactive power within the deadband. However, as the Commission has previously explained, generators do not have a right to compensation for providing reactive power inside the deadband because in so doing they are only meeting their obligations.[85] It is true that reactive power produced by generators in a Schedule 2-A zone may benefit all Midwest ISO transmission users, but the Commission's reactive power compensation policy is that a generator has a right to compensation for producing reactive power within the deadband only if the transmission owner so compensates its own or affiliated generators for this service.[86] In a zone covered by Schedule 2-A, unaffiliated generators will not receive compensation for reactive power that may benefit the entire Midwest ISO system, but neither will affiliated generators located in the same zone.

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[84] Reliant Rehearing Request at 11.

[85] *See supra* n.59 & n.81.

[86] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416. *See also KGen Hinds LLC*, 120 FERC ¶ 61,284 (2007).

G. Comparability Within and Between Zones

1. Arguments on Rehearing

84. On rehearing, Exelon argues that the interaction of Schedule 2-A with existing interconnection agreements can result in non-comparable treatment among generators in the same zone. Exelon observes that Schedule 2-A requires each generator to operate within the deadband required by its interconnection agreement, even if it differs from the deadband specified in Schedule 2-A, and that only generators that operate outside of the deadband can collect reactive power compensation. Exelon argues that this approach creates the possibility that affiliated and unaffiliated generators in the same zone will collect reactive power compensation based on different deadbands. Exelon explains that it is required to operate its Clinton Station generator between 0.95 leading and 0.90 lagging, rather than between 0.95 leading and 0.95 lagging, as specified in Schedule 2-A. Exelon's point appears to be that if an affiliated generator with a 0.95 leading and 0.95 lagging deadband and Clinton Station both operated between 0.95 and 0.90 lagging, only the affiliated generator could collect reactive power compensation because it would be the only generator operating outside of its deadband. Exelon argues that differences in deadbands are unrelated to reactive power compensation, and now that the deadband sets the basis for reactive power compensation, it is unjust and unreasonable for existing interconnection agreements to take precedence over uniform application of Schedule 2-A within a zone.[87]

85. Exelon also argues that Schedule 2-A unduly discriminates among generators in apportioning revenues from through-and-out service. Exelon explains that it must pay Midwest ISO's through-and-out rate when it sells power from its Clinton Station generator into PJM, thereby benefiting generators in Schedule 2 zones. Exelon states that Clinton Station is in the Ameren-Illinois (Ameren) transmission owner-zone, and that if the Commission allows Ameren to decide that Schedule 2-A will apply in that zone, the Commission will have denied Exelon compensation for the reactive power it supplies. Exelon states that the Commission failed to address this argument in the March 2008 Order, focusing instead on undue discrimination in the same zone. Exelon asserts, however, that section 205 of the Federal Power Act also prohibits discrimination between similarly situated parties, and that it is unduly discriminatory for the Midwest ISO Tariff to require all generators to provide the same reactive power service on the through-and-out rate, but to provide compensation for only some of those generators. Exelon contends that this undue discrimination is particularly unfair with respect to Clinton Station, which

[87] Exelon asserts that because the record does not contain information about the power factors of other generators in Ameren's zones, it is impossible to determine whether all generators will be treated on a comparable basis.

will supply most of the reactive power necessary to facilitate Clinton transactions into PJM. Exelon states that Schedule 2-A will compensate generators that do not provide the reactive power to facilitate these transactions, and deny compensation to those that do.

86. FirstEnergy argues that affiliated and unaffiliated generators in a Schedule 2-A zone are likely to receive non-comparable treatment. FirstEnergy argues that one consequence of the Commission's ruling that transmission owners in Schedule 2-A zones remain obligated to compensate generators pursuant to their existing rate schedules unless and until the rate schedules are successfully challenged under section 206 of the Federal Power Act, is that existing generators that collect compensation on a capability basis will continue to collect such compensation while new generators will collect compensation only for providing reactive power outside the deadband. FirstEnergy speculates that the existing generators that will continue to collect capability-based compensation will be affiliated generators, while the new generators that collect compensation pursuant to Schedule 2-A will be unaffiliated generators.

