

Skadden Energy Law Handbook

2014

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Skadden Energy Law Handbook 2014

Thank you to our friends in the energy industry for the overwhelmingly positive response to our 2006 Handbook. We are pleased to provide you with our 2014 edition, which is also available on our website at www.skadden.com/energy-law. We hope this updated edition proves as useful as the first.

Skadden Energy Regulation and Litigation Group*

Kathryn K. Baran

William R. Barksdale

Donna M. Byrne

Gerard A. Clark

William B. Conway Jr.

Andrew R. Corcoran

James Danly

John N. Estes III

Matthew W. S. Estes

Cheryl Foley

David J. Hill

Tim T. Mastrogiacomo

John S. Moot

Mike Naeve

Jerry L. Pfeffer

Gerald L. Richman

John L. Shepherd, Jr.

Robert W. Warnement

Paul F. Wight

* The group thanks Karis Gong, Carl Edman and Christopher Howland for their work on the Handbook while associates at the firm. We also thank our legal assistants Cynthia Lewis and Amber Thornhill for their contribution and the long hours spent on this project.

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Chapter 1

The Hallmarks of a Successful Compliance Program

JOHN S. MOOT

Regulated companies across many industries have incentives to implement strong compliance programs that reduce the likelihood and magnitude of government sanctions. Entities regulated by FERC are no different. FERC has consistently emphasized that “[e]xperience has shown that a strong internal compliance program is an effective way of ensuring compliance with statutes, Commission rules, orders, regulations, and tariff provisions, and significantly increases the likelihood that an entity will abide by and follow the spirit of, relevant rules and regulations.”¹

With the enhanced authority granted by the Energy Policy Act of 2005,² FERC issued a series of compliance-related policy statements and guidelines to address civil penalty assessments and, pertinent to this chapter, the role of compliance programs in mitigating civil penalties. FERC also has issued Show Cause Orders and Orders Approving Settlements that discuss how certain compliance programs have factored into civil penalty assessments. This chapter is intended to provide regulated entities with a framework within which to assess FERC’s policies on compliance and a description of the key elements of a compliance program.

I. FERC’S POLICIES ON COMPLIANCE PROGRAMS

A. FERC’S EARLY POLICY STATEMENTS ON COMPLIANCE PROGRAMS (2005-2008)

EPAct 2005 broadened FERC’s civil penalty authority, in large part by significantly increasing the penalties for violations of FERC-administered statutes.³ Largely in response to EPAct 2005, FERC announced a new policy on enforcement—its *Enforcement Policy Statement*⁴—which for the first time set out factors it would consider to give “credit” for strong

¹ *Conference on Enforcement*, Docket No. AD07-13-006, 2013 Report on Enforcement at 30 (Nov. 21, 2013).

² Pub. L. No. 109-58, 119 Stat. 594 (2005).

³ As discussed in Chapter 3, FERC’s civil penalty authority was also broadened to encompass violations of any provision of Part II of the Federal Power Act, or rules, regulations, or orders thereunder, and the potential penalties were increased to up to \$1 million per day per violation. *See* EPAct 2005 § 1284(e), 119 Stat. at 980 (amending 16 U.S.C. § 825o-1). The potential penalties for violations referred to the Department of Justice for criminal prosecution were likewise greatly increased. *See id.* § 1284(d), 119 Stat. at 980 (amending 16 U.S.C. § 825o(a)).

⁴ *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 at PP 2, 22 (2005) (“*Enforcement Policy Statement*”).

compliance programs.⁵ In its *Enforcement Policy Statement*, FERC made clear that compliance was an essential goal of its enforcement authority and encouraged companies to “have comprehensive compliance programs, to develop a culture of compliance within their organizations, and to self-report and cooperate with the Commission in the event violations occur.”⁶ FERC relied on the experience and enforcement policies of other agencies in the *Enforcement Policy Statement*, including the Securities and Exchange Commission,⁷ the Commodities Futures Trading Commission,⁸ and the Department of Justice.⁹

The *Enforcement Policy Statement* lists several questions FERC considers in assessing the seriousness of a violation¹⁰ and then provides a more expansive list of questions FERC

⁵ In determining the amount of a proposed penalty Enforcement staff seeks in a settlement or FERC imposes through a show cause order, FERC is directed by statute to “take into consideration the seriousness of the violation and the efforts of such person to remedy the violation in a timely manner.” 16 U.S.C. § 825o-1(b) (setting penalties for violations of the Federal Power Act); 15 U.S.C. § 717t-1(c) (setting penalties for violations of the Natural Gas Act).

⁶ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 2.

⁷ *Id.* at PP 7, 10. FERC noted the SEC’s emphasis on cooperation by companies when violations do occur. See *generally Accounting and Auditing Enforcement*, SEC Release No. 1470 (Oct. 23, 2001).

⁸ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at PP 9-10. *CFTC Policy Statement Relating to the Comm’n’s Auth. to Impose Civil Monetary Penalties and Futures Self-Regulatory Orgs.’ Auth. to Impose Sanctions; Penalty Guidelines*, Comm. Fut. L. Rep. (CCH) ¶ 26,265 (CFTC Nov. 1, 1994); *CFTC Enforcement Advisory*, “Cooperation Factors in Enforcement Division Sanction Recommendations” (Aug. 11, 2004), <http://www.cftc.gov/files/enf/enfcooperation-advisory.pdf>.

⁹ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 8. FERC relied upon the DOJ’s Federal Sentencing Guidelines for Organizations (“*Sentencing Guidelines*”), which were promulgated as Chapter 8 of the U.S. Sentencing Guidelines Manual (“USSG”). The current edition of the USSG, last amended in November 2013, is found at http://www.ussc.gov/Guidelines/2013_Guidelines/Manual_PDF/2013_Guidelines_Manual_Full.pdf. FERC also emphasized the “Thompson Memo,” in which the DOJ provided guidance to its employees about charging corporate entities along with individuals in corporate fraud cases. See Memorandum from Deputy Attorney General Larry D. Thompson to Heads of Department Components and United States Attorneys, Principles of Federal Prosecution of Business Organizations at § VII.A (Jan. 20, 2003), available at http://www.usdoj.gov/dag/cftf/corporate_guidelines.htm. The Thompson Memo directs prosecutors to consider several factors, including, among others: the nature and seriousness of the offense; the pervasiveness of wrongdoing in the corporation, including complicity by management; the history of similar misconduct; whether the company timely and voluntarily disclosed wrongdoing; the efficacy of the company’s compliance program; and remedial actions taken by the company.

¹⁰ Factors examined under the “seriousness” prong of the Commission’s analysis include the following: harm caused by the violation; the benefit the wrongdoer gained from the violation; whether the action was willful, manipulative, deceitful, or part of a broader scheme; whether the wrongdoer acted in concert with others; the company’s history of violations; the duration of the wrongdoing; senior management awareness of the wrongdoing; whether there was a cover-up; and the effect of potential penalties on the financial viability of the company that committed the wrongdoing. *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 20. Regardless of any other factor, violators “will be expected to disgorge unjust profits whenever they can be determined or reasonably estimated.” *Id.* at P 19.

considers in determining whether to give a violator “credit” for the company’s “commitment to compliance.”¹¹ With regard to the nature of a company’s compliance program, FERC indicated it would inquire into, among other things, whether the company had an established, formal program that was well documented and widely disseminated; whether the compliance program was fully supported by senior management; the frequency with which the company reviewed and modified the program; and the company’s response to prior wrongdoing.¹² Noting that companies themselves “are in the best position to detect and correct violations” and that FERC expects companies to be “proactive” in this regard, FERC also explained that it would inquire into how the company uncovered the misconduct, whether the company acted immediately—including by stopping the violation(s)—upon learning of the misconduct, and whether the company presented a full and accurate report to FERC that included all relevant evidence and associated individuals.¹³

In May 2008, FERC issued a *Revised Enforcement Policy Statement* that provided additional guidance with respect to compliance programs.¹⁴ The *Revised Enforcement Policy Statement* elevated the importance of a company’s compliance program, stating that the two most important factors in determining whether to impose a civil penalty and the amount of that penalty are the seriousness of the offense and the strength of the entity’s commitment to compliance.¹⁵ The *Revised Enforcement Policy Statement* offered specific actions that FERC considers demonstrative of a robust internal compliance program, including, among others, creating an independent “Compliance Officer” that reports to the chief executive officer or the board of directors and implementing an internal “hotline” through which personnel may anonymously

Furthermore, some conduct may be “so egregious that the full use of the Commission’s penalty authorities is necessary regardless of the presence of other factors.” *Id.* at P 18.

¹¹ *Id.* at P 22.

¹² *Id.* For each of these inquiries, FERC also listed several subsidiary questions, such as whether the compliance program was supervised by a high-ranking official with independent access to the CEO or the Board; whether the program was independent and sufficiently funded; whether the company’s policies around compensation and promotion take into account compliance with FERC regulations; whether trainings were sufficiently detailed and thorough to install an understanding of the relevant rules; and whether the company took disciplinary measures against employees involved in violations. *Id.*

¹³ *Id.* at P 24.

¹⁴ *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156 (2008) (“*Revised Enforcement Policy Statement*”). In 2008, FERC also modified its No-Action Letter process, *Obtaining Guidance on Regulatory Requirements*, 123 FERC ¶ 61,157 (2008), proposed changing certain of its rules regarding ex parte communications and separation of functions as they apply to enforcement investigations, *Ex Parte Contacts and Separation of Functions*, Order No. 718, FERC Stats. & Regs. ¶ 31,279 (2008), and clarified and expanded its rules relating to the rights of a subject under investigation, *Submissions to the Comm’n Upon Staff Intention to Seek an Order to Show Cause*, Order No. 711, FERC Stats. & Regs. ¶ 31,270 (2008).

¹⁵ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 54; see also *Compliance with Statutes, Regulations and Orders*, 125 FERC ¶ 61,058 at P 6 (2008) (“*Compliance Policy Statement*”).

report suspected compliance issues.¹⁶ The *Revised Enforcement Policy Statement* also notes that FERC settlements often include compliance plans in addition to other remedies.¹⁷ In the settlements since 2008, these compliance plans have included, *inter alia*, one to three years of FERC monitoring, periodic sworn reports, measures to end the practices that led to the violations, training, and other steps to implement and improve compliance.¹⁸ Some of the settlements also have required that the subject under investigation commit a specified amount of funding to develop or improve a compliance program, and some require the retention of an independent third party to review and ensure compliance.¹⁹

In October 2008, FERC issued its *Compliance Policy Statement*, which reiterated FERC's "long-standing" statutory interest in promoting and rewarding a company's efforts at compliance.²⁰ According to the *Compliance Policy Statement*, "[a]chieving compliance, not assessing penalties, is the central goal of [FERC's] enforcement efforts."²¹ Turning again to other agencies for guidance, FERC specifically followed the Environmental Protection Agency's audit policy in its *Compliance Policy Statement*.²² FERC's *Compliance Policy Statement* makes explicit that, "if a company acts aggressively to adopt, foster, and maintain a [sic] effective corporate culture of compliance, and has in place rigorous procedures and processes that provide effective accountability for compliance, but a violation nonetheless occurs, the Commission may provide a significant reduction in, or even in some cases the elimination of, the civil penalty that otherwise would be imposed."²³ The *Compliance Policy Statement* supplements rather than replaces the previous policy statements on enforcement. Although FERC explained that it "cannot spell out what constitutes a [sic] effective compliance program in all circumstances," FERC nevertheless focused on four factors that it considered when determining whether to reduce or eliminate penalties: (1) the role of senior management in fostering compliance; (2)

¹⁶ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at PP 58-59. These actions also include preparing an inventory of current compliance risks and practices; providing sufficient funding to the compliance program; promoting compliance by identifying performance targets; linking compliance with compensation and personnel evaluations; providing disciplinary consequences for infractions; providing frequent mandatory training programs; and implementing a comprehensive compliance audit program. *Id.*

¹⁷ *Id.* at P 10.

¹⁸ *Id.* at PP 44-45; see also *In re Make-Whole Payments and Related Bidding Strategies*, 144 FERC ¶ 61,068 (2013); *Deutsche Bank Energy Trading, LLC*, 142 FERC ¶ 61,056 (2013); *Duquesne Light Co.*, 123 FERC ¶ 61,221 at P 12 (2008); *In re Edison Mission*, 123 FERC ¶ 61,170 at P 11 (2008).

¹⁹ See *supra* note 18; see also *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at PP 45-46.

²⁰ *Compliance Policy Statement*, 125 FERC ¶ 61,058.

²¹ *Id.* at P 1.

²² *Id.* at P 24 n.32 (citing *Incentives for Self-Policing: Discovery, Disclosure, Correction, and Prevention of Violations*, *Env'tl. Prot. Agency*, 65 Fed. Reg. 19,618 (Apr. 11, 2000)).

²³ *Id.* at P 4.

effective preventive measures to ensure compliance; (3) prompt detection, cessation, and reporting of violations; and (4) remediation efforts.²⁴

B. THE 2010 *POLICY STATEMENT ON PENALTY GUIDELINES*

In March 2010, as revised in September 2010, FERC issued the *Penalty Guidelines Policy Statement* that marked a critical shift in the way FERC employed its remedial powers. Since 2005, FERC, like the SEC and the CFTC, had employed a “case-by-case” approach to determining remedies, reasoning that such an approach would allow more discretion and flexibility to address each case on the individual facts.²⁵ FERC consistently eschewed the use of a “formula” to the exercise of its enforcement authority and instead assessed a company’s conduct and any penalties on a case-by-case approach.²⁶ In the *Penalty Guidelines Policy Statement*, however, FERC shifted to a “guidelines approach” patterned after the DOJ’s *Sentencing Guidelines*.²⁷ FERC decided that “the advantages of a penalty guidelines approach outweigh[ed] the disadvantages” and that the agency had “gained sufficient experience to employ a guidelines approach as a significant factor to be considered in determining civil penalties.”²⁸

In making this shift, FERC quantified for the first time point values associated with establishing, maintaining, and abiding by an effective compliance program that FERC will credit or deduct when determining the amount of a penalty it will assess a company for a violation.²⁹ FERC noted that a guidelines approach was in the public interest and would provide regulated entities more notice and certainty.³⁰ FERC also pointed out that applying the more straightforward guidelines approach will result in greater consistency and transparency.³¹ FERC acknowledged that a guidelines approach provides less flexibility, but emphasized that the *Penalty Guidelines* produce a penalty range as opposed to a specific figure and that the agency retains discretion and will not “always adhere to a rigid application of” the *Penalty Guidelines*.³² The *Penalty Guidelines Policy Statement* supplements the prior policy statements, and FERC acknowledged that the prior policy statements still provide “useful guidance” that informs FERC’s enforcement program.³³

²⁴ *Id.* at PP 4, 12.

²⁵ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at 10, 13.

²⁶ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 53.

²⁷ *Enforcement of Statutes, Orders, Rules, and Regulations*, 130 FERC ¶ 61,220 at P 1 (2010) (“*Penalty Guidelines Policy Statement*”).

²⁸ *Id.* at P 25.

²⁹ *Id.* at P 3.

³⁰ *Id.* at PP 2-3.

³¹ *Id.* at PP 28-31.

³² *Id.* at P 32.

³³ *Id.* at P 63.

The *Penalty Guidelines Policy Statement* describes how the *Penalty Guidelines* work in practice.³⁴ After determining a base violation level, applying several adjustments, and calculating a “base penalty,” step four of the *Penalty Guidelines* provides for a “culpability score” that is adjusted upward or downward based on six different considerations, including an upward adjustment when high-level personnel participated in, condoned, or were willfully blind of the violation,³⁵ where the organization has a history of committing violations, or where the organization obstructed justice or encouraged the obstruction of justice.³⁶ The fifth factor that impacts a culpability score deals with an organization’s compliance program: FERC will decrease an organization’s culpability score by three points if the violation occurred despite the existence of an effective compliance program, which is measured by seven factors set forth in section 1B2.1 of the *Penalty Guidelines* and described in the next section of this chapter.³⁷ FERC rejected an “all or nothing” approach to compliance credit in the *Revised Penalty Guidelines Policy Statement*, concluding instead that organizations can receive partial credit for effective compliance programs that meet most, but not all, of the requirements listed in section 1B2.1 of the *Penalty Guidelines*.³⁸ Finally, FERC’s sixth consideration is that, consistent with FERC’s prior policy statements, FERC will decrease the culpability score by five points if an organization self-reported the violation, exhibited full cooperation, and accepted responsibility without a trial-type hearing.³⁹ Self-reports, FERC clarified in the *Revised Penalty Guidelines Policy Statement* must not be “unreasonably delayed” in order for the company to receive credit.⁴⁰

There are also certain Settlement and Show Cause Orders that contain findings or proposed findings with respect to particular compliance programs. Not surprisingly, the Settlement Orders tend to not discuss compliance programs in detail, whereas the Show Cause Orders provide more extensive statements of Enforcements Staff’s views.⁴¹ In several cases,

³⁴ A more detailed discussion of the way FERC calculates penalties under the *Penalty Guidelines* is found in Chapter 3.

³⁵ *Id.* at PP 42-43. The *Revised Penalty Guidelines Policy Statement* eliminated a provision in the *Penalty Guidelines* providing that FERC would automatically eliminate any compliance credit when an organization’s high-level personnel was involved in, condoned, or was willfully blind of the violation. *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216 at P 122 (2010) (“*Revised Penalty Guidelines Policy Statement*”). In doing so, FERC explained that it would be unfair to automatically withhold all compliance credit when, despite an organization acting diligently, a rogue employee failed to adhere to clear direction from the company. The current *Penalty Guidelines* are available at the end of the *Revised Penalty Guidelines Policy Statement*.

³⁶ *Penalty Guidelines Policy Statement*, 130 FERC ¶ 61,220 at PP 44-47.

³⁷ *Id.* at P 48.

³⁸ *Revised Penalty Guidelines Policy Statement*, 132 FERC ¶ 61,216 at PP 114-19.

³⁹ *Penalty Guidelines Policy Statement*, 130 FERC ¶ 61,220 at P 49.

⁴⁰ *Revised Penalty Guidelines Policy Statement*, 132 FERC ¶ 61,216 at PP 128-29.

⁴¹ FERC’s Settlement Orders tend to be much more general than its Orders to Show Cause. Compare, e.g., *EnerNOC, Inc.*, 141 FERC ¶ 61,211 (2012) (noting generally that FERC considered that EnerNOC had no history of violations and had cooperated fully during all aspects of the investigation, but

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Enforcement staff has stated that the alleged failure of senior management to supervise manipulative trading conduct was “a particularly significant factor in [FERC’s] determination of the amount of civil penalties.”⁴² FERC emphasized that the trading conduct raised a series of “red flags” that “must have” put senior management on notice of the highly improper conduct.⁴³ FERC has also considered the lack of senior personnel involvement in fashioning remedies.⁴⁴

II. KEY ELEMENTS FOR A SUCCESSFUL COMPLIANCE PROGRAM

Chapter One, Part B of the *Penalty Guidelines* provides a list of specific characteristics of an effective compliance program. According to the *Penalty Guidelines Policy Statement*, these requirements are “consistent with the four hallmarks of effective compliance programs . . . enumerated in [the] Policy Statement on Compliance.”⁴⁵ The *Penalty Guidelines* state that, “[t]o have an effective compliance program, . . . an organization shall (1) exercise due diligence to prevent and detect violations; and (2) otherwise promote an organizational culture that encourages a commitment to compliance with the law.”⁴⁶ To meet the above criteria, the *Penalty Guidelines* provide that a company’s program must, at a minimum, include the components discussed in subsections A through K below.

A. PERIODIC RISK ASSESSMENTS

Compliance is by its nature a dynamic process that requires adjustments to changed circumstances. Among the factors FERC will consider in assessing the effectiveness of a compliance program is how often the program is reviewed and modified.⁴⁷ Accordingly, section 8B2.1(c) of the *Penalty Guidelines* requires that a company periodically assess the risk of violations or unlawful conduct. Upon identification of risk areas, a company must modify its program, as necessary, to reduce the risk of violations in those areas.⁴⁸

To identify its major risk areas, a company should ask:

- What has gone wrong at the company in the past?

without discussing *Penalty Guidelines*’ application), with *Barclays Bank PLC*, 144 FERC ¶ 61,041 at P 123 (2013) (describing application of specific culpability factors).

⁴² *Amaranth Advisors L.L.C.*, 120 FERC ¶ 61,085 at P 125 (2007).

⁴³ *Id.*; see also *In re Atmos Energy Corp.*, 137 FERC ¶ 61,190 at P 23 (2011) (“The civil penalty assessment reflects the nature and extent of high level personnel involvement at both AEM and Trans La who knew or had access to information The evidence establishes that AEM high-level personnel understood the requirements of the Commission’s prohibition on rollovers, but nonetheless elected to engage in a strategy . . . specifically designed to avoid posting the capacity for competitive bidding as required by the Commission’s capacity release regulations.”).

⁴⁴ *In re Westar Energy, Inc.*, 142 FERC ¶ 61,066 at P 10 (2013).

⁴⁵ *Penalty Guidelines Policy Statement*, 130 FERC ¶ 61,220 at P 48.

⁴⁶ *Penalty Guidelines* § 1B2.1(a); see also *Sentencing Guidelines*, USSG § 8B2.1(a).

⁴⁷ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁴⁸ See *Penalty Guidelines* § 1B2.1(c); see also *Sentencing Guidelines*, USSG § 8B2.1(c).

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- What near misses have occurred at the company in the past?
- What compliance failures have occurred at peer companies?
- What could happen in the future?

Sources of information that a company typically can utilize to help answer these questions include:

- Internal documentation relating to:
 - litigation
 - dealings with governments
 - customer complaints
 - employee complaints/concerns
 - audit reports
 - disclosure documents
 - contracts
- External documentation relating to:
 - orders or settlements of regulators in compliance proceedings
 - trade association information
 - public filings of peer companies
 - news stories
- Interviews of:
 - employees in support departments like legal, human resources, audit, and finance departments
 - employees from each business line
 - outside lawyers and consultants with industry experience
- Incentive pay structure:
 - Is compliance with FERC rules and regulations a factor in determining eligibility for and amounts of incentive pay awards?

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- Do incentive pay structures provide financial rewards, however inadvertent, for employees to skirt FERC rules and regulations?

Companies should prioritize their risk assessment findings by evaluating (i) the nature and seriousness of potential unlawful conduct, (ii) the likelihood that certain unlawful conduct may occur because of the nature of the company's business, and, as noted above, (iii) the company's prior history.⁴⁹ The *Penalty Guidelines*' commentary states that "[i]f, because of the nature of an organization's business, there is a substantial risk that certain types of violations may occur, the organization shall take reasonable steps to prevent and detect that type of violation. For example, an organization that, due to the nature of its business, has employees whose compensation is dependent on the final settlement price of a certain product shall establish standards and procedures designed to prevent market manipulation of that final settlement price."⁵⁰ Similarly, a regulated entity that is required to observe certain rules and regulations must ensure that all relevant employees understand and comply with all requirements. By prioritizing its findings, a company will be able first to address its greatest risks.

A company can most effectively manage its risks if it understands their root causes. At one end of the employee misconduct spectrum is misconduct that stems from ignorance or misunderstanding of legal or regulatory requirements or company policy. At the other end is purposeful bad conduct. In the middle, there is a large area representing negligence and lax management oversight and execution. Failure to understand legal requirements suggests a need for better written policies and procedures and/or improved communication of them (e.g., training). On the other hand, negligent or purposeful bad conduct suggests a possible need for better monitoring, auditing, more consistent disciplinary action, changing employee incentives, and/or reevaluating the corporate culture and tone being communicated by senior management.

Enforcement staff has not hesitated to recommend a stiff penalty when a company failed to periodically assess its risks. In a recent order, notwithstanding that the company had a "significant compliance program," Enforcement staff recommended only a single-point credit when a company failed to regularly review its risks.⁵¹ Specifically, the company did not regularly review the team's profits and losses or operations, which led to the company failing to flag suspicious changes in trading practices.⁵²

B. STANDARDS AND PROCEDURES TO PREVENT AND DETECT UNLAWFUL CONDUCT

A central factor considered by FERC when determining whether to give "credit" under its *Enforcement Policy Statement* is whether the company has an established, formal, independent compliance program.⁵³ Similarly, section 1B2.1(b)(1) of the *Penalty Guidelines* requires that a

⁴⁹ *Penalty Guidelines* § 1B2.1, cmt. 6.

⁵⁰ *Id.* § 1B2.1, cmt. 6(A)(ii).

⁵¹ *BP Am. Inc.*, 144 FERC ¶ 61,100 (2013); see also *id.*, Enforcement Staff Report and Recommendation at n.225.

⁵² *Supra* note 51.

⁵³ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

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company “establish standards and procedures to prevent and detect violations.”⁵⁴ As noted above, a company’s risk assessment can help identify those subject areas for which compliance policies and procedures should be developed or modified so that employees can fully understand the company’s expectations for their conduct. Other chapters in this Handbook are devoted to the discussion of specific FERC and related compliance requirements that need to be factored into effective compliance programs for electric companies.

C. DIRECTORS’ PROGRAM OVERSIGHT RESPONSIBILITIES

Effective compliance starts at the top. Key among the factors considered by FERC in determining a company’s commitment to compliance is whether a compliance program is supervised by an officer or other high-ranking official, and whether the company’s designated compliance official reports to or has independent access to the chief executive officer and/or the board of directors.⁵⁵ Section 1B2.1(b)(2)(A) of the *Penalty Guidelines* likewise requires that a company’s board of directors exercise reasonable oversight with respect to the program’s implementation and effectiveness. Set forth below are what we view as some of directors’ principal tasks with respect to overseeing a company’s compliance program. Certain suggestions for addressing these responsibilities are also set forth below.

1. *Know the Primary Features of the Compliance Program*

Directors should be knowledgeable about the content and operation of the company’s compliance program.⁵⁶ Although directors need not know every detail of the program, they should be familiar with its primary features and how they work together to create an effective program. The company officer with responsibility for the program’s day-to-day operations can present directors with an information session about the primary features of the program and any necessary or suggested modifications or improvements to the program.

2. *Know the Company’s Major Compliance Risks and Typical Compliance Problems*

Directors should be knowledgeable about the company’s and industry’s specific compliance risks and should be kept apprised of the typical compliance problems the company and industry face. This can be done by:

- establishing procedures for apprising the board of significant regulatory and industry developments affecting the company’s risk;
- overseeing, and receiving reports on, the risk assessments conducted by the company and the types of compliance issues that have been reported through the helpline or other reporting lines;

⁵⁴ See also *Sentencing Guidelines*, USSG § 8B2.1(b)(1).

⁵⁵ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁵⁶ See *Penalty Guidelines* § 1B2.1(b)(2)(A); see also *Sentencing Guidelines*, USSG § 8B2.1(b)(2)(A).

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- confirming that the program components adequately address the risks identified in any risk assessment; and
- verifying that any material ethics or compliance issue identified has been or is being adequately addressed and that steps have been or are being taken to prevent the problem from recurring, including making modifications to the program where appropriate.

3. *Demonstrate a Strong Tone at the Top*

A critical component of any effective compliance program is a strong tone at the top. A company can have a detailed and elaborate program on paper, but, if employees do not think management and the directors support the program, then it likely will be viewed as ineffective. Indeed, FERC has highlighted this element of compliance, noting that whether compliance is “fully supported by senior management” is a factor to be considered in determining a company’s commitment to compliance.⁵⁷ Directors can demonstrate their commitment to the program by:

- devoting adequate meeting time to its consideration;
- making clear to management its responsibility to report to the board any “red flags” or other signs of improper conduct or questionable risk;
- overseeing management’s involvement in and commitment to the program;
- scrupulously adhering to the code of conduct and other company policies applicable to directors; and
- considering an employee’s compliance with FERC regulations and the reporting of any violations in that employee’s compensation, promotion, and disciplinary action.⁵⁸

4. *Document, Document, Document*

All board actions in connection with its compliance program oversight responsibilities should be documented to facilitate the company’s ability to demonstrate the board’s involvement to an auditor or investigator.⁵⁹ Board and committee minutes should highlight when the board or audit or other committee has addressed program-related matters. Reports presented to the board or applicable committee regarding the program should, as appropriate, and subject to confidentiality and privilege considerations, be retained with the minutes of the meeting.

⁵⁷ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁵⁸ *Id.*

⁵⁹ For a discussion of compliance issues related to records retention, see Chapter 2 “FERC Investigations and Audits” of this Handbook.

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Training programs or information sessions attended by directors also should be documented as appropriate.⁶⁰

D. SENIOR OFFICERS' PROGRAM RESPONSIBILITY

In the *Enforcement Policy Statement*, FERC stated that it will consider whether a compliance program is supervised by an officer or “high-ranking” official when measuring a company’s commitment to compliance.⁶¹ The *Penalty Guidelines* impose a similar but more specific requirement. Section 1B2.1(b)(2)(B) of the *Penalty Guidelines* requires that senior management ensure that the company has an effective compliance program and that one or more specific individual(s) within senior management has been assigned overall program responsibility. Such individual(s) should have regular interaction with the person assigned day-to-day responsibility for the program and should keep other members of the senior management team apprised of the status of the program and any significant updates. It is advisable to delegate such responsibility in a formal fashion (e.g., by board resolution or job description).

Senior officers should (i) be knowledgeable about the content and operation of the compliance program, (ii) conduct their responsibilities in a manner consistent with a Company’s policies and procedures, and (iii) promote a company culture that encourages ethical conduct and a commitment to compliance with the law.⁶² Senior officers, like the board of directors, should lead by example by setting the proper tone at the top. In fact, in a recent Settlement Order, FERC described a company’s compliance program as “inadequate and ineffective” when senior management did not take responsibility for placing sufficient emphasis on compliance and did not ensure adequate compliance procedures.⁶³

Senior officers can help set the proper tone by:

- devoting adequate meeting time to the consideration of compliance;
- scrupulously adhering to company policies and procedures;
- communicating to employees the importance of adhering to company policies and procedures and ensuring effective training of the organization’s employees;⁶⁴
- consistently promoting the program through appropriate incentives;⁶⁵ and

⁶⁰ Section 1B2.1(b)(4) of the *Penalty Guidelines* states that directors should be trained by the company on subjects that are appropriate to the directors’ roles and responsibilities for the company. This requirement is discussed in greater detail below.

⁶¹ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁶² *Penalty Guidelines* § 1B2.1 cmt. 3.

⁶³ *In re Portland Gen. Elec. Co.*, 131 FERC ¶ 61,224 at P 15, Stipulation ¶ 20 (2010).

⁶⁴ *Penalty Guidelines* § 1B2.1(b)(4)(B).

⁶⁵ *Id.* § 1B2.1(b)(6).

- consistently enforcing the program through appropriate disciplinary measures.⁶⁶

E. SPECIFIC INDIVIDUALS' DELEGATED DAY-TO-DAY OPERATIONAL RESPONSIBILITY

The *Enforcement Policy Statement* indicates that a specific person should be designated as a “compliance official,” and that such official should have independent access to the chief executive officer and/or the board of directors.⁶⁷ Likewise, section 1B2.1(b)(2)(C) of the *Penalty Guidelines* requires that a specific individual within the organization be delegated day-to-day operational responsibility for the compliance program. That individual should:

- report periodically to senior management;
- report, at least annually, to the board of directors or a board committee;
- be given adequate resources;⁶⁸
- be given appropriate authority; and
- be given direct access to the board of directors or a board committee.⁶⁹

The purpose of the above requirements is to ensure that the compliance program is given sufficient support and stature. This, in turn, will be a strong indicator of the company's commitment to the success and integrity of its program. To further demonstrate the program's importance, it is advisable to delegate and describe the functions of the individual with operational responsibility for the program by board resolution, job description, or charter.

In a recent Settlement Order, FERC assessed a relatively modest \$200,000 penalty against Black Hills Power, Inc., noting that, in addition to “strong cooperation” by Black Hills, the Commission considered Black Hills’ “subsequent corrective action” and development of a compliance plan in assessing the relatively low penalty.⁷⁰ The compliance plan included a FERC Compliance Manager, a new position filled by an attorney with full-time responsibility for FERC compliance oversight, who reported directly to the Director of Corporate Compliance.⁷¹ FERC specifically called out the company's prior compliance program, a “decentralized approach,” and noted that, at least in part, it had likely led to the violations in the first place.⁷² By contrast, in

⁶⁶ *Id.* For further discussion on this point, see *infra* Part III.J.

⁶⁷ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁶⁸ Under the *Enforcement Policy Statement*, FERC too will examine the sufficiency of resources dedicated to a compliance program in evaluating its effectiveness. *Id.*

⁶⁹ Although the *Enforcement Policy Statement* seemingly suggests that the compliance official have access to “either” the CEO or the board of directors, the *Penalty Guidelines*, which were issued after the *Enforcement Policy Statement* contain only the requirement that the compliance official have access to the board or a subcommittee of the board. See *Penalty Guidelines* § 1.B2.1(b)(2)(c).

⁷⁰ *Black Hills Power, Inc.*, 136 FERC ¶ 61,088 at P 14, Stipulation ¶ 25 (2011).

⁷¹ *Id.*, Order at P 14.

⁷² *Id.*, Stipulation ¶ 24.

FERC's Order in *Lincoln Paper and Tissue*, FERC refused to reduce Lincoln's culpability score because the company had "no chief compliance officer or similar individual specifically tasked with ensuring that Lincoln complied with regulatory requirements."⁷³

F. BACKGROUND CHECKS AT HIRE AND PROMOTION

The *Penalty Guidelines* call for background checks on prospective employees with substantial discretion, including potential traders as well as management-level employees. Section 1B2.1(b)(3) of the *Penalty Guidelines* requires a company to "use reasonable efforts not to include within the substantial authority personnel of a company any individual whom the company knew or should have known through the exercise of due diligence, has engaged in violations or other conduct inconsistent with an effective compliance program."⁷⁴ Commentary to the *Penalty Guidelines* provides that this requirement applies at the time of both hire and promotion.⁷⁵

The components of a background check can vary but should be sufficient to address the above due diligence standard and should correlate with the responsibilities the individual is anticipated to be assigned. For example, a general background check may entail the following checks: (1) education, (2) driver's license, (3) criminal history, and (4) employment history for the preceding five years. Companies hiring or promoting a trader with significant discretion may also wish to consider electronic research in databases of FERC precedent and trade press to see if the trader's name has arisen in connection with conduct that, while not criminal, was deemed unlawful. A background check for an employee who will be assigned accounting/financial responsibilities may also include the following additional checks: (1) credit history, (2) Wall Street (call to the SEC), and (3) FBI.

G. COMMUNICATION OF STANDARDS AND PROCEDURES

A compliance program will not be effective if it is not understood by employees. FERC indicated in its *Enforcement Policy Statement* that the frequency and quality of training will be considered in evaluating a company's commitment to compliance. FERC reflected that a

⁷³ *Lincoln Paper & Tissue, LLC*, 144 FERC ¶ 61,162 at P 73 (2013).

⁷⁴ *Penalty Guidelines* § 1B2.1(b)(3). The commentary to an earlier section defines the term "substantial authority personnel" as follows:

"Substantial authority personnel" means individuals who within the scope of their authority exercise a substantial measure of discretion in acting on behalf of an organization. The term includes high-level personnel of the organization, individuals who exercise substantial supervisory authority (e.g., a plant manager, a sales manager), and any other individuals who, although not a part of an organization's management, nevertheless exercise substantial discretion when acting within the scope of their authority (e.g., an individual with authority in an organization to negotiate or set price levels or an individual authorized to negotiate or approve significant contracts). Whether an individual falls within this category must be determined on a case-by-case basis.

Id. § 1A1.1 cmt. 3(b).

⁷⁵ *Id.* § 1B2.1 cmt. 4(B).

training program should be “sufficiently detailed and thorough to instill an understanding of relevant rules and the importance of compliance.”⁷⁶ Though FERC indicated that training should be provided to “relevant personnel” without further defining such personnel, it makes sense to be cautious and overbroad in determining which personnel are relevant, rather than risk an unmitigated penalty because a wrongdoer was not appropriately trained. Similarly, section 1B2.1(b)(4) of the *Penalty Guidelines* provides that a company must “take reasonable steps to communicate periodically and in a practical manner its standards and procedures, and other aspects of its compliance program, . . . by conducting effective training programs and otherwise disseminating information appropriate to such individuals’ respective roles and responsibilities.” This training requirement applies not only to employees and officers, but also to directors and, as appropriate, agents.

A company’s risk assessment, as discussed above, will often highlight the substantive areas and individuals or functions for which training programs are advisable. All employees should attend certain training programs (e.g., ethics and compliance program, rollout or overview, and sexual harassment prevention programs). Only certain groups of employees need attend other training programs, such as those covering many of the topics addressed in this Handbook. Training programs can be delivered in different formats, such as computer-based or classroom training. Companies can develop training programs in-house or can utilize the resources of external consultants who specialize in developing and implementing training programs.

The *Penalty Guidelines* provide that training programs should be conducted *periodically* and *effectively*. A company can, among other things, utilize the findings of its risk assessments to determine how frequently certain training programs should be conducted. To help determine whether a training program has been effective, there are various methods available, such as (1) reviewing records of post-training misconduct, (2) surveys of employee opinions, (3) tests to assess employees’ understanding after the training, (4) evaluations of the training program completed by employees who attended such program, and (5) focus groups to assess employee opinions. Companies should make attendance at all applicable program training programs mandatory and should also have mechanisms in place to track employee attendance.

Section 8B2.1(b)(4) of the *Penalty Guidelines* also provides that a company should communicate its standards and procedures in ways other than training programs.⁷⁷ This is to encourage companies to remind employees frequently of the importance of the program and of complying with the company’s standards and procedures. Other forms of communication can include (1) newsletters, (2) electronic bulletin boards, (3) email, (4) memoranda or publications, and (5) letters to employees. As discussed in Chapter 8, FERC requires companies to provide copies of procedures for implementing the Standards of Conduct to employees. Senior officers

⁷⁶ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22. Also, as discussed in Chapter 8, FERC requires transmission providers to conduct training on the Standards of Conduct.

⁷⁷ See *Penalty Guidelines* § 1B2.1(b)(4) (requiring companies to take “reasonable steps” for “otherwise disseminating information appropriate to such individuals’ respective roles and responsibilities”).

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also should find opportunities to communicate personally to their employees the importance of conducting business ethically and in compliance with the company's program.

FERC's Orders have made clear that ensuring relevant personnel have sufficient familiarity with the Commission's requirements involves more than simply having in place the formal hallmarks of an effective compliance program. For example, Enforcement staff has found compliance programs inadequate when, despite the company handbook instructing employees to seek heightened review from supervisors before engaging in certain kinds of conduct, the relevant employees demonstrated little familiarity with the company's compliance requirements and did not seek review.⁷⁸ In another recent case, although the company under investigation had a FERC Compliance Program, which included an annual budget, a Chief Ethics and Compliance Officer, a Chief FERC Compliance Officer, training programs, and a compliance hotline, FERC nevertheless faulted the program because it lacked written controls and training on the applicable tariff.⁷⁹ The result was that "relevant personnel lacked sufficient familiarity" with Commission requirements.⁸⁰

H. AUDITING AND MONITORING, INCLUDING INTERNAL REPORTING MECHANISMS

In its recent *Enforcement Policy Statement*, FERC stressed the need for an ongoing process for companies to audit their compliance with FERC's regulations.⁸¹ Similarly, section 1B2.1(b)(5)(A) of the *Penalty Guidelines* provides that a company should take reasonable steps, such as auditing and monitoring, to ensure that its compliance program is followed. Auditing "refers to any systematic attempt to review and verify that there has in fact been compliance with the corporation's published standards" and "tends to have a retrospective or backward-looking connotation."⁸² In contrast, monitoring "tends to mean a contemporaneous inspection of an activity that is under review."⁸³

The methods used to audit a compliance program often depend on the size of a company. Larger public companies tend to have well-staffed internal audit departments which can conduct periodic audits of a company's program. Smaller companies—or, in the case of some specialized topics, even larger companies—may have to depend on others to help conduct a program audit, such as in-house counsel or an outside consultant. Whoever conducts an audit should (1) be independent of line management in order to have credibility with a prosecutor and with the employees who are a source of information, (2) have access to required information or personnel, (3) be of sufficient rank to command access without obstruction, and (4) have access

⁷⁸ *Deutsche Bank Energy Trading, LLC*, 140 FERC ¶ 61,178 at Enforcement Staff Report and Recommendation § V(A) (2012).

⁷⁹ *Duke Energy Carolinas, LLC*, 136 FERC ¶ 61,237 at P 13, Stipulation ¶¶ 10-13 (2011).

⁸⁰ *Id.*, Stipulation ¶ 11.

⁸¹ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁸² Bureau of Nat'l Affairs & American Corp. Counsel Ass'n, *BNA/ACCA Compliance Manual: Prevention of Corporate Liability*, ch. 4 § D at 4:29 (No. 37 1999 & Supp. No. 61 2003).

⁸³ *Id.*

to senior management and, where appropriate, the audit committee of the board of directors.⁸⁴ An example of monitoring is the tracking of attendance at training programs to ensure compliance with employee training requirements.

Internal reporting systems are another monitoring mechanism. The *Enforcement Policy Statement* highlights FERC's interest in discerning how a violation came to light and whether "the company act[ed] immediately when it learned of the misconduct."⁸⁵ Accordingly, FERC stressed that senior management should encourage employees to provide information to identify misconduct.

Section 1B2.1(5)(C) of the *Penalty Guidelines* provides that a company should "have and publicize a system, which may include mechanisms that allow for anonymity or confidentiality, whereby the organization's employees and agents may report or seek guidance regarding potential and actual criminal conduct without fear of retaliation." There are several types of internal reporting mechanisms available. These include (1) helplines (either internally or externally administered), (2) ombudspersons, (3) "open door" policies, and (4) compliance officers' or general counsel's telephone numbers. Whatever mechanisms a company has made available to report or seek guidance should be adequately publicized.

A helpline can facilitate anonymous reporting by employees. Although the *Penalty Guidelines* do not require anonymous reporting,⁸⁶ a helpline or other mechanism that allows anonymous reporting can encourage employees to report or seek guidance. A company should maintain records of the complaints lodged so that the company may, over time, identify any trends that would indicate a need for modifications within the compliance program. Records should also be maintained regarding how each call was addressed. A company will thereby be able to demonstrate that it responds appropriately to issues brought to its attention.

Although a company should endeavor to maintain the confidentiality of individual reports, it cannot guarantee their absolute confidentiality because confidentiality may be limited by the company's legal obligations, such as those relating to self-disclosure, subpoenas, and civil discovery requests, as well as to the needs of a particular investigation. To encourage reporting, company policy should provide that no employee will be subject to retaliation because of a good

⁸⁴ *Id.*

⁸⁵ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 24.

⁸⁶ In contrast to the *Penalty Guidelines*, section 301 of the Sarbanes-Oxley Act of 2002 requires audit committees of public companies to establish procedures for employees to report anonymously concerns regarding questionable accounting or auditing matters. See 15 U.S.C. § 78j-1(m)(4)(B) (requiring audit committees to "establish procedures for . . . the confidential, anonymous submission by employees . . . of concerns regarding questionable accounting or auditing matters"). Certain other regulatory requirements for reporting procedures do not require that they be anonymous. For example, (i) Item 7(h) of Schedule 14A of the Securities Exchange Act of 1934, as amended, requires procedures for communication between shareholders and directors of public companies; and (ii) New York Stock Exchange Rule 303A.03 requires procedures for communication between interested parties and the director who presides at executive sessions of non-management directors or with the non-management directors as a group of listed companies.

faith report of a complaint or concern.⁸⁷ This message should be highlighted in any policy or procedure that discusses the mechanisms available for reporting violations or seeking guidance.

In re ConocoPhillips Co. is instructive in terms of best practices from a monitoring perspective.⁸⁸ There, the Commission applied the *Penalty Guidelines* and imposed a penalty that fell within the *Penalty Guidelines* range.⁸⁹ In arriving at the penalty, FERC noted specifically ConocoPhillips' internal monitoring mechanisms,⁹⁰ emphasizing that Enforcement staff "learned of these violations because ConocoPhillips voluntarily chose to review all of its natural gas transactions during a period of 42 months between January 2004 and July 2007," conducting an internal investigation and filing a written self-report with FERC. In terms of remedial measures, ConocoPhillips strengthened its compliance program by conducting regular audits of its transactions, ensuring that management monitor the trainings to ensure that its employees attend training sessions, creating a new compliance position, and implementing an anonymous hotline whereby employees could report violations.⁹¹

I. PERIODIC EVALUATION OF THE PROGRAM

Electric companies operate in a dynamic environment. Both internal and external changes can impair the effectiveness of a compliance program unless the program is itself dynamically responsive to change. For this reason, FERC has indicated that the frequency of a company's review and modification of its compliance program is a factor to be considered in evaluating its commitment to compliance.⁹² Similarly, section 1B2.1(b)(5)(B) of the *Penalty Guidelines* provides that companies must "evaluate periodically the effectiveness" of their programs to assess if the systems in place are achieving the program's goals.⁹³ This evaluation may be conducted by company personnel or outside compliance program experts. For example, we regularly assist companies in evaluating their respective programs. A compliance program assessment should include a gap analysis that compares the program's components to the legal and regulatory requirements that the program was designed to address, using the *Penalty Guidelines* as the framework for that comparison. If gaps are identified, an action plan for needed or suggested program modifications or additions should be developed and implemented.

How frequently a company evaluates components of or its entire program should be guided by the level of legal risk the company's operations present, ever-changing business activities and regulatory requirements, the results of prior assessments, and claims against the company, among other factors. A company may wish to conduct more focused and frequent reviews of those aspects of its program that address particular high-risk areas and/or complex regulations.

⁸⁷ See *Penalty Guidelines* § 1B2.1(b)(5)(C).

⁸⁸ 138 FERC ¶ 61,004 (2012).

⁸⁹ *Id.* at P 17 n.6.

⁹⁰ *Id.* at PP 18-19.

⁹¹ *Id.*; see also *id.*, Stipulation ¶¶ 14-17.

⁹² *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁹³ *Penalty Guidelines* § 1B2.1(b)(5)(B).

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J. PROMOTE AND ENFORCE THE PROGRAM CONSISTENTLY

In the early days of competition, it was not uncommon for power traders' bonuses to be tied largely or even exclusively to financial performance. Typically there was no company-specified incentive or disincentive related to compliance rules. But, properly structured, such incentives and disincentives can be used to balance priorities and maintain employee activity within regulatory parameters. For this reason, FERC encourages companies to adopt policies regarding compensation and promotion that take into account the employee's compliance with FERC regulations. FERC also notes that disciplinary action against employees involved in violations is an indication of a company's commitment to compliance.⁹⁴ Similarly, section 1B2.1(b)(6) of the *Penalty Guidelines* provides that a company's compliance program should "be promoted and enforced consistently throughout the organization through (A) appropriate incentives to perform in accordance with the compliance program; and (B) appropriate disciplinary measures for engaging in violations and for failing to take reasonable steps to prevent or detect violations."⁹⁵

Among the incentives that could be used to promote compliance with the program are (1) performance evaluations, (2) sector, group, or division goals, or (3) site business goals. Including performance in accordance with the program as a component of a performance evaluation or team goal will underscore the importance of compliance and the program in a positive way.

Disciplinary measures for violations of law and company policy must be appropriate for the particular situation and consistently applied. As stated in Application Note 5 to section 8B2.1 of the *Sentencing Guidelines*, "[a]dequate discipline of individuals responsible for a violation is a necessary component of enforcement; however, the form of discipline that will be appropriate will be case specific."⁹⁶ Companies should keep records of the investigations conducted and any resulting disciplinary action. However, they should not blindly follow the discipline administered in the past. Rather, all the facts and circumstances of each situation should be considered and the appropriate discipline that would be consistent with past practice should be administered.

K. RESPOND APPROPRIATELY TO VIOLATIONS TO PREVENT FUTURE OCCURRENCES

Given the proliferation of behavioral rules applicable to utility employees, it is perhaps inevitable that compliance problems will occur. Taking corrective action could help limit any exposure going forward. For example, FERC penalties can accrue on a daily basis.⁹⁷ Taking immediate steps to stop any misconduct has been deemed important by FERC.⁹⁸ Prompt and full

⁹⁴ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 22.

⁹⁵ *Penalty Guidelines* § 1B2.1(b)(6).

⁹⁶ *Id.* § 1B2.1 cmt. 5.

⁹⁷ See 16 U.S.C. § 825o-1 (permitting FERC to impose penalties of up to \$1,000,000 per day for violations of Part II of the FPA).

⁹⁸ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 24.

HALLMARKS OF A SUCCESSFUL COMPLIANCE PROGRAM

self-reporting of violations, coupled with steps to correct the adverse impact on customers or third parties from the misconduct, may result in a reduction in the level of penalties.⁹⁹ The *Penalty Guidelines* also call for corrective action. Section 1B2.1(b)(7) of the *Penalty Guidelines* provides that, once a company has become aware of violations, it must take reasonable steps, including making necessary modifications to its program, to prevent further similar misconduct.¹⁰⁰ Consequently, after an investigation is completed, the company should endeavor to understand why and how the conduct occurred. Answers to such questions will help the company determine if any modifications to the program or any other business practice are required.

Recently, FERC demonstrated its commitment to these principles. FERC imposed a \$15,000 civil penalty when a company discovered the violations on its own, self-reported the violations to FERC, developed and implemented written procedures and other compliance measures after learning of the violations, and conducted various audits of its operations after its self-report to FERC.¹⁰¹ FERC imposed this relatively minor remedy, despite that the company did not have a fully effective compliance program prior to the violations, demonstrating the importance of a company's response upon uncovering potential violations.

CONCLUSION

Taken together, the *Penalty Guidelines Statement*, as revised, the *Enforcement Policy Statement*, as revised, and the *Compliance Policy Statement* create a strong incentive for companies to adopt a broad-based FERC compliance program. And, with FERC's promulgation of the *Penalty Guidelines*, FERC has provided some measure of clarity and transparency about the factors it will consider in determining whether a company's compliance program is effective. Although there is no "one-size-fits-all" compliance program, companies seeking to implement or modify compliance programs tailored to their specific needs can look to these policy pronouncements by FERC, along with advice from experienced practitioners, to be comfortable that their compliance programs will satisfy FERC and allow companies to reap the benefits of investing in a strong compliance program.

⁹⁹ *Id.* at P 25. Of course, self-reporting also carries with it the risk that FERC will penalize a company for conduct that might not otherwise have been detected.

¹⁰⁰ See *Sentencing Guidelines*, USSG § 8B2.1(b)(7). While this section of the *Sentencing Guidelines* requires that steps be taken to prevent future *criminal* misconduct, a compliance program should also endeavor to foster ethical conduct and compliance with all laws.

¹⁰¹ *DTE Gas Co.*, 143 FERC ¶ 61,188 at PP 2, 14, Stipulation ¶ 11 (2013).

Chapter 2

FERC Investigations and Audits

DONNA M. BYRNE
GERALD L. RICHMAN

FERC, through its Office of Enforcement, conducts investigations and audits of participants in jurisdictional electric and gas markets to ensure compliance with the statutes it administers, as well as FERC regulations and orders. In the past decade, FERC's enforcement activities have taken on an increasingly prominent role in the agency's regulatory agenda. The enactment of the Energy Policy Act of 2005 was a key catalyst for this shift because it significantly increased FERC's authority to pursue charges of energy market manipulation, as well as violations of mandatory reliability standards.¹ EPCA 2005 also dramatically increased FERC's civil penalty authority, both in scope and amount.² FERC's civil penalty authority now covers violations of the FPA, NGA and NGPA, and the penalties FERC is authorized to assess can be as much as \$1 million per violation.³ As the Director of Enforcement testified before a Senate sub-committee in 2014, FERC Enforcement investigations have led to the collection of approximately \$873 million in civil penalties and disgorgement since EPCA 2005 was enacted.⁴

FERC's robust enforcement program and increased enforcement and penalty authority mean that the stakes for an entity being investigated or audited are significant. This chapter provides a brief overview of FERC's Office of Enforcement, describes processes and practices in FERC investigations and audits, and identifies some considerations for the practitioner representing a company or individual in such proceedings.

I. FERC OFFICE OF ENFORCEMENT

FERC's investigative powers flow mainly from the sections of the FPA and NGA authorizing FERC to conduct investigations to detect statutory violations, as well as violations of

¹ See, e.g., Energy Policy Act of 2005, Pub. L. No. 109-58, § 315, 119 Stat. 594, 691 (2005) (Natural Gas Act prohibition on market manipulation); *id.* § 1211, 119 Stat. at 941 (electric reliability standards); *id.* § 1283, 119 Stat. at 979 (Federal Power Act prohibition on market manipulation).

² See *id.* § 314, 119 Stat. at 690-91 (NGA and Natural Gas Policy Act of 1978 civil and criminal penalty authority); *id.* § 1284, 119 Stat. at 980 (FPA civil and criminal penalty authority).

³ *Id.* FERC's civil penalty authority and the procedures and policies for employing it are discussed in Chapter 3.

⁴ Testimony of Norman C. Bay, Dir., Office of Enforcement, Fed. Energy Regulatory Comm'n, before the Committee on Banking, Financial Institutions and Consumer Protection Subcommittee, United States Senate at 2 (Jan. 15, 2014) ("Bay Testimony"), <http://www.ferc.gov/CalendarFiles/20140115143216-Bay-testimony-01-15-2014.pdf>.

FERC's rules, regulations and orders.⁵ The Commission's regulations state that it may "conduct investigations relating to any matter subject to its jurisdiction."⁶ Courts likewise have found FERC's investigatory authority to be broad: "[W]hile the regulatory and rate setting jurisdiction of the Commission is narrowly defined, Congress has given it broad authority to gather data which would in any rational way aid it in the performance of its statutory function."⁷

FERC's principal investigative arm, the Office of Enforcement, was established in August 2002 with the mission "to protect[] customers through understanding markets and their regulation, timely identification and remediation of market problems, and [to] assure[] compliance with [FERC's] rules and regulations."⁸ Prior to this, enforcement activities were generally carried out by the enforcement section within FERC's Office of General Counsel.⁹ Since that time, partially in response to the Western Energy Crisis in 2000 and 2001, FERC has greatly increased its market monitoring and oversight functions. By fiscal year 2012, the professional staff of the Office of Enforcement had grown to over 170 full-time employees, with a total budget for oversight and enforcement of approximately \$42.5 million.¹⁰

Currently, the Office of Enforcement is comprised of four divisions and the Director of Enforcement reports to the FERC Chairman. The Division of Audits and Accounting conducts compliance audits. The Division of Energy Market Oversight performs daily oversight of the natural gas and electric power markets, identifies market events and trends and proposes regulatory strategies for addressing issues. Market Oversight may refer issues of potential market manipulation or rules violations to the Division of Analytics and Surveillance ("DAS") or to the Division of Investigations. The DAS was created in 2012 to develop surveillance tools, conduct surveillance and analyze "transactional and market data to detect potential manipulation, anticompetitive behavior, and other anomalous activity in the wholesale electricity and natural

⁵ These powers are set forth in FPA section 307 and NGA section 14. 16 U.S.C. § 825f; 15 U.S.C. § 717m. *See also* 16 U.S.C. § 825 (FPA section 301, authority to require utilities to maintain accounts and records); 15 U.S.C. § 717g (NGA section 8, same); 16 U.S.C. § 825j (FPA section 311, authority to conduct investigations to enable FERC to make recommendations to Congress concerning legislation).

⁶ 18 C.F.R. § 1b.3.

⁷ *Union Oil Co. of Cal. v. FPC*, 542 F.2d 1036, 1039 (9th Cir. 1976) (construing language in section 14(a) of the NGA, 15 U.S.C. § 717m(a), that is virtually identical to the language in FPA section 307). Comparable provisions of the FPA and NGA are construed *in pari materia*. *See, e.g., Ark. La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981).

⁸ FERC, *Annual Performance Report for Fiscal Year 2003* at 19-20 (Feb. 2004), <https://www.ferc.gov/about/strat-docs/FY03-PR.pdf>. This office was originally called the Office of Market Oversight and Investigation, or OMOI. FERC reorganized staff and structure in 2006 and OMOI became the Office of Enforcement. FERC, *Annual Report 2006* at 29 (2007), http://www.ferc.gov/about/strat-docs/annual_rep.asp.

⁹ FERC, *Annual Report 2001* at 8 (2002), http://www.ferc.gov/about/strat-docs/annual_rep.asp.

¹⁰ FERC, *FY 2014 Congressional Performance Budget Request* at 11 (Apr. 2013), <http://www.ferc.gov/about/strat-docs/fy14-budg.pdf>. (171 full-time equivalent employees for oversight and enforcement for 2012, excluding support staff).

gas markets.”¹¹ The Division of Investigations, as its name suggests, conducts investigations of potential violations. Enforcement staff serves as trial staff if an investigation results in an enforcement action with adjudication before an administrative law judge (“ALJ”).¹² The FPA states that the Commission may be represented in civil penalty actions in federal district court by the Commission’s General Counsel or a Commission attorney designated by the FERC Chairman, in consultation with the Attorney General.¹³ The Director of Enforcement and Enforcement staff attorneys have fulfilled this role in recently filed FPA civil penalty assessment actions in federal district court.¹⁴

II. FERC INVESTIGATIONS

A. INITIATION OF AN INVESTIGATION

FERC investigations are initiated based on information that may come to Enforcement staff’s attention through a variety of channels, including referrals from the Commission itself or from other FERC divisions, reports from market monitors, tips from the industry (via the Enforcement Hotline¹⁵ or otherwise), and self-reports.¹⁶ To determine whether initiation of an investigation is warranted, staff conducts a “preliminary examination of the identified activity”¹⁷ and considers factors including the credibility and detail of the information in question, the nature and seriousness of the alleged violation, the nature and extent of any associated harm, whether the alleged violations were willful or inadvertent, and the compliance history of the alleged wrongdoer.¹⁸ The availability of staff resources may also be a consideration.¹⁹

¹¹ Bay Testimony at 3. “DAS staff includes approximately 45 professionals, including . . . economists, energy industry analysts, former traders, and former risk managers.” *Id.*

¹² *Statement of Admin. Policy Regarding the Process for Assessing Civil Penalties*, 117 FERC ¶ 61,317 at P 5.1.a.i (2006) (“*Civil Penalty Process Statement*”).

¹³ 16 U.S.C. § 823b(d)(6).

¹⁴ See *FERC v. Barclays*, Civil Action No. 13-02093 (E.D. Cal. filed Oct. 9, 2013); *FERC v. Lincoln Paper & Tissue, LLC*, Civil Action No. 13-13056 (D. Mass. filed Dec. 2, 2013) (“*Lincoln Complaint*”); *FERC v. Silkman*, Civil Action No. 13-13054 (D. Mass. filed Dec. 2, 2013).

¹⁵ See 18 C.F.R. §§ 1b.1(d), 1b.21; see also <http://www.ferc.gov/enforcement/staff-guid/enforce-hot.asp> (describing FERC’s Enforcement Hotline).

¹⁶ *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156 at P 23 (2008) (“*Revised Enforcement Policy Statement*”) (staff initiates investigations when it “has reason to suspect violations or when it has received information [suggesting the possibility] from a variety of sources, both internal and external.”); see also *Enforcement of Statutes, Regulations and Orders*, 129 FERC ¶ 61,247 at P 4 (2009) (“*Preliminary Notice of Violations*”) (authorizing secretary to issue staff’s preliminary notice of violations), *reh’g denied*, 134 FERC ¶ 61,054 (2011) (“*Preliminary Notice of Violations Rehearing Order*”).

¹⁷ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at PP 23-24.

¹⁸ *Id.* at P 25.

¹⁹ *Id.*

If Enforcement staff decides to take action, the ensuing investigation is governed by Part 1b of the Commission’s regulations, which provides for both “preliminary” and “formal” investigations.²⁰ Enforcement is authorized to initiate a preliminary investigation at its own discretion.²¹ To initiate a formal investigation, Enforcement staff must obtain an Order of Investigation from the Commission setting forth the matters to be investigated.²²

It should be noted that not all referrals to Enforcement necessarily lead to an investigation. In some situations, staff’s preliminary examination “establishes an adequate justification for the subject activity or otherwise indicates that no further inquiry is needed.”²³ Likewise, not all investigations result in an enforcement proceeding or a settlement. If Enforcement staff determines further investigation is unwarranted,²⁴ the investigation subject is notified but staff typically does not provide a formal written confirmation that the investigation is being closed.²⁵

B. NON-PUBLIC NATURE OF AN INVESTIGATION

Investigations are typically non-public during the initial stages and, while an investigation is on-going, no person is entitled to intervene as a matter of right.²⁶ The same is true in any public proceeding arising from an investigation.²⁷ The Commission has explained that “because a proceeding arising from an investigation is focused on the alleged conduct of a specific entity, intervention ordinarily is inappropriate and may delay or sidetrack the proceeding.”²⁸

The Commission’s regulations require that information obtained by Enforcement staff during the course of an investigation be treated as confidential and non-public, subject to certain exceptions—including Commission authorization for public disclosure, which is a matter within

²⁰ 18 C.F.R. § 1b.4.

²¹ *Id.* §§ 1b.1(b), 1b.6.

²² *Id.* §§ 1b.1(a), 1b.5, 1b.6. Although subpoenas are expressly authorized in a formal investigation, Enforcement also can procure subpoenas in preliminary investigations if necessary to ensure compliance with data requests. In addition, Enforcement can recommend that the Commission institute public proceedings (such as a show cause order) based on the results of a preliminary (as opposed to a formal) investigation. There is, thus, little practical distinction between a preliminary versus a formal investigation, except that some level of Commission awareness can be assumed if an Order of Investigation has been issued.

²³ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 24; *see, e.g., Conference on Enforcement*, Docket No. AD07-13-006, 2013 Report on Enforcement at 22 (Nov. 21, 2013) (“2013 Report on Enforcement”) (providing statistics on disposition of investigations).

²⁴ *Preliminary Notice of Violations*, 129 FERC ¶ 61,247 at P 4.

²⁵ *See id.*

²⁶ 18 C.F.R. § 1b.11.

²⁷ *Id.* § 385.214(a)(4).

²⁸ *Ex Parte Contacts and Separation of Functions*, Order No. 718, FERC Stats. & Regs. ¶ 31,279 at P 2 (2008) (codified at 18 C.F.R. § 385.214).

the Commission’s discretion.²⁹ In the early years following enactment of EAct 2005, investigations typically remained non-public unless and until there was a settlement or the Commission issued a show cause order.³⁰ In 2009, the Commission issued an order revising the standard protocol for public disclosure of an investigation.³¹ Once Enforcement staff has completed its investigation and given the subject an opportunity to respond to staff’s preliminary findings, if staff concludes that a violation has occurred, the Director of Enforcement is authorized to direct issuance of a public Preliminary Notice of Violations (“NOV”).³² The NOV identifies the subject of the investigation, briefly describes the conduct at issue and the regulations, statutes or orders alleged to have been violated.³³

C. FACT-FINDING PHASE

The main fact-finding tools Enforcement staff typically relies on in an investigation are data requests and depositions. In addition, a company or individual under investigation may, upon its own initiative, submit documents, statements of facts, or memoranda of law to explain its position.³⁴ If staff is amenable, it also may be possible to present information in a less formal manner, by arranging a meeting to discuss the facts and issues under investigation. Whether one chooses to affirmatively present information (as opposed to simply responding to Enforcement staff’s requests) is a strategy question that will turn on the unique circumstances of a given case.

It is always important, however, for both in-house and outside counsel to become familiar with the relevant facts (to the extent they can be discerned at the outset) as soon as there is any indication that FERC Enforcement may initiate an investigation. At a minimum, this entails identifying individuals within the company who are most likely to have relevant information and meeting with them to discuss the facts. Counsel should follow appropriate protocols to ensure that potentially applicable privileges—such as the attorney-client communication privilege and the work product doctrine—are preserved and that employees are instructed accordingly.

1. Document Preservation

A company often learns of an investigation when Enforcement staff issues a non-public directive requiring the company to preserve documents that may be relevant to the issues or events under investigation. Upon receiving such a preservation directive, company counsel should promptly issue a “litigation hold” notice, directing all employees with potentially relevant documents to preserve those documents. The directive should be in writing and it should specifically instruct employees that relevant data must be preserved, regardless of its format—hard-copy documents, electronically-stored documents such as emails, and also instant messages, and text and voicemail messages.

²⁹ 18 C.F.R. § 1b.9.

³⁰ *Preliminary Notice of Violations*, 129 FERC ¶ 61,247 at P 3.

³¹ *Id.*

³² *Preliminary Notice of Violations Rehearing Order*, 134 FERC ¶ 61,054 at P 17.

³³ *Preliminary Notice of Violations*, 129 FERC ¶ 61,247 at 62,338.

³⁴ 18 C.F.R. § 1b.18.

The document preservation directive should also cover backup tapes and stored records that might otherwise become unrecoverable pursuant to pre-existing retention policies. For example, companies typically have programs that automatically purge emails after a given time period. Different time frames and protocols may govern retention of different types of electronically stored information. These issues should be considered at the outset of an investigation—or earlier if it appears that an investigation may be forthcoming.

Once a litigation hold has been issued, it may be necessary to update the notice if the company's understanding of the scope of the investigation changes or if additional employees with potentially relevant information are identified. Even if there is no need to revise an existing preservation directive, counsel should follow up to confirm that recipients of the notice have appropriately complied with it.

2. Responding to Data Requests

The scope of an investigation is dictated by Enforcement staff. Indeed, an investigation into one particular issue sometimes expands or shifts focus if Enforcement staff thinks there are other issues that merit investigation.³⁵

The question of scope has particular significance with respect to data requests because of the burden associated with broad requests that sometimes span a multi-year period. This issue can be especially thorny in the early stages of an investigation because staff may assert that wide-ranging discovery is necessary to fully explore the matter under investigation. In addition, because the fact-finding process in a FERC investigation essentially is unilateral, it is very different from discovery in an adjudicatory proceeding where the bilateral nature of the process can make it attractive for the parties to mutually agree on reasonable limitations. Companies that become the subject of an Enforcement investigation should be prepared for staff to request large volumes of data, sometimes consisting of hundreds of thousands or even millions of documents. Although Enforcement staff is often willing to discuss approaches that can reduce the burden of broad requests (e.g., identifying custodians and search terms), companies nonetheless should be aware that disputes over what is reasonable versus burdensome are a common feature of the process.

Enforcement staff's formal data requests typically set a deadline for responses to be provided within thirty days. If additional time is required, staff may be willing to agree to an extension but typically expects a request for additional time to be made well in advance of the stated deadline for providing data. Particularly with respect to broad requests for "all communications" regarding a particular topic, staff typically is willing to agree to a rolling schedule for production of data. Prior to negotiating a production timetable, it is useful to make a preliminary assessment of the volume of data potentially at issue and to estimate the amount of time that will be required to review and produce responsive material.

³⁵ *In re Edison Mission*, 123 FERC ¶ 61,170 at PP 1, 10-11 (2008) (order approving stipulation and consent agreement where investigation of bidding practices resulted in "[n]o findings" regarding conduct in question but company agreed to \$7 million civil penalty and \$2 million in compliance plan investments to settle issues related to obligation to provide accurate, factual and complete information to Enforcement staff).

In comparison to what was common a decade or more ago, the volume and prevalence of electronically-stored information today has changed the nature of (and some of the pitfalls associated with) responding to document requests.³⁶ The changes can be driven by volume, significant amounts of duplication, and the fact that distribution of electronically stored information is easy and therefore often widespread. In larger cases, the electronic discovery process is best handled by a team of experienced professionals, which typically will include the company's own information technology ("IT") team, outside counsel's IT staff, and often one or more specialized third-party vendors. The main components of the process are (1) identifying and preserving data; (2) harvesting it (i.e., extracting the data from company computers and other repositories of electronically-stored information); (3) processing data to make it electronically searchable and "de-duplicating" it; (4) reviewing data for responsiveness and for privilege; and (5) processing responsive, non-privileged data for production in the format specified by Enforcement staff, and with appropriate labels indicating confidential materials, critical energy infrastructure information, etc.

Responding to data requests that involve electronically-stored information requires special attention to safeguard against possible spoliation, which is the destruction or significant alteration of evidence, or the failure to preserve property for another's use as evidence in pending or reasonably foreseeable litigation.³⁷ It is important to remember that spoliation can occur inadvertently. Examples of situations that may result in inadvertent spoliation include incomplete data searches, allowing routine "wipes" of desktops or servers to go forward in spite of a litigation hold, or failing to properly track data that was preserved but "lost" during the fact-finding process. Because early missteps can emerge as a problem at later stages of a FERC investigation, it is important to work with an experienced eDiscovery team from the start. Also, the steps taken in order to respond to requests should be carefully tracked throughout the fact-finding process.

Prior to production, potentially responsive documents should be reviewed to determine if attorney-client, attorney work product, or any other privileges or protections from disclosure apply. Enforcement staff's standard instructions for responding to data requests require that such documents be identified on a privilege log.

Just as in other litigation and enforcement contexts, privilege assertions can be a source of contention in a FERC investigation.³⁸ The Commission has explained that if a company "appropriately" interposes the attorney-client privilege, it will not be considered non-

³⁶ See, e.g., *Fed. Hous. Fin. Agency v. HSBC N. Am. Holdings, Inc.*, Nos. 11 Civ. 6189 (DLC) et al., 2014 WL 584300, at *2 (S.D.N.Y. Feb. 14, 2014) (describing document production in complex modern civil litigation as a "herculean undertaking, requiring an army of personnel and the production of an extraordinary volume of documents").

³⁷ *West v. Goodyear Tire & Rubber Co.*, 167 F.3d 776, 779 (2d Cir. 1999) (citing *Black's Law Dictionary* 1401 (6th ed. 1990)).

³⁸ In Part II.C.4 of this chapter, we discuss some of the dispute resolution paths that are available during a FERC investigation.

cooperative.³⁹ Nevertheless, FERC has warned that “the interposition of the privilege where it does not apply” may be “evidence of non-cooperation” if it is “designed to frustrate” the staff’s efforts to obtain information.⁴⁰ FERC has sought to enforce a subpoena in federal court against a target that withheld information based on a privilege assertion that FERC contested. This effort was unsuccessful in the first such case brought by FERC.⁴¹

In the past, inadvertent disclosure of privileged documents during an investigation, and questions of possible privilege waiver resulting from that disclosure, presented related sources of potential contention. In 2008, Congress addressed some of these issues by enacting Federal Rule of Evidence 502. The two main purposes of this rule are (1) to resolve the longstanding disputes in the courts regarding inadvertent disclosure and subject matter waiver; and (2) to respond to widespread complaints that the costs necessary to protect against privilege or work product waiver had become prohibitive.⁴² To address these issues, Rule 502 states that an inadvertent disclosure of protected communications or information in connection with a federal proceeding or to a federal agency does not constitute a waiver if the holder took reasonable steps to prevent disclosure, as well as reasonable steps to rectify the error once discovered.⁴³

³⁹ *Procedures for Disposition of Contested Audit Matters*, Order No. 675, FERC Stats. & Regs. ¶ 31,209 at P 35, *order on rehearing and clarification*, Order No. 675-A, FERC Stats. & Regs. ¶ 31,217 (2006) (codified at 18 C.F.R. pts. 41, 158, 286, 349). Although the Order No. 675 procedures address audits, the Commission’s discussion of the privilege issue appears equally applicable to investigations.

⁴⁰ Order No. 675, FERC Stats. & Regs. ¶ 31,209 at P 35.

⁴¹ *FERC v. J.P. Morgan Ventures Energy Corp.*, 914 F. Supp. 2d 5 (D.D.C. 2012) (magistrate judge’s order concluding respondent’s assertion of privilege was valid and denying FERC’s motion to compel production), *vacated*, No. 13–5013, 2013 WL 4804324 (D.C. Cir. Aug. 8, 2013) (per curiam) (vacating order based on unopposed motion and stipulation); *see also In re Make-Whole Payments*, 144 FERC ¶ 61,068 (2013) (approving settlement providing for joint motion to vacate order).

⁴² Fed. R. Evid. 502 advisory committee’s note.

⁴³ Fed. R. Evid. 502(b), advisory committee’s note (b). This, of course, leaves the question of “reasonableness” open to dispute. Pursuant to Rule 502(d), the reasonableness requirement effectively can be eliminated by court order in a given case (or by a court order adopting an agreement between the parties to this effect). One of the potential values of such an agreement or order is that the parties can make freer use of electronically-assisted review tools without fear that a court will later determine this was an unreasonable protection against inadvertent disclosure of a privileged document. Rule 502(d), however, is expressly limited to “the litigation pending before the court,” and does not address how this same outcome can be achieved in the context of a non-public investigation where there is no simple means of obtaining a court order to sanction an agreement of this nature between agency investigators and the subject of an investigation. *See* Laura D. Cullison, *Responding to Subpoenas from Federal Agencies: Will FRE 502(d) Provide the Means to Protect Privilege?*, 20 A.B.A Sec. Litig. J. 15 (Winter 2010) (discussing this issue and comments by Judge Shira A. Scheindlin suggesting that moving to quash an agency subpoena in federal court may create litigation that effectively triggers application of Rule 502(d)). Whether or not FERC Enforcement staff is willing to enter into the type of agreement contemplated by Rule 502(e), it is useful to have a discussion with Enforcement staff, prior to any document production, about the treatment of inadvertent disclosures and the process for seeking to “claw” them back.

Finally, before producing documents to staff in response to data requests, all proprietary and commercially sensitive documents should be identified and appropriately marked. FERC's general practice is to treat all information and documents obtained during the course of an investigation or audit as non-public.⁴⁴ Such information is generally subject to the disclosure requirements of the Freedom of Information Act ("FOIA"), subject to the application of statutory exemptions.⁴⁵ FERC's regulations provide that any person compelled to produce information may claim that the information, in whole or in part, is subject to a FOIA exemption and, therefore should not be disclosed.⁴⁶ Making this claim preserves the company's right of prior notice and protest regarding any FERC determination to publicly disclose the material.⁴⁷

3. *Depositions*

The rules governing depositions during a FERC investigation are different from those that apply in federal court litigation, and from the FERC regulations governing depositions in an administrative adjudication. For example, FERC investigations can involve multiple lengthy depositions of a single witness, although they may be characterized as one continuing deposition. This is different from litigation under the Federal Rules of Civil Procedure, where a party typically is limited to deposing a single witness for seven hours.⁴⁸

Particularly when repeat depositions take place after significant periods of time have elapsed, the ability to review the transcript of an earlier deposition is desirable—especially because inconsistencies in testimony might be viewed by Enforcement staff as evidencing a witness' lack of candor. FERC's regulations provide that a witness who has given testimony in an investigation is entitled to procure a transcript upon written request unless Enforcement staff has "good cause" to deny the request.⁴⁹ The regulations also state that "[i]n any event" a witness has the right to "inspect" the official transcript of his or her own testimony "upon proper identification."⁵⁰ In practice, the ability to access transcripts can differ from case to case. Staff sometimes provides transcripts following a deposition but, in other cases, staff has asserted "good cause" under the regulations and declined to provide access to deposition transcripts or exhibits during the non-public investigatory phase.

Although a person compelled to testify in a FERC investigation may be accompanied and advised by counsel,⁵¹ there are restrictions on the attendance of other persons at a deposition. In particular, Enforcement staff may prohibit other potential witnesses from attending. They may also prohibit any counsel who is not representing the deponent. This often means that company

⁴⁴ 18 C.F.R. § 1b.9.

⁴⁵ See generally Freedom of Information Act, 5 U.S.C. § 552; see also 18 C.F.R. § 388.108 (Requests for Commission records not available through the Public Reference Room (FOIA requests)).

⁴⁶ See 18 C.F.R. §§ 1b.20, 388.112.

⁴⁷ *Id.*

⁴⁸ Fed. R. Civ. P. 30(d)(1).

⁴⁹ 18 C.F.R. § 1b.12.

⁵⁰ *Id.*

⁵¹ *Id.* §§ 1b.16(b).

counsel is precluded from attending depositions of company employees if company counsel represents the company, but not the individual employee.

4. *Discovery Disputes During the Non-Public Fact-Finding Phase of an Investigation*

Whether the fact-finding phase of an investigation is conducted informally (on a voluntary basis), or formally through compulsory process (i.e., with administrative subpoenas), disputes sometimes arise. Although it is preferable to resolve such disputes with Enforcement staff if possible, circumstances sometimes arise where this is not possible. Before concluding that an impasse has been reached, it is important for the company to weigh its interest in the dispute at hand against the potential downsides of pursuing resolution through an adversarial process. These risks include souring the relationship with Enforcement staff, possibly complicating the path to a settlement, jeopardizing the cooperation credit under FERC's Civil Penalty Guidelines,⁵² and possibly accelerating public disclosure of the investigation.

If the issue in dispute is important enough to the company, there are two main procedural options for pursuing relief during the non-public, fact-finding phase of an investigation. First, one can seek relief from the Commission. This option is available whether or not an administrative subpoena has been issued, and it can be exercised on a non-public basis. Second, if the Commission denies relief under the first option, or the company chooses not pursue that path, the company may defend its position in federal court. Because subpoenas issued by FERC are not self-executing, if the subpoena recipient refuses to comply, FERC must obtain a federal district court order to enforce the subpoena.⁵³ A company that declines to comply with a subpoena, and therefore causes FERC to seek enforcement in federal court, must do so in good faith to avoid the risk of criminal prosecution.⁵⁴

One factor to consider in determining whether to exercise a good faith objection to a subpoena is the risk that the investigation may be disclosed by FERC making a public filing to enforce the subpoena. Although district courts have procedures for resolving subpoena-enforcement petitions while maintaining the confidentiality of a government investigation,⁵⁵

⁵² The Civil Penalty Guidelines are addressed in Chapter 3.

⁵³ *Belle Fourche Pipeline Co. v. United States*, 751 F.2d 332, 334 (10th Cir. 1984) ("Subpoenas issued by the FERC are not self-executing; rather, to enforce them the FERC must seek an order from a federal district court compelling compliance with all or part of the subpoenas.") (citing 49 U.S.C. § 12(2), (3)).

⁵⁴ Compare 16 U.S.C. § 825f(c) ("Any person who willfully shall fail or refuse to attend and testify or to answer any lawful inquiry or to produce books, papers, correspondence, memoranda, contracts, agreements, or other records, if in his or its power so to do, in obedience to the subpoena of the Commission, shall be guilty of a misdemeanor and, upon conviction, shall be subject to a fine of not more than \$1,000 or to imprisonment for a term of not more than one year, or both.") and 15 U.S.C. § 717m(d) (same), with *Reisman v. Caplin*, 375 U.S. 440, 446-47 (1964) ("[N]oncompliance [with administrative subpoena] is not subject to prosecution . . . when the [summons] is attacked in good faith."); *Belle Fourche*, 751 F.2d at 334-35 (rejecting argument for pre-enforcement review of subpoena because subpoena target was entitled to decline to comply and force FERC to seek judicial enforcement).

⁵⁵ See, e.g., Local Rule 5.1(h) of Local Rules of the U.S. District Court for the District of Columbia (effective as of May 22, 2014) (providing for filing cases under seal).

there is no requirement that FERC utilize these procedures. If it does not, the investigation may be disclosed earlier than it otherwise might have been disclosed.⁵⁶

D. *BRADY* RIGHTS IN A FERC INVESTIGATION

The Commission has confirmed that *Brady v. Maryland*, 373 U.S. 83 (1963), and its progeny apply to section 1b investigations and administrative enforcement actions under Part 385 of the Commission’s regulations.⁵⁷ In *Brady*, the U.S. Supreme Court held that the Due Process Clause obligates government prosecutors to disclose all evidence that is “favorable to an accused” or “would tend to exculpate him or reduce the penalty.”⁵⁸ Thus, *Brady* governs both information that bears on guilt or innocence, and also information relevant to punishment.⁵⁹ The Court has explained that *Brady* applies to evidence that is “material” to guilt or punishment,⁶⁰ that materiality is an “imprecise standard,” and that “the significance of an item of evidence can seldom be predicted accurately until the entire record is complete.”⁶¹ Accordingly, questions of materiality should be resolved in favor of disclosure.⁶²

Describing the disclosure process in FERC investigations and enforcement actions, the Commission has explained that “staff will scrutinize materials it receives from sources other than the investigative subject(s) for material that would be required to be disclosed under *Brady*. Any such materials or information that are not known to be in the subject’s possession shall be provided to the subject.”⁶³ Privileges—including, but not limited to claims of attorney-client,

⁵⁶ 18 C.F.R. § 1b.9 (investigative proceedings shall be treated as nonpublic “except to the extent . . . the Commission . . . authorizes the public disclosure of the investigation”). Notably, some regulatory schemes expressly prohibit the agency from publicly disclosing a non-public investigation when filing to enforce a subpoena. See, e.g., *In re Sealed Case*, 237 F.3d 657, 666-67 (D.C. Cir. 2001) (“[B]oth 2 U.S.C. § 437g(a)(12)(A) and 11 C.F.R. § 111.21(a) plainly prohibit the [Federal Election Commission] from disclosing information concerning ongoing investigations under any circumstances without the written consent of the subject of the investigation. Accordingly, we conclude that the FEC failed to act in accordance with law when it sought to file the subpoena enforcement action on the public docket.”). The statutes administered by FERC do not contain a similar mandate requiring the Commission to maintain confidentiality during a non-public investigation.

⁵⁷ *Enforcement of Statutes, Regulations, and Order; Policy Statement on Disclosure of Exculpatory Materials*, 129 FERC ¶ 61,248 at P 7 (2009) (“*Brady Policy*”)

⁵⁸ 373 U.S. at 87-88.

⁵⁹ See *id.* at 85-86 (affirming appellate court’s decision to remand the case for a new trial on whether the defendant should receive the death penalty or life imprisonment).

⁶⁰ *Moore v. Illinois*, 408 U.S. 786, 794-95 (1972).

⁶¹ *United States v. Agurs*, 427 U.S. 97, 108 (1976).

⁶² *Id.*

⁶³ *Brady Policy*, 129 FERC ¶ 61,248 at P 9 (emphasis added).

work-product, and deliberative process—do not preclude the disclosure of materials otherwise subject to *Brady*.⁶⁴

Although there is no requirement to do so, where it is possible to identify the specific nature of any *Brady* materials that are thought to be in staff’s possession, it can be helpful to provide a general description of such materials (e.g., communications with a market monitor, third-party interviews, etc.). There is no express limitation on when a *Brady* request can be made, and there is good reason to make such a request before exploring settlement. Significant exculpatory information can be obtained through this process, and it may have an impact on the course of settlement negotiations.

E. COMMUNICATIONS WITH COMMISSION

The company may, at any time during an investigation, submit to the Commission written information, including documents, statements of facts, or memoranda of law, for the purpose of explaining its position or furnishing evidence.⁶⁵ As a matter of general policy, however, neither the Commissioners nor their assistants will receive oral communications, in person or by telephone, from the subject of an ongoing staff investigation or their representatives.⁶⁶

F. PRELIMINARY STAFF FINDINGS

After concluding the fact-finding process, Enforcement staff presents its preliminary findings to the subject of the investigation, either orally or in writing.⁶⁷ In some cases, this information is conveyed in an informal meeting and the company is invited to consider making a settlement offer on its own. In other cases, the information is conveyed in a long and detailed “preliminary findings letter.” If this latter procedure is followed, the company is usually given a thirty-day period to respond in writing. Under either procedure, however, even though Enforcement staff’s findings are characterized as “preliminary,” it is typically very difficult to persuade Enforcement staff to change its conclusions in a significant manner at this point in the investigation. If staff is not persuaded to close the matter, the next step is either settlement or the “show cause order” phase.

⁶⁴ *Id.* at P 13 (“Exculpatory materials or information may be contained in documents subject to Commission privilege or immunity. . . . [T]he privileged status of exculpatory material or information will not preclude the disclosure of such material or information. However, the disclosure in Section 1b investigations shall be subject to Commission approval because the privileges belong to the Commission, not to staff, and nonpublic investigative information cannot be disclosed absent Commission direction.” (emphasis added)).

⁶⁵ 18 C.F.R. § 1b.18.

⁶⁶ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 27. The subject of an investigation may speak to decisional staff other than the Commissioners and their assistants about an investigation, and may speak to the Commissioners and their assistants about subjects other than the investigation, as otherwise permitted by the Commission’s regulations. See *Ex Parte Contacts and Separation of Functions*; *Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,634 at P 11 (2008) (“*Ex Parte Contacts and Separation of Functions NOPR*”).

⁶⁷ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 32.

G. SETTLEMENT DISCUSSIONS

Settlement discussions typically commence after Enforcement staff has conveyed its preliminary findings and conclusions to the subject of the investigation and the subject has had an opportunity to respond. If, after considering the response, staff decides not to close the investigation, it will request settlement authority from the Commission. This process is non-public and typically involves staff submitting a recommended settlement range to the Commission in a formal memorandum that is not shared with the company. After addressing concerns and differences of views among the Commissioners, staff may receive authorization to settle within a range of civil penalty amounts and will subsequently present a settlement offer to the company within that range. The range of authorized amounts will not be disclosed to the company.

A variety of factors can influence the length of time that settlement discussions may take, including how close or far apart the parties are, and whether the “gap” between them relates to the amount of the proposed civil penalty or, instead, involves requested mitigation measures that may have implications for how the company conducts its business. Other factors may include Enforcement staff’s caseload, potential statute of limitations issues, and general perceptions about how serious the respective parties are about settling the matter.

If the company reaches agreement with Enforcement staff on a settlement, the agreement is memorialized in a Stipulation and Consent Agreement that typically follows a standard format with a case-specific discussion of the alleged violations, penalty and compliance obligations. The agreement typically is submitted to the Commission for approval on a non-public basis, but the Commission’s ruling on the settlement will be in the form of a public order attaching the Stipulation and Consent Agreement.

H. SHOW CAUSE ORDER PHASE

If settlement negotiations fail, Enforcement staff will prepare a notice pursuant to 18 C.F.R. § 1b.19 (“1b.19 Notice”), notifying the subject of the investigation that it will recommend that the Commission issue a show cause order.⁶⁸ The notice will set forth staff’s position on the alleged violations. The company is permitted to respond, typically within thirty days, and the response is transmitted to the Commission along with Enforcement staff’s report and recommendation.⁶⁹ The company does not receive a copy of Enforcement’s report at this juncture.⁷⁰

⁶⁸ 18 C.F.R. § 1b.19. This notice is required in all but “extraordinary circumstances.” The regulation does not provide specific examples of “extraordinary circumstances” that would justify failure to provide notice, but generally states that they would involve situations where prompt Commission review is necessary “in order to prevent detriment to the public interest or irreparable harm. . . .” *Id.*

⁶⁹ *Id.*

⁷⁰ In an investigation of Energy Transfer Partners, L.P. in 2007, the Commission responded to criticism regarding its approach to separation of functions in enforcement matters by announcing a new policy that would be implemented prospectively. Specifically, the Commission announced that, going forward, designated Office of Enforcement investigative staff would become non-decisional employees

The Commission reviews the Enforcement staff report and the company's 1b.19 response. If a majority of the Commissioners vote in favor of proceeding with the case, the Commission will issue a short Order to Show Cause and Notice of Proposed Civil Penalty. These orders are formulaic and generally state that the allegations set forth in an attached report from Enforcement staff support ordering the company to show cause (i) why it should not be found to have committed the alleged violations; and (ii) why it should not be required to pay the proposed civil penalty. The subject of the investigation is typically given thirty days to answer the Show Cause Order, although extensions are sometimes granted.

If the investigation involves alleged FPA violations, the order also will inform the company of its right to elect procedures for resolving the allegations if the Commission accepts the recommendations in the staff report. Specifically, the company will have the opportunity to choose between (i) an administrative hearing before a FERC administrative law judge, followed by FERC review of the judge's decision, and then review by a United States Court of Appeals, giving deference, as appropriate, to FERC's legal and factual conclusions; or (ii) immediate assessment of the civil penalty followed by a federal district court action to affirm the penalty, in which the court is authorized to review *de novo* both the law and the facts involved.⁷¹ If a federal district court proceeding is not elected in writing within thirty days, that right is forfeited and any adjudication of the charges will be before a FERC administrative law judge.

I. ADJUDICATION OF THE MERITS OF AN ALLEGED VIOLATION

FERC has explained that the process for adjudicating the merits of an alleged violation depends on whether the statute alleged to have been violated is the FPA, the NGA or the NGPA.⁷² As noted above, the FPA expressly provides that the penalty target is entitled to elect either (a) an administrative hearing before a FERC ALJ, or (b) an immediate assessment by the Commission, followed by an action in federal district court where the court is authorized to review *de novo* both the law and the facts involved.⁷³ The proper application of the FPA provision authorizing a *de novo* district court action is currently being litigated in a number of FERC cases pending in federal district court.⁷⁴

under the Commission's separation of functions once the 1b.19 recommendation is submitted to the Commission. *Energy Transfer Partners, L.P.*, 121 FERC ¶ 61,282 at P 89 (2007). Later, in a rulemaking issued on May 15, 2008, the Commission stated that the initiation of a formal proceeding would be a "more practical triggering event" for designating Enforcement staff as non-decisional for the remainder of the enforcement proceeding at issue. *Ex Parte Contacts and Separation of Functions NOPR*, FERC Stats. & Regs. ¶ 32,634 at P 7; Order No. 718, FERC Stats. & Regs. ¶ 31,279 (adopting proposal set forth in NOPR) (codified at 18 C.F.R. § 385.2202).

⁷¹ FPA section 31(d)(2)-(3), 16 U.S.C. § 823b(d)(2)-(3); *Civil Penalty Process Statement*, 117 FERC ¶ 61,317 at P 5.

⁷² See generally *Civil Penalty Process Statement*, 117 FERC ¶ 61,317.

⁷³ FPA section 31(d)(2)-(3), 16 U.S.C. § 823b(d)(2)-(3).

⁷⁴ See *supra* note 14. FERC has previously stated that election of *de novo* procedures under FPA section 31(d) triggers a trial *de novo*. See *Procedures for the Assessment of Civil Penalties Under Section 31 of the Fed. Power Act*, Order No. 502, FERC Stats. & Regs. ¶ 30,828 at 31,220 (1988)

The NGA differs from the FPA in that it does not expressly provide for the option of a federal district court adjudication. FERC has concluded that the “NGA civil penalty process does not include the possibility for the person to receive a *de novo* review in district court.”⁷⁵

The procedures for NGPA civil penalty assessment are substantially the same as the judicial assessment option under the FPA.⁷⁶ If the penalty target chooses to contest an alleged violation, the Commission assesses the penalty and, if it is not paid, the Commission institutes an action in federal district court.⁷⁷ Although the NGPA does not expressly provide for the option of an ALJ hearing, the Commission has asserted the authority to order one.⁷⁸

The procedures for penalty assessment are discussed in more detail in Chapter 3, Civil and Criminal Penalties Under the Federal Power and Natural Gas Acts.

III. FERC AUDITS

FERC Enforcement, acting through its Division of Audits and Accounting (“audit staff”), undertakes audits under the authority of FPA section 301, which requires electric utilities to maintain books and records for FERC examination. Audit staff conducts audits in order to “enable the Commission to maintain effective and appropriate oversight over jurisdictional entities while ensuring compliance, accountability, and transparency.”⁷⁹

(codified at 18 C.F.R. pt. 385); *Consumers Power Co.*, 68 FERC ¶ 61,077 at 61,380 (1994). Nevertheless, FERC has asserted a different position in the three civil penalty assessment actions it filed in 2013. See, e.g., Lincoln Complaint ¶ 86 (“[T]his Court can and should affirm the penalty assessment without modification following a review of the Order Assessing Civil Penalty and the materials presented to the Commission during the penalty assessment process.”).

⁷⁵ *Civil Penalty Process Statement*, 117 FERC ¶ 61,317 at P 7. FERC’s interpretation has been challenged but never resolved by the courts. See, e.g., *Energy Transfer Partners, LP v. FERC*, 567 F.3d 134, 146 (5th Cir. 2009) (“The proper construction of the NGA must await resolution when and if the Commission determines that the NGA has been violated and assesses a penalty. As we have said, the NGA’s statutory scheme is far from clear. Congressional action to chart with clarity the desired course of proceedings in this regard would not be unwelcome.”).

⁷⁶ NGPA section 504, 15 U.S.C. § 3414(b)(6)(E)-(F); *Civil Penalty Process Statement*, 117 FERC ¶ 61,317 at P 11.

⁷⁷ 15 U.S.C. § 3414(b)(6)(E)-(F).

⁷⁸ *Compare Civil Penalty Process Statement*, 117 FERC 61,317 at P 12 (“The NGPA does not provide for an on-the-record hearing before an ALJ. Rather, after considering the response to the proposed penalty (and in the absence of a settlement of the matter), the Commission assesses the penalty by order after considering the facts presented.”), with *Energy Transfer Partners, L.P.*, 121 FERC ¶ 61,282 at P 32 (“[W]hile NGPA section 504 does not provide a person with the right to require an evidentiary hearing before an ALJ, that does not prevent the Commission from holding such a proceeding if we find it is appropriate.”).

⁷⁹ *2013 Report on Enforcement* at 29.

FERC INVESTIGATIONS AND AUDITS

Audit staff typically initiates audits without any suggestion that there has been wrongdoing by a particular company.⁸⁰ This contrasts investigations, which are triggered by alleged or suspected violations. The purpose of an audit is not to impose sanctions, but rather to ensure compliance with the Commission's statutes and regulations.⁸¹ Accordingly, audits tend to focus on subject matters of current interest to the Commission. Nevertheless, the audit staff will refer matters to Enforcement's Division of Investigations when audits uncover suspected violations that appear to warrant investigation.⁸²

According to recent data, audit staff completed 29 financial and operational audits of public utilities and natural gas pipelines in fiscal year 2013.⁸³ These audits, which explored a wide range of topics, resulted in 360 recommendations for corrective action and directed \$15.4 million in refunds.⁸⁴ Other recommendations directed improvements to companies' internal processes and procedures, enhancements to the accuracy and transparency of reports and websites, and more efficient and cost-effective operations.⁸⁵

In terms of audit subject matter under the FPA, roughly one quarter of all audits in the 2013 fiscal year involved electric reliability issues. The next largest number of FPA audits involved transactions between affiliates, and the third largest category involved matters related to market-based rates and Electronic Quarterly Reports. Besides these subjects, FPA audits during this period also involved compliance with Commission directives in orders approving utility mergers and acquisitions; compliance with Commission directives in orders granting transmission incentives; calculation of formula rates; compliance with RTO/ISO rules related to capacity markets and demand response; debt and security issuance; and various FERC accounting requirements.⁸⁶ These figures are mostly consistent with the Commission's reported experience with FPA audits during the 2012 fiscal year.⁸⁷

Audit staff commences audits by sending the target company a short letter generally describing the audit's subject matter. The commencement letter typically will be a public

⁸⁰ *Id.*

⁸¹ *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 14.

⁸² *See, e.g., Entergy Servs., Inc.*, 142 FERC ¶ 61,241 (2013) (order approving stipulation and consent agreement following referral of reliability concerns arising during audit); *Portland Gen. Elec. Co.*, 131 FERC ¶ 61,224 (2010) (order approving stipulation and consent agreement following referral of OATT issues arising during audit); *Duquesne Light Co.*, 123 FERC ¶ 61,221 (2008) (order approving stipulation and consent agreement following referral of affiliate rules issues arising during audit); *Otter Tail Power Co.*, 123 FERC ¶ 61,213 (2008) (order approving stipulation and consent agreement following referral of OATT and transmission concerns arising during audit).

⁸³ *2013 Report on Enforcement* at 32.

⁸⁴ *Id.* Audit staff also directed accounting adjustments that collectively removed \$200,000 from utility plant accounts. *Id.*

⁸⁵ *Id.*

⁸⁶ *Id.* at 32-46.

⁸⁷ *Conference on Enforcement*, Docket No. AD07-13-005, 2012 Report on Enforcement at 29 (Nov. 15, 2012).

document, though informational requests and company responses remain non-public. Audit staff collects information through data requests, telephone interviews and site visits. Just as in an Enforcement investigation, FERC places great importance on a company's cooperation with staff. FERC has clarified, however, that the requirement of cooperation is not meant to "suggest that efforts by an audited person taken in good faith to resolve issues that arise in the course of an audit would be construed as evidence of non-cooperation. Where an audited person believes that data requests create a substantial burden that could be relieved by limiting the scope of the request, by the audited person providing other information that would achieve the same purpose, or by some other resolution that would satisfy audit staff, an audited person is not failing to cooperate if it suggests changes to, or narrowing of, the data requests."⁸⁸

At the conclusion of audit staff's information gathering activities, audit staff typically will conduct a "wrap-up" conference, where audit staff and the company try to clarify issues, resolve disputes, and discuss proposed findings and remedies.⁸⁹ Ultimately, audit staff will provide the company a draft version of an audit report or similar document summarizing staff's findings and recommendations, and the company is given a certain number of days to submit written comments (or challenges to findings or proposed remedies).⁹⁰ Following receipt of the comments and subsequent discussions with the company, if the company and audit staff reach an agreement, the Director of Enforcement typically issues an order under delegated authority⁹¹ adopting a final (public) report constituting audit staff's findings and the recommendations to which the company has agreed.

Where the audited company contests some or all audit findings, the process is governed by regulations issued in Order No. 675.⁹² Any initial order that the Commission subsequently may issue with respect to the public audit report or similar document shall note, but not address on the merits, the findings or proposed remedies with which the audited company disagrees.⁹³ The Commission shall provide the company thirty days to respond to the initial order and address the issues with which it disagrees.⁹⁴ If the company has decided to challenge the audit

⁸⁸ Order No. 675, FERC Stats. & Regs. ¶ 31,209 at P 35. Order No. 675 issued procedures governing contested audits, *see infra* Part II.C.4. While those procedures do not govern non-public investigations, *id.* at P 42, it appears reasonable to assume that this FERC discussion of good-faith data production would be equally applicable in the contexts of investigations.

⁸⁹ *See id.* at P 18.

⁹⁰ The *audited* company will have 15 days to comment, although additional time can be requested. 18 C.F.R. § 41.1(b).

⁹¹ *Id.* § 375.311.

⁹² *See supra* note 39.

⁹³ 18 C.F.R. § 41.1(b).

⁹⁴ *Id.*

findings, it may elect either shortened procedures (essentially, a paper hearing) or a trial-type proceeding before an administrative law judge.⁹⁵

Unless the Commission expressly states that its findings apply to other parties, a Commission order approving an *uncontested* audit report has no precedential value.⁹⁶ However, if an audited company contests audit findings through either shortened or trial-type procedures, the matter becomes an on-the-record proceeding and the legal reasoning and conclusions of the resulting order will apply to non-parties.⁹⁷

As in other formal proceedings, interested parties may seek leave to intervene, but a successful intervenor in a contested audit proceeding will be limited to arguments or facts that directly relate to a finding or proposed remedy that is already at issue in the contested audit proceeding, and was noted in the Commission's initial order concerning the audit report.⁹⁸

The Commission emphasizes that the procedural rules for contested audits issued in Order No. 675 are not intended to discourage informal contacts between an audited company and audit staff where appropriate.⁹⁹ While the Commission declined to establish a specific "informal procedure," Order No. 675 notes that an audited company can request to speak with audit staff management at any time during an audit up to the time that the company indicates in writing that it contests specified findings or proposed remedies.¹⁰⁰ Order No. 675 emphasizes that existing practices regarding "wrap-up" conferences and draft audit reports continue to apply.¹⁰¹

⁹⁵ 18 C.F.R. §§ 41.2, 41.3. The Commission will honor an election of trial-type procedures unless it determines that no material facts are in dispute. *Id.* § 41.7. Conversely, the Commission reserves the discretion at any time to set the matter for hearing for a trial-type hearing. *Id.*

⁹⁶ Order No. 675, FERC Stats. & Regs. ¶ 31,209 at P 32.

⁹⁷ *Id.* The Commission acknowledges that because a practice was successfully implemented by one audited company, this does not necessarily mean that the same practice will be a good fit elsewhere. *Id.* at P 48. The Commission has stated that practices implemented by a company to improve compliance may serve as useful references, but they are not binding on others. *Id.*

⁹⁸ Order No. 675-A, FERC Stats. & Regs. ¶ 31,217 at P 7.

⁹⁹ Order No. 675, FERC Stats. & Regs. ¶ 31,209 at P 17.

¹⁰⁰ *Id.* at P 18 (footnote omitted).

¹⁰¹ *Id.*; see also, *Revised Enforcement Policy Statement*, 123 FERC ¶ 61,156 at P 17 (reemphasizing that existing practices regarding wrap-up conferences and draft audit reports continue to apply).

Chapter 3

Civil and Criminal Penalties Under the Federal Power and Natural Gas Acts

DONNA M. BYRNE
GERALD L. RICHMAN

The Energy Policy Act of 2005¹ significantly increased the potential penalties for violations of the statutes administered by FERC. The Commission's previous penalty authority was deemed inadequate to discharge its responsibility to oversee electric and natural gas markets.² The new penalty provisions therefore raise the stakes for noncompliance with FERC rules and regulations and FERC itself has alluded to that authority as one reason for regulated companies to develop comprehensive compliance programs.³

I. CIVIL PENALTIES

A. STATUTORY AUTHORITY

Congress first granted the Commission civil penalty authority under the Federal Power Act in 1986, when it enacted the Electric Consumers Protection Act.⁴ FPA section 31 allows the Commission to impose penalties of up to \$10,000 per day for violations of any order, license or exemption issued under the hydroelectric power provisions of FPA Part I.⁵ Until the enactment of EAct 2005, FERC had only limited authority to seek civil penalties for violations of FPA Part II, which governs wholesale power sales and electric transmission service. Specifically, FPA section 316A previously restricted the Commission's authority to impose civil penalties up to \$10,000 per day for violations of only four sections of FPA Part II.⁶ EAct 2005 amended

¹ Pub. L. No. 109-58, 119 Stat. 594 (2005).

² For example, Commissioner Joseph Kelliher wrote that FERC's inability to assess civil penalties for *all* Part II violations, as well as the \$10,000 per day cap, was a "severe handicap in the Commission's enforcement of market rules." Joseph T. Kelliher, *Market Manipulation, Market Power, and the Auth. of the Fed. Energy Regulatory Comm'n*, 26 Energy L.J. 1, 23 (2005).

³ *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 at PP 2, 6, 22 (2005) ("*Enforcement Policy Statement*").

⁴ Pub L. No. 99-495, § 12, 100 Stat. 1243, 1255 (1986).

⁵ See 16 U.S.C. § 823b.

⁶ Before the enactment of EAct 2005, the Commission's authority to impose civil penalties under the FPA Part II was limited to rules and orders issued under the following statutory provisions: (i) FPA sections 211 and 212, 16 U.S.C. §§ 824j, 824k, concerning mandated wheeling and interconnections; (ii) FPA section 213, 16 U.S.C. § 824l, concerning information requirements for responses to requests for wholesale transmission service, and (iii) FPA section 214, 16 U.S.C. § 824m,

section 316A⁷ to cover violations of any provision of FPA Part II, including any implementing rule, regulation, or order issued thereunder and raised the penalty ceiling from \$10,000 to \$1,000,000 for each day for each violation.⁸

Similarly, with respect to natural gas, FERC had authority to issue civil penalties only for violations of the Natural Gas Policy Act of 1978, a statute that under some circumstances covers services by or on behalf of intrastate natural gas pipelines. The principal statute governing FERC regulation of the natural gas industry, the Natural Gas Act, did not provide FERC with any civil penalty authority.⁹ When Congress enacted EAct 2005, however, it granted FERC authority, in NGA section 22, to impose civil penalties of up to \$1,000,000 for NGA violations.¹⁰

In its *Enforcement Policy Statement*, the Commission made clear that this enhanced civil penalty authority exists in addition to other remedies it may impose for a single violation. Thus, FERC's "enhanced civil penalty authority [under EAct 2005] will operate in tandem with [its] existing authority to require disgorgement of unjust profits obtained through misconduct and/or to condition, suspend, or revoke . . . market-based rate authority for sellers of electric energy."¹¹ Indeed, "companies will be expected to disgorge unjust profits whenever they can be determined or reasonably estimated."¹² Hence, the imposition of civil penalties will not preclude the simultaneous disgorgement of profits and other remedies, such as revocation or suspension of market-based rate authority.¹³

B. PENALTY GUIDELINES

In 2010, the Commission issued a Policy Statement on Penalty Guidelines, which adopted mechanisms for calculating civil penalties for under the FPA, NGA, and NGPA.¹⁴ The

concerning rates charged by exempt wholesale generators ("EWGs"). See 16 U.S.C. § 825o-1(a) (2004). Violations of these four statutory provisions were punishable only through civil penalties under FPA section 316A; they were expressly excluded from the reach of the criminal penalties provided for under FPA section 316. See *id.* § 825o(c). As a result of EAct 2005, violations of these provisions are now subject to both the FPA's criminal and civil penalty provisions. See EAct 2005, § 1284(d)(3)), 119 Stat. at 980 (striking 16 U.S.C. § 825o(c)).

⁷ 16 U.S.C. § 825o-1.

⁸ See EAct 2005, § 1284(e)(1), 119 Stat. at 980 (amending 16 U.S.C. § 825o-1(a)).

⁹ See *Coastal Oil & Gas Corp. v. FERC*, 782 F.2d 1249, 1253 (5th Cir. 1986).

¹⁰ 15 U.S.C. 717t-1; see EAct 2005, § 314(b), 119 Stat. at 690-91 (renumbering NGA sections 22 through 24 and creating a new section 22 codified at 15 U.S.C. § 717t-1).

¹¹ *Enforcement Policy Statement*, 113 FERC ¶ 61,068 at P 12. FERC intends "to take the full range of possible remedies into account in determining whether a penalty should be imposed in addition to other remedies and, if so, the appropriate amount of the penalty." *Id.* (footnote omitted).

¹² *Id.* at P 19.

¹³ Courts have long recognized that FERC's discretion is at its "zenith" when fashioning remedies. See, e.g., *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967).

¹⁴ *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216 (2010) ("Revised Penalty Guidelines Policy Statement"). The Commission initially issued a Policy Statement

Commission explained that the principal purpose of the *Penalty Guidelines* is to add greater fairness, consistency and transparency to FERC's enforcement program and the imposition of civil penalties thereunder.¹⁵ The *Penalty Guidelines* were expressly based on the United States Sentencing Guidelines for the sentencing organizations in criminal proceedings in the federal courts.¹⁶

The Commission uses the *Penalty Guidelines* to determine the range of penalties it may seek against organizations for violations of the statutes, rules, regulations, restrictions, conditions or orders overseen by the Commission.¹⁷ However, the Commission retains the discretion to depart from the calculated penalty guideline ranges or and even to refrain entirely from seeking any penalties.¹⁸ In addition to penalties, the Commission retains separate authority and discretion to order disgorgement if a violation resulted in pecuniary gain to the violator.¹⁹

1. Violation Level

A penalty guidelines calculation begins by identifying a numerical violation level.²⁰ The *Penalty Guidelines* establish violation levels for three categories of violations:

- *Violations of Commission-Approved Reliability Standards.*²¹ This section applies to independent reliability investigations conducted by FERC's Office of Enforcement. Such investigations, in contrast to penalties assessed by NERC, typically occur in response to high visibility events like blackouts or other major disturbances. For

adopting civil penalty guidelines in March of 2010. *Enforcement of Statutes, Orders, Rules, and Regulations*, 130 FERC ¶ 61,220 (2010). Shortly thereafter, the Commission suspended the Policy Statement in order to allow interested entities an opportunity to comment on the proposed guidelines before adopting them. *Enforcement of Statutes, Orders, Rules, and Regulations*, 131 FERC ¶ 61,040 (2010). Based on comments by industry participants, the Commission modified its proposal in various respects before issuing the *Revised Penalty Guidelines Policy Statement*.

¹⁵ *Revised Penalty Guidelines Policy Statement*, 132 FERC ¶ 61,216 at P 2.

¹⁶ *Id.* at PP 3, 6.

¹⁷ See *Penalty Guidelines* § 1A1.1(1). The *Penalty Guidelines* apply to organizations, not individuals. *Id.* ("This chapter applies to the penalties to be imposed on all organizations for violations of the statutes, rules, regulations, restrictions, conditions or orders overseen by the Federal Energy Regulatory Commission."). The Commission has explained that it "will determine the appropriate penalty for natural persons based on the facts and circumstances of the violation but will look to [the] Guidelines for guidance in setting those penalties." *Id.*, cmt. appl. note 1.

¹⁸ *Id.* § 1A1.1(1).

¹⁹ *Id.* § 1B1.1.

²⁰ *Id.* § 1C2.1.

²¹ *Id.* § 2A1.1. For violations of reliability standards, in contrast to other types of violations treated under the *Penalty Guidelines*, multiple violations leading the same event are treated as single violation for purposes of calculating penalties. *Id.* § 1A1.1(3).

these offenses, the base violation level is 6.²² This offense level is then subject to enhancement based either on risk of loss or loss of load.²³

- *Risk of Loss.* This potential enhancement, based on the level of risk in combination with the level of harm, ranges from 0 to 26.²⁴ A figure at the lower end of the scale applies where there is a low risk of minor harm, such as a week's lapse in maintenance record keeping.²⁵ A figure at the higher end of this range would apply where there is a high risk of extreme harm, such as where there are multiple violations similar to those determined to have caused the 2003 Northeast blackout.²⁶
- *Loss of Load.* The load factor ranges from 0 to 32.²⁷ The low end of this range corresponds to a loss of less than 10 MWh of firm load and the high end to a loss of 10,000 or more MWh of firm load.²⁸
- Only the larger of these two potential enhancements is added to the base violation level to reach the final, adjusted base violation level.²⁹
- *Intentional or Reckless Misrepresentations and False Statements to the Commission or Commission Staff.* This section of the *Penalty Guidelines* covers serious falsehoods with an intent to deceive.³⁰ The base violation level is 18 for such violations, reflecting that the Commission views potential violations of this kind to be very serious.³¹ Indeed, the base level of 18 may be increased by 3 points if the violation resulted in substantial interference with the administration of justice,³² and

²² *Id.* § 2A1.1(a).

²³ *Id.* § 2A1.1(b).

²⁴ *Id.* § 2A1.1.

²⁵ *Id.* § 2A1.1, cmt. illus. ex. (1)(A).

²⁶ *Id.* § 2A1.1(b)(1); *id.*, cmt. illus. ex. (1)(H).

²⁷ *Id.* § 2A1.1(b)(2).

²⁸ *Id.*

²⁹ *Id.* § 2A1.1(b); *see id.*, cmt. appl. note 1.

³⁰ Besides stating that section 35.41(b), 18 C.F.R. § 35.41(b), of the Commission's regulations "is one of the requirements that could be covered" under this section of the *Penalty Guidelines*, the Commission declined to identify any other statutory provision or rule that, if violated, could trigger application of this guideline. *Revised Penalty Guidelines Policy Statement*, 132 FERC ¶ 61,216 at PP 174-76.

³¹ *Penalty Guidelines* § 2C1.1(a).

³² *Id.* § 2C1.1(b)(1). The Commission defines substantial interference to include any deception that results in the Commission or staff taking official action it otherwise would not have, such as closing an investigation, as well as the unnecessary expenditure of Commission resources. *Id.* § 2C1.1, cmt. appl. note 2.

by an additional 2 points if it involved a substantial number of records, documents or tangible objects, or was otherwise extensive in scope, planning or preparation.³³

- *Fraud, Anti-Competitive Conduct and Any Other Rule, Tariff and Order Violations.*³⁴ This catch-all category covers most economic violations. The base violation level is 6.³⁵ This base violation level may be enhanced based on dollar amount of loss, volume or duration, and seriousness.
 - *Loss Factor.* The loss factor depends on the total losses suffered by others due to the offense conduct and ranges from 0 (for losses totaling less than \$5,000)³⁶ to 30 (for losses totaling \$400 million or more).³⁷ The *Penalty Guidelines* take a very broad view of losses, defining them to be the larger of the actual losses suffered (which includes all pecuniary harm that the offender either knew, or reasonably should have known, could result from the offense) and intended losses (including pecuniary harm, even if it “would have been impossible or unlikely to occur”).³⁸ The Commission has stated that it need only make a reasonable estimate of loss, as opposed to an exact calculation.³⁹
 - *Size Factor.* This factor depends on the duration of the violation or the amount of the affected commodity.⁴⁰ For duration, the enhancement ranges from 0 (for 10 days or less)⁴¹ to 6 (for more than 250 days).⁴² For size, the enhancement ranges from 0 (for 70,000 MMBtu or less of natural gas or 10,000 MWh or less of electricity)⁴³ to 6 (for more than 700,000 MMBtu of natural gas or 100,000 MWh of electricity).⁴⁴
 - *Seriousness.* Finally, in addition to the loss and size factors, the violation level is also increased to a minimum of 16 if the violation presented a serious threat to market transparency.⁴⁵

³³ *Id.* § 2C1.1(b)(2).

³⁴ *Id.* § 2B1.1.

³⁵ *Id.* § 2B1.1(a).

³⁶ *Id.* § 2B1.1(b)(1)(A).

³⁷ *Id.* § 2B1.1(b)(1)(P).

³⁸ *Id.* § 2B1.1, cmt. appl. note 2(A).

³⁹ *Id.* § 2B1.1, cmt. appl. note 2(C).

⁴⁰ *Id.* § 2B1.1(b)(2).

⁴¹ *Id.* § 2B1.1(b)(2)(D).

⁴² *Id.* § 2B1.1(b)(2)(F).

⁴³ *Id.* § 2B1.1(b)(2)(A).

⁴⁴ *Id.* § 2B1.1(b)(2)(C).

⁴⁵ *Id.* § 2B1.1(b)(3).

2. Base Penalty

The next step in the *Penalty Guideline* process, after calculation of the adjusted base violation level, is determination of the base penalty.⁴⁶ The higher the violation level, the higher the base penalty will be.⁴⁷ For violation levels of 6 or below, the base penalty is at the minimum of \$5,000. For violation levels of 38 or above, the base penalty is at the maximum of \$72.5 million. At the violation level of 22, the base penalty is \$1.2 million.

However, if either the actual pecuniary gain to the violator⁴⁸ or the actual pecuniary loss to the victims⁴⁹ is larger than the adjusted base penalty level, the actual gain or loss is used to calculate the penalty range.

3. Culpability Scores and Multipliers

The final step in the calculation of a penalty range under the *Penalty Guidelines* is determination of a culpability score. With a high culpability score, the penalty range can substantially exceed the adjusted base penalty level. Conversely, with a low culpability score, the penalty range may be far below the adjusted base penalty level.

The default culpability score of 5 may be adjusted up or down based on numerous factors:⁵⁰

- Culpability may be adjusted based on the number of employees in the offending unit. The relevant unit may be the entire corporation if the highest level of management is deemed to have been involved in the misconduct. But if the conduct is confined to senior management of a division or subsidiary, this may be the relevant unit. Culpability is increased by between 1 (units with at least 10 employees) to 5 (5,000 or more employees).⁵¹
- Culpability is increased by 1 if the organization committed any part of the instant violation less than ten years after a prior FERC adjudication of any violation or less than ten years after an adjudication of “similar misconduct” by any other enforcement agency; culpability is increased by 2 if the organization committed any part of the instant violation less than five years after a prior FERC adjudication of any violation or less than five years after an adjudication of “similar misconduct” by any other enforcement agency.⁵² For purposes of determining this factor, a “prior adjudication”

⁴⁶ *Id.* § 1C2.2.

⁴⁷ *Id.* § 1C2.2(b)(1).

⁴⁸ *Id.* § 1C2.2(a)(2).

⁴⁹ *Id.* § 1C2.2(a)(3).

⁵⁰ *Id.* § 1C2.3(a).

⁵¹ *Id.* § 1C2.3(b).

⁵² *Id.* § 1C2.3(c).

includes a settlement, even if the settlement did not include an admission of liability.⁵³

- Culpability is increased by 2 if the organization violated an order specifically directed at it.⁵⁴
- Culpability is increased by 3 if the organization committed, or aided or abetted, an obstruction of justice in the investigation.⁵⁵
- Culpability is decreased by up to 3 if the organization has an effective compliance program and did not unduly delay reporting the violation to appropriate government authorities.⁵⁶ For an organization's compliance program to be deemed effective, the organization must, among other requirements, exercise due diligence to prevent and detect violations, promote an organizational culture that encourages a commitment to compliance with the law, and establish standards and procedures to prevent and detect violations.⁵⁷
- Furthermore, an organization can reduce its culpability by taking responsibility in several distinct ways:⁵⁸ prompt self-reporting of the violation prior to an imminent threat of disclosure or government investigation (2 point deduction); full cooperation with the investigation (1 point deduction); and resolving the matter without a trial (1 point deduction).
- The culpability score will be reduced by an additional point if the organization "clearly demonstrated recognition and affirmative acceptance of responsibility for its violation."⁵⁹ However, such an admission can have serious negative consequences in other forums. Most significantly, such an admission may collaterally estop the organization from denying the alleged misconduct if raised by an opponent in collateral litigation.⁶⁰

⁵³ *Id.* § 1C2.3(c), cmt. appl. note 1; § 1A1.1, cmt. appl. note 3(e).

⁵⁴ *Id.* § 1C2.3(d).

⁵⁵ *Id.* § 1C2.3(e).

⁵⁶ *Id.* § 1C2.3(f).

⁵⁷ *Id.* § 1B2.1.

⁵⁸ *Id.* § 1C2.3(g).

⁵⁹ *Id.* § 1C2.3(g)(4).

⁶⁰ Moreover, a Commission finding that the organization unlawfully affected electric or gas prices to a specific degree may permit a court in such a subsequent litigation to impose damages based on this price distortion without offering the organization any protection ordinarily afforded by the filed rate doctrine. *Cf. Medco Energi US, L.L.C. v. Sea Robin Pipeline Co.*, 729 F.3d 394, 398 (5th Cir. 2013) (any filed rate approved by the governing regulatory agency is *per se* reasonable and unassailable in judicial proceedings) (citation omitted).

The final culpability score dictates the factors by which the adjusted base penalty is multiplied to determine the dollar range of the penalty.⁶¹ At a maximum culpability factor of 10 or more, the penalty range is from two to four times the base penalty.⁶² At a minimum culpability of 0 or less, the penalty range is from 5% to 20% of the base penalty. At the default culpability of 5, the penalty range is from the base penalty to twice that sum. Significantly, the culpability table is particularly sensitive at the extreme ranges of culpability (near 0 or 10) where a single point of culpability (such as one earned by fully cooperating with the investigation) can shift the penalty range by large factors.

The impact of the culpability factor, particularly in cases involving serious violations, can be dramatic. For a very serious offense (with a maximum violation level), a large organization (or unit) whose conduct the Commission deems especially egregious may face a penalty range that extends up to \$290 million (or even more if the Commission deems the harm to third parties to exceed \$72.5 million). For the same offense, a smaller organization (or unit) with conduct the Commission otherwise deems exemplary could face a significantly lower penalty of less than \$4 million.

If the penalty range dictated by the *Penalty Guidelines* exceeds the maximum penalty authorized by statute (typically, \$1 million per occurrence per day), the penalty is capped at the statutory maximum.⁶³ In addition, the Commission has stated it may reduce the penalty below the range calculated under the *Penalty Guidelines* if the penalty level might otherwise impair the organization's ability to disgorge profits from the violation or imperil the organization's continued viability.⁶⁴

C. ENFORCEMENT PROCESSES

The process for imposing civil penalties is dictated by the specific statutory schemes set forth in the FPA, NGA, and NGPA, respectively, which the Commission has interpreted to call for different enforcement processes and procedures.⁶⁵

1. Federal Power Act

FPA section 31,⁶⁶ the civil penalty enforcement provision of Part I of the FPA, initially applied only to that Part. But when Congress amended the FPA to expand the scope of the Commission's civil penalty authority to apply to violations of certain sections of Part II of the Act in 1992,⁶⁷ it instructed the Commission to enforce these new penalties "in accordance with

⁶¹ *Penalty Guidelines* § 1C2.5.

⁶² *Id.* § 1C2.4.

⁶³ *Id.* § 1C3.1.

⁶⁴ *Id.* § 1C3.2.

⁶⁵ See *Process for Assessing Civil Penalties*, 117 FERC ¶ 61,317 (2006) ("Civil Penalty Process Statement").

⁶⁶ 16 U.S.C. § 823b.

⁶⁷ Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (1992).

the same provisions as are applicable under [section 31(d)] in the case of civil penalties assessed under [section 31].”⁶⁸ Since section 1284(e) of EPLA 2005 expanded the Commission’s authority to impose penalties for violations of the FPA, penalties under all parts of that Act are now covered by the enforcement provisions of FPA section 31.

FPA section 31 provides that civil penalties “shall be assessed by the Commission after notice and opportunity for public hearing.”⁶⁹ The Commission must provide a person with such notice and “inform such person of his opportunity to elect in writing” to proceed either in an agency hearing or in district court.⁷⁰

If the penalty target chooses an agency hearing, the Commission must make a “determination of violation . . . on the record after an opportunity for an agency hearing” pursuant to the Administrative Procedure Act⁷¹ “before an administrative law judge [(“ALJ”)].”⁷² The Commission’s penalty assessment order, like other final Commission orders, can be appealed to the appropriate federal appellate court under FPA section 313.⁷³ In such appellate review, “[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive.”⁷⁴ To the extent that either the administrative law judge or the Commission get the facts wrong, securing relief on appeal can be an uphill battle because of the deferential substantial evidence standard.

If the penalty target chooses to proceed in district court, “the Commission shall promptly assess” the penalty after the required notice has been provided.⁷⁵ If the penalty is not paid within 60 days, “the Commission shall institute an action” in the appropriate federal district court “for an order affirming the assessment.”⁷⁶ In that action, the court “shall have authority to review *de novo* the law and facts involved, and shall have jurisdiction to enter a judgment enforcing, modifying, and enforcing as so modified, or setting aside in whole or in [p]art, such assessment.”⁷⁷ In the only published order applying this statutory provision, the court stated that it would give “no deference” to the Commission’s decision in such an action.⁷⁸ Rather, the court makes an independent determination regarding the pertinent issues of fact and of law.⁷⁹ As the

⁶⁸ 16 U.S.C. § 825o-1(b).

⁶⁹ *Id.* § 823b(c).

⁷⁰ *Id.* § 823b(d)(1).

⁷¹ 5 U.S.C. § 554.

⁷² 16 U.S.C. § 823b(d)(2).

⁷³ *Id.* § 825l(b).

⁷⁴ *Id.*

⁷⁵ *Id.* § 823b(d)(3)(A).

⁷⁶ *Id.* § 823b(d)(3)(B).

⁷⁷ *Id.*

⁷⁸ *FERC v. MacDonald*, 862 F. Supp. 667, 672 (D. N.H. 1994) (citing *Doe v. United States*, 821 F.2d 694, 697-98 (D.C. Cir. 1987)).

⁷⁹ *Id.*

first post-EPA 2005 FPA civil penalty actions that did not result in settlements are now making their way through the courts, the appropriate application of the FPA's judicial assessment scheme is one of the issues being litigated.⁸⁰

2. *Natural Gas Policy Act*

The Commission was first granted civil penalty authority with the passage of the NGPA in 1978. The procedures for NGPA civil penalty assessment are substantially the same as the judicial assessment option that was subsequently adopted in FPA section 31.⁸¹ “Before assessing any civil penalty . . . the Commission shall provide to such person notice of the proposed penalty. Following receipt of notice of the proposed penalty by such person, the Commission shall, by order, assess such penalty.”⁸² If the civil penalty remains unpaid for 60 days after assessment, “the Commission shall institute an action in the appropriate district court of the United States for an order affirming the assessment of the civil penalty.”⁸³ In that proceeding, the federal district “court shall have authority to review *de novo* the law and the facts involved.”⁸⁴ Although the NGPA does not expressly provide for the option of an ALJ hearing, the Commission has asserted the authority to order one.⁸⁵

3. *Natural Gas Act*

As originally enacted in 1938, the NGA provided the Commission only with the power of injunctive enforcement⁸⁶ and assigned enforcement of criminal violations to the Attorney General.⁸⁷ Under NGA section 24, federal district courts have exclusive jurisdiction over both

⁸⁰ See generally *FERC v. Barclays*, Civil Action No. 13-02093 (E.D. Cal. filed Oct. 9, 2013); *FERC v. Lincoln Paper & Tissue, LLC*, Civil Action No. 13-13056 (D. Mass. filed Dec. 2, 2013); *FERC v. Silkman*, Civil Action No. 13-13054 (D. Mass. filed Dec. 2, 2013).

⁸¹ Indeed, the legislative history for FPA section 31 confirms that it was based on the civil penalty provision of the NGPA. H.R. Rep. No. 102-474, pt. I, at 78, 196 (1992), *reprinted in* 1992 U.S.C.C.A.N. 1954, 2019 (stating that the provision, which “comprise[d] new civil penalties for violations of [the FPA was] . . . modeled on similar provisions of the [NGPA]”).

⁸² 15 U.S.C. § 3414(b)(6)(E).

⁸³ *Id.* § 3414(b)(6)(F).

⁸⁴ *Id.*

⁸⁵ Compare *Civil Penalty Process Statement*, 117 FERC 61,317 at P 12 (“The NGPA does not provide for an on-the-record hearing before an ALJ. Rather, after considering the response to the proposed penalty (and in the absence of a settlement of the matter), the Commission assesses the penalty by order after considering the facts presented.”), with *Energy Transfer Partners, L.P.*, 121 FERC ¶ 61,282 at P 32 (2007) (“[W]hile NGPA section 504 does not provide a person with the right to require an evidentiary hearing before an ALJ, that does not prevent the Commission from holding such a proceeding if we find it is appropriate.”).

⁸⁶ *Id.* § 717s(a).

⁸⁷ *Id.*; see also *id.* § 717t.

suits in which the Commission seeks to enjoin violations of the Act or compel compliance with it, as well as an “action” to enforce “any liability” under the Act.⁸⁸

When Congress granted the Commission authority to assess civil penalties for NGA violations, it used language that was nearly identical to certain of the civil penalty provisions in the FPA, calling for “penalt[ies] [to] be assessed by the Commission after notice and opportunity for public hearing.”⁸⁹ The NGA provisions, however, do not include the detailed procedures mandated under the FPA.

In the absence of express language in the NGA, the Commission has stated that no *de novo* federal district court action is permitted under the NGA’s civil penalty scheme.⁹⁰ No court has yet ruled on the validity of the Commission’s interpretation.⁹¹

II. CRIMINAL PENALTIES

In addition to the civil penalties discussed above, FPA section 316 and NGA section 21 provide for criminal penalties for “[a]ny person who willfully and knowingly does or causes or suffers to be done any act” forbidden by the respective Acts, “or who willfully and knowingly omits or fails to do any act” required by the Acts, “or willfully and knowingly causes or suffers such omission or failure.”⁹² These sections apply to both individuals and corporations⁹³ and extend to violations of “any rule, regulation, restriction, condition, or order made or imposed by the Commission under authority of” the Acts.⁹⁴ Under EPAAct 2005, the potential sanctions for such violations under the FPA were increased to include fines of up to \$1,000,000 (up from \$5,000) and terms of imprisonment for up to five years (up from two), as well as an additional \$50,000 (up from \$500) for a continuing violation under the NGA and \$25,000 per day (up from

⁸⁸ *Id.* § 717u.

⁸⁹ Compare 15 U.S.C. § 717t-1(b) (NGA), with 16 U.S.C. § 823b(c) (FPA Part I) and 16 U.S.C. § 825o-1(b) (FPA Part II).

⁹⁰ *Civil Penalty Process Statement*, 117 FERC ¶ 61,317 at P 8; see also *Energy Transfer Partners, L.P.*, 121 FERC ¶ 61,282 at PP 53-66 (discussing rationale).

⁹¹ FERC’s position on this issue was challenged in *Energy Transfer Partners, L.P. v. FERC*, 567 F.3d 134 (5th Cir. 2009), but dismissed by the court as unripe. The court called the statutory scheme “far from clear.” See *id.* at 146. The case subsequently settled.

⁹² 16 U.S.C. § 825o(a); 15 U.S.C. § 717t(a).

⁹³ The Acts define a “person” as “an individual or corporation.” 16 U.S.C. § 796(4); 15 U.S.C. § 717a(1). The term “corporation” does not include municipalities. 16 U.S.C. § 796(3); 15 U.S.C. § 717a(2).

⁹⁴ 16 U.S.C. § 825o(b); 15 U.S.C. § 717t(b). FPA section 316 similarly criminalizes the violation of “any rule or regulation imposed by the Secretary of the Army” issued under the provisions governing hydroelectricity in Part I of the FPA. 16 U.S.C. § 825o(b). Criminal penalties were not previously available for violations of the four enumerated sections of FPA Part II punishable exclusively through civil penalties, but those violations are now punishable as crimes under EPAAct 2005. See *infra* note 6.

\$500) for a continuing violation under the FPA.⁹⁵ Evidence of criminal violations is referred to the Department of Justice for prosecution.⁹⁶

⁹⁵ 15 U.S.C. § 717t(a) and 16 U.S.C. § 825o(a) (as amended by EPAct 2005, §§ 314(a)(1), 1284(d), 119 Stat. at 690, 980).

⁹⁶ 16 U.S.C. § 825m(a); 15 U.S.C. §§ 717s(a), 3414(b)(5); *see also Enforcement Policy Statement*, 113 FERC ¶ 61,068 at PP 4 & n.5, 5 & n.10.

Chapter 4

FERC Market Manipulation Enforcement

JOHN ESTES
PAUL WIGHT
ANDREW R. CORCORAN

This chapter addresses the manner in which FERC has implemented its statutory authority to police market manipulation, including an analysis of the key legal issues that have arisen and the various types of conduct that FERC considers to be potentially manipulative. This area of FERC regulation presents significant compliance risks to market participants because the standards are not yet well-defined and the potential civil penalties for alleged violations are significant.

We begin with a review of FERC's statutory anti-manipulation authority and then offer a taxonomy of FERC's manipulation cases to date. While there currently are disputes in existing cases about much of the content we address below, we typically do not delve into the merits of those questions, but simply set forth FERC's stated views.

I. FERC MARKET MANIPULATION RULES AND REGULATIONS

A. THE COMMISSION'S ANTI-MANIPULATION STATUTORY AUTHORITY AND REGULATIONS

Before 2005, FERC had only nominal authority to prevent market manipulation¹ and “few remedies to address misconduct by market participants.”² Penalties were limited to \$11,000 per day under the Federal Power Act and \$5,500 per day under the Natural Gas Policy Act of 1978. This all changed with passage of the Energy Policy Act of 2005.³

1. *The Energy Policy Act of 2005 Anti-Manipulation Provisions*

EPAct 2005 dramatically expanded the Commission's oversight of the energy markets and its enforcement authority, particularly with respect to manipulative conduct in the energy

¹ See Joseph T. Kelliher, *Market Manipulation, Market Power, and the Authority of the Federal Energy Regulatory Commission*, 26 Energy L.J. 1 (2005) (Hon. Joseph T. Kelliher) (former FERC chairman generally discussing the Commission's “insufficient” authority over market manipulators prior to EPAct 2005 and arguing for increased authority).

² FERC, *Energy Market Oversight and Enforcement: Accomplishments and Proposal for Enhanced Penalty Authority* (Mar. 2005), available at <http://www.ferc.gov/legal/maj-ord-reg/land-docs/03-2005-cp-rept.pdf>.

³ Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

markets. Sections 315 and 1283 of EAct 2005 amended the Natural Gas Act⁴ and Part II of the Federal Power Act⁵ by adding “virtually identical” prohibitions on “the use or employment of manipulative or deceptive devices or contrivances in connection with the purchase or sale of natural gas, electric energy, or transportation or transmission services subject to the jurisdiction of the Commission.”⁶

Specifically, section 1283 of EAct 2005 amended Part II of the FPA by adding the following:

It shall be unlawful for any entity (including an entity described in section 201(f)), directly or indirectly, to use or employ, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission, any manipulative or deceptive device or contrivance (as those terms are used in section 10(b) of the Securities Exchange Act of 1934 (15 U.S.C. 78j(b))), in contravention of such rules and regulations as the Commission may prescribe as necessary or appropriate in the public interest or for the protection of electric ratepayers.

Similarly, section 315 of EAct 2005 amended the NGA by adding a new section 4A, duplicating the FPA provision but “in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to the jurisdiction of the Commission.”

Both of these provisions “closely track the prohibited conduct language in section 10b of the Securities Exchange Act of 1934,”⁷ and the Commission has stated that its anti-manipulation regulations “were ‘intended to be interpreted consistent with analogous SEC precedent that is appropriate under the circumstances.’”⁸ Unlike section 10b of the Securities Exchange Act, however, neither of these provisions created a private right of action.⁹

In addition to expanding the Commission’s authority over market manipulation claims, EAct also raised the maximum civil penalty it could assess to a million dollars per violation per

⁴ 15 U.S.C. §§ 717-717w (2006).

⁵ 16 U.S.C. §§ 791-825r (2006).

⁶ *Prohibition of Energy Mkt. Manipulation*, Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 6, *reh’g denied*, Order No. 670-A, 114 FERC ¶ 61,300 (2006) (codified at 18 C.F.R. pt. 1c).

⁷ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 6 (citing section 10(b) of the Securities Exchange Act of 1934 (“Exchange Act”), 15 U.S.C. 78j(b)).

⁸ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 2 (quoting *Prohibition of Energy Mkt. Manipulation; Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,591 at P 10 (2005)).

⁹ See EAct 2005 §§ 315, 1283 (both sections include language specifically stating that “[n]othing in this section shall be construed to create a private right of action”).

day, as discussed in more detail in Chapter 3.¹⁰ The Commission may also revoke market-based rate authority.¹¹

B. THE MARKET MANIPULATION REGULATIONS IMPLEMENTING EPCA 2005

The Commission's substantive implementation of the anti-manipulation provisions of EPCA 2005 is found in Order No. 670 on the Prohibition of Energy Market Manipulation.¹² As the Commission stated, "the language of EPCA 2005 sections 315 and 1283 does not, by itself, make any particular act unlawful" and thus the Commission's Final Rule as provided in Order No. 670 "serves as the implementing provision designed to prohibit manipulation and fraud in the markets the Commission is charged with regulating."¹³ As established by the Commission pursuant to Order No. 670 and codified as 18 C.F.R. sections 1c.1 and 1c.2,¹⁴

(a) It shall be unlawful for any entity, directly or indirectly, in connection with the purchase or sale of [natural gas or electric energy] or the purchase or sale of [transportation or transmission] services subject to the jurisdiction of the Commission,

(1) To use or employ any device, scheme, or artifice to defraud,

(2) To make any untrue statement of a material fact or to omit to state material fact necessary in order to make the statements made, in light of the circumstances under which they were made, not misleading, or

(3) To engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity,

(b) Nothing in this section shall be construed to create a private right of action.

In addition to adopting the above regulations, Order No. 670 also set forth (i) the Commission's interpretation of certain jurisdictional terms such as "entity" and "in connection with,"¹⁵ (ii) the standards for fraud and scienter,¹⁶ (iii) the applicability of certain affirmative

¹⁰ EPCA 2005 also expanded the Commission's civil penalty authority to all provisions of FPA Part II and the NGA.

¹¹ See *J.P. Morgan Ventures Energy Corp.*, 141 FERC ¶ 61,131 (2012).

¹² See Order No. 670, FERC Stats. & Regs. ¶ 31,202; see also *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 (2005) (FERC policy statement on the expansion of the Commission's civil penalty authority and how the Commission's prior precedent and regulations would be integrated with this expanded authority).

¹³ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 5.

¹⁴ Although the operative language of sections 1c.1 and 1c.2 are identical, section 1c.1 relates to the purchase or sale of natural gas or the purchase or sale of transportation services, whereas section 1c.2 relates to the purchase or sale of electric energy or the purchase or sale of transmission services.

¹⁵ See Order No. 670, FERC Stats. & Regs. ¶ 31,202 at PP 16-22, 76.

defenses and safe harbors,¹⁷ (iv) the statute of limitations,¹⁸ (v) the applicability of securities law concepts,¹⁹ and (vi) general procedures for handling manipulation claims.²⁰ As set forth below, the Commission’s rulings regarding these issues have been controversial in some cases and have not yet been tested in court.

1. *The Commission’s Jurisdiction Over Manipulative Conduct*

Although EAct 2005 provided the Commission with jurisdiction to investigate and impose civil sanctions related to market manipulation, it did not expand the Commission’s general jurisdictional boundaries under the FPA and NGA. Indeed, in Order No. 670 the Commission explicitly acknowledged that “Congress did not expand the Commission’s traditional NGA and FPA subject matter jurisdiction in Sections 315 or 1283 of EAct [2005], but rather gave the Commission broad jurisdiction over the entities that engage in certain conduct affecting our subject matter jurisdiction.”²¹

a. *Jurisdiction Over Conduct “In Connection With” Transactions Subject to the Commission’s Jurisdiction*

EAct 2005 provided the Commission with authority to pursue manipulation claims with respect to conduct that is “in connection with” a transaction subject to the Commission’s jurisdiction.²² In Order No. 670, the Commission looked to the Supreme Court’s interpretation of the same language as used in section 10(b) of the Securities Exchange Act, stating that the Supreme Court has broadly construed section 10(b)’s “in connection with” requirement but acknowledging that the Supreme Court has also cautioned that this requirement should not be interpreted so broadly “as to convert every common law fraud that happens to involve securities into a violation” of section 10(b) and Rule 10b-5.”²³ The Commission also specifically acknowledged that, “unlike the SEC, which has broad jurisdiction over securities transactions,

¹⁶ See *id.* at PP 45-53.

¹⁷ See *id.* at PP 64-66.

¹⁸ See *id.* at PP 61-62.

¹⁹ See *id.* at PP 48-53.

²⁰ See *id.* at PP 68-70.

²¹ *Id.* at P 20.

²² See EAct 2005 §§ 315, 1283; Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 1.

²³ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 22 (citing, among others, *SEC v. Zandford*, 535 U.S. 813, 825 (2002), which found certain transactions “in connection with” the securities sales within the meaning of section 10(b)); see also *Merrill Lynch, Pierce, Fenner & Smith Inc. v. Dabit*, 547 U.S. 71, 85 (2006) (holding that the “in connection with” language is to be given a broad interpretation). But see, e.g., *Anwar v. Fairfield Greenwich Ltd.*, 728 F. Supp. 2d 372 (S.D.N.Y. 2010) (fraud related to Madoff feeder fund was not “in connection with” securities transaction because there were multiple layers of non-instantaneous transactions between plaintiff’s investments and purported purchase of covered securities by Madoff).

[FERC's] jurisdiction is limited to certain wholesale transactions that remain within the ambit of the NGA, NGPA, and FPA.”²⁴

Accordingly, the Commission has stated that it “views the ‘in connection with’ element in the energy context as encompassing situations in which there is a nexus between the fraudulent conduct of an entity and a jurisdictional transaction.”²⁵ The Commission further explained that such a “nexus” exists when “the entity . . . intended to affect, or . . . acted recklessly to affect, a jurisdictional transaction” and that the Commission “do[es] not intend to construe [its market manipulation rules] so broadly as to convert every common-law fraud that happens to touch a jurisdictional transaction into a violation of [its market manipulation rules].”²⁶

The Commission has found that such a nexus can exist if manipulation of non-jurisdictional transactions indirectly affects jurisdictional transactions and thus is “in connection with” jurisdictional transactions.²⁷ In a recent matter involving allegedly manipulative natural gas trading, for example, the Commission held that the “in connection with” requirement was satisfied and thus it had jurisdiction where defendants’ “use of non-jurisdictional transactions and transportation to manipulate [index prices] affected jurisdictional transactions whose settlement price was based on that index.”²⁸

This broad assertion of authority has not, however, gone unchallenged. For example, a federal court reversed the Commission’s finding that its manipulation jurisdiction extends to purely financial transactions under the jurisdiction of the Commodities Futures Trading Commission (“CFTC”), even if those transactions could affect FERC-jurisdictional transactions. Section 2(a)(1)(A) of the Commodity Exchange Act (“CEA”) vests the CFTC with “exclusive jurisdiction” over “accounts, agreements . . . and transactions involving swaps or contracts of sale of a commodity for future delivery . . . , traded or executed on” a market regulated by the CFTC.²⁹ In *Hunter v. FERC*, the D.C. Circuit explained that, “[b]y CEA section 2(a)(1)(A)’s plain terms, the CFTC has exclusive jurisdiction over the manipulation of natural gas futures contracts.”³⁰ And “absent a clearly expressed congressional intention to repeal CEA section 2(a)(1)(A),” the court concluded that FERC “lack[ed] jurisdiction to charge Hunter with manipulation of natural gas futures contracts.”³¹ In the wake of *Hunter*, the CFTC and FERC

²⁴ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 22.

²⁵ *Id.* (citations omitted).

²⁶ *Id.* The “nexus” language that the Commission adopted was previously used in certain precedent regarding section 10(b) cited by the Commission in Order No. 670. *See id.* at n.37 (citing *Head v. Head*, 759 F.2d 1172, 1175 (4th Cir. 1985)).

²⁷ *BP Am. Inc.*, 147 FERC ¶ 61,130 (2014).

²⁸ *Id.* at P 26.

²⁹ 7 U.S.C. § 2(a)(1)(A).

³⁰ *See Hunter v. FERC*, 711 F.3d 155, 158 (D.C. Cir. 2013) (holding that the CFTC had exclusive jurisdiction over trader’s alleged manipulative conduct because it involved commodities futures contracts and thus FERC lacked jurisdiction to bring action for market manipulation).

³¹ *Id.* at 160 (internal citations omitted).

entered into a Memorandum of Understanding concerning the sharing of information obtained in connection with market surveillance and potential manipulation, fraud, or market power investigations in order to ensure better coordination.³²

b. Jurisdiction Over Individuals

EPA 2005 prohibits “any entity” from engaging in unlawful manipulative conduct.³³ Order No. 670 mirrored this language by also prohibiting “any entity” from engaging in certain manipulative conduct,³⁴ and incorporated a broad definition of the term “entity.”³⁵ The Commission has applied the term “entity” to include individual persons:

“Any entity” is a deliberately inclusive term. Congress could have used the existing defined terms in the NGA and FPA of “person,” “natural-gas company,” or “electric utility,” but instead chose to use a broader term without providing a specific definition. Thus the Commission interprets “any entity” to include any person or form of organization, regardless of its legal status, function or activities.³⁶

Whether the term “any entity” was intended to cover individual persons or just organizations has been raised in a number of cases. For example, in the *Amaranth* matter, several individual traders named as defendants in a FERC market manipulation investigation involving natural gas trading challenged the Commission’s assertion that the term “entity” includes organizations and individuals.³⁷ The individual traders argued that “the use of the terms ‘person’ and ‘entity’ in the NGA reflect[s] Congress’ desire to draw a distinction between those terms.”³⁸ The traders asserted two major arguments. First, they argued that “the NGA repeatedly uses ‘person’ or ‘individual’ instead of ‘entity’ when referring to natural persons” and, where the statutory language uses the word person in some instances, the term entity must have a different meaning.³⁹ Second, they argued that “[o]ther uses of the term ‘entity’ in the NGA, such as section 23, demonstrate that the term applies to companies and organizations but

³² See Memorandum of Understanding Between the CFTC and the Federal Energy Regulatory Commission Regarding Information Sharing and Treatment of Proprietary Trading and Other Information at 3 (Jan. 2, 2014) (providing that, among other things, the oversight and enforcement staffs of the CFTC and FERC “are authorized to share information concerning ongoing oversight (including market surveillance), investigative, and enforcement activities”), available at <https://www.ferc.gov/legal/mou/mou-ferc-cftc-info-sharing.pdf>.

³³ EPA 2005 §§ 315, 1283.

³⁴ See Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 1; 18 C.F.R. §§ 1c.1, 1c.2.

³⁵ See Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 18.

³⁶ *Id.* (citations omitted).

³⁷ *Amaranth Advisors L.L.C.*, 124 FERC ¶ 61,050 at PP 39-48 (2008).

³⁸ *Id.* at P 39.

³⁹ *Id.* (quotations and citations omitted).

not to individuals” based on “the rule of statutory construction that a word is presumed to have the same meaning in all subsections of the same statute.”⁴⁰

The Commission rejected the *Amaranth* traders’ narrow interpretation of the term “any entity.”⁴¹ On review of this order, the United States Court of Appeals for the District of Columbia Circuit did not reach this issue as it held that the Commission did not have jurisdiction over the trading conduct at issue.⁴² No court has ruled on this issue to date.

2. *The Substantive Elements of a Manipulation Claim*

Assuming all of the jurisdictional requirements have been met, the Commission asserts that a market manipulation claim exists:

[W]here an entity: (1) uses a fraudulent device, scheme or artifice, or makes a material misrepresentation or a material omission as to which there is a duty to speak under a Commission-filed tariff, Commission order, rule or regulation, or engages in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity; (2) with the requisite scienter. . . .⁴³

Thus, to establish a market manipulation claim, the Commission must prove both fraud and scienter.

a. *Fraud*

(i) *The Commission’s Broad Standard of Fraud*

“The Commission defines fraud generally, that is, to include any action, transaction, or conspiracy for the purpose of impairing, obstructing or defeating a well-functioning market.”⁴⁴ As the Commission stated in a recent order approving a stipulation and consent agreement regarding certain alleged manipulative conduct:

In the wake of Enron’s schemes in the CAISO market, the Energy Policy Act of 2005 gave the Commission “broad authority to prohibit manipulation” and “an intentionally broad proscription against all kinds of deception, manipulation, deceit and fraud.” Both the breadth of Congress’ authorization to the Commission and the breadth of the Anti-Manipulation Rule itself are a response to what courts have long recognized: the impossibility of foreseeing the “myriad

⁴⁰ *Id.* at PP 40.

⁴¹ *Id.* at PP 49-55.

⁴² *See supra* note 30.

⁴³ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 49.

⁴⁴ *Id.* at P 50 (citing *Dennis v. United States*, 384 U.S. 855, 861 (1966), for the proposition that “fraud within the meaning of a statute need not be confined to the common law definition of fraud: any false statement, misrepresentation or deceit”).

means” of misconduct in which market participants may engage. For that reason, as the Commission observed in 2006, “[N]o list of prohibited activities could be all-inclusive.” Instead, as Order No. 670 emphasizes, fraud is a question of fact to be determined by all the circumstances of a case, not by a mechanical rule limiting manipulation to tariff violations. . . . Conduct, as opposed to a specific false oral or written statement, is sufficient to establish a violation of Rule 1c, which is patterned on the SEC’s Rule 10b-5.⁴⁵

The Commission thus has taken the position that its anti-market manipulation authority is not bound by traditional common law definitions of fraud.⁴⁶

(ii) *The Commission’s Reliance on Dennis v. United States*

The Commission has based its expansive definition of fraud on a Supreme Court case called *Dennis*.⁴⁷ There the Supreme Court addressed a provision of the general federal conspiracy statute, which states that it is a crime “to defraud the United States, or any agency thereof in any manner or for any purpose.”⁴⁸ As the Supreme Court held:

It has long been established that [the provision of section 371 prohibiting a party from “defraud[ing] the United States, or any agency thereof in any manner or for any purpose”] is not confined to fraud as that term has been defined in the common law. It reaches “any conspiracy *for the purpose of impairing, obstructing, or defeating the lawful function of any department of government.*”⁴⁹

The Commission adapted the italicized language from *Dennis*, thus defining fraud as conduct “impairing, obstructing, or defeating a well-functioning market.”

Dennis did not, however, overturn the Supreme Court’s prior holdings, which made clear that to demonstrate a conspiracy to defraud the United States requires some showing of “deceit,

⁴⁵ *In Re Make-Whole Payments and Related Bidding Strategies*, 144 FERC ¶ 61,068 at PP 83-84 (2013) (citations omitted).

⁴⁶ See, e.g., *Deutsche Bank Energy Trading, LLC*, 140 FERC ¶ 61,178 at App. A, n.78 (2012) (citing *Dennis*, 384 U.S. at 861); see also *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 114 FERC ¶ 61,165 at P 24 (2006) (“Furthermore, we recognize that fraud is a very fact-specific violation, the permutations of which are limited only by the imagination of the perpetrator. Therefore, no list of prohibited activities could be all-inclusive. The absence of a list of specific prohibited activities does not lessen the reach of the new anti-manipulation rule, nor are we foreclosing the possibility that we may need to amplify section 1c.2 as we gain experience with the new rule, just as the SEC has done.”).

⁴⁷ See Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 50.

⁴⁸ See *Dennis*, 384 U.S. at 859-61 (interpreting and applying 18 U.S.C. § 371).

⁴⁹ *Id.* at 861 (emphasis added and citation omitted).

craft or trickery, or . . . dishonest[y].”⁵⁰ And fraud itself was a given in *Dennis* because the defendants there lied to the government in false affidavits.⁵¹

Subsequently, the lower courts have rejected analogous efforts to rely on *Dennis* to avoid proving fraud in cases about defrauding the government. The Seventh Circuit has ruled that “a defendant cannot be found guilty of defrauding the United States without some showing of fraud.”⁵² The Ninth Circuit, in a colorful opinion by now-Chief Judge Kozinski, explained why fraud is an irreducible requirement in such a case. As Judge Kozinski explained, “[t]he Supreme Court has made it clear that ‘defraud’ is limited only to wrongs done ‘by deceit, craft or trickery, or at least by means that are dishonest.’”⁵³ To elaborate:

There are places where, until recently, “everything which [was] not permitted [was] forbidden [W]hatever [was] permitted [was] mandatory Citizens were shackled in their actions by the universal passion for banning things.” *Yeltsin Addresses RSFSR Congress of People’s Deputies*, BBC Summary of World Broadcasts, Apr. 1, 1991, available in LEXIS, Nexis Library, OMNI File. Fortunately, the United States is not such a place, and we plan to keep it that way. If the government wants to forbid certain conduct, it may forbid it. If it wants to mandate it, it may mandate it. But we won’t lightly infer that in enacting 18 U.S.C. § 371 Congress meant to forbid all things that obstruct the government, or require citizens to do all those things that could make the government’s job easier. So long as they don’t act dishonestly or deceitfully, and so long as they don’t violate some specific law, people living in our society are still free to conduct their affairs any which way they please.⁵⁴

(iii) *Fraud and Open-Market Manipulation*

The Commission has also held that open-market manipulation—meaning visible conduct in an open-market forum—may nonetheless constitute fraud. In adopting this position, the Commission has relied heavily upon the U.S. Court of Appeals for the District of Columbia Circuit decision in *Markowski v. SEC*.⁵⁵

⁵⁰ *Hammerschmidt v. United States*, 265 U.S. 182, 188 (1924).

⁵¹ *Dennis*, 384 U.S. at 857.

⁵² *United States v. Knapp*, 25 F.3d 451, 455 (7th Cir. 1994) (discussing the holdings of *Hammerschmidt*, 265 U.S. 182, which was not overturned by the holding in *Dennis*, and *United States v. Caldwell*, 989 F.2d 1056 (9th Cir. 1993)).

⁵³ *Caldwell*, 989 F.2d at 1061.

⁵⁴ *Id.*

⁵⁵ 274 F.3d 525 (D.C. Cir. 2001), *cert. denied*, 537 U.S. 819 (2002); *see, e.g., Brian Hunter*, 137 FERC ¶ 61,146 at P 13 (2011).

In *Markowski*, the D.C. Circuit upheld the Securities and Exchange Commission's interpretation that "'manipulation' can be illegal solely because of the actor's purpose."⁵⁶ Accordingly, the court found that open-market manipulation can occur and, thus, conduct that involved real transactions and real customers could be a "manipulative . . . device" under section 10(b).⁵⁷

Citing *Markowski* in support, the Commission has held that open-market manipulation can be illegal and that "[t]he difference between legitimate open-market transactions and illegal open-market transactions may be nothing more than a trader's manipulative purpose for executing such transactions."⁵⁸ In *Hunter*, for example, the Commission rejected an argument that open-market trading cannot constitute manipulation in the absence of other deceptive conduct, finding that "open market transactions send false information into the marketplace if such transactions are undertaken with the intention of creating a false price."⁵⁹ The courts have not yet addressed FERC's heavy reliance on *Markowski* to make intent paramount.

In the analogous securities context, open-market manipulation cases have proved difficult for the government. The first case to consider an open-market manipulation claim in depth was *United States v. Mulheren*.⁶⁰ In that case, the court reversed a conviction for evidentiary reasons and noted that "[n]one of the traditional badges of manipulation [we]re present" in the case, explaining that manipulation typically involves any of a variety of deceptive techniques rather than straightforward open-market trading.⁶¹ Since then, a number of courts have rejected open-market manipulation claims.⁶² The Second Circuit more recently has ruled that manipulative conduct must fall "outside the 'natural interplay of supply and demand'" and "send[] a false pricing signal to the market."⁶³

b. Intent

In Order No. 670, the Commission held that its market manipulation rule "is not intended to regulate negligent practices or corporate mismanagement, but rather to deter or punish fraud in

⁵⁶ *Markowski*, 274 F.3d at 528-29 (citation omitted).

⁵⁷ *Id.* at 529.

⁵⁸ *Barclays Bank PLC*, 144 FERC ¶ 61,041 at P 52 (2013) (quoting *Brian Hunter*, 135 FERC ¶ 61,054 at P 49, *order denying reh'g*, 137 FERC ¶ 61,146 (2011), *rev'd sub nom. Hunter v. FERC*, 711 F.3d 155 (D.C. Cir. 2013)).

⁵⁹ *Brian Hunter*, 135 FERC ¶ 61,054 at PP 48-50 (concluding that Brian Hunter intentionally deceived market participants by making open-market sales that drove down the index settlement price in order to benefit other financial positions that Brian Hunter had taken).

⁶⁰ 938 F.2d 364 (2d Cir. 1991).

⁶¹ *Id.* at 369-71.

⁶² See, e.g., *GFL Advantage Fund, Ltd. v. Colkitt*, 272 F.3d 189, 207 (3d Cir. 2001); *In re Initial Pub. Offering Sec. Litig.*, 241 F. Supp. 2d 281, 391 (S.D.N.Y. 2003) (warning that "there is no such thing" as open-market manipulation as distinct from any other form of manipulative conduct).

⁶³ *ATSI Commc'ns, Inc. v. Shaar Fund, Ltd.*, 493 F.3d 87, 100 (2d Cir. 2007).

wholesale energy markets.”⁶⁴ However, the Commission also rejected “requests to incorporate a specific intent standard into the Final Rule,” instead holding that, as a result of Congress’s directive “that the terms ‘manipulative or deceptive device or contrivance’ as they appear in Section 1283 and 315 of EPCA 2005 be interpreted in accordance with Section 10(b) of the Exchange Act” and pertinent Supreme Court precedent interpreting section 10(b) of the Exchange Act, “any violation of the Final Rule requires a showing of scienter.”⁶⁵

As the Commission noted in Order No. 670, however, “recklessness satisfies the scienter element of the Final Rule.”⁶⁶ Thus, “[f]or purposes of establishing a violation [of the Commission’s Anti-Manipulation Rule], scienter requires knowing, intentional, or reckless misconduct, as opposed to mere negligence.”⁶⁷ In adopting this position, the Commission relied on several decisions by U.S. Courts of Appeals but specifically acknowledged that the Supreme Court has not yet ruled on this issue.⁶⁸

Federal courts have held that manipulative intent “must normally be shown inferentially from the conduct of the accused.”⁶⁹ This is most commonly shown through statements made in instant messages (“IMs”), emails, audio recordings, or other contemporaneous documentary evidence. For example, in *Amaranth*, the court relied on Hunter’s “numerous instant messages,” which included statements about waiting to sell near the end of the day and hoping contract prices dropped, as its evidence of intent to manipulate prices.⁷⁰

Although IMs and emails often provide the primary evidence cited in support of a finding of scienter, the Commission may also rely on behavioral evidence. Several courts have held that such evidence regarding trading timing and patterns can provide the necessary inference of manipulative intent.⁷¹

⁶⁴ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 5.

⁶⁵ *Id.* at P 52 (citing *Ernst & Ernst v. Hochfelder*, 425 U.S. 185, 197 (1976), and *Aaron v. SEC*, 446 U.S. 680, 690 (1980), for the proposition that the Supreme Court has interpreted similar language in section 10(b) regarding use of the terms “manipulative or deceptive” in conjunction with the words “device or contrivance” to indicate that section 10(b) was meant to apply to knowing or intentional misconduct and thus the similar language as used in the Commission’s Final Rule demonstrates that a violation will only exist upon a showing of scienter).

⁶⁶ *Id.* at P 53 & n.109 (noting that the Supreme Court has not yet decided whether recklessness satisfies the scienter requirement of section 10(b) but that “Courts of Appeals are in general agreement that that [sic] recklessness in some form satisfies the scienter requirement of SEC Rule 10b-5”).

⁶⁷ *Barclays Bank*, 144 FERC ¶ 61,041 at P 62.

⁶⁸ See Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 53 & n.109.

⁶⁹ *CFTC v. Amaranth*, 554 F. Supp. 2d 523, 532 (S.D.N.Y. 2008) (“*Amaranth I*”).

⁷⁰ *Id.* at 533.

⁷¹ See, e.g., *Amaranth II*, 587 F. Supp. 2d at 535 (allegations that defendants repeatedly sold large numbers of futures just before the close of the settlement period was sufficient to allege intent); *SEC v. Kwak*, No. 3:04-cv-1331 (JCH), 2008 WL 410427, at *3 (D. Conn. Feb. 12, 2008) (evidence that

3. *The Statute of Limitations*

Manipulation claims brought by FERC are governed by the general federal statute of limitations, 28 U.S.C. § 2462,⁷² which requires commencement of an action, suit, or proceeding within five years from the date when the alleged claim first accrued.⁷³ In recent court filings, FERC has interpreted section 2462 to mean that it has five years to begin an administrative proceeding, and then an *additional* five years to file an action in court where a party opts for *de novo* review in federal district court pursuant to FPA section 31(d)(3).⁷⁴ In support of this position, FERC relies on the First Circuit's holding in *United States v. Meyer*.⁷⁵ In that case, the court held, in the context of a Department of Commerce anti-boycott action, that where an administrative action is a prerequisite to filing an enforcement action, the statute of limitations does not begin to run on the enforcement action until five years after the underlying agency action occurs. Thus, under FERC's statutory view, it would have five years to initiate an investigation, and, if a penalty is assessed, an additional five years from that date to bring a formal proceeding either before an Administrative Law Judge or for *de novo* review in federal district court (depending on a party's election pursuant to section 31(d)(3) of the FPA). This interpretation is currently being challenged in federal court, where defendants are arguing that the *Meyer* decision court does not survive the Supreme Court's more recent opinion in *Gabelli v. SEC*,⁷⁶ which found that "a claim based on fraud accrues [under 28 U.S.C. § 2462]... when a defendant's allegedly fraudulent conduct occurs."⁷⁷

C. FERC'S MARKET BEHAVIOR RULES

When the Commission implemented the anti-manipulation authority provided by EPAAct 2005, it determined that four of the six Market Behavior Rules should be retained. Several of

defendants engaged in trades at particular times and in particular amounts in an effort to assist the scheme sufficient to show manipulative intent); *Masri*, 523 F. Supp. 2d at 370 (explaining that timing of transactions near the close of the day "provides some limited evidence of manipulative intent").

⁷² See *Prohibition of Energy Mkt. Manipulation*, 114 FERC ¶ 61,300 at P 6 (2006) ("[B]ecause section 4A and section 222 are silent as to a statute of limitations, and no statute of limitations of general applicability appears in the NGA or FPA, the Commission is limited by the five-year statute of limitations found in 28 U.S.C. § 2462 that applies to any 'action, suit or proceeding for the enforcement of any civil fine, penalty, or forfeiture. . . .'").

⁷³ See 28 U.S.C. § 2462 ("Except as otherwise provided by Act of Congress, an action, suit or proceeding for the enforcement of any civil fine, penalty, or forfeiture, pecuniary or otherwise, shall not be entertained unless commenced within five years from the date when the claim first accrued. . . .").

⁷⁴ See *FERC v. Silkman*, No. 1:13-CV-13054, Federal Energy Regulatory Commission's Opposition to Respondents' Motion to Dismiss and Incorporated Memorandum at 2-4 (D. Mass. Jan. 9, 2014) (ECF. No. 18).

⁷⁵ 808 F.2d 912 (1st Cir. 1987).

⁷⁶ 133 S. Ct. 1216 (2013).

⁷⁷ *Id.* at 1220.

these rules could be relevant to FERC investigations or actions concerning allegedly manipulative conduct.⁷⁸

For example, the “Unit Operation” Market Behavior Rule could potentially be implicated in actions involved allegations of physical or economic withholding by the owner or operator of a wholesale generating facility because it mandates certain requirements for operating or scheduling generating facilities.⁷⁹ The only Commission order to date involving the enforcement of this Market Behavior Rule is an order approving a stipulation and consent agreement whereby the Commission settled with a generator that the Commission found violated this rule “[b]ecause [it] did not follow ISO-NE requirements regarding maintenance and outage notification.”⁸⁰ The Commission’s “Records Retention” rule also remains in effect and could be implicated if the target of a Commission investigation into alleged market manipulation is unable to produce the required records.⁸¹ It is possible that the Commission could also potentially find adequate evidence of manipulative conduct from other sources and thus potentially impose civil penalties for both market manipulation and violations of this rule.⁸²

Although rescinded by the Commission following adoption of its Prohibition of Market Manipulation pursuant to EPAct 2005 sections 315 and 1283,⁸³ the Commission’s interpretation and brief application of Market Behavior Rule 2, which addressed market manipulation, may still be of some relevance.⁸⁴ In particular, the Commission adopted a legitimate business purpose

⁷⁸ 18 C.F.R. § 35.41(a)-(d).

⁷⁹ The “Unit Operation” Market Behavior Rule provides that: “Where a Seller participates in a Commission-approved organized market, Seller must operate and schedule generating facilities, undertake maintenance, declare outages, and commit or otherwise bid supply in a manner that complies with the Commission-approved rules and regulations of the applicable market. A Seller is not required to bid or supply electric energy or other electricity products unless such requirement is a part of a separate Commission-approved tariff or is a requirement applicable to Seller through Seller’s participation in a Commission-approved organized market.” 18 C.F.R. § 35.41(a).

⁸⁰ *Dartmouth Power Assocs. Ltd. P’ship*, 134 FERC ¶ 61,085 at PP 13, 20-21 (2011).

⁸¹ The “Records Retention” Rule provides that: “A Seller must retain, for a period of five years, all data and information upon which it billed the prices it charged for the electric energy or electric energy products it sold pursuant to Seller’s market-based rate tariff, and the prices it reported for use in price indices.” 18 C.F.R. § 35.41(d).

⁸² The Commission also retained its “Communications” rule, requiring that parties make accurate and factual and not misleading communication to the Commission, 18 C.F.R. § 35.41(b), and its “Price Reporting” rule which require that prices submitted to publishers of price indices, 18 C.F.R. § 35.41(c), both of which could potentially be implicated in Commission investigations or actions concerning allegations of market manipulation. These rules are discussed in detail in Chapter 11.

⁸³ See *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 115 FERC ¶ 61,053 at P 1 (2006).

⁸⁴ Market Behavior Rule 2 provided that “Actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products are prohibited,” including but not limited to “wash trades,” “submitting false information to transmission providers [or operators],” creating

exemption in that context.⁸⁵ This exemption was intended to save sellers from the need to guess whether their actions were unlawful if they were grounded in “the seller’s own business practices and motives.”⁸⁶

The Commission still considers the legitimate business purpose defense in market manipulation claims, but it is no longer an absolute defense as it was under Market Behavior Rule 2.⁸⁷ Rather, under its Current Prohibition on Market Manipulation, the defense is only “one of many [factors] that the Commission w[ill] consider to determine whether each [defendant] possessed scienter.”⁸⁸ The foregoing precedent applicable to Market Behavior Rule 2 is therefore relevant but not dispositive in this context.

II. SPECIFIC TYPES OF PROHIBITED MANIPULATIVE CONDUCT

While it is not possible to list all potential strategies that could violate the Anti-Manipulation Rule, the following discussion offers a “taxonomy” of FERC manipulation cases to date.

A. ALTERING PRICE OUTCOMES

1. Withholding

While classically viewed as a simple exercise of market power, FERC also views both physical and economic withholding as fraud-based market manipulation.⁸⁹ Physical withholding is generally defined as a seller “caus[ing], or attempt[ing] to cause, an artificial shortage by physically withholding sufficient and otherwise available power from the market for the purpose of raising the sales price obtainable by other units participating in the market.”⁹⁰ Economic

“artificial congestion” and colluding with another party to “manipulate market prices, market conditions, or market rules.” 18 C.F.R. §§ 284.288(a), 284.403(a) (2005) (emphasis added).

⁸⁵ See *Amendments to Blanket Sales Certificate*, Order No. 644, FERC Stats. & Regs. ¶ 31,153 (2003), *reh’g denied*, 107 FERC ¶ 61,174 (2004); *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 (2003), *reh’g denied*, 107 FERC ¶ 61,175 (2004).