2. Commission Determination

87. We deny rehearing. First, we reject Exelon's claim that Schedule 2-A is unduly discriminatory because generators in Schedule 2-A zones cannot collect compensation for providing reactive power within the deadband, but must pay a through-and-out export rate that compensates generators in other Midwest ISO zones for providing reactive power within the deadband. This argument is merely a variation of the general argument that Schedule 2-A fails to treat all generators in Midwest ISO on a comparable basis. However, as the Commission explained in the March 2008 Order, and again in this order, the comparability requirement is satisfied if all generators within a particular RTO zone, both affiliated and unaffiliated, receive compensation on the same basis.[88] Schedule 2-A requires such treatment. Moreover, while generators in a Schedule 2-A zone may have to pay a rate that includes compensation for reactive power inside the deadband (either for exports outside of Midwest ISO or for delivery within Midwest ISO to a Schedule 2 zone), they will pay this rate without regard to affiliation; that is, all generators in a Schedule 2-A zone—affiliated and unaffiliated—must pay the rate.

88. Additionally, we reject two other aspects of Exelon's argument. In the course of its through-and-out argument, Exelon asserts that if the Commission accepts Schedule 2-A, it will deny Exelon compensation for the reactive power it supplies. This claim

[88] We also note that the Commission has allowed compensation methodologies (for reimbursement of generator interconnection upgrade costs) to differ among Midwest ISO zones. *See Int'l Transmission Co.*, 120 FERC ¶ 61,220 (2007), *reh'g denied*, 123 FERC ¶ 61,065 (2008); *Am. Transmission Co. LLC*, 120 FERC ¶ 61,221 (2007), *reh'g denied*, 123 FERC ¶ 61,065 (2008); *ITC Midwest, LLC*, 124 FERC ¶ 61,150 (2008).

suggests that Exelon has a right to such compensation. As the Commission has repeatedly explained, however, generators do not have a right to compensation for providing reactive power inside the deadband since they are only meeting their obligations.[89] Moreover, Exelon's discussion of its Clinton Station generator incorrectly suggests that "need" is relevant to determining a generator's reactive power compensation. Exelon states that it exports energy from Clinton Station into PJM, and that Clinton Station itself is the main supplier of the reactive power necessary to facilitate the exports. Exelon argues that because Clinton Station provides reactive power within the deadband that is needed to facilitate the transactions, it should receive compensation (or not have to pay other generators) for reactive power inside the deadband. As we explained at length in this order, however, there is no needs test in either Schedule 2 or Schedule 2-A,[90] and there is no categorical requirement that, absent a needs test, every generator must receive compensation under Schedule 2, i.e. for providing reactive power within the deadband. Moreover, Exelon's example does not violate the comparability requirement because, as we have explained, all generators located in the same zone as Clinton Station, both affiliated and unaffiliated, will have to pay the same through-and-out rate when exporting energy from Midwest ISO.[91]

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[89] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 546 (emphasis added). The Commission recognized certain limited exceptions that are not applicable here. Providing reactive power within the deadband is an obligation of a generator, and is as much an obligation of a generator as, for example, operating in accordance with Good Utility Practice. *Compare id*. P 546 *with id*. P 537; *accord Entergy,* 114 FERC ¶ 61,303 at P 17. Indeed, section 9.6.2 of the Commission's Order No. 2003 *pro forma* Large Generator Interconnection Agreement expressly provides that generators are required "to operate. . . to produce or absorb reactive power within the design limitations" of the facility.

[90] Thus, the fact that the reactive power that a generator is capable of producing is not used at some particular given time (as in Exelon's example, for generators being compensated by the through-and-out rate for exports from Clinton Station) does not render the generator's filed rates based on reactive power capability unjust or unreasonable. *See MISO III,* 114 FERC ¶ 61,192 at P 19.

[91] In any event, the reactive power scenario in Exelon's example is based on Exelon's choice to export the output from the Clinton Station into PJM. A different choice on where to sell the output (or looking at a different generator) might result in a different reactive power outcome. Citing one example whose outcome is based on Exelon's own business decision to export power from a particular generator is not a valid basis for the Commission to find that Schedule 2-A, which applies to all generators in a particular zone, is unjust and unreasonable.