⁸⁶ Order No. 644, FERC Stats. & Regs. ¶ 31,153 at P 35.

⁸⁷ See *id.* at P 35; *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 107 FERC ¶ 61,175 at PP 38, 167; *Intertie Bidding in the Cal. Indep. Sys. Operator’s Supplemental Energy Mkt.*, 112 FERC ¶ 61,333 at 62,481 (2005).

⁸⁸ See *Barclays Bank*, 144 FERC ¶ 61,041 at P 61 (stating that “an entity’s business purposes will be relevant to an inquiry into manipulative intent, but a ‘legitimate business purpose’ is not an affirmative defense to manipulation”).

⁸⁹ One commentator has written at length on why alleged “market power manipulation” schemes do not involve fraud. C. Pirrong, *Energy Market Manipulation: Definition, Diagnosis and Deterrence*, 31 Energy L.J. 1 (2010).

⁹⁰ See *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 38. In its pre-EPAAct 2005 discussion of manipulation, FERC determined that a seller who engaged in such behavior “may be found to have engaged in market manipulation, as

withholding has been defined by FERC as “bidding available supply at a sufficiently high price in excess of the supplier’s marginal costs and opportunity costs so that it is not called on to run and where, as a result, the market clearing price is raised.”⁹¹

In sum, withholding can be viewed as intentionally foregoing positive revenue opportunities on one unit, by either physically or financially restraining its output, in order to elevate margins earned by other units. Such a strategy typically would make sense only in a single-price Regional Transmission Organization auction market. Accordingly, defending against such claims typically involves analyzing whether the allegedly withheld unit would have been expected to be economic on a stand-alone basis, putting aside margins earned by other units in the seller’s portfolio. Because RTO markets today have must-offer requirements, the frequency of withholding claims has dropped substantially. One emerging area where we may see an increase in such claims involves the retirement of units that thus no longer will offer into a capacity market.

2. Related Positions

While the frequency of withholding claims has dropped, “related positions” manipulation cases have become much more common. A “related positions” violation generally involves a market participant taking a position in one market (for example, a market that sets index prices) that benefits its position in another market (for example, a market that relies upon index prices). The first cases brought by FERC in its modern enforcement era—*Energy Transfer Partners, L.P.*⁹² and *Amaranth Advisors, L.L.C.*⁹³—fell into this category. Former Chairman Wellinghoff focused on these cases when he offered guidance to “all wholesale market participants,” urging them to “not trade uneconomically on one position in order to benefit the value of another.”⁹⁴

prescribed by Market Behavior Rule 2, *i.e.*, under these circumstances, there can be no legitimate business purpose attributable to such behavior.” *Id.* Market Behavior Rule 2 was later rescinded as “unnecessary” in light of EPCA 2005’s prohibition on market manipulation. *See Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 114 FERC ¶ 61,165 at P 21. This was done “[t]o avoid the potential for uneven application of regulatory requirements” based on a market participant’s status, but given the new anti-manipulation statute, FERC was sure that rescission of Rule 2 would “not dilute consumer protection.” *Id.* at PP 21, 25.

⁹¹ *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 102 n.57. *See also* Fereidoon P. Sioshansi, ed., *Competitive Electricity Markets: Design, Implementation, Performance* 231 (Elsevier Ltd. 2008) (“Economic withholding refers to raising offer prices substantially above marginal cost, including opportunity cost, so as to affect the market clearing price. Typically, an offer that is economically withheld is one that has raised its price sufficiently to not get picked by the auction.”); Scott M. Harvey & William W. Hogan, *Market Power and Withholding* (Dec. 20, 2001) (further discussing economic withholding), available at <http://www.hks.harvard.edu/fs/whogan/Market%20Power%20&%20Withholding%20Harvey-Hogan%2012-20-01.pdf>.

⁹² *Energy Transfer Partners, L.P.*, 120 FERC ¶ 61,086 at P 4 (2007).

⁹³ *Amaranth Advisors, L.L.C.*, 120 FERC ¶ 61,085 at P 5 (2007).

⁹⁴ *Constellation Energy Commodities Grp., Inc.*, Docket No. IN12-7-000, Statement of Chairman Jon Wellinghoff on the Constellation Energy Commodities Group Investigation (Mar. 15, 2012).

Other related positions enforcement cases include *Constellation*,⁹⁵ *Deutsche Bank*,⁹⁶ *Barclays*,⁹⁷ *BP*,⁹⁸ and *Louis Dreyfus*.⁹⁹

As suggested by former Chairman Wellinghoff's statement, Commission precedent in early cases indicated that trading in related positions cases would only be considered a violation of the Anti-Manipulation Rule if the conduct involved intentionally losing money in one market in order to benefit another position in another market. But that apparently no longer is the case. In the *Deutsche Bank* case, one of the company's chief defenses was that it never intentionally traded "against its interests in any market at any time," and that its physical transactions were intended to be independently profitable (while also relieving congestion that was negatively affecting the company's financial position).¹⁰⁰ FERC rejected that defense, however, contending that there was no profitability safe harbor, and that "trading in one product (physical exports) with the intent to benefit a second product (the [congestion revenue rights] position)" is "cross-product manipulation" that violates FERC's Anti-Manipulation Rule.¹⁰¹

As a result, there currently is no bright line separating legitimate, non-manipulative trading in related markets from trading that FERC Enforcement might consider manipulative. Hedging and other legitimate trading activity necessarily can and must involve related positions, so the resulting uncertainty has serious repercussions.

The most common form of related positions allegations is that a trading firm intentionally lost money in one market to make money elsewhere. But such allegations can take other forms. In *BP*, for example, one claim is that the defendant used gas transportation capacity in sub-optimal ways to change the balance of supply and demand at a particular location in a fashion said to benefit related positions. In theory, in the wake of the *Deutsche Bank* case, trading might be clearly profitable on a stand-alone basis but still be subject to the contention that it benefited related positions in a manipulative way.

There also are complexities surrounding FERC's typical measure of "money-losing" trading. Where trading conduct helps form index price outcomes, FERC typically will measure profit by comparing the average price of the disputed trades to the index price outcome. Trading that, for example, averages a lower price than the index might be alleged as part of a scheme to drive the index lower to benefit related positions. But traders seeking to "beat the index" will fail to meet that objective at least some of the time. And there can be profit-seeking objectives to

⁹⁵ *Constellation Energy Commodities Grp., Inc.*, 138 FERC ¶ 61,168 (2012), *reh'g denied*, 145 FERC ¶ 61,203 (2013).

⁹⁶ *Deutsche Bank Energy Trading, LLC*, 142 FERC ¶ 61,056 (2013).

⁹⁷ *Barclays Bank*, 144 FERC ¶ 61,041.

⁹⁸ *BP Am. Inc.*, 144 FERC ¶ 61,100 at P 2 (2013).

⁹⁹ *MISO Virtual and FTR Trading*, 146 FERC ¶ 61,072 (2014).

¹⁰⁰ *Deutsche Bank Energy Trading, LLC*, Docket No. IN12-4-000, Answer of DB Energy Trading, LLC to Order to Show Cause at 2-7 (Nov. 5, 2012).

¹⁰¹ *Deutsche Bank*, 142 FERC ¶ 61,056 at P 18.

trading in an index-formation market beyond “beating the index.” A trading firm might be looking to manage risk, to capture spreads between different locations, or to collect market intelligence, and therefore not be concerned with whether the average price of its trades during the period that the index is formed compares favorably to the index itself. And given enough observation points, any after-the-fact examination of how a trading firm fared vis-à-vis an index might reveal instances where the firm “lost” vis-à-vis the index, and held related positions that would profit from a lower index price outcome, even though that outcome was never intended and was, instead, random.

Finally, alleged related positions manipulation schemes share a common core with withholding cases. Both types of alleged conduct involve trading where the profit motive lies elsewhere. In a withholding case, the profit would come from better performance by other, non-withheld resources. In a related positions case, the profit would come from better performance by the related position.

B. “RTO PAYMENT” CASES

Another emerging category of FERC enforcement cases involve receiving some form of payment from an RTO that FERC considers excessive or inappropriate. In the *J.P. Morgan* case, certain generating resources allegedly collected excessive uplift payments.¹⁰² Because RTO systems and rules do not necessarily precisely match the actual physical characteristics and costs of some generating units, RTOs typically make various out-of-market payments to suppliers. In some circumstances, those payments can offer opportunities for increased margins. In FERC’s view, conduct exposing a resource or resources to the prospect of earning those increased margins can, depending on the circumstances, constitute manipulation.

A second set of examples are the PJM “Up-To Congestion” cases. There, FERC contends that certain “up-to congestion” trades were vehicles to receive “transmission loss credits.”¹⁰³ FERC Enforcement has analogized some of these trades to wash trades. Among other things, however, unlike wash trades, these transactions often were profitable on a stand-alone basis. But Enforcement apparently does not view the loss credits themselves as a legitimate component of the equation of revenues and costs presented by the transactions.

A third vein of these cases involves demand response payments. In the *Silkman, Lincoln*, and *Rumford* cases, FERC claimed that the defendants established their “baseline” for purposes of receiving demand response payments in was that inflated those payments.¹⁰⁴ In *Enerwise*, the

¹⁰² *In re Make-Whole Payments and Related Bidding Strategies*, 144 FERC ¶ 61,068.

¹⁰³ *In re PJM Up-To Congestion Transactions*, 142 FERC ¶ 61,088 at P 11, Stipulation ¶ 16 (2013).

¹⁰⁴ *Richard Silkman*, 140 FERC ¶ 61,033 (2012); *Lincoln Paper*, 140 FERC ¶ 61,031 at P 2; *Rumford Paper Co.*, 142 FERC ¶ 61,218 (2013).

defendant allegedly inflated the amount of demand response that one of its clients could achieve.¹⁰⁵

In general, FERC views these “RTO Payment” cases as “exploiting loopholes,” “extracting” payments that are “too good to be true,” or “targeting” some particular RTO revenue stream. These cases can be challenging from a compliance perspective because the disputed conduct can be in conformance with the existing market rules, and the form of payment at issue can be expressly provided for in the RTO’s tariff. In addition, these cases often do not fit traditional theories of fraud. They thus typically involve “prior notice” problems (because there was no prior notice that the conduct at issue was unlawful).¹⁰⁶

C. OTHER CASES

Finally, there are two other types of FERC manipulation cases that do not fit neatly into the two categories set forth above.

1. Wash Trades

As FERC has explained, wash trades involve “pre-arranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in beneficial ownership (sometimes called ‘wash trades’).”¹⁰⁷ FERC identified “the two key elements of a wash trade”—the transactions must be “(i) prearranged to cancel each other out; and (ii) involve no economic risk.”¹⁰⁸ In Order No. 670, FERC also reaffirmed that wash trades “are examples of prohibited manipulation.”¹⁰⁹

2. Collusive Acts

As with wash trades, FERC’s pre-EPA 2005 rules prohibited “collusion with another party for the purpose of manipulating market prices, market conditions, or market rules for electric energy or electricity products.”¹¹⁰ We discuss the prohibitions against collusion contained in federal antitrust statutes in Chapter 6.

FERC viewed its prohibition on collusion as distinct from federal antitrust law because FERC’s authority “derives not from federal antitrust law, but rather from the FPA itself and its requirement that all rates and charges made, demanded, or received by any public utility subject

¹⁰⁵ *Enerwise Global Techs., Inc.*, 143 FERC ¶ 61,218 at P 3 (2013).

¹⁰⁶ As noted at the outset of this chapter, it is beyond the scope of this article to discuss the responses that have been, and will be, made by the defendants in such cases.

¹⁰⁷ *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 52.

¹⁰⁸ *Id.* at P 53.

¹⁰⁹ Order No. 670, FERC Stats. & Regs. ¶ 31,202 at P 59.

¹¹⁰ *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 at P 85 (adopting Market Behavior Rule 2(d)).

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to [FERC's] jurisdiction and all rules and regulations affecting or pertaining to such rates and charges be just and reasonable.”¹¹¹ Thus FERC's jurisdiction to investigate and penalize collusive acts may overlap with and even exceed that of federal antitrust regulators. As a result, for example, FERC's prohibition on collusion “also encompasses ‘partnerships’ whose existence do not implicate anti-trust concerns.”¹¹² Following EPCRA 2005, FERC affirmed in Order No. 670 that collusion is an “example[] of prohibited manipulation,” prohibited by the Anti-Manipulation Rule, and “subject to punitive and remedial action.”¹¹³

CONCLUSION

In sum, FERC's anti-market manipulation program is continuing to evolve and several lines of cases have created controversy and uncertainty. Not surprisingly, it may therefore fall to the courts to draw clearer boundaries and provide more certainty to market participants.

¹¹¹ *Id.* at P 89.

¹¹² *Id.*

¹¹³ *Id.* at P 59.

Chapter 5

CFTC Regulation of Energy Markets

DAVID J. HILL

DONNA BYRNE

This chapter addresses the Commodity Futures Trading Commission regulation of energy markets under the Commodity Exchange Act (“CEA”),¹ particularly with respect to enforcement actions regarding market manipulation.

I. CFTC JURISDICTION OVER ENERGY TRANSACTIONS

The CFTC has long exercised its anti-manipulation and related jurisdiction in connection with power and natural gas commodities trading in both cash and futures markets.² Congress, most notably in the Commodity Futures Modernization Act of 2000 (“CFMA”),³ exempted from CEA regulation certain qualifying transactions in non-agricultural commodities, including many power and natural gas futures transactions (the so-called “Enron Loophole”).⁴ Congress restored the CFTC’s jurisdiction over these transactions in 2008.⁵

In 2010, Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act (“Dodd-Frank”)⁶ which, among many other things, expanded the CFTC’s anti-manipulation jurisdiction to include fraud-based enforcement powers, similar to those of FERC,⁷ and established a special regulatory regime for swaps. Under the CEA as it exists today, subject to certain exceptions, the CFTC has exclusive jurisdiction with respect to “accounts, agreements

¹ 7 U.S.C. §§ 1-26.

² See, e.g., *In re DiPlacido*, Comm. Fut. L. Rep. (CCH) ¶ 29,153 at 54,002 (CFTC Sept. 12, 2002) (finding respondent liable for manipulating the settlement prices of Palo Verde and California Oregon Border electricity futures contracts traded on the New York Mercantile Exchange during the period April through August 1998).

³ See H.R. 4541, 106th Cong. (2000); 106 Cong. Rec. H12,502 (Dec. 15, 2000).

⁴ See I P. JOHNSON ET AL., DERIVATIVES REGULATION § 1.17 (2004) & 2014 Cumulative Supp. at 136-48.

⁵ Food, Conservation, and Energy Act of 2008, Pub. L. No. 110-246, 122 Stat. 1651 (2008).

⁶ Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, 124 Stat. 1376 (2010).

⁷ 7 U.S.C. § 6b. Compare 16 U.S.C. § 824v; *Prohibition of Energy Mkt. Manipulation*, Order No. 670, FERC Stats. & Regs. ¶ 31,202, *reh’g denied*, 114 FERC ¶ 61,300 (2006) (codified at 18 C.F.R. pt. 1c).

... , and transactions involving swaps or contracts of sale of a commodity for future delivery.”⁸ This exclusive jurisdiction encompasses both power and natural gas futures trading.

Pursuant to the Energy Policy Act of 2005,⁹ the CFTC and FERC entered into a Memorandum of Understanding (“MOU”) regarding information sharing and treatment of proprietary trading and other information.¹⁰ Nevertheless, these agencies have been at odds regarding regulatory jurisdiction over over-the-counter derivatives. In 2013, the D.C. Circuit rejected FERC’s claim of jurisdiction over alleged manipulative trading in natural gas futures contracts.¹¹ The court held this conduct fell within the CFTC’s exclusive jurisdiction.¹²

In 2014, FERC and the CFTC signed two new MOUs.¹³ The new “jurisdiction” MOU sets out a process under which the agencies are to notify each other of activities that may involve overlapping jurisdiction and coordinate to address the agencies’ regulatory concerns. This MOU does not, however, substantively address the scope of each agency’s respective jurisdiction. The new “information sharing” MOU establishes procedures through which the agencies are to share on an ongoing basis information related to their respective market surveillance and investigative responsibilities, including data relating to financial markets for gas and electricity.

II. PROHIBITED TRANSACTIONS

Various provisions of the CEA address market behavior, including alleged market manipulation. Of particular interest here are CEA sections 4c(a)(1)(A)-(B),¹⁴ 6(c), 6(d), and 9(a)(2).¹⁵

⁸ 7 U.S.C. § 2(a)(1)(A).

⁹ See sections 316 and 1281 of the Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

¹⁰ Memorandum of Understanding Between FERC the Federal Energy Regulatory Commission (FERC) and the Commodity Futures Trading Commission (CFTC) Regarding Information Sharing and Treatment of Proprietary Trading and Other Information (Oct. 12, 2005), <http://www.ferc.gov/legal/mou/mou-33.pdf>.

¹¹ *Hunter v. FERC*, 711 F.3d 155, 156, 158-60 (D.C. Cir. 2013).

¹² *Id.* at 157.

¹³ CFTC Press Release No. PR6816-14, FERC, CFTC Sign MOUs on Jurisdiction and Information Sharing (Jan. 2, 2014), <http://www.cftc.gov/PressRoom/PressReleases/pr6816-14>.

¹⁴ 7 U.S.C. § 6c(a)(1)(A)-(B).

¹⁵ *Id.* §§ 9, 13b, and 13(a)(2). Dodd-Frank, which amended 7 U.S.C. §§ 9 and 13(a)(2), is discussed *infra*. These CEA provisions apply to both business entities and individuals and, under CEA section 2, 7 U.S.C. § 2, the acts or omissions of individuals within the scope of their employment are attributable to the corporation or other legal entity.

A. FALSE REPORTS AFFECTING PRICE; FALSE STATEMENTS TO A REGISTERED ENTITY

Among other things, CEA section 9(a)(2)¹⁶ makes it unlawful “knowingly to deliver or cause to be delivered for transmission through the mails or interstate commerce . . . false or misleading or knowingly inaccurate reports concerning crop or market information or conditions that affect or tend to affect the price of any commodity in interstate commerce.” The CFTC has actively pursued both civil and criminal cases involving alleged misreporting to trade publications.¹⁷

CEA section 9(a)(4) makes it unlawful for any person to willfully “falsify, conceal, or cover up by any trick, scheme, or artifice a material fact, make any false, fictitious, or fraudulent statements or representations, or make or use any false writing or document knowing the same to contain any false, fictitious, or fraudulent statement or entry to a registered entity, board of trade, swap data repository, or futures association.”¹⁸

B. DISRUPTIVE PRACTICES

Under CEA section 4c(a)(5),¹⁹ it is unlawful for any person to engage in any trading on a registered entity that violates bids or offers; demonstrates intentional or reckless disregard for the orderly execution of transactions during the closing period; or “is, is of the character of, or is commonly known to the trade as, ‘spoofing’ (bidding or offering with the intent to cancel the bid or offer before execution).”

C. WASH SALES

Section 4c of the CEA expressly prohibits “wash sale” transactions (sometimes referred to as “round-trip” transactions), which typically feature one party agreeing to buy from another party and agreeing to sell to that same other party the same amount of the same commodity at the same price for completion at the same time and place.²⁰ The CFTC has stated that “wash sales are ‘grave’ violations, even in the absence of customer harm or appreciable market effect,

¹⁶ *Id.* § 13(a)(2).

¹⁷ *See, e.g., United States v. Futch*, 278 F. App’x 387 (5th Cir. 2008); *CFTC v. NRG Energy, Inc.*, No. 04-3090 (MJD/AJB), Consent Order of Permanent Injunction, Civil Monetary Penalty and Other Equitable Relief Against NRG Energy, Inc. (D. Minn. Feb. 13, 2007); *United States v. Valencia*, Crim. No. H-04-514, Indictment (S.D. Tex. Nov. 17, 2004); CFTC Press Release No. 5292-07, United States Commodity Futures Trading Commission Settles Action Charging NRG Energy Inc. With Falsely Reporting Natural Gas Trades (Feb. 15, 2007), <http://www.cftc.gov/PressRoom/PressReleases/pr5292-07>.

¹⁸ 7 U.S.C. § 13(a)(4); *see, e.g., CFTC v. Optiver US, LLC*, No. 08 Civ. 6560, Final Consent Order of Permanent Injunction, Civil Monetary Penalty and Other Relief (S.D.N.Y. Apr. 19, 2012) (false statements made to NYMEX in the course of its inquiry into Optiver’s trading practices violated CEA section 9(a)(4)).

¹⁹ 7 U.S.C. § 6c(a)(5).

²⁰ *Id.* § 6c(a)(1)-(2).

because ‘they undermine confidence in the market mechanism that underlies price discovery.’”²¹ The CFTC also has taken the position that establishing a wash sale violation does not require a showing of intent to manipulate or affect market prices.²²

D. SECTION 9(A) PRICE MANIPULATION (COMPLETED OR ATTEMPTED)

CEA section 9(a) makes it unlawful to manipulate or attempt to manipulate “the price of any commodity in interstate commerce, or for future delivery on or subject to the rules of any registered entity, or of any swap, or to corner or attempt to corner any such commodity.”²³ This provision applies to cash as well as futures trading. Completed manipulation can occur when a party, through any form of conduct, intentionally creates an artificial price. An “artificial price” is a price that does not reflect the legitimate forces of supply and demand.²⁴

The CEA does not define the term “manipulation.” However, in a 2013 case involving the regulation of swap dealers, the CFTC observed:

By way of background, under long-standing Commission precedent, manipulation was historically described as “any and every operation or transaction or practice, the purpose of which is not primarily to facilitate the movement of the commodity at prices freely responsive to the forces of supply and demand; but, on the contrary, is calculated to produce a price distortion of any kind in any market either in itself or in its relation to other markets. If a firm is engaged in manipulation it will be found using devices by which the prices of contracts for some one month in some one market may be higher than they would be if only the forces of supply and demand were operative Any and every operation, transaction, device, employed to produce those abnormalities of price relationship in the futures markets, is manipulation.”²⁵

²¹ *BP Energy Co.*, Comm. Fut. L. Rep. (CCH) ¶ 29,903 at 56,700 (CFTC Nov. 4, 2004) (quoting *In re Piasio*, Comm. Fut. L. Rep. (CCH) ¶ 28,276 at 50,691 (CFTC Sept. 29, 2000)); *In re Reliant Energy Servs., Inc.*, Comm. Fut. L. Rep. (CCH) ¶ 29,639 at 55,758 (CFTC Nov. 25, 2003). Both the BP Energy matter and the Reliant Energy Services matter involved alleged physical power wash trades, and both were ultimately resolved by administrative settlements.

²² See, e.g., *BP Energy Co.*, Comm. Fut. L. Rep. (CCH) ¶ 29,903 at 56,700 n.4; see also *CFTC v. Royal Bank of Can.*, No. 1:12-cv-02497, Complaint (S.D.N.Y. filed Apr. 2, 2012) (alleging wash trading scheme in connection with exchange-traded stock futures contracts).

²³ 7 U.S.C. § 13(a).

²⁴ See *In re Ind. Farm Bureau Coop. Ass’n, Inc.*, Comm. Fut. L. Rep. (CCH) ¶ 21,796 at 27,282 & n.2 (CFTC Dec. 17, 1982).

²⁵ *JPMorgan Chase Bank., N.A.*, Comm. Fut. L. Rep. (CCH) ¶ 32,838 (CFTC Oct. 16, 2013) (quoting *Indiana Farm Bureau*, Comm. Fut. L. Rep. (CCH) ¶ 21,796 at 27,282 (quoting *Volkart Bros., Inc. v. Freeman*, 311 F.2d 52, 58 (5th Cir. 1962) (quoting testimony before a Senate subcommittee of Arthur R. Marsh, a former president of the New York Cotton Exchange)).

The Eighth Circuit stated in an often-quoted order: “We think the test of manipulation must largely be a practical one if the purposes of the Commodity Exchange Act are to be accomplished. The methods and techniques of manipulation are limited only by the ingenuity of man. The aim must be therefore to discover whether conduct has been intentionally engaged in which has resulted in a price which does not reflect basic forces of supply and demand.”²⁶ Although it is the second sentence of this statement that is most frequently quoted, it is the last sentence that defines the relevant inquiry.²⁷

1. *The Elements of Proving a Section 9(a) Completed Manipulation Claim*

When investigating alleged completed price manipulation under section 9(a)(2), the CFTC evaluates four factors: (i) whether the trading entity had the ability to influence prices; (ii) whether it specifically intended to create an artificial price; (iii) whether an artificial price existed; and (iv) causation.²⁸ Market manipulation is a conduct offense, requiring actual behavior supportive of such a claim.²⁹ These elements, especially price artificiality, are complex and can be difficult to prove.³⁰

a. *The ability to affect prices*

- In a classic “squeeze” or “corner” case, whether a firm has successfully foreclosed competition in the delivery of a commodity initially requires a determination of the “available supply” of the underlying cash commodity (e.g., physical power or gas) at the time of the alleged manipulation.
- Then, it must be determined whether the firm’s control of the commodity was sufficient to preclude sellers from fulfilling their contract obligations except by either purchasing inventory from the accused firm or offsetting with the accused in the futures market—either or both at above-market prices.³¹

²⁶ *Cargill, Inc. v. Hardin*, 452 F.2d 1154, 1163 (8th Cir. 1971); *see also Indiana Farm Bureau, Comm. Fut. L. Rep. (CCH) ¶ 21,796 at 27,282-83.*

²⁷ *See* III JOHNSON, DERIVATIVES REGULATION at 1277, n.15.

²⁸ *See In re Amaranth Natural Gas Commodities Litig. v. J.P. Morgan Chase & Co.*, 730 F.3d 170, 173 (2d Cir. 2013) (citing *Hershey v. Energy Transfer Partners, L.P.*, 610 F.3d 239, 247 (5th Cir. 2010)); *In re Soybean Futures Litig.*, 892 F.Supp. 1025, 1045 (N.D. Ill. 1995) (citing *Frey v. CFTC*, 931 F.2d 1171, 1177-78 (7th Cir. 1991)).

²⁹ *See In re Hohenberg Bros. Co.*, Comm. Fut. L. Rep. (CCH) ¶ 20,271 at 21,477 (CFTC Feb. 18, 1977) (“A finding of manipulation in violation of the Act requires a finding that the party engaged in conduct with the intention of affecting the market price of a commodity . . . and as a result of such conduct or course of action an artificial price was created”) (emphasis added).

³⁰ *See* III JOHNSON, DERIVATIVES REGULATION at 1257 (quoting *In re Global Minerals and Metals Corp.*, Comm. Fut. L. Rep. (CCH) ¶ 27,914 (CFTC Nov. 12, 1999) (Initial Decision)).

³¹ *See id.* at 1243-52.

- In other cases, the CFTC and the courts have focused on the underlying conduct in lieu of market control.³²

b. Specific intent to create an artificial price

- To prove the intent element of manipulation (or attempted manipulation), it must be shown that the respondent “acted (or failed to act) with the purpose or conscious object of causing or effecting a price or price trend in the market that did not reflect the legitimate forces of supply and demand.”³³ Absent proof that the defendant actually intended to bring about artificial prices, no manipulation finding can be made.³⁴
- Proof of intent can be based on circumstantial rather than direct evidence.³⁵ This often includes communications such as emails and trader voice recordings that are frequently ambiguous but nonetheless can be problematic for defendants.³⁶

³² See *DiPlacido v. CFTC*, 364 F. App’x 657, 660 (2d Cir. 2009) (summary order) (“DiPlacido argues further that the Commission denied due process by abandoning an existing requirement for proof of defendant’s control over the relevant market. The Commission’s well-established precedents are plainly to the contrary, indicating that market control may be a feature of some forms of manipulation, e.g., a “corner” or “squeeze,” but is *not* a requirement of manipulation in all its forms.”) (emphasis in original and citations omitted).

³³ *Indiana Farm Bureau*, Comm. Fut. L. Rep. (CCH) ¶ 21,796 at 27,282. A profit motive may also be evidence of intent, although profit motive is not a necessary element of an attempted manipulation. See *In re DiPlacido*, Comm. Fut. L. Rep. (CCH) ¶ 30,970 at 62,484 (CFTC Nov. 5, 2008) (citing *In re Hohenberg Bros. Co.*, Comm. Fut. L. Rep. (CCH) ¶ 20,271 at 21,478), *aff’d*, 364 F. App’x 657 (2d Cir. 2009) (summary order).

³⁴ See *Indiana Farm Bureau*, Comm. Fut. L. Rep. (CCH) ¶ 21,796 at 27,281-82 (“[I]ntent is the essence of manipulation [I]t must be proven that the accused acted (or failed to act) with the purpose or conscious object of causing or effecting a price or price trend in the market that did not reflect the legitimate forces of supply and demand influencing futures prices in the particular market at the time of the alleged manipulative activity.”); see also *Hohenberg*, Comm. L. Rep. (CCH) ¶ 20,271 at 21,477; *Great W. Food Distribs., Inc. v. Brannan*, 201 F.2d 476, 479 (7th Cir. 1953); *Cargill*, 452 F.2d at 1162, 1163.

³⁵ See *United States v. U.S. Gypsum Co.*, 438 U.S. 442, 445 (1978) (antitrust); *G. H. Miller & Co. v. United States*, 260 F.2d 286, 290 (7th Cir. 1958) (CEA). See III JOHNSON, DERIVATIVES REGULATION at 1268-70 (“[W]hile knowledge of relevant market conditions is probative of intent, it is not necessary to prove that the accused knew to any particular degree of certainty that his actions would create an artificial price. It is enough to present evidence from which it may reasonably be inferred that the accused ‘consciously desire[d] that result, whatever the likelihood of that result happening from his conduct.’”) (citing *U.S. Gypsum Co.*, 438 U.S. at 445).

³⁶ Compare *Cargill*, 452 F.2d at 1171 (citing an internal Cargill inter-office telegram and a statement made by a Cargill official to the Department of Agriculture in support of its finding that Cargill’s actions were intentional), with *Utesch v. Dittmer*, 947 F.2d 321, 328 (8th Cir. 1991) (holding that neither testimony that the defendant told a witness that defendant “was going to drive the . . . market

- The CFTC bears the burden of proving intent.³⁷

c. Existence of an artificial price

- In various cases, the government has submitted evidence and expert testimony comparing (a) futures and cash prices with actual supply/demand conditions, (b) prior or subsequent time periods with the period of the alleged manipulation, (c) spreads between monthly futures contracts, (d) historical (multi-year) prices, and (e) prices in separate locations.
- In one leading case, *Cargill*,³⁸ the government successfully proved that the defendant had manipulated the price of wheat futures as compared to the cash price of wheat at the time. The U.S. Court of Appeals acknowledged “the difficulty of determining the cash price of wheat, for actual cash trades on the Chicago spot market are relatively infrequent and the prices of individual transactions may vary greatly depending on the positions of the parties, the quantity involved, and the time of the transaction.”³⁹ Nonetheless, the court concluded that the government had proved the existence of an artificial price by a preponderance of the evidence.⁴⁰
- On the other hand, in *In re Indiana Farm Bureau Cooperative Ass’n, Inc.*,⁴¹ a CFTC administrative law judge found that July 1973 corn futures reached artificial levels on July 20, 1973 but concluded that respondents’ trading “was not a culpable or legal cause of the prices” and that respondents did not “attempt or intend to cause the prices that were reached.” On appeal, the CFTC concluded that the July 1973 corn futures price increase was the product of forces of supply and demand and dismissed the complaint.⁴²

d. Causation

- It must be established that the desired price movement in fact occurred as a result of the manipulation.⁴³

low” or an expert’s opinion that such a trader “could influence” or “could cause the price . . . to change” was sufficient to establish the necessary element of causation).

³⁷ *Hohenberg*, Comm. Fut. L. Rep. (CCH) ¶ 20,271 at 21,479.

³⁸ 452 F.2d 1154.

³⁹ *Id.* at 1168 (footnote omitted).

⁴⁰ *Id.* at 1169.

⁴¹ Comm. Fut. L. Rep. (CCH) ¶ 20,964 at 23,857-59 (CFTC Dec. 12, 1979), *aff’d*, Comm. Fut. L. Rep. (CCH) ¶ 21,796 (CFTC Dec. 17, 1982).

⁴² *Indiana Farm Bureau*, Comm. Fut. L. Rep. (CCH) ¶ 21,796 at 27,285-87.

⁴³ See *Utesch*, 947 F.2d at 325 (plaintiff must prove that the actions complained of “were intended to and did produce an artificially low price”).

- In *Cargill*, the court of appeals upheld the government’s causation findings, relying heavily on market patterns in futures trading by Cargill itself and other sellers.⁴⁴ In *Indiana Farm Bureau*, however, the CFTC concluded the respondents did not cause the large increase in prices on the final trading day of the July 1973 corn futures contract, citing the large short positions of other traders that were carried into the final day of trading.⁴⁵

2. *The Elements of Proving a Section 9(a) Attempted Manipulation Claim*

Attempted price manipulation is a separate statutory offense under CEA section 9(a).⁴⁶ A charge of attempted manipulation requires evidence of “(1) an intent to affect the market price; and (2) some overt act in furtherance of that intent.”⁴⁷ As described above, proving intent requires a showing of specific intent to create an artificial price.⁴⁸ To prove the “overt act” element of the offense, it must be shown that the defendants performed an act that constituted a step toward causing or effecting a price or price trend in the market that would not reflect the legitimate forces of supply and demand.⁴⁹

E. FRAUD-BASED MANIPULATION

The CEA has expressly prohibited fraud since its original enactment in 1936.⁵⁰ In the Dodd-Frank Act, Congress gave the CFTC additional authority to pursue market manipulation based on fraud—similar to the authority given to FERC in the Energy Policy Act of 2005.⁵¹ Like

⁴⁴ See *Cargill*, 452 F.2d at 1169-70.

⁴⁵ Comm. L. Rep. (CCH) ¶ 21,796 at 27,286.

⁴⁶ 7 U.S.C. § 13(a)(2).

⁴⁷ *In re Avista Energy Inc.*, Comm. Fut. L. Rep. (CCH) ¶ 28,623 at 52,356 (CFTC Aug. 21, 2001).

⁴⁸ See *supra* note 43.

⁴⁹ *In re Paul K. Kelly*, Comm. Fut. L. Rep. (CCH) ¶ 30,653 (CFTC Oct. 25, 2007).

⁵⁰ Commodity Exchange Act, Pub. L. No. 674, 49 Stat. 1491, 74th Cong., Second Sess. (1936). Section 4b of the Act, 7 U.S.C. § 6, prohibited commodity sales in interstate commerce that were or may be used for specified trading purposes: “(A) to cheat or defraud or attempt to cheat or defraud such person; (B) willfully to make or cause to be made to such person any false report or statement thereof, or willfully to enter or cause to be entered for such person any false record thereof; [or] (C) willfully to deceive or attempt to deceive such person by any means whatsoever in regard to any such order or contract or the disposition or execution of any such order or contract, or in regard to any act of agency performed with respect to such order or contract for such person” The CEA’s predecessor statute, the Grain Futures Act of 1922, prohibited manipulation but not fraud. See *Horn v. Ray E. Friedman & Co.*, 776 F.2d 777 (8th Cir. 1985) (elements of fraud action under CEA section 4b are derived from common law and include a false representation of material fact with knowledge of falsity, made with intent to induce reliance, resulting in damage from justifiable reliance).

⁵¹ Compare section 6(c)(1) of the CEA, 7 U.S.C. § 9, with section 222 of EPCA 2005, codified at 16 U.S.C. § 824v.

FPA section 222 (discussed in Chapter 4), the anti-manipulation provision in amended CEA section 6(c) is based on section 10(b) of the Securities Exchange Act of 1934. When the CFTC promulgated Rule 180.1 to implement these Dodd-Frank provisions, it observed that “[g]iven the similarities between CEA section 6(c)(1) and Exchange Act section 10(b), the Commission deems it appropriate and in the public interest to model final Rule 180.1 on SEC Rule 10b-5.”⁵² However, the CFTC also noted: “To account for the differences between the securities markets and the derivatives markets, the Commission will be guided, but not controlled, by the substantial body of judicial precedent applying the comparable language of SEC Rule 10b-5.”⁵³

New Rule 180.1 prohibits actual or attempted manipulative or deceptive acts “in connection with” any swap, cash commodity sale, or futures contract.⁵⁴ Rule 180.1 provides in pertinent part:

- a) It shall be unlawful for any person, directly or indirectly, in connection with any swap, or contract of sale of any commodity in interstate commerce, or contract for future delivery on or subject to the rules of any registered entity, to intentionally or recklessly:⁵⁵
 - (1) Use or employ, or attempt to use or employ, any manipulative device, scheme, or artifice to defraud;
 - (2) Make, or attempt to make, any untrue or misleading statement of a material fact or to omit to state a material fact necessary in order to make the statements made not untrue or misleading;
 - (3) Engage, or attempt to engage, in any act, practice, or course of business, which operates or would operate as a fraud or deceit upon any person; or,
 - (4) Deliver or cause to be delivered, or attempt to deliver or cause to be delivered, for transmission through the mails or interstate commerce, by any means of communication whatsoever, a false or

⁵² *Prohibition on the Employment, or Attempted Employment, of Manipulative and Deceptive Devices and Prohibition on Price Manipulation*, 76 Fed. Reg. 41,398, 41,399 (July 14, 2011) (effective Aug. 15, 2011) (codified at 17 C.F.R. § 180.1).

⁵³ *Id.*

⁵⁴ *Id.* at 41,410. “The Commission interprets the words ‘in connection with’ broadly, not technically or restrictively. Section 6(c)(1) and final Rule 180.1 reach all manipulative or deceptive conduct in connection with the purchase, sale, solicitation, execution, pendency, or termination of any swap.” *Id.* at 41,405.

⁵⁵ *JPMorgan*, Comm. Fut. L. Rep. (CCH) ¶ 32,838 at 73,952 (defining recklessness “as an act or omission that ‘departs so far from the standards of ordinary care that it is very difficult to believe the actor was not aware of what he or she was doing.’”) (quoting *Drexel Burnham Lambert Inc. v. CFTC*, 850 F.2d 742, 748 (D.C. Cir. 1988)).

misleading or inaccurate report concerning crop or market information or conditions that affect or tend to affect the price of any commodity in interstate commerce, knowing, or acting in reckless disregard of the fact that such report is false, misleading or inaccurate. Notwithstanding the foregoing, no violation of this subsection shall exist where the person mistakenly transmits, in good faith, false or misleading or inaccurate information to a price reporting service.

Section 180.1(b) provides that “[n]othing in this section shall be construed to require any person to disclose to another person nonpublic information that may be material to the market price, rate, or level of the commodity transaction, except as necessary to make any statement made to the other person in or in connection with the transaction not misleading in any material respect.” Section 180.1(c) states: “Nothing in this section shall affect, or be construed to affect, the applicability of Commodity Exchange Act section 9(a)(2).”

CEA section 180.2, Prohibition on price manipulation, restates the pre-Dodd-Frank prohibition on actual or attempted price manipulation:

It shall be unlawful for any person, directly or indirectly, to manipulate or attempt to manipulate the price of any swap, or of any commodity in interstate commerce, or for future delivery on or subject to the rules of any registered entity.

III. CEA ENFORCEMENT PROCEEDINGS AND REMEDIES

Alleged violations of the CEA may be enforced through administrative action by the CFTC itself, through civil suits for damages or injunctive relief filed by the CFTC in federal district court, through the criminal prosecution of individuals or corporate entities referred by the CFTC to the Department of Justice and, in certain instances, by the states and by private civil suits for damages.

A. ADMINISTRATIVE PROCEEDINGS AND REMEDIES

The CFTC may institute administrative proceedings within the agency, to be tried before an administrative law judge, subject to appeal to the Commissioner and thereafter normally to a U.S. Court of Appeals. CFTC civil sanctions in administrative proceedings include cease-and-desist orders, suspension or revocation of any CFTC registration, prohibition against using the CFTC-regulated markets, civil penalties per “violation” of up to \$140,000 (an amount periodically adjusted for inflation)⁵⁶ or triple any monetary gain if higher, disgorgement, and restitution to customers. For a civil violation of the prohibition against actual or attempted price manipulation committed on or after August 15, 2011, the penalty shall be “not more than the greater of \$140,000 or triple the monetary gain to such person for each such violation.”⁵⁷ The

⁵⁶ See 17 C.F.R. § 143.8 (inflation-adjusted civil monetary penalties).

⁵⁷ *Id.* § 143.8(a)(2)(i).

penalty for *fraud-based* manipulation or attempted manipulation violations is higher—up to the greater of \$1,000,000 (since adjusted to \$1,025,000) or triple the monetary gain for each such violation committed on or after August 15, 2011.⁵⁸

The CFTC also polices the conduct of parties filing information with the agency and parties under investigation. For example, the CFTC has imposed civil penalties on companies for filing inaccurate reports required by CFTC regulations,⁵⁹ for making false statements and/or failing to disclose information in CFTC filings,⁶⁰ and making false statements in CFTC investigative testimony.⁶¹ The agency also charged four individual natural gas traders for violating section 4c(b) of the CEA⁶² by allegedly mismarking their own open option positions and fabricating options quotes that supposedly supported their marks.⁶³

B. CIVIL PROCEEDINGS AND REMEDIES

The CFTC also may institute, in its own name, a civil action in a federal district court to seek civil penalties or enjoin alleged violations of the CEA.⁶⁴ The CFTC normally reserves injunctive actions for situations where immediate judicial intervention is desired.

Notable energy-related civil proceedings brought in federal district court by the CFTC have involved companies such as Enron, American Electric Power Co., AEP Energy Services, Inc., BP Products, Energy Transfer Partners, Marathon Oil, Parnon Energy, Optiver US, and Amaranth Advisors. Brief descriptions of these cases appear in the Appendix to this chapter.

C. CRIMINAL PROCEEDINGS

The DOJ prosecutes criminal charges under CEA section 9 through a U.S. Attorney's office in an appropriate venue. There have been a number of indictments of energy companies

⁵⁸ 7 U.S.C. § 13a; *see also* 17 C.F.R. § 143.8; *CFTC v. Hunter Wise Commodities, LLC*, No. 12-81311-CV, 2014 WL 2022239 (S.D. Fla. May 16, 2014) (describing penalty options and assessing \$55.4 million in penalties, representing triple the amount of the alleged monetary gain).

⁵⁹ *In re J.P. Morgan Sec. LLC*, Comm. Fut. L. Rep. (CCH) ¶ 33,209 (CFTC July 29, 2014) (filing inaccurate large trader reports).

⁶⁰ *CFTC v. Growth Capital Mgmt. LLC*, No. 3:10-cv-1473, Consent Order of Injunctive and Other Equitable Relief Against Defendant Robert Mihailovich, Jr. (N.D. Tex. June 11, 2012).

⁶¹ *In re Susan Butterfield*, Comm. Fut. L. Rep. (CCH) ¶ 32,812 (CFTC Sept. 16, 2013).

⁶² 7 U.S.C. § 6c(b); *see also* 17 C.F.R. § 33.10 (fraud in connection with commodity option transactions).

⁶³ *CFTC v. Lee*, Case No. 08-CIV-9962 (GDB), Consent Order and Judgment of Permanent Injunction, Civil Monetary Penalty, and Other Equitable Relief Against Defendant David Lee (S.D.N.Y. Nov. 5, 2009).

⁶⁴ 7 U.S.C. § 13a-1.

and traders for false price reporting.⁶⁵ Various traders have pleaded guilty to crimes; at least two traders have been convicted.

Dodd-Frank gave the CFTC enhanced criminal penalty authority for fraud-based manipulation.⁶⁶ Section 9(a) of the CEA⁶⁷ provides that violations shall be felonies punishable by a fine of not more than \$1,000,000 or imprisonment for not more than five years, or both, together with the costs of prosecution. Congress is free to raise these criminal penalties and has done so from time to time.

D. SUITS BY THE STATES

Under section 6d of the CEA,⁶⁸ a state may bring in federal district court a suit in equity or an action at law on behalf of its residents to enjoin acts or practices prohibited under the CEA; to enforce compliance with the CEA and CFTC rules, regulations, or orders; and to obtain damages on behalf of their residents. The CFTC has the right to intervene in such an action and, upon doing so, “shall be heard on all matters arising therein,” and has the right to file petitions for appeal.⁶⁹

E. PRIVATE CIVIL ACTIONS

Section 22 of the CEA,⁷⁰ provides for a private right of action for violations of the Act “if the violation [involving a contract of sale of any commodity for future delivery] constitutes . . . a

⁶⁵ See, e.g., *United States v. Phillips*, No. CR H-04-512-S, Superseding Indictment (S.D. Tex. filed Oct. 31, 2005); *United States v. Reliant Energy Servs., Inc.*, No. CR 04-0125, Second Superseding Indictment (N.D. Cal. filed Oct. 11, 2005); *United States v. Valencia*, No. CR 04-514, Indictment (S.D. Tex. filed Nov. 17, 2004); *United States v. Michelle Valencia*, No. CR H-03-0024, Indictment (S.D. Tex. filed Jan. 22, 2003); *United States v. Todd Geiger*, No. CR H-02-712, Indictment (S.D. Tex. filed Dec. 2, 2002); CFTC Press Release No. PR5409-07, U.S. Commodity Futures Trading Commission Settles Natural Gas False Reporting and Attempted Manipulation Lawsuit with Energy Trader (Nov. 8, 2007) (three natural gas traders, two former employees of Mirant and one former employee of Cinergy pleaded guilty to criminal charges of false price reporting in June 2006), <http://www.cftc.gov/PressRoom/PressReleases/pr5409-07>. But see *United States v. Radley*, 659 F. Supp. 2d 803 (S.D. Tex. 2009), *aff'd*, 632 F.3d 177 (5th Cir. 2011) (charging named defendant and three other former BP Products employees with conspiracy, price manipulation and attempted price manipulation in violation of the CEA, and wire fraud; all counts dismissed).

⁶⁶ See, e.g., *JPMorgan*, Comm. Fut. L. Rep. (CCH) ¶ 32,838.

⁶⁷ 7 U.S.C. § 13(a) (providing for criminal penalties).

⁶⁸ *Id.* § 13a-2.

⁶⁹ *Id.*

⁷⁰ *Id.* § 25(a)(1)(D).

manipulation of the price of any such contract or swap or the price of the commodity underlying such contract.”⁷¹

Class action plaintiffs frequently have availed themselves of this provision. For example, in 2004 plaintiffs brought two class actions against numerous companies, alleging manipulation of gas futures markets by falsely reporting data on natural gas trades in the physical market.⁷² Another class action lawsuit was filed against Amaranth and ultimately resulted in a settlement.⁷³

Energy Transfer Partners successfully defeated two putative class action lawsuits based on alleged violations of the CEA.⁷⁴

IV. CALCULATING CIVIL PENALTIES

A. BACKGROUND

Under section 6(c) of the CEA, “[i]f the Commission has reason to believe that any person . . . has manipulated or attempted to manipulate” the price of a commodity, it may “assess such person . . . a civil penalty . . . for each such violation.”⁷⁵ In formulating the amount of the penalty to be imposed, the Commission must “consider the appropriateness of such penalty to the gravity of the violation.”⁷⁶

The CFTC has stated that the amount of an appropriate civil monetary penalty is one that “deters future violations by making it beneficial financially to comply with the requirements of the Act and Commission regulations rather than risk violations.”⁷⁷ The only clear CFTC policy regarding calculation of civil penalties occurs in cases where the respondent realized a

⁷¹ In addition, section 14 of the CEA, 7 U.S.C. § 18, authorizes “any person” to file an action at the CFTC against a registered entity for actual and punitive damages. See I JOHNSON, DERIVATIVES REGULATION at 295-98.

⁷² See *In re Natural Gas Commodity Litig.*, 337 F. Supp. 2d 498 (S.D.N.Y. 2004) (granting in part and denying in part motions to dismiss.).

⁷³ See *In re Amaranth Natural Gas Commodities Litig.*, 587 F. Supp. 2d 513 (S.D.N.Y. 2008) (granting in part and denying in part motions to dismiss); *In re Amaranth Natural Gas Commodities Litig.*, No. 07-cv-6377, 2012 WL 2149094, at *1 (S.D.N.Y. June 11, 2012).

⁷⁴ See *Hershey v. Energy Transfer Partners, L.P.*, 610 F.3d 239, 241 (5th Cir. 2010) (affirming district court’s dismissal of class action suit for failure “to sufficiently allege that Defendants specifically intended to manipulate NYMEX natural gas futures contracts”); *Rio Grande Royalty Co., Inc. v. Energy Transfer Partners, L.P.*, 620 F.3d 465 (5th Cir. 2010) (affirming district court’s dismissal of class action suit for failure to prove fraud).

⁷⁵ 7 U.S.C. § 9; see *id.* § 13b.

⁷⁶ *Id.* § 9a(1).

⁷⁷ *In re Gordon*, Comm. Fut. L. Rep. (CCH) ¶ 25,667 at 40,182 (CFTC Mar. 16, 1993) (citation omitted).

quantifiable gain or victims suffered a quantifiable loss. Under such circumstances, the penalty amount consists approximately of that sum plus a deterrence premium.

B. WHAT CONSTITUTES A SEPARATE VIOLATION?

In CFTC civil actions, there is no clear line of authority on what constitutes a single or separate “violation” of the CEA.⁷⁸ This question has arisen frequently in CFTC administrative cases and in federal court cases and results vary considerably.

One illuminating case on this subject is *Slusser v. CFTC*,⁷⁹ where the Seventh Circuit held that the civil penalty was limited to the number of counts alleged in the complaint times \$100,000 per violation.⁸⁰ On remand, the CFTC imposed the \$600,000 penalty cited by the Seventh Circuit, but noted that “[t]he allegations in this case involve the type of broad-based, repeated wrongdoing that *we would normally view as involving hundreds of violations*” and that the CFTC typically does not “equate the number of violations at issue in an enforcement proceeding with the number of Counts included in a Complaint.”⁸¹

Some courts have treated all infractions under one statute or regulation as a single “violation.”⁸² In still other cases, the courts have defined the term “violation” to mean the number of investors/victims, the number of illegally opened trading accounts, or, in one case, the number of testifying victims. In *CFTC v. Emerald Worldwide Holdings, Inc.*,⁸³ the court reviewed a complaint which alleged that more than 300 customers had been fraudulently solicited by a respondent, and determined that “the civil monetary penalty . . . could potentially be as high as \$36 million (300 times \$120,000).”⁸⁴ Ultimately, the court imposed a penalty of

⁷⁸ When filing a case in federal court, however, the agency typically alleges that each occurrence of, for example, price misreporting, is a distinct violation. See, e.g., *CFTC v. Richmond*, No. 05-M-668 (OES), Complaint for Injunctive and other Equitable Relief and Civil Monetary Penalties Under the Commodity Exchange Act at ¶ 41 (D. Colo. filed Apr. 12, 2005) (“Each occasion upon which defendant delivered, or caused to be delivered, for transmission through the mails or interstate commerce . . . false or misleading or knowingly inaccurate transaction information concerning natural gas transactions is alleged herein as a separate and distinct violation of section 9(a)(2) of the Act.”).

⁷⁹ 210 F.3d 783, 784-88 (7th Cir. 2000).

⁸⁰ *Id.*; see also *CFTC v. Gibraltar Monetary Corp.*, No. 04-80132-CIV, 2006 WL 1789018 (S.D. Fla. May 30, 2006) (same).

⁸¹ *In re Slusser*, Comm. Fut. L. Rep. (CCH) ¶ 29,411 (CFTC Feb. 28, 2003) (emphasis added).

⁸² See, e.g., *CFTC v. Poole*, No. 1:05CV00859, 2006 WL 1174286, at *6-7 (M.D.N.C. May 1, 2006) (ordering the defendant to pay a \$240,000 civil monetary penalty (\$120,000 for violating each of two sections of the CEA)).

⁸³ No. CV03-8339AHM, 2005 WL 1130588 (C.D. Cal. Apr. 19, 2005).

⁸⁴ *Id.* at *11-13 (finding that, in light of evidence that defendant and its affiliates had fraudulently induced more than 300 customers to make deposits into their bank accounts, CFTC’s request for a civil monetary penalty of \$9 million was not unreasonable).

just over \$8 million, which was triple the defendant's improper monetary gain, a sum that fell below the maximum allowable penalty.⁸⁵

Accordingly, the CFTC has very broad latitude when calculating how many "violations" it wishes to cite and, because the number of cited violations directly affects the maximum amount of civil penalties that it may collect from offenders, the CFTC has every reason to cite as many violations as possible. Nonetheless, reviewing courts may take a narrower view of what constitutes a violation.

⁸⁵ *Id.*; see also *Brenner v. CFTC*, 338 F.3d 713 (7th Cir. 2003) (apparently basing penalty on the number of accounts defrauded); *CFTC v. Vandeveld*, No. 04-2181-D/An., 2007 WL 2823307, at *10 (W.D. Tenn. Sept. 27, 2007) (treating each deceived investor and potential investor as a single violation of the CEA and assessing penalty of \$1,920,000 (\$120,000 times 16 investors and potential investors)); *CFTC v. Millenium Trading Grp., Inc.*, No. 07-CV-11626, 2007 WL 2639474 (E.D. Mich. Sept. 6, 2007) (treating each investor as a separate violation for determining penalties); *In re Howard Miller*, Comm. Fut. L. Rep. (CCH) ¶ 29,825 (CFTC July 23, 2004) (basing penalty on the number of testifying customers).

APPENDIX

SUMMARY OF SELECTED CFTC CASES INVOLVING ENERGY SECTOR

- *CFTC v. Amaranth Advisors LLC*, No. 1:07-cv-06682-RA, Complaint (S.D.N.Y. filed July 25, 2007). The Amaranth corporate entities settled with the CFTC. *CFTC v. Amaranth Advisors LLC*, No. 07-Civ.-6682 (DC), Consent Order of Permanent Injunction, Civil Monetary Penalty and Other Relief as to Defendants Amaranth Advisors L.L.C. and Amaranth Advisors (Calgary) ULC (S.D.N.Y. July 23, 2009). The CFTC's case against Brian Hunter was settled shortly before trial.⁸⁶ See *CFTC v. Brian Hunter*, No. 07 Civ. 6682 (RA), Consent Order for Civil Monetary Penalty and Other Equitable Relief Against Defendant Brian Hunter (S.D.N.Y. Sept. 15, 2014).
 - FERC also sued Amaranth in 2007 for alleged market manipulation of natural gas futures prices. *Amaranth Advisors L.L.C.*, 120 FERC ¶ 61,085 (2007). The Amaranth corporate entities subsequently settled with FERC, but Amaranth's head natural gas futures trader litigated the FERC case and lost. *Brian Hunter*, 135 FERC ¶ 61,054, *reh'g denied*, 137 FERC ¶ 61,146 (2011). However, in *Hunter v. FERC*, 711 F.3d 155, 156 (D.C. Cir. 2013), with the CFTC intervening on the side of the trader, the D.C. Circuit granted the petition for review on the ground that the FERC-alleged scheme encompassed transactions involving commodity futures contracts and thus came within the CFTC's exclusive jurisdiction.
- *CFTC v. American Electric Power Co., Inc.*, No. 2:03-cv-891, Final Judgment and Consent Order (S.D. Ohio Jan. 26, 2005); CFTC Press Release No. 5041-05, U.S. Commodity Futures Trading Commission Settles Lawsuit with American Electric Power Company and AEP Energy Services, Inc. for False Reporting and Attempted Manipulation in Energy Markets (Jan. 26, 2005), www.cftc.gov/opa/enf05/opa5041-05.htm. In September 2006, a former AEP trader agreed to pay a \$350,000 penalty to settle related civil charges. See CFTC Press Release No. 5236-06, U.S. Commodity Futures Trading Commission Settles Natural Gas Attempted Manipulation Lawsuit with Joseph P. Foley, a Former American Electric Power Company, Inc. Trader (Oct. 2, 2006), <http://www.cftc.gov/PressRoom/PressReleases/pr5236-06>. On September 30, 2003, the CFTC brought a civil suit in federal district court alleging that AEP engaged in false reporting of natural gas transactions and attempted market manipulation. In January 2005, AEP settled this proceeding, paying \$30 million in civil penalties. AEP also settled related CEA criminal charges brought by the DOJ for an additional \$30 million in penalties.

⁸⁶ The federal court order required that Hunter pay a \$750,000 civil monetary penalty, permanently banned him from trading in the settlement period for the last day of trading in all CFTC-regulated products, and permanently banned him from trading all CFTC-regulated natural gas products during the daily closing period. The order further permanently prohibited Hunter from registering with the CFTC or claiming exemption from registration.

- *CFTC v. BP Products North America, Inc.*, No. 1:06C-cv-03503, Complaint for Injunctive and Other Equitable Relief and Civil Monetary Penalties Under the Commodity Exchange Act (N.D. Ill. filed June 28, 2006). In June 2006, the CFTC filed a civil complaint in federal district court against BP Products, charging that BP Products manipulated the market for February 2004 propane and cornered the propane market in February 2004 in violation of, among other provisions, CEA section 9(a)(2). In October 2007, BP Products paid a total of \$303 million to settle claims brought by the CFTC and criminal charges brought by the DOJ. See CFTC Press Release No. PR5405-07, BP Agrees to Pay a Total of \$303 Million in Sanctions to Settle Charges of Manipulation and Attempted Manipulation in the Propane Market (Oct. 25, 2007), <http://www.cftc.gov/PressRoom/PressReleases/pr5405-07>.
- *CFTC v. Bradley*, 408 F. Supp. 2d 1214, 1217-18 (N.D. Okla. 2005). The CFTC claimed the defendants had conspired to submit false reports of physical natural gas transactions for a particular pipeline location to a reporting service that published an index price. The false reports consisted of fictitious trades that never occurred, false information about certain actual trades, and trades falsely characterized as index-based. Again, the scheme that the CFTC alleged did not depend on actual bids or offers. It was based, instead, on the submission of false information. The court rejected defendants' CEA section 2(g) defense for the same reason as the *Johnson* court, noting that each of the operative terms (contract, agreement, or transaction) "denotes a mutual understanding between parties creating rights or obligations that are enforceable or are recognized at law," and reporting false trade information had nothing to do with these concepts. *Id.* at 1219.
- *CFTC v. Energy Transfer Partners, L.P.*, No. 8-07CV1301-K, Complaint for Injunctive and Other Equitable Relief and Civil Monetary Penalties Under the Commodity Exchange Act (N.D. Tex. filed Jul. 26, 2007) (settled).
- *CFTC v. Enron Corp.*, No. H-03-909, Consent Order of Permanent Injunction and Other Relief Against Defendant Enron Corp. (S.D. Tex. May 28, 2004). The complaint, filed March 12, 2003, charged Enron and one of its natural gas trading managers with market manipulation and false price reporting. As part of the settlement, which was approved by the bankruptcy court, Enron agreed to pay a civil penalty of \$35 million. The individual trading manager subsequently settled with the CFTC, agreeing to pay a \$300,000 civil penalty. *CFTC v. Hunter Shively*, No. H-03-909, Consent Order of Permanent Injunction and Other Relief Against Defendant Hunter Shively (S.D. Tex. Jul. 16, 2004); CFTC Press Release No. 4960-04, Natural Gas Trader Hunter Shively Agrees to Cooperate with U.S. Commodity Futures Trading Commission in Settling Manipulation Case (Jul. 19, 2004), <http://www.cftc.gov/opa/enf04/opa4960-04.htm>.
- *CFTC v. Johnson*, 408 F. Supp. 2d 259 (S.D. Tex. 2005). The CFTC alleged that the defendants violated the false reporting and attempted manipulation provisions of CEA section 9(a)(2) in connection with the price of natural gas. The CFTC claimed the defendants had reported natural gas market information based on fictitious physical

trades to certain trading services. The trading services that received this inaccurate information then used it to produce price indices that were used by market participants to settle physical and bilateral derivatives transactions. Importantly, the alleged scheme did not include any actual bids or offers. The court rejected the defendants' claim that the conduct at issue was exempt under CEA section 2(g), holding that alleged false reporting was not a contract, agreement, or transaction. *Id.* at 271-72.

- In July 2004, the CFTC brought a civil action for injunctive relief in federal district court against NRG Energy, Inc. The complaint charged that NRG gas traders transmitted false and misleading reports to the trade press. NRG settled this case in February 2007, agreeing to pay a \$2 million civil penalty. *See CFTC v. NRG Energy, Inc.*, No. 04-3090 (MJD/AJB), Consent Order of Permanent Injunction, Civil Monetary Penalty and Other Equitable Relief Against NRG Energy, Inc. (D. Minn. Feb. 13, 2007); CFTC Press Release No. 5292-07, United States Commodity Futures Trading Commission Settles Action Charging NRG Energy Inc. with Falsely Reporting Natural Gas Trades (Feb. 15, 2007), <http://www.cftc.gov/PressRoom/PressReleases/pr5292-07>.
- *CFTC v. Optiver US, LLC*, No. 08 Civ. 6560 (LAP/THK), Final Consent Order of Permanent Injunction, Civil Monetary Penalty and Other Relief as to Defendants Optiver US, et al. (S.D.N.Y. Apr. 19, 2012). The CFTC charged both corporate and individual defendants with manipulating prices in crude oil, heating oil, and New York Harbor gasoline in 2007 in violation of CEA sections 6(c), 6(d), and 9(a)(2). The CFTC also charged the individual defendants with violations of CEA section 9(a)(4) for making false statements to NYMEX during its own inquiry into Optiver's trading. Pursuant to the settlement, the defendants paid \$13 million in civil penalties for which all defendants were jointly and severally liable. The three individuals' potential contributions to this payment were capped at \$1.75 million, \$1.25 million, and \$400,000. Optiver was ordered to pay \$1 million in disgorgement. The individuals were also subject to trading bans. This case is notable, not only for the penalties incurred by the individual defendants but also for the CFTC's heavy reliance on contemporaneous written and oral communications, which were laid out in great detail in the 51-page complaint. *CFTC v. Optiver US, LLC*, No. 08 Civ. 6560, Complaint (S.D.N.Y. filed July 24, 2008).
- *CFTC v. Parnon Energy Inc.*, 875 F. Supp. 2d 233 (S.D.N.Y. 2012) (denying motion to dismiss); *CFTC v. Parnon Energy Inc.*, No. 11 Civ. 3548 (WHP), Final Consent Order of Permanent Injunction, Civil Monetary Penalty and Other Relief (S.D.N.Y. Aug. 4, 2014). The complaint charged defendants with unlawfully manipulating and attempting to manipulate New York Mercantile Exchange (NYMEX) crude oil futures prices from January 2008 to April 2008 involving the accumulation and sell-off of a substantial position in physical crude oil to manipulate futures prices. The complaint charged that defendants made in excess of \$50 million in unlawful profits. By the terms of the settlement, Parnon agreed to pay a \$13 million civil penalty.
- *In re DiPlacido*, Comm. Fut. L. Rep. (CCH) ¶ 29,153 (CFTC Sept. 12, 2002). In *DiPlacido*, the respondent was charged with manipulation of the settlement prices of the

Palo Verde and California Oregon Border electricity futures contracts traded on the New York Mercantile Exchange during the period from April through August 1998.

- *Marathon Petroleum Co. LLC*, Comm. Fut. L. Rep. (CCH) ¶ 30,591 (CFTC Aug. 1, 2007) (imposing a \$1 million civil penalty for attempting to manipulate the price of West Texas Intermediate crude oil).
- *United States v. Futch*, 278 F. App'x 387 (5th Cir. 2008). The government indicted a natural gas trader for knowingly delivering inaccurate reports concerning market information tending to affect the price of natural gas in violation of CEA section 9(a)(2). Defendant responded to the monthly survey by Inside FERC Gas Market Report with information about alleged transactions knowing “that [the company] had not entered into any of the trades at the prices and volumes he reported.” *Id.* at 390. Defendant pled guilty and was sentenced to 57 months imprisonment. The Fifth Circuit rejected the defendant’s appeal and affirmed the plea agreement.
- On February 1, 2005, the CFTC announced that it had brought five civil actions for injunctive relief and civil monetary penalties in federal district court against a total of fifteen natural gas energy traders and one company formed by several of these traders, for false reporting to the trade press and attempted market manipulation. See CFTC Press Release No. 5045-05, U.S. Commodity Futures Trading Commission Launches Multiple Federal Actions Against a Total of 15 Energy Traders, Charging Them With False Reporting and Attempted Manipulation (Feb. 1, 2005), <http://www.cftc.gov/opa/enf05/opa5045-05.htm>. The individual traders eventually settled by agreeing to pay civil penalties.⁸⁷

⁸⁷ In November 2006, two of these individuals paid a total of \$550,000 in civil monetary penalties to settle the civil claims. See CFTC Press Release No. 5258-06, U.S. Commodity Futures Trading Commission Settles Natural Gas False Reporting and Attempted Manipulation Lawsuit with Two Energy Traders (Nov. 17, 2006), <http://www.cftc.gov/PressRoom/PressReleases/pr5258-06>. In March 2007, two additional individuals and their company, Concord Energy, paid a total of \$1.6 million in civil penalties in settlement. See CFTC Press Release No. 5300-07, Defendants Ordered to Pay \$1.6 Million in Government’s Attempted Manipulation Case Against Concord Energy, LLC & Natural Gas Energy Traders Shawn McLaughlin and Darrell Danyluk (Mar. 14, 2007), <http://www.cftc.gov/PressRoom/PressReleases/pr5300-07>. In June 2007, two former CMS Field Services traders paid a total of \$125,000 in civil monetary penalties to settle claims of price misreporting and attempted manipulation. See CFTC Press Release No. 5346-07, U.S. Commodity Futures Trading Commission Settles Natural Gas False Reporting and Attempted Manipulation Lawsuit with Former CMS Field Services Natural Gas Trader Jeffrey Bradley and Supply Director Robert Martin (June 26, 2007), <http://www.cftc.gov/PressRoom/PressReleases/pr5346-07>. In November 2007, five Coral traders agreed to pay jointly and severally a total fine of \$1 million. See CFTC Press Release No. PR5411-07, Five Current and Former Coral Energy Traders Settle CFTC Charges for False Reporting and Attempted Manipulation in Natural Gas Market (Nov. 7, 2007), <http://www.cftc.gov/PressRoom/PressReleases/pr5411-07>.

Chapter 6

Antitrust Enforcement

John H. Lyons[†]

The Supreme Court has observed that the antitrust laws stand as “the Magna Carta of free enterprise. They are as important to the preservation of economic freedom and our free-enterprise system as the Bill of Rights is to the protection of our fundamental personal freedoms.”¹ The antitrust laws aim to promote consumer welfare by protecting competition, not competitors.²

Although federal and state statutes provide for extensive regulation of U.S. electric power and natural gas utilities, these laws and regulations do not exempt utilities from the antitrust laws. To the contrary, the antitrust laws apply to many aspects of the energy industry, particularly to those that involve unregulated or lightly regulated competitive conduct (e.g., power trading and marketing), which are the principal but not sole focus of this chapter. In general, regulatory and antitrust principles reinforce each other. All are designed to prevent or curb the acquisition or exercise of market power—i.e., profitably reducing output or quality, or increases in price. Consequently, the key to compliance is understanding the basic requirements of the antitrust statutes and recognizing the co-existence of and interplay between them and the requirements of the regulatory regimes.

I. THE STATUTORY FRAMEWORK

Three principal federal antitrust statutes apply to the energy industry: the Sherman Act, the Clayton Act, and the Federal Trade Commission Act. In addition, most states have enacted unfair competition statutes that parallel the federal antitrust laws, although some state laws have additional or different provisions.

A. THE SHERMAN ACT

Section 1 of the Sherman Act prohibits businesses from entering into agreements, express or implied, that unreasonably restrain trade.³ Certain agreements (called “*per se* offenses”) are

[†] Partner, Skadden, Arps, Slate, Meagher & Flom LLP. Mr. Lyons has represented a wide range of clients in antitrust matters before the Antitrust Division of the U.S. Department of Justice, the Federal Trade Commission, and state attorneys general, as well as in federal and state court litigation. In particular, he has advised electric utilities, independent power producers, and marketers on antitrust compliance issues and represented them in antitrust investigations of mergers, acquisitions, and market conduct.

¹ *United States v. Topco Assocs.*, 405 U.S. 596, 610 (1972).

² *Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc.*, 429 U.S. 477, 488 (1977).

³ 15 U.S.C. § 1.

deemed to be so inherently anticompetitive that they are *always illegal* under section 1, *regardless* of the intent of the parties or the actual effect of the agreements.⁴ These include agreements between competitors to fix prices or the terms and conditions of sale (including credit terms and discounts), agreements to limit output, agreements to rig bids, agreements to allocate customers or territories, agreements not to deal with any person or persons (“group boycotts”), resale price agreements, and, in certain circumstances, agreements to sell one product conditioned on an agreement by the buyer to purchase a second, distinct product (“tying arrangements”).⁵

Other activities—including requirements contracts, exclusive dealing contracts, and cooperative marketing activities—are analyzed under a “rule of reason,” under which competitive intent and effect are weighed along with the business justifications for the activities to determine their legality.

Section 2 of the Sherman Act prohibits a firm from unlawfully monopolizing, attempting to monopolize, or conspiring to monopolize the purchase or sale of a product in a market.⁶

B. THE CLAYTON ACT

The Clayton Act, among other things, prohibits a seller from conditioning the sale or lease of a product on the buyer’s agreement not to deal in the products of a competitor where the effect may be to lessen competition or to tend to create a monopoly.⁷ The Clayton Act is also the primary federal statute governing the legality of mergers, stock acquisitions, asset acquisitions, and other corporate combinations.⁸ In addition, the Clayton Act prohibits a person from serving simultaneously as a director or board-elected or board-appointed officer of two or more

⁴ *Broadcast Music, Inc. v. CBS*, 441 U.S. 1, 19-20 (1979); *Cont’l T.V., Inc. v. GTE Sylvania Inc.*, 433 U.S. 36, 50 (1977); *Northern Pac. Ry. v. United States*, 356 U.S. 1, 5 (1958).

⁵ *Bus. Elecs. Corp. v. Sharp Elecs. Corp.*, 485 U.S. 717, 735-36 (1988) (minimum resale price maintenance agreements); *Jefferson Parish Hosp. Dist. No. 2 v. Hyde*, 466 U.S. 2 (1984) (tying agreements); *United States v. Trenton Potteries Co.*, 273 U.S. 392, 396-401 (1927) (direct price-fixing agreements).

⁶ 15 U.S.C. § 2. Federal antitrust authorities have rarely investigated or pursued enforcement actions in the electric power and natural gas industries under section 2 of the Sherman Act, although in November 2012 the Department of Justice acknowledged having undertaken such an investigation. See Press Release, U.S. Department of Justice, Justice Department Statement on Entergy Corp.’s Transmission System Commitments and Acquisition of KGen Power Corp.’s Plants in Arkansas and Mississippi (Nov. 14, 2012), http://www.justice.gov/atr/public/press_releases/2012/288781.htm.

⁷ 15 U.S.C. § 14.

⁸ Section 7 of the Clayton Act prohibits stock or asset acquisitions that may substantially lessen competition, or tend to create a monopoly, in any properly defined market. *Id.* § 18. The Hart-Scott-Rodino Antitrust Improvements Act of 1976 amended the Clayton Act to require parties to a stock or asset transaction meeting certain size thresholds to notify and submit certain information about the transaction to the Federal Trade Commission and the Department of Justice, and to observe a waiting period before closing that allows one of the agencies to investigate the competitive implications of the transaction under the “substantial lessening of competition” standard of section 7. *Id.* § 18a.

competing companies.⁹ (The Federal Power Act has its own interlocking directorate provision, discussed in Chapter 15.) Moreover, Clayton Act provisions enable private civil actions to recover treble damages or to obtain injunctive relief.¹⁰

C. THE FEDERAL TRADE COMMISSION ACT

Section 5 of the Federal Trade Commission Act (“FTC Act”) prohibits all “unfair methods of competition” and “unfair or deceptive acts or practices.”¹¹ The FTC Act has been interpreted to cover Sherman Act violations, conduct that falls short of, but might ultimately lead to, Sherman Act violations, and anticompetitive practices similar to those prohibited by the Clayton Act.¹² In addition, the FTC Act prohibits all forms of deceptive or misleading advertising and trade practices, such as disparaging a competitor’s product or service offerings, harassing a customer, or stealing trade secrets or customers lists.¹³

D. PENALTIES

The penalties for violating the antitrust laws are severe and can be applied to both the company and to individuals. The United States, through the Department of Justice, may prosecute Sherman Act violators as criminal felons.¹⁴ Employees, officers, directors, or agents who authorize or participate in many types of antitrust offenses (such as price fixing and bid rigging) can be imprisoned for up to ten years and can be fined, for each offense, up to the greatest of: (i) \$1,000,000; (ii) twice the gross monetary loss caused to the victim(s) of the crime; or (iii) twice the gross monetary gain derived from the crime. The company also could be fined for each offense, up to the greater of: (i) \$100 million; (ii) twice the gross monetary loss caused to the victim(s) of the crime; or (iii) twice the gross monetary gain derived from the crime.¹⁵

⁹ *Id.* § 19.

¹⁰ *Id.* §§ 15, 26.

¹¹ *Id.* § 45.

¹² See, e.g., *FTC v. Motion Picture Adver. Serv. Co.*, 344 U.S. 392, 394-95 (1953); *FTC v. Cement Inst.*, 333 U.S. 683, 694 (1948); *Fashion Originators’ Guild of Am., Inc. v. FTC*, 312 U.S. 457, 463-64 (1941); *Am. News Co. v. FTC*, 300 F.2d 104, 108 (2d Cir. 1962).

¹³ See, e.g., *FTC v. Colgate-Palmolive Co.*, 380 U.S. 374, 387 (1965); *Jay Norris Corp.*, 91 F.T.C. 751 (1978), *enforced as modified*, 598 F.2d 1244 (2d Cir. 1979); *Borden, Inc.*, 92 F.T.C. 669 (1978), *vacated and remanded for entry of consent judgment*, 461 U.S. 940 (1983); *Portwood v. FTC*, 418 F.2d 419 (10th Cir. 1969). The FTC summarized the law of deception and its enforcement approach in a still-operative policy statement. *Deceptive Acts and Practices*, FTC Policy Statement (Oct. 14, 1983), *reprinted in* 4 Trade Reg. Rep. (CCH) ¶ 13,205, *and appended to Cliffdale Assocs., Inc.*, 103 F.T.C. 110 (1984).

¹⁴ When the Sherman Act was enacted in 1890, sections 1, 2, and 3 were criminal provisions only. See 15 U.S.C. §§ 1-3. Civil actions based on Sherman Act violations were not possible until passage of the Clayton Act in 1914.

¹⁵ Section 215 of the Antitrust Criminal Penalty Enhancements and Reform Act of 2004 amended sections 1, 2, and 3 of the Sherman Act to significantly increase the maximum prison term from

In addition, government prosecutors today routinely add wire fraud and mail fraud counts to antitrust charges, which may result in additional prison sentences and/or fines.¹⁶ Government prosecutors also can add “racketeering” counts, which can result in longer prison sentences and/or larger fines. Government lawyers also vigorously prosecute cases of perjury and false declarations, which are punishable by monetary fines and/or imprisonment.

Furthermore, private parties, the federal government as a consumer, and state attorneys general acting on the state’s behalf as a consumer and/or on behalf of persons who are residents in the state (“*parens patriae*”) can bring civil suits and recover three times their actual damages, plus court costs and, other than in suits by the federal government, attorneys’ fees.¹⁷ Treble damage judgments can quickly amount to hundreds of millions of dollars.

Remember, even if they are ultimately shown to be meritless, antitrust suits are expensive and time consuming to defend, and disruptive to personal lives and business operations.

II. SPECIFIC POTENTIAL COMPLIANCE ISSUES

A. RELATIONS WITH COMPETITORS

Electric power industry deregulation and restructuring have led to changes in business activities that require industry participants to be more aware of antitrust risks than ever before. The greatest potential for antitrust problems arises from relations with competitors. Any type of agreement, understanding, or arrangement between competitors, whether written or oral, formal or informal, express or implied, that limits competition is subject to antitrust scrutiny under section 1 of the Sherman Act. To establish a section 1 violation, the government or private plaintiff must prove: (1) the fact of a contract, combination, or conspiracy (i.e., an agreement) between two or more independent actors that (2) unreasonably restrains trade, and (3) affects interstate or foreign commerce.¹⁸ The Supreme Court has defined “agreement” under section 1 as “a unity of purpose or a common design and understanding, or a meeting of minds in an

36 months to 10 years, and the maximum fine for an individual from \$350,000 to \$1 million for each offense. The statute also raised the maximum fine for a corporation from \$10 million to \$100 million per offense.

¹⁶ 18 U.S.C. §§ 1341-43. See *United States v. Ames Sintering Co.*, 927 F.2d 232 (6th Cir. 1990) (per curiam) (affirming convictions for wire fraud and attempted wire fraud); *United States v. MMR Corp.*, 907 F.2d 489 (5th Cir. 1990) (affirming mail fraud conviction).

¹⁷ 15 U.S.C. §§ 15, 15a, 15c. The statute of limitations for civil antitrust actions is four years after the cause of action accrued. *Id.* § 15b.

¹⁸ E.g., *Maric v. St. Agnes Hosp. Corp.*, 65 F.3d 310, 313 (2d Cir. 1995). In addition, a private plaintiff must prove it has suffered “antitrust injury,” i.e., injury caused by a reduction in competition rather than an increase in competition. See *Brunswick Corp.*, 429 U.S. at 488.

unlawful arrangement.”¹⁹ In addition, a conspiratorial agreement may be inferred by a jury from wholly circumstantial evidence.²⁰

To be clear, section 1 is not intended to prohibit or interfere with ordinary business conduct, including price discovery, associated with legitimate attempts to buy or sell products or services in the marketplace. Instead, section 1 is directed at agreements that could directly or indirectly affect the prices, output, or other competitive choices or decisions of particular third parties or the market as a whole. Moreover, any *attempt* to reach such agreements, understandings, or arrangements may be unlawful, *even if* it is unsuccessful. As discussed in sections that follow, even seemingly innocent conversations between or among employees, representatives, or agents of competitors could support an allegation that competitors have reached or attempted to reach an unlawful agreement.

1. Price Fixing: Agreements That Directly Affect Price

Agreements or attempts to enter into agreements between or among competitors (acting as competitors and not as customers or suppliers) with respect to prices charged to third parties are *illegal*, regardless of whether the prices are higher or lower, reasonable or unreasonable, or whether they are identical or different.²¹ Such agreements would include any understanding that prices should or should not be raised or lowered, or that any price differential will be maintained or should be changed. No explanation or defense will be considered once such an agreement is entered into or even attempted.²²

In particular, the advent of market-based rate authority and the development of wholesale power trading markets have necessarily been accompanied by dramatic increases in entirely legitimate interactions and exchanges of information among employees of competitors in the electric power industry. While it is perfectly lawful for energy traders to agree upon the prices at which they will engage in an actual transaction to buy and sell electricity and/or fuel, any agreement or understanding between or among traders concerning or affecting prices at which they will transact business *with third parties* is absolutely forbidden.²³ It makes no difference

¹⁹ *Copperweld Corp. v. Independence Tube Corp.*, 467 U.S. 752, 771 (1984) (quoting *Am. Tobacco Co. v. United States*, 328 U.S. 781, 810 (1946)).

²⁰ *Apex Oil Co. v. DiMauro*, 822 F.2d 246, 253 (2d Cir. 1987); see *Monsanto Co. v. Spray-Rite Serv. Corp.*, 465 U.S. 752, 765-66 (1984).

²¹ *FTC v. Superior Court Trial Lawyers Ass’n*, 493 U.S. 411, 421-23 (1990); *Ariz. v. Maricopa Cnty. Med. Soc’y*, 457 U.S. 332, 342 (1982); *United States v. Socony-Vacuum Oil Co.*, 310 U.S. 150, 223 (1940); *Trenton Potteries Co.*, 273 U.S. at 396-401.

²² *Superior Court Trial Lawyers Ass’n*, 493 U.S. at 423; *NCAA v. Bd. of Regents*, 468 U.S. 85, 103-04 (1984); *Maricopa Cnty. Med. Soc’y*, 457 U.S. at 347; *Northern Pac. Ry. Co.*, 356 U.S. at 5; *Socony-Vacuum Oil Co.*, 310 U.S. at 221-22; *Drury Inn—Colo. Springs v. Olive Co.*, 878 F.2d 340, 342-43 (10th Cir. 1989) (“per se rule condemns conduct without proof of power, effect, or purpose and without hearing claims of legitimate objectives”) (internal quotations and citation omitted).

²³ *Catalano, Inc. v. Target Sales, Inc.*, 446 U.S. 643, 647-48 (1980) (per curiam); *Citizen Publ’g Co. v. United States*, 394 U.S. 131, 134-36 (1969); *Socony-Vacuum Oil Co.*, 310 U.S. at 221, 223, 224 n.59; *Vandervelde v. Put & Call Brokers & Dealers Ass’n*, 344 F. Supp. 118 (S.D.N.Y. 1972) (uniform

whether the prices agreed upon are higher, lower, or merely stabilized. In particular, the following must be avoided:

- agreements with competitors on what bid or ask prices they will make for electricity and/or fuel to be purchased and/or sold to third parties or the market as a whole;
- agreements with competitors to fix, raise, lower, or maintain quotas or prices for electricity and/or fuel to be purchased and/or sold in the market;
- agreements with competitors to fix, increase, decrease, or maintain any inside spread or the size of any quote increment for electricity and/or fuel to be purchased and/or sold in the market; or
- agreements with competitors to adhere to any quoting convention concerning increments used to update quotes.

There is a critical distinction, however, between price fixing, which is strictly illegal, and an independent (and perfectly lawful) decision to match a competitor's price. Indeed, competition often requires a firm to match or better its competitors' prices. Matching a competitor's business behavior is not illegal unless there is some agreement or understanding with a competitor to mirror a competitor's pricing or quoting practices.²⁴ Thus, it is perfectly acceptable from an antitrust standpoint for a firm to:

- unilaterally set its own bid and ask prices for electricity and/or fuel to be traded, the prices at which it is willing to buy and/or sell any volume of electricity and/or fuel, and the quantity (or volume) of electricity and/or fuel that it is willing to buy and/or sell;
- unilaterally set its own inside spread, quote increment, or quantity of electricity and/or fuel for its quotations;
- communicate its own bid and ask prices, or the price at which or the quantity of electricity and/or fuel that it is willing to buy or sell to any potential customer or supplier, for the purposes of exploring the possibility of a purchase or sale of electricity and/or fuel, and to negotiate for or agree to such purchase or sale; or
- take any unilateral action or make any unilateral decision regarding competitors with which it will trade and the terms on which it will trade.²⁵

discounts by brokers per se illegal). Gas transportation services also are regulated by FERC and subject to the antitrust laws.