89. We also reject FirstEnergy's claim that affiliated and unaffiliated generators in a Schedule 2-A zone are likely to receive non-comparable treatment because Schedule 2-A does not abrogate any existing rate schedules. FirstEnergy argues that affiliated generators are likely to continue collecting compensation under their existing, capability-based rate schedules, while new, unaffiliated generators will only collect compensation for providing reactive power outside of the deadband. As the Commission explained in the March 2008 Order, and again in this order, Schedule 2-A was a section 205 filing; it did not, and could not, abrogate, eliminate, or revise any existing rate schedule.[92] Consequently, transmission owners that switch to Schedule 2-A remain obligated to compensate generators in their zones pursuant to the generators' filed rate schedules, unless and until those rate schedules are successfully challenged under section 206 of the Federal Power Act.[93] If the situation that FirstEnergy describes comes to fruition, the correct course of action would be for one of the unaffiliated generators to institute a section 206 proceeding.

90. Finally, Exelon maintains that if the Ameren transmission owner-zone switches to Schedule 2-A, it is possible that affiliated generators that operate under the same conditions as its Clinton Station generator will collect outside-of-the deadband compensation while Clinton Station does not because it is contractually obligated to maintain a deadband different from the standard deadband specified in Schedule 2-A. This argument is premature. Ameren has not yet and may never switch to Schedule 2-A. Moreover, as Exelon itself observes, the record in this proceeding does not contain any information about the deadbands of other generators in Ameren's zone, and therefore makes it impossible to determine if the scenario Exelon describes is realistic or merely hypothetical.[94] Finally, because a transmission owner must make a section 205 filing before it can switch between Schedule 2 and Schedule 2-A,[95] Exelon will have an opportunity to raise this issue if and when Ameren decides to switch to Schedule 2-A.

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[92] March 2008 Order, 122 FERC ¶ 61,305 at P 38.

[93] *Id*.

[94] Exelon Rehearing Request at 5-6 ("The record does not demonstrate the [deadbands] of the other generators in the Ameren-Illinois zone or in the Ameren-Missouri zones . . . . In other words, it is impossible to know if by electing Schedule 2-A, Ameren will be providing comparable service to unaffiliated generators in its zones based on possibly different deadbands.").

[95] March 2008 Order, 122 FERC ¶ 61,305 at P 119.

H. Full Compensation, Competitive Disadvantage, and Lost Revenues

1. Argument on Rehearing

91. In paragraph 38 of the March 2008 Order, the Commission stated that transmission owners that choose to switch to Schedule 2-A remain obligated to compensate generators in their zones pursuant to the generators' filed rate schedules unless and until the rate schedules are successfully challenged under section 206 of the Federal Power Act. FirstEnergy argues that paragraph 38 suggests that if a currently-effective, capability-based rate schedule is successfully challenged under section 206, the affected generator will be restricted to compensation as described in Schedule 2-A, jeopardizing its right to continue collecting compensation for the full cost of providing reactive power.

92. FirstEnergy asserts that the ability of many generators to remain in operation may depend on the revenue they collect under their capability-based rate schedules. FirstEnergy also speculates that denying full recovery to generators in Schedule 2-A zones could reduce or eliminate incentives for new entry into the market, or may cause new generation to develop on a disproportionate basis in Schedule 2 zones. FirstEnergy asserts that if existing generators cease operating or an insufficient amount of new generation enters Schedule 2-A zones, the remaining generators in Midwest ISO, many of which are affiliated with the Filing Transmission Owners, will benefit from reduced competition for the supply of electricity in competitive wholesale markets.[96] FirstEnergy argues that, especially under these circumstances, there is no rational basis for depriving a generator with an existing capability-based rate schedule of the opportunity to continue to collect charges commensurate with its costs. FirstEnergy therefore requests that the Commission summarily reject Schedule 2-A, or in the alternative, modify paragraph 38 of the March 2008 Order to state that even if the Commission determines that an existing reactive power rate schedule is successfully challenged under section 206, the generator's compensation under any superseding rate schedule would not be limited by the manner prescribed in Schedule 2-A.[97]

93. Dynegy argues that generators in Schedule 2-A zones will be at a competitive disadvantage relative to similarly situated generators in Schedule 2 zones. Dynegy explains that Midwest ISO's Day-2 market generates Locational Marginal Prices based on reference levels initially set by the Independent Market Monitor, who must approve any adjustment. Dynegy states that generators bid based on recovery of their costs, and that those bids are used to identify the generation that will be dispatched in the market –

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[96] FirstEnergy Rehearing Request at 19.