²⁴ See *Great Atl. & Pac. Tea Co., Inc., v. FTC*, 440 U.S. 69, 83 n.16 (1979).

²⁵ *United States v. Colgate & Co.*, 250 U.S. 300 (1919).

2. Price Fixing: Agreements That Indirectly Affect Price

The prohibition against price fixing also bars agreements, understandings, arrangements, or attempts to enter into such agreements, understandings, or arrangements between or among competitors that indirectly affect prices or terms and conditions of sale, such as restrictions on output, participation in a market, or extensions of credit.²⁶

3. Agreements to Allocate Customers, Territories, Markets, or Products

Competing firms should never agree with each other to divide or allocate customers or territories, or to refrain from selling a certain product generally or in any geographic area or to any category of customers. These agreements or arrangements between competitors, like price fixing, are always illegal.²⁷

4. Agreements to Refuse to Buy From Particular Suppliers or Sell to Particular Customers

Competing firms should not communicate with competitors concerning decisions whether or not to buy from or sell to any third party. Although a firm generally has the right to decide *independently* that it does not wish to buy from or sell to a particular person,²⁸ such a decision becomes an illegal “group boycott” when reached jointly with a competitor, and may be illegal *regardless* of whether it may seem commercially reasonable or morally justifiable.²⁹

²⁶ *Catalano, Inc.*, 446 U.S. at 645, 648. In *United States v. KeySpan Corp.*, 763 F. Supp. 2d 633 (S.D.N.Y. 2011), and *United States v. Morgan Stanley*, 881 F. Supp. 2d 563 (S.D.N.Y. 2012), the Department of Justice and, respectively, KeySpan and Morgan Stanley settled by consent decrees allegations that a swap agreement had altered KeySpan’s incentives for offering its generation in the NYISO auctions for installed capacity, leading to higher clearing prices for installed capacity in the New York City zone. Subsequent putative federal and state class actions were dismissed on filed rate doctrine, federal preemption, and other grounds. See *Simon v. KeySpan Corp.*, 694 F.3d 196 (2d Cir. 2012), *cert. denied*, 133 S. Ct. 1998 (2013); *Perez v. KeySpan Corp.*, 941 N.Y.S.2d 608 (N.Y. App. Div. 2012).

²⁷ It is perfectly lawful, however, for states and/or their political subdivisions to award franchises to utilities to provide exclusive service in designated geographic territories.

²⁸ This is one instance in which FERC regulation is more restrictive than the antitrust laws, because Order No. 888 and FERC regulations require electric utilities to provide non-discriminatory open access to their transmission facilities. See *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, 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 (1998), *aff’d in relevant part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom. New York v. FERC*, 535 U.S. 1 (2002) (codified at 18 C.F.R. § 35.28); see generally *Verizon Commc’ns Inc. v. Law Offices of Curtis v. Trinko, LLP*, 540 U.S. 398, 412 (2004) (noting, in the context of Federal Communications Commission regulation, that the access provisions of the Telecommunications Act of 1996 significantly diminish the likelihood of major antitrust harm).

²⁹ *Northwest Wholesale Stationers, Inc. v. Pac. Stationery & Printing Co.*, 472 U.S. 284, 293-95 (1985).

Section 1 of the Sherman Act does not preclude sharing information through a trade association or otherwise regarding a particular customer's credit history, although the specific terms of credit and the decision to sell or not to sell to a particular customer should *not* be discussed.

5. *Agreements to Control or Limit Production*

Competing firms should never agree to (1) limit the quantity or quality of production or the quantity of product that is to be sold to any customer or in any market; (2) refrain from introducing new products or services or from eliminating old ones; or (3) accelerate or postpone the introduction or withdrawal of a product or service.³⁰ While in certain instances it is lawful for competitors to enter into an agreement to establish industry standards for products or service standards, such instances must be carefully monitored to ensure that the agreement will not have, intentionally or inadvertently, an anticompetitive effect. Accordingly, a firm should exercise caution when any of its employees enter into even preliminary discussions, either bilaterally or through a trade association, regarding the establishment of industry standards without first receiving guidance from legal counsel.

6. *Agreements Regarding Bidding Practices*

A firm must take extreme care when preparing and submitting bids in response to requests for proposals. Direct or indirect agreements between or among competitors that affect bid prices is illegal.³¹ The following types of agreements, understandings, or arrangements between or among two or more competitors also are strictly prohibited:

- advance discussion or exchange of specific bid-related information (e.g., non-public cost information or outage information);
- submission of “complementary,” “shadow,” or “protective” bids whereby competitors agree to submit token bids that are too high or contain special terms so as make them unacceptable while appearing genuine;
- bid rotation whereby competitors agree to take turns “winning” a recurring bid competition by being the “low” bidder; and
- bid suppression or retraction whereby competitors agree to refrain from bidding or withdraw their bids so that one competitor's bid will be accepted.

7. *Communications With Competitors*

The unlawful agreements discussed above need not take the form of a written contract or contain express commitments or mutual assurances. Courts can—and do—infer agreements based on “loose talk,” “informal discussions,” or the mere exchange of pricing information between competitors if it is done outside of a legitimate purchase and sale context. Agreements can be inferred from parallel behavior coupled with an opportunity to discuss and/or agree upon

³⁰ *Hartford-Empire Co. v. United States*, 323 U.S. 386, 406-07 (1945).

³¹ *Northwest Wholesale Stationers*, 472 U.S. at 293-95.

prices. Any communication with a competitor's employee, representative, or agent, no matter how innocuous it may seem at the time, may later be subject to antitrust scrutiny.

The safest course is to avoid talking to competitors about competitively sensitive information unless it is necessary to do so, such as in connection with a specific purchase from or sale to that competitor in its capacity as a supplier or customer. All interactions—oral as well as written—with competitors, their employees, representatives, or agents should be conducted as if they were completely in the public view and subject to probing examination and unfavorable interpretation by a government prosecutor or a treble-damages plaintiff.

a. Prohibited Topics of Conversation

Other than in connection with a bona fide purchase and sale transaction, the following topics should be avoided in any communication between or among competitors, their employees, representatives, or agents:

- prices and pricing policies, terms, or conditions of sale (including discounts and allowances);
- credit terms and billing practices;
- suppliers' terms and conditions;
- profits or profit margins;
- costs;
- marketing and/or distribution plans and practices;
- bids, including an intent to bid or not to bid for a particular contract or program;
- allocation of sales territories;
- selection, retention, or quality of customers and/or suppliers;
- refusals to deal with a supplier or customer;
- type or quality of production;
- new products, product innovations, or product eliminations; and
- new services, service innovations, or service eliminations.

If a competitor initiates a conversation about any of these subjects, it is best to *immediately and emphatically* refuse to continue the discussion and to report the incident to legal counsel.

b. Trade Associations and Other Industry Gatherings

Trade association meetings and other industry gatherings present a danger area under the antitrust laws because they bring together competitors—people with common interests and problems—who are prone to discuss matters of mutual concern. For that reason, membership in trade associations, while permissible, should be approved in advance by legal counsel and only after management has determined that the association serves an important and proper purpose and that all of its activities are adequately supervised by counsel. Copies of all trade association minutes, agendas, or any other documents received from or provided to trade associations should be reviewed by legal counsel on a periodic basis.

The most serious problems presented by trade association activities are apt to arise at informal social gatherings, particularly in a hotel room or hospitality suite after the official meeting has ended. A general gripe session at which one or more competitors expresses the view that prices are too low or that margins are being squeezed, followed shortly thereafter by price increases by some industry participants, could lead to an inference of an agreement to raise prices. It is best to avoid such situations, and to inform legal counsel of any troubling discussion or activity.

c. Communications Through Brokers

Brokers, acting as middlemen for purchases and/or sales of power and/or fuel, may be viewed by the antitrust enforcement authorities as “facilitators” of or “conduits” for price-fixing or bid-rigging schemes. It therefore is wise to be careful of loose talk when dealing with brokers who inadvertently may convey competitively sensitive information between or among competitors during purchase and sale negotiations. Information that provides insight into non-public costs or future bidding strategies (including decisions not to bid) may have an effect on future bid positions of others. Although unintentional, such information exchanges through brokers may trigger unwanted government scrutiny. Consequently, the operating assumption should be that brokers will pass on competitively sensitive information, so efforts should be made to ensure that such information is presented carefully and cannot be misconstrued to suggest unlawful coordination by market participants.

8. Competitors as Customers or Suppliers

As mentioned above, it is not uncommon for competitors in one context to be customers or suppliers in a different context. It is entirely lawful to carry on bona fide customer and supplier relations with such companies, provided there is no improper discussion about situations in which the companies compete, or improper agreements relating to third-party customers or suppliers. It is important to train employees who are likely to interact with competitors, such as power traders, to recognize that a lawful conversation can become high-risk in a heartbeat, to internalize the parameters and limits of a proper conversation, and to react appropriately if the conversation turns toward a problematic subject. Such concepts should reinforce and dovetail with other training initiatives concerning a firm’s corporate policies on business ethics and integrity, and handling of proprietary and other company confidential information.

9. *Competitor Collaborations*

Competing firms sometimes collaborate to achieve legitimate business goals (e.g., research and development, product development, or construction of production capacity) that each competitor acting alone could not achieve as efficiently or at all. Such collaborations can take a variety of legal forms, but are typically referred to as joint ventures. Joint ownership of a generating unit by several competitors and the formation of regional transmission organizations are obvious examples of joint ventures in the electric power industry. Although a joint venture may be lawful, it also may raise difficult antitrust problems depending on (1) the nature of the venture's business activities, (2) whether the joint venture participants remain active in the same business or any closely-related businesses, and (3) what steps are taken to control the flow of competitively sensitive information into and out of the joint venture. Competitively sensitive business information obviously includes pricing and cost information, and also includes any of the prohibited topics of discussion listed above.

Discussions among joint venture partners should be limited to the subject of the joint venture. Because a joint venture often is an ongoing relationship that entails a close working relationship among the venture and its parents, potential antitrust problems or concerns may frequently arise. It is important for antitrust counsel to provide ongoing guidance concerning any joint venture among competitors.

10. *Company Documents Regarding Competition*

It sometimes happens that interoffice documents or memoranda dealing with the subject of competition or competitors' prices are written (perhaps to impress others in the organization with the writer's knowledge of the competitive situation) so as to suggest, contrary to fact, that there is some sort of understanding or sharing of information among competitors about pricing. Every memorandum or document on such subjects should merely state what the facts are and should contain no editorial comment other than, if appropriate, the writer's opinion as to the accuracy of what is being reported. If price information is given, the source of the information should be included in the memorandum to make it clear that it was obtained from a proper source, not from a questionable exchange of competitively sensitive information. In effect, each memorandum or document should be written on the assumption that at some future date it will be produced for inspection by antitrust enforcement authorities or plaintiffs in a treble damages action who will tend to interpret any language in the worst light possible as "evidence" of anticompetitive intent.

B. RELATIONS WITH CUSTOMERS AND SUPPLIERS

Certain arrangements between suppliers and their customers can restrict competition and therefore may be illegal under the Sherman Act. Such arrangements could arise in several electric power industry contexts, including in particular the marketing and sales of electric power.

1. *Selection and Termination of Customers and Suppliers*

In general, and absent a regulatory mandate to the contrary (e.g., FERC open access requirements), a firm has the right to choose the customers and suppliers with whom it will deal,

provided that decisions not to deal with particular customers or suppliers are made *independently* and *unilaterally*.³² In the electric power industry, refusals to deal implicate a variety of statutory and regulatory requirements and should always be reviewed in advance with legal counsel.

Similarly, a firm may unilaterally terminate a customer or supplier for legitimate business reasons, such as the customer's inability to pay or the supplier's failure to deliver products on time or within specification. The emphasis on "unilateral" termination is important because any termination that is the result of an agreement with another party could be challenged as an illegal agreement under the antitrust laws. In making a unilateral decision to terminate a customer or supplier, a firm may use information about that customer or supplier received from competing customers or suppliers. However, the termination cannot be the result of collusion with those competing customers or suppliers. Decisions to terminate customers or suppliers also should be made fairly and with due regard for their legitimate interests. Due to the sensitivities and potential for litigation surrounding the termination of any commercial relationship, legal counsel should be involved in any termination decision and a contemporaneous written record should be created that clearly states the legitimate basis for the termination.

2. *Exclusive Dealing*

"Exclusive dealing" refers to an exclusive sales arrangement by which a supplier agrees to sell to a customer only on the condition that the customer refrains from dealing with any of the supplier's competitors. Such agreements may be deemed illegal if they unreasonably restrain competition, based on the facts in each particular case.³³ Nevertheless, a customer may choose to purchase all or substantially all of its requirements from a single supplier. However, a customer should not attempt to coerce a supplier into refusing to sell to the customer's competitors. In general, the safest course is not to interfere in any manner with a customer's or supplier's other commercial relationships. In any event, legal counsel should be involved whenever an exclusive dealing contract is contemplated.

3. *Cooperative Purchasing*

Cooperative purchasing agreements under some circumstances may constitute an unreasonable restraint of trade. While not all buying agencies or other cooperative buying arrangements are unlawful under the antitrust laws, there must be a justification for such activity, e.g., increased efficiencies or reduced costs, and there must be no adverse effect on competition. Accordingly, legal counsel should be involved in a decision to enter into any cooperative purchasing agreement.

C. MONOPOLIZATION AND ATTEMPTS TO MONOPOLIZE

The law of monopolization and attempted monopolization is complicated, involving difficult questions about what constitutes monopoly power, intent to monopolize, the product and geographic "markets" in which the monopoly or attempt is measured, and what constitutes unlawful use of monopoly power. As a rule, when a product or service enjoys a strong market

³² *Verizon*, 540 U.S. at 408.

³³ *Tampa Elec. Co. v. Nashville Coal Co.*, 365 U.S. 320 (1961).

position (e.g., a significant market share of sales in a particular market), the seller of that product or service should be concerned with questions relating to monopolization, and legal counsel should be consulted with respect to the marketing and pricing of the product or service.

In general, a firm with a strong market position must not take any actions that could be construed as evidence of an intent to acquire or maintain monopoly power, to drive a particular competitor out of business, or to prevent a person from entering the market.³⁴ The following types of conduct have been held to be illegal as acts of monopolization or attempts to monopolize:

- localized price cutting in a competitor’s primary market area with intent to drive that competitor out of business;
- sales below the average variable cost of producing and distributing additional product or providing additional service, or sales below the average total cost, in order to drive out competitors and then raise prices; and
- attempts to limit a competitor’s access to a product to drive that competitor out of business.

Nevertheless, the Supreme Court recently acknowledged that lawful conduct in pursuit of monopoly power “is an important element of the free-market system. The opportunity to charge monopoly prices – at least for a short time – is what attracts ‘business acumen’ in the first place; it induces risk taking that produces innovation and economic growth.”³⁵ Moreover, the Court held that, as a matter of law, where a federal or state statute or regulatory regime provides for access to so-called “essential” facilities (such as transmission facilities), a monopolization claim based on a refusal to deal theory cannot be maintained. The Court made clear that courts do not have the requisite expertise to adjudicate such claims, fashion effective remedies, and monitor compliance. Instead, such claims should be handled by the regulatory agencies with industry expertise.

D. PUBLIC STATEMENTS, INTERNAL MEMORANDA, AND CORRESPONDENCE

Enforcement authorities, competitors, and customers frequently monitor a company’s statements for any suggestion of conduct that may have anticompetitive consequences. Statements to the effect that a firm “dominates” or “controls” a market will raise the concerns and suspicions of these observers. Consequently, care should be taken to avoid any inference that a firm has engaged in conduct that might restrict or eliminate competition. If there is any doubt concerning whether a particular statement is appropriate, legal counsel should be consulted.

Careful language will not avoid antitrust liability when the conduct involved is illegal. Conduct that is perfectly legal, however, may become suspect because of poor word selection or a misleading manner of expression. Avoid unnecessary and perhaps inaccurate characterizations

³⁴ See *Aspen Skiing Co. v. Aspen Highlands Skiing Corp.*, 472 U.S. 585, 602 (1985).

³⁵ *Verizon*, 540 U.S. at 408.

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regarding intangibles such as purpose, intent, and state of mind. Careless and inappropriate language can have an extremely adverse effect on a firm's or an individual's position in an antitrust investigation or lawsuit.

Under discovery procedures, the Justice Department, the FTC, a state attorney general, and private litigants may have broad access to a defendant's documents and data. Materials that may have to be disclosed are not limited to final versions of memoranda or letters, but also include drafts, handwritten notes, individual calendars and diaries, expense records, telephone records, trader tapes, voicemail messages, email, instant messaging, and all other material that can be retrieved from a computer or computer network. Bear in mind that, with increased use of computers and electronic messaging, documents are often widely distributed and saved indefinitely. Copies are often kept on back-up systems, unbeknownst to the author. Similarly, documents maintained in "personal" files or on laptops or kept at home typically must be produced. All documents and electronic communications should be carefully written so as to avoid misstatements of fact and inferences or conclusions that might be misinterpreted or taken out of context by a suspicious person.

III. SIGNIFICANT UNCERTAINTIES

The main source of antitrust uncertainty (i.e., risk) for participants in the electric power industry is the absence of routine regulatory activity by the antitrust enforcement agencies. Unlike expert state and federal regulatory agencies, the antitrust agencies do not publish rules or regulations that prescribe specific business conduct that, if followed, will be deemed compliant with the antitrust laws. In addition, they do not mandate the creation and retention of particular business records, periodic filings, occasional compliance audits, or other processes that ordinarily provide calibration and feedback concerning antitrust compliance.

Moreover, although the antitrust agencies monitor developments in the industry, they become familiar with individual companies or the workings of particular markets only in the course of investigating conduct or mergers that may violate the antitrust laws. Conduct investigations may be triggered by complaints from customers, suppliers, or competitors—anyone who would benefit in a private treble damages action if an antitrust agency were to establish that an antitrust violation occurred. In particular, it is not uncommon for companies that find themselves in financial difficulty to allege anticompetitive conduct by others in the marketplace as the source of their troubles. Similarly, because merger investigations may result in mandatory dispositions of assets, other market participants may have an extra incentive to cooperate with antitrust investigators. Antitrust agencies are acutely aware that the complaints of private parties may be driven by ulterior motives, but they will pursue allegations that appear to be based on plausible theories of harm to competitive markets, not just individual companies.

IV. COMPLIANCE RECOMMENDATIONS

In view of the potential penalties for both companies and individuals, there is an obvious need for all directors, officers, and employees of a firm to be familiar with the antitrust laws. Following ethical business practices is not sufficient, for inadvertent violations can occur and have occurred in good companies, and good intentions are often held to be irrelevant. Pursuing an anticompetitive course of conduct for the "good of the industry," for the "benefit of a

customer,” or even because it seems to be the “right thing to do” will not excuse the resulting violation of the antitrust laws.

Appearances as well as actual facts are important. A violation of the antitrust laws can be established by circumstantial evidence alone, even though there is direct evidence contradicting the existence of such a violation. It is far better and easier to avoid situations and actions that might convey an erroneous impression than to have to explain them in the future when an antitrust investigation or action is in progress.

Consequently, to ensure compliance with the antitrust laws, a company should:

- Establish and publish a clear statement that it is the company’s policy to comply with the antitrust laws.
- Publish a compliance guide containing the policy statement and instructions on how to comply with the antitrust laws, and require employees to sign a form acknowledging that they have read and agree to comply with the policy.
- Conduct mandatory annual training sessions for employees on how to comply with the antitrust laws.
- Designate at least one in-house attorney to be a resource for business people to contact with antitrust questions or issues, and arrange for additional antitrust training for that attorney.
- Establish a “tip” line that allows employees to anonymously report potential violations of the company’s policy.
- Consult with outside legal counsel when in doubt about any decision or course of conduct.

Chapter 7

Reliability Standards and Practices

GERARD A. CLARK
KATHRYN K. BARAN
TIM MASTROGIACOMO

Through the Energy Policy Act of 2005, Congress added section 215 to the Federal Power Act.¹ Section 215 made compliance with electric reliability standards mandatory, authorized the creation of an Electric Reliability Organization (“ERO”)—and regional reliability entities—to establish and enforce reliability standards, and gave FERC jurisdiction over the ERO and all users, owners, and operators of the bulk-power system for purposes of approving and enforcing compliance with the reliability standards. This chapter describes the process through which the reliability standards are developed and enforced. This chapter first discusses FERC’s jurisdiction over the users, owners, and operators of the bulk electric system, including the compliance registration process and FERC’s definition of “bulk electric system.” The chapter then describes the reliability standards and the process in which the standards are drafted and interpreted. The chapter then describes the three-tiered enforcement process for reliability standards involving the FERC-certified ERO (NERC), the regional reliability entities, and FERC. Finally, the chapter discusses penalties for violations of the reliability standards.

I. JURISDICTION AND APPLICABILITY OF THE RELIABILITY STANDARDS

Section 215(b) of the FPA broadly gives FERC jurisdiction within the United States (other than Alaska and Hawaii) over “all users, owners and operators of the bulk-power system, including but not limited to the entities described in section 201(f)” for purposes of approving and enforcing the reliability standards and further provides that “all users, owners and operators of the bulk-power system” must comply with the reliability standards.² Under this provision, many entities not previously subject to FERC jurisdiction fall within FERC’s reliability jurisdiction because they use, own, or operate the bulk-power system. For example, federal entities generally exempt from FPA requirements under section 201(f)³ must comply with the reliability standards if they use, own, or operate the bulk-power system,⁴ although the U.S. Court

¹ See 16 U.S.C. § 824o.

² See *id.* § 824o(b).

³ FPA section 201(f) generally excludes from FPA jurisdiction federal and state entities, or any political subdivisions thereof, or an electric cooperative that receives financing under the Rural Electrification Act of 1936 or that sells less than 4,000,000 megawatt hours of electricity per year. *Id.* § 824(f).

⁴ *North Am. Elec. Reliability Corp.*, 133 FERC ¶ 61,214 (2010), *reh’g denied*, 137 FERC ¶ 61,044 (2011) (finding that the Army Corps of Engineers is subject to FERC’s reliability jurisdiction under FPA section 215).

of Appeals for the D.C. Circuit has held that federal entities are not subject to monetary penalties under FPA section 215(e).⁵ Also, qualifying small power production and cogeneration facilities (“QFs”)—which are exempt from many FPA requirements under section 292.601(c) of FERC’s regulations⁶—are not exempt from the reliability standards under FPA section 215.⁷

Because the potential scope of entities subject to FERC’s reliability jurisdiction is so broad—e.g., all “users” of the bulk-power system—FERC and NERC adopted a Compliance Registry process to manage the applicability of the reliability standards and identify users, owners, and operators that must register for compliance. In addition, because FERC’s jurisdiction applies only to users, owners, and operators of the “bulk power system,” the definition of the bulk-power system also limits the scope of the entities that must comply with the reliability standards. This section examines the compliance registry process and the definition of the term “bulk power system.”

A. COMPLIANCE REGISTRY PROCESS

All users, owners, and operators of the bulk-power system are required to register with NERC and the applicable Regional Entity⁸ for each region within which it uses, owns, or operates bulk-power system facilities.⁹ NERC uses two primary devices to manage the registration of those required to comply with the reliability standards: (1) the Functional Model, which groups the users, owners, and operators into fifteen categories based on the functions they perform; and (2) the Compliance Registry, which is an updated list of all entities that have registered for compliance and the functions and regions in which they have registered.

Under the Functional Model, users, owners, and operators of the bulk-power system are required to register in one or more of the following fifteen functional categories: (1) Reliability Coordinator; (2) Transmission Operator; (3) Balancing Authority; (4) Planning Authority; (5) Transmission Planner; (6) Transmission Service Provider; (7) Transmission Owner; (8) Resource Planner; (9) Distribution Provider; (10) Generator Owner; (11) Generator Operator; (12) Load-Serving Entity (“LSE”); (13) Purchasing-Selling Entity; (14) Interchange Authority; and (15) Reserve Sharing Group. The definition of each of these functional categories is contained in the

⁵ See *Southwestern Power Admin. v. FERC*, 763 F.3d 27 (D.C. Cir. 2014) (holding that the Southwestern Power Administration was not subject to penalties under section 215(e) because neither sections 215(e) nor 215(b) were sufficiently clear to waive the federal government’s sovereign immunity from penalties).

⁶ 18 C.F.R. § 292.601(c).

⁷ *Applicability of Fed. Power Act Section 215 to Qualifying Small Power Prod. and Cogeneration Facilities*, Order No. 696, 119 FERC ¶ 61,149 (2007).

⁸ As explained further *infra*, there are eight Regional Entities: Florida Reliability Coordinating Council (“FRCC”), Midwest Reliability Organization (“MRO”), Northeast Power Coordinating Council (“NPCC”), ReliabilityFirst Corporation (“RFC”), SERC Reliability Corporation (“SERC”), Southwest Power Pool (“SPP”), Texas Regional Entity (“TRE”), and Western Electric Coordinating Council (“WECC”).

⁹ 18 C.F.R. § 39.2(c).

NERC Glossary,¹⁰ and the criteria governing each category is described in the NERC Statement of Compliance Registry, which is contained in Appendix 5B of NERC's Rules of Procedure.¹¹

For Load-Serving Entities, Distribution Providers, Generator Owners/Operators, and Transmission Owners/Operators, the Statement of Compliance Registry excludes entities from the obligation to register if they otherwise fall within the definition of these functional categories but do not meet certain criteria. These criteria generally are designed to eliminate the obligation for smaller entities to register. For example, to be required to register, Load-Serving Entities and Distribution Providers generally must serve a peak load greater than 25 kW and be directly connected to the bulk-power system, and Generator Owners/Operators must have an individual generating unit with a gross nameplate of 20 MVA or greater or combined units totaling 75 MVA or greater. Further, to limit the burden on smaller entities, NERC's Rules allow entities to create Joint Registration Organizations to accept registration and compliance responsibility for their members.¹²

NERC maintains on its website a Compliance Registry which lists all of the registered entities and the functions and regions in which they are registered.¹³ The process for registering with NERC and applicable Regional Entities is described in section 500 and Appendix 5A of the NERC Rules of Procedure.¹⁴ NERC and the Regional Entities have the obligation to identify and register all entities that meet the criteria for inclusion on the Compliance Registry. If NERC or a Regional Entity find an entity that is not, but should be, listed on the Compliance Registry, they are obligated to initiate action to add that entity to the Compliance Registry. Once added to the Registry, the entity will be required to comply with the reliability standards on a prospective basis, but will not be subject to penalties for past violations that occurred when the entity was not registered.¹⁵

If an entity believes that NERC or a Regional Entity has made an error in requiring its registration, it may submit a challenge to such designation with the ERO and ultimately file an appeal with FERC if it believes that it should not be registered. FERC has ruled on many

¹⁰ NERC, *Glossary of Terms Used in NERC Reliability Standards* (Aug. 20, 2014), http://www.nerc.com/files/glossary_of_terms.pdf.

¹¹ NERC Rules of Procedure, Appendix 5B (Statement of Compliance Registry Criteria). The NERC Rules of Procedure are available at <http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx>.

¹² See NERC Rules of Procedure §§ 501, 507.

¹³ NERC Compliance Registry (Sept. 24, 2014), <http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx>.

¹⁴ See NERC Rules of Procedure § 500; *id.*, Appendix 5A.

¹⁵ *Mandatory Reliability Standards for the Bulk-Power Sys.*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 97 ("While the Commission may take prospective action against an entity that was not previously identified as a user, owner or operator through the NERC registration process once it has been added to the registry, the Commission will not assess penalties against an entity that has not previously been put on notice, through the NERC registration process, that it must comply with particular Reliability Standards."), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007) (codified at 18 C.F.R. pt. 40).

appeals from NERC compliance registry decisions. These cases demonstrate that FERC will reverse NERC's rulings if NERC does not comply with its Compliance Registry criteria. For example, in *Direct Energy Services, LLC*,¹⁶ FERC reversed a NERC decision requiring retail marketers to register as Load-Serving Entities. FERC determined that retail marketers did not qualify as LSEs under NERC's Compliance Registry criteria because they do not own or operate physical assets that are directly connected to the bulk-power system.¹⁷ FERC also expressed a concern that excluding retail marketers from the Compliance Registry might create a "reliability gap" because retail marketers may "possess information relevant to the reliable operation of the Bulk-Power System that is not provided by other users, owners or operators."¹⁸ FERC, therefore, ordered NERC to submit a compliance filing to revise its Compliance Registry to eliminate the potential reliability gap.¹⁹ Also, in *U.S. Department of Energy, Portsmouth/Paducah Project Office*,²⁰ FERC reversed a NERC decision finding that the U.S. Department of Energy ("DOE") was an LSE because NERC failed to demonstrate that DOE was the entity responsible for securing energy and transmission service for the end-use customer.

In addition, in a series of orders, FERC upheld NERC rulings requiring generators that own or operate generator lead lines to register as Transmission Owners and Transmission Operators.²¹ FERC ruled that the generator lead lines had a material impact on bulk-power system reliability and that failure to register the owners and operators of those lines as Transmission Owners and Transmission Operators would create a reliability gap. However, in response to industry complaints that FERC's rulings would create undue burdens for generation owners, NERC revised its rules to specify and limit the reliability requirements applicable to owners and operators of generation lead lines.²²

B. DEFINITION OF BULK-POWER SYSTEM

Section 215(a)(1) of the FPA defines "bulk-power system" to mean:

(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.²³

¹⁶ 121 FERC ¶ 61,274 (2007).

¹⁷ *Id.* at PP 36-40.

¹⁸ *Id.* at P 49.

¹⁹ *Id.* at P 50.

²⁰ 139 FERC ¶ 61,054, *order on reh'g*, 141 FERC ¶ 61,108 (2012).

²¹ *See, e.g., Cedar Creek Wind Energy, LLC*, 135 FERC ¶ 61,241, *reh'g denied*, 137 FERC ¶ 61,141 (2011); *New Harquahala Generating Co., LLC*, 123 FERC ¶ 61,173 (2008).

²² *Generator Requirements at the Transmission Interface*, Order No. 785, 144 FERC ¶ 61,221 (2013).

²³ 16 U.S.C. § 824o(a)(1); *see also* 18 C.F.R. § 39.1.

This statutory definition differed from the term “bulk electric system,” which was defined in the NERC glossary:

As defined by the Regional Reliability Organization, the electric generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.²⁴

In Order No. 693, FERC adopted NERC’s definition of “bulk electric system” for the initial version of the reliability standards, although FERC determined that the statutory term “Bulk-Power System reaches farther than those facilities that are included in NERC’s definition of the bulk electric system.”²⁵ However, FERC expressed concern that NERC’s definition allowed regional variation which created “the potential for gaps in coverage of facilities.”²⁶ FERC, therefore, ordered NERC to submit a filing that includes a complete set of the regional definitions of bulk electric system and stated its intent to address the need for a uniform definition in the future.²⁷

FERC fulfilled its commitment in Order No. 693 to revisit the definition of bulk electric system when it issued Order No. 743.²⁸ In Order No. 743, FERC ordered NERC to revise the definition of bulk electric system through the Standards Development Process by eliminating the regional discretion in the existing definition, maintaining the bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and establishing an exemption process and criteria for excluding facilities that are not necessary for operating the interconnected transmission network. FERC also stated that NERC could propose a different solution for defining the bulk electric system as long as it was equally effective in addressing FERC’s concerns.

In response to Order No. 743, NERC submitted two petitions to FERC: (1) a proposed revision to the definition of “bulk electric system,” which includes a core definition and examples of facilities that are included and excluded; and (2) revisions to the NERC rules of procedure (an exceptions process) to classify or declassify an element as part of the bulk electric system. The revised “core” definition of bulk electric system states:

Unless modified by the [inclusion or exclusion] lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy.

²⁴ Glossary of Terms Used in NERC Reliability Standards at 13.

²⁵ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 75-76.

²⁶ *Id.* at P 77.

²⁷ *Id.*

²⁸ *Revision to Elec. Reliability Org. Definition of Bulk Elec. Sys.*, Order No. 743, 133 FERC ¶ 61,150 (2010), *order on reh’g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011), *appeal pending sub nom. People of N.Y. v. FERC*, No. 13-2316 (2d Cir. filed June 12, 2013).

The revised definition also listed five types of configurations that should be included within the definition and four types of configurations that should be excluded. The five inclusions are: (I1) transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher; (I2) generator resources with a gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA; (I3) Blackstart Resources identified in the Transmission Operator's restoration plan; (I4) dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above; and (I5) static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 100 kV or higher, or through a dedicated transformer with a high-side voltage of 100 kV or higher. The four exclusions are: (E1) radial systems that only serve load or generation resources less than or equal to 75 MVA; (E2) generating units on the customer's side of the retail meter that serve all or part of the retail load; (E3) local networks; and (E4) reactive power devices owned and operated by the retail customer solely for its own use.

In Order No. 773,²⁹ FERC approved NERC's modifications to the definition of bulk electric system and the revisions to NERC rules to adopt the exceptions process. FERC found that NERC's revised definition appropriately established a bright-line 100 kV test and removed language allowing for regional discretion in determining elements of the bulk electric system. FERC further found that the list of included and excluded configurations provided additional granularity that improves consistency and provides a practical means to determine the status of common system configurations. In a subsequent order, FERC approved NERC's revised definition of bulk electric system effective July 1, 2014.³⁰

II. RELIABILITY STANDARDS AND THE STANDARDS DEVELOPMENT AND INTERPRETATION PROCESS

Once an entity is included in the Compliance Registry, it has an obligation to comply with the reliability standards that have been approved by FERC.³¹ This section describes the reliability standards, the process in which the standards are developed and revised and approved by FERC, and certain issues relating to the interpretation of the reliability standards.

A. RELIABILITY STANDARDS

FPA section 215 defines "reliability standard" as "a requirement, approved by the Commission . . . , to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not

²⁹ *Revisions to Elec. Reliability Org. Definition of Bulk Elec. Sys. and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012), *order on reh'g and clarification*, Order No. 773-A, 143 FERC ¶ 61,053, *reh'g denied*, 144 FERC ¶ 61,174 (2013).

³⁰ *North Am. Elec. Reliability Corp.*, 146 FERC ¶ 61,199 (2014).

³¹ 18 C.F.R. § 40.2(a).

include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.”³² Currently, there are 104 continent-wide mandatory reliability standards subject to enforcement.³³

Each reliability standard follows the same format: The Introduction provides the title, number, purpose, and effective date of the standard and identifies the subset of users, owners, and operators of the bulk-power system to which a particular reliability standard applies. The Requirements section, which FERC has designated “the most critical element of a Reliability Standard,”³⁴ sets forth the binding obligations that must be complied with under the standard. The Measures section provides the evidence that an entity must present to show compliance with a reliability standard.³⁵ The Compliance section sets out the Levels of Non-Compliance which are used in determining penalty amounts based on established criteria for determining the severity of non-compliance with a reliability standard.³⁶ FERC has stated the Measures and Levels of Non-Compliance sections of a reliability standard “provide useful guidance to the industry” but do not contain the binding obligations of a standard.³⁷ The reliability standards also contain a section describing any Regional Differences in application of the standard, a section with the Version History of the standard, including all revisions to the standard, and an appendix containing any formal interpretations of the standard.

To assist in the enforcement of the reliability standards, each requirement or sub-requirement of a reliability standard is associated with a Violation Risk Factor (“VRF”) and Violation Severity Level (“VSL”). VRFs and VSLs are factors used when determining the size of a penalty or sanction associated with the violation of a reliability requirement. VRFs identify the potential reliability significance of non-compliance with a requirement. VSLs define the degree to which compliance with a requirement was not achieved. NERC’s website contains matrices listing the VRFs and VSLs for every requirement and sub-requirement in each of the

³² 16 U.S.C. § 824o(a)(3); 18 C.F.R. § 39.1.

³³ The Commission’s regulations require NERC to post the currently effective and enforceable reliability standards on the NERC website. See 18 C.F.R. § 40.3. The current set of *enforceable* reliability standards can be found at <http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf>. The fourteen categories are as follows: (1) Resource and Demand Balancing (“BAL”); (2) Critical Infrastructure Protection (“CIP”); (3) Communications (“COM”); (4) Emergency Preparedness and Operations (“EOP”); (5) Facilities Design, Connections, and Maintenance (“FAC”); (6) Interchange Scheduling and Coordination (“INT”); (7) Interconnection Reliability Operations and Coordination (“IRO”); (8) Modeling, Data, and Analysis (“MOD”); (9) Nuclear (“NUC”); (10) Personnel Performance, Training, and Qualifications (“PER”); (11) Protection and Control (“PRC”); (12) Transmission Operations (“TOP”); (13) Transmission Planning (“TPL”); and (14) Voltage and Reactive (“VAR”).

³⁴ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 253 (citation omitted); *North Am. Elec. Reliability Corp.*, 132 FERC ¶ 61,200 at P 9 (2010).

³⁵ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 238 n.118.

³⁶ *Id.* at P 238 n.119.

³⁷ *Id.* at P 253.

mandatory reliability standards.³⁸ These matrices provide a good checklist for all reliability requirements applicable to each functional category.³⁹

In addition to reliability standards that generally are applicable in all regions, the enforceable reliability standards also include regional standards that apply only in a specific region. FPA section 215(e)(4) authorizes regional entities to propose to NERC reliability standards that would apply only in that region.⁴⁰ The regional reliability standards follow the same format as the other reliability standards and also have VRFs and VSLs associated with their requirements.

B. STANDARDS DRAFTING PROCESS

Development of each reliability standard is governed by the Commission-approved NERC Standards Development Process. The multi-step process applies to proposals for a new standard, modifications or withdrawals of existing standards, revisions to a standard remanded to NERC by the Commission, or development of a standard in response to a Commission or other Governmental Authority directive. The standards development is governed by section 300 of the NERC Rules of Procedure and set forth in the NERC Standard Process Manual (Appendix 3A of the Rules of Procedure).⁴¹ Any action on a reliability standard requires final approval by a two-thirds vote on a sector-weighted basis before it is submitted to the NERC Board of Trustees. With the NERC Board's approval, the new reliability standard or revision is subsequently filed with the Commission and any other Applicable Governmental Authority for approval.⁴²

The Commission has authority to approve or remand a proposed standard, but does not have statutory authority to draft it in the first instance.⁴³ However, the Commission has authority to require NERC "to submit to the Commission a proposed reliability standard or a modification to a proposed reliability standard that addresses a specific matter if the Commission considers

³⁸ Revisions to Outstanding Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), http://www.nerc.com/pa/Stand/Pages/Revisions_Outstanding_VRFs_VSLs.aspx.

³⁹ All defined terms in the reliability standards are listed in the Glossary of Terms Used in NERC Reliability Standards.

⁴⁰ 16 U.S.C. § 824o(e)(4). Although regional reliability standards reduce the uniformity of the reliability requirements, FERC will allow two types of regional differences in regional reliability standards: (1) a regional difference that is more stringent than the continent-wide reliability standard, including a regional difference that addresses matters that the continent-wide standard does not; and (2) a regional reliability standard that is necessitated by a physical difference in the bulk-power system. *Rules Concerning Certification of the Elec. Reliability Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 291, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) (codified at 18 C.F.R. pt. 39).

⁴¹ Section 215 of the FPA requires NERC, as the ERO, to develop reliability standards by way of rules that provide reasonable notice and opportunity for public comment, due process, openness, and a balance of interests. See 16 U.S.C. § 824o(c)(2)(D).

⁴² NERC Rules of Procedure, Appendix 3A §§ 4.7-4.15.

⁴³ 16 U.S.C. § 824o(d)(2)-(4).

such a new or modified reliability standard appropriate to carry out this section.”⁴⁴ Moreover, FPA section 215(d)(2) requires that the Commission give “due weight to [NERC’s] technical expertise,” but there is little guidance as to the scope and meaning of this phrase.

Unsurprisingly, a certain amount of tension existed initially between NERC and FERC as to how much, if any, deference FERC should give to NERC in the reliability standards development process. The friction reached its apex when, on March 18, 2010, the Commission issued an order directing that NERC revise its Rules of Procedure in order that the drafting process be adequately responsive to a Commission directive.⁴⁵ In the order, the Commission explained that it had growing concerns that the then-effective process could be used in such a way as to allow stakeholders to thwart approval of a draft reliability standard adequately responsive to a Commission directive.⁴⁶ Following extensive protests, comments, responses by various parties and intervenors, and Commission denials of requests for rehearing, NERC sought and received from the Commission approval of amendments to the Standards Development Process in order to develop “an affirmative mechanism [through which] to submit to the Commission a new or modified Reliability Standard pursuant to a [Commission] directive under section 215(d)(5) of the FPA.”⁴⁷ The NERC Standards Development Process now provides for alternative processes that can be implemented whenever the NERC Board determines that the Standards Development Process does not produce a draft reliability standard that is responsive to a Commission directive.⁴⁸ Meanwhile, although section 215(d)(2) requires that the Commission give “due weight to the [NERC’s] technical expertise,” the Commission appears mindful of the need to use its authority to issue directives under FPA section 215(d)(5) “judiciously,” and has been open to finding means to identify, communicate, and prioritize its reliability objectives.⁴⁹ Moreover, the Commission “will consider an equivalent alternative approach provided that the [NERC] demonstrates that the alternative will address the Commission’s underlying concern or goal as efficiently and effectively as the Commission’s proposal.”⁵⁰

Once a draft standard, revision, or withdrawal has been approved by the NERC Board, NERC files for FERC approval of that proposal. The Commission may take one of four possible courses of action with regard to the submitted proposal: (1) approve the proposed reliability standard; (2) approve the reliability standard as mandatory and enforceable and direct modification pursuant to section 215(d)(5); (3) request additional information; or (4) remand the proposal.⁵¹ The Commission views the second option as an exercise of its authority (a) to approve a proposed reliability standard and (b) to direct NERC to submit a modification of the reliability standard to address specific issues or concerns identified by the Commission, pursuant

⁴⁴ *Id.* § 824o(d)(5).

⁴⁵ *North Am. Elec. Reliability Corp.*, 130 FERC ¶ 61,203 (2010).

⁴⁶ *Id.* at P 22.

⁴⁷ *North Am. Elec. Reliability Corp.*, 132 FERC ¶ 61,218 at P 4 (2010).

⁴⁸ NERC Rules of Procedure § 321.

⁴⁹ *North Am. Elec. Reliability Corp.*, 134 FERC 61,216 at P 31 (2011).

⁵⁰ Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 185-86.

⁵¹ *Id.* at P 184.

to section 215(d)(5) of the FPA.⁵² The Commission may order a deadline by which NERC must submit a proposed or modified reliability standard.⁵³

C. INTERPRETATIONS OF RELIABILITY STANDARDS

NERC's Rules establish a process for interested parties to seek an interpretation of an existing reliability standard or requirement. Section 7.0 of the NERC Standards Development Manual states that a person that is "directly and materially affected" by bulk-power system reliability may request an interpretation of a reliability standard.⁵⁴ The process for developing an interpretation is similar to the process for developing or revising the standard itself. After receiving a request from a qualified entity, NERC will establish a team of experts to address the requested interpretation and form a ballot pool. The team of experts must develop the interpretation and submit it to the ballot pool for interpretation. If approved by the ballot pool, the interpretation must then be submitted for approval by the NERC Board of Trustees.

As with a reliability standard, a NERC interpretation also must be filed with and approved by FERC. NERC will file the full interpretation development record with FERC as part of its filing for approval of the interpretation. FERC has the same options in ruling on interpretations that it has in ruling on reliability standards that are filed by NERC. That is, FERC may approve the interpretation, reject the interpretation, or remand the interpretation to NERC for further consideration.⁵⁵ Once FERC approves an interpretation, the interpretation is permanently attached as a subsection of the reliability standard.

FERC has addressed many NERC filings of reliability standard interpretations. In most cases, FERC has approved NERC's interpretations. However, FERC has disagreed with and remanded NERC interpretations on several occasions. For example, FERC remanded NERC's interpretation of reliability standard VAR-001, disapproving of NERC's conclusion that the standard did not require voltage schedules to have a technically sound basis.⁵⁶ FERC also remanded two interpretations of CIP reliability standards (CIP-002 and CIP-006) on the grounds that NERC's interpretations were not reasonable and were inconsistent with the standard and other interpretations.⁵⁷ In Order No. 754, FERC initially proposed to reject NERC's interpretation of reliability standard TPL-002, which concluded that the standard did not require Transmission Planners to consider protective system failures in planning for system

⁵² *Id.*

⁵³ See 18 C.F.R. § 39.5(g).

⁵⁴ NERC Rules of Procedure, Appendix 3A § 7.0.

⁵⁵ See 16 U.S.C. § 824o(d).

⁵⁶ See *Elec. Reliability Org. Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards*, Order No. 724, 127 FERC ¶ 61,158 (2009).

⁵⁷ See *North Am. Elec. Reliability Corp.*, 142 FERC ¶ 61,204 (2013); *North Am. Elec. Reliability Corp.*, 142 FERC ¶ 61,203 (2013).

contingencies, but then changed its mind and upheld the interpretation after extensive industry comments opposing FERC's proposal.⁵⁸

Besides formal interpretations, NERC has other less formal processes for interpreting and providing guidance on the meaning of the reliability standards. For example, Compliance Application Notices ("CANs") provide compliance guidance to the industry on the reliability standards. CANs are not formal interpretations and are not attached to a reliability standard. A CAN will be retired if it is superseded or replaced by a formal interpretation. Under NERC's CAN process, an interested party can request compliance guidance by submitting potential issues for CANs. CANs are then developed by NERC staff, after review and input from NERC committees and industry comments. An interested party that takes issue with a CAN may request a high-level review of the CAN by NERC.⁵⁹ In addition to CANs, NERC can also provide informal guidance to the industry on the meaning of reliability standards through Compliance Process Bulletins and NERC Alerts and Directives.

III. ENFORCEMENT SCHEME

The enforcement scheme for the reliability standards is complex, and it includes three different levels of enforcement: the Regional Entities, NERC, and FERC. This section examines the three different enforcers and the enforcement process for each of them.

A. THREE-TIERED ENFORCEMENT PROCESS

1. NERC

Pursuant to section 215(e)(1) of the FPA, the Commission-certified Electric Reliability Organization may impose a penalty on a user, owner, or operator of the bulk-power system (a "registered entity") for a violation of a reliability standard approved by the Commission.⁶⁰ In July 2006, the Commission certified NERC as the ERO.⁶¹

NERC's procedures for monitoring and enforcement of compliance with reliability standards are set forth in section 400 of the NERC Rules of Procedure. In accordance with these

⁵⁸ See *Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 (2011).

⁵⁹ See NERC, *Compliance Application Notice (CAN) Process* (Apr. 2012), [http://www.nerc.com/pa/comp/Resources/Compliance%20Application%20Notices%20DL/CAN%20Process%20\(clean\).pdf](http://www.nerc.com/pa/comp/Resources/Compliance%20Application%20Notices%20DL/CAN%20Process%20(clean).pdf).

⁶⁰ 16 U.S.C. § 824o(e)(1).

⁶¹ *North Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009). In accordance with the Commission's regulations at 18 C.F.R. § 39.3(c), on July 21, 2014, NERC submitted its Five-Year Electric Reliability Organization Performance Assessment Report in Docket No. RR14-5-000.

rules, NERC has developed a Compliance Monitoring and Enforcement Program (“CMEP”)⁶² and Sanction Guidelines.⁶³

To impose a penalty on a registered entity for violating a reliability standard, NERC, as the ERO, must first file a Notice of Penalty with the Commission. Each penalty determination, including a zero dollar penalty, is subject to Commission review, on its own motion or by the filing of an application for review by the registered entity subject to the penalty.⁶⁴ The registered entity must file any appeal of the assessment within thirty days after the date NERC files the applicable Notice of Penalty.⁶⁵ If there is not an appeal filed or other action taken by the Commission, any penalty NERC files takes effect by operation of law upon the expiration of the applicable thirty-day period.⁶⁶

To address lower-risk violations, the Commission has accepted NERC’s Find, Fix, Track and Report (“FFT”) initiative whereby NERC and the Regional Entities have the flexibility to address certain lower-risk (and now moderate-risk) possible violations through an FFT informational filing and mitigation monitoring as opposed to issuing and filing a Notice of Penalty.⁶⁷ The FFT program is designed to give NERC and the Regional Entities flexibility to focus their resources on issues that pose the greatest threat to reliability. On March 15, 2013, NERC submitted its required 12-month report regarding implementation of FFT.⁶⁸ In its March 2013 FFT Report, NERC stated that the implementation of the FFT program has freed NERC and the Regional Entities to devote more resources to serious and substantial risk events and has reduced its backlog of processing violations.⁶⁹ NERC also proposed certain enhancements to FFT, most of which the Commission accepted.⁷⁰ In particular, FERC accepted NERC’s proposal to expand the FFT program by allowing FFT treatment for some moderate-risk possible violations, subject to NERC’s reporting on its implementation of this initiative.⁷¹ The Commission also directed NERC to address several specific topics in another report.⁷² On June

⁶² See NERC Rules of Procedure, Appendix 4C (Compliance Monitoring and Enforcement Program).

⁶³ See NERC Rules of Procedure, Appendix 4B (Sanction Guidelines).

⁶⁴ 18 C.F.R. § 39.7(e).

⁶⁵ *Id.*

⁶⁶ *Id.*

⁶⁷ See *North Am. Elec. Reliability Corp.*, 138 FERC ¶ 61,193 at P 81, *order on reh’g and clarification*, 139 FERC ¶ 61,168 (2012), *order on compliance filing*, 143 FERC ¶ 61,253 (2013).

⁶⁸ See *North Am. Elec. Reliability Corp.*, Docket No. RC11-6-000, Compliance Filing and Report on the Compliance Enforcement Initiative and Proposed Enhancements to the Find, Fix, Track and Report (FFT) Program (Mar. 15, 2013) (“March 2013 FFT Report”).

⁶⁹ See *North Am. Elec. Reliability Corp.*, 143 FERC ¶ 61,253 at PP 8-9 & nn.6-10 (citing March 2013 FFT Report).

⁷⁰ *Id.* at PP 15-22, 26.

⁷¹ *Id.* at P 26.

⁷² *Id.* at PP 26, 33-34.

20, 2014, NERC submitted the required report, providing, among other information, the number and types of FFTs that were moderate-risk possible violations since June 20, 2013, and a detailed explanation of the steps that NERC has taken to ensure that the Regional Entities are determining risk in a consistent manner.⁷³ NERC also argued that additional flexibility regarding the required 90-day time frame for completion of mitigating activities was warranted.⁷⁴

In addition to the FFT program, NERC has instituted its Reliability Assurance Initiative (“RAI”), which recognizes that it is not practical, effective, or sustainable for the ERO and the Registered Entities to monitor and control all compliance to the same degree or to treat all findings and discrepancies as violations triggering the same degree of enforcement and evidentiary documentation.⁷⁵

The RAI program has three main goals: (1) build on the success of FFT and develop enforcement incentives to distinguish between poor performance that must to be discouraged and positive behaviors that contribute to higher accountability and improved performance; (2) design a compliance program that recognizes an entity’s risk to reliability along with its management controls and corrective action programs used to meet the reliability standards; and (3) reduce the administrative burdens of the compliance and enforcement program on industry while gaining efficiencies.⁷⁶

As part of the RAI, NERC and the Regional Entities collaborated with a Registered Entity focus group to develop User Guides for Self Reports and Mitigation Plans. These User Guides, which will continue to be developed, provide guidance on the information necessary for NERC and Regional Entities to support a determination to resolve an instance of non-compliance outside of enforcement action.⁷⁷ In addition, NERC and the Regional Entities instituted a “self-logging” initiative whereby certain Registered Entities are permitted to maintain a log of minimal risk issues and report them in an aggregate manner over a six-month period.⁷⁸ The

⁷³ See *North Am. Elec. Reliability Corp.*, Docket No. RC11-6-004, Compliance Filing and Report on the Compliance Filing and Report on the Find, Fix, Track and Report Program (June 20, 2014).

⁷⁴ *Id.* at 47-50.

⁷⁵ Documents explaining the RAI and its development are available at <http://www.nerc.com/pa/comp/pages/reliability-assurance-initiative.aspx>.

⁷⁶ NERC, *Reliability Assurance Initiative Presentation* at 3 (Oct. 20, 2013), <http://www.serc1.org/Documents/Compliance/2013%20Program/Seminars/Oct%202013%20Compliance%20Seminar%20-%20Charlotte,%20NC%20&%20WebEx/Oct%202013%20Compliance%20Seminar%20Presentations/06%20Hughes%20-%20Compliance%20Seminar%20Oct%202013%20-%20NERC%20RAI%20Explained.pdf>.

⁷⁷ NERC, *Reliability Assurance Initiative, Summary of Comments and Responses to the ERO Mitigation Plan and Self-Report User Guides* at 2 (Apr. 2014), <http://www.nerc.com/pa/comp/Reliability%20Assurance%20Initiative/Summary%20of%20RAI%20ERO%20User%20Guides%20Comments%20and%20Responses.pdf>.

⁷⁸ *Id.*

envisioned “future state” provides an alternative to processing every individual instance of non-compliance through the formal enforcement process.⁷⁹

2. Regional Entities

Pursuant to section 215(e)(4) of the FPA, the ERO may enter into an agreement to delegate authority to a regional entity for the purpose of enforcing reliability standards.⁸⁰ The criteria required to be certified as a Regional Entity are set forth in section 215(e)(4) of the FPA.⁸¹ The Commission has approved agreements between NERC and each of eight Regional Entities which delegate enforcement authority to the Regional Entities.⁸²

Incorporated into each delegation agreement is NERC’s CMEP, subject to approved deviations for particular Regional Entities. Under the CMEP, the Regional Entities are the primary first-line enforcers of reliability standards in the United States. If a registered entity contests a violation alleged, or a penalty proposed, by a Regional Entity’s compliance staff, the registered entity may request a hearing before the Regional Entity’s hearing body.

The ERO holds the ultimate responsibility for enforcement of reliability standards, thus any delegation of this responsibility to a Regional Entity is subject to ERO oversight.⁸³ NERC, as the ERO, acts to ensure quality and consistency among the Regional Entities, particularly in the area of enforcement audits.⁸⁴ If a Regional Entity determines to impose a penalty, it must submit a notice to NERC, as the ERO, which may then submit the notice of penalty to the Commission.⁸⁵ NERC and each Regional Entity are required to report promptly to the Commission any self-reported violation or investigation of a violation or an alleged violation of a reliability standard and its eventual disposition.⁸⁶

⁷⁹ *Id.*

⁸⁰ 16 U.S.C. § 824o(e)(4). Separate from section 215(e) of the FPA, which authorizes the ERO to enter into an agreement to delegate authority to a qualified regional entity for the purpose of proposing and enforcing reliability standards, the Energy Policy Act of 2005 also provided for the creation of Regional Advisory Bodies composed of one governor-appointed member from each participating State in the region, to provide advice to the ERO, a Regional Entity, or the Commission regarding reliability standards. *See id.* § 824o(j).

⁸¹ *Id.* § 824o(e)(4).

⁸² NERC’s eight Regional Entities are (i) Texas Regional Entity, a Division of the Electric Reliability Council of Texas (“ERCOT”); (ii) Midwest Reliability Organization; (iii) Northwest Power Coordinating Council: Cross Border Regional Entity, Inc.; (iv) ReliabilityFirst Corporation; (v) SERC Reliability Corporation; (vi) Southwest Power Pool; (vii) Western Electricity Coordinating Council; and (viii) Florida Reliability Coordinating Council.

⁸³ *See* Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 654.

⁸⁴ *See, e.g., North Am. Elec. Reliability Corp. Reliability Standards Dev. and NERC and Reg’l Entity Enforcement*, 132 FERC ¶ 61,217 at PP 124-27 (2010).

⁸⁵ Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 654.

⁸⁶ 18 C.F.R. § 39.7(e)(2).

3. FERC

As discussed above, any penalty proposed to be levied by the ERO or a Regional Entity is subject to review by the Commission. Application to the Commission for review, or the initiation of review by the Commission on its own motion, shall not operate as a stay of such penalty unless the Commission otherwise orders upon its own motion or upon application by the user, owner, or operator that is the subject of such penalty.⁸⁷ As a general rule, the Commission must act within sixty days on an application for review of a penalty.⁸⁸ After notice and hearing, the Commission may affirm, set aside, modify, or remand the proposed penalty.⁸⁹ Review proceedings are public unless the Commission determines that a non-public proceeding is necessary and lawful.⁹⁰

Pursuant to section 215(e)(3) of the FPA, the Commission, on its own motion or in response to a complaint, may order compliance with a reliability standard and may impose a penalty against a user, owner, or operator of the bulk-power system if the Commission finds a violation of a reliability standard.⁹¹ FERC's reliability investigations are governed by FERC's Rules Relating to Investigations, found in section 1b of its regulations.⁹²

The Commission's enforcement authority is separate from, and not restrained by, the enforcement authority of NERC and the Regional Entities. In fact, the Commission may initiate its own investigation on a matter already under investigation by NERC or a Regional Entity.⁹³ It also may direct NERC or the Regional Entity to refer the matter to FERC.⁹⁴

B. AUDITS

NERC and the Regional Entities maintain a rigorous audit program to ensure that regulated utilities comply with all reliability standards. FERC directed the NERC and Regional Entities to develop and maintain this audit program in Order No. 672.⁹⁵ Pursuant to FERC's directive, NERC and the Regional Entities operate a joint audit program.⁹⁶ Each year, NERC issues a Compliance Monitoring and Enforcement Program Annual Implementation Plan.⁹⁷ The

⁸⁷ *Id.* § 39.7(e)(3).

⁸⁸ *Id.* § 39.7(e)(6).

⁸⁹ *Id.* § 39.7(e)(5).

⁹⁰ *Id.* § 39.7(e)(7).

⁹¹ *Id.* § 824o(e)(3); 18 C.F.R. § 39.7(f).

⁹² 18 C.F.R. pt. 1b.

⁹³ Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 485.

⁹⁴ *Id.*

⁹⁵ *Id.* at PP 463-64.

⁹⁶ *See id.* at P 463.

⁹⁷ *See, e.g.,* NERC, *ERO 2013 Implementation Plan and Actively Monitored List* (2013), <http://www.nerc.com/files/Session%20IV%20-%20202013%20Implementation%20Plan%20and%20AML.pdf>.

Annual Plan provides regulated entities with a list of actively monitored reliability standards and identifies certain requirements as high-risk priority standards. However, while NERC's actively monitored list indicates which standards NERC and the Regional Entities may be most focused on, NERC and the Regional Entities retain the authority to enforce any and all reliability standards at any time.⁹⁸ Balancing Authorities, Reliability Coordinators, and Transmission Operators are audited at least once every three years.⁹⁹ Other registered entities are audited at least once every six years, but this schedule may be adjusted by NERC upon a showing of good cause.¹⁰⁰

NERC audits are initiated by the Regional Entities, which must inform entities that they will be audited no later than October 1 of the year before the audit.¹⁰¹ Thereafter, the Regional Entity must send a Notice of Audit to the target entity no later than ninety days prior to the start of the audit.¹⁰² This notice identifies the reliability standards to be evaluated and requests that the target entity complete a pre-audit questionnaire.¹⁰³ The Regional Entity auditors then request various types of data from the target entity, which the auditors review in order to determine whether the entity is in compliance with the specified requirements. At the end of the audit, the Regional Entity auditors conduct an exit briefing and review a draft of their audit report with the target entity.¹⁰⁴ The audit report details any of the auditors' areas of concern and, if applicable, provides recommended remediation steps.¹⁰⁵ After the report is finalized by the audit team and approved by the Regional Entity, it is forwarded to NERC, which in turn forwards the report to FERC.¹⁰⁶ If the auditors identify possible violations of reliability standards, the Enforcement Actions procedures contained in Appendix 4C, section 5 of NERC's Rules of Procedure will be followed.¹⁰⁷ In the event that possible violations are identified in the audit report, the report will not be publicly released by NERC until either the possible violation is dismissed before becoming a Confirmed Violation, NERC files a Notice of Penalty with FERC, or the audited entity executes a settlement agreement regarding the alleged violation.¹⁰⁸ In addition to this standard audit process, NERC and the Regional Entities may conduct spot checks,¹⁰⁹ enforcement investigations,¹¹⁰ or require registered entities to self-certify that they are in

⁹⁸ See NERC Rules of Procedure § 401(6).

⁹⁹ ERO 2013 Implementation Plan and Actively Monitored List at 13.

¹⁰⁰ See *id.*; see also NERC Rules of Procedure § 403(11).

¹⁰¹ NERC Rules of Procedure, Appendix 4C § 3.1.2.

¹⁰² *Id.* § 3.1.1.

¹⁰³ *Id.*

¹⁰⁴ *Id.*

¹⁰⁵ *Id.* § 3.1.6.

¹⁰⁶ *Id.*

¹⁰⁷ See *infra* Part III.A.1, describing the NERC enforcement process.

¹⁰⁸ NERC Rules of Procedure, Appendix 4C § 3.1.6.

¹⁰⁹ See *id.* § 3.3.

¹¹⁰ See *id.* § 3.4.

compliance with reliability requirements.¹¹¹ NERC also encourages registered entities to self-report violations as they become aware of them.¹¹²

In addition to the audits conducted by NERC and the Regional Entities, FERC retains the authority to conduct audits of utility compliance with reliability regulations. Such audits are conducted by the FERC Office of Enforcement under FPA sections 301, 307, and 311. An extensive discussion of the procedures followed during FERC audits is found in Chapter 2 of this handbook. As with audits conducted by NERC and the Regional Entities, FERC audit activity and reports remain non-public until the report is finalized, and FERC audit staff share their draft report with the audited entity. FERC regulations provide specific procedures for audited entities to challenge the contents of audit reports and provide audited entities with the ability to seek a Commission hearing on the contents of a report; these procedures are likewise discussed at length in Chapter 2. FERC reliability audits are far less common than those conducted by NERC Regional Entities and are more likely to be triggered either by specific problems or by FERC's desire to ensure that a particular regulation or set of regulations are being followed. During the course of an audit, audit staff may refer certain alleged violations to FERC Enforcement staff, which may initiate a separate investigation into the alleged reliability rule violations.¹¹³

As an example of a recent FERC reliability audit, the Commission conducted a reliability audit of a federal power marketer and balancing authority for the period from 2007 to 2013 and approved an audit report in April 2013.¹¹⁴ The audit report identified several areas where the utility could improve its compliance with reliability standards, including protection systems maintenance and testing, outage coordination with neighboring entities, load shedding plans, transmission planning, and equipment tracking.¹¹⁵ The report recommended various measures the utility could take to improve compliance in these areas, including the implementation of load shedding drills, the creation of new procedures to track newly energized equipment, and the implementation of new tools to assist in the monitoring of distribution utility load shedding.¹¹⁶

As another example, in July 2013 FERC approved a reliability audit report for another utility also covering the period from 2007 to 2013.¹¹⁷ The audit report identified various areas in which the utility could improve, including critical infrastructure protection training, electronic security perimeter procedures, plans for loss of control center functionality, system operator training, and distribution operator load shedding training.¹¹⁸ Among other things, audit staff

¹¹¹ See *id.* § 3.2.

¹¹² See *id.* § 3.5.

¹¹³ See, e.g., *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,019 (2013); *Entergy Servs., Inc.*, 142 FERC ¶ 61,241 (2013).

¹¹⁴ *Bonneville Power Admin.*, Docket No. PA12-17-000 (Apr. 24, 2013) (unpublished delegated letter order).

¹¹⁵ *Id.*, Audit Report at 2-3.

¹¹⁶ *Id.*, Audit Report at 3-4.

¹¹⁷ *Salt River Project Agricultural Improvement & Power Dist.*, Docket No. PA12-11-000 (July 18, 2013) (unpublished delegated letter order).

¹¹⁸ *Id.*, Audit Report at 2-3.

recommended that the utility develop formal processes and procedures for detecting unauthorized access to electronic security perimeters, strengthen its cyber security training program, and develop new training for distribution operators on load shedding procedures.¹¹⁹

IV. PENALTIES

EPAct 2005 amended the FPA to permit FERC to impose a penalty of up to \$1 million per day per violation of the FPA or of a FERC regulation or order.¹²⁰ Civil penalties may be levied under the FPA by either FERC or NERC. In either case, the penalties may not exceed the \$1 million per day per violation cap contained in FPA section 316A.¹²¹ When FERC finds violations of reliability standards following a FERC-initiated audit or investigation, it may impose a civil penalty under its civil penalty guidelines. These guidelines, however, do not apply to civil penalties proposed by NERC.¹²² NERC determines such penalties using its own standards and files notices of the penalties with FERC, which may then review and approve the penalties without referring to the FERC civil penalty guidelines.¹²³ The majority of civil penalties for reliability standard violations are levied in this fashion.

Penalties proposed by NERC following a NERC-initiated audit or investigation are governed by NERC's Sanction Guidelines.¹²⁴ The Sanction Guidelines establish a general rule that "[p]enalties and sanctions levied for the violation of a Reliability Standard shall bear a reasonable relation to the seriousness of the violation while also reflecting consideration of the other factors specified in the[] Sanction Guidelines."¹²⁵ In determining the seriousness of the violation, NERC will review the Violation Risk Factors of the Reliability Standard and the Violation Severity Level assessed for the violation.¹²⁶ NERC will also attempt to fashion a fine proportional to the size of the entity which has committed the violation—a large, wealthy entity may therefore be required to pay a larger fine than would a smaller, leaner entity which committed the same violation.¹²⁷

In addition to monetary penalties, NERC "may apply, at its discretion, non-monetary sanctions including limitations on activities, functions, operations, or placement of the violator's name on a reliability watch list of major violators."¹²⁸ NERC's guidelines also emphasize that

¹¹⁹ *Id.*, Audit Report at 4-5.

¹²⁰ EPAct 2005 § 825(a), 119 Stat. at 980 (amending FPA § 316A, 16 U.S.C. § 825o-1).

¹²¹ Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 575.

¹²² *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216 at P 4 (2010).

¹²³ FERC's Penalty Guidelines are found in *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216.

¹²⁴ NERC Rules of Procedure, Appendix 4B (Sanction Guidelines).

¹²⁵ *Id.* § 2.3.

¹²⁶ *Id.* § 3.1.

¹²⁷ *See id.* § 2.6.

¹²⁸ *Id.* § 2.12.

possible or alleged violations may be “resolved through settlements” reached between NERC and the entity alleged to have committed the violation.¹²⁹

For civil penalties imposed following a FERC-initiated audit or investigation, Chapter 2 of FERC’s Penalty Guidelines (“Guideline for Violations of Commission-Approved Reliability Standards”) identifies two factors which the Commission will take into account.¹³⁰ First, the Commission will consider the risk of loss or harm that was created by the reliability violation.¹³¹ The Commission considers both the likelihood and severity of such risk. Second, the Commission will consider whether and how much loss of firm load the violation caused.¹³² The Commission has explained, however, that “[w]hen an underlying violation requires an operator to shed load pursuant to a Reliability Standard as a necessary means to avoid a further risk to the Bulk-Power System, the operator’s decision to shed load is not itself a violation and no penalty would be sought for that decision.”¹³³ Nevertheless, “the fact that the underlying violation required load shedding will be considered in assessing the risk created by the underlying violation.”¹³⁴

In addition to monetary civil penalties, FERC also has the authority to impose non-monetary penalties for violations of reliability rules. In its *Enforcement Policy Statement*, the Commission explained that its “enhanced civil penalty authority [under EPCA 2005] . . . operate[s] in tandem with [its] existing authority to require disgorgement of unjust profits obtained through misconduct and/or to condition, suspend, or revoke . . . market-based rate authority for sellers of electric energy.”¹³⁵ The Commission further explained that it “take[s] the full range of possible remedies into account in determining whether a penalty should be imposed in addition to other remedies and, if so, the appropriate amount of the penalty.”¹³⁶

In general, civil penalties issued through a NERC-initiated investigation or audit are smaller than those likely to be issued following a FERC-initiated reliability investigation or audit. However, NERC-imposed penalties are much more common. NERC maintains a spreadsheet tracker of Notices of Penalties issued for reliability violations on its website.¹³⁷ In 2013, NERC issued 1,065 Notices of Penalties, with an average fine amount of \$95,000. FERC also maintains on its website a list of civil penalties including those issued for reliability

¹²⁹ *Id.* § 2.1.

¹³⁰ FERC’s Penalty Guidelines distinguish reliability violations from economic violations and violations involving making false statements to the Commission, for which penalties are governed by other factors.

¹³¹ Penalty Guidelines § 2.

¹³² *Id.*

¹³³ *Id.* § 2A1.1, cmt. appl. Note 4.

¹³⁴ *Id.*

¹³⁵ *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 at P 12 (2005).

¹³⁶ *Id.*

¹³⁷ See NERC, Enforcement and Mitigation, <http://www.nerc.com/pa/comp/CE/Pages/Enforcement-and-Mitigation.aspx>.

violations.¹³⁸ From the beginning of 2009 to the end of 2013, FERC imposed civil penalties in eight reliability cases through stipulation and consent agreements. These civil penalties ranged from \$50,000 to \$25 million.¹³⁹

FERC is more likely to commence its own investigation and pursue civil penalties in situations where there has been a significant loss of load or a significant system disturbance.¹⁴⁰ In such investigations, FERC staff will consider, among other things, whether utilities complied with load balancing rules, communications rules, emergency preparedness standards, protection and control standards, transmission operations standards, transmission planning standards, and personnel performance and training standards.¹⁴¹ FERC is likely to seek both civil penalties and to request that the utilities agree to take specific reliability improvement measures. The responsible utility may be required to enhance its training and certification requirements, improve its disturbance response systems performance, improve its emergency operating procedures, and enhance equipment inspection and maintenance practices.

FERC may also, however, impose civil penalties even for less serious reliability violations and require associated mitigation plans.¹⁴²

¹³⁸ See FERC, Civil Penalties, <http://www.ferc.gov/enforcement/civil-penalties.asp>.

¹³⁹ See *id.*

¹⁴⁰ *In re Cal. Indep. Sys. Operator Corp.*, 141 FERC ¶ 61,209 (2012) (approving a stipulation and consent agreement requiring CAISO to pay a \$200,000 civil penalty following a load shedding event and stating that the ISO had not conducted adequate operational planning to replace generation requirements and had not adequately trained operators on load shedding requirements); *PacifiCorp*, 137 FERC ¶ 61,176 (2011) (approving stipulation and consent agreement requiring utility to pay civil penalty of \$3.9 million following a load shedding event where FERC and NERC alleged twenty-three violations of fifteen reliability standards); *Fla. Blackout*, 130 FERC ¶ 61,163 (2010) (approving a stipulation and consent agreement requiring utility to pay an additional \$350,000 civil penalty for additional alleged reliability violations involving the same blackout, including failure to use three-way repeat procedures under COM-002 and for operating a substation in an unknown state); *Fla. Blackout*, 129 FERC ¶ 61,016 (2009) (approving a stipulation and consent agreement requiring utility to pay a \$25 million civil penalty following a blackout, where FERC staff had alleged that the utility violated various reliability rules including, *inter alia*, resource balancing rules, emergency preparedness rules, personnel training and qualification rules, and protection and control rules).

¹⁴¹ See *Fla. Blackout*, 129 FERC ¶ 61,016 at PP 9-16.

¹⁴² *Entergy Servs.*, 142 FERC ¶ 61,241 (alleged violations include, *inter alia*, facilities ratings methodology and transmission system modeling practices protocols); *Grand River Dam Auth.*, 136 FERC ¶ 61,132 (2011) (alleged violation include, *inter alia*, lack of redundant communication systems, the failure to test alarms, a lack of qualified training staff, and the failure to notify reliability coordinator neighbors when carriers on its system were out of service); *Western Elec. Coordination Council*, 136 FERC ¶ 61,020 (2011) (alleged violations include, *inter alia*, standards relating to the use of emergency alerts, communications rules, and special protection system models).

Chapter 8

FERC's Affiliate Rules

GERALD RICHMAN

FERC maintains three basic sets of rules governing affiliate relations in the electric industry. First, the “Standards of Conduct for Transmission Providers” (the “Standards of Conduct” or “Standards”)¹ govern the relationship between electric transmission providers and their affiliated wholesale power marketing functions.² Second, the “Affiliate Restrictions”³ govern the relationship between franchised public utilities with captive customers and their unfranchised wholesale power marketing affiliates with market-based rates. Finally, the “Affiliate Cross-Subsidization Rules”⁴—often referred to as the “Asymmetrical Pricing Rules”—govern transactions involving *non-power* goods and services between franchised public utilities with captive customers and *all* affiliates (i.e., *regardless* of the affiliate’s line of business).

FERC’s Office of Enforcement historically has closely focused on compliance with these rules and standards, although in recent years Enforcement has shifted substantial resources to

¹ The current version of FERC’s Standards of Conduct was promulgated in *Standards of Conduct for Transmission Providers*, Order No. 717, FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh’g and clarification*, Order No. 717-A, FERC Stats. & Regs. ¶ 31,297, *order on reh’g and clarification*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh’g and clarification*, Order No. 717-C, 131 FERC ¶ 61,045 (2010), *order on reh’g and clarification*, Order No. 717-D, 135 FERC ¶ 61,017 (2011) (codified at 18 C.F.R. pt. 358).

² The Standards of Conduct also apply to the relationship between interstate natural gas pipelines and their affiliated wholesale gas marketing functions. While this chapter focuses on the electric industry, we also include discussion of gas cases that appear relevant to FERC’s application of the Standards of Conduct on the electric side.

³ The current version of FERC’s Affiliate Restrictions was promulgated in *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh’g and clarification*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *order on reh’g and clarification*, 124 FERC ¶ 61,055, *order on reh’g and clarification*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh’g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh’g and clarification*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305, *order on clarification*, 131 FERC ¶ 61,021 (2010), *reh’g denied*, 134 FERC ¶ 61,046 (2011), *aff’d sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012) (codified at 18 C.F.R. § 35.39).

⁴ The current version of FERC’s Affiliate Cross-Subsidization Rules was promulgated in *Cross-Subsidization Restrictions on Affiliate Transactions*, Order No. 707, FERC Stats. & Regs. ¶ 31,264, *order on reh’g and clarification*, Order No. 707-A, FERC Stats. & Regs. ¶ 31,272 (2008) (codified at 18 C.F.R. § 35.44).

investigations of market manipulation and reliability violations,⁵ with a commensurate reduction in focus on inter-affiliate relations. Further, industry changes may have lessened somewhat the importance of these rules. For example, transmission providers who have ceded operational control of their transmission facilities to Regional Transmission Organizations or Independent System Operators have less exposure to Standards of Conduct violations. Similarly, franchised public utilities operating in retail access states have had success obtaining waivers from the Affiliates Restrictions on the grounds that they do not have captive customers.⁶

Notwithstanding these developments, FERC's affiliate rules still can result in Enforcement investigations⁷ and audits.⁸ For example, even if a transmission provider turns over operational control of its system to a Commission-approved RTO or ISO, the transmission provider remains subject to the Standards of Conduct to the extent that it continues to have access to non-public transmission function information.⁹ As discussed below, such access can create compliance issues, even in an RTO/ISO context. Similarly, the Affiliate Restrictions remain applicable to all franchised public utilities in non-retail access states, and even a franchised utility in a retail access state must first secure a waiver in order to escape application of the Affiliate Restrictions. Finally, while there have been no recent public Enforcement investigations involving the Affiliate Cross-Subsidization Rules, cross-subsidization remains a focus of Enforcement's Division of Audits.¹⁰

The following is a detailed description of each of these important rules regulating affiliate relationships.

⁵ See Chapters 4 and 7.

⁶ See, e.g., *Pub. Serv. Elec. & Gas Co.*, 134 FERC ¶ 61,138 (2011); *NSTAR Elec. Co.*, 131 FERC ¶ 61,097 (2010); *Duke Energy Retail Sales, LLC*, 127 FERC ¶ 61,027 (2009); *Sunbury Generation, LLC*, 108 FERC ¶ 61,160 (2004); *Potomac Power Res., Inc.*, 93 FERC ¶ 61,246 (2000). Prior to Order No. 697, what are now referred to as the Affiliate Restrictions were embodied in "Codes of Conduct" contained in individual FERC-approved market-based rate tariffs. Some of the waiver orders cited in this footnote refer to the Codes of Conduct rather than the currently codified Affiliate Restrictions.

⁷ See, e.g., *Alliance Pipeline L.P.*, 141 FERC ¶ 61,182 (2012) (assessing civil penalties for Standards of Conduct violations).

⁸ See, e.g., *Ariz. Pub. Serv. Co.*, Docket No. PA11-1-000, Audit Report (Dec. 20, 2011); *Pepco Holdings, Inc.*, Docket No. FA10-1-000, Audit Report (May 2, 2011); *Avista Corp.*, Docket No. PA07-2-000, Audit Report (July 16, 2008); *Puget Sound Energy, Inc.*, Docket No. PA07-1-000, Audit Report (July 16, 2008); *Portland Gen. Elec. Co.*, PA06-9-000, Audit Report (July 16, 2008); *Kan. City Power & Light Co.*, Docket No. PA06-6-000, Audit Report (Nov. 27, 2007).

⁹ 18 C.F.R. § 358.1(c).

¹⁰ See, e.g., *Southern Co.*, Docket No. FA12-1-000, Audit Report (May 28, 2013); *NiSource Inc.*, Docket No. FA11-5-000, Audit Report (Oct. 24, 2012); *Progress Energy, Inc.*, Docket No. FA11-6-000, Audit Report (Sept. 20, 2012); *MidAmerican Energy Holdings Co.*, Docket No. FA11-3-000, Audit Report (Jan. 5, 2012); *Pepco Holdings, Inc.*, Docket No. FA10-1-000, Audit Report (May 2, 2011); *Allegheny Energy, Inc.*, Docket No. FA08-3-000 (Nov. 13, 2008); *Exelon Corp.*, Docket No. FA08-4-000, Audit Report (Sept. 29, 2008).

FERC'S AFFILIATE RULES

I. THE STANDARDS OF CONDUCT

The Standards of Conduct are designed to “ensure that transmission providers cannot extend their market power over transmission by giving marketing affiliates undue preferential treatment.”¹¹ The “core abuse” at which this regulation is aimed is “undue preference in favor of an affiliate (defined to include divisions of the transmission provider as well as separate corporate entities), ...”¹² More basically, the Standards are intended to ensure that a transmission provider’s “transmission function employees” (a defined term, *see infra*) take no action that improperly benefits “marketing function employees” (likewise, a defined term) working in any business organization affiliated with the transmission provider.¹³ To implement this goal, the Standards spell out four general principles:

- (1) A transmission provider must treat all transmission customers, affiliated and non-affiliated, on a not unduly discriminatory basis, and must not make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage with respect to any transportation or sale of energy in interstate commerce.¹⁴
- (2) A transmission provider’s transmission function employees must function independently from its marketing function employees.¹⁵ These terms are defined below.
- (3) A transmission provider and its employees, contractors, consultants and agents are prohibited from disclosing, or using a conduit to disclose, non-public transmission function information (defined below) to the transmission provider’s marketing function employees.¹⁶
- (4) With some exceptions mentioned below, a transmission provider must provide equal access to non-public transmission function information to all its transmission customers, affiliated and non-affiliated.¹⁷

¹¹ *Sawgrass Storage, L.L.C.*, 138 FERC ¶ 61,180 at P 49 (2012), *vacated on other grounds*, 146 FERC ¶ 61,133 (2014).

¹² Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 23. This was also the core abuse at which the pre-Order No. 717 Standards of Conduct were directed. *See, e.g., Alcoa Power Generating Inc.*, 108 FERC ¶ 61,243 at P 155 (2004); *Carolina Power & Light Co.*, 97 FERC ¶ 61,063 at 61,350 (2001).

¹³ Under the Standards, an “[a]ffiliate of a specified entity means . . . [a]nother person that controls, is controlled by or is under common control with, the specified entity.” 18 C.F.R. § 358.3(a)(1). In addition, an “[a]ffiliate includes a division of the specified entity that operates as a functional unit.” *Id.*

¹⁴ *Id.* § 358.2(a).

¹⁵ *Id.* § 358.2(b).

¹⁶ *Id.* § 358.2(c).

¹⁷ *Id.* § 358.2(d).

A. STRICT TARIFF ENFORCEMENT REQUIREMENT

To implement the first principle—that all transmission customers be treated equally and without undue discrimination—the Standards create four specific operational requirements for transmission providers with affiliated marketing functions:

- The transmission provider must strictly enforce all tariff provisions relating to the sale or purchase of open access transmission service, if the tariff provisions do not permit the use of discretion.¹⁸
- The transmission provider must apply all tariff provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all transmission customers in a not unduly discriminatory manner, if the tariff provisions permit the use of discretion.¹⁹
- The transmission provider may not, through its tariffs or otherwise, give undue preference to any person in matters relating to the sale or purchase of transmission service.²⁰
- The transmission provider must process all similar requests for transmission in the same manner and within the same period of time.²¹

These four operation requirements track the non-discrimination requirements, imposed on *all* transmission providers, discussed in Chapter 9.

B. INDEPENDENT FUNCTIONING

A transmission provider's transmission function employees must function independently of its marketing function employees,²² except in emergency circumstances.²³ A transmission

¹⁸ *Id.* § 358.4(a).

¹⁹ *Id.* § 358.4(b).

²⁰ *Id.* § 358.4(c).

²¹ *Id.* § 358.4(d).

²² *Id.* § 358.5(a).

²³ Order No. 717-A, FERC Stats. & Regs. ¶ 31,297 at P 116. Companies should note that this discussion of emergency circumstances in Order No. 717-A by its terms focuses on *communications* with marketing function employees rather than the independent functioning requirement. Moreover, the provisions in the current Standards of Conduct that apply to emergencies—or information necessary to maintain or restore operations of the transmission system or generation units or that may affect the dispatch of generating units—also explicitly only discuss communications. 18 C.F.R. § 358.7(g)(2), (h)(2)(ii). The current Order No. 717 Standards of Conduct do not contain a precise counterpart to *old* section 358.4(a)(2) of the Order No. 2004, *infra* note 33, Standards (18 C.F.R. § 358.4(a)(2) (2006)), which provided an across-the-board emergency exception from the independent functioning requirement. No order in the Order No. 717 series explicitly discusses this language change. However, the notice of

provider is prohibited from permitting its marketing function employees to conduct transmission functions or have access to the system control center or similar facilities used for transmission operations that differs in any way from the access available to other transmission customers.²⁴ Similarly, a transmission provider is prohibited from permitting its transmission function employees to conduct marketing functions.²⁵

A transmission function employee is “an employee, contractor, consultant or agent of a transmission provider *who actively and personally engages on a day-to-day basis in transmission functions.*”²⁶ A “Transmission function,” in turn, involves “planning, directing, organizing or carrying out of *day-to-day transmission operations*, including the granting and denying of transmission service requests.”²⁷ Because of the “day-to-day” limitation, “[l]ong range planning regarding the transmission system” is not a transmission function, and “employees engaged in such long-range planning, *provided they [are] not also actively and personally involved in the day-to-day operation of the transmission system*, [are] not . . . considered transmission function employees.”²⁸

Similarly, a marketing function employee is “an employee, contractor, consultant or agent of a transmission provider or of an affiliate of a transmission provider *who actively and personally engages on a day-to-day basis in marketing functions.*”²⁹ “Marketing functions are “the sale for resale in interstate commerce, or the submission of offers to sell in interstate

proposed rulemaking that led to the Order No. 717 Standards of Conduct—*Standards of Conduct for Transmission Providers; Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,630 (2008) (“Order No. 717 NOPR”)—contained an Appendix B with a side-by-side comparison of the Order No. 2004 Standards and the proposed new Standards ultimately adopted in Order No. 717. From the discussion in the table of the proposed revision of old section 358.4(a)(2), Order No. 717 NOPR, FERC Stats. & Regs. ¶ 32,630 at 33,630, it does not appear that FERC intended to revoke the overall exception to independent functioning in emergency situations. However, any exception to independent functioning based on a system emergency will be subject to strict FERC scrutiny.

²⁴ 18 C.F.R. § 358.5(b)(1).

²⁵ *Id.* § 358.5(b)(2). To safeguard independent functioning, a transmission provider must maintain its books of account and records separately from those of affiliates (other than functional business divisions within the transmission provider) that employ or retain marketing function employees, and the books and records must be available for Commission inspections. *Id.* § 358.8(d). While FERC has clarified that a “functional unit” of a transmission provider that performs marketing functions is not required to keep its books separate from those of the transmission provider, FERC emphasizes that the no-conduit rule (discussed below) “prohibits a transmission provider from allowing non-public transmission function information to be disclosed to marketing function employees through a joint set of books and records.” Order No. 717-A, FERC Stats. & Regs. ¶ 31,297 at P 124.

²⁶ 18 C.F.R. § 358.3(i) (emphasis added).

²⁷ *Id.* § 358.3(h) (emphasis added). “Transmission” itself means “electric transmission, network or point-to-point service, ancillary services or other methods of electric transmission, or the interconnection with jurisdictional transmission facilities.” *Id.* § 358.3(f).

²⁸ Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 146 (emphasis added).

²⁹ 18 C.F.R. § 358.3(d) (emphasis added).

commerce, of electric energy or capacity, demand response, virtual transactions, or financial or physical transmission rights”³⁰ The marketing function definition by its terms does not include asset purchases, and FERC explicitly refused requests during the Order No. 717 proceeding to add power purchases to the definition.³¹ Further, generation dispatch (absent a sales component) is not itself “inherently” a marketing function.³²

The focus of the independent functioning analysis is on the employee and his or her function, not on the employee’s job title or organization. Prior to Order No. 717, the Standards of Conduct issued under Order No. 2004³³ imposed corporate separation between “energy affiliates” rather than separation between transmission and marketing functions. Over time, however, FERC found that a corporate separation rule made it difficult for companies to transact needed business because (with some exceptions) such a rule required all employees of a marketing affiliate or division to be walled off from the transmission provider’s transmission function employees.³⁴ Therefore, in Order No. 717 the Commission adopted an employee “functional approach” and eliminated the concept of energy affiliates.³⁵

On its face, the functional approach to independent functioning is straight forward—an employee is either a transmission function employee, a marketing function employee, or an employee who falls outside *both* of those definitions. Further, an employee that is neither a transmission function employee nor a marketing function employee is not captured by the independent functioning requirement.³⁶ However, an employee’s status under the Standards *always* is a factual question based on what the employee actual does. Difficulties can arise with

³⁰ *Id.* § 358.3(c). The definition of marketing excludes bundled retail sales, including sales of electric energy made by providers of last resort (“POLRs”) acting in their POLR capacity. *Id.*

³¹ Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 77.

³² *Id.* at P 175.

³³ *Standards of Conduct for Transmission Providers*, Order No. 2004, FERC Stats. & Regs., ¶ 31,155 (2003), *order on reh’g*, Order No. 2004-A, FERC Stats. & Regs. ¶ 31,161, *order on reh’g*, Order No. 2004-B, FERC Stats. & Regs. ¶ 31,166, *order on reh’g*, Order No. 2004-C, FERC Stats. & Regs. ¶ 31,172 (2004), *order on reh’g and clarification*, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), *vacated and remanded as applied to natural gas pipelines sub nom. Nat’l Fuel Gas Supply Corp. v. FERC*, 468 F.3d 831 (D.C. Cir. 2006) (previously codified at 18 C.F.R. pt. 358).

³⁴ Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 123.

³⁵ *Id.* at P 12. In fact, Order No. 717 *readopted*, with some distinctions, the functional approach that the Commission utilized with the original electric Standards of Conduct promulgated in *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh’g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049, *reh’g denied*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *aff’d in substantial part sub nom. Transmission Access Policy Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff’d sub nom. New York v. FERC*, 535 U.S. 1 (2002) (codified at 18 C.F.R. pt. 37). See Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 2.

³⁶ *Id.* at PP 123, 129. As will be discussed in the section on information access and disclosure under the Standards, *all* employees, regardless of their job functions, at all times are subject to the no-conduit rule regarding information disclosure, see below.

employees who have broad oversight or support responsibilities, such as board members; senior officers; accountants; risk managers; engineering and maintenance personnel; rate design employees; and attorneys. Such persons regularly may interact with either transmission function employees, marketing function employees or both. FERC has not provided post-Order No. 717 guidance with respect to when such employees might become subject to the independent functioning rule.

Prior to Order No. 717, the Order No. 889 and Order No. 2004 Standards of Conduct each had a concept of permissibly “shared” employees who did not “direct, organize, or execute” *either* transmission operations or reliability functions or “wholesale merchant functions”³⁷ or were not “operating employees.”³⁸ Order No. 717, by employing a strictly functional approach, eliminated the “shared” employee concept as “unnecessary.”³⁹ It appears clear, however, that once an individual starts engaging in day-to-day transmission or marketing functions *in addition* to his/her regular job, that individual will be covered by the independent functioning requirement.⁴⁰ Moreover, as discussed in the following subsection, an employee who becomes a marketing function employee must be cut off from access to non-public transmission information.

C. INFORMATION DISCLOSURE AND ACCESS RESTRICTIONS

The Commission holds that “in order to remedy undue discrimination in the provision of transmission services it is necessary to have non-discriminatory access to transmission information, ...”⁴¹ From their initial inception in Order No. 889, one central purpose of the

³⁷ See generally *Am. Elec. Power Serv. Corp.*, 81 FERC ¶ 61,332 at 62,513 (1997) (“AEP”), *order on reh’g and clarification*, 82 FERC ¶ 61,131 (1998).

³⁸ See generally Order No. 2004, FERC Stats. & Regs. ¶ 31,155 at PP 95-112.

³⁹ Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 129. As will be discussed below, the concept of permissibly “shared” employees was retained in the Affiliate Restrictions codified by Order No. 697.

⁴⁰ Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 131 (the determination of whether employees are subject to the Independent Functioning Rule “depends on [whether] such employees function in their stated roles, or do they also actively and personally perform day-to-day transmission functions or marketing functions”). *C.f.* Order No. 2004-B, FERC Stats. & Regs. ¶ 31,166 at P 74 (to the extent that a lawyer, in addition to his or her traditional role, conducts transmission functions, “s/he is dedicated to that function”). While the functional-based Order No. 717 Standards have replaced the Order No. 2004 Standards, this discussion from Order No. 2004-B remains relevant because it is focused on actual job functions.

⁴¹ *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,722 (1996), *clarified*, 76 FERC ¶ 61,009 (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 (1998), *aff’d in substantial part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, *aff’d sub nom. New York v. FERC*, 535 U.S. 1 (2002) (codified at 18 C.F.R. § 35.28).

Standards of Conduct has been “to prevent the utility from giving its merchant arm preferential access to transmission information.”⁴²

“Transmission function information” in this context means any “information relating to transmission functions.”⁴³ That is obviously an extremely broad definition, and FERC has not provided an exhaustive list of what information (if non-public) cannot be disclosed to or accessed by marketing function employees. At a *minimum*, however, transmission function information includes information concerning:

- Physical power flows.⁴⁴
- Transmission loading relief⁴⁵
- Transmission outages or other system conditions.⁴⁶
- Balancing load with energy or capacity.⁴⁷
- Available transmission capability.⁴⁸
- Granting or denying of transmission service requests (including interconnection requests).⁴⁹
- Day-to-day system operations.⁵⁰
- Sales of ancillary services under an Open Access Transmission Tariff to transmission customers.⁵¹

⁴² *Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power Sys.; Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,641 at P 5, *final rule*, Order No. 729, 129 FERC ¶ 61,155 (2009), *order on reh’g*, Order No. 729-A, 131 FERC ¶ 61,109, *order on reh’g and reconsideration*, Order No. 729-B, 132 FERC ¶ 61,027 (2010).

⁴³ 18 C.F.R. § 358.3(j).

⁴⁴ Order No. 717, FERC Stats. & Regs. ¶ 31,280 at P 122.

⁴⁵ *See id.*

⁴⁶ *Id.* at P 239.

⁴⁷ *Id.* at P 122

⁴⁸ *Id.* at P 275.

⁴⁹ 18 C.F.R. § 358.3(h); Order No. 717, FERC Stats. & Regs. ¶ 31,280 at PP 122, 276.

⁵⁰ *Id.* at PP 40, 122.

⁵¹ *Id.* at PP 78, 263.

The Standards restrict information sharing through two rules, the “no conduit rule” and the “transparency rule.” Under the no conduit rule, “[a] transmission provider is prohibited from using anyone as a conduit for the disclosure of *non-public* transmission function information to its marketing function employees.”⁵² Under the no conduit rule:

- Transmission function employees cannot disclose non-public transmission function information to marketing function employees.
- Non-marketing function employees with access to non-public transmission function information cannot disclose that information to marketing function employees.
- A marketing function employee who obtains access to non-public transmission function information must not disseminate that information to other marketing function employees.⁵³

Turning to the transparency rule, that rule provides (subject to certain exceptions) that if a transmission provider discloses non-public transmission function information in a manner “contrary” to the no-conduit rule, the transmission provider must *immediately* post the information that was disclosed on its public Internet website.⁵⁴

Companies should be aware that, absent certain exceptions discussed below, the Standards by their terms create an absolute bar against dissemination of *non-public* transmission function information to marketing function employees. While the absence of commercial value to the information may be a mitigating factor, the Commission has never held that the absence of commercial value precludes a finding that improper access or disclosure is a violation.

Improper access or disclosure can be a particular problem for transmission providers that have joined RTOs and ISOs. While Commission-approved RTOs and ISOs themselves are (in their capacity as transmission providers) explicitly exempted from the Standards of Conduct,⁵⁵ a public utility transmission owner that participates in the RTO or ISO remains covered unless it establishes through a waiver request *both* that it (a) does not operate or control its transmission system *and* (b) has no access to transmission function information.⁵⁶ Of course, transmission provider members of RTOs/ISOs in reality often still employ transmission function employees and other employees with legitimate access to non-public transmission function information.

⁵² 18 C.F.R. § 358.6(a) (emphasis added).

⁵³ *See id.* § 358.6(b).

⁵⁴ *Id.* § 358.7(a). If improperly disclosed information was either non-public transmission customer information, critical energy infrastructure information as defined in 18 C.F.R. § 388.113(c)(1), “or any other information that the Commission by law has determined is to be subject to limited dissemination,” the transmission provider must immediately post *notice* on its website that the information was disclosed. *Id.* § 358.7(b).

⁵⁵ *Id.* § 358.1(c).

⁵⁶ *Id.*

Such companies in particular should ensure that their employees understand their obligations under the no-conduit and transparency rules.

D. EXCEPTIONS TO THE INFORMATION DISCLOSURE AND ACCESS RESTRICTIONS

As mentioned above, the Standards contain explicit exceptions to the information disclosure and access restrictions. These restrictions are narrowly crafted, and in some cases come with record-keeping requirements. Because the exceptions are narrowly crafted, companies can expect the Commission and its Office of Enforcement to narrowly construe any application of an exception:

- *Exclusion for Specific Transaction Information.* A transmission provider's transmission function employee may discuss with its marketing function employee a specific request for transmission service submitted by the marketing function employee without simultaneously posting the information⁵⁷—but only if the information relates *solely* to the marketing function employee's specific request for transmission service.⁵⁸
- *Voluntary Consent Provision.* A transmission customer may voluntarily consent, in writing, to allow the transmission provider to disclose the transmission customer's non-public information to the transmission provider's marketing function employees. If the transmission customer authorizes the transmission provider to disclose its information to marketing function employees, the transmission provider must post notice of the customer's consent, along with a statement that the transmission provider did not provide any preferences, either operational or rate-related, in exchange for that voluntary consent.⁵⁹
- *Exchanges of Certain Information Related to Reliability or Maintaining or Restoring System Operations.* A transmission provider's transmission function employees and marketing function employees may exchange certain non-public transmission function information (a) pertaining to compliance with FERC-approved reliability standards or (b) necessary to maintain or restore operation of the transmission system or generating units, or that may affect the dispatch of generating units.⁶⁰

⁵⁷ When the Standards refer to posting, this means posting on a transmission provider's public Internet website. The transmission provider may also post the information on its Open Access Same-Time Information System, but is not required to do so. *Id.* § 358.7(g)(1).

⁵⁸ *Id.* § 358.7(b).

⁵⁹ *Id.* § 358.7(c).

⁶⁰ *Id.* § 358.7(h). In such cases, the transmission provider must make and retain a contemporaneous record of all such exchanges except in emergency circumstances, in which case a record must be made of the exchange as soon as practicable after the fact. The transmission provider shall make the record available to the Commission upon request. The record may consist of hand-written or typed notes, electronic records such as e-mails and text messages, recorded telephone exchanges, and the like, and must be retained for a period of five years. *Id.*

E. OTHER REQUIREMENTS

The Standards of Conduct impose various additional requirements. To ensure internal company compliance, a transmission provider must designate and post the name of a chief compliance officer responsible for the Standards of Conduct.⁶¹ The transmission provider must draft, post on the Internet, and distribute Standards of Conduct compliance procedures to all of its transmission function employees, marketing function employees, officers, directors, supervisory employees, and “any other employees likely to become privy to transmission function information.”⁶² In addition, a transmission provider must provide annual training on the Standards to all employees in those categories, and to new employees in those categories within the first 30 days of their employment.⁶³

Next, to further guarantee transparency, the Standards impose additional public Internet posting requirements beyond those previously discussed. First, the transmission provider must post the following company-related information:

- The names and addresses of all its affiliates that employ or retain marketing function employees.⁶⁴
- A complete list of the employee-staffed facilities shared by any of the transmission provider’s transmission function employees and marketing function employees. The list must include the types of facilities shared and the addresses of the facilities.⁶⁵
- Information concerning potential merger partners as affiliates that may employ or retain marketing function employees, within 7 days after the potential merger is announced.⁶⁶
- The job titles and job descriptions of its transmission function employees.⁶⁷
- Notice of any transfer of a transmission function employee to a position as a marketing function employee, or any transfer of a marketing function employee to a position as a transmission function employee. The information must remain posted for 90 days.⁶⁸

⁶¹ *Id.* § 358.8(c)(2).

⁶² *Id.* §§ 358.7(d), 358.8(b).

⁶³ *Id.* § 358.8(c)(1). The transmission provider must require each employee who has taken the training to certify electronically or in writing that s/he has completed the training. *Id.*

⁶⁴ *Id.* § 358.7(e)(1).

⁶⁵ *Id.* § 358.7(e)(2).

⁶⁶ *Id.* § 358.7(e)(3).

⁶⁷ *Id.* § 358.7(f)(1).

⁶⁸ *Id.* § 358.7(f)(2). The information must include the name of the transferring employee, the

The transmission provider must update all informational postings required by the Standards of Conduct within 7 business days of any change, and post the date on which the information was updated.⁶⁹

II. THE AFFILIATE RESTRICTIONS

A. BASIC REQUIREMENTS

Prior to Order No. 697, FERC required that companies seeking market-based rate authority submit—as part of their proposed market-based rate tariff—a “Code of Conduct” governing relations between the franchised public utility and its affiliated power marketers. The Commission reviewed these company-specific Codes of Conduct on a case-by-case basis. Over a period of time, the various Codes tended to become standardized in response to Commission orders reviewing prior Code of Conduct filings. Ultimately, the Commission published a “model” Code of Conduct and informed sellers that the Commission would reject Codes inconsistent with the model.⁷⁰ Finally, in Order No. 697, FERC codified into its regulations a revised version of the model Code, now referred to as the Affiliate Restrictions.⁷¹ Adherence to the Affiliate Restrictions is a condition of obtaining and retaining market-based rate authority, and failure to adhere is deemed a tariff violation.⁷²

As with the Codes of Conduct they replaced, the Affiliate Restrictions are designed “to ensure that franchised public utility sellers with captive customers will not be able to engage in affiliate abuse to the detriment of those captive customers.”⁷³ Under the Affiliate Restrictions, a

respective titles held while performing each function (i.e., as a transmission function employee and as a marketing function employee), and the effective date of the transfer. *Id.* FERC cautions that job transfers must not be used as means to circumvent the Standards of Conduct. *Id.*

⁶⁹ *Id.* § 358.7(g)(1). In the event that an emergency, such as an earthquake, flood, fire or hurricane, severely disrupts a transmission provider’s normal business operations, the transmission provider may suspend Standards of Conduct posting requirements. *Id.* § 358.7(g)(2). If the disruption lasts longer than one month, the transmission provider must so notify the Commission and may seek a further exemption from the posting requirements. *Id.*

⁷⁰ See *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*; *Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,602 at PP 120-21 (2006).

⁷¹ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 467.

⁷² 18 C.F.R. § 35.39(a).

⁷³ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 583. It is important to understand that FERC’s Affiliate Restrictions and its Standards of Conduct serve different regulatory functions. “The purpose of this separation of functions and the restrictions on the sharing of market information in the market-based rate affiliate restrictions is to guard against the potential for a franchised public utility with captive customers to interact with its market-regulated power sales affiliate in ways that transfer benefits to the affiliate’s stockholders to the detriment of the *captive customers*. By contrast, the purpose of the Standards of Conduct is to prevent transmission providers from giving *undue preference* to their wholesale merchant and/or marketing functions (as well as separate, affiliated corporate entities) over *non-affiliated customers*.” *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity, Ancillary Servs. by Pub. Utils.*, 131 FERC ¶ 61,021 at P 33 (“2010 Clarification Order”) (citation omitted).

captive customer is any wholesale or retail electric energy customer served by a franchised public utility under cost-based regulation.⁷⁴ Captive customers do *not* include “customers who have retail choice, i.e., the ability to select a retail supplier based on the rates, terms and conditions of service offered.”⁷⁵ However, a franchised public utility that believes that it does not have captive customers must nonetheless first seek concurrence from FERC before assuming the Affiliate Restrictions do not apply.⁷⁶

The Affiliate Restrictions place limitations on interactions between public utilities with a franchised service obligation under State law (“franchised public utilities”)⁷⁷ that have captive customers and their “market-regulated power sales affiliates.” This latter term, created by Order No. 697, refers to “any power seller affiliate *other than a franchised public utility*, including a power marketer, exempt wholesale generator, qualifying facility or other power seller affiliate, *whose power sales are regulated in whole or in part on a market-rate basis.*”⁷⁸ Thus, one important difference between the Standards of Conduct and the Affiliate Restrictions is that the Standards govern conduct and communications between affiliated transmission and marketing functions, even when those functions are housed within a single franchised utility; whereas the Affiliate Restrictions do not apply to interactions or information sharing within a single public utility, or even between affiliate franchised utilities. Rather, the Affiliate Restrictions *only* apply to interactions between a franchised utility with captive customers and its market regulated power sales affiliate.⁷⁹

B. SEPARATION OF FUNCTIONS

The separation of functions requirement in the Affiliate Restrictions is similar, but not identical, to the Standards of Conduct independent functioning requirement. The Affiliate Restrictions provide that “[t]o the maximum extent practical,” employees of a market-regulated power sales affiliate must operate separately from employees of any affiliated franchised public utility with captive customers.⁸⁰ It will be noted that, unlike the current Standards of Conduct,

⁷⁴ 18 C.F.R. § 35.36(a)(6). As discussed *infra*, the definition of captive customers under the Order No. 707 Affiliate Cross-Subsidization rules are somewhat different than the definition of captive customers under the Order No. 697 Affiliate Restrictions.

⁷⁵ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 479; *see id.* at P 478.

⁷⁶ *See generally id.* at P 551.

⁷⁷ 18 C.F.R. § 35.36(a)(5).

⁷⁸ *Id.* § 35.36(a)(7) (emphasis added).

⁷⁹ The Affiliate Restrictions presently do not apply to relations between franchised public utilities with captive customers and affiliated franchised public utilities *that do not have captive customers*. However, in Order No. 697 the Commission said that “there may be circumstances in which it also would be appropriate to impose similar restrictions on the relationship of two affiliated franchised public utilities where one of the affiliates has captive customers and one does not have captive customers.” Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 492. FERC will “evaluate whether to impose the affiliate restrictions in such situations on a case-by-case basis.” *Id.* (codified at 18 C.F.R. § 35.39(h)).

⁸⁰ 18 C.F.R. § 35.39(c)(2)(i). The usefulness of the “to the maximum extent practical” proviso

the Affiliate Restrictions' separation of functions requirement is stated in corporate rather than functional terms.⁸¹

The Affiliate Restrictions provide that franchised public utilities with captive customers are permitted to share support employees and field and maintenance employees with their market-regulated power sales affiliates.⁸² Moreover, franchised public utilities with captive customers also are permitted to share senior officers and boards of directors with their market-regulated power sales affiliates *as long as* the shared officers and boards of directors do not "participate in directing, organizing or executing generation or market functions."⁸³

The Affiliate Restrictions do not define the concept of "directing, organizing or executing generation or market functions." The phrase "directing, organizing or executing"—sometimes colloquially referred to as "DOE"—itself originated with FERC's implementation of the Standards of Conduct issued under Order No. 889. FERC then held that "[t]o meet the functional unbundling requirement, the employees, officers or directors of the transmission provider who are engaged in transmission system operations (that is, participate in directing, organizing or executing transmission system operations or reliability functions) cannot engage in wholesale merchant functions (that is, participate in directing, organizing or executing wholesale merchant functions)."⁸⁴ The Commission never defined the DOE concept in the Standards of Conduct context. However, it appears to have served as the genesis for the Standards' current concept of "active[] and personal[] engage[ment] on a day-to-day basis" in marketing or transmission functions. This strongly suggests that, under the Affiliate Restrictions, senior officers and board members cannot be shared between franchised public utilities and their market-regulated power sales affiliates if they are actively and personally involved on day-to-day basis in either generation dispatch or market functions.⁸⁵

is unclear at best. FERC has yet to identify any situations where, absent a waiver, employees not subject to explicit regulatory exceptions (see below) may be shared.

⁸¹ With respect to the separation of functions requirement, "entities acting on behalf of and for the benefit of a franchised public utility with captive customers (such as entities controlling or marketing power from the electrical generation assets of the franchised public utility) are considered part of the franchised public utility. Entities acting on behalf of and for the benefit of the market-regulated power sales affiliates of a franchised public utility with captive customers are considered part of the market-regulated power sales affiliates." *Id.* § 35.39(c)(1). Moreover, FERC requires that companies proposing to merge must treat each other as affiliates under the Affiliate Restrictions (and must identify such entities as affiliates under their market-based rate tariffs) from the date a merger is announced. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 501.

⁸² 18 C.F.R. § 35.39(c)(2)(ii).

⁸³ *Id.*

⁸⁴ *AEP*, 81 FERC ¶ 61,332 at 62,513 & n.19 (citing Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,599).

⁸⁵ *C.f. Entergy Servs., Inc.*, 136 FERC ¶ 61,218 at P 20 (2011) (granting waiver for certain joint operations by employees of Entergy Corporation's franchised and market-regulated nuclear fleets in part on the representation that certain relevant shared senior officers "are engaged in corporate oversight and

Regarding “shared support staff” under the Affiliate Restrictions, the Commission does not provide a complete list. At a minimum, however, “[s]uch employees include those in legal, accounting, human resources, travel and information technology.”⁸⁶ Unlike the case of shared officers and directors, the provision for shared support employees is not followed by the proviso that they not “participate in directing, organizing or executing generation or market functions.” Nonetheless, it appears reasonable (and prudent) to read such a proviso into the regulation. In Order No. 697, the Commission stated that generally “the types of permissibly shared support employees under the [S]tandards of [C]onduct are the types of permissibly shared employees that will be allowed under the [A]ffiliate [R]estrictions. . . .”⁸⁷ At the time both Order Nos. 697 and 697-A were issued, the Order No. 2004 Standards of Conduct still were in effect. The Order No. 2004 Standards contained an exception for shared support employees, but excluded from the exception employees who (a) executed or approved power sales agreements, transmission service or interconnection agreements; (b) exercised discretion in tariff administration; or (c) engaged in day-to-day transmission system operations.⁸⁸ This strongly suggests that permissibly shared support employees under the Affiliate Restrictions likewise cannot conduct DOE functions.

Turning to field and maintenance employees, in Order No. 697, FERC stated that such employees “perform purely manual, technical or mechanical duties that are supportive in nature and do not have planning or direct operational responsibilities.”⁸⁹ In particular, “[a] field or maintenance employee cannot be shared if that employee also engages in marketing activities, makes decisions that would affect marketing activities, or controls generation.”⁹⁰ The immediate supervisors of field and maintenance employees can be shared “so long as they cannot control operations, *e.g.* restrict or shut down generation facilities.”⁹¹ In Order No. 697-A, the Commission further clarified that field and maintenance employees includes “technical and engineering personnel engaged in generation-related activities, provided that such employees do not themselves: (1) [b]uy or sell energy; (2) make economic dispatch decisions; (3) determine (as opposed to implement) outage schedules; or (4) engage in power marketing activities.”⁹² The Commission further clarified that companies may share employees and supervisors who have the authority to curtail or stop the operation of generation facilities “solely for operational reasons,” but such employees “may not be involved in decisions regarding the marketing or sale of

neither perform wholesale power sales activities nor are involved *in the daily functions* of directing, organizing and executing the business decisions of either organization”) (emphasis added).

⁸⁶ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 564.

⁸⁷ *Id.*

⁸⁸ Order No. 2004-A, FERC Stats. & Regs. ¶ 31,161 at P 131.

⁸⁹ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 565.

⁹⁰ *Id.*

⁹¹ *Id.* (footnote omitted).

⁹² Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 251.

electricity from the facilities, may not make economic dispatch decisions, and may not determine the timing of scheduled outages for facilities.”⁹³

Finally, following Order No. 697, the Commission clarified that a franchised public utility with captive customers and its market-regulated power sales affiliates may not share employees that make economic dispatch decisions,⁹⁴ determine the timing of scheduled outages,⁹⁵ engage in resource planning,⁹⁶ or engage in fuel procurement.⁹⁷ While the Commission has granted a number of waivers from these requirements, FERC has done so only on specific showings that captive customers would not be harmed and, at least in some instances, would benefit from the specific employee sharing in question.⁹⁸ Moreover, with respect to joint

⁹³ *Id.* at P 253. Such employees are not precluded from involvement in emergency forced outages. *Id.*

⁹⁴ *2010 Clarification Order*, 131 FERC ¶ 61,021 at P 40.

⁹⁵ *Id.*

⁹⁶ *Id.* at 41. The Commission asserts that “[i]f the franchised public utility and its market-regulated power sales affiliate are permitted to share employees that make strategic decisions about future generation supply, such as deciding when and/or where to build or acquire generating capacity, such strategic decision-making by a shared employee could result in generation being built or acquired for the benefit of the market-regulated power sales affiliate, and at the expense of the captive customers of the franchised public utility. *In this regard, we note that the corporate entity has an inherent incentive to decrease its market-regulated power sales affiliate’s costs in order to maximize profits for shareholders.*” *Id.* (emphasis added).

⁹⁷ *Id.* With respect to fuel procurement, the Commission believes that “a shared employee that procures fuel for both the franchised public utility and the market-regulated power sales affiliate may have the incentive to allocate purchases of lower priced fuel supplies to the market-regulated power sales affiliate while allocating purchases of higher priced fuel supplies to the franchised public utility. By contrast, if the two entities are required to independently procure fuel, they would compete for the market’s best priced fuel.” *Id.* at P 42.

⁹⁸ *Am. Elec. Power Serv. Corp.*, 145 FERC ¶ 61,269 at PP 6, 42-48 (2013) (granting waivers of the information sharing and separation of functions requirements and allowing the provision of operation and maintenance (“O&M”) services to a market-regulated power sales affiliate with respect to a single plant in response to corporate reorganization plan mandated by the relevant State public utility commission); *Am. Elec. Power Serv. Corp.*, 145 FERC ¶ 61,268 at PP 38-44 (2013) (granting waivers to allow (a) shared outage planning and resource allocation services, (b) shared capital spare parts and a centralized machine shop arrangement; and (c) provision of O&M services by franchised public utility to market-regulated power sales affiliate at co-owned plant and joint fuel procurement at the same plant); *Entergy Servs.*, 136 FERC ¶ 61,218 at PP 26-28 (granting waivers to allow (a) shared fuel procurement employees, outage scheduling personnel, and certain unit-specific information with respect to certain co-owned units; and (b) joint fuel procurement and outage schedule across franchised and market-regulated nuclear fleets); *Fla. Power & Light Co.*, 136 FERC ¶ 61,217 at PP 22-25 (2011) (waiver allowing the sharing of nuclear fuel design, procurement, and fabrication functions for franchised and market-regulated nuclear fleets); *FirstEnergy Corp.*, 136 FERC ¶ 61,216 at PP 15-17 (2011) (waiver to allow sharing of employees engaged in fuel procurement, economic dispatch and outage scheduling at jointly-owned facilities); *Va. Elec. & Power Co.*, 136 FERC ¶ 61,215 at PP 29-30 (2011) (granting waiver for shared fuel procurement employees).

resource planning, the length of time FERC devoted to resolving the one waiver request filed thus far suggests particular Commission sensitivity to joint resource planning efforts by franchised public utilities with captive customers and their market-regulated power sales affiliates.⁹⁹

C. MARKET INFORMATION RESTRICTIONS

The Affiliate Restrictions restrict inter-affiliate sharing of market information, and the definition of “market information” under the Affiliate Restrictions is extremely broad:

Market information means non-public information related to the electric energy and power business including, but not limited to, information regarding sales, cost of production, generator outages, generator heat rates, unconsummated transactions, or historical generator volumes. Market information includes information from either affiliates or non-affiliates.¹⁰⁰

The Affiliate Restrictions provide that a franchised public utility with captive customers may not share market information with a market-regulated power sales affiliate if the sharing “*could* be used to the detriment of captive customers,” unless the market information is simultaneously posted on the Internet.¹⁰¹ The “could be used language” was added by Order No.

⁹⁹ Over a period of several years, FERC addressed requests by the Dominion Companies to clarify the scope of the restriction on shared resource planning. First, the Dominion Companies in 2011 sought FERC approval to share all employees involved in what the companies identified as resource planning processes, but FERC rejected that request in early 2013 as too broad in scope. *Va. Elec. & Power Co.*, 142 FERC ¶ 61,103 (2013). In July 2013, the Dominion Companies filed a more narrow resource planning waiver request, with the following representations: First, the waiver would be restricted to nine employees not “responsible on a day-to-day basis for marketing functions” but who would prepare various initial analyses to be handed off to senior decisions makers. Further, the market-regulated power sales affiliates would not build or buy wholesale generation projects in the three states where their affiliated franchised public utility has captive customers. Next, the franchised public utility will have a right of first refusal on *any* wholesale generation project in PJM Interconnection, L.L.C. under consideration by the Dominion Companies. Additionally, to ensure compliance, the Dominion Companies promised to keep documented internal policies outlining the right-of-first-refusal processes for both generation project development and wholesale sales opportunities. In addition, ratepayer-focused evaluations for generation projects and sales opportunities will be documented and maintained for audit purposes, and the Dominion Companies will annually conduct a self-audit of compliance with these commitments, as well as adopt training and additional compliance controls as appropriate to ensure compliance. Power sales from existing franchised and market-regulated generation, as well as power sales that are not specific to any generator, will continue to be carried out by independent, functionally-separated regulated and unregulated trading groups. Finally, no market-regulated power sales affiliate will enter into any agreement under which it acquires control over a new or existing wholesale generating unit in the three states with captive customers. On the basis of these collective representations, the Commission granted the waiver. *Va. Elec. & Power Co.*, 147 FERC ¶ 61,011 (2014)

¹⁰⁰ 18 C.F.R. § 35.36(a)(8) (emphasis added).

¹⁰¹ *Id.* § 35.39(d)(1) (emphasis added). As originally promulgated in Order No. 697, the information-sharing restriction prohibited sharing by the market-regulated power sales affiliate as well as

697, and FERC there provided a *non-exhaustive* list of disclosures likely to cause harm to captive customers:

- Information concerning sales and purchases that will *not* be made by the franchised public utility, such as in circumstances where parties have discussed a potential contract but no agreement has been reached.¹⁰²
- Any non-public information acquired by the franchised public utility through unsuccessful negotiations conducted with an unaffiliated generator to acquire power.¹⁰³
- Any non-public information acquired by a franchised public utility about a non-affiliated generator's upcoming maintenance or outage schedules or information about the non-affiliated generator's historical generation volumes.¹⁰⁴
- Information concerning the franchised public utility's intent to sell power to a third party, including (but not limited to) the price and quantity it intends to offer.¹⁰⁵

Conversely, neither Order No. 697 nor any subsequent order provides even a non-exhaustive list of market information whose disclosure could *not* harm captive customers. It is possible, of course, to argue that disclosure of a franchised public utility's market information to a market-regulated power sales affiliate is unlikely to harm captive customers, for example, where the affiliates operate in different geographic markets (e.g., the southeast versus the Pacific northwest). Nonetheless, in situations where affiliated companies have not already received an Affiliate Restrictions waiver, one should expect that FERC's Office Enforcement will both interpret "market information" as broadly as possible and take an expansive view of whether any particular sharing "could" be of detriment to captive customers.

At the same time, the Affiliate Restrictions provide that permissibly-shared support employees, field and maintenance employees, and senior officers and board of directors *may* have access to the franchised public utility's market information.¹⁰⁶ However, in similar fashion to the Standards of Conduct, the Affiliate Restrictions provide that a franchised public utility with captive customers and a market-regulated power sales affiliate are prohibited from using anyone, including asset managers, as a conduit to circumvent the Affiliate Restrictions.¹⁰⁷ The

by the franchised public utility with captive customers. However, this was revised by Order No. 697-A to the current "one-way" restriction applicable only to the franchised public utility. Order 697-A, FERC Stats. & Regs. ¶ 31,268 at P 241.

¹⁰² Order 697, FERC Stats. & Regs. ¶ 31,252 at P 593.

¹⁰³ *Id.* at P 594.

¹⁰⁴ *Id.*

¹⁰⁵ *See id.*

¹⁰⁶ 18 C.F.R. § 35.39(d)(2).

¹⁰⁷ *Id.* § 35.39(g).

Affiliate Restrictions explicitly make permissibly-shared support employees, field and maintenance employees and senior officers and board of directors subject to this no-conduit rule.¹⁰⁸

D. RESTRICTIONS ON AFFILIATE POWER SALES

As a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy or capacity may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without *prior* FERC approval.¹⁰⁹ This requirement for prior FERC approval, which predates the Affiliate Restrictions, applies regardless of whether the transaction itself is at market-based or cost-based rates.¹¹⁰

In evaluating such inter-affiliate transactions, FERC utilizes standards and criteria established in the so-called *Edgar* and *Allegheny* cases.¹¹¹ In *Edgar*, FERC described three *alternative* types of evidence that can be used to show that an affiliate power sales transaction does not involve improper corporate self-dealing to the detriment of captive customers:

- Evidence of direct head-to-head competition between the affiliate and competing unaffiliated suppliers in a formal solicitation or informal negotiation process.
- Evidence of the prices non-affiliated buyers were willing to pay the affiliate for similar power supplies.
- Benchmark evidence that shows the prices, terms, and conditions of sales made by non-affiliated sellers.¹¹²

Allegheny, in turn, establishes four guidelines that the Commission will use to determine if a competitive solicitation process satisfies *Edgar*:

- Is the process transparent?

¹⁰⁸ *Id.* § 35.39(d)(2).

¹⁰⁹ *Id.* § 35.39(b). This requirement is reiterated in the Affiliate Cross-Subsidization Rules promulgated by Order No. 707. *See id.* 18 C.F.R. § 35.44(a). All Commission authorizations to engage in affiliate wholesale sales of electric energy or capacity must be listed in a seller's market-based rate tariff. *Id.* § 35.39(b).

¹¹⁰ *Southern Cal. Edison Co.*, 106 FERC ¶ 61,183, *order on reh'g*, 109 FERC ¶ 61,086 (2004) ("*Mountainview*").

¹¹¹ *Boston Edison Co. Re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382 (1991) ("*Edgar*"); *Allegheny Energy Supply Co.*, 108 FERC ¶ 61,082 (2004) ("*Allegheny*"). It should be noted that while the *Mountainview* case applied *Edgar* to cost-based affiliate sales transactions, it did so only for long-term (one year or longer) power purchase agreements. *See* 106 FERC ¶ 61,183 at P 58.

¹¹² *Edgar*, 55 FERC ¶ 61,382 at 62,168-69.

- Are the solicited products well defined?
- Are bids evaluated comparably with no advantage to affiliates?
- Is the process designed and evaluated by an independent entity?¹¹³

While proper use of the *Allegheny* standards can serve as “safe harbor,”¹¹⁴ FERC in Order No. 697 emphasized that “using a competitive solicitation by applying the *Allegheny* and *Edgar* guidelines is not the only way an affiliate transaction can address our concerns that the transaction does not pose undue preference concerns.”¹¹⁵ FERC stated that it would “consider other approaches on a case-by-case basis.”¹¹⁶

E. LIMITATIONS ON AFFILIATE POWER BROKERING

The Affiliate Restrictions carried forward prior Code of Conduct restrictions on power brokering transactions between franchised public utilities with captive customers and their market-regulated power sales affiliates.¹¹⁷ If a market-regulated power sales affiliate brokers power for a franchised public utility with captive customers, the affiliate must offer the franchise utility’s power first, the arrangement must be non-exclusive, and the affiliate may not accept any brokering fees.¹¹⁸

Conversely, if a franchised public utility with captive customers brokers power for its market-regulated power sales affiliate, the franchised utility must charge the higher of its costs or the market price for such service, market its own power first, simultaneously post any market information shared during brokering, and post the actual brokering charges imposed.¹¹⁹

¹¹³ *Allegheny*, 108 FERC ¶ 61,082 at PP 22-35.

¹¹⁴ Order 697, FERC Stats. & Regs. ¶ 31,252 at P 540.

¹¹⁵ *Id.*

¹¹⁶ *Id.* Also, to the extent a seller is not bound by the Affiliate Restrictions because “neither the seller nor the buyer has captive customers,” the *Edgar/Allegheny* principles do not apply and the seller may make an affiliate sale under its market-base rate tariff without the need for a separate rate filing. *Id.* FERC’s “concern in cases involving sales to affiliates has been the potential for cross-subsidization at the expense of the public utility’s captive customers,” *id.* (citing *Mountainview*, 109 FERC ¶ 61,086 at P 35). Such concerns do not arise in retail-access states where customers have a choice of supplier beyond the local franchised public utility.

¹¹⁷ The regulations do not require prior Commission approval, simply adherence to the requirements.

¹¹⁸ 18 C.F.R. § 35.39(f)(1).

¹¹⁹ *Id.* § 35.39(f)(2).

III. THE AFFILIATE CROSS-SUBSIDIZATION (ASYMMETRICAL PRICING) RULES

A. BASIC REQUIREMENTS

In order to avoid the transfer of benefits from a franchised public utility to what is now referred to as a market-regulated power sales affiliate (and, ultimately, from the captive customers to the corporate shareholders), the pre-Order No. 697 Codes of Conduct typically contained provisions regulating *non-power* transactions between affiliated franchised and non-franchised power sellers. These provisions became standardized over time, and Order No. 697 expressly codified them in the Affiliate Restrictions.¹²⁰

Following promulgation of the Affiliate Restrictions, FERC issued Order No. 707, *supra* note 4, which promulgated new Affiliate Cross-Subsidization (or Asymmetrical Pricing) Rules patterned after the provisions of the Affiliate Restrictions dealing with non-power goods and services.¹²¹ However, the Order No. 707 rules cover a broader universe of transactions. Whereas the Order No. 697 asymmetrical pricing rules apply only to non-power transactions between a franchised public utility with captive customers and its market regulated power sales affiliates, the Order No. 707 rules apply to non-power transactions between (1) a franchised public utility that has captive customers *or that owns or provides transmission service* over FERC-jurisdictional transmission facilities and (2) any market-regulated power sales affiliate *or any non-utility affiliate* with respect to transactions involving non-power goods or services.¹²² Because the Order No. 697 and Order No. 707 asymmetrical pricing rules have similar structure but the Order No. 707 rules have broader application, this section focuses on asymmetrical pricing in the Order No. 707 context.

B. GENERAL RULES

A franchised public utility with captive customers or that owns or provides transmission services may sell non-power goods or services to a market-regulated power sales affiliate or non-utility affiliate only at the higher of cost or market.¹²³ Conversely, a franchised public utility with captive customers or that owns or provides transmission services may purchase non-power

¹²⁰ 18 C.F.R. § 35.39(e).

¹²¹ The Affiliate Cross-Subsidization (Asymmetrical Pricing) Rules do not require prior Commission approval for inter-affiliate non-power transactions.

¹²² Because the Order No. 707 rules cover franchised public utilities that have captive customers *or that own or provide transmission service*, utilities that previously received exemptions from the Code of Conduct/Order No. 697 asymmetrical pricing rules but own or provide transmission service over FERC-jurisdictional transmission facilities remain subject to the Order No. 707 asymmetrical pricing rules (absent a new waiver). In order to obtain a waiver, an applicant must demonstrate “that the transmission customers of a franchised public utility that does not have captive customers do not bear the costs of inappropriate cross-subsidization.” Order No. 707-A, FERC Stats. & Regs. ¶ 31,272 at P 69.

¹²³ 18 C.F.R. § 35.44(b)(1).

goods or services from a market-regulated power sales affiliate or non-utility affiliate only at a price that does not exceed a market price.¹²⁴

FERC has never provided a definitive definition of a “non-power” good or service. However, prior to Order No. 697 it had approved Codes of Conduct that used a plain meaning interpretation, defining non-power goods and services as “[a]ll goods other than electric power and all services other than those services directly associated with the sale, transmission, and distribution of electric power.”¹²⁵ Non-power services typically are provided in two forms: (1) services provided by a single employee, such as a shared employee, and (2) services provided company-to-company. Non-power goods can range from *de minimis* items such as office supplies to high-cost items like turbines, emissions allowances, and fuel.¹²⁶

FERC audits indicate some expectation that a company “conduct formal market studies to ensure its [franchised public utilities] comply with Commission pricing restrictions for affiliated transactions of non-power goods and services.”¹²⁷ FERC auditors likewise expect that a company will have in place “policies, procedures, and controls to ensure that the [franchised public utilities] follow Commission pricing restrictions of affiliate transactions when selling non-power goods and services to market-regulated power sales affiliates and non-utility affiliates.”¹²⁸ However, FERC has not provided guidance on how one determines a market price in all cases, and a market price will not always be clearly established. For example, while the “cost” of a shared accountant’s service may be determined multiplying his or her hourly wage times the number of hours he or she provided accounting services to a particular affiliate, can the “market” price of those services be readily derived from rate charged by private accountants? In what geographic location? At what level of expertise? Should the utility solicit quotes? And how serious will the request for quotes be taken if it becomes clear that the company is not really soliciting accounting services? Absent clearer FERC guidance, companies should be prepared either to document any market price calculation or be able to explain why, in a particular context, a valid market price cannot feasibly be determined.

C. SPECIAL RULES

A franchised public utility with captive customers or that owns or provides transmission services over jurisdictional facilities may purchase or receive non-power goods and services from a centralized service company only at cost.¹²⁹ At the same time, a company in a single-state holding company system *may* provide general administrative and management non-power

¹²⁴ *Id.* § 35.44(b)(2).

¹²⁵ See *San Diego Gas & Elec. Co.*, 83 FERC ¶ 61,199 at 61,891 (quoting the codes of conduct of Enova Energy, Inc. and San Diego Gas & Electric Company), *reh’g denied*, 83 FERC ¶ 61,199 (1998).

¹²⁶ Neither a power contract nor a rate schedule is a non-power good or service. *Portland Gen. Elec. Co.*, 81 FERC ¶ 61,374 at 62,775-76 (1997).

¹²⁷ *Pepco Holdings, Inc.*, Docket No. FA10-1-000, Audit Report at 20 (May 2, 2011).

¹²⁸ *Id.* at 22.

¹²⁹ 18 C.F.R. § 35.44(b)(3).

goods and services to, or receive such other services from, other companies in the same holding company system at cost (provided that the only parties to the transaction are affiliates or associated companies).¹³⁰ Finally, purchases properly included in a franchised utility's fuel adjustment clause are exempt from the asymmetrical pricing requirements.¹³¹

¹³⁰ *Id.* § 35.44(b)(4).

¹³¹ *Id.* § 35.44(c). The Commission has regulations specifically dealing with fuel cost and purchased economic power adjustment clauses. *Id.* § 35.14. Because those regulations incorporate extensive oversight measures, including a provision that fuel charges by affiliated companies that do not appear reasonable may result in the suspension of the fuel adjustment clause or an investigation under FPA section 206, FERC exempted from its affiliate pricing restrictions transactions for fuel where the price of fuel from a company-owned or controlled source is found or presumed to be reasonable under 18 C.F.R. § 35.14 and thus includable in the adjustment clause. Order No. 707-A, FERC Stats. & Regs. ¶ 31,272 at P 50.

Chapter 9

Open Access Tariff Compliance

GERARD A. CLARK
TIM MASTROGIACOMO

The purpose of this chapter is to describe FERC regulations and orders applicable to the provision of transmission and interconnection service by public utilities. The chapter focuses principally on (i) Order Nos. 888 and 890, which require public utilities to provide unbundled transmission service pursuant to a *pro forma* Open Access Transmission Tariff, and (ii) Order Nos. 2003 and 2006, which require public utilities to provide interconnection service to generators pursuant to Standard Generator Interconnection Procedures and a Standard Generator Interconnection Agreement. Each of these orders creates significant compliance issues for public utilities in applying and, in many cases, interpreting these regulations and *pro forma* tariffs. We provide examples of the types of uncertainties and disputes that arise under these orders, as well as a discussion of the types of remedies that FERC may impose for noncompliance.

I. OPEN ACCESS TRANSMISSION AND INTERCONNECTION

A. TRANSMISSION SERVICE PROVIDED PURSUANT TO ORDER NOS. 888 AND 890

Section 205 of the Federal Power Act¹ requires FERC to ensure that the rates, terms and conditions for transmission service in interstate commerce are just, reasonable, and not unduly discriminatory. With the emergence of independent (non-utility) suppliers of electricity, FERC became increasingly concerned that vertically-integrated utilities might use their ownership and control of the transmission system to discriminate against competing suppliers. To remedy this potential undue discrimination, FERC issued Order No. 888 in 1996.²

In Order No. 888, FERC required all transmission-owning public utilities to operate their transmission systems under an OATT. Order No. 888 attached a *pro forma* OATT that specified uniform terms and conditions for transmission service.³ Transmission providers were required to

¹ 16 U.S.C. § 824d.

² *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, *clarified*, 76 FERC ¶ 61,009 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (codified at 18 C.F.R. § 35.28).

³ The original *pro forma* OATT is found in Appendix D of Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,926-64. The *pro forma* OATT was later revised in Order No. 890, discussed *infra*.

use the *pro forma* OATT in developing their individual OATTs and were allowed to deviate from the *pro forma* OATT only if they could show that the deviations were “consistent with or superior to” the *pro forma* OATT. In order to promote uniformity, FERC has construed the “consistent with or superior to” standard as a high hurdle and has permitted deviations under that standard sparingly.⁴

Under Order No. 888, all transmission customers of public utilities are required to take transmission service under the transmission provider’s OATT, unless, at the time Order No. 888 was issued, the customer was taking service pursuant to an existing—or “grandfathered”—transmission contract.⁵ In addition, the utility is required to take service under the transmission provider’s OATT when transmitting its own power to wholesale customers and when delivering unbundled power to retail customers in states with retail access programs.⁶ Order No. 888 did not require a utility to use the OATT when providing bundled service to its retail customers.⁷ However, FERC subsequently ruled that Order No. 888 requires a utility to designate the network resources that are used to serve bundled retail customers.⁸

The requirements of Order No. 888 apply to all public utilities that provide transmission service in interstate commerce. Order No. 888 does not apply to state or municipal utilities that

⁴ See, e.g., *Niagara Mohawk Power Corp.*, 86 FERC ¶ 61,009 (1999); *Pub. Serv. Co. of N.M.*, 82 FERC ¶ 61,127, *reh’g denied*, 85 FERC ¶ 61,240 (1998); *N.Y. State Elec. & Gas Corp.*, 78 FERC ¶ 61,114 (1997), *reh’g denied*, 82 FERC ¶ 61,209 (1998); *Tucson Elec. Power Co.*, 78 FERC ¶ 61,091 (1997).

⁵ In Order No. 888, the Commission declined to order generic abrogation of existing transmission contracts as it did in its unbundling of the natural gas industry. See FERC Stats. & Regs. ¶ 31,036 at 31,663-65. However, FERC did allow generic modification of requirements contracts to allow the purchaser to take open access transmission service and to allow the public utility to add a stranded cost recovery provision. See *id.* When entities attempt to renew grandfathered transmission service by exercising rollover rights, the Commission may require the entities to conform their exercise of the rollover rights to the requirements of the applicable OATT, despite the fact that service previously provided under the contract may not have conformed with the OATT. See *NorthWestern Corp.*, 144 FERC ¶ 61,184 at PP 24-27 (2013) (requiring customer, in rolling over its contract rights to long-term firm point-to-point transmission service, to take service only as permitted by transmission owner’s OATT and holding that “[a]ny historical accommodation afforded to [the customer] at [the transmission owner’s] discretion is not relevant to the rollover rights the [transmission owner] is required to offer”).

⁶ See FERC Stats. & Regs. ¶ 31,036 at 31,700-01; Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,216-17; see also 18 C.F.R. § 35.28(c)(2) (2005). In a subsequent order, FERC required public utilities to file forms of service agreements with the utility’s merchant function to “make public the fact that [the utility’s merchant function] is taking service under its own tariff.” *Allegheny Power Sys., Inc.*, 80 FERC ¶ 61,143 at 61,536 (1997).

⁷ See Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,217. The Commission’s decision not to assert jurisdiction by applying its open access remedy to bundled retail transmissions was specifically affirmed by the Supreme Court as a statutorily-permissible policy choice. See *New York v. FERC*, 535 U.S. at 25-28.

⁸ See, e.g., *Aquila Power Corp. v. Entergy Servs., Inc.*, 90 FERC ¶ 61,260, *reh’g denied*, 92 FERC ¶ 61,064 (2000), *reh’g denied*, 101 FERC ¶ 61,328 (2002), *aff’d sub nom. Entergy Servs., Inc. v. FERC*, 375 F.3d 1204 (D.C. Cir. 2004).

are not “public utilities” as defined in section 201 of the FPA.⁹ However, under the “reciprocity” requirement of Order No. 888, all transmission customers under the OATT (including non-jurisdictional utilities) must offer comparable open access transmission service in order to be entitled to receive open access transmission service from public utilities.¹⁰ FERC allows non-jurisdictional utilities to submit to FERC “safe harbor” tariffs and request FERC to certify that those tariffs are sufficiently comparable to the Order No. 888 *pro forma* OATT to satisfy the reciprocity requirement.¹¹ Many non-jurisdictional utilities have taken advantage of this procedure and now have in place FERC-certified safe harbor tariffs.¹² FERC also has authority to order a non-jurisdictional utility to submit an OATT under section 211A,¹³ but has not yet exercised that authority.¹⁴

In addition, Order No. 888 allowed small public utilities with *de minimis* transmission facilities that do not form part of the integrated grid to petition FERC for waiver of the requirements of Order No. 888.¹⁵ FERC generally has granted such waivers when the transmission facilities were “limited and discrete” (facilities that do not form an integrated transmission grid) and the public utility was unlikely to receive requests for transmission service over those facilities.¹⁶ For example, FERC has granted waivers for generators whose only transmission facilities were interconnection facilities used to interconnect the generator to the transmission system.¹⁷ However, the Commission has stated that all waivers are subject to the condition that the public utility receiving such waiver must file a *pro forma* tariff within sixty days of receiving a request for transmission service.¹⁸ The Commission has also routinely waived the requirements to establish an Open Access Same-Time Information System (“OASIS”) and to abide by the Standards of Conduct for applicants who either (1) own, operate,

⁹ See 16 U.S.C. §§ 824(b)(1), 824(e), 824(f).

¹⁰ See Order No. 888, FERC Stats. & Regs. ¶ 61,036 at 31,636, 31,691; *pro forma* OATT § 6.

¹¹ See 18 C.F.R. § 35.28(e).

¹² See, e.g., *Umatilla Elec. Coop. Assoc.*, 97 FERC ¶ 61,235 (2001); *Tri-State Generation & Transmission Assoc., Inc.*, 96 FERC ¶ 61,268 (2001); *S.C. Pub. Serv. Auth.*, 75 FERC ¶ 61,209 (1996).

¹³ 16 U.S.C. § 824j-1.

¹⁴ *Iberdrola Renewables, Inc. v. Bonneville Power Admin.*, 137 FERC ¶ 61,185 (2011), *reh’g denied*, 141 FERC ¶ 61,233 at P 37 (2012) (granting complaint and ordering comparable transmission service under section 211A, but declining to require filing of an entire OATT).

¹⁵ See 18 C.F.R. § 35.28(d); see also *Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232 at 61,941 (1996) (permitting waivers for small public utilities that transmit less than 4 million MWh annually unless the utility is a member of a tight power pool).

¹⁶ See, e.g., *Sulphur Springs Valley Elec. Coop., Inc.*, 109 FERC ¶ 61,181 at PP 7-8 (2004); *Golden Spread Elec. Coop., Inc.*, 106 FERC ¶ 61,151 at PP 7, 10 (2004). The Commission has explained that “limited and discrete” facilities are those which “do not form an integrated transmission grid.” *Terra-Gen Dixie Valley, LLC*, 132 FERC ¶ 61,215 at P 47 (2010).

¹⁷ See, e.g., *Entergy La., Inc.*, 110 FERC ¶ 61,300 (2005).

¹⁸ See, e.g., *Ariz. Solar One LLC*, 147 FERC ¶ 61,015 at P 9 (2014), *Soyland Power Coop.*, 102 FERC ¶ 61,244, *reh’g granted*, 104 FERC ¶ 61,288 (2003); *Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232 at 61,941.

or control only limited and discrete transmission facilities; or (2) are small public utilities that own, operate, or control integrated transmission grid but which disposes of no more than 4 million MWh of energy annually.¹⁹ In May 2014, the Commission issued a Notice of Proposed Rulemaking proposing to grant a blanket waiver of all OATT, OASIS, and Standards of Conduct requirements to electric utilities that would be subject to those requirements only because they own generator tie lines which serve their generation facilities.²⁰ This proposal would also eliminate the standard requirement that such entities file an OATT upon a third-party request.²¹

The Order No. 888 *pro forma* OATT covers the following areas, among others:

- The process for obtaining and evaluating requests for transmission service;²²
- The terms and conditions for network and point-to-point transmission service, including payment for those services;
- The types of ancillary services transmission customers must either purchase or self-provide in order to support any transmission service they receive, including the rate for purchasing those services from the transmission provider;
- The nature and types of studies that must be conducted to determine the availability of transmission service, and the timelines for those studies;
- The priorities among competing transmission service requests, including rights of first refusal and curtailment priorities;
- Provisions dealing with billing and payment and risk allocation, including creditworthiness, force majeure, and indemnification; and

¹⁹ *E.g.*, *Ariz. Solar One LLC*, 147 FERC ¶ 61,015 at P 10; *Wolverine Power Supply Coop.*, 127 FERC ¶ 61,159 at P 15 (2009) (discussing 4 million MWh standard).

²⁰ *Open Access Priority Rights on Interconnection Customer's Interconnection Facilities*, 147 FERC ¶ 61,123 at P 35 (2014) (proposing amendment to 18 C.F.R. § 35.28).

²¹ The Commission explained that it instead proposes to address such situations on a case-by-case basis. *Id.* at P 36.

²² Transmission service is reserved using a transmission provider's OASIS, which is intended to provide existing and potential transmission customers the same access to transmission information. All public utilities that own, control or operate facilities used in the transmission of electric energy in interstate commerce are required to create or participate in an OASIS by Order No. 889, which was issued concurrently with Order No. 888. *See Open Access Same-Time Info. Sys. and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,583 (1996), *clarified*, 77 FERC ¶ 61,335 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049, *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *aff'd in substantial part sub nom. Transmission Access Policy Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002). Part 37 of the Commission's regulations provides requirements for operation of OASIS, as well as references to documents that provide more detailed guidance. 18 C.F.R. pt. 37.

- The obligation of a transmission facility owner to upgrade or expand its existing facility to accommodate new requests for service by parties which are willing to fund the necessary upgrades or expansions.

In 2007, the Commission adopted a number of changes to the *pro forma* OATT in Order No. 890.²³ The Commission explained that “[i]n the ten years since Order No. 888, . . . the Commission has found that the OATT contains flaws that undermine realizing its core objective of remedying undue discrimination.”²⁴ Order No. 890 contained a wide range of provisions addressing the transmission services a transmission provider must offer under its OATT. The order’s primary reforms regarding transmission service were:

- A requirement that transmission providers and NERC develop consistent methods for calculate Available Transfer Capability (“ATC”) and provide greater transparency regarding ATC calculations;
- A requirement that transmission providers revise their OATTs to add generator imbalance service as a new ancillary service;
- New requirements for coordinated transmission upgrade planning to ensure that transmission providers do not provide affiliates with undue preference;²⁵
- Changes to the conditions under which a network customer may receive credits for the costs of new transmission facilities;
- New rules governing the identification of transmission upgrades and temporary redispatch options to accommodate new service requests and penalties for the failure to complete transmission service request studies on time;²⁶

²³ *Preventing Undue Discrimination and Preference in Transmission Servs.*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh’g and clarification*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh’g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh’g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009) (codified at 18 C.F.R. pts. 35, 37).

²⁴ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1.

²⁵ See *id.* at P 84 (“To ensure that truly comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, we amend the *pro forma* OATT to require coordinated, open, and transparent transmission planning on both a sub-regional and regional level.”).

²⁶ The Commission imposed a \$500 a day penalty for each day a transmission provider takes beyond sixty days to complete a system impact study after the study agreement is completed. *Id.* at P 1340. However, civil penalties for failure to respond to transmission service requests are not limited to this amount. In *In re NorthWestern Corp.*, the Commission approved a Stipulation and Consent Agreement requiring a utility to pay a \$1 million civil fine for its failure to respond to such requests. 118 FERC ¶ 61,029 at PP 1, 3 (2007). Additionally, for a discussion of the Commission’s authority to levy fines under the Energy Policy Act of 2005, see Part III below.

- A requirement that transmission customers, not transmission providers, determine whether they meet network resource requirements; and
- Several clarifications regarding the rules for designation of network resources, some of which were viewed by the industry as imposing new requirements.

The *pro forma* OATT provides that a utility must make capacity on its transmission facilities available on a first-come, first-serve basis. However, the Commission may permit preferential assignment of transmission facility capacity in three situations. First, the Commission may grant generation project developers priority rights over generator lead lines when the generation project being developed is dependent on access to the lead line. The Commission only grants such priority access if the developer has “specific plans and milestones for construction” of their generation project, and has made “material progress towards meeting those milestones.”²⁷ In a Notice of Proposed Rulemaking issued in 2014, the Commission proposed to create a five-year presumption that such a developer would use the lead line capacity, which would eliminate the need to make a milestone showing for that period of time.²⁸ Second, under a new policy adopted in 2013, the Commission will allow the developers of merchant transmission projects, as well as nonincumbent cost-based, participant-funded transmission projects, to allocate up to 100 percent of the capacity of their projects to individual parties (including affiliates) through bilateral negotiations, provided that the developers first hold “open solicitations” to identify potential customers.²⁹ Third, the Commission has in the past allowed the developers of participant-funded transmission facilities to grant priority rights over the transmission facilities’ capacity to the funding parties.³⁰ It must be noted, however, that if a

²⁷ *Milford Wind Corridor, LLC*, 129 FERC ¶ 61,149 at P 22 (2009); see also, e.g., *Avalon Wind, LLC*, 141 FERC ¶ 61,220 at P 11 (2012). The Commission applies this standard on a case-by-case basis. In April 2012, the Commission issued a Notice of Inquiry regarding whether and how the Commission’s generator lead line priority access policy should be revised. See *Open Access and Priority Rights on Interconnection Facilities*, 139 FERC ¶ 61,051 (2012).

²⁸ *Open Access and Priority Rights on Interconnection Customer’s Interconnection Facilities*, FERC Stats. & Regs. ¶ 32,701 at P 54.

²⁹ *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects*, 142 FERC ¶ 61,038 at P 19 (2013) (“*Allocation of Capacity Policy Statement*”); see also *id.* at P 18 (“[U]nder this final policy statement the Commission will allow merchant transmission developers to allocate up to 100 percent of their projects’ capacity through bilateral negotiations. The Commission will also allow capacity allocation to affiliates, when done in a transparent manner with the transparency protections adopted in this final policy statement, so that other interested parties can voice concern if they believe the affiliate was treated preferentially at the expense of another party.”). The Policy “allow[s] the developer of a new merchant transmission project to select a subset of customers, based on not unduly discriminatory or preferential criteria, and negotiate directly with those customers to reach agreement on the key rates, terms, and conditions for procuring up to the full amount of transmission capacity, when the developer (1) broadly solicits interest in the project from potential customers and (2) demonstrates to the Commission that the developer has satisfied the solicitation, selection and negotiation process criteria set forth herein.” *Id.* at P 16.

³⁰ See *Northeast Utils. Serv. Co.*, 127 FERC ¶ 61,179 at P 27 (2009) (granting priority rights over high voltage direct current line); see also *Nat’l Grid Transmission Servs. Corp.*, 139 FERC ¶ 61,129 at PP 29-33 (2012) (providing further guidance on the Commission’s standard). It remains to be seen

transmission facility owner uses one of these means to secure priority rights over all of a facility's existing capacity, the owner will nevertheless be obliged to upgrade or expand the facility to accommodate a service request made by a third party who is willing to fund the necessary upgrade or expansion.³¹

B. INTERCONNECTION SERVICE PROVIDED PURSUANT TO ORDER NOS. 2003 AND 2006

When issued in 1996, the Order No. 888 OATT applied to requests for transmission service, but it did not specifically address interconnection service for generators seeking to interconnect to the transmission system. Four years later, in *Tennessee Power Co.*,³² FERC clarified that generator interconnection service also was covered under the OATT and encouraged transmission providers to adopt standardized generator interconnection procedures as attachments to their OATTs. In response, many jurisdictional transmission providers adopted and attached to their OATTs generator interconnection procedures and an agreement to govern requests by generators to interconnect to the transmission system.³³ Subsequently, in 2003, FERC issued Order No. 2003³⁴ which required all FERC-jurisdictional transmission providers to adopt and attach to their OATTs standard interconnection procedures and a standard interconnection agreement for new generator interconnection requests made by Large Generators—i.e., generators adding capacity of 20 MW or more. In Order No. 661-A, the Commission adopted special addendums to the *pro forma* Standard Large Generator Interconnection Procedures (“LGIPs”) and the Standard Large Generator Interconnection Agreement (“LGIA”) for large wind generators.³⁵

how this precedent has been effected by the *Allocation of Capacity Policy Statement* adopted by the Commission in 2013.

³¹ See, e.g., *Avalon Wind, LLC*, 141 FERC ¶ 61,220 at P 15; *Northeast Utils. Serv. Co.*, 127 FERC ¶ 61,179 at P 27.

³² 90 FERC ¶ 61,238 (2000).

³³ See, e.g., *Southern Co. Servs., Inc.*, 94 FERC ¶ 61,131, *reh'g denied*, 95 FERC ¶ 61,078 (2001); *Va. Elec. & Power Co.*, 93 FERC ¶ 61,307 (2000), *reh'g denied*, 94 FERC ¶ 61,164 (2001); *Am. Elec. Power Serv. Corp.*, 91 FERC ¶ 61,308 (2000), *reh'g denied*, 94 FERC ¶ 61,166 (2001); *Entergy Servs., Inc.*, 91 FERC ¶ 61,149 (2000), *reh'g denied*, 94 FERC ¶ 61,257 (2001).

³⁴ *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 (2004), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171, *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Assoc. of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (codified at 18 C.F.R. pt. 35).

³⁵ See *Interconnection for Wind Energy*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005) (codified at 18 C.F.R. pt. 35), App. B (creating new *pro forma* LGIA Appendix G), App. C (creating new *pro forma* LGIPs Appendix 7).

The LGIPs and the LGIA established in Order No. 2003 govern the generator interconnection process from the time of the initial request to the execution and filing of the LGIA.³⁶ The LGIPs and LGIA cover, *inter alia*, the following areas:

- Procedures for requesting and evaluating requests to interconnect new generation to the transmission system or to modify existing interconnections materially (e.g., by adding capacity to an existing generator);³⁷
- Studies necessary for determining safe and reliable interconnection, including the timelines for those studies;³⁸
- Establishment of the interconnection queue and the management of, and priorities within, the interconnection queue;³⁹
- Types of interconnection service available, including energy resource interconnection service and network resource interconnection service;⁴⁰
- Allocation of the costs of the facilities necessary to provide interconnection service;⁴¹
- Risk allocation between the transmission provider and generator, including indemnification, creditworthiness, security, defaults, etc.;⁴² and
- Repayment of amounts advanced for network upgrades.⁴³

Under Order No. 2003, the LGIPs and LGIA apply to all requests to interconnect to the transmission system of a public utility and to requests to interconnect to the distribution system of a public utility, if the generator intends to make wholesale sales and if the distribution facilities are already subject to the transmission provider's OATT. The LGIPs also apply to the interconnection of the utility's own generation to the transmission system,⁴⁴ although FERC has

³⁶ The LGIPs are found at the conclusion of Order No. 2003-A in Appendix B. The LGIA is likewise found at the conclusion of the LGIPs in Appendix 6. The LGIPs and LGIA as of the issuance of Order No. 2003-C are available at <http://www.ferc.gov/industries/electric/indus-act/gi/stdn-gen.asp>.

³⁷ See LGIPs §§ 3.3, 7-10.

³⁸ See *id.* §§ 7-8, 10.

³⁹ See *id.* § 4.

⁴⁰ See *id.* § 3.2; LGIA art. 4.1.

⁴¹ See LGIA arts. 5.1-5.3, 11.

⁴² See *id.* arts. 11.5, 16-18.

⁴³ See *id.* art. 11.4.1.

⁴⁴ See LGIPs § 1, *Definitions* (defining "Interconnection Customer" to mean "any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System") (emphasis added).

not required a vertically-integrated utility's merchant function to enter into an interconnection agreement with its transmission function when interconnecting a generator to serve native load.

The flexibility for a transmission provider to deviate from the terms and conditions of the LGIPs and LGIA depends on whether the transmission provider is "independent," i.e., whether it has any affiliated generation interests. For a non-independent transmission provider (e.g., an integrated utility), deviations from the standard procedures and agreement are allowed only under the stringent "consistent with or superior to" standard used for deviations from the OATT.⁴⁵ Independent transmission providers (independent system operators, regional transmission organizations, or stand-alone transmission companies) have greater flexibility and are allowed to customize interconnection procedures and agreements to fit regional needs.⁴⁶ In addition, like Order No. 888, Order No. 2003 allows small public utilities to seek from FERC waiver of the requirements of Order No. 2003.⁴⁷

The Commission established a *pro forma* tariff requirement in Order No. 2003 that required transmission providers to grant interconnection customers transmission service credits in exchange for amounts spent by the customers to fund network upgrades required for the customers' interconnection.⁴⁸ However, because Order No. 2003 permitted independent transmission providers to propose different approaches,⁴⁹ independent system operators filed and received approval for proposals to reduce or eliminate the 100 percent reimbursement provided to interconnection customers.⁵⁰

In addition to the large generator interconnection process established in Order No. 2003, the Commission established a separate standardized interconnection process for interconnecting Small Generating Facilities in Order No. 2006.⁵¹ Generation facilities governed by these procedures are those which are not larger than 20 MW and that (1) are to be interconnected to a transmission or distribution facility that is already subject to the Transmission Provider's OATT at the time of the interconnection request and (2) the purpose of the interconnection is to make wholesale sales from the generation facility.⁵² In Order No. 2006-B, the Commission required

⁴⁵ See Order No. 2003, FERC Stats. & Regs. ¶ 31,036 at PP 825-26.

⁴⁶ See *id.* at PP 823-24, 827.

⁴⁷ See *id.* at PP 830-31; see also 18 C.F.R. § 35.28(f)(3).

⁴⁸ *Id.* at P 28.

⁴⁹ *Id.* PP 26, 28, 34, 92, 147, 177, 822-24, 827; see also *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 at P 3 (2009).

⁵⁰ For example, in MISO interconnection customers in most zones now receive a reimbursement of 10 percent of the amount spent to fund network upgrades over 345 kV. See *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 at PP 8, 48 n.99, 52; see also *Interstate Power & Light Co. v. ITC Midwest, LLC*, 144 FERC ¶ 61,052 at PP 5-6, 41, 42 (2013).

⁵¹ *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006) (codified at 18 C.F.R. pt. 35).

⁵² See Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at PP 700, 706, 710, 730.

utilities to update their tariffs to include the Commission’s new Small Generator Interconnection Procedures (“SGIPs”) and a Small Generator Interconnection Agreement (“SGIA”).⁵³ The SGIPs and SGIA govern the small generator interconnection process from the time of the initial request to the execution and filing of the SGIA. The SGIPs and SGIA cover, *inter alia*, the following areas:

- Pre-application procedures, interconnection requests, and queue positions;⁵⁴
- Fast-track processing of interconnection requests for generation facilities no larger than 2 MW;⁵⁵
- The study process for interconnection requests for facilities larger than 2 MW and no larger than 20 MW;⁵⁶
- The Transmission Provider’s responsibility to coordinate studies with other Affected System operators;⁵⁷
- Allocation of the costs of the facilities necessary to provide interconnection service;⁵⁸
- Risk allocation between the transmission provider and generator, including indemnification, creditworthiness, security, and defaults;⁵⁹ and
- Repayment of amounts advanced for network upgrades.⁶⁰

In Order No. 792,⁶¹ the Commission made several amendments to the SGIPs and SGIA. The Commission provided interconnection customers with the ability to request pre-application reports from transmission providers which detail possible points of interconnection.⁶² Order No. 792 also provided interconnection customers with new options regarding supplemental reviews

⁵³ The current versions of the SGIPs and SGIA are available at <http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp>.

⁵⁴ See SGIPs § 1.2-1.3, 1.6.

⁵⁵ See *id.* § 2.

⁵⁶ See *id.* § 3.

⁵⁷ See *id.* § 4.9.

⁵⁸ See SGIA art. 5.

⁵⁹ See *id.* art. 7.

⁶⁰ See *id.* art. 5.2.1.

⁶¹ *Small Generator Interconnection Agreements and Procedures*, Order No. 792, 145 FERC ¶ 61,159 (2013) (codified at 18 C.F.R. pt. 35).

⁶² See SGIPs §§ 1.2.2–1.2.4. The Commission explained that the ability to obtain such reports “may diminish the practice of requesting multiple interconnection requests for a single project.” Order No. 792, 145 FERC ¶ 61,159 at P 37.

to be conducted if a customer's project fails the fast track screen⁶³ and also provides customers with the right to provide written comments on the transmission provider's findings regarding the network upgrades which are necessary to facilitate the interconnection.⁶⁴ The Commission also adopted SGIP and SGIA provisions to be used for energy storage devices.⁶⁵

II. COMPLIANCE ISSUES

The Commission's orders on open access transmission and interconnection service present two general categories of compliance issues for transmission providers. The first involves simply understanding and applying the specific tariff provisions adopted by each rule, many of which contain general language susceptible to differing interpretations. The second involves areas where FERC has not been prescriptive, but rather has left certain decisions to the discretion of the Transmission Provider. The most common compliance problem in each category involves allegations that the utility incorrectly applied a tariff requirement, or otherwise exercised its discretion, in a manner that favored its own generation business and, hence, either violated the tariff or otherwise engaged in undue discrimination under the FPA. We describe below the types of compliance issues which have arisen most frequently in recent years.

A. TRANSMISSION

1. *Affiliate Preference in Type of Service Offered*

Order No. 888 requires that Transmission Providers offer third parties transmission service on a comparable basis to the service they provide to the generation portion of their business. A public utility therefore cannot offer its wholesale merchant function or generation affiliate a form of transmission service that is not available to its competitors. This occurred in *Washington Water Power Co.*⁶⁶ In that case, FERC held that the Transmission Provider had offered to its marketing affiliate (Avista Energy, Inc.) a form of "interruptible firm" transmission service that was not available to nonaffiliates under the OATT.⁶⁷ As a remedy for this violation, FERC revoked the utility's market-based rate authority for six months and ordered it to disgorge the profits it earned from the unauthorized sales.⁶⁸

As another example, in *Aquila Power Corp. v. Entergy Services, Inc.*,⁶⁹ FERC found that a public utility had reserved transmission interface capacity without designating network resources as required by OATT Section 28.2.⁷⁰ The utility had reserved all of the firm

⁶³ See SGIPs §§ 2.4.4.1-2.4.4.3.

⁶⁴ See Order No. 792, 145 FERC ¶ 61,159 at PP 203-09.

⁶⁵ See SGIPs, Attach. 1 (amending the definition of Small Generating Facility to include "storage for later injection"); SGIA, Attach. 1 (definition of Small Generating Facility).

⁶⁶ 83 FERC ¶ 61,097, *order on response to show cause order*, 83 FERC ¶ 61,282 (1998).

⁶⁷ See *id.*, 83 FERC ¶ 61,097 at 61,463.

⁶⁸ See *id.*, 83 FERC ¶ 61,282 at 62,169.

⁶⁹ 90 FERC ¶ 61,260.

⁷⁰ *Id.* at 61,859-60.

transmission capacity at four key interfaces in order to import power to serve native load and maintain system reliability. FERC found that the utility was required to reserve capacity using network resource designations just like any other network customer under the OATT.⁷¹ A remedy was not ordered in that proceeding because the utility already had filed revised procedures complying with FERC's network designation requirements in a separate proceeding, and FERC found no basis to award refunds.⁷² FERC also declined to revoke the utility's market-based rate authority because that question was already before FERC in a separate proceeding.⁷³

As another example, in *Arizona Public Service Co.*,⁷⁴ the Commission issued an order approving an audit report issued by FERC's Office of Market Oversight and Investigations ("OMOI") and directing compliance actions proposed in the audit report. OMOI's report found that the utility had allowed its wholesale merchant function to make off-system power sales at trading hubs from system resources without properly requesting, scheduling, and paying for point-to-point transmission service under the OATT.⁷⁵ The utility agreed to settle this and other allegations by, *inter alia*, making an unrecoverable payment to upgrade a transmission line, contributing to low-income energy assistance programs, and installing an independent transmission market monitor.

In *Black Hills Power, Inc.*,⁷⁶ Black Hills Power, Inc. ("BH Power") allowed an affiliate to use its firm transmission service rights over a DC tie line without charge. BH Power then retroactively charged the affiliate a reduced rate for the service. The Commission found that this was a "discount that BH Power did not make available to all eligible customers" and therefore determined that PH Power had violated its OATT.⁷⁷ The Commission also found that BH Power had failed to list capacity available on the DC line on its OASIS for over two years.⁷⁸ This may have prevented interested, non-affiliate customers from obtaining non-discriminatory access to the line. For these and other violations, the Commission approved a Stipulation and Consent Agreement requiring BH Power to pay a civil penalty of \$200,000.⁷⁹

2. Permissible Uses of Network Transmission Service

A number of recent cases have involved allegations that utilities have violated their OATTs' requirements regarding the use of network transmission service. Use of secondary

⁷¹ See *id.*

⁷² See *id.* at 61,860.

⁷³ See *id.*

⁷⁴ 109 FERC ¶ 61,271 (2004).

⁷⁵ See *id.* at P 6.

⁷⁶ 136 FERC ¶ 61,088 (2011).

⁷⁷ *Id.* at P 7. The Commission explained that the practice "violated Section 23 of BH Power's OATT, which requires that all sales or assignments of capacity be posted on the OASIS, and Schedule 10 of its OATT, which requires BH Power to offer the same discount to all eligible customers." *Id.*

⁷⁸ *Id.* at P 4.

⁷⁹ *Id.* at P 1.

network transmission service (i.e., service provided pursuant to Section 28.4 of the *pro forma* OATT) to deliver an off-system purchase can raise compliance issues whenever concurrent off-system sales also are scheduled. FERC applies an “intent test” to determine whether the use of secondary network transmission service is appropriate under such circumstances. Under that test, FERC determines whether the utility’s intent at the time of the purchase was to use the purchased power to serve designated network load.⁸⁰ If so, secondary network service may be used to deliver the purchase. Otherwise, the use of secondary network service is not appropriate.⁸¹ Because the test applied by FERC is a test of intent, it is not possible to specifically identify all circumstances when the use of secondary network service to deliver an off-system purchase will be deemed appropriate, and when it will not. FERC has indicated that, if a question arises in this regard, it may examine transactional data, trading room tapes, e-mails, deal documentation, and any other information indicating whether or not there is a linkage between (a) an off-system purchase that is delivered using secondary network transmission service and (b) a concurrent off-system sale.

A similar issue may arise for deliveries of resources that are located outside of the transmission provider’s territory. In that circumstance, firm or conditional firm point-to-point transmission service is used to deliver power from the resource to the transmission provider’s border. Network service then is used to deliver the power from the border to network load. A question can arise about the use of network service to deliver that resource when the network customer is making off-system sales. Again, it is not possible to specifically identify all circumstances when the use of network service to deliver the off-system purchase will be deemed appropriate. To the extent the network resource is a short-term resource, it appears that the same rules applicable to secondary network service should be applied. If the off-system resource is a long-term resource, it appears that it should be treated the same as a designated network resource located within the transmission provider’s system.

When designing specific controls for this area, emphasis should be placed on (a) when possible, providing specific guidance to the persons responsible for compliance with the rules, (b) fostering an environment where those persons check first if there is any question about the use of network transmission service, and (c) encouraging documentation about the reasons for a purchase, particularly when there is a question about the appropriate use of network service.

Several cases demonstrate the types of compliance actions which may arise in connection with secondary network transmission service. In Order No. 890-A, the Commission highlighted *MidAmerican Energy Co.*,⁸² as a case which the Commission “intend[s] to serve as guidance to the industry regarding the appropriate use of secondary network service and the documentation

⁸⁰ See Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 957 (“The primary focus of the Commission’s analysis is whether the energy delivered using secondary network service was intended to serve network load.”).

⁸¹ Section 28.6 of the *pro forma* OATT (Restrictions on Use of Service) states that “[t]he Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties.”

⁸² 112 FERC ¶ 61,346 (2005).

that would be relevant for analysis.”⁸³ In *MidAmerican*, FERC approved an Audit Report in which audit staff found that MidAmerican Energy Company (“MidAmerican”) improperly “permitted its wholesale merchant function [(“Electric Trading”)] to use network service to import power into MidAmerican’s system to make possible off-system sales.”⁸⁴ The report explained that “Electric Trading regularly used network transmission service to bring short-term energy purchases onto its system while it simultaneously made off-system sales.”⁸⁵ In these transactions, “Electric Trading would purchase energy from outside of its control area and use point-to-point service to deliver the energy to its border.”⁸⁶ Then, “Electric Trading would use network transmission service to move the energy from its border to one of its generator buses.”⁸⁷ Next, “Electric Trading would arrange an off-system sale and procure the necessary point-to-point transmission service.”⁸⁸ Staff concluded that this behavior “afforded MidAmerican additional protection against transmission curtailments” and allowed Electric Trading to “potentially avoid[] the need to voluntarily redispatch its system to protect purchases that used network transmission service.”⁸⁹ The Commission ordered MidAmerican to comply with various compliance recommendations provided by the report, including, *inter alia*, requirements that “Electric Trading should explicitly designate a resource in association with each new and existing confirmed request for firm network transmission service” and that “MidAmerican’s transmission function should develop specific procedures that describe the process network transmission customers will use to formally submit an application to designate a new network resource.”⁹⁰

Following the enactment of the Energy Policy Act of 2005,⁹¹ the Commission began assessing significant civil penalties for these types of violations. In *In re PacifiCorp*,⁹² Commission Enforcement Staff found a transmission provider’s merchant function had used network transmission service instead of point-to-point transmission service to return power to a utility.⁹³ Staff also found that the transmission provider’s merchant function used network transmission instead of point-to-point to import power to facilitate off-system sales.⁹⁴ Additionally, the transmission provider’s merchant function used network transmission service

⁸³ Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 957.

⁸⁴ 112 FERC ¶ 61,346 at P 1.

⁸⁵ *Id.*, Audit Report at 62,515.

⁸⁶ *Id.*

⁸⁷ *Id.*

⁸⁸ *Id.*

⁸⁹ *Id.* at 62,516.

⁹⁰ 112 FERC ¶ 61,346 at 62,509; Audit Report at 62,518.

⁹¹ Pub. L. No. 109-58, 119 Stat. 594, 980 (2005).

⁹² 118 FERC ¶ 61,026 (2007).

⁹³ *Id.* at P 4; Stipulation and Consent Agreement at P 11 (holding that “[b]ecause return energy is not used to serve the returning utility’s load or another utility’s load within the returning utility’s control area,” the transmission provider “should have used [point-to-point] service”).