[97] *Id*.

that is, the generation that Midwest ISO will use in the Day-Ahead and Real-Time Markets to build the supply curve and clear the market. Dynegy asserts that small differences in bids can result in being selected to run (cleared) in the market or not, which could limit cost recovery.

94. FirstEnergy makes the related argument that there is no evidence that generators in Schedule 2-A zones will be able to adjust their market-based rates sufficiently to recover their lost revenues, and that the Commission's suggestion otherwise is merely speculation. FirstEnergy asserts that it is unreasonable for the Commission to accept Schedule 2-A based on such a speculative assumption.

2. Commission Determination

95. We deny rehearing. At the outset, we reject FirstEnergy's assertion that Schedule 2-A jeopardizes the "right" of existing generators to continue to collect "full compensation" for the cost of supplying reactive power. While FirstEnergy is correct that if the currently-effective reactive power rate schedule of a generator in a Schedule 2-A zone is successfully challenged under section 206 of the Federal Power Act, the generator will prospectively receive compensation pursuant to Schedule 2-A, it incorrectly claims that such a result will deny the generator its "right" to full compensation. As the Commission has repeatedly explained, generators do not have a right to compensation for providing reactive power inside the deadband because in so doing they are *only* meeting their obligations.[98] The Commission's reactive power compensation policy is that a generator has a right to such compensation only if the transmission owner so compensates its own or affiliated generators for this service.[99] In Schedule 2-A zones, however, all affiliated and unaffiliated generators can receive reactive power compensation only if they provide reactive power outside the deadband.

96. We are also not persuaded by FirstEnergy's speculation that Schedule 2-A will either reduce or eliminate incentives for new entry into the market, or cause new generation to develop in Schedule 2 zones on a disproportionate basis. As the Commission has previously noted, the incremental cost to the generator of reactive power within the deadband is minimal, and the purpose for which generating assets are built (including reactive power capability to maintain voltage levels for generation entering the grid) is to make sales of real power.[100] Moreover, FirstEnergy has provided no evidence

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[98] *See supra* n.59 & n.81.

[99] Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 416. *See also KGen Hinds LLC*, 120 FERC ¶ 61,284 (2007).

[100] *See Bonneville Power. Admin.*, 120 FERC ¶ 61,211, at P 21 (2007).

to support its claim that certain generators may cease operation if they cannot collect reactive power compensation on a capability basis.

97. We also reject Dynegy's and FirstEnergy's arguments related to their ability to recover their lost revenues. These arguments amount to the assertion that the Commission should guarantee unaffiliated generators full recovery of their lost revenue notwithstanding any drop in sales. In other words, Dynegy and FirstEnergy are seeking something more akin to a cost-of-service rate,[101] while still otherwise retaining a market-based rate. However, in requesting that the Commission reject Schedule 2-A and essentially guarantee full recovery of its reactive power costs, Dynegy and First Energy are making a request that is well beyond the demands of comparability. As the Commission has previously explained, comparability requires only that affiliates and non-affiliates be treated comparably.[102] Just as Schedule 2-A transmission owners have an opportunity to recover their lost revenue in their power sales rates, so the independent power producers have an opportunity to seek rates that make up the revenue that they previously might have earned through a separate charge for reactive power inside the deadband; comparability does not require that the Commission guarantee that affiliates and non-affiliates will be equally successful in pursuing such opportunities.[103] Dynegy and FirstEnergy have not contested the fact that they have an opportunity to recover their lost revenue in their market-based power sales rates; they simply doubt their ability to find alternative ways to recover their lost revenue.[104]

I. Order No. 888

1. March 2008 Order

98. In the March 2008 Order, the Commission rejected Reliant's claim that Schedule 2-A violates the functional unbundling requirement of Order No. 888.[105] The

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[101] In fact, even a cost-of-service rate does not guarantee recovery of a utility's costs. *See MISO III*, 102 FERC ¶ 61,192,at P 27 & n.47 (2003).