⁹⁴ *Id.*, 118 FERC ¶ 61,026 at P 4.

instead of point-to-point or secondary network service to bring power onto its system from resources not designated as network resources.⁹⁵ For these and other violations, the Commission approved a Stipulation and Consent Agreement which included a \$10 million civil penalty and an independent review of the transmission provider's business practices.⁹⁶

In *In re Xcel Energy, Inc.*,⁹⁷ the Commission approved a Stipulation and Consent Agreement requiring a transmission provider to pay a civil penalty of \$2 million and to submit compliance monitoring reports. Enforcement staff had concluded that the transmission provider violated its OATT by using firm Network Integrated Transmission Service for purchase and sale transactions which were not eligible for such service because the resources used in the transactions did not qualify as designated network resources and because the load to be served did not qualify as designated network load.⁹⁸ Staff concluded that the transmission provider should have used point-to-point transmission service for the portion of the transmission occurring outside its system and secondary network service for the portion of the transmission occurring on its own system instead of Network Integrated Transmission Service.⁹⁹

In *In re Westar Energy, Inc.*,¹⁰⁰ the Commission Enforcement Staff determined that a transmission provider "made numerous off-system short-term purchases during the study period, using secondary [Network Integrated Transmission Service]" and that "[w]hile some were economy energy purchases made to serve network load, others facilitated off-system sales instead, and therefore should have used point-to-point (PTP) transmission service."¹⁰¹ Staff found 823 such violations, resulting in over \$750,000 of unjust profit. Enforcement Staff favorably reported that no "high-level personnel" had been involved with the violations and that the transmission provider cooperated fully with the investigation.¹⁰² The Commission approved a Stipulation and Consent Agreement requiring the transmission provider to pay a \$420,000 civil penalty and to disgorge over \$1.1 million.¹⁰³

3. *Facilitating and Processing Transmission Service Requests*

The Commission's *pro forma* OATT requires that all requests for transmission service be made over the Transmission Provider's OASIS.¹⁰⁴ Deficiencies in the information that is

⁹⁵ *Id.*

⁹⁶ *Id.* at P 1.

⁹⁷ 138 FERC ¶ 61,026 (2012).

⁹⁸ *See id.* at PP 6, 9.

⁹⁹ *Id.* at P 9.

¹⁰⁰ 142 FERC ¶ 61,066 at P 4 (2012).

¹⁰¹ *Id.*

¹⁰² *Id.* at P 10.

¹⁰³ *Id.* at PP 1, 8.

¹⁰⁴ *See pro forma* OATT §§ 17.1, 18.1; *see also* 18 C.F.R. § 37.6(e)(1).

supplied by Transmission Providers regarding available capacity, as well as irregularities in the processing of transmission service requests, may trigger Commission enforcement actions.

Section 17.5 of the *pro forma* OATT requires Transmission Providers to respond within thirty days to requests for firm point-to-point transmission service and to inform the customer whether it can fulfill the request or whether a system impact study is needed. In *NorthWestern Corp.*,¹⁰⁵ Commission Enforcement Staff found that a transmission provider failed to act within thirty days on 83 such requests, thereby violating its OATT.¹⁰⁶ The transmission provider “fully cooperated” with Enforcement Staff’s investigation and “did not appreciably profit from the alleged violations and created little harm to the market.”¹⁰⁷ The Commission approved a Stipulation and Consent Agreement which required the transmission provider to pay a \$1 million civil penalty.¹⁰⁸

Transmission Providers use OASIS to generate assignment reservation numbers for each leg of the transmission path which will be used to accommodate the request. These numbers are forwarded to balancing authorities which then accept or reject the transmission requests. Non-physical aspects of a transaction may properly receive a “No OASIS Required” designation (“NOR”). Transmission Providers must ensure that NOR designations are not improperly used to obtain physical transmission. In *PacifiCorp*, Commission Enforcement Staff found that a transmission provider “did not have in place an effective mechanism either for rejecting . . . improper e-Tags, or for identifying and penalizing the unreserved use of its transmission system resulting from the acceptance of e-Tags containing such improper designations.”¹⁰⁹ Staff identified 22 occasions on which transmission customers submitted improper NOR designations and concluded that the transmission provider violated its OATT “by failing to timely identify and penalize the unreserved use of [the] transmission.”¹¹⁰ The Commission therefore approved a Stipulation and Consent Agreement which required the transmission provider to pay a civil penalty of \$265,000, to adopt remedial measures, and to allow compliance monitoring.¹¹¹ In arriving at its recommended civil penalty amount, Enforcement Staff took into consideration the transmission provider’s active and full cooperation with Staff’s investigation.¹¹²

In *In re Portland General Electric Co.*,¹¹³ Commission Enforcement Staff found that a transmission provider violated Commission regulations¹¹⁴ and as well as its OATT by allowing

¹⁰⁵ 118 FERC ¶ 61,029.

¹⁰⁶ *Id.* at PP 3-4.

¹⁰⁷ *Id.* at PP 5, 7.

¹⁰⁸ *Id.* at P 1.

¹⁰⁹ 141 FERC ¶ 61,156 at P 8 (2012).

¹¹⁰ *Id.* at PP 9-10.

¹¹¹ *Id.* at P 1.

¹¹² *Id.* at P 14.

¹¹³ 131 FERC ¶ 61,224 (2010).

¹¹⁴ 18 C.F.R. §§ 37.6(e), 358.5(c)(5) (since recodified at 18 C.F.R. § 358.4(c)).

an affiliate “to schedule firm point-to-point transmission service using non-public scheduling numbers . . . instead of using an OASIS reservation for the first leg of certain transactions.”¹¹⁵ Because these transmission legs did not have OASIS reservation numbers, nonaffiliated customers may have lacked the knowledge necessary to schedule transmission service between certain locations. Enforcement Staff found that the amount of harm caused by this was unquantifiable.¹¹⁶ Staff concluded that the violation was unintentional and cited the transmission provider’s cooperation in working to correct the problem and prevent future such occurrences.¹¹⁷ For this and other violations, the Commission approved a Stipulation and Consent Agreement requiring the transmission provider to pay a \$375,000 civil penalty.¹¹⁸ This and other cases¹¹⁹ demonstrate that Commission Enforcement Staff may closely consider whether Transmission Providers have maintained transparency in the use their OASIS.

B. INTERCONNECTION

In the interconnection context, potential compliance issues include whether the transmission provider has the correct rules in place and whether it processes interconnection requests according to those rules and in a nondiscriminatory manner.

In reviewing or auditing a transmission provider’s compliance with the standardized interconnection rules, FERC is particularly interested in whether the utility treats affiliate interconnection requests in a manner similar to nonaffiliate requests. For example, the LGIPs specify the interconnection studies that need to be performed and the timelines for processing those studies.¹²⁰ If the study timelines cannot be met, the transmission provider must provide notice and revised timelines.¹²¹ To minimize compliance issues, transmission providers should either meet these timelines or provide the required notice if they cannot be met. Also, transmission providers should use the same interconnection studies and study methodologies for affiliate and nonaffiliate requests and process affiliate and nonaffiliate requests under the same timelines. While it is understandable that such timelines may vary due to the individualized nature of the requests, shorter timelines for affiliate requests may be subject to audit scrutiny. To avoid or minimize such scrutiny, companies may wish to take steps to ensure that affiliate requests are not processed faster. In any event, careful documentation of the timing is prudent.

Certain system operators have developed complex, multi-stage processes for evaluating interconnection projects.¹²² Because interconnection capacity in some systems is a scarce

¹¹⁵ 131 FERC ¶ 61,224 at P 8.

¹¹⁶ *Id.*, Stipulation and Consent Agreement at P 9.

¹¹⁷ *Id.*, 131 FERC ¶ 61,224 at P 9.

¹¹⁸ *Id.* at P 1.

¹¹⁹ *See, e.g., Black Hills Power, Inc.*, 136 FERC ¶ 61,088 at PP 1, 4 (finding that utility failed to post available capacity on OASIS for over two years and approving a Stipulation and Consent Agreement providing for a \$200,000 civil penalty).

¹²⁰ *See* LGIPs §§ 6-8, 10.

¹²¹ *See id.* §§ 6.3, 7.4, 8.3, 10.3.

¹²² *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,233, *order on*

resource, various disputes have arisen in recent years between interconnection project developers and transmission providers. The Commission has in certain instances shown a willingness to thoroughly review the circumstances in which interconnections are allocated to customers.¹²³ Any departure from standard practices may attach heightened Commission scrutiny.

Disputes may also arise regarding Transmission Providers' identification of network upgrades needed to facilitate the interconnection of new customers. The Commission's *pro forma* LGIPs defines network upgrades as "the additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connects to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System."¹²⁴ This rule effectively establishes a "but for" pricing standard.¹²⁵ In other words, a Transmission Provider may not assign the costs of a network upgrade to new customers if the upgrade would not be needed but for the customer's new interconnection request.¹²⁶ This standard can create compliance issues in several situations, including where a Transmission Provider's system was already overloaded before a new customer made a service request. The Transmission Provider may encounter difficulty assigning upgrade responsibility to the new customer if the customer is able to identify evidence that the Transmission Provider had planned or identified an upgrade to address the overload and then attempted to assign the costs of that same upgrade to the new customer requesting service.¹²⁷

reh'g and compliance, 139 FERC ¶ 61,253 (2012) (addressing MISO's interconnection queue reform efforts).

¹²³ See, e.g., *Shetek Wind Inc. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,250 (2012) (setting for hearing review of the process by which Net Zero Interconnections in MISO were allocated; this was a new type of interconnection in which new generators pair with existing generators to share interconnection capacity); *Edison Mission Energy v. Midwest Indep. Transmission Sys. Operator, Inc.*, 136 FERC ¶ 61,035 (2011) (granting complaint and finding that MISO incorrectly applied its interconnection queue rules by requiring interconnection customer to meet a milestone requirement from which it was exempted under the MISO Tariff).

¹²⁴ Order No. 2003-A, FERC ¶ 31,160 at P 76, App. B § 1.

¹²⁵ See *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,019 at P 23 & n.52 (2009), *order on reh'g and compliance*, 131 FERC ¶ 61,165 (2010); *N.Y. Indep. Sys. Operator, Inc.*, 97 FERC ¶ 61,118 at 61,576 (2001); *PJM Interconnection, L.L.C.*, 87 FERC ¶ 61,299 at 62,204 (1999).

¹²⁶ See *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,019 at P 23 ("[G]eneration developers are to be allocated the costs for transmission system upgrades that would not have been made but for the interconnection of the developers, minus the cost of any facilities that the ISO's regional plan dictates would have been necessary anyway for load growth and reliability purposes.") (quoting *N.Y. Indep. Sys. Operator, Inc.*, 97 FERC ¶ 61,118 at 61,573)); see also *Jeffers S., LLC*, 144 FERC ¶ 61,033 at P 51 (2013) (rejecting MISO's attempt to assign the costs of network upgrades to a new interconnection customer where the customer presented evidence that MISO Transmission Owners had previously included the same upgrades in their comprehensive transmission system plan and where MISO had failed to present evidence that the interconnection request triggered the need for all of the upgrades for which MISO attempted to assign the customer responsibility).

¹²⁷ See *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,019 at P 23 & n.52 (rejecting MISO's attempt to assign the costs of the previously-planned 345 kV Brookings Line to new

The filing requirements for interconnection agreements also may give rise to specific compliance issues. Under Order No. 2001,¹²⁸ Order No. 2003, and Order No. 2006, LGIAs and SGIAs do not need to be filed with the Commission but only listed in electronic quarterly reports.¹²⁹ However, if an interconnection agreement varies from the standardized terms and conditions, then that agreement needs to be filed under section 205 of the FPA.¹³⁰ Also, if an interconnection agreement is terminated for any reason other than expiration under its terms, then a notice of termination must be filed with and approved by FERC.¹³¹

An additional filing issue involves preliminary agreements to fund interconnection facilities and upgrades before the interconnection process is complete. The standardized interconnection procedures allow the parties to enter into an Engineering and Procurement (“E&P”) Agreement in order to begin the purchase and construction of the necessary interconnection facilities that have long construction lead times.¹³² These E&P Agreements must be filed with the Commission under section 205 of the FPA.¹³³ If they are not filed, the transmission-owning utility may have to refund the time value of the money collected under those agreements during the period when the agreements were not on file.¹³⁴

interconnection customers).

¹²⁸ *Revised Pub. Util. Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127, *reh’g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *order on reconsideration and clarification*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing and providing details*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing review and refiling*, Order No. 2001-D, 102 FERC ¶ 61,334, *order refining electric quarterly report filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order adopting electric quarterly report data dictionary*, Order No. 2001-G, 120 FERC ¶ 61,270, *order on reh’g and clarification*, Order No. 2001-H, 121 FERC ¶ 61,289 (2007), *order revising electric quarterly report (EQR) data dictionary*, 125 FERC ¶ 61,103 (2008) (codified at 18 C.F.R. pt. 35).

¹²⁹ See Order No. 2006, 111 FERC 61,220 at P 560; Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 913 & n.173 (citing Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 18).

¹³⁰ See Order No. 2006, 111 FERC 61,220 at P 561; Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 914-15.

¹³¹ See Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 249.

¹³² See LGIPs § 9. Note that Order No. 2003 specifically requires the Interconnection Customer to bear the cost risk if it chooses to use this “optional procedure.” *Id.*; accord Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 228.

¹³³ See, e.g., *GenPower Anderson, LLC v. Duke Energy Corp.*, 101 FERC ¶ 61,038 at P 13 & nn.10 & 11 (2002) (finding that a utility was required to file an E&P agreement because it “involve[d] the construction of facilities necessary to provide jurisdictional transmission services” and “[a]ll charges assessed to recoup the cost of facilities used to provide transmission service are jurisdictional rates” (citing, *inter alia*, *Am. Elec. Power Serv. Corp.*, 96 FERC ¶ 61,136 at 61,570 (2001))). The Commission routinely approves E&P agreements through delegated orders. See, e.g., *Southwestern Pub. Serv. Co.*, Docket No. ER14-645-000 (unpublished delegated letter order issued Feb. 4, 2014); *Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER14-232-000 (unpublished delegated letter order issued Dec. 17, 2013).

¹³⁴ See *Genpower Anderson, LLC*, 101 FERC ¶ 61,038 at P 30 (“The Commission requires parties to make time value refunds for amounts improperly collected pursuant to [an agreement], with a

III. POTENTIAL REMEDIES AND PENALTIES

There are several potential remedies that could apply to the compliance issues addressed in this chapter. Sections 205 and 206 of the FPA have long provided FERC with the remedial discretion to require a transmission provider to refund any amounts improperly collected from ratepayers as the result of a tariff violation, such as a violation of the OATT or LGIP.¹³⁵ In addition, EPAct 2005 gives FERC authority to punish tariff violations by imposing civil penalties of up to \$1 million per day per violation of any rule or order issued in connection with the Commission's jurisdiction to regulate wholesale power sales and transmission in interstate commerce under the FPA.¹³⁶

FERC may pursue non-monetary remedies to address violations of its open access orders.¹³⁷ For example, in *Washington Water Power Co.*, FERC revoked a utility's market-based rate authority in part because it offered its merchant affiliate a form of transmission service that was not made available to nonaffiliates.¹³⁸ FERC has also considered increased oversight as a remedy, such as in *Tucson Electric Power Co.*¹³⁹ and *Arizona Public Service Co.*,¹⁴⁰ where both utilities agreed to install an independent market monitor.¹⁴¹

The Commission does not, however, always impose a penalty when it finds that a tariff violation has occurred. If the Commission approves of an activity for policy reasons but finds that the action did not comply with the requirements of a tariff, the Commission may order that

floor to protect the party performing the construction from constructing such facilities at a loss.”); *Re Western Mass. Elec. Co.*, 61 FERC ¶ 61,182 at 61,664 (1992) (citing *Cent. Me. Power Co.*, 56 FERC ¶ 61,200, *reh'g denied*, 57 FERC ¶ 61,083 (1991)), *petition denied*, 165 F.3d 922 (D.C. Cir. 1999); *see also Carolina Power & Light Co.*, 87 FERC ¶ 61,083 (1999) (clarifying refund policy).

¹³⁵ *See, e.g., La. Pub. Serv. Comm'n v. FERC*, 174 F.3d 218, 224-25 (D.C. Cir. 1999); *Towns of Concord v. FERC*, 955 F.2d 67, 76 (D.C. Cir. 1992); *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967); *Southern Co. Servs., Inc.*, 110 FERC ¶ 61,362 at P 6 n.7 (2005); *Entergy Servs., Inc.*, 104 FERC ¶ 61,061 at P 17 (2003), *appeal denied*, 400 F.3d 5 (D.C. Cir. 2005).

¹³⁶ *See* Pub. L. No. 109-58, § 1284(e), 119 Stat. at 980 (amending section 316A of the FPA, 16 U.S.C. § 825o-1). The Commission has issued a policy statement explaining the factors it will rely upon in assessing penalties under the new statute. *See Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 (2005) (“*Enforcement Policy Statement*”).

¹³⁷ As the Commission explained in the *Enforcement Policy Statement*, its “enhanced civil penalty authority will operate in tandem with [its] existing authority to require disgorgement of unjust profits obtained through misconduct and/or to condition, suspend, or revoke certificate authority or other authorizations, such as market-based rate authority for sellers of electric energy.” *Id.* at P 12.

¹³⁸ 83 FERC ¶ 61,097 at 61,462-63, *order on responses to show cause order*, 83 FERC ¶ 61,282 (1998).

¹³⁹ 109 FERC ¶ 61,272 (2004).

¹⁴⁰ 109 FERC ¶ 61,271 (2004).

¹⁴¹ *See Tucson Elec. Power Co.*, 109 FERC ¶ 61,272 at P 4; *Ariz. Pub. Serv. Co.*, 109 FERC ¶ 61,271 at P 4; *see also UniSource Energy Corp.*, 109 FERC ¶ 61,047 at P 19 (2004) (approving the market monitoring plan submitted by Tucson Electric Power Co.).

the tariff be amended to permit the activity. Additionally, if the Commission finds that a tariff violation has occurred but also finds that the violation did not result in any harm, it may forego a penalty.¹⁴²

¹⁴² See, e.g., *Shetek Wind Inc. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 138 FERC ¶ 61,250 at PP 3, 30, 142 (finding that MISO “violated its Tariff” by providing a type of interconnection service which was not provided for under its Tariff, setting for hearing the issue of whether any harm resulted from this action, and ordering that a compliance filing be made in the future to conform the service provided to new tariff provisions when such provisions are approved by the Commission); *ConocoPhillips Co. v. Entergy Servs., Inc.*, 129 FERC ¶ 61,243 at PP 20, 28 (2009) (explaining that the Commission had determined that a violation of Entergy’s OATT had occurred but decided not to provide any remedy for the violation) (citing *ConocoPhillips Co.*, 124 FERC ¶ 61,085 (2008)).

Chapter 10

Natural Gas Transportation: Shipper-Must-Have-Title Rule and Capacity Release Requirements

CHERYL M. FOLEY

This chapter covers FERC’s “shipper-must-have-title” rule and other rules and prohibitions relating to releases by shippers of firm transportation and storage capacity rights on interstate natural gas pipelines. FERC’s main goal in its capacity release program is to ensure that the secondary market for pipeline transportation and storage services operates in an open and nondiscriminatory manner through a process that requires posting of and bidding for capacity available for release. FERC has provided exemptions from some of the rules to allow for what it deems to be pro-competitive asset management arrangements and state retail access programs, but is otherwise prescriptive in the structure of the rules and in its enforcement efforts. This chapter only explains requirements relating to capacity release and does not address the full panoply of FERC rules and regulations regarding interstate pipeline transportation, exchanges and displacements,¹ open access requirements, postings, reports, certificate authorizations or other requirements that may apply to interstate natural gas pipelines and shippers in the primary transportation markets.

I. CAPACITY RELEASES IN GENERAL

A. BACKGROUND

FERC’s open access regime for natural gas pipelines was implemented in stages. First, in 1985, FERC issued Order No. 436, which established rules for pipelines to offer open-access transportation service independent of their “bundled” sales service.² Then, in 1992, FERC issued

¹ Whereas some types of “exchanges” under blanket certificates and FERC’s capacity release rules fall under the “buy/sell” prohibitions described in Part VII of this chapter, other types of exchanges or displacements of gas may be permitted pursuant to other FERC authorizations. See *Northern Ill. Gas Co.*, 90 FERC ¶ 61,308 (2000). If in doubt as to whether a particular transaction constitutes an exchange or displacement deemed to be a prohibited buy/sell, it is advisable to consult counsel.

² *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, FERC Stats. & Regs. ¶ 30,665, *order on reh’g*, Order No. 436-A, FERC Stats. & Regs. ¶ 30,675 at 31,686 (1985), *order on reh’g*, Order No. 436-B, FERC Stats. & Regs. ¶ 30,688, *reh’g denied*, Order No. 436-C, 34 FERC ¶ 61,404, *reh’g denied*, Order No. 436-D, 34 FERC ¶ 61,405, *recon. denied*, Order No. 436-E, 34 FERC ¶ 61,403 (1986), *aff’d in part and vacated and remanded in part sub nom. Associated Gas Distribs. v. FERC*, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988) (codified as amended at 18 C.F.R. pts. 2, 157, 250, 284, 375, 381).

Order No. 636, which mandated that natural gas pipelines unbundle their gas sales and gas transportation services and provide comparable transportation and storage service to all shippers—regardless of whether they purchase gas from the pipeline’s corporate family or a third-party gas seller.³

During the period between Order No. 436 and Order No. 636, FERC approved a number of “capacity brokering” arrangements on particular pipelines. Under those arrangements, firm shippers could assign their capacity directly to a replacement shipper on a first-come, first-served basis—without any requirement that the “brokering” shipper post the availability of its capacity or allocate it to the highest bidder.⁴ However, when FERC imposed unbundling on the pipelines in Order No. 636, the agency also concluded that these capacity brokering arrangements were no longer satisfactory and that there were too many different programs for the Commission effectively to monitor.⁵ FERC thus eliminated the old capacity brokering programs and promulgated capacity release regulations of uniform applicability. The regulations were intended to assure the transparency of capacity release transactions and a nondiscriminatory allocation of any released capacity. As part of the pipeline restructuring process that followed Order No. 636, each pipeline was required to implement, through tariffs filed for Commission approval, capacity release procedures compliant with the regulations.

The capacity release regulations have been in effect since 1992. FERC made substantial revisions to the regulations in Order No. 712, and the revised regulations became effective on July 30, 2008.⁶ Those revisions, while important, did not change a basic precept—that the capacity release regulations represent the *only* means by which FERC allows shippers to “broker” their capacity.

³ *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission’s Regulations; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, FERC Stats. & Regs. ¶ 30,939, *order on reh’g*, Order No. 636-A, FERC Stats. & Regs. ¶ 30,950, *order on reh’g*, Order No. 636-B, 61 FERC ¶ 61,272 (1992), *reh’g denied*, 62 FERC ¶ 61,007 (1993), *aff’d in part and vacated and remanded in part sub nom. United Distrib. Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied*, 520 U.S. 1224 (1997), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997), *reh’g denied*, Order No. 636-D, 83 FERC ¶ 61,210 (1998) (codified at 18 C.F.R. pt. 284).

⁴ *See, e.g., Algonquin Gas Transmission Corp.*, 59 FERC ¶ 61,032 (1992).

⁵ Order No. 636, FERC Stats. & Regs. ¶ 30,939 at 30,416.

⁶ *Promotion of a More Efficient Capacity Release Mkt.*, Order No. 712, FERC Stats. & Regs. ¶ 31,271, *order on reh’g and clarification*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *order on reh’g and clarification*, Order No. 712-B, 127 FERC ¶ 61,051 (2009), *petitions for review denied sub nom. Interstate Natural Gas Ass’n of Am. v. FERC*, 617 F.3d 504 (D.C. Cir. 2010) (codified at 18 C.F.R. §§ 284.8, 284.13).

B. THE BASIC RULES

FERC's capacity release regulations, codified at 18 C.F.R. § 284.8, can be summarized as follows. If a firm shipper wants to release capacity,⁷ it must notify the pipeline of the terms and conditions under which it will release its capacity and of any replacement shipper designated to obtain the released capacity.⁸ Releasing shippers can release all or a part of their capacity on a permanent or temporary basis.⁹ Information regarding the terms and conditions of a release must be posted on the pipeline's Internet website¹⁰ The rate charged the replacement shipper for a release of capacity for more than one year may not exceed the applicable pipeline maximum rate.¹¹ However, no rate limitation applies to the release of capacity for a period of one year or less.¹²

Order No. 712 modified the capacity release regulations to facilitate both asset management agreements and state retail open access programs by exempting capacity releases made under either qualified asset management agreements or state approved programs from capacity release bidding requirements and tying prohibitions.¹³ These exemptions are discussed in Part VIII of this chapter.

II. POSTING

Some release transactions need to be posted in advance for bidding, while others do not.

- Capacity released to a designated replacement shipper for a period of *31 days or less* does *not* have to be posted in advance for competitive bidding.¹⁴ However, capacity released for a period of 31 days or less may not be rolled over, extended or otherwise provided to the same shipper or any affiliate without subjecting it to the posting and bidding requirements, unless a period of more than 28 days has passed since the expiration of the initial release. See Part V regarding the prohibitions against “flipping” for a detailed discussion of these rules.

⁷ As used in this memo, the terms “capacity” and “transportation” include transportation of natural gas in interstate commerce by an interstate natural gas pipeline and interstate natural gas storage services.

⁸ 18 C.F.R. § 284.8(c). The capacity release regulations by their terms only apply to firm pipeline capacity, *id.* § 284.8(a), and the Commission has rejected proposals to apply the firm capacity release bidding procedures to allocation of interruptible capacity. See *Viking Gas Transmission Co.*, 63 FERC ¶61,104 at 61,673 (1993) (“Capacity release is available only for the assignment of firm transportation capacity.”).

⁹ 18 C.F.R. § 284.8(b)(1).

¹⁰ *Id.* § 284.8(c), (d).

¹¹ *Id.* § 284.8(b)(2).

¹² *Id.*

¹³ *Id.* § 284.8(h)(3), (4). See also Order No. 712, FERC Stats. & Regs. ¶ 31,271 at PP 199-200.

¹⁴ 18 C.F.R. § 284.8(h)(1). See discussion of capacity release “flipping,” *infra*.

- Similarly, the release of capacity to a designated replacement shipper for a period of *more than one year* need not be posted for competitive bidding, provided that the release is at *the relevant pipeline's maximum tariff rate*.¹⁵

Subject to the exceptions discussed in Part VIII,¹⁶ all releases other than those described above—in other words, all long-term releases (in excess of one year) not reassigned to a designated replacement shipper at the maximum rate and all releases of capacity for one year or less (but in excess of 31 days)—*must* be posted for competitive bidding, and the pipeline must allocate the capacity to the person offering the highest rate and meeting any other terms and conditions in the release.¹⁷ However, the regulations permit the releasing shipper to choose a pre-arranged replacement shipper who can retain the capacity by matching the highest bid rate.¹⁸

Even if a capacity release is not subject to the pre-bid posting requirement, a shipper who releases capacity that is not subject to pre-bid posting must provide a notice of release on the pipeline's Internet website (hereafter referred to as a "notice of release") as soon as possible after the release has been agreed to, but not later than the first nomination commencing the release transaction.¹⁹

It should be noted that release of pipeline capacity by a releasing shipper is a FERC-jurisdictional transaction. The regulations explicitly provide that firm shippers release capacity pursuant to a limited "blanket certificate" under the NGA.²⁰

III. THE MAXIMUM RATE

Prior to Order No. 712, the maximum rate ceiling on capacity release transactions applied on *all* releases, with waivers granted sparingly.²¹ However, in Order No. 712 the Commission

¹⁵ 18 C.F.R. § 284.8(h)(1)(iii).

¹⁶ These exceptions relate to transactions undertaken in conjunction with asset management arrangements or state-approved retail access programs.

¹⁷ 18 C.F.R. § 284.8(c)-(e).

¹⁸ *Id.* § 284.8(b), (e).

¹⁹ *Id.* § 284.8(h)(1).

²⁰ *Id.* § 284.8(g).

²¹ FERC (on individual application) waived the ceiling for releasing shippers seeking to permanently exit the natural gas business or permanently exit a service. *See Duke Energy Mktg. Am., LLC*, 114 FERC ¶ 61,198 at P 25 (2006) (To the extent the winning bidder of a package of releases will be paying up to the negotiated contract rate for the released capacity with regard to a particular release, the Commission indicated a willingness to permit such a result based upon the company's representations that it was attempting to divest itself of its natural gas contracts due to a corporate merger.). *See also Tenn. Gas Pipeline Co.*, 113 FERC ¶ 61,106 at P 9 (2005) (The Commission permitted a releasing shipper to permanently release capacity associated with a negotiated rate contract with a pipeline that it obtained when it converted from incremental service to a higher quality Part 284 service. In order to take capacity under the higher quality service and still compensate the pipeline for its expansion costs the shipper paid a negotiated rate higher than the maximum rate. The Commission found the circumstances of the release to

concluded that the rate ceiling interfered with efficient capacity allocation. The Commission thus eliminated the rate cap on capacity releases of one year or less:

The Commission finds that [lifting the rate ceiling on releases of one year or less] will improve shipper options and market efficiency, particularly during peak periods, by allowing the prices of short-term capacity release transactions to reflect short-term variations in the market value of that capacity. This will enable shippers to better integrate capacity with the underlying gas transactions, and will permit more flexible methods of pricing capacity to better reflect the value of that capacity as revealed by the market price of gas at different trading points. The Commission has previously provided pipelines with the flexibility to enter into negotiated rate transactions which are permitted to exceed the maximum rate ceiling, and this rule will permit releasing shippers similar flexibility in pricing release transactions.²²

At the same time, Order No. 712 retained the maximum rate ceiling on releases for terms in excess of one year.²³ In determining whether a long-term release exceeds the maximum rate, FERC has looked to the entirety of the financial package. For example, the Commission has held that any consideration paid by the releasing shipper to a pre-arranged replacement shipper must be taken into account in determining whether the release is at the maximum rate.²⁴ Where releasing and replacement shippers execute “joint marketing arrangements” under which a replacement shipper agrees either to (a) share with the releasing shipper revenues obtained by the replacement shippers on the sales of the gas transported by means of the released capacity, or (b) pay the releasing shipper prices based on the amount of gas transported and sold, those payments may violate the rate ceiling to the extent that they exceed the maximum pipeline tariff rates.²⁵

In the past, because the rate ceiling applied regardless of the term of the release, FERC exempted pre-arranged releases at the maximum rate from competitive bidding. The pipeline had to post a notice of release for informational purposes, but by definition there was no need for bidding on a release at the maximum rate.²⁶ This *still* applies with respect to releases at the

be unique.). These cases involved situations where (1) the releasing shippers (pursuant to FERC rules on negotiated pipeline rates) were paying negotiated rates to the pipeline in excess of the maximum tariff rate; and (2) the pipeline would not agree to the permanent release of the capacity to a replacement shipper who did not pay the same rate that the releasing shipper paid.

²² Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 30.

²³ *Id.* at P 78.

²⁴ *Louis Dreyfus Energy Servs., L.P.*, 114 FERC ¶ 61,246 at P 15 (2006).

²⁵ Nevertheless, Order No. 712 created special exemptions governing capacity release arrangements between shippers and their asset managers that can provide safe harbors for joint marketing arrangements. *See infra* Part VIII.

²⁶ Note, in this regard, that FERC also has held that where a designated replacement shipper agrees to pay the pipeline the maximum rate for the released capacity, but the *releasing* shipper agrees to make a payment to the replacement shipper, the release is really a release at less than the maximum rate and the posting and bidding requirements apply. *Consumers Energy Co.*, 84 FERC ¶ 61,240 (1998).

maximum rate for terms in excess of one year. However, with the rate ceiling removed for releases of one year or less, all pre-arranged releases for one year or less (in excess of 31 days) that are not undertaken as part of asset management arrangements or pursuant to a state retail access program must now be posted in advance for competitive bidding.²⁷ A designated replacement shipper in such a pre-arranged release still has the option to meet competing bids, but that designated replacement shipper can no longer lock in a guaranteed maximum rate.

IV. PROHIBITIONS AGAINST TYING

All terms and conditions for a capacity release transaction must be posted on the pipeline's Internet website.²⁸ The Commission also requires that "*all* terms and conditions for capacity release must be . . . nondiscriminatory, and must relate *solely* to the details of acquiring transportation on interstate pipelines. *Releases of pipeline capacity cannot be tied to any other conditions.*"²⁹ In Order No. 636-B, the Commission made specific reference to "tying arrangements" in the context of the tying of transportation services together that are commercially distinct. The Commission indicated that these types of arrangements were contrary to the spirit of unbundling.³⁰ This policy against tying "is meant to prevent pipelines from requiring shippers to take capacity that the shippers do not want in order to get capacity that the shippers do want."³¹ However, the Commission has subsequently clarified that the prohibition on tying is "far broader" than an attempt to tie a release of "valuable capacity to relatively worthless capacity."³²

In Order No. 712, the Commission recognized that the prohibition against tying arrangements can interfere with legitimate asset management arrangements and state-approved retail access programs. Thus, Order No. 712 revises the tying prohibition to exempt releases in conjunction with qualified Asset Management Arrangements and state-approved retail access programs from the prohibition against tying. (Qualified Asset Management Arrangements and state-approved retail access programs are discussed below).

Further, Order No. 712 recognizes that "storage capacity is inextricably attached to the gas in storage."³³ Therefore, the Commission allows an exception to the tying rule to "allow a shipper that releases storage capacity to require the replacement shipper to (1) take title to any gas in the released storage capacity at the time the release takes effect and/or (2) return the

²⁷ See Order No. 712, FERC Stats. & Regs. ¶ 31,271 at PP 72-73.

²⁸ 18 C.F.R. § 284(d).

²⁹ Order No. 636-A, FERC Stats. & Regs. ¶ 30,950 at 30,559 (emphasis added).

³⁰ Order No. 636-B, 61 FERC ¶ 61,272 at 62,012.

³¹ *Transwestern Pipeline Co.*, 92 FERC ¶ 61,035 at 61,080 (2000).

³² *Louis Dreyfus Energy Servs., L.P.*, 114 FERC ¶ 61,246 at P 20.

³³ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 190.

storage capacity to the releasing shipper at the end of the release with a specified amount of gas in storage.”³⁴

V. PROHIBITIONS AGAINST “FLIPPING”

As discussed above, the capacity release regulations provide that a release of capacity for any period of 31 days or less—which we for convenience will refer to as a “short-term release”—need not be posted for bidding.³⁵ However, the parties may not “roll over, extend, or in any way continue the release to the same shipper” without posting the capacity for bid.³⁶ In addition, the releasing shipper “may not re-release to the same replacement shipper [without competitive bidding] at less than the maximum tariff rate until 28 days after the first release period has ended.”³⁷

The prohibition against roll-overs of short-term releases to the same replacement shipper raised a question concerning back-to-back short-term releases to different replacement shippers, where the second replacement shipper was affiliated to the first replacement shipper. In an early pipeline restructuring case following Order No. 636, FERC reviewed the tariff of El Paso Natural Gas Company, which contained an exemption from competitive bidding for discounted releases of 30 days or less (at the time the regulation used 30 days rather than 31). A protester argued that while this may be consistent with regulatory requirements, the exemption would allow pipelines and releasing shippers with more than one affiliate to circumvent open season and competitive bidding procedures by alternating short-term releases between or among affiliates, thereby removing capacity from the open market for more than 30 days. To avoid this situation, the protester recommended that the Commission require El Paso to implement open season, competitive bidding procedures for any short-term capacity release involving the pipeline’s affiliate or the releasing shipper’s affiliate.³⁸ The Commission rejected this request, but added:

The Commission agrees, however, that there is a potential that short-term releases among affiliated companies could permit these companies to avoid the necessity to post transactions for more than one month for competitive bids. The requirement that notice of short-term releases be posted on the bulletin board within 48 hours is designed to expose these kinds of abuses should they occur. *If they do, the Commission will take action to prevent recurrences. The Commission will scrutinize any pattern of releases to affiliates to prevent the discriminatory release or releases of capacity.*³⁹

³⁴ *Id.*

³⁵ 18 C.F.R. § 284.8(h)(1). Notice of the release must be posted no later than the first nomination after the release transaction commences. *Id.*

³⁶ *Id.* § 284.8(h)(2).

³⁷ *Id.*

³⁸ *El Paso Natural Gas Co.*, 61 FERC ¶ 61,333 at 62,296 (1992).

³⁹ *Id.* (emphasis added).

Similar language appeared in other post-Order No. 636 restructuring cases.⁴⁰ FERC stated at that time that “[t]he Commission does not believe that a prohibition on rollovers to affiliates of the pipeline or the releasing shipper should be required before any experience is gained with the operation of [the pipeline’s] capacity release program,”⁴¹ and that “any patterns of abuse may be scrutinized in complaint proceedings.”⁴² From these early orders, the extent to which back-to-back, discounted short-term releases could be made to affiliated replacement shippers without competitive bidding was not entirely clear.⁴³

However, clarity came in 2007 when the Commission assessed a \$7 million penalty against BP Energy Company (“BP Energy”).⁴⁴ That case encompassed, among other things, a practice FERC called “flipping.” FERC defined “flipping” as “repeated short-term releases of discounted rate capacity to two or more affiliated replacement shippers on an alternating monthly basis in order to avoid the competitive bidding requirement for discounted long-term capacity releases.”⁴⁵ According to the Commission:

The effect of flipping is to create a long-term, non-competitive discounted rate release. Flipping is an inappropriate strategy that defeats, and therefore violates, the posting and bidding requirements, and the prohibition on roll-overs or extensions set out in 18 C.F.R. § 284.8. *We see no legitimate business or operational reason for arranging capacity releases from a single releasing shipper to multiple affiliated entities on an alternating monthly basis.*⁴⁶

BP Energy also involved violations of the shipper-must-have-title rule and the Commission’s prohibition on buy/sells, and the penalty amount was not apportioned between the various categories of violations. Nonetheless, the Commission considered the “flipping” as “particularly serious in nature.”⁴⁷ FERC viewed the practice as “a deliberate attempt to circumvent the Commission’s rules requiring posting and competitive bidding for discounted, long-term releases of capacity” and could see “no other reason for alternating monthly releases

⁴⁰ See *Transwestern Pipeline Co.*, 61 FERC ¶ 61,332 at 62,243 (1992); *Tex. E. Transmission Corp.*, 62 FERC ¶ 61,051 at 61,100-01 (1993).

⁴¹ *Transwestern Pipeline Co.*, 63 FERC ¶ 61,138 at 61,904 (1993).

⁴² *Id.*

⁴³ *C.f. Northern Ill. Gas Co.*, 102 FERC ¶ 61,298, 61,493, 61,946-47 (2003) (in resolving all issues related to a non-public investigation of, *inter alia*, capacity release transactions that Nicor Gas admitted “may” have violated the capacity release regulations, Nicor Gas agreed that it would not release capacity at less than the maximum tariff rate for periods of 31 days or less unless it has completed a checklist, with respect to any such release, that shows that Nicor Gas had not released capacity in the previous month on the same pipeline at less than the maximum rate to the proposed pre-arranged replacement shipper or an affiliate of such shipper).

⁴⁴ *In re BP Energy Co.*, 121 FERC ¶ 61,088 (2007).

⁴⁵ *Id.* at P 8.

⁴⁶ *Id.* (emphasis added).

⁴⁷ *Id.* at P 22.

other than to disguise a long-term discounted rate release as a series of short-term releases to avoid the requirement to post such releases for competitive bidding.”⁴⁸ Subsequently, FERC assessed a \$5 million civil penalty against Constellation NewEnergy – Gas Division, LLC (and ordered disgorgement of approximately \$1.9 million plus interest on unjust profits) for, among other things, flipping.⁴⁹

In addition to violations of the shipper-must-have-title rule and the prohibition against buy/sells, both discussed below, flipping has been one of the most common violations of FERC’s capacity release rules and its definition has been expanded over the years. FERC has found that either the shipper releasing the original capacity or the customer contracting for the released capacity can be guilty of flipping violations.⁵⁰ Further, the Commission has deemed unposted re-releases to the same company as a version of flipping,⁵¹ as well as releases by and among affiliates, where the terms and conditions of the releases are “substantially similar.”⁵²

VI. THE SHIPPER-MUST-HAVE-TITLE RULE

The “shipper-must-have-title” rule requires that a shipper on an interstate natural gas pipeline must satisfy three conditions. First, the shipper must have a capacity contract with the pipeline.⁵³ Second, the shipper must have title to the gas at the time the gas is delivered to the pipeline for transportation.⁵⁴ Third, the shipper must have title to the gas while it is being transported or stored by the pipeline or storage company.⁵⁵ In other words, these three conditions mean that the shipper of record transacting with the pipeline or storage company and the holder of title to the gas being shipped or stored must be one and the same. Moreover, these conditions must be met even when an agency arrangement exists between the shipper and a third party (such as the supplier of the gas being shipped).⁵⁶ The shipper-must-have-title rule is not limited to capacity releases and applies to both firm and interruptible transportation and storage

⁴⁸ *Id.*

⁴⁹ *In re Constellation NewEnergy – Gas Div., LLC*, 122 FERC ¶ 61,220 (2008). Recent cases continue to confirm the Commission’s prohibition against flipping, defined as “the repeated short-term release of discounted rate capacity to two or more affiliated replacement shippers on an alternating monthly basis that avoids the competitive bidding requirements.” *DTE Gas Co.*, 143 FERC ¶ 61,188 at P 6 (2013).

⁵⁰ *See, e.g., id.*; *In re Mo. Gas Energy*, 140 FERC ¶ 61,135 (2012) (“*Missouri Gas*”); *In re ConocoPhillips Co.*, 138 FERC ¶ 61,004 at P 5 (2012).

⁵¹ *DTE Gas Co.*, 143 FERC ¶ 61,188 at P 6; *Missouri Gas*, 140 FERC ¶ 61,135 at P 5 (described the violation as an “impermissible rollover”).

⁵² *In re Atmos Energy Corp.*, 137 FERC ¶ 61,190 at P 9 (2011); *see Missouri Gas*, 140 FERC ¶ 61,135 at P 5.

⁵³ *See, e.g., Rendezvous Gas Servs., L.L.C.*, 113 FERC ¶ 61,169 at P 40 (2005).

⁵⁴ *See, e.g., Consolidated Gas Transmission Corp.*, 38 FERC ¶ 61,150 at 61,408-10 (1987).

⁵⁵ *Id.*

⁵⁶ *Enron Energy Servs., Inc.*, 85 FERC ¶ 61,221 at 61,906 (1998).

and to shippers in both the primary and secondary (capacity release) transportation and storage markets.

The rule is intended to assure nondiscriminatory access to transportation by preventing unauthorized capacity brokering by pipeline transportation and storage customers.⁵⁷ The rule is also intended to provide transparency to jurisdictional transactions and to prevent the withholding of interstate capacity.⁵⁸

The shipper-must-have-title rule actually predates FERC's capacity release regulations, having been developed in the late 1980s as a major element of the agency's pipeline open-access regime.⁵⁹ After the promulgation of the capacity release regulations, some shippers argued that the shipper-must-have-title rule no longer served a purpose and should be eliminated. FERC disagreed, finding that without the rule, shippers would be unlikely to use capacity release, because they could simply transport gas over the pipeline for another entity—*without* being subject to any of the capacity release requirements, such as transactional reporting or capacity allocation between replacement shippers.⁶⁰

Of the Natural Gas Act civil penalties that FERC has assessed following enactment of the Energy Policy Act of 2005,⁶¹ the vast majority have involved some aspect of the shipper-must-have-title rule. And in the notice of proposed rulemaking that ultimately led to the issuance of Order No. 712, the Commission highlighted the rule's importance to enforcement of the capacity release regulations:

[T]he shipper-must-have-title requirement . . . has become the foundation for the Commission's capacity release program. . . . Without the shipper-must-have-title requirement, "capacity holders could simply transport gas over the pipeline for another entity," without complying with any of the requirements of the capacity release program. Thus, the capacity holder could charge the other entity any rate it desired for this service, and the capacity holder would not need to post the arrangement with the other entity for bidding to permit others to obtain the service at a higher rate.

⁵⁷ See, e.g., *Tex. E. Transmission Corp.*, 37 FERC ¶ 61,260 at 61,683-85 (1986).

⁵⁸ See, e.g., *Rendezvous Gas Servs., L.L.C.*, 113 FERC ¶ 61,169 at P 40.

⁵⁹ See, e.g., *Tex. E. Transmission Corp.*, 37 FERC ¶ 61,260 at 61,683-85; *Consolidated Gas Transmission Corp.*, 38 FERC ¶ 61,150 at 61,408.

⁶⁰ See *Regulation of Short-Term Natural Gas Transp. Servs. and Regulation of Interstate Natural Gas Transp. Servs.*, Order No. 637, FERC Stats. & Regs. ¶ 31,091 at 31,300, *order on reh'g*, Order No. 637-A, FERC Stats. & Regs. ¶ 31,099, *reh'g denied*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part sub nom. Interstate Natural Gas Assoc. of Am. v. FERC*, 285 F.3d 18 (D.C. Cir.), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g and clarification*, 106 FERC ¶ 61,088 (2004).

⁶¹ Pub. L. No. 109-58, § 314(b)(1)(B), 119 Stat. 594, 961 (2005) (codified at 15 U.S.C. § 717t-1).

*By contrast, under the shipper-must-have-title requirement, an assignment of capacity from one shipper to another may only be accomplished through the capacity release program.*⁶²

Accordingly, without further extensive discussion, Order No. 712 left the shipper-must-have-title rule in place.⁶³

The inter-play between the shipper-must-have-title rule and the capacity release regulations can be illustrated by the *Calpine Energy Servs., L.P.* case.⁶⁴ In that case, Calpine Corporation (“Calpine”) created a service company to consolidate its affiliated natural gas and power marketing activities into a single subsidiary. The service company acted as the fuel manager for its affiliates, many of which held title to interstate pipeline capacity. The service company, not the individual generating plants, managed transportation capacity, including capacity procurement. And where a plant held gas transportation capacity in its own name, the service company acted on behalf of the plant by nominating and scheduling service, even when title to the gas transported was held by the service company. The service company thus violated the “shipper-must-have-title” requirement by transporting gas to which it held title using capacity rights of other Calpine affiliates.⁶⁵ FERC found that none of these transactions created identifiable financial harm to any third party and, had they been structured differently, generally could be undertaken as pre-arranged capacity releases at the maximum pipeline rate, without any requirement of competitive bidding. Nonetheless, in assessing a civil penalty, FERC held that by failing to engage in proper capacity releases followed by Internet postings, the service company shielded from non-affiliated market participants relevant information concerning the use being made of capacity held by Calpine affiliates. In this way, FERC said, the shipper-must-have title violations undermined the market transparency necessary for the Commission’s open access policies to function properly.⁶⁶

The importance that FERC places on the shipper-must-have-title rule, as well as the rule’s essentially technical nature, can be seen in other FERC civil penalty assessments involving the rule. For example, in *Entergy New Orleans, Inc.*,⁶⁷ a local distribution company (“LDC”) was cited for violations that occurred because the LDC preferred to take title to its gas at the pipeline’s delivery point rather than the receipt point. The LDC undertook that practice in order to have the timing of the billing for its gas supply match the timing of the delivery of the gas for purposes of the LDC’s monthly purchased gas adjustment filings with its local regulatory body.⁶⁸

⁶² *Promotion of a More Efficient Capacity Release Mkt.; Notice of Proposed Rulemaking*, 121 FERC ¶ 61,170 at PP 106-07 (2007) (emphasis added) (footnotes and citations omitted).

⁶³ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 7 & n.10.

⁶⁴ 119 FERC ¶ 61,125 (2007).

⁶⁵ *Id.* at P 9.

⁶⁶ *Id.* at PP 10-11.

⁶⁷ 122 FERC ¶ 61,219 (2008).

⁶⁸ *Id.* at P 3.

The *Constellation NewEnergy* case, already discussed with reference to “flipping,” also involved the shipper-must-have-title rule. The company was cited by FERC because (1) a Constellation affiliate serving as an agent for a gas customer used the customer’s pipeline capacity to ship the affiliate’s gas either to the customer or a third party; (2) a Constellation affiliate shipped gas to which each affiliate held title but used another affiliate’s pipeline capacity; (3) a third-party’s storage and transportation capacity was used to serve Constellation customers; and (4) there were numerous mismatches between capacity rights and gas ownership during integration of newly-acquired natural gas companies and other retail natural gas assets.⁶⁹ Likewise, the Commission has cited companies for shipper-must-have-title violations in the context of marketer and asset managers shipping their own gas using customers’ pipeline capacity.⁷⁰ In all these cases, FERC appears to view the shipper-must-have-title rule as a *per se* rule. The agency may examine various factors to determine penalty amounts, if any, but the agency’s approach to determining the existence of a violation is essentially mechanical.

VII. THE PROHIBITION AGAINST “BUY/SELLS”

“Buy/sells” were pre-Order No. 636 arrangements that typically involved LDCs holding interstate pipeline transportation capacity. Under a buy/sell, a shipper holding interstate pipeline capacity would buy gas at the direction of, on behalf of, or directly from another entity (e.g., an end-user), ship that gas using its own interstate pipeline capacity, and then resell an equivalent quantity of gas to such entity at the delivery point.⁷¹ In *El Paso Natural Gas Co.*, the Commission concluded that it has jurisdiction over buy/sell arrangements.⁷² The Commission also concluded that buy/sells would no longer be authorized, because the arrangements were not consistent with the capacity release regulations:

[W]e believe that to permit new buy/sell transactions to utilize interstate pipeline capacity after the capacity release mechanism goes into effect will frustrate this nationally uniform program. To allow any new buy/sell arrangements to be negotiated totally outside the capacity release mechanism at that time would provide a major loophole, potentially inviting substantial circumvention of the capacity release mechanism. It is, therefore, necessary for us in the exercise of our exclusive jurisdiction over access to interstate pipeline capacity to prohibit all new buy/sell transactions entered into after the time that a pipeline’s capacity release mechanism goes into effect.⁷³

⁶⁹ 122 FERC ¶ 61,220 at P 12, Stipulation at PP 12-6.

⁷⁰ *In re Integrys Energy Servs., Inc.*, 125 FERC ¶ 61,089 at P 10 (2008); *In re Enbridge Mktg. (U.S.) L.P.*, 125 FERC ¶ 61,088 at P 6 (2008); *BP Energy*, 121 FERC ¶ 61,088 at PP 12-13.

⁷¹ The Commission defines buy/sells in more recent cases using virtually identical language. See *Missouri Gas*, 140 FERC ¶ 61,135 at P 12.

⁷² 59 FERC ¶ 61,031, *order denying reh’g and clarifying prior order*, 60 FERC ¶ 61,117 (1992).

⁷³ *Id.*, 59 FERC at 61,080.

Consistent with that holding, the Commission in Order Nos. 636 and 636-A concluded that as of the effective date of a pipeline's compliance with restructuring pursuant to Order No. 636, no new buy/sell arrangement could be consummated and all allocations of capacity could be accomplished only under the capacity release regulations.⁷⁴ And the Commission continues to enforce this prohibition. The above-cited *BP Energy*, *Constellation NewEnergy* and *Missouri Gas* cases, in addition to involving capacity release "flipping," all involved prohibited buy/sells.

The first such transaction in the *BP Energy* case involved BP Energy (as an asset manager) purchasing its customer's gas and shipping it using BP's capacity rights between an onshore pool and downstream points where the customer held interstate pipeline capacity. BP Energy then resold the gas back to its customer at the downstream points.⁷⁵ Second, in a different transaction, under a comprehensive asset management arrangement with a gas end-user, BP Energy purchased the customer's gas at certain points along the transportation path and sold equal amounts of gas to the customer at downstream delivery points in order to reduce fuel and commodity costs on the pipelines.⁷⁶

The *Constellation NewEnergy* case also involved two examples of buy/sells. In the first example, a Constellation retail gas marketer sold its gas to its retail affiliate for transport over the affiliate's capacity rights on a particular pipeline. The affiliate then resold the gas back to the retail marketer once the transportation was complete.⁷⁷ In a separate single-day transaction, a Constellation wholesale marketer sold gas to its affiliated retail marketer for transport using the retail marketer's pipeline capacity for ultimate resale back to the wholesale marketer.⁷⁸

In both *BP Energy* and *Constellation NewEnergy* and in the more recent cases, such as *Missouri Gas*, the Commission has emphasized that buy/sell transactions circumvent, and therefore frustrate, the Commission's pipeline open-access policies by effectively allowing capacity brokering outside the structure of the Commission capacity release regulations (including the requirements of posting and competitive bidding).⁷⁹ Order No. 712 left the prohibition against buy/sells in place.⁸⁰

⁷⁴ Order No. 636, FERC Stats. & Regs. ¶ 30,939 at 30,416-17; Order No. 636-A, FERC Stats. & Regs. ¶ 30,950 at 30,570.

⁷⁵ *BP Energy*, 121 FERC ¶ 61,088 at P 16.

⁷⁶ *Id.*

⁷⁷ *Constellation NewEnergy*, 122 FERC ¶ 61,220 at P 15.

⁷⁸ *Id.*

⁷⁹ In *Missouri Gas*, 140 FERC ¶ 61,135 at P 12, the Commission stated, "By prohibiting buy-sell transactions, the Commission prevents a capacity holder with priority to pipeline capacity from acting as a broker of transportation capacity or assigning transportation capacity to end-use customers. This prohibition was intended to prevent circumvention of the Commission's open access transportation policy and regulations which require released capacity to be posted and bid on a nondiscriminatory basis." See also *BP Energy*, 121 FERC ¶ 61,088 at P 17; *Constellation NewEnergy*, 122 FERC ¶ 61,220 at P 16.

⁸⁰ Order No. 712 does grant an exemption from the buy/sells prohibition for asset management arrangements that otherwise qualify for the exemptions from bidding and tying, but only for volumes of

VIII. SPECIAL RULES FOR CAPACITY RELEASED TO ASSET MANAGERS OR
UNDER STATE-APPROVED RETAIL ACCESS PROGRAMS

A. REQUIREMENTS – ASSET MANAGEMENT AGREEMENT

When FERC first promulgated its capacity release regulations in the early 1990s, the agency’s focus was on regulating capacity brokering. In other words, FERC sought to regulate the methods by which capacity holders sold unneeded capacity into the secondary market. However, FERC did not foresee another aspect of capacity release—that owners of gas-fired generation or local gas distribution companies would seek to release capacity to a third party in conjunction with asset management arrangements (“AMAs”), where the third party acts as a natural gas asset manager for the releasing shipper. In Order No. 712, FERC recognized the benefits of AMAs and that those benefits could be frustrated by the then-existing capacity release rules.⁸¹ Accordingly, in Order No. 712 FERC established certain exemptions (described below) applicable only to capacity released to an asset manager.

A release eligible for these AMA exemptions is any pre-arranged release that contains a condition that the releasing shipper may, on any day during a minimum period of five months out of each twelve-month period of the release, call upon the replacement shipper (i.e., the asset manager) to:

- (i) deliver to the releasing shipper a volume of gas up to 100 percent of the daily contract demand of the released transportation or storage capacity or
- (ii) purchase a volume of gas up to the daily contract demand of the released transportation capacity.⁸²

If the capacity release is for a period of one year or less, the asset manager’s delivery or purchase obligation must apply for the lesser of five months or the term of the release.⁸³ If the capacity release is for a period of more than one year, the purchase obligation must apply during a minimum period of five months for each twelve-month period, and on five-twelfths of the days of any additional period not equal to twelve months.⁸⁴ If the capacity release is a release of storage capacity, the asset manager’s delivery or purchase obligation need only be 100 percent of the daily contract demand under the release for storage withdrawals or injections, as applicable.⁸⁵

gas re-delivered to the releasing shipper by the asset manager. Order No. 712, FERC Stats. & Regs. ¶ 31,271 at PP 163, 165.

⁸¹ See *id.* at P 109.

⁸² 18 C.F.R. § 284.8(h)(3).

⁸³ *Id.* § 284.8(h)(3)(i).

⁸⁴ *Id.* § 284.8(h)(3)(ii).

⁸⁵ *Id.* § 284.8(h)(3)(iii).

While advance posting for competitive bidding is not required for AMAs, information must be provided not later than the first nomination after the release transaction commences,⁸⁶ identifying the release as an AMA and specifying the volumetric level of the replacement shippers delivery or purchase obligation and the time periods during which that obligation is in effect.

B. REQUIREMENTS – STATE-APPROVED RETAIL ACCESS PROGRAMS

In order to qualify for the retail access exemptions granted under Order No. 712, the pipeline capacity must be released by an LDC pursuant to a state-approved retail access program and must be used by the replacement shipper to fulfill the gas supply requirements of the retail customers of the releasing LDC. FERC notes that “a key component of most such programs is a provision for the LDC to make periodic releases, at the maximum rate, of its interstate pipeline capacity to the marketers participating in the program . . . [who] then use the released capacity to transport the gas supplies that they sell to their retail customers.”⁸⁷

Similar to AMAs, advance posting for competitive bidding is not required for capacity released pursuant to a state-approved retail access program. However, a notice of release must be provided not later than the first nomination after the release transaction commences,⁸⁸ identifying the release as one pursuant to such state program.

C. EXEMPTIONS

The first AMA and retail access exemption applies to the bidding requirement. FERC recognizes that all capacity releases made to implement AMAs are pre-arranged, as the releasing shipper must be able to use the asset manager of its choice to effectuate the components of the agreement.⁸⁹ Unlike a normal capacity release—where the releasing shipper is often shedding excess capacity and has no intention of an ongoing relationship with the replacement shipper—in the AMA context the identity of the replacement shipper is often critical because it will manage the releasing shipper’s portfolio for some time into the future.⁹⁰ Accordingly, the Commission now exempts capacity releases made as part of AMAs from the requirement of competitive bidding.⁹¹

⁸⁶ *Id.* § 284.8(h)(1)(v).

⁸⁷ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 194.

⁸⁸ *Id.* § 284.8(h)(1)(v).

⁸⁹ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 133.

⁹⁰ *Id.*

⁹¹ 18 C.F.R. § 284.8(h)(1)(i). As noted earlier, the Commission has also clarified that the rollover prohibitions of section 284.8(h)(2) do not apply to qualified AMAs or state-approved retail access programs. Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 at PP 92-94.

Similar considerations apply to state-approved retail access programs, where LDCs are required to make pipeline capacity available to marketers who will use it to serve the LDC's retail customers.⁹²

For similar reasons, Order No. 712 exempts capacity releases made as part of AMAs and retail access programs from FERC's restriction on tying arrangements. FERC recognizes that AMAs effectively require that the releasing shipper be able to release both its capacity and its natural gas supply arrangements in a single package.⁹³ Order No. 712 notes, in fact, that the very purpose of the transaction would be frustrated if the releasing shipper could not combine the supply and capacity components of the deal.⁹⁴ Order No. 712 thus provides that a releasing shipper in a pre-arranged release to its asset manager may require that the asset manager (a) agree to supply the releasing shipper's gas requirements and (b) take assignment of the releasing shipper's gas supply contracts, as well as released transportation capacity on one or more pipelines and storage capacity with the gas currently in storage.⁹⁵

State-approved retail access programs that qualify for the exemptions under Order No. 712 by definition tie the release of capacity by an LDC to a marketer to the marketer's agreement to use that capacity to serve the LDC's customers under the program. FERC views these programs as pro-competitive and beneficial to customers, and thus, believes that this kind of tying should be exempt from its general prohibition.⁹⁶

To the extent that an AMA-related release transaction will be for a term in excess of one year, the maximum rate cap on capacity release transactions will continue to apply.⁹⁷ However, Order No. 712 also amended the regulations to clarify that payments or other consideration exchanged between releasing and replacement shippers in a release to an asset manager are not subject to the relevant pipeline maximum rate.⁹⁸ This clarification should facilitate profit sharing arrangements between releasing shippers and asset managers. In other words, the Commission believes that the clarification will provide the parties to an AMA with the flexibility to negotiate mutually acceptable arrangements under which the asset manager shares with the releasing shipper the value the former obtains from the released capacity, without running afoul of the capacity release price ceiling.⁹⁹

⁹² 18 C.F.R. § 284.8(h)(1)(ii).

⁹³ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 128.

⁹⁴ *Id.*

⁹⁵ *Id.* at P 127.

⁹⁶ *Id.* at PP 199-200.

⁹⁷ *Id.* at P 158.

⁹⁸ 18 C.F.R. § 284.8(b).

⁹⁹ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 158. Order No. 712 notes that the price ceiling will continue to apply to the rates that the asset manager pays to the *pipeline* for the released capacity. *Id.* The Commission in Order No. 712 explicitly declined to remove the maximum rate ceiling on pipeline capacity. *Id.* at P 82.

IX. WAIVERS

Subsequent to adoption of its capacity release program that was designed to “permit shippers to ‘reallocate unneeded firm capacity’ to those who need it” and “‘promote efficient load management by the pipeline and its customers,’”¹⁰⁰ the Commission has been faced with multiple requests for waivers over the years. Although many have been denied,¹⁰¹ the Commission has granted several waivers, particularly in cases involving shippers exiting the natural gas transportation business or otherwise engaged in a corporate restructuring. Some of the first such cases involved requests for waiver of the Commission’s restrictions against combining (or “tying”) capacity and sales agreements into a single package. The Commission determined that a waiver was in the public interest when the shipper proposed to effectuate a *permanent* release of capacity and its gas sales contracts to a pre-arranged shipper, where the releasing shipper itself was *permanently exiting* either the gas business¹⁰² or a particular service.¹⁰³

In 2009, in response to a request to clarify through a new rulemaking its generic policy on waivers, the Commission declined, stating that waivers

by their very nature need to be done on a case-by-case basis, because they turn on the specific circumstances of individual cases. In this regard, applicants for a waiver of the capacity release regulations and policies should (1) identify with as much specificity as possible the regulations and policies for which they seek waiver, (2) identify the pipeline capacity at issue, (3) provide a sufficient description of the overall transaction and its claimed benefits to permit the Commission and other interested parties to analyze whether granting the

¹⁰⁰ Order No. 712, FERC Stats. & Regs. ¶ 31,271 at P 119 (quoting Order No. 636, FERC Stats. & Regs. ¶ 30,939 at 30,418).

¹⁰¹ For example, Louis Dreyfus Energy Services, L.P. (“LDES”), sought a waiver to release capacity at above the pipeline’s maximum rate and a waiver of FERC’s policy limiting tying arrangements. The Commission denied both requests, holding that LDES was not exiting the business, but was simply trying to remedy a business risk that it had undertaken. *Louis Dreyfus Energy Servs., L.P.*, 114 FERC ¶ 61,246. See also *Northern Natural Gas Co.*, 119 FERC ¶ 61,204 (2007) (denial of attempt to release capacity at a discounted rate due to finding that request was not supported and not associated with any exiting of the gas business); *Gas Transmission Nw. Corp.*, 119 FERC ¶ 61,031 (2007) (denial of request for limited waivers of GTN’s tariff so that shipper’s U.S. and Canadian transportation contracts may be posted and bid upon as a bundled package through a single reverse auction procedure and so that shipper could “economically” exit its gas operations in Canada only); *Wy. Interstate Co.*, 110 FERC ¶ 61,325 (2005) (denial of attempt to allow the purchasers of gas production properties to receive the associated transportation capacity); *Cheyenne Plains Gas Pipeline Co.*, 110 FERC ¶ 61,326 (2005) (same).

¹⁰² See *Pac. Gas Transmission Co.*, 82 FERC ¶ 61,227 (1998).

¹⁰³ See *Duke Energy Mktg. Am., LLC*, 114 FERC ¶ 61,198. See also *Vitol Inc.*, 121 FERC ¶ 61,099 (2007); *Wasatch Energy, LLC*, 118 FERC ¶ 61,173 (2007); *Duke Energy Mktg. Am., LLC*, 114 FERC ¶ 61,309 (2006); *Tenn. Gas Pipeline Co.*, 111 FERC ¶ 61,509 (2005); *Northwest Pipeline Corp.*, 109 FERC ¶ 61,044 (2004), *clarification denied*, 112 FERC ¶ 61,187 (2005).

requested waivers are in the public interest . . . , and (4) file the request as much in advance of the requested action date as possible.¹⁰⁴

Although it declined to modify its capacity release rules generically, in its 2009 order terminating the requested rulemaking docket, the Commission cited four cases involving mergers and corporate restructurings as guidance to the industry as to the types of facts and circumstances that could justify a broad-based waiver of its capacity release rules.¹⁰⁵ For example, in the *Macquarie Cook Energy* case, which involved a phased sale by Constellation Energy Commodities Group, Inc. of its entire wholesale natural gas trading portfolio to Macquarie Cook Energy, applicants requested temporary waivers of the Commission's prohibition against tying, as well as the Commission's shipper-must-have-title policy, its prohibition on buy/sell arrangements, and its restrictions on capacity releases above or below the maximum rate.¹⁰⁶ The Commission granted the requested waivers for a ninety-day period after the closing of each phase of the transactions, stating that it

did not contemplate that the capacity release posting and bidding requirements would necessarily apply in the cases of the merger or sales of entire business units as part of a corporate restructuring, including, as, here, the transfer of transportation contracts, supply contracts, employees, data systems and technology. The Commission finds that the capacity release mechanism is not suited to these types of complex, integrated deals which do not permit the disaggregation of assets.¹⁰⁷

Under the Commission's waiver policy, a well-supported request for waiver in conjunction with a complex sale or corporate restructuring involving an exit from the gas business is likely to receive a temporary waiver of the capacity release rules. However, a request for a waiver based on economic factors or avoidance of business risks, or a request that is not well-supported with a full explanation of the facts and the public interest that will be served is not likely to be granted.

¹⁰⁴ *Request for Clarification of Policy Regarding Waivers of Applicable Requirements to Facilitate Integrated Transfers of Mktg. Businesses*, 127 FERC ¶ 61,106 at P 10 (2009).

¹⁰⁵ *Id.* at P 5 (citing *Macquarie Cook Energy, LLC*, 126 FERC ¶ 61,160 (2009)); *Barclays Bank PLC*, 125 FERC ¶ 61,383 (2008); *Bear Energy LP*, 123 FERC ¶ 61,219 (2008); *Sempra Energy Trading Corp.*, 121 FERC ¶ 61,005 (2005)). *See also* *Big Sandy Pipeline, LLC*, 141 FERC ¶ 61,151 (2012); *Antero Res. Corp.*, 139 FERC ¶ 61,258 (2012); *Salmon Res., LTD*, 138 FERC ¶ 61,059 (2012); *Big Sandy Pipeline, LLC*, 136 FERC ¶ 61,130 (2011); *BHP Billiton Petroleum (Fayetteville) LLC*, 135 FERC ¶ 61,088 (2011); *Wis. Elec. Power Co.*, 131 FERC ¶ 61,104 (2010); *Total Gas & Power N. Am., Inc.*, 131 FERC ¶ 61,023 (2010); *EnergyMark, LLC*, 130 FERC ¶ 61,059 (2010); *Sequent Energy Mgmt., L.P.*, 129 FERC ¶ 61,188 (2009).

¹⁰⁶ *Macquarie Cook Energy*, 126 FERC ¶ 61,160 at P 5.

¹⁰⁷ *Id.* at P 14.

Chapter 11

False Statements and Duty of Candor

WILLIAM R. BARKSDALE

This chapter discusses 18 C.F.R. § 35.41(b), which requires that submissions to FERC and certain other entities be accurate, not misleading, and omit no material information. This regulation was part of the original “Market Behavior Rules” adopted following the California energy crisis and was retained by FERC when those rules were modified in the context of implementing the Energy Policy Act of 2005.¹ FERC considers it a powerful enforcement tool and has not hesitated to use it in recent years.

I. FERC’S ACCURACY REQUIREMENT: BRIEF OVERVIEW AND HISTORY

Pursuant to 18 C.F.R. § 35.41(b):

A Seller must provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercises due diligence to prevent such occurrences.

“Seller,” as that term is used in section 35.41(b), includes “any person that has authorization to or seeks authorization to engage in sales for resale of electric energy, capacity or ancillary services at market-based rates under section 205 of the Federal Power Act.”² This rule applies both to voluntary and non-voluntary communications made by sellers,³ and on its face incorporates a due diligence defense.

As indicated, prior to being codified as 18 C.F.R. § 35.41(b), FERC’s accuracy requirement was embodied in Old Market Behavior Rule 3, the text of which is virtually identical to section 35.41(b). At the time, FERC conditioned all then-existing or future market-based rate (“MBR”) tariffs and authorizations on the seller’s compliance with Market Behavior Rule 3 and five other Market Behavior Rules that, among other things, proscribed the manipulation of energy markets and related conduct, such as wash trades.⁴ In 2005, FERC

¹ Pub. L. No. 109-58, 119 Stat. 594 (2005).

² 18 C.F.R. § 35.36(a)(1).

³ See *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 (2003) (“*Market Behavior Rule Order*”), *order on reh’g*, 107 FERC ¶ 61,175 at P 94 (2004) (“*Market Behavior Rehearing Order*”).

⁴ *Market Behavior Rule Order*, 105 FERC ¶ 61,218.

proposed to eliminate Market Behavior Rule 3 on the grounds that it would be subsumed by Order No. 670's Anti-Manipulation Rule.⁵ But after comment, FERC recognized that Market Behavior Rule 3 "is somewhat broader than the new anti-manipulation rule, as it applies to all communications, not just those that are material in furtherance of a fraudulent or deceptive scheme," and chose to codify the rule in its regulations without substantive changes.⁶

II. FERC'S RELIANCE ON SECTION 35.41(B)

Over the past several years, FERC has pursued and punished conduct it believed violated section 35.41(b). Recent penalties in cases involving charges of violating section 35.41(b) include suspension of market-based rate authority and, in one case, the imposition of civil penalties and disgorgement of \$245 million.⁷ In the latter case, as in other similar cases, violations of section 35.41(b) were resolved along with allegations of market manipulation. As a result, one cannot easily apportion the shares of the resulting penalty between those violations.

Charges that a seller violated FERC's accuracy requirement arise in a variety of circumstances. First, violations of section 35.41(b) may derive from the same conduct constituting violations of other FERC rules. FERC has, in recent years, tacked on violations of section 35.41(b) in some manipulation cases.⁸ This is significant because, as described below,

⁵ *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 113 FERC ¶ 61,190 at PP 19, 25 (2005) (order proposing revisions to market-based rate tariffs and authorizations). FERC promulgated Order No. 670 as a result of EPCA 2005, which prohibited the use or employment of "any manipulative or deceptive device or contrivance" in connection with the purchase or sale of electric energy or transmission services subject to the jurisdiction of the Commission.

⁶ *Investigation of Terms and Conditions of Pub. Util. Market-Based Rate Authorizations*, 114 FERC ¶ 61,165 at P 43 ("Order Revising MBR Tariffs and Authorizations"), *reh'g denied*, 115 FERC ¶ 61,053 (2006); *Conditions for Pub. Util. Market-Based Rate Authorization Holders*, Order No. 674, 114 FERC ¶ 61,163 (2006). Not all of FERC's original six Market Behavior Rules were codified in FERC's revised regulations. Old Market Behavior Rule 2 and all of its subparts, which forbade market manipulation and associated conduct, were rescinded because FERC's new anti-manipulation rule rendered them superfluous. This included Old Market Behavior Rule 2(b), which had prohibited conducting "transactions predicated on submitting false information to transmission providers or other entities responsible for operation of the transmission grid (such as inaccurate load or generation data, or scheduling non-firm service for products sold as firm)." *Market Behavior Rule Order*, 105 FERC ¶ 61,218 at P 64; *Order Revising MBR Tariffs and Authorizations*, 114 FERC ¶ 61,165 at P 24. Old Market Behavior Rule 2(b) had an intent requirement and also incorporated a due diligence standard. *Market Behavior Rule Order*, 105 FERC ¶ 61,218 at PP 64-65, App. A. Section 35.41(b) does not have such an intent requirement.

⁷ *J.P. Morgan Ventures Energy Corp.*, 141 FERC ¶ 61,131 (2012) (suspension of MBR authority) ("*J.P. Morgan*"); *Constellation Energy Commodities Grp., Inc.*, 138 FERC ¶ 61,168 (2012) ("*Constellation I*") (civil penalty of \$135 million and disgorgement of \$110 million in unjust profits).

⁸ For example, in *Deutsche Bank Energy Trading, LLC*, 142 FERC ¶ 61,056 (2013), FERC investigated trading allegedly done to relieve congestion in order to benefit the companies' other positions. FERC held that "Deutsche Bank falsely designated many of its physical transactions as Wheeling-Through transactions" where "[t]he relevant CAISO Tariff required a Wheeling Through transaction to have a resource outside of CAISO and a Load outside of CAISO," and Deutsche Bank

(cont'd)

unlike the Anti-Manipulation Rule, there is no intent requirement for violations of section 35.41(b), and intent is often the most difficult element of a manipulation claim for FERC to prove.

Second, violations may arise from a seller's conduct during the course of an investigation. If a seller's response to data requests, correspondence, or verbal representations to Enforcement Staff turn out to be wrong, misleading, or materially incomplete, then the seller may be subjected to a charge of violating section 35.41(b). In *Constellation II*,⁹ the company "asserted orally and then in writing to staff that CAISO supported closing the investigation without penalty."¹⁰ In fact, after the oral representation, but before the written representation, CAISO had told the company that it could not support that position.¹¹ The company "stated that its oral assertion was made in good faith and that the language in its written response to staff was left in by mistake."¹² Nonetheless, FERC found a violation to have occurred.¹³ As the number of FERC investigations grows, so too do the number of opportunities in which a seller might run afoul of section 35.41(b), particularly in cases where Enforcement Staff demands the production of voluminous material in a short amount of time.

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"lacked a resource or a Load outside the CAISO for its designated Wheeling-Through transactions." *Id.* at P 14. Deutsche Bank argued that CAISO's Tariff was ambiguous. *Deutsche Bank Energy Trading, LLC*, Docket No. IN12-4-000, Answer of DB Energy Trading LLC to Order to Show Cause at 70 (Nov. 5, 2012). Not only was the resource/load requirement not set out in either the CAISO Tariff or in CAISO's Business Practice Manual—instead it was relegated to an appendix—but also CAISO had given mixed advice, sometimes approving the Wheeling Through designation for transactions similar to Deutsche Bank's. *Id.* at 18-20, 69-72. CAISO also approved schedules which included NERC tags for all of Deutsche Bank's Wheeling Through transactions that accurately reflected the source, sink, and transmission path. *Id.* Moreover, CAISO subsequently revised its Business Practices Manual to explicitly include the requirement, thereby implicitly acknowledging its prior ambiguity. *Id.* Deutsche Bank's arguments did not sway FERC. See *Deutsche Bank Energy Trading, LLC*, 142 FERC ¶ 61,056 at P 14. *Gila River Power, LLC*, 141 FERC ¶ 61,136 (2012), and *Constellation Energy Commodities Group, Inc.*, 145 FERC ¶ 61,062 at PP 4-5, Stipulation ¶¶ 4-8 (2013) ("*Constellation II*"), also involved transactions allegedly misidentified as "Wheeling Through" transactions.

⁹ 145 FERC ¶ 61,062.

¹⁰ *Id.*, Stipulation ¶ 9.

¹¹ *Id.*

¹² *Id.*

¹³ *Id.*; see also *J.P. Morgan*, 141 FERC ¶ 61,131 (finding violation for inaccurate statements that concerned the investigation itself, not the underlying conduct being investigated); *Constellation I*, 138 FERC ¶ 61,168 at PP 18-20, 34 (alleging violation where company "stated in its communications with the NYISO, that its decisions to participate in the NYISO virtual market were based on market fundamentals and omitted the fact that the virtual trading was directly related to its CFDs [contract for differences]"); *In re Edison Mission*, 123 FERC ¶ 61,170 (2008) (alleging violation where company provided inaccurate information to Enforcement Staff related to its trading activity even though market manipulation claims ultimately were not pursued).

Third, violations may arise during the course of more routine submissions and regulatory filings in a non-adversarial context.¹⁴

III. LACK OF INTENT AND THE DUE DILIGENCE DEFENSE

FERC has held that section 35.41(b) does not contain an intent element.¹⁵ Instead, when determining whether a seller has violated section 35.41(b), “the Commission’s task is first, to determine whether a qualifying misrepresentation or material omission has been made, and second, to the extent necessary, to evaluate whether the seller has exercised due diligence.”¹⁶ According to FERC, a seller’s “intent or state of mind is irrelevant to this inquiry because neither demonstrates the veracity or accuracy” of its statements or that it “exercised due diligence.”¹⁷ However, in order to be held liable, one must still act without the requisite standard of care; the regulation provides a safe harbor for sellers that “exercise[] due diligence to prevent such occurrences.”¹⁸

FERC’s holding on the absence of an intent requirement was upheld by the D.C. Circuit in *Kourouma v. FERC*.¹⁹ There, Moussa Kourouma, a trader at Energy Endeavors, formed his own trading firm. In order to conceal his identity from his employer with whom he had entered into a non-compete agreement, Kourouma incorporated his firm using his daughter’s name as registered agent and again used his daughter’s name and the name of a friend when submitting applications to FERC and PJM Interconnection, L.L.C.—applications which turned out to be unnecessary. Kourouma argued that he should not be held liable because he had no intent to mislead FERC or PJM; he only intended to mislead Energy Endeavors.

As the court explained, although the regulation does not have language expressly eschewing an intent requirement, the lack of such a requirement is consistent with the fact that,

¹⁴ *In re Vista Energy Mktg., L.P.*, 139 FERC ¶ 61,154 (2012) (FPA section 205 market-based rate application); *Cobb Customer Requesters v. Cobb Elec. Membership Corp.*, 136 FERC ¶ 61,084 (2011) (declining to investigate alleged violations with respect to market-based rate filings); *Dartmouth Power Assocs.*, 134 FERC ¶ 61,085 (2011) (real-time energy offer and failure to alert ISO of unit unavailability due to repairs).

¹⁵ The Commodities Exchange Act (“CEA”) also prohibits making false statements to the CFTC, but, unlike section 35.41(b), the CEA is a criminal prohibition and contains an intent requirement. Specifically, the CEA provides that “[i]t shall be unlawful for any person to make any false or misleading statement of a material fact to the Commission, including in any registration application or any report filed with the Commission under this chapter, or any other information relating to a swap, or a contract of sale of a commodity, in interstate commerce, or for future delivery on or subject to the rules of any registered entity, or to omit to state in any such statement any material fact that is necessary to make any statement of a material fact made not misleading in any material respect, if the person knew, or reasonably should have known, the statement to be false or misleading.” 7 U.S.C. § 9.

¹⁶ *J.P. Morgan*, 141 FERC ¶ 61,131 at P 45.

¹⁷ *Id.*

¹⁸ 18 C.F.R. § 35.41(b).

¹⁹ 723 F.3d 274 (D.C. Cir. 2013).

“in 2004, FERC considered but rejected the option of adding an ‘express intent requirement’ to § 35.41(b).”²⁰ The court further explained that the absence of an intent element is also not inconsistent with the statement in the “initial promulgation of Market Behavior Rule 3 . . . that the Rule was ‘prohibit[ing] the knowing submission of false or misleading data.’”²¹ That statement, the court reasoned, “was intended to clarify that ‘inadvertent submission of inaccurate or incomplete information will not be sanctioned.’”²²

Kourouma also argued that, even if the rule lacks an intent requirement, it nonetheless “fails to provide constitutionally adequate notice to regulated parties of what is forbidden and invites discriminatory enforcement.”²³ The court also rejected this attack on a “garden-variety ban on making false statements,” holding that “the Rule’s clear terms provide sufficient notice to regulated parties of what conduct the Rule prohibits, and those clear enforcement parameters prevent FERC from engaging in unconstitutionally discriminatory enforcement.”²⁴

As indicated, however, section 35.41(b) does not, however, impose strict liability for the submission of false or misleading information. Instead, the rule only imposes liability where the seller makes such false statements *and* “fails to exercises due diligence to prevent such occurrences.”²⁵ FERC has offered relatively little guidance about what would constitute sufficient due diligence to avoid liability.²⁶ In *J.P. Morgan*,²⁷ FERC found that due diligence “may extend beyond reliance on memory,” and that the “retainer of qualified attorneys does not constitute sufficient due diligence to exonerate [a seller’s] violations,” at least where the seller does not explain “how its counsel performed due diligence to ensure that all statements it made to the Commission . . . were accurate.”²⁸ There, FERC concluded that it “fail[ed] to see how JP Morgan’s representative exercised the ‘best-practice due diligence . . . that companies should take to address government investigations.’”²⁹ In 2011, Enforcement Staff provided some additional insight when it reported that it had closed an investigation into whether a generator had violated section 35.41(b) by reporting a unit for fast start and at full load when the unit was not so available. Although Enforcement Staff closed the investigation with no action, it did

²⁰ *Id.* at 279 (citing *Market Behavior Rehearing Order*, 107 FERC ¶ 61,175 at P 96).

²¹ *Id.* (quoting *Market Behavior Rule Order*, 105 FERC ¶ 61,218 at P 110).

²² *Id.* (brackets in original) (quoting same).

²³ *Id.* at 278 n.1.

²⁴ *Id.*

²⁵ 18 C.F.R. § 35.41(b).

²⁶ In the context of a similar due diligence defense to Market Behavior Rule 2(b), FERC declined the invitation to establish “*a priori* rules” or to “prejudge or otherwise commit the Commission to any advance determinations regarding the existence or absence of due diligence in a given case.” *Market Behavior Rehearing Order*, 107 FERC ¶ 61,175 at P 70.

²⁷ 141 FERC ¶ 61,131.

²⁸ *Id.* at PP 41-43.

²⁹ *Id.* at P 43 (citation omitted).

determine that the “generator did not have a good faith basis to offer the unit as it did” where it “did not test whether the unit could perform at full load after returning the unit to service.”³⁰

Despite this lack of specific guidance, FERC has held that a seller may present all relevant facts as part of a due diligence defense. On rehearing of the establishment of its Old Market Behavior Rule 3, FERC clarified that it “believe[s] that a due diligence defense will give sellers sufficient latitude to bring all relevant facts on this issue before the Commission in advance of any action which may be taken against the seller.”³¹

Availing oneself of the due diligence defense may be complicated by the fact that much of the risk posed by section 35.41(b) involves statements by counsel or by a client in the course of a legal representation. Demonstrating that due diligence in such circumstances can be difficult or impossible without negotiating a limited waiver of the attorney-client privilege and work product protection. There are obvious sensitivities associated with such a course of action. Any privileged communications voluntarily produced to Enforcement Staff might be made public if FERC issues a show cause order, an order assessing civil penalties, or an order approving a settlement.

IV. MATERIAL OMISSIONS

There is also relatively little FERC guidance as to what constitutes a “material” omission. In the context of Old Market Behavior Rule 3, FERC stated that, while materiality “may not be given to a precise before-the-fact definition in every case, we believe the seller will have sufficient notice regarding the requirements of our rule. First, materiality can be established with sufficient particularity by the seller by reference to Commission-approved rules and industry practices. In addition, sellers will also be accorded a safe harbor under our rule to allow for reasonable, unforeseen differences regarding the meaning of our requirement as it may be applied, *i.e.*, our rule will not be applied against a seller shown to have exercised due diligence.”³²

In at least one instance, FERC has relied on securities law precedent when determining whether information was material.³³ In *Cobb*, FERC decided not to initiate an investigation based on customers’ claims that respondents omitted or provided misleading information in their MBR filings. Guided by securities law precedent, FERC explained that “none of these

³⁰ *Conference on Enforcement*, Docket No. AD07-13-004, 2011 Report on Enforcement at 23-24 (Nov. 17, 2011) (“2011 Report on Enforcement”).

³¹ *Market Behavior Rehearing Order*, 107 FERC ¶ 61,175 at P 96. This statement came in response to concerns that the omission of material information should not be penalized where the omission is attributable to a legal requirement to protect confidential information.

³² *Id.* at P 95.

³³ *Cobb*, 136 FERC ¶ 61,084 at P 42 (“Guided by securities law precedent, a fact is considered material if there is ‘a substantial likelihood that a reasonable market participant would consider it in making its decision to transact because the material fact significantly altered the total mix of information available.’”).

allegations is *germane to the factors the Commission considers* when evaluating market-based rate applications, which are, among other things, whether the applicant has market power in generation or transmission and, if so, whether the applicant has adequately mitigated these market power concerns.”³⁴

V. LIABILITY FOR STATEMENTS THAT DO NOT MISLEAD

FERC has held that liability for a violation of its accuracy requirements is not conditioned on FERC or another entity actually being misled. In *J.P. Morgan*, the company argued that it could not have misled FERC or CAISO by failing to cite FERC communications because both FERC and CAISO possessed the information contained in those communications.³⁵ FERC rejected this argument, holding that “JP Morgan’s purported inability to mislead . . . neither shows that the statements at issue were accurate nor that JP Morgan exercised due diligence.”³⁶ “The regulation does not require that the recipient actually be misled or even be capable of being misled.”³⁷

VI. DISPOSITION OF SECTION 35.41(B) CHARGES

J.P. Morgan demonstrates FERC’s willingness to impose sanctions for violations of section 35.41(b) prior to the completion of the underlying investigation, at least under the circumstances presented there. Specifically, FERC declined to defer considering the section 35.41(b) violation until Enforcement Staff had concluded its market manipulation investigation because the two involved distinct facts and had distinct causes of action.³⁸ FERC held that, unlike the Anti-Manipulation Rule, section “35.41(b) requires neither a showing of a seller’s intent nor a showing that the statements were made in connection with a jurisdictional transaction.”³⁹ However, if FERC attempts to impose a civil penalty for an alleged violation of this requirement, it must afford the defendant the statutory procedures (*de novo* review in federal court or a trial before an administrative law judge). In the one case, where such proceedings did not occur (*Kourouma*⁴⁰), the defendant’s own admission had eliminated any disputed issue of material fact. The procedural protection provided by these statutory procedures applicable to civil penalties is also consistent with FERC’s holding that the due diligence defense affords the seller the ability “to bring all relevant facts” to the Commission’s attention.

³⁴ *Id.* (emphasis added).

³⁵ *J.P. Morgan*, 141 FERC ¶ 61,131 at P 34.

³⁶ *Id.* at P 46.

³⁷ *Id.*

³⁸ *J.P. Morgan*, 141 FERC ¶ 61,131 at PP 54-55.

³⁹ *Id.* at P 55.

⁴⁰ *Kourouma*, 723 F.3d at 277 (“We agree with FERC that Kourouma’s admissions supported summary disposition without a hearing We have routinely recognized that an agency need not hold an administrative hearing when no material facts are in dispute.”).

VII. DETERMINATION OF PENALTIES

In determining an appropriate penalty, FERC is guided by, among other things, its *Revised Policy Statement on Enforcement* and its *Revised Policy Statement on Penalty Guidelines*.⁴¹

In the past, FERC has taken into account the effects of the alleged false statements when determining the appropriate penalty. In *Edison Mission*, for example, FERC obtained a settlement at a cost to the seller of approximately \$9 million, a large penalty at the time.⁴² In justifying the penalty, FERC repeatedly stressed the wasted resources caused by the seller's frequently changing stories during the course of the investigation: "Edison Mission's conduct and actions that misled staff concerning the high offer strategy greatly hampered and delayed Enforcement's understanding, analysis, and investigation of that strategy, causing staff to waste resources analyzing different explanations offered by Edison Mission for its bidding practices."⁴³ Additionally, Enforcement Staff has referenced the lack of financial harm and unjust profits in its decisions to close investigations of section 35.41(b) violations without sanction. In 2009, for example, Enforcement Staff reported that it had investigated a company's specified capacity commitment made to an RTO, which turned out to be inaccurate. Enforcement "Staff concluded that "the[] events presented no demonstrable financial harm to the market and Company generated no unjust profits. The investigation was therefore closed without sanctions."⁴⁴

FERC has held, however, that such specific harms need not be proven before sanctions can be imposed. In *J.P. Morgan*, FERC underscored that "harm caused by a violation, whether it is economic or physical, is merely one factor in determining the appropriate penalty to be imposed."⁴⁵ There, FERC imposed a significant penalty—suspension of J.P. Morgan's MBR authority for a period of six months along with concomitant caps—based on the general proposition that "misrepresentations by market-based rate sellers are serious violations causing harm to the integrity of the Commission's market-based rate authorizations,"⁴⁶ and its view that

⁴¹ See *Enforcement of Statutes, Orders, Rules, and Regulations*, 132 FERC ¶ 61,216 (2010) ("Revised Policy Statement on Penalty Guidelines"); *Enforcement of Statutes, Regulations and Orders*, 123 FERC ¶ 61,156 (2008) ("Revised Policy Statement on Enforcement").

⁴² *Edison Mission*, 123 FERC ¶ 61,170 at PP 1.

⁴³ *Id.* at P 4; see also *id.* at PP 2, 6, 9, Stipulation ¶¶ 19, 23.

⁴⁴ *Conference on Enforcement*, Docket No. AD07-13-002, 2009 Report on Enforcement at 17 (Dec. 17, 2009). Staff also noted that the company "had good reason to believe that its communication was correct when made" and that the company had already paid a deficiency charge assessed by the ISO. *Id.* Similarly, in 2011, Enforcement Staff closed an investigation without sanctions concerning a generator that had inaccurately reported to an RTO/ISO that a unit was available for fast start and at full load. 2011 Report on Enforcement at 23-24. Although Enforcement Staff determined that the generator did not have a good faith basis to make such offer, it "determined, however, that the generator did not unjustly profit from its offer because it promptly repaired the unit and confirmed its performance such that the unit was available consistent with its offer the next time the RTO/ISO called upon it." *Id.* at 23.

⁴⁵ *J.P. Morgan*, 141 FERC ¶ 61,131 at P 60.

⁴⁶ *Id.*; see also *id.* at P 57.

“JP Morgan offered no form of cooperation until after its misrepresentations had been exposed” instead “repeatedly ma[king] deceptive and misleading statements over a period of several months.”⁴⁷

At the other end of the spectrum, in *Kourouma*, FERC applied the factors set out in the *Revised Policy Statement on Enforcement*⁴⁸ to impose a penalty of \$50,000, which FERC described as “a tiny fraction of the maximum statutory penalty.”⁴⁹ In that case, FERC seems to have been driven primarily by Kourouma’s cooperation and his precarious financial situation.⁵⁰ FERC did however find that the violation—the submission of false, and omission of material, information in applications that were not required to be filed—was “serious” because the seller’s conduct “harmed the integrity of the regulatory process as well as undermined the transparency of the PJM market,” the seller was indifferent as to whether FERC was misled, and the seller’s conduct was “deliberate[.]” and occurred “in three filings and to PJM Staff in at least two communications . . . over several months.”⁵¹

VIII. OTHER CONSEQUENCES OF FALSE STATEMENTS

Aside from forming the basis for a section 35.41(b) violation, the submission of false or misleading information may have additional consequences. First, one may also run afoul of similar provisions contained in RTO and ISO tariffs. Second, FERC may view false statements as additional evidence of a manipulative scheme.⁵² Third, FERC may take false statements into account when assessing a penalty for a separate violation of its rules. “[C]ompanies that initially earn cooperation credit can lose that credit through uncooperative conduct, such as . . . misrepresentation.”⁵³ Enforcement Staff has refused to give cooperation credit where a seller “failed to ensure that . . . assertions made to Enforcement staff were accurate.”⁵⁴ Fourth, false statements may also give rise to criminal investigations and prosecutions. “[T]he United States Criminal Code [18 U.S.C. § 1001] provides that under certain circumstances, knowingly falsifying or concealing a material fact is a felony which may result in fines of up to \$10,000,

⁴⁷ *Id.* at P 62.

⁴⁸ *Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 at PP 55-71.

⁴⁹ Brief of Respondent Federal Energy Regulatory Commission, *Kourouma v. FERC*, 723 F.3d 274 (D.C. Cir. 2013) (No. 11-1283), 2012 WL 345933, at *21.

⁵⁰ *Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 at PP 6, 55.

⁵¹ *Moussa I. Kourouma d/b/a Quntum Energy LLC*, 135 FERC ¶ 61,245 PP 43-48 (2011) (order on show cause response).

⁵² In *Constellation I*, for example, Enforcement Staff “further determined that [Constellation]’s failure to provide accurate information to the NYISO MMP provided additional evidence to Enforcement of [Constellation]’s scheme to manipulate the virtual and physical markets to impact DA price.” *Constellation I*, 138 FERC ¶ 61,168 at P 35.

⁵³ *Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 at P 68.

⁵⁴ *Constellation II*, 145 FERC ¶ 61,062 at P 6.

and/or five years imprisonment, or both.”⁵⁵ That particular code provision, discussed further below, applies to sworn and unsworn statements made to the federal government. False statements made under oath may also constitute perjury under 18 U.S.C. § 1621, which also provides for fines and imprisonment of up to five years. Fifth, false statements made by legal counsel may result in sanctions under 18 C.F.R § 385.2101, which provides that, “[a]fter a hearing, the Commission may disqualify and deny, temporarily or permanently, the privilege of appearing or practicing before it in any way to a person who is found . . . [t]o have engaged in unethical or improper professional conduct”⁵⁶

⁵⁵ *Revised Policy Statement on Enforcement*, 123 FERC ¶ 61,156 at P 68 n.62 (citing 18 U.S.C. § 1001). In 2014, the Solicitor General took a position that suggests the Department of Justice will set a higher intent requirement for section 1001: that the person making the statement must know not only that the statement is false, but also that it is unlawful. See Tony Mauro, *DOJ’s Quiet Concession*, Nat’l L. J., May 12, 2014, available at <http://www.nationallawjournal.com/id=1202654724066/DOJs-Quiet-Concession?slreturn=20140815122740>.

⁵⁶ 18 C.F.R § 385.2101.

Chapter 12

FPA Section 203: Mergers, Acquisitions and Reorganizations

WILLIAM B. CONWAY
MATTHEW W.S. ESTES

Section 203 of the Federal Power Act¹ requires prior approval by FERC for a wide variety of transactions including (i) mergers, consolidations and other direct and indirect changes in control of public utilities, (ii) sales, purchases, and leases of jurisdictional assets, and (iii) internal reorganizations. The Commission interprets its section 203 jurisdiction broadly and in ways that can sometimes pose a trap for the unwary. Accordingly, this chapter provides an outline of the types of transactions that require approval under FPA section 203, as well as a short summary of the standards applied by the Commission when deciding whether or not to grant section 203 approval.

I. SPECIFIC COMPLIANCE REQUIREMENTS

A. TYPES OF TRANSACTIONS COVERED BY SECTION 203

FPA section 203 has multiple jurisdictional prongs as described below, and transactions are often subject to Commission approval under more than one of these provisions.

- *Sale of Jurisdictional Facilities.* Prior Commission approval is required under section 203(a)(1)(A) for a public utility² to “sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of \$10,000,000.”³ The Commission has interpreted the phrase “or otherwise dispose of” to include indirect as well as direct changes in control over jurisdictional facilities, such as through internal corporate reorganizations and parent holding company mergers.
- *Mergers.* Prior Commission approval is required under section 203(a)(1)(B) for a public utility to “merge or consolidate, directly or indirectly, [its] facilities or any part thereof with those of any other person, by any means whatsoever.”⁴ While

¹ 16 U.S.C. § 824b.

² Under FPA section 201(e), a “public utility . . . means any person who owns or operates facilities subject to the jurisdiction of the Commission.” *Id.* § 824(e). Facilities subject to the Commission’s jurisdiction are described below.

³ *Id.* § 824b(a)(1)(A).

⁴ *Id.* § 824b(a)(1)(B).

203(a)(1)(A) above applies only to the sell side of a transaction (i.e., sales, leases or other direct or indirect dispositions by a public utility) and has a \$10 million threshold, the Commission interprets section 203(a)(1)(B) as giving it jurisdiction to review purchases of jurisdictional assets by public utilities, as well as mergers and without regard to the cost of the transaction.⁵ Under this provision, the Commission has asserted jurisdiction over the purchase of assets valued as low as ten dollars.⁶

- *Securities.* Prior Commission approval is required under section 203(a)(1)(C) for a public utility to purchase, acquire or take “any security with a value in excess of \$10,000,000 of any other public utility.”⁷
- *Generating Facilities.* Prior Commission approval is required under section 203(a)(1)(D) for a public utility to “purchase, lease, or otherwise acquire an existing generation facility” valued at more than \$10 million that is used for interstate wholesale sales and over which the Commission has jurisdiction for ratemaking purposes.⁸
- *Holding Companies.* Prior Commission approval is required under section 203(a)(2) for a company that is a holding company (as defined by the Public Utility Holding Company Act of 2005)⁹ in a holding company system that includes a transmitting utility or an electric utility to (i) purchase, acquire, or take any security with a value in excess of \$10 million of a transmitting utility, an electric utility company, or a holding company in a holding company system that includes a transmitting utility, or an electric utility company or (ii) directly or indirectly merge or consolidate with an electric utility company, or a holding company in a holding company system that includes a transmitting utility, or an electric utility company.¹⁰

The following discussion is organized according to the different types of jurisdictional transactions commonly entered into by public utilities regulated by the Commission. First, asset

⁵ See *id.*

⁶ See *Consolidated Edison Co. of N.Y.*, 131 FERC ¶ 62,200 (2010).

⁷ 16 U.S.C. § 824b(a)(1)(C).

⁸ *Id.* § 824b(a)(1)(D).

⁹ The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 and replaced it with PUHCA 2005. Pub. L. No. 109-58, §§ 1261-77, 119 Stat. 594, 972-78 (2005) (codified at 42 U.S.C. §§ 15801, 16451-63 and 16 U.S.C. §§ 824(g)(5), (m)). Under PUHCA 2005, a company is considered a holding company if it owns or controls 10 percent or more of any electric utility company or gas utility company or of a holding company of such a company. See 42 U.S.C. §§ 16451(8), (14). PUHCA 2005 defines an “electric utility company” as “any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale.” *Id.* § 16451(5). PUHCA 2005 defines a “gas utility company” as “any company that owns or operates facilities used for distribution at retail (other than the distribution only in enclosed portable containers or distribution to tenants or employees of the company operating such facilities for their own use and not for resale) of natural or manufactured gas for heat, light, or power.” *Id.* § 16451(7).

¹⁰ 16 U.S.C. § 824b(a)(2).

dispositions are discussed, followed by transfers of jurisdictional contracts, mergers, reorganizations, and transfers of securities. Next, there is a discussion of change in control issues generally, including the identification of certain types of agreements that may involve a change in control and thus be subject to prior Commission approval under FPA section 203. Finally, after describing the broad jurisdiction of the Commission to review transactions, we describe the blanket approvals provided for in the Commission's regulations, which have the effect of limiting the types of transactions for which applications under FPA section 203 must be filed.

As a general matter, the Commission has taken an expansive reading of its jurisdiction under section 203:

Neither section 203 nor any other provision of the FPA defines the terms “dispose,” “facilities subject to the jurisdiction of the Commission,” “merge,” “consolidate,” and “control.” However, we do not believe these terms should be read narrowly. To do so would result in a jurisdictional void in which certain types of power sales facilities and corporate transactions could escape Commission oversight.¹¹

1. *Asset Transactions*

a. *Transmission Facilities*

Sales of Transmission Facilities. A common example of FERC jurisdiction under section 203 is the sale or lease by a public utility of transmission facilities. In addition to transmission lines, transmission facilities also include interconnection facilities such as generator step-up transformers, generator leads, tie-lines, transformers, conductors, disconnect switches, and substations for purposes of FERC jurisdiction under section 203(a)(1)(A).¹² Any sale of such assets valued at more than \$10 million by a public utility requires prior FERC approval under section 203.¹³ However, a transfer of distribution facilities alone does not trigger the prior approval requirement.¹⁴

If a seller of jurisdictional transmission facilities is a non-jurisdictional entity, such as a public power entity, the Commission does not have jurisdiction over the sale by such entity

¹¹ *Enova Corp.*, 79 FERC ¶ 61,107 at 61,489 (1997).

¹² However, notwithstanding their jurisdictional status under FPA section 203, generator step-up transformers are not considered transmission facilities for purposes of functionalizing facilities to develop rates under FPA section 205. *Ky. Utils. Co.*, 85 FERC ¶ 61,274 at 62,111-13 (1998).

¹³ In its section 203 regulations, the Commission has established a rebuttable presumption that the value of transferred facilities in transactions between unaffiliated entities equals the market value of the facilities. For transactions between affiliated entities, the value is equal to the original, undepreciated cost of the facilities or original book cost, as applicable. 18 C.F.R. § 33.1(b)(3)(i).

¹⁴ See *Duke Power Co. v. FPC*, 401 F.2d 930 (D.C. Cir. 1968). However, if distribution facilities also are used to make wholesale sales, section 203 jurisdiction will be asserted. See also *Kandiyohi Power Coop.*, 107 FERC ¶ 61,285 (2004).

under section 203(a)(1)(A). However, the Commission may nevertheless have jurisdiction over the purchase of assets from a non-jurisdictional entity, as explained below.

Purchases of Transmission Facilities. In addition to asserting jurisdiction over the sale of jurisdictional transmission assets by public utilities under section 203(a)(1)(A), the Commission also asserts jurisdiction over the purchase of such facilities by public utilities under its authority to review mergers and consolidations pursuant to section 203(a)(1)(B). Further, because section 203(a)(1)(B) does not include a \$10 million threshold for the exercise of jurisdiction, the Commission has taken the position that its approval for the purchase of jurisdictional transmission assets is required regardless of the value of the assets being purchased.¹⁵

By taking this position, the Commission has in most cases effectively eliminated the statutory \$10 million threshold for the sale of jurisdictional assets that is set forth in section 203(a)(1). Unless a purchaser of transmission assets is a non-jurisdictional entity, it will need to obtain section 203 approval, and thus the Commission will review the transaction even if, technically, the selling public utility does not need approval because the value of the assets is below \$10 million.

Similarly, the fact that a seller of transmission assets is not a public utility under the FPA does not mean that its sale of the assets is not subject to FERC's section 203 review. If the purchaser of the facilities is a public utility, and if the assets would be subject to the Commission's jurisdiction after the sale, the Commission will assert jurisdiction under section 203(a)(1)(B).¹⁶

b. Generation Facilities

Generation facilities are not subject to the Commission's jurisdiction for most purposes, and, prior to enactment of EAct 2005, transfers or leases of generation facilities were not subject to section 203 jurisdiction unless they included associated jurisdictional assets (such as interconnection facilities or wholesale sales contracts).¹⁷ However, EAct 2005 added a new provision requiring prior FERC approval for a public utility to purchase, lease, or transfer an existing generation facility valued at more than \$10 million in cases where the generation facility "is used for interstate wholesale sales and over which the Commission has jurisdiction for

¹⁵ *Consolidated Edison Co. of N.Y.*, 131 FERC ¶ 62,200.

¹⁶ See, e.g., *Puget Sound Power & Light Co.*, 50 FPC 72 (1973); see also *Duke Power*, 401 F.2d at 937-38 (noting that the statutory language requiring approval when a public utility merges or consolidates its facilities with those of another person reflects Congress' intention to govern acquisitions of jurisdictional facilities by public utilities); *MidAmerican Energy Co.*, 112 FERC ¶ 62,025 (2005) (approving acquisition of jurisdictional facilities by public utility from nonjurisdictional entity); *Am. Transmission Co.*, 106 FERC ¶ 62,005 (2004) (same); *Fla. Power Corp.*, 85 FERC ¶ 62,032 (1998) (same).

¹⁷ See *Perryville Energy Partners, L.L.C.*, 109 FERC ¶ 61,019 (2004) (disclaiming jurisdiction where seller kept interconnection facilities and provided service over them to buyer under a cost-of-service transmission rate schedule); see also *Am. Pub. Power Ass'n*, 94 FERC ¶ 61,104 (2001), *aff'd sub nom. Citizen Power, Inc. v. FERC*, 38 F. App'x. 18 (D.C. Cir.), *cert. denied*, 537 U.S. 1046 (2002).

ratemaking purposes.”¹⁸ Generation facilities located in the balancing authority area of the Electric Reliability Council of Texas, and in Alaska and Hawaii are not subject to this provision because such generation facilities are not used for interstate wholesale sales and the Commission does not have ratemaking jurisdiction over such facilities.

2. *Assignment or Transfer of Jurisdictional Contracts*

FERC and the courts have interpreted jurisdictional facilities to include not only physical facilities, such as transmission lines and associated equipment, but also so-called “paper facilities” such as wholesale tariffs, rate schedules, power sales contracts, and related accounts and records pertaining to wholesale sales or interstate transmission.¹⁹ Thus, if a public utility sells or assigns contracts for jurisdictional sales or services, rate schedules, or books and records necessary to make jurisdictional sales, such sale or assignment must receive prior FERC approval. The same jurisdictional limits described above for the sale and purchase of transmission facilities also apply to these paper facilities.²⁰

3. *Mergers*

The merger or consolidation of two public utilities is another common transaction requiring prior section 203 approval. As noted above, while all other transactions requiring prior approval under section 203 are subject by statute to a minimum jurisdictional trigger (\$10 million), there is no such statutory threshold for mergers. It should be noted that entities owning only “paper facilities,” defined above, are deemed to be public utilities subject to this section 203 approval requirement. Thus, for example, a transaction that directly or indirectly involves an entity with a market-based rate tariff requires section 203 authorization, even if the entity owns no hard assets.

It is important to be aware of several requirements potentially applicable to merger applicants beyond the obligation to file a request for prior approval under section 203. If a

¹⁸ 16 U.S.C. § 824b(a)(1)(D). In addition to the prior approval requirements of FPA section 203, it should be noted that the Commission requires a separate notice of generating capacity acquisitions under the reporting requirements of section 205 for entities with market-based rate authority. Under Order No. 652, such entities must disclose a purchase or acquisition of control of generation facilities greater than 100 MW or inputs to electric power production (other than fuel) within 30 days of closing, even if that transaction does not trigger section 203 review and even if the seller’s triennial market power update is not due. *Reporting Requirement for Changes in Status for Pub. Utils. with Market-Based Rate Auth.*, Order No. 652, FERC Stats & Regs. ¶ 31,175, *order on reh’g*, 111 FERC ¶ 61,413 (2005) (codified at 18 C.F.R. § 35.42(A)(1), (B)). This reporting requirement under section 205 is discussed in more detail in Chapter 14 on Power Sales.

¹⁹ See, e.g., *Enova Corp.*, 79 FERC ¶ 61,107 at 61,489 (citing *Hartford Elec. Light Co.*, 131 F.2d 953, 961 (2d Cir. 1942), *cert. denied*, 319 U.S. 741 (1943); *Conn. Light & Power Co. v. FPC*, 324 U.S. 515, 528 n.6 (1945)).

²⁰ Similar to the way that physical assets are valued, the rebuttable presumption is that the value of wholesale contracts transferred between non-affiliated entities is equal to the market price of the transaction. 18 C.F.R. § 33.1(b)(3)(ii). Wholesale contracts transferred between affiliated entities are valued by reference to total expected contract revenues over the remaining life of the contract. *Id.*

merger directly or indirectly involves a traditional franchised utility, after the merger transaction is announced the merger parties are required to treat each other as affiliates by committing to seek prior section 205 approval for power sales between the merging companies (or their affiliates). The companies must also apply asymmetrical pricing rules for the sale of non-power goods and services, to the extent required for affiliate transactions.²¹ In addition, under the Standards of Conduct, transmission-owning utilities involved in a pending merger transaction must post the name and addresses of potential merger partners on their OASIS or Internet website.²² Public utilities involved in mergers should also be aware of obligations under section 204²³ to the extent they are not otherwise exempt (relating to securities that may be issued or assumed as part of a merger transaction), section 205²⁴ (with respect to jurisdictional contracts executed or assigned as part of the merger transaction that may be jurisdictional), and section 305²⁵ (relating to interlocking directorates established as part of the newly-formed entity).²⁶

4. *Mergers of Holding Companies*

EPAct 2005 codified the Commission's prior practice of asserting jurisdiction over mergers involving holding companies.²⁷ It is important to recognize that the Commission's approval is required for transactions involving holding companies that have subsidiaries engaged in FERC-jurisdictional activities, such as power marketing, even if the merging companies

²¹ See, e.g., *New Century Servs., Inc.*, 86 FERC ¶ 61,307 at 62,065 (1999), *reh'g denied*, 96 FERC ¶ 61,223 (2001).

²² *Standards of Conduct for Transmission Providers*, Order No. 2004-A, FERC Stats. & Regs. ¶ 31,161 at P 168 (2004) (later revised and recodified at 18 C.F.R. § 358.7(a)).

²³ 16 U.S.C. § 824c.

²⁴ *Id.* § 824d.

²⁵ *Id.* § 825d.

²⁶ The Commission also has jurisdiction over the payment of dividends out of capital accounts, which is sometimes necessary following a merger conducted pursuant to the purchase method of accounting. Under that accounting method, retained earnings accounts are eliminated and the balances in those accounts are reflected in paid-in capital accounts. Under FPA section 305(a), public utilities may not pay dividends from capital accounts, which could interfere with a public utility's ability to pay dividends at historic levels, post-merger. See *id.* § 825d(a). As a result, it may be necessary when a merger is conducted pursuant to the purchase accounting method to request a declaratory judgment from the Commission (as part of the merger application) that the future payment of dividends from capital accounts does not implicate section 305(a) under the circumstances presented. See, e.g., *Exelon Corp.*, 109 FERC ¶ 61,172 (2004); *Niagara Mohawk Holdings, Inc.*, 95 FERC ¶ 61,381 at 62,415-16 (2001); *New England Power Co.*, 89 FERC ¶ 61,266 (1999). However, on July 17, 2014, the Commission issued a Policy Statement clarifying that section 305(a) does not prohibit the payment of dividends from funds included in capital account by any public utility that has a market-based rate tariff on file with the Commission, does not have captive customers, and does not provide transmission or local distribution services. *Payment of Dividends From Funds Included in Capital Account*, 148 FERC ¶ 61,020 (2014).

²⁷ See, e.g., *Enova Corp.*, 79 FERC ¶ 61,107 at 61,491-96.

themselves are not traditional public utility holding companies and the FERC-jurisdictional activities are only incidental to their primary business.²⁸

Amended section 203(a)(2) requires prior approval for a holding company “in a holding company system that includes a transmitting utility or an electric utility” to directly or indirectly merge or consolidate with “a transmitting utility, an electric utility company, or a holding company in a holding company system that includes a transmitting utility, or an electric utility company.”²⁹ There are two important points to be made with respect to this statutory language.

First, section 203(a)(2) refers to transactions involving a holding company that owns an “electric utility,” or a “transmitting utility,” each of which is defined differently from a “public utility.” While the definition of a transmitting utility in FPA section 1(23)³⁰ requires that the entity transmit wholesale electricity in interstate commerce and therefore does not include entities that are not also public utilities, the definition of an electric utility simply refers to an entity “that sells electric energy,” without any requirement that the sale be made in interstate commerce or, indeed, that the entity even be located in the United States.³¹

Second, the statutory language applies to acquisitions of interests in holding companies that own an “electric utility company,” a term that is slightly different from the term “electric utility” and which is not defined in the FPA. The Commission has chosen to interpret this term differently from an “electric utility,” and instead has decided to incorporate the definition that appears in PUHCA 2005, which is “any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale.”³² As in the case of the definition of an “electric utility,” this definition does not include a requirement that there be any interstate activity involved and thus covers the distribution and not just the transmission of electricity.

In Order No. 669, in which the Commission implemented the EPA 2005 changes to FPA section 203, FERC relied on the broad statutory language of section 203(a)(2) to assert jurisdiction over transactions involving holding company systems that include a broad range of entities that do not fit the definition of a public utility, including utilities located in ERCOT and other locations that are not part of the interstate grid, foreign utility companies (“FUCOs”), exempt wholesale generators (“EWGs”), and qualifying facilities (“QFs”).³³ However, recognizing that many of these transactions are routine and do not raise significant issues, the

²⁸ See, e.g., *JPMorgan Chase & Co.*, 123 FERC ¶ 61,088 (2008) (FERC approval required for JPMorgan Chase’s acquisition of The Bear Stearns Companies, Inc.); *Morgan Stanley Capital Grp., Inc.*, 79 FERC ¶ 61,109 (1997) (FERC approval required for the merger of Morgan Stanley and Dean Witter).

²⁹ 16 U.S.C. § 824b(a)(2).

³⁰ *Id.* § 796(23).

³¹ *Id.* § 796(22).

³² 18 C.F.R. § 33.1(b)(4); see also EPA 2005, § 1262(5) (codified at 42 U.S.C. § 16451(5)).

³³ *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 at PP 47-61 (2005), *order on reh’g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh’g*, Order No. 669-B, FERC Stats. & Regs. ¶ 31,225 (2006) (codified at 18 C.F.R. pts. 2, 33).

Commission went on to implement blanket approvals for many of these transactions, including transactions involving intrastate and foreign utilities, described in more detail below.³⁴

5. *Purchase or Acquisition of Securities of a Public Utility or Holding Company*

In addition to mergers and consolidations, FPA sections 203(a)(1)(C) and 203(a)(2) give the Commission statutory jurisdiction over, respectively, (1) a public utility's purchase of the securities valued at more than \$10 million of another public utility, or (2) a holding company's purchase of the securities valued at more than \$10 million of a transmitting utility, an electric utility company, or a holding company in a holding company system that includes a transmitting utility, or an electric utility company.³⁵ The provision of section 203(a)(2) regarding holding companies applies to the same broad group of entities described in Part A.4. above. The Commission has granted a number of blanket approvals for the purchase or sale of securities covered by this requirement, which are described below.

The Commission also held in Order No. 699 that it has jurisdiction over intra-system financing, or "money pooling" arrangements in which associate companies in the same holding company system share available funds on a short-term basis in order to manage more effectively the immediate financial needs of the companies as a whole.³⁶ However, the Commission has implemented blanket authorizations for certain types or categories of these transactions, which are described below.

6. *Change of Control Issues Generally*

If a transaction is not a sale, lease or merger, but nonetheless results in a direct or indirect change in control over a jurisdictional entity or facility, it still may trigger the requirement for prior approval under FPA section 203. Determining whether a transaction would result in a change in control for purposes of section 203 is not always straightforward. The Commission has conceded that it "has not established a 'bright-line' test for a percentage of ownership that constitutes control over, or ability to influence, an entity's actions" and it has expressed an unwillingness to do so.³⁷ Indeed, the Commission has recognized that it is difficult to identify every transaction that will trigger its section 203 jurisdiction: "We acknowledge that we cannot definitively identify every combination of entities or disposition of assets that may trigger section 203 jurisdiction, since we cannot anticipate every type of restructuring that might occur. . . . However, it should be clear that our concern is with changes in control, including direct or indirect mergers, that affect jurisdictional facilities (whether physical or 'paper' facilities)."³⁸ Although the Commission has stated that it considers change in control issues on a case-by-case

³⁴ Order No. 669, FERC Stats. & Regs. ¶ 31,200 at P 57.

³⁵ 16 U.S.C. § 824b(a)(1)(C), (a)(2). The value of securities is established by reference to the market price at the time the security is acquired, unless there is a transfer of securities that are not widely traded between two affiliated entities, in which the value is determined pursuant to a complex formula set forth in FERC's regulations. 18 C.F.R. § 33.1(b)(3)(iii).

³⁶ See Order No. 699, FERC Stats. & Regs. ¶ 31,200 at P 141.

³⁷ *ITC Holdings Corp.*, 111 FERC ¶ 61,149 at P 24 (2005).

³⁸ *Enova Corp.*, 79 FERC ¶ 61,107 at 61,496.

basis, the Commission generally presumes that the direct or indirect acquisition of less than 10 percent or more of a public utility's voting securities does not accomplish a change in control of the public utility.³⁹ Moreover, to the extent that a person acquires 10 percent or more of the outstanding voting securities of a public utility or its parent holding company in a secondary market transaction of which the public utility and parent company are unaware, the public utility has no liability under section 203(a)(1).⁴⁰

Another type of transaction that may trigger the need for FPA section 203 approval is a service agreement under which the owners of a generating facility confer a degree of control over plant operation and marketing to third parties. The Commission has suggested, without ever definitively ruling, that operation and maintenance agreements⁴¹ and so-called energy management agreements ("EMA")⁴² may require prior approval under section 203 if the third party exercises independent control over the operation of the facility or the marketing of its output such that the contract operator could limit or withhold the output of the facility as part of an effort to increase market prices.

7. Blanket Approvals

As described above, the amendments to FPA section 203 made by EPAct 2005 expanded the Commission's jurisdiction to review transactions involving the electric industry. However, the Commission has recognized that for many of these transactions there is no public interest benefit in requiring the submission of applications, or prior Commission review, before the transactions can be implemented. Consequently, the Commission has established various

³⁹ See *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 at P 57 (2007) ("*Supplemental Merger Policy*") ("Based on the industry's need for further guidance on what may or may not constitute a transfer of control of jurisdictional facilities under section 203, and for greater regulatory certainty in undertaking utility investments, the Commission's general policy in future cases will be to presume that a transfer of less than 10 percent of a public utility's holdings is not a transfer of control if: (1) after the transaction, the acquirer and its affiliates and associate companies, directly or indirectly, in aggregate will own less than 10 percent of such public utility; and (2) the facts and circumstances do not indicate that such companies would be able to directly or indirectly exercise a controlling influence over the management or policies of the public utility."), *clarification and reconsideration denied*, 122 FERC ¶ 61,157 (2008).

⁴⁰ *Supplemental Merger Policy*, FERC Stats. & Regs. ¶ 31,253 at P 36.

⁴¹ See *Cent. Miss. Generating Co.*, 106 FERC ¶ 61,006 at PP 27-29 (2004); *Entergy Miss., Inc.*, 102 FERC ¶ 61,105 at P 10 (2003).

⁴² For example, in 2002, the Commission set for hearing the question of whether Enron Corporation violated section 203 or 205 by entering into an EMA with El Paso Electric Company that allegedly gave Enron control over El Paso's sales of electricity. *El Paso Elec. Co.*, 100 FERC ¶ 61,188 (2002). Ultimately, the Commission issued a ruling holding that the EMA implicated section 205, but that Enron was authorized under its market-based rate tariff to enter into the agreement and thus there was no violation of section 205. *El Paso Elec. Co.*, 108 FERC ¶ 61,071 at P 19 (2004). However, the Commission failed to address the question of whether a section 203 filing also was required.

categories of transactions in its Part 33 regulations for which it has granted blanket pre-approval.⁴³ The transactions for which blanket approval has been granted are as follows:

- (1) The acquisition by a holding company in a holding company system that includes a transmitting utility or an electric utility (“Affected Holding Company”) of any security of: (i) an intrastate utility involved solely in intrastate transmission or sale of electricity (i.e., it is located in ERCOT or Hawaii or otherwise is not connected to the interstate grid); (ii) a utility that owns only facilities used solely for local distribution and/or sales of electric energy at retail regulated by a state commission; or (iii) an electric utility company that owns generating facilities that total 100 MW or less and are fundamentally used for its own individual load or for sales to affiliated end-users.⁴⁴
- (2) The acquisition by an Affected Holding Company of: (i) any non-voting security in a transmitting utility, an electric utility company, or an Affected Holding Company; (ii) any voting security in a transmitting utility, an electric utility company, or an Affected Holding Company if, after the acquisition, the Affected Holding Company will own less than 10 percent of the outstanding voting securities; or (iii) any security of a subsidiary company within the holding company system of the Affected Holding Company.⁴⁵
- (3) The acquisition of a foreign utility company by an Affected Holding Company.⁴⁶
- (4) Internal corporate reorganizations within an Affected Holding Company system that do not result in the reorganization of a traditional public utility that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities.⁴⁷
- (5) The purchase by a public utility of any security of a public utility in the same Affected Holding Company system in connection with an intra-system cash management program.⁴⁸
- (6) The acquisition by an entity that is a holding company solely with respect to one or more EWGs, FUCOs, or QFs of the securities of additional EWGs, FUCOs, or QFs.⁴⁹

⁴³ See 18 C.F.R. § 33.1(c).

⁴⁴ *Id.* § 33.1(c)(1).

⁴⁵ *Id.* § 33.1(c)(2).

⁴⁶ *Id.* § 33.1(c)(5).

⁴⁷ *Id.* § 33.1(c)(6).

⁴⁸ *Id.* § 33.1(c)(7).

⁴⁹ *Id.* § 33.1(c)(8).

- (7) The acquisition by a holding company, or a subsidiary of that company, that is regulated by the Board of Governors of the Federal Reserve Bank or by the Office of the Comptroller of the Currency of an unlimited amount of the securities of Affected Holding Companies if such acquisitions and holdings are in the normal course of its business and the securities are held: (i) as a fiduciary; (ii) as principal for derivatives hedging purposes incidental to the business of banking and it commits not to vote such securities to the extent they exceed 10 percent of the outstanding shares; (iii) as collateral for a loan; or (iv) solely for purposes of liquidation and in connection with a loan previously contracted for and owned beneficially for a period of not more than two years.⁵⁰
- (8) The acquisition by a holding company, or a subsidiary of that company, of any security of a public utility or a holding company that includes a public utility: (i) for purposes of conducting underwriting activities; or (ii) for purposes of engaging in hedging transactions, subject in the case of (ii) to the condition that if such holdings are 10 percent or more of the voting securities of a given class, the holding company or its subsidiary shall not vote such holdings to the extent that they are 10 percent or more.⁵¹
- (9) The transfer by a public utility of a wholesale market-based rate contract to any other public utility affiliate that has the same ultimate upstream ownership, provided that neither affiliate is affiliated with a traditional public utility with captive customers.⁵²
- (10) The transfer by a public utility of its outstanding voting securities to a person other than a holding company if after such transfer such person and its affiliated entities will own less than 10 percent of the outstanding voting securities of such public utility.⁵³
- (11) The transfer by a public utility of its outstanding voting securities to holding companies authorized to acquire those securities under the blanket authorizations described in (2)(ii), (6), (7) and (8) above.⁵⁴
- (12) The acquisition or disposition by a public utility of a jurisdictional contract where neither the acquirer nor transferor has captive customers or owns or provides transmission service over jurisdictional transmission facilities, the contract does

⁵⁰ *Id.* § 33.1(c)(9).

⁵¹ *Id.* § 33.1(c)(10).

⁵² *Id.* § 33.1(c)(11).

⁵³ *Id.* § 33.1(c)(12)(ii). This blanket authorization like several others is subject to certain reporting requirements as specified in 18 C.F.R. § 33.1(c)(17). However, many parties do not comply with the reporting requirements under this blanket authorization because the Commission has separately stated that it presumes there is no change in control of a public utility at ownership levels of voting securities below 10 percent. *See supra* note 39.

⁵⁴ 18 C.F.R. § 33.1(c)(12)(i), (13), (14), (15).

not convey control over the operation of a generation or transmission facility, and the acquirer is a public utility.⁵⁵

The exact requirements for each approval are technical in nature and in some cases subject to additional conditions beyond those outlined above. In addition, certain of the blanket approvals include post-transaction reporting requirements even though there is no prior approval required. Consequently, it is important to review the specific requirements associated with each of the blanket approvals to determine its applicability to a transaction, as well as the compliance obligations that must be satisfied in connection with the transaction.

B. GENERATION TRANSACTIONS BETWEEN A FRANCHISED UTILITY AND ITS UNREGULATED AFFILIATE

In the past, the Commission has expressed the concern that transfers of generation facilities between a franchised utility and a merchant affiliate “have an inherent potential for discriminatory treatment in favor of the affiliate”⁵⁶ and may potentially be unfair because they may provide a “safety net” that unaffiliated generators lack when market conditions are adverse.⁵⁷ Therefore, the Commission has applied its so-called “*Edgar*”⁵⁸ standards to section 203 applications involving a franchised utility’s purchase of generation assets from an unregulated affiliate.⁵⁹ The *Edgar* standards are intended to ensure that the franchised utility does not favor affiliates over nonaffiliates in its acquisitions and sales. Under the *Edgar* line of cases, a utility must demonstrate lack of affiliate abuse by showing either:

- evidence of direct head-to-head competition between affiliated and unaffiliated suppliers in a formal solicitation or information negotiation process;
- evidence of the prices that nonaffiliated buyers were willing to pay; or
- “benchmark” evidence of the prices, terms and conditions of sales made by nonaffiliated sellers.

Although the Commission has not required acquiring utilities to conduct competitive solicitations, it has adopted guidelines on requests for proposals that, if followed, “should greatly reduce application processing time (including litigation) and increase the likelihood of timely Commission approval.”⁶⁰

Finally, although the *Ameren* decision in which FERC applied its *Edgar* standards to section 203 applications speaks only to asset sales from the market-regulated affiliate to a

⁵⁵ *Id.* § 33.1(c)(16).

⁵⁶ *Ameren Energy Generating Co.*, 108 FERC ¶ 61,081 at P 59 (2004) (“*Ameren*”).

⁵⁷ *Id.* at P 11.

⁵⁸ *See Boston Edison Co. Re: Edgar Elec. Co.*, 55 FERC ¶ 61,382 (1991).

⁵⁹ *See Ameren*, 108 FERC ¶ 61,081 at P 59.

⁶⁰ *Id.* at P 68.

franchised public utility with captive customers, it is possible that the Commission could find that the standards apply equally to assets sales from the franchised utility to the market-regulated affiliate. Even if the standard is not directly applied, it will be necessary in such a circumstance to demonstrate that the transfer is consistent with the public interest under FERC's cross-subsidization standards, discussed in Part II.A below, and it seems logical that an *Edgar*-type showing could be required to make such a showing. Consequently, companies entering into such a transaction should consider addressing the question of the applicability of *Edgar* with Commission staff prior to filing a section 203 application.

II. BRIEF OVERVIEW OF SECTION 203 APPROVAL CRITERIA AND PROCESS

While not squarely a compliance issue, section 203 approval criteria and process are considerations in conducting initial feasibility and timing analyses of transactions that are jurisdictional under section 203.

A. APPROVAL CRITERIA

The Commission must find a transaction to be consistent with the "public interest" in order to approve it under section 203.⁶¹ In applying this public interest test, the Commission generally considers three factors: whether the transaction will have an adverse effect on competition, an adverse effect on rates, or an adverse effect on regulation.⁶² EAct 2005 provides an additional statutory criterion, obligating the Commission to find that the transaction "will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest."⁶³

⁶¹ Section 203's "phrase 'consistent with the public interest' does not connote a public benefit to be derived or suggest the idea of a promotion of the public interest. . . . It is enough if the applicants show that the proposed merger is compatible with the public interest." *Pac. Power & Light Co. v. FPC*, 111 F.2d 1014, 1016 (9th Cir. 1940). The Commission is required to evaluate whether the merger "taken as a whole, is consistent with the public interest" rather than to evaluate the effect of the merger on any one individual. *Ne. Utils. Serv. Co. v. FERC*, 993 F.2d 937, 951 (1st Cir. 1993).

⁶² See *Inquiry Concerning the Commission's Merger Policy Under the Fed. Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 at 30,111 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) ("*Merger Policy Statement*") (codified at 18 C.F.R. pt. 2.26).

⁶³ EAct 2005, § 1289(a)(4) (codified at 16 U.S.C. § 824b(a)(4)). FERC also may consider whether a merger affects reliability in a material way. A Commission policy statement, issued in response to a Commission staff report on the August 2003 blackout, stated that the Commission considers the reliability implications of merger applications. See *Policy Statement on Matters Related to Bulk Power Sys. Reliability*, 107 FERC ¶ 61,052 at P 37 (2004) (citing U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, at 147 (Apr. 2004), <http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf> (recommending that the Commission incorporate a formal reliability impact consideration in reviewing proposed mergers)). While reliability concerns have not been an issue in recent cases under FPA section 203, applicants should be prepared to respond to any comments on reliability issues.

The standards utilized by the Commission to evaluate these four primary areas of FERC review (prior to EPAAct 2005) are briefly summarized below.

Effect on Competition. The purpose of the Commission’s review of competition is to analyze whether a merger or acquisition will change market concentration levels sufficiently to give the applicants greater incentive or ability to profitably withhold output or foreclose rivals in an effort to raise prices. The Commission considers both “horizontal” effects on competition, which involve the combination of the parties’ generation capacity, and “vertical” effects on competition, which involve the combination of generation capacity with assets used as an input to generation such as, for example, the merger of a company owning generation facilities with a company that owns substantial coal mining assets used to supply fuel to electric generation facilities.

Horizontal Competition. The Commission analyzes horizontal competitive effects in each “geographic market” (either a regional transmission organization or, for transactions not involving an RTO, the relevant balancing authority area) in which the parties to the transaction own generation. If parties do not both own generation in a particular geographic market, or if the combined market share of the parties in the market would be “*de minimis*” the Commission considers no horizontal competitive effects to be raised in that geographic market.⁶⁴ The Commission has not defined what is meant by a *de minimis* amount of generation. In recent cases, however, the Commission appears to have adopted an informal threshold of no more than approximately a 3 percent share of generation ownership in a geographic market as constituting a *de minimis* share of the market.⁶⁵

In geographic markets where both parties have more than a *de minimis* share of generation capacity, the Commission has adopted a horizontal screen analysis to enable the Commission to identify proposed mergers or acquisitions that are unlikely to present competitive concerns. The required analysis was originally set forth in Appendix A of the Commission’s *Merger Policy Statement*,⁶⁶ and since has been incorporated into FERC’s merger regulations.⁶⁷ If a proposed combination or acquisition fails the screen, the Commission may require applicants to submit more detailed analyses to rebut the presumption of market power. Typically, in cases where a combination or acquisition produces screen failures, the initial application will contain proposed mitigation measures (e.g., generation auctions and divestures) and analyses demonstrating that the proposed mitigation measures eliminate screen failures.

Vertical Competition. Vertical merger applications (those that involve the combination of entities owning generation with those owning inputs to generation) are subject to an additional competitive analysis. If the upstream merging firm sells a product that produces a *de minimis*

⁶⁴ 18 C.F.R. § 33.3(a)(2)(i).

⁶⁵ See, e.g., *Seneca Generation, LLC*, 145 FERC ¶ 61,098 (2013) (2.1% of PJM market); *Edison Int’l*, 144 FERC ¶ 62,073 (2013) (2.7% of PJM market); *Dynegy Roseton, L.L.C.*, 142 FERC ¶ 62,148 (2013) (3.2% of NYISO market); *Macho Springs Power, I, LLC*, 135 FERC ¶ 62,200 (2011) (3% of El Paso BAA).

⁶⁶ FERC Stats. & Regs. ¶ 31,044 at 30,128-37.

⁶⁷ 18 C.F.R. § 33.3.

amount of the relevant product in the downstream geographic market, or sells no product in the downstream electricity geographic market, only minimal information and analysis is necessary.⁶⁸ If a full vertical competitive analysis is needed, merging companies must (1) define the relevant products sold by the merging firms; (2) define the relevant geographic markets; (3) evaluate competitive conditions using market share and standard market concentration measures (known as the Herfindahl-Hirschman Indices or “HHIs”) in the respective geographic markets; and (4) evaluate potential adverse effects of the proposed merger in these markets, along with other factors that could counteract such effects.⁶⁹

In the past, the Commission considered whether an applicant’s ownership of electric transmission facilities raises vertical market power concerns. This concern typically was addressed by merger applicants agreeing to provide open-access transmission or agreeing to join or form an RTO. More recently, however, the Commission has not required RTO membership as a prerequisite to merger approval, and has found that an open-access transmission tariff adequately addresses transmission-related market power concerns.⁷⁰

Effect on Regulation. Prior to the enactment of EAct 2005, the Commission’s primary concern in reviewing a transaction’s effect on regulation was the effect on its own jurisdiction when the transaction would result in the formation of a registered holding company under PUHCA 1935. In those circumstances regulation by the SEC displaced FERC jurisdiction under the FPA for certain purposes. However, since the repeal of PUHCA 1935 in EAct 2005 “there is no longer a concern about any potential shift in regulation from [the] Commission to the SEC”⁷¹ and, in Order No. 669, the Commission eliminated any consideration of the effect of a transaction on its own jurisdiction.⁷²

The Commission currently uses its consideration of the effect of a transaction on regulation to address concerns regarding state jurisdiction—specifically whether a transaction would cause a state utility commission to lose jurisdiction over a utility previously subject to its jurisdiction. Under this prong, the Commission requires applicants to state whether state regulatory bodies have jurisdiction to review the merger, and reserves the ability to investigate state regulatory concerns raised by states that do not have such jurisdiction.⁷³

⁶⁸ *Revised Filing Requirements Under Part 33 of the Commission’s Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,903 (2000), *order on reh’g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001) (codified at 18 C.F.R. pt. 33).

⁶⁹ Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,903-04.

⁷⁰ *See, e.g., Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261 at P 46 (2013); *Fla. Power & Light Co.*, 145 FERC ¶ 61,018 at P 50 (2013); *Duke Energy Corp.*, 136 FERC ¶ 61,245 at P 161 (2011).

⁷¹ Order No. 669, FERC Stats. & Regs. ¶ 31,200 at P 196.

⁷² *Id.* at PP 196, 202. Nevertheless, the Commission continues to address the effect of a transaction on its own jurisdiction in its merger orders. *See, e.g., Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261 at P 74.

⁷³ Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914-15.

Effect on Rates. Applicants have the burden to prove that captive wholesale ratepayers will not be harmed by a proposed transaction. This burden can be discharged in a number of ways. To the extent that any relevant power sales agreements have been entered into pursuant to the seller's market-based rate authority, the Commission has held that the affected wholesale customers are not captive and that no further showing is required.⁷⁴ Where the contracts in question have not been entered into pursuant to market-based rate authority, applicants can show that all customers are served under fixed rates or are located in a retail access state so that the ultimate retail electric consumers are not "captive" and have the option to purchase from a competitive supplier. Alternatively, if the applicants have long-term contracts with rate adjustment clauses, the applicants can propose a rate freeze or open season to protect captive customers. Any such ratepayer protection mechanisms must clearly identify what customer groups are covered, what types of costs are covered, and the time period of the protection.⁷⁵ Often, applicants make a "hold-harmless" ratepayer protection commitment, stating that applicants will not include merger-related costs in rates unless they can show that such costs are offset by merger-related benefits.

Recently, the Commission has increased its scrutiny of the effect of transactions on rates and the implementation of hold-harmless commitments, in three respects:

First, the Commission has emphasized that a sufficient hold-harmless commitment does not include only "transaction" costs, such as legal and consultants fees, incurred to consummate the merger, but also "transition costs" incurred in connection with consolidating two companies and achieving the cost savings associated with a transaction.⁷⁶

Second, the Commission has clarified what merger applicants must do if in the future they attempt to recover transaction costs. If they want to recover transaction costs through an existing formula rate that allows for such recovery, the applicants must make a compliance filing in the section 205 docket in which the formula rate was approved by the Commission, as well as the section 203 docket. If the applicants seek to recover transaction-related costs in a new rate (either a new formula rate or a new stated rate), then that filing must be made in a new section 205 docket as well as in the section 203 docket. In such a filing, the applicants must: (1) specifically identify the transaction-related costs they are seeking to recover, and (2) demonstrate that those costs are exceeded by the savings produced by the transaction, in addition to any requirements associated with filings made under section 205.⁷⁷

Third, the Commission has made clear that it applies a different standard to acquisition premiums than it does to other transaction costs and that, in order to recover an acquisition

⁷⁴ See *Ameren Energy Generating Co.*, 145 FERC ¶ 61,034 at PP 83-84 (2013).

⁷⁵ Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914.

⁷⁶ See, e.g., *Silver Merger Sub*, 145 FERC ¶ 61,261 at P 68; *Exelon Corp.*, 138 FERC ¶ 61,167 at P 118 (2012); *ITC Midwest LLC*, 133 FERC ¶ 61,169 at P 24 (2010).

⁷⁷ *Id.* at P 25 (footnotes omitted); see also *FirstEnergy Corp.*, 133 FERC ¶ 61,222 at P 63 (2010); *PPL Corp.*, 133 FERC ¶ 61,083 at PP 26-27 (2010).

premium, merger applicants must demonstrate that the acquisition was “prudent and provides measurable, demonstrable benefits to ratepayers.”⁷⁸

Cross Subsidization. Under the amendments to section 203 implemented by the EPAct 2005, the Commission “shall approve” a proposed transaction “if it finds that the proposed transaction . . . will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless . . . the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.”⁷⁹

In Order Nos. 669, 669-A, and 669-B, the Commission identified a four-factor test that applicants must satisfy in order to address the concerns identified in section 203 regarding any possible cross-subsidization, pledge or encumbrance of utility assets associated with the proposed transaction. Under this test, the Commission examines whether a proposed transaction, at the time of the transaction or in the future, results in:

- (1) transfers of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company;
- (2) new issuances of securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company;
- (3) new pledges or encumbrances of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company; and
- (4) new affiliate contracts between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the FPA.⁸⁰

In its *Supplemental Merger Policy*, the Commission recognized that three types of transactions are unlikely to raise cross-subsidization issues and therefore established “safe harbors” for these types of transactions where no detailed case-specific inquiry is required: (1) transactions where a franchised public utility with captive customers is not involved; (2) transactions where the relevant state utility commission has jurisdiction to review the transaction

⁷⁸ See, e.g., *Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261 at P 68 (citing *ITC Holdings Corp.*, 139 FERC ¶ 61,112 at P 50 & n.116 (citing *Minn. Power & Light Co.*, 43 FERC ¶ 61,104 at 61,342, *reh’g denied*, 43 FERC ¶ 61,502 (1988); *Duke Energy Moss Landing, LLC*, 83 FERC ¶ 61,318 at 62,304 (1998); *PSEG Power Conn., LLC*, 110 FERC ¶ 61,020 at P 32 (2005))).

⁷⁹ 16 U.S.C. § 824b(a)(4).

⁸⁰ 18 C.F.R. § 33.2(j)(1)(ii).

and impose any necessary protections against cross-subsidization; and (3) transactions where the franchised utility transacts only with non-affiliates.⁸¹

B. APPROVAL PROCESS

Upon receipt of an application under FPA section 203, the Commission issues a notice of filing requiring comments within 15 to 60 days, depending on the nature of the filing and whether the applicants submitted detailed market power studies. When a detailed market power study is included with an application, the Commission typically provides for a 60-day notice period, while the comment period for other applications will be significantly shorter.⁸²

The majority of section 203 transactions, particularly those where there is no material overlap in generation ownership among the applicants, are approved on a delegated basis by the Director, Division of Electric Power Regulation - West. Approval under delegated authority is permissible when there are no protests or substantive interventions. Usually, such approvals are issued within four to six weeks of filing.

If substantive issues are raised in protests to a section 203 application, the review process takes considerably longer and resolution requires an order of the Commission. However, the 2005 EAct amendments imposed a requirement in section 203(a)(5) that the Commission rule on a section 203 application in 180 days, subject to a single 180-day extension for good cause.⁸³ As a practical matter, this time limitation prevents the Commission from initiating an evidentiary hearing regarding a section 203 application, but instead requires the Commission to rule based on affidavits and arguments submitted by the applicants and any parties protesting the application. For most applications that have been submitted since the effectiveness of the EAct 2005 amendments, FERC has ruled within the initial 180-day time frame without resort to an extension.

III. REMEDIES FOR NONCOMPLIANCE

A. FAILURE TO OBTAIN REQUIRED APPROVAL

EAct 2005 granted the Commission civil penalty authority to punish violations of most operative sections of the FPA, including section 203, in an amount up to \$1,000,000 per day per violation. In several orders issued in the first half of 2005, before the passage of the EAct 2005, the Commission stated that while it did “not have civil penalty authority . . . the Applicants’ failure to obtain prior Commission approval for [a section 203 jurisdictional] transaction is the type of violation for which the imposition of a penalty would be appropriate.”⁸⁴ Further, the Commission has stated, “we take [section 203] violations seriously, and we expect

⁸¹ FERC Stats. & Regs. ¶ 31,253 at PP 16-19.

⁸² Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,878.

⁸³ EAct 2005, § 1289(5) (codified at 16 U.S.C. § 824b(a)(5)).

⁸⁴ *Puget Sound Energy, Inc.*, 110 FERC ¶ 61,161 at P 16 (2005); *see also Mesquite Investors L.L.C.*, 111 FERC ¶ 61,162 at P 19 (2005); *Northern Iowa Windpower II LLC*, 110 FERC ¶ 61,059 at P 13 (2005).

public utilities that are planning transactions that may be jurisdictional to come to the Commission for guidance, before consummating the questionable transactions.”⁸⁵

There have been only two cases since EAct 2005 was enacted in which the Commission has imposed penalties for failure to obtain section 203 approval. The first involved a transaction in which FPL Energy, LLC (“FPLE”) acquired Gexa Energy, L.L.C. (“Gexa”).⁸⁶ The prior owners of Gexa represented to FPLE that Gexa was not a public utility subject to the Commission’s jurisdiction, and therefore that no section 203 authorization was required. Subsequent to the acquisition, FPLE determined that, in fact, Gexa had obtained market-based rate authority prior to the acquisition and therefore Gexa technically was a public utility and section 203 approval of the transaction was required. FPLE thereafter self-reported the violation. In considering what penalty to impose, the Commission noted that FPLE had promptly self-reported the violation when it became aware of it, that it had replaced the Gexa senior management personnel responsible for the violation, that it had instituted new compliance procedures to ensure that the violation did not recur, and that it self-imposed a six month moratorium on making market-based rate sales.⁸⁷ The Commission nevertheless imposed a \$500,000 civil penalty and disgorgement of \$12,481.41 in profits, with interest.⁸⁸

The second involved ITC Holdings Company (“ITC”), which entered into twenty different transactions between 2005 and 2011 in which it acquired jurisdictional transmission facilities, the value of which ranged from \$0 to approximately \$6.7 million.⁸⁹ Because the value of each transaction was below the \$10 million threshold that appears in FPA section 203(a)(1)(A), ITC did not believe that section 203 approval was required.⁹⁰ However, as described in Part I.A.1.a above, the Commission has taken the position that acquisitions of transmission facilities are subject to its jurisdiction under FPA section 203(a)(1)(B), which has no minimum value threshold, and thus the Commission’s approval is required. The Commission initiated an investigation of the transactions and on March 11, 2014 entered into a settlement with ITC that addressed these transactions, as well as ITC’s failure to file 174 FERC-jurisdictional agreements pursuant to FPA section 205. In the settlement, ITC agreed to pay a civil penalty of \$750,000 and to submit to at least one year of compliance monitoring, with another year of monitoring at Enforcement Staff’s discretion.⁹¹

The Commission evaluates late-filed section 203 applications based on present day circumstances and approves them if it believes that the analysis of competitive, rate, and regulatory effects would not be materially different than it would have been at the time of the

⁸⁵ *Kandiyohi Power Coop.*, 107 FERC ¶ 61,285 at 62,344.

⁸⁶ *In re Gexa Energy, L.L.C.*, 120 FERC ¶ 61,175 (2007).

⁸⁷ *Id.* at P 14.

⁸⁸ *Id.* at P 1.

⁸⁹ *Int’l Transmission Co.*, 146 FERC ¶ 61,172 (2014).

⁹⁰ *See, e.g., Int’l Transmission Co.*, 139 FERC ¶ 61,003 at P 10 (2012).

⁹¹ *Int’l Transmission*, 146 FERC ¶ 61,172 at P 10.

transaction.⁹² Nevertheless, the Commission has reminded public utilities that its approval of a transaction that already has closed does not provide insulation from requests by affected parties for a court to void a transaction that was consummated without *prior* approval.⁹³

B. FAILURE TO COMPLY WITH MERGER CONDITIONS

The Commission has also developed the practice of conducting post-closing audits of transaction parties' compliance with the conditions placed by the Commission to its approval of a transaction.⁹⁴ To date, these audits have found only minor violations. For example, in *BHE Holdings Inc.*, the Commission cited BHE Holdings' failure to submit required final accounting entries within six months of the closing, for which the Commission imposed no fine but simply required changes to the company's compliance procedures.⁹⁵ The most significant finding to date has been the Commission's determination that FirstEnergy Corporation failed to adequately track its merger-related costs after its merger with Allegheny Energy, Inc., and thus inappropriately included merger-related costs in certain formula rates in violation of its rate hold-harmless commitment. The Commission required that FirstEnergy not only strengthen its compliance and cost-tracking procedures, but also required a \$1.2 million refund of amounts included in rates in violation of the hold-harmless commitment. The Commission did not, however, impose any additional fine or penalty for this violation.⁹⁶

IV. COMPLIANCE RECOMMENDATIONS

It is critical to ensure that all jurisdictional transactions are submitted to the Commission prior to being consummated. For transactions where it is not clear whether section 203 applies, companies should consider consulting with Commission staff prior to the transaction, requesting a ruling disclaiming jurisdiction or simply consent to section 203 jurisdiction⁹⁷ and request expedited approval. Public utilities also should take steps to ensure that all legal and business staff are aware of the section 203 requirements and understand the importance of identifying potentially jurisdictional transactions before they are consummated. Companies should develop a checklist of the types of transactions and activities that could possibly trigger approval under section 203 and require business staff to consult with counsel if any of those transactions are

⁹² *PDI Stoneman, Inc.*, 104 FERC ¶ 61,270 at P 19 (2003); *see also Gexa Energy*, 120 FERC ¶ 61,175 at P 10.

⁹³ *See PDI Stoneman*, 104 FERC ¶ 61,270 at P 25.

⁹⁴ *See, e.g., Duke Energy Corp.*, Docket No. PA14-2-000 (Jan. 29, 2014) (notice of commencement of audit of Duke Energy Corporation's compliance with conditions established in Commission orders authorizing its merger with Progress Energy, Inc.); *Exelon Corp.*, Docket No. PA13-15-000 (Apr. 18, 2013) (notice of commencement of audit of Exelon Corporation's compliance with conditions established in Commission orders authorizing its merger with Constellation Energy Group, Inc., Public Service Enterprise Corporation, Inc., and Commonwealth Edison Company).

⁹⁵ *BHE Holdings Inc.*, Docket No. PA13-8-000, Audit Report at 2 (Jan. 27, 2014).

⁹⁶ *FirstEnergy Corp.*, Docket No. PA12-5-000, Letter Order at P 3, Audit Report at 3-4 (Nov. 1, 2013).

⁹⁷ *See, e.g., San Diego Gas & Elec. Co.*, 137 FERC ¶ 61,232 at P 25 (2011) (citing *Ocean State Power*, 47 FERC ¶ 61,321 at 62,130 (1989)).

contemplated.⁹⁸ Given that transactional lawyers are typically involved in the early stages of potential transactions, companies should train them to spot fact patterns that may result in transactions that are or may be jurisdictional under section 203.⁹⁹

FPA section 203 compliance issues can also arise in the post-closing stage of a jurisdictional transaction. Once a transaction is approved, the applicant typically is required to notify the Commission within 10 days of consummation of the transaction. Also, applicant commitments during the approval phase or FERC-imposed conditions must be tracked. Mergers, for example, are often conditioned on the applicants enforcing hold-harmless rate mechanisms, upgrading transmission capacity, implementing independent market monitoring mechanisms, holding annual energy auctions, divesting generation, or increasing reporting to the Commission. The Commission closely monitors the implementation and effectiveness of these applicant commitments and, as noted above, has recently commenced a number of post-closing audits of compliance with merger conditions. Accordingly, it is important that a system be developed by the company's regulatory staff to track ongoing compliance with these types of obligations.

⁹⁸ See *Enforcement of Statutes, Orders, Rules, and Regulations*, 113 FERC ¶ 61,068 at PP 2, 22 (2005) (Policy Statement on enforcement).

⁹⁹ More generally, see Chapter 1, The Hallmarks of a Successful Compliance Program, for a description of how to develop a compliance program consistent with the Commission's Policy Statement on Enforcement.

Chapter 13

FPA Section 204: Issuance of Securities and Assumption of Liabilities

ROBERT W. WARNEMENT

Section 204 of the Federal Power Act grants FERC jurisdiction to regulate the issuance of securities and the assumption of liabilities in respect of securities by a public utility, subject to certain exceptions.¹ The primary purpose of FPA section 204 is to ensure the financial viability of public utilities that serve retail consumers of electricity.²

Since the enactment of the Energy Policy Act of 2005,³ section 204 has acquired increased regulatory importance. While EAct 2005 did not amend FPA section 204 directly, it significantly altered the regulatory landscape under section 204 in two ways. First, EAct 2005 repealed both the Public Utility Holding Company Act of 1935, and FPA section 318 which together gave the U.S. Securities and Exchange Commission exclusive jurisdiction over the issuance, acquisition, redemption and retirement of securities (as well as certain other business activities) by registered public utility holding company systems and their subsidiaries.⁴ Public utilities that are part of what would have previously been registered holding company systems are now subject to section 204. Second, EAct 2005 expanded the Commission's authority to

¹ Section 204 provides in pertinent part:

No public utility shall issue any security, or assume any obligation or liability as guarantor, indorser, surety, or otherwise in respect of any security of another person, unless . . . upon application by the public utility, the Commission by order authorizes such issue or assumption of liability. The Commission shall make such order only if it finds that such issue or assumption (a) is for some lawful object, within the corporate purposes of the applicant and compatible with the public interest . . . and (b) is reasonably necessary or appropriate for such purposes.

16 U.S.C. § 824c(a).

² See *Merrill Lynch Commodities, Inc.*, 108 FERC ¶ 61,233 at P 16 & n.11 (2004) (citing *Citizens Energy Corp.*, 35 FERC ¶ 61,198 at 61,455 (1986); *Howell Gas Mgmt. Co.*, 40 FERC ¶ 61,336 at 62,026 (1987)). See *Invenenergy Wind Dev. Mich. LLC*, 136 FERC ¶ 61,209 at P 10 n.33 (2011) (citing, *inter alia*, *Merrill Lynch Commodities, Inc.*).

³ Pub. L. No. 109-58, 119 Stat. 594 (2005).

⁴ See *id.* § 1277, 119 Stat. at 978 (repealing 16 U.S.C. § 825q and amending 16 U.S.C. § 824(g)(5)).

punish violations of the FPA, including violations of FPA section 204 and orders issued thereunder.⁵

This chapter discusses: (i) the extent of Commission jurisdiction under FPA section 204, including FERC’s evolving case law, (ii) the requirements for Commission approval of individual securities issuances or assumptions of liability, (iii) blanket authorizations, and (iv) and the procedures used to obtain such approvals.

I. COMMISSION JURISDICTION UNDER FPA SECTION 204

A. PUBLIC UTILITIES

The Commission only has authority under FPA section 204 to regulate securities issuances and assumptions of liability by public utilities. Issuances of securities and assumptions of liability by holding companies and affiliates of public utilities do not require section 204 authorization unless those companies also happen to be public utilities. Section 201(e) of the FPA defines a public utility as “any person who owns or operates facilities subject to the jurisdiction of the Commission.”⁶ Facilities subject to the jurisdiction of the Commission include facilities for “the transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce.”⁷ As such, any “company transmitting electric energy in interstate commerce or selling electric energy at wholesale in interstate commerce” is a public utility for purposes of section 204.⁸ The Commission makes no distinction under section 204 with respect whether a public utility is investor-owned or not-for-profit.⁹

⁵ See *id.* § 1284(e), 119 Stat. at 980 (amending FPA section 316A, 16 U.S.C. § 825o-1). Furthermore, EPAct 2005 raised the penalty ceiling from \$10,000 to \$1,000,000 per day for each violation. See *id.* A detailed discussion of the Commission’s penalty authority is found in Chapter 3 of this Handbook.

⁶ 16 U.S.C. § 824(e). The scope of Commission jurisdiction under section 204 is analyzed through application of section 201(e). See, e.g., *Gulf States Utils. Co. v. FPC*, 411 U.S. 747, 750 (1973); *Jersey Cent. Power & Light Co. v. FPC*, 319 U.S. 61, 63 (1943); *City of Lafayette v. SEC*, 454 F.2d 941, 944 (D.C. Cir. 1971); *Multitrade Ltd. P’ship*, 63 FERC ¶ 61,252 (1993); *UtiliCorp United Inc.*, 59 FERC ¶ 61,220 (1992). Section 201(f) of the FPA, however, excludes from the definition of public utility and the Commission’s jurisdiction “the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing” 16 U.S.C. § 824(f) (internal citation omitted).

⁷ 16 U.S.C. § 824(b)(1). Jurisdictional facilities include “paper” facilities such as rate schedules, tariffs, wholesale power sales contracts and other contracts under which jurisdictional services are provided. See *Hartford Elec. Co. v. FPC*, 131 F.2d 953, 961 (1942); *Citizens Energy Corp.*, 35 FERC ¶ 61,198 (1986).

⁸ *City of Lafayette*, 454 F.2d at 944.

⁹ See *PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,278 (2010) (granting authorization under section 204 to non-profit regional transmission entities); *ISO New England Inc.*, 97 FERC ¶ 61,304

B. SECURITIES

The plain terms of FPA section 204 require that an issuance or assumption of liability must involve a “security” to fall within the ambit of the section. This requirement raises a number of questions.

The first is whether section 204 approval is required for an otherwise jurisdictional borrowing by a public utility where the borrowing is not evidenced by a note or other instrument typically thought of as a security. The answer is almost certainly “yes” because section 3(16) of the FPA defines a “security” somewhat broadly as “any note, stock, treasury stock, bond, debenture, or *other evidence of interest in or indebtedness of a corporation* subject to the provisions of [the FPA].”¹⁰ In instances where a borrowing is not evidenced by a note or similar instrument, a credit agreement or similar lending document would nevertheless seem reasonably to constitute “evidence of . . . indebtedness of” the borrower and therefore constitute a security for purposes of section 204.

Assuming that to be the case, the second question that arises is whether the mere execution of a credit agreement or other lending document by a public utility as borrower constitutes the issuance of a security for purposes of section 204 if actual borrowings under the agreement will only occur thereafter at the public utility’s discretion some time in the future—such as would be the case with a revolving line of credit. Relying again on the plain terms of section 204, the correct answer seems to be that section 204 jurisdiction would only attach at such point as when actual borrowing takes place under the relevant agreement because before that time there is no “indebtedness” under the security in question. While the Commission has never directly addressed these conclusions, case law under section 204 is consistent with them.¹¹

(2001) (granting authorization under section 204 to self-funded, not-for-profit independent system operator seeking to borrow \$40 million under an existing credit facility); *Cal. Power Exch. Corp.*, 86 FERC ¶ 62,195 (1999) (granting authorization under section 204 to not-for-profit public benefit corporation to issue long-term debt).

¹⁰ 16 U.S.C. § 796(16) (emphasis added).

¹¹ The Commission frequently grants authorizations to public utilities seeking approval under section 204 to make future borrowings up to a capped aggregate amount under loan or credit agreements. *See, e.g., Entergy Gulf States La., L.L.C.*, 140 FERC ¶ 62,233 (2012) (approving borrowings under credit agreement providing for revolving credit loans and periodic issuances of commercial paper); *Fall River Rural Elec. Coop., Inc.*, 104 FERC ¶ 62,156 (2003) (approving request to borrow approximately \$13 million under a master loan agreement with the National Rural Utilities Cooperative Finance Corporation (“CFC”)); *NewCorp Res. Elec. Coop., Inc.*, 104 FERC ¶ 62,155 (2003) (approving request to borrow \$31.5 million under a bank loan secured by applicant’s jurisdictional transmission assets); *Smarr EMC*, 91 FERC ¶ 62,187 (2000) (approving request to borrow up to \$195 million under a loan agreement with the CFC over a two-year period); *Cal. Power Exch. Corp.*, 86 FERC ¶ 62,195 (approving request to acquire loans or other evidences of indebtedness on a revolving basis with no more than \$500 million outstanding at any one time); *Or. Trail Elec. Consumers Coop., Inc.*, 79 FERC ¶ 62,142 (1997) (approving request to enter into and borrow funds under a \$5 million line-of-credit agreement with the CFC); *Pac. Nw. Generating Coop.*, 78 FERC ¶ 62,002 (1997) (approving request to enter into a twelve-month revolving line-of-credit agreement with the CFC under which applicant would borrow up to \$5 million).

Under Commission precedent there are limits to what constitutes a security for purposes of FPA section 204. In *UtiliCorp United Inc.*,¹² UtiliCorp, which was itself a public utility, had several non-utility, unregulated subsidiaries. When lending institutions dissatisfied with “comfort letters” requested that UtiliCorp formally guarantee the performance of its subsidiaries’ contractual obligations to third parties, the company asked FERC to disclaim jurisdiction over the guarantees under FPA section 204.¹³ UtiliCorp argued that the contractual guarantees at issue were not “in respect of any security” because its subsidiaries’ contractual obligations were not in the form of securities and thus fell outside the Commission’s jurisdiction.¹⁴ The Commission agreed:

[W]e find that UtiliCorp must seek Commission approval prior to guaranteeing any note, stock, treasury stock, bond, or debenture, or any “evidence of interest in or indebtedness of a corporation” when that evidence is of a like kind to notes, stocks, treasury stocks, bonds, and debentures. All other guarantees are not subject to the Commission’s limited jurisdiction under section 204 of the FPA.¹⁵

The Commission also clarified that when a guarantee by a public utility is with respect to a “security” for purposes of section 204, the full value of the guarantee must be recognized.¹⁶

To mitigate compliance risk, when in doubt over whether a particular financial activity involves the jurisdictional issuance of a security or assumption of liability by a public utility, one conservative approach is to seek a declaratory order from the Commission disclaiming jurisdiction. Alternatively, it may be more efficient to ask the Commission to assume jurisdiction rather than address the sometimes difficult issues that can arise in a disclaimer request.¹⁷

C. OTHER JURISDICTIONAL LIMITS

Section 204 specifically excludes from Commission jurisdiction certain issuances and assumptions by public utilities. The Commission does not have jurisdiction over: (i) the issuance by a public utility of short-term debt maturing not more than one year after issuance and aggregating not more than 5 percent of the par value of the utility’s other securities then

¹² 59 FERC ¶ 61,220.

¹³ See *id.* at 61,755-56.

¹⁴ *Id.* at 61,758-59.

¹⁵ *Id.* at 61,759 (emphasis added) (citing *Ass’n of Am. R.R. v. United States*, 603 F.2d 953, 963-64 (D.C. Cir. 1979) (construing section 20a of the Interstate Commerce Act, the statute on which FPA section 204 was modeled)).

¹⁶ *Id.* at 61,758.

¹⁷ The Commission will assume jurisdiction, even where jurisdiction over a particular type of transaction or issuance is unclear, when asked to do so by the applicant. See, e.g., *Entergy Ark. Inc.*, 145 FERC ¶ 61,093 at PP 25 & n.27, 40 & n.38 (2014) (citing *Ocean State Power*, 47 FERC ¶ 61,321 (1989)). Such an approach avoids the filing fee and time required for a declaratory order and provides regulatory certainty for the applicant.

outstanding,¹⁸ or (ii) the issuance of securities by a public utility *organized and operating* in a state that regulates the issuance of such securities.¹⁹ As many states regulate the issuance of securities by public utilities, an applicant should make sure that no state commission has jurisdiction over the issuance before seeking FERC approval.

There is an open question as to whether the Commission's jurisdiction under FPA section 204 extends to a public utility that is organized and operating in a state that regulates its securities issuances *and* also operates in other states that do not regulate its security issuances. An underlying purpose of section 204(f) is to fill a regulatory gap that would exist absent state commission review. This purpose plus the plain language of FPA section 204(f) and of the Commission's regulations under section 204(f) suggest that the Commission would not have jurisdiction in this context.²⁰

However, in *Southwest Power Pool, Inc.*,²¹ the Commission arguably implied the opposite. Southwest Power Pool, Inc., a regional transmission organization and public utility, operates in several states, but is organized in Arkansas, and the Arkansas Public Service Commission asserts jurisdiction over its activities, including securities issuances. In response to SPP's request for clarification as to whether section 204 applied to its financing activities, the Commission held: "We interpret Commission section 204 jurisdiction to attach where, as here, an RTO public utility [i.e., SPP] is operating a transmission system spanning several states. Therefore, we will assert jurisdiction."²² However, as pointed out in SPP's section 204 application, the Commission has previously asserted that RTOs (unlike traditional vertically-integrated utilities) are generally subject to exclusive FERC jurisdiction.²³ That fact argues

¹⁸ 16 U.S.C. § 824c(e).

¹⁹ *Id.* § 824c(f) (emphasis added).

²⁰ See *id.* ("The provisions of this section shall not extend to a public utility *organized and operating* in a State under the laws of which its security issues are regulated by a State Commission.") (emphasis added); 18 C.F.R. § 34.1(c)(1) ("If an agency of the State in which the utility is *organized and operating* approves or authorizes, in writing, the issuance of securities prior to their issuance, the utility is exempt from the provisions of sections 19, 20 and 204 of the [FPA] and the regulations under this part, with respect to such securities.") (emphasis added).

²¹ 120 FERC ¶ 61,160 (2007).

²² *Id.* at P 8 (footnote omitted).

²³ See *Southwest Power Pool, Inc.*, Docket No. ES07-40-000, Application of Southwest Power Pool, Inc. Under Section 204 of the Federal Power Act at 8 (June 20, 2007) ("'[B]ecause RTOs/ISOs provide transmission service and may operate wholesale markets, they do not provide retail electric service, and, therefore, fall under the exclusive jurisdiction of the Commission. This means that RTOs and ISOs, unlike vertically integrated [investor-owned utilities], are not subject to direct oversight by state commissions.'" (quoting *Fin. Reporting and Cost Accounting, Oversight and Recovery Practices for Reg'l Transmission Orgs. and Indep. Sys. Operators*, 108 FERC ¶ 61,237 at P 8 (2004)); see also *Reg'l Transmission Orgs.*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,213 (1999) (stating "[T]his Rule takes a flexible approach that allows states to play appropriate roles in RTO matters, consistent with this Commission's exclusive responsibilities and authorities under the FPA."), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *appeals dismissed sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) (per curiam) (codified at 18 C.F.R. § 35.34).

against extending *Southwest Power Pool, Inc.* beyond its facts and RTO context. The issue, however, remains open and should be considered by those public utilities operating in multiple states when evaluating whether FERC may have jurisdiction over their securities issuances and assumptions of liability.

II. COMMISSION APPROVAL

Three basic requirements must be met before the Commission may approve the issuance of a security or assumption of a liability in respect of a security. The Commission must find that the issuance or assumption: (i) is for some lawful object, within the corporate purposes of the applicant and compatible with the public interest; (ii) is necessary or appropriate for or consistent with the proper performance by the applicant of service as a public utility; and (iii) does not impair the applicant's ability to perform that service.²⁴

A. THE *WESTAR* ORDERS

In addition to the above statutory requirements, in 2003 the Commission announced in *Westar Energy, Inc.*²⁵ that "all future issuances of secured and unsecured debt authorized by the Commission"²⁶ would be conditioned on the following restrictions:

- Public utilities seeking authorization to issue debt secured by utility assets must use the proceeds of such debt for utility purposes only;
- If any utility assets that are used to secure debt issuances are divested or "spun-off," the debt must "follow" the asset and be divested or "spun-off" as well;
- If any of the proceeds from unsecured debt are used for non-utility purposes, the debt must follow the non-utility assets;
- If the non-utility assets are divested or "spun-off," then a proportionate share of the debt must follow the divested or "spun-off" non-utility asset; and

²⁴ 16 U.S.C. § 824c(a). In addition, the Supreme Court has held that the Commission, at least when asked, must also consider the anticompetitive consequences of the issuance of a security. *See Gulf States Utils. Co. v. FPC*, 411 U.S. at 759 ("Under the express language of § 204 the public interest is stressed as a governing factor. There is nothing that indicates that the meaning of that term is to be restricted to financial considerations, with every other aspect of the public interest ignored. . . . Without a more definite indication of contrary legislative purpose, we shall not read out of § 204 the requirement that the Commission consider matters relating to both the broad purposes of the [FPA] and the fundamental national economic policy expressed in the antitrust laws."). Subsequent appellate courts interpreting *Gulf States* have muted the effect of the decision by emphasizing the broad deference generally afforded to administrative agencies. *See Mich. Pub. Power Agency v. FERC*, 963 F.2d 1574, 1579-81 (D.C. Cir. 1992) (upholding the Commission's denial of intervenors' protest where the Commission found that intervenors had not shown that anticompetitive activity would occur as a result of the authorization).

²⁵ 102 FERC ¶ 61,186 (2003).

²⁶ *Id.* at P 1.