[102] *BPA*, 125 FERC ¶ 61,273 at P 15.

[103] *SPP II*, 121 FERC ¶ 61,196 at P 18.

[104] *See BPA*, 125 FERC ¶ 61,273 at P 15.

[105] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *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

(continued…)

Commission found that Reliant's argument overlooked the evolution of Commission policy since Order No. 888 and amounted to a collateral attack on the subsequently issued Order Nos. 2003 and 2003-A, which specifically addressed the circumstances and manner in which a transmission owner must pay for reactive power inside the deadband.

99. The Commission also rejected the argument that Schedule 2-A is unduly discriminatory because transmission owners may have other avenues to recover their reactive power costs. The Commission stated that it had previously addressed this argument in *SPP*, where it explained that the fact that transmission owners have an opportunity to recover their reactive power costs through retail rates does not render a tariff revision that treats affiliated and non-affiliated generators comparably unduly discriminatory.[106] The Commission further stated that comparability requires only that unaffiliated generators and transmission owners have a similar opportunity to make up the revenue that they previously might have earned through a separate charge for reactive power inside the deadband, and that it does not require the Commission to guarantee that unaffiliated generators and transmission owners will be equally successful in pursuing such opportunities.[107] The Commission explained that just as transmission owners have the opportunity to recover their costs for producing reactive power inside the deadband through means other than the ancillary service provisions of open access transmission tariffs, so unaffiliated generators have the opportunity to find other ways to recover their costs. For example, the Commission noted that unaffiliated generators may negotiate agreements recovering these costs through their market based power sales.

2. <u>Arguments on Rehearing</u>

100. Reliant challenges what it characterizes as the Commission's finding that Order No. 2003 modified Order No. 888's functional unbundling requirement. Reliant asserts that Order No. 2003 addressed an entirely different issue—whether a transmission provider could terminate reactive power compensation inside the deadband for unaffiliated generators if it ceased compensating itself inside the deadband—and at no point addressed the functional unbundling requirement. Reliant contends that if the Commission intended to modify the functional unbundling requirement in Order No. 2003, it was obligated to propose a specific revision during the Order No. 2003 proceedings. Reliant also challenges what it characterizes as the Commission's finding

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(1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[106] *SPP I*, 119 FERC ¶ 61,199 at P 39; *SPP II*, 121 FERC ¶ 61,196 at P 18.

[107] *SPP II*, 121 FERC ¶ 61,196 at P 18.

that the unbundling policy has evolved to permit re-bundling of reactive power service. Reliant argues that there is no basis in Order No. 2003 for allowing transmission owners to re-bundle the cost of providing reactive power into their wholesale energy rates.

101. Reliant contends that the only consequence of Order No. 2003 with respect to the unbundling requirement is that when a transmission provider elects to cease compensating itself and unaffiliated generators for reactive power inside the deadband, the separate reactive power charge set forth on Schedule 2 is zero. According to Reliant, this means that when a transmission customer obtains transmission service for its energy purchases from the transmission provider, the customer will pay no charge for reactive power and the transmission provider may not re-bundle a reactive power charge into its power rates in order to collect a charge in excess of the zero rate stated in Schedule 2.

102. Reliant contends that the Commission erred in finding that Schedule 2-A is not unduly discriminatory because both affiliated and unaffiliated generators have a comparable opportunity to recover their reactive power costs through means other than the ancillary service provisions of the Tariff. Reliant argues that Midwest ISO transmission owners have no authority to sell reactive power through any means other than Schedule 2, and thus the Commission's finding erroneously effectuates comparability through reliance on a violation of the functional unbundling requirement. Reliant explains that the existence of a comparable opportunity to recover reactive costs is premised on transmission owners recovering these costs through means other than Schedule 2, which Reliant claims they cannot do. Reliant asserts that the Commission may not excuse the Transmission Owners' obligation to comply with the unbundling requirement to justify a failure to compensate unaffiliated generators.

3. Commission Determination

103. We deny rehearing. The Commission did not suggest that Order No. 2003 or subsequent Commission precedent eliminated or modified Order No. 888's functional unbundling requirement; rather, the Commission merely stated that any discussion of reactive power compensation cannot ignore subsequent developments in Commission policy, particularly Order Nos. 2003 and 2003-A, which specifically addressed the circumstances and manner in which a transmission provider must pay for reactive power inside the deadband. In this vein, Order Nos. 2003 and 2003-A establish a reactive power compensation policy that, in the first instance, treats the provision of reactive power inside the deadband as an obligation of good utility practice rather than as a compensable service and permits compensation inside the deadband only as a function of comparability.[108]

[108] *See, e.g.*, *SPP I*, 119 FERC ¶ 61,199 at P 29 (citing Order No. 2003 at P 546 and P 537).

104. In any event, functional unbundling is intended to provide customers of utilities the opportunity to purchase unbundled, as opposed to bundled, services from utilities.[109] That is *not* what is involved here. What is at issue here is not whether transmission owners' customers have access to unbundled services. Rather, what is at issue here is whether unaffiliated generators have a right to compensation for providing reactive power inside the deadband. The two issues are very different. The services that the transmission owners' customers have access to will not change regardless of whether unaffiliated generators receive such compensation. Thus, whether Midwest ISO transmission owners have functionally unbundled does not depend on whether unaffiliated generators receive compensation for supplying reactive power inside the deadband. Moreover, the only support Reliant offers for its allegation that there is a violation of functional unbundling is the possibility that Midwest ISO transmission owners might recover lost revenues in their power sales rates. However, the possibility that transmission owners might generate new revenue to replace the revenue lost by terminating reactive power compensation inside the deadband does not mean that they are bundling their reactive power costs or that customers are deprived of the opportunity to purchase unbundled services.[110]

J. Disputes Between Transmission Owners

1. March 2008 Order

105. In its comments, Michigan Public Power questioned the adequacy of the Filing Transmission Owners' proposal to submit disputes between transmission owners in the same zone over whether to select Schedule 2 or Schedule 2-A to Midwest ISO's dispute resolution process. Michigan Public Power argued that dispute resolution is not the proper forum for such a dispute because the choice between Schedule 2 and Schedule 2-A is an either/or choice not conducive to negotiation. Michigan Public Power asserted that the Commission should modify Schedule 2-A to provide that in zones with multiple transmission owners, only those serving load should have the ability to decide whether to choose Schedule 2 or Schedule 2-A because they are the ones that pay Schedule 2 (or 2-A) charges and receive compensation from such charges.

106. In the March 2008 Order, the Commission stated that it was satisfied that the dispute resolution provisions in the Tariff would allow transmission owners to resolve disputes pertaining to Schedule 2-A in an equitable manner. The Commission noted that, under Schedule 2-A, no switch can occur until disagreements between transmission owners in the same zone are resolved. In addition, the Commission observed that a

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[109] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,718.

[110] *See BPA*, 125 FERC ¶ 61,273 at P 19.

transmission owner must make a section 205 filing before it can switch between Schedule 2 and Schedule 2-A and that parties would have a chance to raise concerns about any unresolved disputes when such a filing is made.[111]

2. **Arguments on Rehearing**

107. Michigan Public Power argues that the March 2008 Order fails to adequately address its concerns about disputes over whether to choose Schedule 2 or Schedule 2-A in zones with multiple transmission owners. Michigan Public Power explains that it is a participating transmission owner in the Greater Michigan Joint Pricing Zone with, among others, Michigan Electric Transmission Company, LLC (Michigan Electric). Michigan Public Power states that it has elected Schedule 2-A, while Michigan Electric chose to continue operating under Schedule 2. Michigan Public Power claims that because Michigan Electric has no customers to answer to for excessive Schedule 2 charges, it has no financial stake in whether Schedule 2 or Schedule 2-A applies, and thus no incentive to work with Michigan Public Power in resolving their different decisions.

108. Michigan Public Power speculates that the Commission may have thought that it provided a forum for transmission owners to air out their differences by requiring them to make a section 205 filing before switching between Schedule 2 and Schedule 2-A, but that this forum will not materialize if transmission owners that do not intend to switch from Schedule 2 to Schedule 2-A do not need to make a section 205 filing. Michigan Public Power argues that the Commission should require all transmission owners to make an initial section 205 filing stating whether they will continue to operate under Schedule 2 or switch to Schedule 2-A.

109. Michigan Public Power also contends that the Commission failed to address the concern that the Midwest ISO dispute resolution process is an inadequate method to resolve such disputes. Michigan Public Power argues that the dispute resolution process is a mechanism for customers to dispute charges under the Tariff, to question the applicability or interpretation of the Tariff in a given circumstance, or to address the distribution of revenues among multiple transmission owners in the same zone, but that it is not suited for resolving fundamental differences like the "either/or decision" to use Schedule 2 or Schedule 2-A. Michigan Public Power claims that the dispute resolution process will only delay relief and will ultimately result in the parties bringing the dispute before the Commission, which is contrary to its request for expedited decision-making.

110. Finally, Michigan Public Power requests that the Commission clarify that disagreements among transmission owners in the same zone do not preclude a transmission owner from making a section 205 filing to announce its election and that the

[111] March 2008 Order, 122 FERC ¶ 61,305 at P 119.

consent of the control area operator is not dispositive if there is no consensus within the zone. Michigan Public Power explains that paragraph 119 of the March 2008 Order states that no transmission owner may switch to Schedule 2-A until disagreements among transmission owners in its zone are resolved, while paragraph 116 requires that a transmission owner consult and gain the approval of the control area operator before choosing Schedule 2-A. Michigan Public Power is concerned that some parties may interpret these directives to prevent a transmission owner seeking to switch schedules from making a section 205 filing with the Commission unless and until there is consensus among the Transmission Owners and control area operator in the same zone.

111. Michigan Electric[112] filed an answer to Michigan Public Power's rehearing request.

3. **Commission Determination**

112. Rule 713(d) of the Commission's Rules of Practice and Procedure[113] prohibits an answer to a request for rehearing. Accordingly, we reject Michigan Electric's answer.

113. We deny rehearing. Michigan Public Power's claim that the Tariff's dispute resolution process is destined to fail is mere speculation. Michigan Public Power has not attempted to work through the process to produce agreement among transmission owners in the Greater Michigan Joint Pricing Zone on the question of whether to choose Schedule 2 or Schedule 2-A. Instead, it has simply written off the process based on its assumptions about how the dialogue will unfold. Consequently, we are not persuaded that the existing dispute resolution provisions in the Tariff are inadequate.

114. We also reject Michigan Public Power's request that we require transmission owners that intend to maintain their existing Schedule 2 rate schedules to file a section 205 filing to make that choice effective. Rate schedules that have been accepted by the Commission remain on file and effective unless they are superseded by a new rate schedule or are successfully challenged under section 206 of the Federal Power Act. Michigan Public Power's request is a backdoor attempt to abrogate an existing rate schedule through a section 205 proceeding.

115. Finally, we do not think that paragraphs 116 and 119 in the March 2008 Order are unclear. In paragraph 116, the Commission stated that a transmission owner must gain the approval of the control area operator before choosing Schedule 2-A:

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[112] The answer was filed by International Transmission Company and Michigan Electric.

[113] 18 C.F.R. § 385.713(d) (2009).

> We agree that a transmission owner must consult and gain the approval of the control area operator before choosing Schedule 2-A. Therefore, we direct the [Filing] Transmission Owners to revise the tariff language in Schedule 2-A to require that, when a transmission owner is not also the control area operator of its zone, both entities must agree to any change to Schedule 2-A, and to include such changes in the compliance filing directed below.[114]

Similarly, in paragraph 119 the Commission agreed that if there is a dispute between transmission owners in a zone over whether to choose Schedule 2 or Schedule 2-A, Schedule 2 will apply during the dispute:

> As the [Filing] Transmission Owners point out, no switch can occur until disagreements between transmission owners in the same zone are resolved. In addition, as discussed above, a filing must be made under section 205 of the [Federal Power Act] to revise the [Tariff] before a transmission owner can switch between Schedule 2 and Schedule 2-A; parties can raise concerns about any unresolved disputes when such a filing is made.[115]

Taken together, these paragraphs mean that a transmission owner cannot switch schedules until there is agreement between transmission owners and the control area operator in the same zone. In asking us to clarify that such agreement is not necessary, Michigan Public Power is actually asking us to grant rehearing. We deny the request. Michigan Public Power has not offered any persuasive reason why it was an error to require the approval of the control area operator. Moreover, by its own terms Schedule 2-A institutes zone-based reactive power compensation. It requires that the transmission owners in each zone must decide as a zone whether Schedule 2 or Schedule 2-A will apply. Schedule 2-A does not permit individual transmission owners within a zone to operate under Schedule 2-A's compensation provisions while other transmission owners operate under Schedule 2's compensation provisions. All of the transmission owners within a zone must agree before Schedule 2-A can apply to their zone.[116]

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[114] March 2008 Order 122 FERC ¶ 61,305 at P 116.

[115] *Id*. P 119.

[116] This is not to say that the decision of transmission owners in a zone to adopt Schedule 2-A would invalidate any rate schedules filed in that zone. As we have explained, if the transmission owners within a zone decide to switch to Schedule 2-A

(continued…)

K. Miscellaneous

1. Arguments on Rehearing

116. Dynegy asserts that the Commission erred in concluding that Dynegy did not explain why it believes the formula in its interconnection agreement is better than Schedule 2-A's lost opportunity cost formula. Dynegy argued that the provisions in its agreement are better able to capture its lost opportunity costs, and that it even provided the formula identifying the costs that can be contrasted with the cost recovery proposed in Schedule 2-A.

117. FirstEnergy contends that the Commission failed to address its concern that Schedule 2-A will hinder efforts to develop coordinated markets between Midwest ISO and PJM. FirstEnergy states that the convergence of these markets will enhance wholesale electricity competition in both markets, and that participants in these markets have devoted substantial time and resources to removing barriers to sales between them. FirstEnergy claims that accepting Schedule 2-A as part of the Midwest ISO Tariff will impede development of consistent market practices between PJM and Midwest ISO, and will therefore interfere with efforts to improve market efficiency. Specifically, FirstEnergy speculates that accepting Schedule 2-A may encourage generators in PJM to game the seam by taking advantage of locational marginal pricing differences created by inconsistent reactive power pricing regimes. FirstEnergy asserts that the Commission has previously expressed the desirability of removing barriers to competition between generators in both of these markets. FirstEnergy argues that the Commission should grant rehearing or require further modifications to Schedule 2-A in order to bring its provisions into alignment with PJM's reactive power compensation practices.

2. Commission Determination

118. We acknowledge that Dynegy stated in its protest that the lost opportunity cost formula in Schedule 2-A does not provide for the possibility that a generator's actual costs could exceed an lost opportunity cost tied to locational marginal prices and that Dynegy believed that the compensation provisions under the Dynegy interconnection agreement are better designed to capture Dynegy's lost opportunity costs.[117] However,

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existing rate schedules would remain on file and effective unless and until successfully challenged under section 206 of the Federal Power Act.

[117] Dynegy Protest at 47.

we continue to find that the lost opportunity cost formula, in Schedule 2-A is just and reasonable, for the reasons outlined in the March 2008 Order.[118]

119. We also reject FirstEnergy arguments. Although FirstEnergy claimed that the "vastly inferior" Schedule 2-A "may encourage generators in PJM to game the seam by taking advantage of [locational marginal pricing] differences created by inconsistent pricing of reactive power service,"[119] FirstEnergy provided no evidence to support that claim. In addition, the Commission does not require that Midwest ISO and PJM have identical market practices.

The Commission orders:

The requests for rehearing are hereby denied, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[118] March 2008 Order, 122 FERC ¶ 61,305 at P 101-103.

[119] FirstEnergy Rehearing Request at 20.