- If utility assets financed by unsecured debt are divested or “spun-off” to another entity, then a proportionate share of the debt must also be divested or “spun-off.”²⁷

The Commission explained that the additional restrictions are necessary to confront the proliferation of public utilities borrowing substantial amounts of money to invest in non-utility businesses and assets, thereby putting at risk their utility operations to the detriment of their electric consumers.²⁸

In a subsequent order, the Commission clarified certain issues raised by the *Westar* restrictions and granted certain exemptions.²⁹ First, the above restrictions are not retroactively applied to debt issuances occurring prior to the order.³⁰ Second, unsecured debt used to purchase an asset must follow that asset upon divestiture, regardless of whether such divestiture is to an affiliated or non-affiliated entity.³¹ Third, although public utilities are prohibited from using the proceeds from debt secured by a utility asset for non-utility purposes, nothing prevents a public utility from issuing unsecured debt for non-utility purposes.³² Finally, the Commission typically grants exemptions to cooperatives whose ownership structures mitigate the potential conflict of interest between owner shareholders and customers that the *Westar* restrictions are designed to prevent (i.e., the owners are also the customers).³³

Although the *Westar* restrictions have not been the subject of much litigation at FERC, they do present certain compliance issues. First, the “utility” or “non-utility” purposes for which secured or unsecured debt may or may not be used are not defined by the Commission. Instead, the Commission has decided that it will “make such determinations on a case-by-case basis after carefully considering all the facts and circumstances for a specific debt issuance.”³⁴ A potential consequence of this lack of guidance is that a public utility may have to re-apply for Commission approval if a future transaction involves the disposition of assets acquired using the proceeds of its previously-authorized debt issuance and if the utility versus non-utility purpose of the assets to be sold is for some reason unclear or in doubt. Second, while not expressly prohibiting negative covenants, the Commission in *Westar* did state that “public utilities that become subject to the [*Westar* restrictions] must follow those restrictions and should not enter into any agreements, including indentures, that would prevent them from satisfying those restrictions.”³⁵ Such language suggests that the Commission will deny any future applications involving a security subject to such restrictions. Moreover, it also suggests the Commission may seek to

²⁷ *Id.* at PP 20-21 (collectively, “*Westar* restrictions”).

²⁸ *Id.* at P 22 (footnote omitted).

²⁹ *See Westar Energy, Inc.*, 104 FERC ¶ 61,018 (2003).

³⁰ *See id.* at P 16.

³¹ *Id.* at PP 20-21.

³² *Id.* at P 24.

³³ *See Golden Spread Elec. Coop., Inc.*, 144 FERC ¶ 62,084 at 3-4 (2013) (citing *Kandiyohi Power Coop.*, 106 FERC ¶ 61,010 at PP 15-16 (2004)).

³⁴ *Westar Energy, Inc.*, 104 FERC ¶ 61,018 at P 26.

³⁵ *Id.* at P 14 (footnote omitted).

impose sanctions if it comes to the Commission's attention that a public utility has issued a security pursuant to a credit agreement, indenture or other contractual arrangement that imposes such restrictions.

B. THE *NATIONAL GRID* REQUIREMENTS

Prior to the passage of EAct 2005, non-interest bearing, open account advances and capital contributions made by registered holding companies to their direct or indirect subsidiaries were authorized by the SEC pursuant to Rule 45(b) of the SEC's regulations implementing PUCHA 1935 and did not require case-specific SEC approval.³⁶ In *National Grid USA*,³⁷ the Commission established its own policy regarding non-interest bearing, open account advances and capital contributions in place of the SEC's prior rule.

Under *National Grid USA*, the Commission permits holding companies to make capital contributions and non-interest bearing, open account advances to direct or indirect public utility subsidiaries (i) without any limitation on the amount of the capital contribution or advance, and (ii) without advance Commission authorization under section 204 if the contribution or advance does not involve the issuance of a security.³⁸

Capital contributions that involve the issuance of a security (i.e., in this case stock or a similar equity instrument) require prior Commission authorization.³⁹ Non-interest bearing open account advances that involve the issuance of a security do not require prior Commission authorization. However, the public utility receiving the advance is required to have an authorized officer certify within thirty days of the date of the advance (i) that as of the time of the advance, repayment of the advanced funds by the public utility would not impair its ability to perform its public utility service, and (ii) the intended uses of the advanced funds. The public utility must retain the certifications in its records for a period of five years following the closing of the transaction. In addition, the certifications must be made available to Commission upon request.⁴⁰

C. BLANKET AUTHORIZATIONS

Although the requirements of section 204 are statutory and thus cannot be waived, the Commission traditionally grants blanket authorizations for the issuance of securities and the assumption of liabilities by power marketers and generation owners who are not subject to cost-based rate regulation—typically in the context of a market-based rate application.⁴¹ As the

³⁶ See 17 C.F.R. § 250.45(b)(4) (repealed 2005).

³⁷ 115 FERC ¶ 61,241 (2006).

³⁸ See *id.* at PP 16, 18. Consistent with earlier discussion above, if no security is issued the Commission lacks jurisdiction.

³⁹ See *id.* at P 16.

⁴⁰ See *id.* at PP 18-19.

⁴¹ See, e.g., *Merrill Lynch Commodities, Inc.*, 108 FERC ¶ 61,233 at P 16 & n.10 (citing *Golden Spread Elec. Coop., Inc.*, 97 FERC ¶ 61,025 at 61,069 (2001)).

Commission has explained, since the purpose of section 204 is to ensure the financial viability of public utilities obligated to serve retail electric consumers, prior authorization is appropriate for power marketers and power sellers having market-based rates who do not intend to become traditional utilities.⁴² However, the Commission has refused to grant blanket authorizations to other entities such as merchant transmission line operators authorized to provide transmission service at negotiated rates.⁴³

III. PROCEDURE

A public utility seeking Commission authorization under FPA section 204 must comply with Part 34 of the Commission's regulations.⁴⁴ As discussed below, the application must include, among other things: (i) a full description of the securities proposed to be issued, (ii) the purpose(s) for which the securities are to be issued, and (iii) a detailed statement of fact that the issuance will comply with the statutory requirements of section 204.⁴⁵ In addition, because copies of certain corporate documentation and board resolutions must be included with an application, an applicant must be in existence when an application is filed. The principal lead-time item in developing a section 204 application is the compilation of required financial

⁴² See *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity, and Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 998-99, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012); *Merrill Lynch Commodities, Inc.*, 108 FERC ¶ 61,233 at P 16.

⁴³ See *Cross-Sound Cable Co.*, 139 FERC ¶ 61,191 at P 7 (2012) (refusing to grant blanket authorizations to a merchant transmission provider); *Sea Breeze Pac. Juan de Fuca Cable, LP*, 112 FERC ¶ 61,295 at P 39 (2005) (same); *Conjunction LLC*, 103 FERC ¶ 61,198 at P 27 (2003) (same). *Cf. Cogen Techs. Linden Venture, L.L.P.*, 127 FERC ¶ 61,181 at P 20 (2009) (granting request for blanket authorization to merchant transmission provider for case-specific reasons). In the past the Commission has granted blanket authorization under section 204 to special purpose entities not selling at cost-based rates and not holding market-based rate authority that only own and operate generation tie lines used exclusively by an affiliate to interconnect with the grid. See *Bishop Hill Interconnection LLC*, 138 FERC ¶ 61,159 (2012); *Invenergy Wind Dev. Mich. LLC*, 136 FERC ¶ 61,209. In a potential reversal of policy, the Commission in *Maine GenLead, LLC*, 146 FERC ¶ 61,223 (2014), refused a similar grant on the basis that Maine GenLead, LLC, did not have, and had not applied for, market-based rate authority. See *id.* at P 20. The Commission's decision in *Maine GenLead* is currently pending a decision on rehearing. If rehearing is denied, a special purpose subsidiary that owns and operates a generation tie line for the use of an affiliate will need to apply for and obtain market-based rate authority in order to be eligible to receive blanket authorization under section 204.

⁴⁴ 18 C.F.R. §§ 34.1-34.9.

⁴⁵ *Id.* § 34.3; see also *id.* § 34.4.

information (e.g., *pro forma* balance sheet, income statement, and statement of cash flows and computation of the interest coverage ratio).⁴⁶

The Commission's regulations require applicants to submit their applications electronically.⁴⁷ After receipt of the application at the Commission, notice of the application is published in the *Federal Register*. If no petition, protest or request opposing the granting of the application is received by the Commission during the notice period, the Commission will generally rule on the security issuance through a delegated staff order.⁴⁸

A. REQUIRED ELEMENTS

A section 204 application must include the following information:⁴⁹

- *Name and Address of the Company.* The application must identify the legal name and mailing address of the applicant(s).⁵⁰
- *State of Incorporation of the Company.* The application must identify the state of the applicant's incorporation, the date of incorporation and the state(s) where the applicant intends to operate.⁵¹
- *Name, Address and Telephone Number of Persons Authorized to Receive Notices and Communications.* The application must provide contact information for regulatory counsel and financial office representatives.⁵²
- *Date by Which Commission Action Is Requested.* The application must identify the *earliest* date by which the applicant will need to issue the securities.⁵³

⁴⁶ Newly-created entities may use projections provided they are supported by future revenue streams supported under approved rates or existing contracts. In addition, the Commission permits existing entities to make a showing in the application of an alternative basis or supporting business case if the underlying revenues supporting the securities issuance are not yet being collected under an authorized rate.

⁴⁷ See *Elec. Filing of the Application for Authorization for the Issuance of Sec. or the Assumption of Liabs.*, Order No. 657, 111 FERC ¶ 61,282 (2005) (codified at 18 C.F.R. pts. 34, 131).

⁴⁸ For examples of such orders, see *supra* note 11.

⁴⁹ See 18 C.F.R. § 34.3. The Commission refers to the filing requirements of Part 34 as "FERC Filing No. 523." However, there is no pre-printed form 523 for applicants to complete. Instead, applicants prepare their own filing that includes all the information required under 18 C.F.R. pt. 34. Newly-created applicants with no operating history may seek waiver of certain filing requirements, including some of the required *pro forma* financial information.

⁵⁰ 18 C.F.R. § 34.3(a).

⁵¹ *Id.* § 34.3(b).

⁵² See *id.* § 34.3(c).

⁵³ See *id.* § 34.3(d).

- *Description of the Securities Proposed to be Issued.* The application must identify:⁵⁴
 - Each type of short-term debt (e.g., commercial paper, promissory notes, lines of credit, internal borrowing from upstream parent holding companies or money pools,⁵⁵ etc.) and long-term debt (e.g., first mortgage bonds, notes, debentures and preferred securities) for which approval is being sought.⁵⁶
 - The aggregate dollar amount of short-term debt and the aggregate amount of long-term debt that may be outstanding at any time during the authorization period.⁵⁷
 - Maximum assumed interest rates or dividends for both the short-term debt and long-term debt, if any.⁵⁸ Typically, the maximum rates are linked to a defined published index (e.g., LIBOR) and a fixed maximum spread to account for periodic market volatility (e.g., “XX” basis points above the specified index). The application must include a link to the website for the index.
 - The institutional ratings of the securities.⁵⁹
 - The stock exchanges on which the securities will be listed.⁶⁰
- *Purpose for Issuing Securities.* The application must identify the general purposes for which the funds obtained under the short- and long-term financings are to be used. Such purposes may include: financing the construction, acquisition and maintenance of new and existing electric transmission facilities; refinancing existing debt; providing a source of funds for working capital requirements (including construction expenditures); and other legitimate corporate purposes.⁶¹

⁵⁴ *Id.* § 34.3(e).

⁵⁵ In order to use a cash management or money pool arrangement for funding short-term financing needs, an applicant must have access to a money pool arrangement that has been filed with the Commission pursuant to 18 C.F.R. § 141.500 in accordance with the Commission’s *Regulation of Cash Management Practices*, Order No. 634-A, FERC Stats. & Regs. ¶ 31,152 (2003).

⁵⁶ *See* 18 C.F.R. § 34.3(e)(1).

⁵⁷ *See id.* § 34.3(e)(2). When borrowing against a line of credit, only the amounts actually drawn are counted against the aggregate dollar cap on short-term debt.

⁵⁸ *See id.* § 34.3(e)(3).

⁵⁹ *See* 18 C.F.R. § 34.3(e)(5). If not yet rated, the application *may* provide an estimated rating. If the securities will not be rated, the application must provide an explanation as to why they are not rated. *Id.*

⁶⁰ *Id.* § 34.3(e)(6).

⁶¹ *See id.* § 34.3(f).

- *Required State Authorizations.* The application must identify any applicable state approvals for the proposed financings.⁶²
- *Lawfulness of the Proposed Financings.* The application must include (i) a general representation that the proceeds of the proposed securities issuances are for lawful purposes and consistent with the issuer's corporate charter and public utility obligations;⁶³ and (ii) a representation committing to comply with the Commission's *Westar's* restrictions.⁶⁴
- *Effect of Bond Indenture or Other Limitations.* The application must include a statement of the bond indenture or other limitations on interest and dividend coverage, and the effect of such limitations on the issuance of additional debt or equity securities.⁶⁵
- *Rate Changes.* The application must include a brief summary of any rate changes that became effective during the period covered under the financial statement provided by applicant, or that will become effective after such period.⁶⁶
- *Required Exhibits.* The application must include the following exhibits:⁶⁷
 - *Exhibit A.* The applicant's Articles of Incorporation.⁶⁸
 - *Exhibit B.* Certified resolution(s) of the applicant's Board of Directors authorizing the issuance of securities for which the application is made.⁶⁹
 - *Exhibit C.* Applicant's balance sheet and attached notes for the most recent twelve-month period on both an actual and *pro forma* basis.⁷⁰

⁶² *Id.* § 34.3(g).

⁶³ *See id.* § 34.3(h).

⁶⁴ *See Westar Energy, Inc.*, 102 FERC ¶ 61,186 at PP 20-21. *See also infra* Part II.A (discussing *Westar* restrictions).

⁶⁵ 18 C.F.R. § 34.3(i).

⁶⁶ *Id.* § 34.3(j). The purpose is to provide assurances that all debt service costs will be recoverable by the applicant through its rates.

⁶⁷ *Id.* § 34.3(e)(l).

⁶⁸ *Id.* § 34.4(a).

⁶⁹ *Id.* § 34.4(b). Exhibit B also requires a copy of the resolution of the stockholders approving such issuance if approval has been obtained. *Id.*

⁷⁰ *Id.* § 34.4(c). If the most recent twelve-month period ended more than four months prior to filing of the application, an updated balance sheet must be provided. *Id.*

- o *Exhibit D.* Applicant's income statement and attached notes for the most recent twelve-month period on both an actual and *pro forma* basis.⁷¹
- o *Exhibit E.* Applicant's statement of cash flows and computation of interest coverage for the most recent twelve-month period on both an actual and *pro forma* basis.⁷²
- o *Exhibit F.* A copy of applicant's registration statement and exhibits filed with the SEC.⁷³

B. TYPICAL WAIVERS

Applicants for long-term debt authorizations typically request waiver of the Commission's competitive bidding and negotiated placement requirements,⁷⁴ which are routinely granted.⁷⁵ The Commission's requirements are primarily designed to prevent excessive fees or self-dealing. Applicants typically support their request for such waivers using a combination of the following reasons: (i) the securities will be issued to commercial and investment banks, insurance companies, or other sophisticated investors or similar institutions; (ii) all securities will bear interest at rates related to current market conditions; and (iii) there will be no material savings in interest expense resulting from the imposition of a bidding or negotiated placement requirement and that such requirements would make it difficult to move quickly under changing capital market conditions.

C. COMMON ISSUES

Historically staff has allowed section 204 applicants the opportunity to supplement their applications without resorting to the formal issuance of a deficiency letter;⁷⁶ an offer most applicants accept.⁷⁷ As a result, the best way to identify issues on which staff is focusing and

⁷¹ *Id.* § 34.4(d). If the most recent twelve-month period ended more than four months prior to filing of the application, an updated income statement must be provided. *Id.*

⁷² *Id.* § 34.4(e). If the most recent twelve-month period ended more than four months prior to filing of the application, an updated statement of cash flows and computations of interest coverage must be provided. *Id.*

⁷³ *Id.* § 34.4(f).

⁷⁴ *See id.* § 34.2.

⁷⁵ *See, e.g., Am. Transmission Co.*, 147 FERC ¶ 61,180 (2014); *Wolverine Power Supply Coop., Inc.*, 147 FERC ¶ 62,133 (2014); *Entergy Ark., Inc.*, 145 FERC ¶ 61,093; *Mont. Albert Tie Ltd*, 141 FERC ¶ 62,228 (2012); *Miss. Power Co.*, 137 FERC ¶ 62,208 (2011).

⁷⁶ We have identified only a few having been issued in the last five years.

⁷⁷ Why applicants accept the offer is likely tied to the time sensitivity usually related to the securities issuances. Typically, the supplemented application results from a call by staff to the applicant to discuss questions or issues staff believes may be raised by the application. At that point the applicant may opt to supplement its application or await the issuance of a formal deficiency letter. Although supplementing the application will trigger a new notice period and introduce a certain amount of delay, because (i) the Commission has no set time by which it must issue a deficiency letter and (ii) a deficiency

might result in a deficient application is to compare the supplemented applications to the original. On that basis, issues and deficiencies drawing increasing staff attention include, but are not limited to:

- failure to specify applicable interest rate caps precisely (e.g., Fed Funds rate or LIBOR plus [XX] basis points);
- failure to include links to referenced published indexes such as Fed Funds rate or LIBOR;
- failure to provide certified copies of board resolutions or verified secretary representations;
- failure of the financial coverage exhibits⁷⁸ to reflect the highest requested authorized rate;
- failure of the interest rate coverage calculations to include the total dollar level of previously-authorized issuances, even if such amounts have not been issued (i.e., the application generally must demonstrate a 2.0 interest rate coverage ratio assuming all previously-authorized debt is outstanding, even if not all such debt has been issued or provide explanation and information as to why a lower coverage ratio is adequate);⁷⁹
- inclusion of incremental revenues from increased rates or assumptions of future cost recovery in the required financial exhibits to demonstrate compliance with the 2.0 coverage ratio; applicants must submit Exhibits C, D and E using actual revenues but may include information regarding prospective revenues that could provide the Commission with an alternative basis for concluding that applicants with less than 2.0

letter when issued will likely result in a supplemented application, voluntarily supplementing the application generally will result in a shorter delay.

⁷⁸ These are Exhibits C, D and E discussed above.

⁷⁹ The 2.0 or greater interest rate coverage ratio is a “screen test” used by the Commission to provide comfort that the issuance will not impair the public utility’s ability to perform its public utility service. See *ITC Great Plains, LLC*, 147 FERC ¶ 61,005 at PP 10-12 (2014). The 2.0 or greater interest rate coverage ratio is not expressly required under FPA section 204 or Part 34 of the Commission’s regulations. The Commission, however, does accept an interest rate coverage ratio of less than 2.0 upon an express showing in the application of an alternative basis supporting the adequacy of a lower coverage ratio that allows the Commission to conclude the proposed issuance “will not impair [the applicant’s] ability to perform public utility service.” See, e.g., *S.C. Elec. & Gas Co.*, 149 FERC ¶ 61,008 at P 15 (2014) (approving interest rate coverage ratio of 1.41 upon showing that exclusive nature of long-term power sales agreement with affiliate co-applicant and formula rate providing guaranteed revenue stream and parent guarantee for third-party debt provided an alternative basis upon which the proposed issuance will not impair ability to perform public utility service); *Portland Gen. Elec. Co.*, 145 FERC ¶ 61,063 at P 17 (2014) (approving interest rate coverage ratio of 1.67 upon showing it was due to two non-recurring events, the utility was financially sound and otherwise retained access to the capital markets).

coverage ratio can service the proposed debt issuance without impairing the applicant's ability to perform public utility services;⁸⁰

- proposed rate caps that use relatively large spreads (e.g., 800 to 1000 points above referenced floating rates such as Fed Funds rate and LIBOR);
- financial statements (i.e., balance sheets, income statements and statements of cash flow) older than 120 days; and
- excessive redactions of information as non-public (i.e., redacted information should be limited to information not yet disclosed to the SEC or otherwise not disclosed in the ordinary course of business such as planned capital expenditures, etc.).

D. AUTHORIZATION PERIOD

Commission authorization for the issuance of securities is typically valid for a period of two years.⁸¹ An applicant must re-apply to the Commission and receive new authorization prior to the expiration of the authorized period in order to be able to continue to issue securities or assume liabilities beyond that time. Further, the applicant must file a report with the Commission no later than thirty days after the sale or placement of long-term debt or equity securities pursuant to the terms of each order authorizing its issuances.⁸² Finally, as a compliance issue, it is important to note that any issuance of securities must be specifically tailored to the timing, type of issuance and purposes expressly authorized by the Commission in its order and all issuances of secured and non-secured debt must comply with the *Westar* requirements set forth above.

⁸⁰ See, e.g., *ITC Great Plains*, 147 FERC ¶ 61,005 at PP 11-12 (formula transmission rate provides assurance of future cost recovery and alternative basis to conclude that applicant failing to demonstrate 2.0 coverage ratio can nonetheless service debt without impairing public utility service); *Am. Transmission Co.*, 147 FERC ¶ 61,180 (2013) (same); *AEP Generating Co.*, 148 FERC ¶ 61,143 at PP 13-16 (2014) (terms of long-term power supply agreement provide assurance of cost recovery and alternative basis to conclude that applicant failing to demonstrate 2.0 coverage ratio can nonetheless service debt without impairing public utility service).

⁸¹ See, e.g., *Fall River Rural Elec. Coop., Inc.*, 104 FERC ¶ 62,156 at 64,428 (2003). But cf. *Cal. Power Exch. Corp.*, 86 FERC ¶ 62,195 at 64,257 (permitting the applicant "to acquire loans or other evidences of indebtedness on a revolving basis" for 33 months "with not more than \$500 million outstanding at any one time"); *Old Dominion Elec. Coop.*, 100 FERC ¶ 62,140 (2002) (authorizing issues for a period of 36 months); *Northwestern Corp.*, 88 FERC ¶ 62,032 (1999) (same).

⁸² 18 C.F.R. § 34.9.

Chapter 14

FPA Section 205: Power Sales and Related Services

MIKE NAEVE
JERRY L. PFEFFER

One of the most significant areas of the Commission's jurisdiction is its authority to regulate the rates, terms, and conditions of jurisdictional sales of energy and transmission service under FPA section 205.¹ The focus of this chapter is on the Commission's regulation of wholesale power sales and related services, with a particular concentration on its regulation of market-based sales. (Chapter 9 addresses the Commission's regulation of transmission service under section 205). Over the past two decades, negotiated sales at market prices have increasingly displaced highly regulated, cost-based sales which historically were the predominant form of wholesale power transactions. While market-based sales are subject to a lesser degree of FERC regulation, there are still a number of important compliance issues for market participants.

The essence of section 205 compliance is determining whether there is a jurisdictional service being provided by a public utility and thus a requirement for prior Commission approval of the rates, terms, and conditions of that service. As a general rule, section 205 requires that anyone making jurisdictional wholesale power sales (whether cost- or market-based) or engaging in certain types of jurisdictional services related to power sales must have a tariff² on file with the Commission prior to commencing the jurisdictional service. Thus, while a power generator is not a public utility by virtue of its ownership of generating facilities, and those facilities per se are not "jurisdictional facilities," with limited exceptions, generators who make wholesale power sales in interstate commerce become public utilities and the books and records associated with those sales become jurisdictional facilities.

In this chapter, we address the broad standards governing which entities and which types of agreements related to wholesale power sales and services are FERC-jurisdictional and, of those, which must be filed with the Commission. Given the growing importance of market-based sales, we place a special focus on how parties can obtain market-based rate ("MBR") authorization and comply with Commission rules and reporting obligations associated with that authorization. The chapter also outlines the basic compliance framework for cost-based power sales, ancillary service sales, and providers of demand-side services.

¹ 16 U.S.C. § 824d.

² The term "rate schedule" generally refers to a contractual agreement among *named* parties, while a "tariff" is an offering of general applicability to provide service to *any* eligible party.

I. SCOPE OF FERC JURISDICTION

A. GENERAL

FPA section 205(a) provides the Commission with jurisdiction to ensure that “[a]ll *rates and charges* made, demanded, or received by any public utility *for or in connection with* the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all *rules and regulations affecting or pertaining to such rates or charges* shall be just and reasonable.”³ Section 205(c), in turn, authorizes the Commission to require the *filing* of a wide range of contracts by a public utility, including certain agreements that do not directly provide for the sale of wholesale power or transmission service. Specifically, section 205(a) provides that the Commission may require the filing of “all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and . . . all contracts which *in any manner* affect or relate to such rates, charges, classifications, and services.”⁴

B. SPECIFIC TYPES OF JURISDICTIONAL AGREEMENTS

As outlined below, there are three lines of inquiry which determine whether an agreement is jurisdictional and must be filed under section 205(a).

(i) Is the party providing the service under the contract a public utility as defined in section 201? The filing obligation under section 205(a) is on the public utility providing the service and not the purchaser.⁵

(ii) If the service provider is a public utility, does the service include wholesale power sales or transmission service in interstate commerce? If so, the agreement is a jurisdictional agreement under the FPA and must be filed under section 205(a).

(iii) Even if the agreement does not directly provide for wholesale power sales or the provision of transmission service, does it affect the rates, terms, and conditions of wholesale power sales or transmission service? As discussed below, section 205 requires that many such agreements with only a limited nexus to wholesale power sales or the provision of transmission service must be filed with the Commission.

In the following section, we review the regulatory framework governing these inquiries and outline the key compliance issues arising from the requirement to have agreements for jurisdictional services on file with the Commission prior to commencing service.

1. *Is the seller or service provider an FPA “public utility”?*

FPA section 201 grants FERC jurisdiction over wholesale sales of energy by public utilities.⁶ A “public utility” is defined as “any person who owns or operates” jurisdictional

³ *Id.* § 824d(a) (emphasis added).

⁴ *Id.* § 824d(c) (emphasis added).

⁵ Note that it is possible to have an agreement where two or more parties to the agreement are public utilities engaging in power exchanges, selling to one another, or providing a jurisdictional service. In such instances, each party may have a separate filing obligation under section 205(a).

facilities used for wholesale sales or transmission of electric energy in interstate commerce.⁷ Although section 201(b) explicitly states that generation facilities are not jurisdictional, the courts have found that the books and records of entities engaged in wholesale power sales to be the jurisdictional facilities required to cause a generator selling power for resale seller to become a public utility.

2. *Does the relevant power sales agreement need to be filed?*

The Commission regards any contract, agreement, or tariff that sets forth the rates, terms, or conditions for wholesale power sales or transmission service by a public utility or that allocates wholesale power costs to be jurisdictional.⁸ Wholesale sales include any sales-for-resale in interstate commerce⁹ of *any* amount of power.¹⁰ Sales to end users are not jurisdictional because they are not sales-for-resale.¹¹ An evolving area of Commission jurisdiction involves agreements providing for “net metering” of distributed (behind-the-meter) generation such as rooftop solar installations.¹² The question raised is whether all energy produced behind the retail meter is subject to FERC jurisdiction, or only the amount of energy that exceeds the amount consumed behind the meter. The Commission has held that jurisdictional wholesale sales are deemed to occur from distributed generation only if the amount generated exceeds the amount consumed by the distributed generation owner over a monthly billing cycle.¹³

3. *Is the seller providing other jurisdictional services that require prior approval under FPA section 205?*

While the wholesale sale of energy and capacity clearly are jurisdictional, agreements addressing various services *related to* wholesale power sales have a less certain jurisdictional

⁶ *Id.* § 824(b)(2)(e).

⁷ *Id.* The definition of a “person” generally excludes agencies of federal, state, and local government and certain cooperatively-owned utilities. An entity that is owned by a foreign government making wholesale sales in interstate commerce is subject to the Commission’s section 205 jurisdiction.

⁸ *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 965 (1986).

⁹ Sales in the portion of the Texas market operated by the Electric Reliability Council of Texas (“ERCOT”), Alaska, Hawaii, and Puerto Rico are not considered to be sales in interstate commerce and are not subject to the Commission’s section 205 jurisdiction.

¹⁰ The Commission has ruled that there is no *de minimis* exception to its jurisdiction over wholesale power sales. See *Prior Notice and Filing Requirements Under Part II of the Fed. Power Act*, 64 FERC ¶ 61,139 at 61,994 (“Prior Notice”), *order on reh’g*, 65 FERC ¶ 61,081 (1993) (codified at 18 C.F.R. § 35.3).

¹¹ Sales to large industrial customers, especially sales of relatively large blocks of power, are sometimes incorrectly characterized as “wholesale” sales. These are *retail* sales to an end user and *not* FERC-jurisdictional sales.

¹² Net metering allows retail customers to offset the costs of their electricity purchases from the grid with billing credits for electricity generated behind the retail meter.

¹³ See *Sun Edison LLC*, 129 FERC ¶ 61,146 (2009); *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001).

status. If an agreement does not provide for wholesale power sales or transmission service, the jurisdictional inquiry turns on whether the agreement nonetheless establishes “rules and regulations affecting or pertaining to” jurisdictional rates and/or prices in wholesale electricity markets. This type of inquiry is fact-intensive and there are several common metrics or tests used by the Commission to determine jurisdiction. The most important of these metrics is whether an agreement conveys effective *control* over a jurisdictional facility or otherwise conveys an ability to set the terms of service or establish the rate for a wholesale transaction.

The question of FERC jurisdiction over an “operation and maintenance” (“O&M”) agreement frequently arises, and the answer turns on the extent to which such agreement transfers control over jurisdictional services to the O&M service provider.¹⁴ The essence of the control test used by the Commission in its section 205 jurisdictional analysis is whether the O&M service provider needs approval from the owner of the facility for non-routine actions.¹⁵ If it does, then control is not deemed to have been conveyed to the operator. If, however, the O&M provider has full discretionary authority or otherwise has broad decision-making authority constrained only by some variation of a good utility practice standard, or the O&M provider otherwise has “full discretionary authority,” then the O&M provider is deemed to have been delegated “control and decisionmaking” authority, and thus the O&M agreement is subject to the Commission’s section 205 jurisdiction.¹⁶

The Commission also applies a “control” test to establish the jurisdictional status of a wide range of services provided under so-called “energy management agreements” that are increasingly common in competitive energy markets. In *El Paso Electric Co.*,¹⁷ the Commission held that Enron Power Marketing, Inc. had assumed “control” over certain jurisdictional power sales made by El Paso Electric Co. because “El Paso Electric admitted that it gave Enron

¹⁴ See *Prior Notice*, 64 FERC ¶ 61,139 at 61,993-94.

¹⁵ The party that “operates” is the “entity [that] keeps control and [maintains] decisionmaking authority over major matters.” *Puget Sound Power & Light Co.*, 64 FERC ¶ 61,335 at 63,427 (1993) (quoting *Prior Notice*, 64 FERC ¶ 61,139 at 61,993); see also, e.g., *James River Paper Co.*, 73 FERC ¶ 61,025 at 61,058-59 (1995) (finding that petitioner did not “operate” facilities because (a) its activities would be subject to approval, (b) it would not have full operational responsibility for the facility, (c) it would not be responsible for energy sales, billing, and collections, operating budget, and payment of fees and expenses, and (d) it did not have final authority over all operating decisions); *Ogden Martin Sys. of Clark Ltd. P’ship.*, 66 FERC ¶ 61,152 at 61,295 (1994) (determining that the entity with the power to make all significant decisions and to approve an agent’s actions is the “operator,” and one is not the “operator” if its responsibilities are subject to direction and approval of another).

¹⁶ *Puget Sound*, 64 FERC ¶ 61,335 at 63,428; see also *Duke Energy Corp.*, 97 FERC ¶ 61,177 at 61,823-24 (2001) (disclaiming jurisdiction over agreements) (citing *Bechtel Power Corp.*, 60 FERC ¶ 61,156 (1992)); *Long Island Lighting Co.*, 67 FERC ¶ 61,361 at 62,254 (1994) (stating that an agreement to provide O&M services need not be filed with the Commission if “the entity performing the O&M service under the agreement acts merely as the agent of another party wielding authority to make main operational decisions . . . even if [the O&M service provider] is a public utility”) (emphasis added); *PSI Energy, Inc.*, 63 FERC ¶ 61,107 at 61,753 (1993) (finding jurisdiction where operator constrained only by “prudent utility practice”); *Western Mass. Elec. Co.*, 61 FERC ¶ 61,182 at 61,664 (1992) (finding jurisdiction where operator had “full discretionary authority to conduct any necessary O&M work”).

¹⁷ 108 FERC ¶ 61,071 at P 14 (2004).

discretion on how, when, and to whom it could sell power on El Paso Electric's behalf while Enron ran the El Paso Electric trading desk.”¹⁸

A similar result was reached in *R.W. Beck Plant Management, Ltd.*¹⁹ In that case, the Commission held that the manager of a power plant (and associated jurisdictional facilities) was a public utility because “except for certain powers reserved to the [owner], Beck has complete authority to manage, control and make all decisions affecting the business and affairs of [the plant]” and, furthermore, the owner had “no employees and no company personnel responsible for the management of the [plant].”²⁰ Beck thus was deemed to be the operator of the jurisdictional facilities and was required to file for market-based rate authority.²¹

In Order No. 697, the Commission declined to provide a bright-line “control” test for energy management and comparable service agreements. Instead, the Commission affirmed its long-standing policy of examining such agreements on a case-specific basis to determine whether they conveyed control (both for market power purposes but presumably for jurisdictional purposes as well). The Commission concluded that “energy management and comparable agreements do not necessarily convey unlimited discretion and control away from the entity that owns the plant. In this regard . . . it is the totality of the circumstances that will determine which entity controls a specific asset.”²²

Although the full extent of jurisdictional agreements that relate to the sale of power or operation of generating facilities is beyond the scope of this discussion, the following are among the other types of agreements that have been found to be jurisdictional:

- Power Consulting Services Agreements,²³
- Operations & Maintenance Agreements,²⁴ and
- Unit Contingent or Tolling Agreements.²⁵

¹⁸ *Id.*

¹⁹ 109 FERC ¶ 61,315 (2004).

²⁰ *Id.* at PP 3, 12.

²¹ *Id.* at P 15.

²² *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 197, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012).

²³ *See El Paso Elec. Co.*, 108 FERC ¶ 61,071 at P 19.

²⁴ *See Ill. Power Co.*, 102 FERC ¶ 61,184 at P 54 (2003); *ITC Holdings Corp.*, 102 FERC ¶ 61,182 at PP 57-59 (2003).

At the same time, FERC has explicitly disclaimed jurisdiction over certain generic types of agreements related to “demand-side” activities where the service provider does not make wholesale power sales nor operate facilities otherwise subject to the Commission’s jurisdiction.²⁶

As noted, FPA section 205 also authorizes FERC to require a utility to file any contract that “in any manner affect[s] or relate[s] to [jurisdictional] rates, charges, classifications, and services.”²⁷ The courts have characterized this as an “amorphous directive” and have held that “only those practices that affect rates and service *significantly*” can be said to fall within the Commission’s purview.²⁸ The Commission has applied this standard using what it calls a “rule of reason” test.²⁹

Like the jurisdictional analysis cases noted above, the rule of reason test is, of necessity, highly fact-specific. There are many cases that apply the test, but the following two are particularly illustrative because they compare and contrast practices that do and do not need to be filed. In the first, *Easton v. Delmarva Power & Light Co.*,³⁰ the Commission ruled that the “minute detailed operating procedures” of a power pool need not be filed, but that “requirements for obtaining transmission capacity” must be filed.³¹ In the second, *PacifiCorp*,³² the Commission held that regional reliability council documents that merely “recommend[]” operating procedures need not be filed, but those that dictate transmission procedures must be filed.³³

C. COMPLIANCE WHERE THERE IS AMBIGUITY

Recognizing that uncertainty will arise about the status of specific agreements, the Commission has held that, when in doubt, a utility may file its agreements and request that the Commission make a determination as to whether they are jurisdictional and must be kept on file. Specifically, FERC stated that “any utility, if uncertain as to its obligation under the FPA to file for Commission review or as to the jurisdictional status of a particular agreement, should take the initiative to seek case-specific guidance from the Commission in advance of the effectuation of

²⁵ See, e.g., *AES Huntington Beach, L.L.C.*, 87 FERC ¶ 61,221 at 61,877 (1999).

²⁶ See discussion later in this chapter on the jurisdictional status of transactions involving demand-side resources.

²⁷ 16 U.S.C. § 824d(c).

²⁸ *Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (emphasis in original).

²⁹ See *Pub. Serv. Comm’n of N.Y. v. FERC*, 813 F.2d 448, 454 (D.C. Cir. 1987) (holding that the Commission properly excused utilities from filing policies or practices that dealt only with matters of “practical insignificance” to serving customers); *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 FERC ¶ 61,137 at 61,401 (2002) (“It appears that the proposed Operating Protocols could significantly affect certain rates and services and as such are required to be filed pursuant to Section 205.”).

³⁰ 24 FERC ¶ 61,251 at 61,531-32 (1983).

³¹ *Id.* at 61,531.

³² 70 FERC ¶ 61,322 (1995).

³³ *Id.* at 61,984-85.

jurisdictional service.”³⁴ Other cases similarly support the notion of “when in doubt, file.”³⁵ Given this guidance, FERC is less likely to consider arguments that remedies (such as time value refunds) should not be imposed for the failure to file a particular agreement due to uncertainty regarding whether that agreement was jurisdictional (as distinct from an inadvertent failure to file). FERC also is generally unreceptive to arguments related to “administrative burdens” as a reason for not filing a potentially jurisdictional agreement.³⁶

D. COMPLIANCE RECOMMENDATIONS

The Commission’s broad jurisdiction to approve, or require the filing of, power sales and transmission service-related agreements means that companies need to adopt internal review procedures for identifying contractual arrangements and operating protocols that *could* require a filing under FPA section 205. This review should occur at the time the agreement is being negotiated because, as explained below, jurisdictional agreements must ordinarily be filed *before* they take effect.³⁷ Furthermore, if legal review is obtained at the time an agreement is being negotiated, there may be modest changes to the agreement that could minimize or eliminate jurisdictional concerns. These internal procedures should be adopted not only by public utilities but also by other companies that provide energy management and consulting services that might convey control over jurisdictional services or assets.³⁸

II. PRIOR NOTICE AND FILING REQUIREMENTS

A. GENERAL

As noted, wholesale power sellers and other jurisdictional service providers are required to file proposed agreements for prior Commission approval and the rates for such sales or services cannot be collected until the rate is accepted for filing by the Commission. Under Part

³⁴ *Montana-Dakota Utils. Co.*, 81 FERC ¶ 61,298 at 62,407 (1997).

³⁵ *See, e.g., Pub. Serv. Co. of Colo.*, 67 FERC ¶ 61,371 at 62,267-68 (1994) (refusing to disclaim jurisdiction over 18 agreements and stating that, “[f]rom the Commission’s perspective, [public utilities should] file all agreements under which they are providing service that possibly can be considered jurisdictional”).

³⁶ *See, e.g., Idaho Power Co.*, 102 FERC 61,351 at P 26 (2003).

³⁷ The Commission recently imposed a civil penalty on a utility, in part, for multiple failures to timely file agreements it deemed jurisdictional under FPA section 205, including agreements dealing with common facilities, O&M, revenue distribution, facilities upgrades, and a variety of other matters presumably deemed to significantly affect wholesale rates and conditions of service. The civil penalty was imposed *in addition to* applicable time value refund obligations arising from the individual agreements based on the company’s failure to have adequate compliance protocols in place to assure that such agreements were filed on a timely basis. *See Int’l Transmission Co.*, 146 FERC ¶ 61,172 at P 10 (2014). A dissent in this case highlighted the tension between providing incentives for parties to voluntarily disclose instances of agreements that should have been filed and the imposition of penalties as a deterrent to future violations.

³⁸ The *R.W. Beck* line of cases shows that technical service providers and consulting firms can be deemed to be public utilities providing jurisdictional services under certain circumstances and their agreements must be filed for prior approval under section 205.

35 of the Commission's regulations,³⁹ any new or amended wholesale power sales agreement or transmission services agreement (other than service agreements negotiated pursuant to a tariff of general applicability such as an MBR tariff or open access transmission tariff ("OATT")) must be filed with FERC no less than 60 days and no more than 120 days prior to the amendment's proposed effective date.⁴⁰ The procedural framework governing these prior notice and filing obligations was clarified in a series of cases in the early 1990s⁴¹ where the Commission offered a one-time "amnesty" for the filing of jurisdictional agreements and explained the rules of the road going forward under the section 205 prior notice requirements as to which agreements had to be filed before commencing service, by whom, and when. The prior notice rules also required the filing of proposed amendments (including what might be deemed non-substantive changes) to jurisdictional contracts, namely that the Commission and the public be given 60 days' notice of any change in rates, services, or terms before they take effect.⁴² This requirement allows the Commission staff sufficient time to determine whether a proposed tariff or rate (or changes thereof) satisfies the "just and reasonable standard" under section 205.⁴³

The Commission's rules also specify that the prior notice requirements apply to cancellation or termination of a rate schedule or a portion thereof.⁴⁴ As a general rule, a filing to change or cancel a rate schedule must be submitted at least 60 days, but not more than 120 days, prior to the date it is proposed to take effect.⁴⁵ All filings that contain original or modified tariff sheets must be filed electronically through the eTariff system pursuant to the requirements of 18

³⁹ 18 C.F.R. § 35.12.

⁴⁰ This means that the effective date must be 61 days from the filing date.

⁴¹ See *Prior Notice*, 64 FERC ¶ 61,139 at 61,984; *Cent. Hudson Gas & Elec. Co.*, 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089 (1992); *Cent. Me. Power Co.*, 56 FERC ¶ 61,200, *order on reh'g*, 57 FERC ¶ 61,083 (1991).

⁴² 16 U.S.C. § 824d(d). This rule does not apply to an "initial" rate, but FERC has defined "initial rate" very narrowly and hence virtually every new contract or tariff will be considered to be a change in rate and will therefore be subject to a prior notice requirement, as well as the potential for suspension of the rate and refunds. *Middle S. Energy, Inc. v. FERC*, 747 F.2d 763, 772 (D.C. Cir. 1984). As a general rule, an initial rate must involve both a new service and a new customer. *Chehalis Power Generating, L.P.*, 112 FERC ¶ 61,144 at P 23 (2005).

⁴³ The Commission has explained that it cannot "ignore its statutory duty to determine whether rates are just and reasonable by permitting utilities to submit filings whenever convenient," and that it "must have the opportunity to examine proposed rates, terms, and conditions of jurisdictional service before that service commences." *El Paso Elec. Co.*, 105 FERC ¶ 61,131 at P 14 (2003).

⁴⁴ Companies must file notification of cancellation or termination no less than 60 days and no more than 120 days prior to the expiration of an existing contract or service agreement for all sales of unbundled transmission service and for all power sales contracts executed or filed prior to July 9, 1996, and for power sales contracts executed after that date that do not terminate by their own terms. For any power sales contract executed or filed on or after July 9, 1996 that terminates by its own terms, a notice of termination must be filed within 30 days after such termination takes place. See 18 C.F.R. § 35.15.

⁴⁵ See *id.* FERC's rules also specify that notice of a successor in interest or name changes of the tariff holder be filed within 30 days of such change. See *id.* § 35.16.

C.F.R. Parts 35, 131, and 154, as amended by Order No. 714.⁴⁶ Section 205 applicants must register on the eTariff system prior to their first rate filing.⁴⁷

In most cases, the Commission acts on section 205 filings within the 60-day statutory period.⁴⁸ FERC action within the statutory period varies depending on the circumstances of the filing, as described below:

- If all affected parties agree to the filing, FERC ordinarily will *accept*⁴⁹ the agreement without suspension or hearing.
- If a customer or other affected party protests the filing, FERC may accept the agreement, suspend it,⁵⁰ and set the matter for hearing. Hearings are required only where “material issues of fact” exist and are most likely ordered in contested rate proceedings or where the parties disagree over the interpretation of an agreement.
- Where only policy or legal issues are presented, or where factual issues can be decided on the existing paper record, FERC may rule summarily on any disputed issues within the 60-day period and not order any further proceedings.
- If the utility has not submitted sufficient information (e.g., cost support) to permit FERC to determine the merits of the filing, FERC Staff may issue a “deficiency letter” requesting that more information be submitted within 30 days.⁵¹ The response to such a letter is considered an amendment to the filing, subject to a new notice and comment period. Thus, the issuance of such a letter tolls the time for FERC action on the filing and a new “60-day clock” commences when the utility amends its application with the requested information. Staff also may contact applicants

⁴⁶ *Elec. Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008), *clarified*, Order No. 714-A, FERC Stats. & Regs. ¶ 31,356 (2014) (codified at 18 C.F.R. § 35.9). When Order No. 714 first became effective, the Commission required electronic filings only for tariffs of general applicability and did not require electronic submission of bilateral agreements until such agreements were amended.

⁴⁷ Subsequent rate or tariff filings by that legal entity can be submitted under the same registration profile established in the initial filing.

⁴⁸ There are circumstances in which FERC does not always act on rate-related filings within the 60-day period, including (i) when a filing is made in compliance with a prior Commission order; and (2) if a filing is made more than 120 days before the requested effective date.

⁴⁹ The Commission generally uses the term “accepts for filing” versus “approved.”

⁵⁰ Under section 205, FERC has the authority to effectively delay (i.e., “suspend”) the effectiveness of the proposed rates for periods from one day to up to five months. The decision to suspend a rate filing is announced in the hearing order. If a rate is suspended, customers will receive refunds if the final rate resulting from the proceeding are lower than the proposed rates. As discussed later in this section, the amount of the refund is the difference between the amounts paid under the filed rate and the amount that would have been paid under the ultimately approved rate, plus interest. Refund calculations begin as of the refund effective date.

⁵¹ A detailed listing of all the required elements of filings under FPA section 205 are set forth in the Commission’s regulations and is beyond the scope of this Handbook.

informally (typically by telephone) and request supplemental information which, upon submission, also may be deemed an “amended” filing, triggering a new 60-day clock.

- In rare cases, FERC will reject the filing summarily.⁵² This can occur, for example, where the utility has failed to follow the requirements for proposed rate increases in section 35.13⁵³ or has not complied with a *Mobile Sierra*⁵⁴ clause that restricts unilateral rate changes.

B. WAIVER OF THE PRIOR NOTICE REQUIREMENT

The Commission may waive the 60-day prior notice requirement if the filing party requests a waiver and can demonstrate “good cause.”⁵⁵ For example, the Commission generally will grant waivers for filings that result in rate reductions or incorporate non-substantive changes that do not materially affect pricing or terms of service. FERC also has granted waivers for amendments that would increase rates, but only if the rate change and effective date are prescribed by contract, such as annual rate revisions required by contract to become effective on a date specified in the contract.⁵⁶ Waivers also may be granted in cases where the parties have agreed to a retroactive date or otherwise were put on notice with regard to the effective date of the rate change.

The Commission has shown a predisposition against granting waivers where the proposed rate change involves an increased charge to non-consenting customers⁵⁷ or where the applicant has otherwise failed to show good cause.⁵⁸ Waivers of the prior notice requirement have become considerably more difficult to obtain in recent years absent compelling circumstances, ministerial changes to a filed rate or tariff, or where the filing would facilitate

⁵² The legal standard is that FERC rejection is appropriate if the filing does not conform to the requirements for section 205 submissions as set forth in the Commission’s regulations. *See Mun. Light Bds. of Reading & Wakefield, Mass. v. FPC*, 450 F.2d 1341, 1345 (D.C. Cir. 1971) (finding rejection appropriate if a filing is “patently . . . deficient in form or a substantive nullity”); *see also Ky. Utils. Co.*, 67 FERC ¶ 61,189 at 61,575 (1994); *Pa. Power & Light Co.*, 23 FERC ¶ 61,215 at 61,446 (1983).

⁵³ 18 C.F.R. § 35.13.

⁵⁴ *See FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956); *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956). In *New England Power Generators Ass’n v. FERC*, 707 F.3d 364, 370-71 (D.C. Cir. 2013), the court determined that the Commission is legally authorized to impose a more rigorous application of the statutory “just and reasonable” standard of review on future changes to certain types of agreements.

⁵⁵ *Cent. Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106 at 61,338-39.

⁵⁶ *CalPeak Power, LLC*, 110 FERC ¶ 61,145 at P 11 (2005) (citing cases).

⁵⁷ *Old Dominion Elec. Coop.*, 110 FERC ¶ 61,165 at P 7 (2005) (denying request for waiver because proposal to modify the classification of certain accounts from demand to energy will result in some customers experiencing an increase in rates); *see also Pac. Gas & Elec. Co.*, 109 FERC ¶ 61,093 at PP 22-30 (2004).

⁵⁸ *See Mirant Ams. Energy Mktg., L.P. v. ISO New England Inc.*, 112 FERC ¶ 61,056 (2005).

policy outcomes that are a high priority of the Commission. The Commission has cited the following justification for granting one-time waivers of the prior notice requirement for proposed tariff changes: (1) an underlying error was made in good faith; (2) the waiver is of limited scope; (3) a “concrete problem” needed to be remedied; and (4) the waiver did not have “undesirable consequences, such as harming third parties.”⁵⁹ In some cases, the Commission has waived the prior notice requirement to allow sellers using new technologies to begin making sales on an expedited basis.⁶⁰

Otherwise, requests for waiver of the prior notice requirement for new rates or tariffs that appear to be based on little more than lack of awareness, administrative oversight, or procrastination by the applicant are unlikely to be granted.⁶¹ This is especially true in the case of late-filed market-based rate tariffs.⁶² Indeed, the Commission increasingly is imposing remedies (including time value refund obligations) for commencing any type of jurisdictional service without having the required tariff or rate on file. (See penalty section below.)

C. FILING TIMELINES AND NOTICE REQUIREMENTS

Companies should establish procedures that assure sufficient time for preparation of any required filings under section 205 before a jurisdictional agreement becomes effective. The required lead times vary substantially depending on the nature of the contract. Traditional cost-based power sales requiring submission of extensive cost-of-service information typically need considerable time to prepare. As noted, however, in recent years there are relatively fewer cost-based transactions that require submission of a full cost-of-service rate package (e.g., new requirements service to distribution utilities, proposed increases to filed rates, sales by franchised utility sellers that do not qualify for market-based sales in their local balancing authority areas, and certain generation-related ancillary services). The more common type of section 205 filings

⁵⁹ *N.Y. Indep. Sys. Operator, Inc.*, 144 FERC ¶ 61,147 at P 8 (2013); *N.Y. Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,108 at P 14 (2012); *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,184 at P 13 (2011); *ISO New England Inc.*, 134 FERC ¶ 61,182 at P 8 (2011); *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,004 at P 10 (2010); *ISO New England Inc.*, 122 FERC ¶ 61,297 at P 13 (2008); *Acushnet Co.*, 122 FERC ¶ 61,045 at P 14 (2008); *Cent. Vt. Pub. Serv. Corp.*, 121 FERC ¶ 61,225 at P 28 (2007); *Waterbury Generation LLC*, 120 FERC ¶ 61,007 at P 31 (2007).

⁶⁰ *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,218 at P 14 (2006) (finding that good cause had been shown for granting waiver of the 60-day prior notice requirement to permit an effective date one day after filing because the filing presented “greater opportunity for the adoption of advanced technologies”); *AES Energy Storage, LLC*, Docket No. ER09-38-000 (unpublished delegated letter order issued Nov. 10, 2008) (granting market-based rate authority effective one business day after the date of filing for entity offering new battery technology).

⁶¹ *Trigen-St. Louis Energy Corp.*, 120 FERC ¶ 61,044 (2007); see also *OREG 1, Inc.*, 135 FERC ¶ 61,150 (2011), *order denying reh’g*, 138 FERC ¶ 61,110 (2012).

⁶² *El Segundo Power, LLC*, 84 FERC ¶ 61,011 at 61,060, *order on reh’g*, 85 FERC ¶ 61,123 (1998), *order on reh’g*, 87 FERC ¶ 61,208 (1999), *order on reh’g*, 90 FERC ¶ 61,036 (2000); see also *FC Landfill Energy, LLC*, 133 FERC ¶ 61,041 at P 30 n.17 (2010) (citing *El Segundo Power, LLC*, 84 FERC ¶ 61,011); *BC Landfill Energy, LLC*, 127 FERC ¶ 61,113 at P 36 n.23 (2009) (citing *El Segundo Power, LLC*, 84 FERC ¶ 61,011).

today under are those for new market-based rate authorizations, most of which are relatively simple to prepare and have shorter lead times.⁶³

The prior discussion outlined the general rules and timelines for satisfying the prior notice requirements of section 205 and the Commission's granting of waivers respecting such notice. These rules vary somewhat, however, as applied to particular transactions. For example, in some situations, FERC does not require the filing of an agreement before it takes effect. This situation most commonly arises for service agreements entered into under "tariffs of general applicability." For example, if a utility receives approval of a tariff authorizing power sales to any wholesale customer at negotiated, transaction-specific rates (whether market-based rates or cost-based rates "up to" a ceiling rate), the agreements (often "confirmation letters") associated with particular transactions entered into pursuant to that tariff do not need to be filed with FERC.⁶⁴ As noted, however, individual transactions under such agreements still are subject to the Commission's EQR reporting requirements.

Public utilities may file standard forms of service agreements for Commission approval for all of their jurisdictional cost-based transmission and power sales services. Public utilities that have Commission-approved standard forms of agreements in their transmission tariffs, cost-based power sales tariffs, or tariffs for other generally applicable services are not required to file with the Commission copies of conforming service agreements.⁶⁵ However, individual service agreements for transmission or interconnection services, cost-based power sales, and other generally applicable services that do *not* conform to a standard form agreement on file with the Commission, such as agreements containing customized terms and conditions, must be filed with the Commission for prior approval.⁶⁶ As discussed below, service agreements under market-based sales tariffs do not have to be filed individually, but sales under such agreements must be reported in the seller's Electronic Quarterly Report ("EQR") submission.

⁶³ As discussed below, certain market-based rate applications may require preparation of a market power study, and applicants need to allow longer lead times to assure the filing package can be submitted in sufficient time to become effective prior to the planned commencement of sales.

⁶⁴ See *City of Santa Clara v. Enron Power Mktg., Inc.*, 110 FERC ¶ 61,281 at PP 28-29 & n.25 (2005) (explaining the Commission's policy does not require the filing of subsequent agreements or confirmation letters for individual transactions).

⁶⁵ *Revised Pub. Util. Filing Requirements*, Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 18, *reh'g denied*, Order No. 2001-A, 100 FERC ¶ 61,074, *order on reconsideration and clarification*, Order No. 2001-B, 100 FERC ¶ 61,342, *order directing filing and providing details*, Order No. 2001-C, 101 FERC ¶ 61,314 (2002), *order directing review and refiling*, Order No. 2001-D, 102 FERC ¶ 61,334 (2003), *order refining electric quarterly report filing requirements*, Order No. 2001-E, 105 FERC ¶ 61,352 (2003), *order on clarification*, Order No. 2001-F, 106 FERC ¶ 61,060 (2004), *order adopting electric quarterly report data dictionary*, Order No. 2001-G, 120 FERC ¶ 61,270, *order on reh'g and clarification*, Order No. 2001-H, 121 FERC ¶ 61,289 (2007), *order revising electric quarterly report (EQR) data dictionary*, 125 FERC 61,103 (2008) (codified at 18 C.F.R. pt. 35).

⁶⁶ *Id.* at P 19.

D. FAILURE TO FILE IN A TIMELY MANNER

The Commission penalizes market-participants that begin making jurisdictional power sales (either market-based or cost-based) or providing other jurisdictional services without first having the rates or contracts for such sales and/or services approved by the Commission. Parties found to have violated the section 205 requirement to have rates on file before commencing services generally must refund the time value of the revenues collected⁶⁷ for the entire period that the jurisdictional service was provided without authorization.⁶⁸ In such cases the Commission examines, *inter alia*, the period of time for which the sale or service was provided without a rate on file, whether a market-based sale should have been made on a cost-of-service basis, and whether the seller incurred costs to provide the service that should be taken into consideration in deciding the level of refunds. Any refunds of revenues collected are separate from any civil penalties that might be imposed for the underlying violations.

A utility found to have made jurisdictional sales without a rate on file must submit a refund report containing the calculation of its refund obligations under section 35.19. The Commission does not require violators to pay time value refunds of the full amount of revenues collected if doing so will result in the utility providing service or operating its facilities at a financial loss.⁶⁹ In these types of situations, the Commission has directed the utility to file its refund report, but has allowed the utility to make a showing of its potential operating losses.⁷⁰ If the Commission determines that the rate that had been charged was not just and reasonable (i.e., in excess of what the Commission determines to be the cost-justified rate), refunds of revenues collected in excess of the revenues that would have been collected under a cost-based rate (in addition to time value refunds) could be required, with the result that the revenues that a company is allowed to retain for the period in which an unauthorized sale or service was transacted could be less than the rate level that the Commission determines to be the just and reasonable rate for the sale or service.⁷¹

⁶⁷ Time value refunds must be computed using a Commission-approved interest rate calculated pursuant to section 35.19a of the Commission's regulations, 18 C.F.R. § 35.19a.

⁶⁸ *Vt. Elec. Coop. Inc.*, 108 FERC ¶ 61,223 at PP 22-23 (2004), *order on reh'g*, 110 FERC ¶ 61,232 (2005); *see also Prior Notice*, 64 FERC ¶ 61,139 at 61,979.

⁶⁹ *See Carolina Power & Light Co.*, 87 FERC ¶ 61,083 at 61,357 (1999) (limiting application of time value formula to an amount that permits a utility to recover its variable costs such as fuel and O&M expenses); *see also Southern Cal. Edison Co.*, 98 FERC ¶ 61,304 at 62,302 (establishing a "floor" as to the total amount of time value refunds in order to ensure that the utility did not ultimately construct interconnection facilities at a financial loss); *Fla. Power & Light Co.*, 98 FERC ¶ 61,276 at 62,150-51 (2002) (establishing a "floor," as in *Southern California Edison Co.*, 98 FERC ¶ 61,304, and noting that "[because] the monies . . . at issue here did not include any profit, consistent with *Carolina Power & Light*, we will limit the time value refunds to ensure that FP&L will be returning to [the generation company] only the interest on monies that it was never authorized to receive, with a floor to protect it from constructing such facilities at a loss") (quoting *Carolina Power & Light*, 87 FERC ¶ 61,083 at 61,357).

⁷⁰ *See, e.g., Carolina Power & Light*, 87 FERC ¶ 61,083 at 61,357.

⁷¹ *Prior Notice*, 64 FERC ¶ 61,139 at 61,979 n.11.

If the sale was made at an unauthorized market-based rate, then the utility may be required to refund all revenues resulting from the difference, if any, between the market-based rate and a cost-based rate.⁷² For example, a generator may be required to refund amounts above its production cost from the units supplying the power sold, whereas a marketer would have to refund amounts in excess of its acquisition cost for the power resold. The Commission also may void power sale or service agreements entered into without authorization, or limit charges to a cost-based rate for the duration of the contract.⁷³ Even in cases where the Commission ultimately determines that the unauthorized charges at issue were just and reasonable, it almost always imposes a refund as a deterrent to unauthorized sales or services in violation of the FPA and Commission regulations.⁷⁴

III. RULES APPLICABLE TO PARTICULAR TYPES OF POWER TRANSACTIONS

This section briefly describes the substantive requirements and compliance issues applicable to several types of power sales transactions subject to the Commission's jurisdiction under FPA section 205. The principal focus of this discussion is on the filing and reporting requirements associated with market-based rates since these requirements pose a significant compliance burden for most of today's electric market participants.

A. MARKET-BASED RATES

1. *Applications for Market-Based Rate Authorization*

FERC may authorize a seller to make (negotiated) market-based sales of energy, capacity, and certain ancillary services to any willing purchaser where the Commission determines that the seller and its affiliates cannot exercise market power over the potential purchaser of such services. Where the seller does not have market power, FERC deems the negotiated rates to be consistent with the just and reasonable standard of FPA section 205.⁷⁵ Market-based transactions generally include any sales of capacity or energy that are not made pursuant to a filed cost-based rate schedule. While most market-based sales are made pursuant to a blanket authorization in a tariff of general applicability, the Commission also approves individual market-based power sale agreements where the seller can demonstrate the absence of any market power concerns.

⁷² *Id.* at 61,980; *Southern Cal. Water Co.*, 106 FERC ¶ 61,305 at PP 15-16, *reh'g denied*, 108 FERC ¶ 61,168 (2004).

⁷³ *Prior Notice*, 64 FERC ¶ 61,139 at 61,980.

⁷⁴ *Carolina Power & Light*, 87 FERC ¶ 61,083 at 61,356 (“[W]hen utilities fail to file rates in a timely manner, there is injury to ‘the Commission’s ability to ensure that all rates for jurisdictional service . . . are just and reasonable *at the time they are being charged.*’ Factoring the duration of the violation into the refund amount encourages utilities to practice constant vigilance not only with respect to new rates, but also to ensure that existing agreements are appropriately filed.”) (quoting *PacifiCorp Elec. Operations*, 60 FERC ¶ 61,292 at 62,039 (1992), *reh'g granted on other grounds*, 64 FERC ¶ 61,325 (1993)).

⁷⁵ *See Pub. Util. Dist. No. 1 of Snohomish Cnty. v. Dynegy Power Mktg., Inc.*, 384 F.3d 756, 760-61 (9th Cir. 2004); *Elizabethtown Gas Co. v. FERC*, 10 F.3d 866, 870-71 (D.C. Cir. 1993).

The current rules governing market-based rates are codified in the Order No. 697 line of cases.⁷⁶ To qualify for market-based rate authority, a seller must submit an application and proposed tariff sheet (in Order No. 714 compliant format). An application must include the following elements and must be submitted through the Commission's eTariff system:⁷⁷

- A transmittal letter explaining the filing and supporting documents.
- A description of the specific products and services to be offered under the market-based rate tariff including energy, capacity, and certain ancillary services (with the latter further identified by type and the Balancing Authority Area ("BAA") market in which sales would be made).⁷⁸
- A listing of the applicant's and its affiliates' business activities including all upstream owners (entities or individuals) holding 10 percent or more of the applicants' voting shares⁷⁹ (a rebuttable threshold for imputing affiliation). The *MBR NOPR* would require applicants to include an organizational chart (similar to those filed in section 203 applications) when describing their ownership structure, affiliates, and upstream owners.
- Representations of how the applicant satisfies the horizontal market power guidelines (including preparation of quantitative market share studies) if applicant and its affiliates own or control generation.
- Representations of how the applicant satisfies the Commission's vertical market power guidelines, consistent with 18 C.F.R. §§ 35.37(d) and (e).

⁷⁶ *Supra* note 22.

⁷⁷ In June 2014, FERC issued a Notice of Proposed Rulemaking that, if adopted, would modify and streamline certain of the filing and reporting requirements associated with MBR authorizations. See *Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.; Notice of Proposed Rulemaking*, 147 FERC ¶ 61,232 (2014) ("*MBR NOPR*"). The most significant of these proposed changes, which are unlikely to become effective until sometime in early 2015, are noted at relevant points in the discussion of the current rules.

⁷⁸ The Commission has authorized market-based sales of certain ancillary services in organized Regional Transmission Organization ("RTO") markets with approved market monitoring and mitigation. As outlined below, these markets currently include the ISO-NE, NYISO, PJM, MISO, SPP, and CAISO markets. Otherwise, sellers of ancillary services (other than the transmission service provider) are subject to the so-called "third-party provider" rules governing market-based sales prescribed in Order No. 784 which are part of the standard language of market-based tariffs. See *Third-Party Provision of Ancillary Servs.; Accounting and Fin. Reporting for New Elec. Storage Techs.*, Order No. 784, FERC Stats. & Regs. ¶ 31,349 (2013), *order on clarification*, Order No. 784-A, 146 FERC ¶ 61,114 (2014).

⁷⁹ See *AES Creative Res., L.P.*, 129 FERC ¶ 61,239 (2009). FERC staff has carefully scrutinized so-called "passive" ownership arrangements and frequently require applicants to file supplemental information regarding the specific types of control that can be exercised over the applicants. These issues are discussed in greater detail in the chapter on section 203 filing obligations for changes in control over jurisdictional assets.

- A request for the Commission to designate the seller as either a Category 1 or Category 2 seller under rules governing the requirement to regularly update the seller's market power status. If the applicant is seeking Category 1 status, it must provide a narrative describing why it meets the Category 1 requirements (does not own nor is affiliated with entities that, taken together, own or control transmission, a franchised utility, or more than 500 MW of generation) in any or all of the six geographic regions.⁸⁰
- Requests for waivers or authorizations under certain Commission rules including waiver of certain filing and accounting requirements and blanket approval for securities issuances.⁸¹
- An electronic copy of the proposed tariff in the format required by Order No. 714 that includes all the required "standard" provisions of Order No. 697, any new standard provisions periodically adopted by the Commission, a listing of proposed waivers from Commission regulations, and limitations on authorized sales (e.g., markets subject to mitigation, affiliate rule waivers, etc.).
- An asset-ownership matrix in the format required by Appendix B of Order No 697 listing all generation and transmission assets, and natural gas intrastate pipelines and gas storage facilities owned or controlled by the applicant and any of its affiliates in each BAA market. The *MBR NOPR* would require that Appendix B be submitted in (searchable) electronic spreadsheet format and would require applicants to include some additional asset categories.

The previously referenced 60-day prior notice provision of section 205 applies to market-based rate tariffs, although FERC may grant waiver and approve an earlier effective date upon a showing of good cause.

2. Key Issues in FERC Review of MBR Applications

The primary focus of the Commission's evaluation of market-based rate applications is a review of the seller's ability to exercise horizontal and vertical market power over prospective customers. Under Commission policy, market power determinations are based on the consolidated resources owned or controlled by the applicant and all of its upstream and downstream "affiliates," with affiliation implied by the right to vote 10 percent or more of a

⁸⁰ 18 C.F.R. §§ 35.36(a)(2), 35.37(a)(1). The representations regarding seller category status in each region must be included in the applicant's proposed MBR tariff sheets.

⁸¹ The Commission typically grants (1) waiver of the filing requirements of subparts B and C of Part 35 of the Commission's regulations, except sections 35.12(a), 35.13(b), 35.15, and 35.16; (2) waiver of the accounting and other requirements of Parts 41, 101, and 141, except sections 141.14 and 141.15, of the Commission's regulations; and (3) blanket authorization under section 204 of the FPA and Part 34 of the Commission's regulations for all future issuances of securities and assumptions of liability. Franchised utility applicants are not granted waivers of the accounting and section 204 requirements.

company's voting securities.⁸² The analysis assumes that the applicant can control not only its own generation but also all of the generation owned or controlled by either upstream or downstream affiliates.

The quantitative screens and criteria used by FERC to determine whether market-based pricing should be authorized has evolved significantly over the past two decades as the Commission has gained more experience with competitive markets. The current screen methodology is prescribed in Order No. 697⁸³ and considers both (i) horizontal (generation) market power screens; and (ii) vertical market power criteria dealing with transmission and other inputs to electric power generation.

Horizontal Market Power. To evaluate horizontal market power, FERC applies two indicative screens which focus on the applicant's control of generation in each relevant geographic market⁸⁴ in which it seeks market-based rate authorization: the market share screen and the pivotal supplier screens.⁸⁵ If an applicant passes both screens for a particular geographic market, there is a rebuttable presumption that the applicant cannot exercise horizontal market power in that market. Conversely, if an applicant fails either screen, it must prepare three more detailed screens using the so-called Delivered Price Test ("DPT"), the pivotal supplier and market share screens, along with a calculation of the Herfindahl-Hirschman Index ("HHI") of market concentration. These horizontal screens typically are a factor only for sellers in markets outside of RTO or Independent System Operator ("ISO") administered market areas. For such sellers, the relevant market is defined by the individual BAA boundaries.⁸⁶

⁸² In cases where there are two unaffiliated upstream owners (A and B), each holding more than 10 percent of the voting shares of the applicant (C), the market power determinations for the applicant are made on the basis of the combined holdings of A+B+C. The common ownership interest in C does not result in A being deemed an affiliate of B. However, if A owns 10 percent of the voting shares of B, and B owns 10 percent of the voting shares of C, then A, B, and C are all considered to be affiliates of one another.

⁸³ Both Order Nos. 697 and 697-A contain detailed specifications of the technical requirements for preparing the necessary market power screens. See Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 80-386; Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at PP 31-150. The *MBR NOPR* includes a number of changes to the Order No. 697 screen preparation guidelines, so MBR applicants should review provisions of the final rule to assure their filings reflect the applicable methodology at the time of filing.

⁸⁴ For the purposes of both screens, the Commission has stated that the relevant geographic market is the seller's BAA or the RTO BAA in which its generation is located. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 231. In preparing the screens, sellers must also consider whether there are any sub-markets within their BAA markets.

⁸⁵ An applicant satisfies the indicative screens if it is not a pivotal supplier and its market share is less than 20 percent in each BAA market where it proposes to sell. The DPT screens are satisfied if it passes the pivotal supplier and market share screens and the market concentration level (HHI) is below a 2,500 point threshold. *Id.* at P 113.

⁸⁶ We use the term "RTO market" in this chapter to include both RTO- and ISO-administered markets.

The substantially larger geographic footprint of the RTO (and market-specific monitoring and mitigation protocols approved for the RTO) means that even the largest sellers are unlikely to fail the market power screens. One of the most significant changes proposed by the *MBR NOPR* would be to eliminate the need to prepare market power screens for generation owned or controlled in RTO markets with Commission-approved market monitoring and mitigation.⁸⁷ Similarly, the *MBR NOPR* would eliminate the need to prepare market power screens if an MBR seller and its affiliates' capacity in the relevant BAA markets are fully committed under long-term contracts of one year or longer.⁸⁸

If the applicant fails either of the indicative screens and one of the DPT-based screens⁸⁹ in any BAA market, it is presumed to have generation market power in that market, leaving several options. First, the applicant can offer extrinsic evidence as to why it cannot exercise generation market power notwithstanding the screen failures. Various arguments have been periodically accepted by the Commission as evidence that the seller cannot exercise generation market power⁹⁰ and, in those few cases, the applicant has been allowed to make market-based sales notwithstanding the screen failures.⁹¹ Second, the seller can argue that its market power has been sufficiently mitigated. This option typically is invoked by MBR sellers in RTO markets who rely upon the Commission-approved market power mitigation requirements of those markets as sufficient mitigation.⁹² Third, the applicant can withdraw its request for market-based rates in the market in question and instead sell at cost-based rates. If it chooses this third option, the applicant can use the "default" cost-based rates set forth in Order No. 697⁹³ or it can seek approval of alternative forms of "customized" cost-based rates.

⁸⁷ These markets currently include ISO-NE, NYISO, PJM, MISO, SPP, and CAISO.

⁸⁸ Under the *MBR NOPR*, sellers claiming that all of their relevant capacity is "fully committed" would have to represent that the commitment of the generation capacity is not limited on a seasonal basis or limited based on any other factor (e.g., native load obligations or transmission interruptions) that would allow the seller to reclaim control during emergency conditions.

⁸⁹ In virtually all cases where there have been generation screen failures, the problems were encountered in the results for the market share screen.

⁹⁰ Examples include capacity committed to serve native load, historical sales data, physical constraints on withholding capacity from coal and nuclear units, absence of economic incentives to withhold where profits from off-system sales flow through to customers, etc.

⁹¹ *Kan. City Power & Light Co.*, 113 FERC ¶ 61,074 at P 31 (2005).

⁹² Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 240-42, 246, 290; *see, e.g., PSEG Energy Res. & Trade, LLC*, Docket No. ER99-3151-017 (unpublished delegated letter order issued June 29, 2011); *see also* Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 111 ("[T]o the extent a seller seeking to obtain or retain market-based rate authority is relying on existing Commission-approved RTO/ISO market monitoring and mitigation, we adopt a rebuttable presumption that the existing mitigation is sufficient to address any market power concerns."); *NRG Power Mktg. LLC*, Docket No. ER97-4281-018 (unpublished delegated letter order issued Apr. 27, 2009); *PSEG Energy Res. & Trade LLC*, 125 FERC ¶ 61,073 at P 35 (2008); *Dominion Energy Mktg., Inc.*, 125 FERC ¶ 61,070 at P 27 (2008).

⁹³ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 606. As discussed later in this chapter, the Commission has established default (cost-based) mitigation rates for short-term sales of power of one

Vertical Market Power. FERC has identified two categories of vertical market power concerns: transmission market power and barriers to entry.⁹⁴

(i) *Transmission Market Power.* FERC requires that, if an applicant and/or its affiliates own transmission facilities, their potential transmission market power is adequately mitigated if they provide open, non-discriminatory access to those facilities under a Commission-approved OATT.⁹⁵ If the utility is an RTO participant, transmission market power is deemed to be mitigated by having transferred operational control over transmission facilities to that RTO. The Commission generally has not expressed vertical market power concerns with respect to discrete generation tie lines (sometimes referred to as “gen-leads”) and similar facilities used to interconnect generation to the grid, although MBR applicants should identify such facilities in their applications.⁹⁶

(ii) *Barriers to Entry.* FERC also requires applicants for market-based rates to indicate whether they control any energy-related assets that could be used as a barrier to market entry by competing suppliers. The Commission distinguishes between two categories of such inputs. The first category consists of facilities that are presumed to not create vertical market power concerns and need not be identified in MBR applications and market power updates. These are natural gas supply, interstate natural gas transportation (which includes interstate natural gas storage), oil supply, and oil transportation facilities.⁹⁷

The second category consists of intrastate natural gas transportation, intrastate natural gas storage, or distribution facilities; sites for generation capacity development; and sources of coal supplies and the transportation of coal supplies such as barges and rail cars. While the Commission has created a rebuttable presumption that control over facilities in the second category does not allow a seller to erect barriers to entry, such facilities must be identified and described in MBR applications.⁹⁸

Since FERC began allowing market-based sales in the 1990s, nearly all the cases where the Commission has rejected proposed market-based rate tariffs have involved horizontal generation market power concerns. Given that all transmission owners have filed OATTs or participate in Commission-approved ISOs/RTOs and there is a general presumption that control over other resources cannot be used to erect market-entry barriers, there have been few cases

week or less, sales of power of more than one week but less than one year, and new contracts for sales of power for one year or longer. Applicants also retain the option of proposing alternative “customized” cost-based mitigation rates.

⁹⁴ *Id.* at P 440. The filing requirements for the vertical market power demonstration appear at 18 C.F.R. § 35.37(e).

⁹⁵ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 400, 417.

⁹⁶ *See, e.g., Entergy Miss., Inc.*, 112 FERC ¶ 61,228 at P 22 (2005); *Black Creek Hydro, Inc.*, 77 FERC ¶ 61,232 at 61,941 (1996).

⁹⁷ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 441-42.

⁹⁸ *Id.* at P 447.

where applicants have been denied market-based rate authorization based on vertical market power concerns.

Affiliate Issues. FERC no longer requires MBR applicants to include affirmative representations that they will not engage in affiliate abuse in their applications and instead incorporates a standard set of affiliate restrictions in all approved MBR tariffs unless sellers obtain explicit waiver of those restrictions. Specifically, the Commission's rules governing MBR sales states that, "[a]s a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy or capacity may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act."⁹⁹ In addition to restricting affiliate sales, the affiliate restrictions applicable to MBR sellers also prohibit exchanges of market information between a franchised utility and its market-regulated affiliate and impose so-called asymmetric pricing rules on sales of non-power goods and services.¹⁰⁰ (A more complete discussion of the Commission's affiliate restrictions is contained in Chapter 8 of this Handbook.)

Requests for blanket waiver of the affiliate restrictions where a seller's franchised utility has no captive customers can be included as part of an initial MBR application or in a subsequent amendment filing. FERC also has granted limited waiver of the affiliate rules in certain limited instances where applicants can show that captive customers are sufficiently protected.¹⁰¹

3. *Compliance Obligations for Market-Based Rate Sellers*

The Commission's rules governing MBR sellers are fairly extensive and require adequate controls to be in place to ensure compliance. Once an application for MBR authorization is approved,¹⁰² conforming sales under the seller's MBR tariff do not require prior approval. In

⁹⁹ 18 C.F.R. § 35.39(b). This standard language is included in every MBR tariff, with citations to any waivers explicitly cited in the exceptions and limitation paragraph of the tariff.

¹⁰⁰ *Id.* § 35.39(e).

¹⁰¹ See, e.g., *Entergy Servs., Inc.*, 136 FERC ¶ 61,218 (2011) (granting waiver to allow the sharing of employees engaged in fuel procurement, outage scheduling, and economic dispatch); *FirstEnergy Corp.*, 136 FERC ¶ 61,216 at P 17 (2011) (granting waiver to allow the sharing of employees engaged in fuel procurement, economic dispatch, and outage scheduling); *Va. Elec. & Power Co.*, 136 FERC ¶ 61,215 (2011) (granting waiver to allow the sharing of joint fuel procurement employees); *Cleco Power LLC*, 130 FERC ¶ 61,102 (2010) (granting waiver to allow the sharing of employees engaged in outage scheduling); *Allegheny Energy, Inc.*, 119 FERC ¶ 61,025 (2007) (granting waiver to allow the sharing of spare parts at cost).

¹⁰² Applications for MBR authorization are subject to the standard 60-day approval window under FPA section 205 although many applications are approved in less than 60 days. If an MBR application is deemed deficient and must be amended, the 60-day clock is restarted as of the filing date of the amended application. The Commission has stated that, for market-based rates in particular, it "does not allow market-based rates to go into effect before a [tariff] filing has been tendered with the Commission." *El Segundo Power, LLC*, 84 FERC ¶ 61,011 at 61,060; see also *FC Landfill Energy, LLC*, 133 FERC ¶ 61,041 (citing *El Segundo Power, LLC*, 84 FERC ¶ 61,011).

Order No. 2001,¹⁰³ the Commission waived the requirement for market-based sellers to file conforming power sales agreements for prior approval and indicated it would treat such sales as service agreements under their MBR tariffs.¹⁰⁴ However, sales under MBR tariffs still are subject to certain ongoing compliance conditions, some of which are codified in the Commission's regulations and are applicable to all MBR sellers, and some of which may be specific to their individual circumstances and are detailed in the order approving their MBR authorizations. Not all of the reporting obligations are routine and some involve subjective judgments and are subject to varying degrees of ambiguity.

While MBR sellers (other than traditional franchised utilities) are considered FPA public utilities, they are granted waivers from (or blanket approvals with respect to) certain of the Commission's Part II regulations applicable to traditional franchised public utilities, including:

- FPA section 204 related to securities issuances and financing,
- Subparts B and C of 18 C.F.R. Part 35, requiring the filing of cost-of-service information, except for 18 C.F.R. § 35.12(a) and § 35.13(b) related to the initial MBR tariff filing and the contents thereof, § 35.15 related to notices of termination/cancellation, and § 35.16 related to Notices of Succession,
- 18 C.F.R. Part 41 (Accounts, Records, Audits),
- 18 C.F.R. Part 101 (Uniform System of Accounts),¹⁰⁵ and
- 18 C.F.R. Part 141 (Statements and Reports; Schedules).

The following are some of the principal ongoing compliance obligations applicable to MBR sellers:

a. Triennial Market Power Updates

MBR sellers may be required to submit an updated market analysis at three-year intervals in accordance with a schedule provided in Appendix D of Order No. 697.¹⁰⁶ As noted, all entities receiving MBR authorization are divided into two categories:

¹⁰³ Order No. 2001, FERC Stats. & Regs. ¶ 31,127.

¹⁰⁴ The Commission no longer accepts filings of long-term power sale contracts negotiated by sellers pursuant to market-based rate authorization, even where the seller voluntarily seeks to have the contract placed "on file" with the objective of preempting future challenges by state regulators.

¹⁰⁵ The Commission recently clarified that hydropower licensees are required to comply with the requirements of the Uniform System of Accounts pursuant to 18 C.F.R. Part 101 and that a licensee's status as a market-based rate seller under section 205 does not exempt the MBR seller from its accounting compliance obligations. See *Seneca Generation, LLC*, 145 FERC ¶ 61,096 at P 23 n.20 (2013).

¹⁰⁶ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 850.

- “Category 1” sellers are those with a small market presence and are exempt from the triennial reporting requirement. These are defined as those sellers not having ownership or control, either directly or through affiliates, of 500 MW of generation (in aggregate) in any of the six reporting regions;¹⁰⁷ do not own, operate, or control transmission facilities and are not affiliated with anyone that owns, operates, or controls transmission facilities in the same region as the seller’s generation assets; are not affiliated with a franchised public utility in the same region as the seller’s generation assets; and that do not raise other vertical market power issues.
- “Category 2” sellers are all sellers that do not meet the criteria for Category 1 sellers.¹⁰⁸ Category 2 sellers must file a single, consolidated regional filing¹⁰⁹ for all market-based rate sellers in the corporate family, rather than submitting individual filings for each affiliated subsidiary with MBR authorization.

A triennial report must include the same market power screens and representations discussed above for an initial MBR application and thus, as a practical matter, constitute a “new” application for continued MBR authorization. However, a seller’s market-based rate authorization does not “expire” at the end of this three-year period and continues until such time the Commission issues an order under FPA section 206 to revoke the authorization. So long as the triennial update has been submitted on a timely basis and the seller has complied with the terms of its tariff and all the applicable Commission regulations, the seller’s MBR authorization remains effective.¹¹⁰

If, upon review of an updated market power analysis, FERC finds that an MBR seller fails the market power screens or may otherwise have the potential to exercise horizontal or vertical market power, the Commission will institute a section 206 investigation to determine whether MBR authorization should be revoked, and will set a refund effective date.¹¹¹ This means that, if FERC revokes MBR authority, the applicant may be required to pay time value refunds to its customers (typically the difference between cost-based rates and market-based

¹⁰⁷ Appendix D of Order No. 697 identified the six reporting regions (Northeast, Southeast, Central (MISO), Southwest Power Pool (SPP), Southwest, and Northwest) where Category 2 sellers that own or control generation assets in each region are required to file an updated market power analysis for that region every three years based on a rotating schedule shown in the Appendix. *Id.* at P 885. An updated version of the regional market power update filing schedule is now posted on the Commission’s website at <http://www.ferc.gov/industries/electric/gen-info/mbr/triennial.asp>. Each region may include one or more BAA markets and submarkets.

¹⁰⁸ *Id.* at P 849 & n.1000.

¹⁰⁹ Where a seller owns or controls generation in multiple BAA markets in a reporting region, its triennial report must include a separate screen analysis for each market.

¹¹⁰ 18 C.F.R. § 35.37(a)(1). The failure to submit a triennial report on a timely basis constitutes a violation of a seller’s market-based rate tariff and can result in revocation of MBR authorization.

¹¹¹ See *AEP Power Mktg., Inc.*, 107 FERC ¶61,018 at P 201, *order on reh’g*, 108 FERC ¶61,026 at P 30 & n.23 (2004).

rates plus interest), retroactive for all sales made subsequent to a refund effective date established in the section 206 order.¹¹²

FERC has revoked the market-based rate authority of a number of entities that failed to respond to an order notifying them that they had not filed their triennial market updates on a timely basis, and requiring them to file those updates within 60 days.¹¹³ Compliance with the triennial update reporting obligation was simplified somewhat by Order No. 697, which provides that the updates be prepared on a consolidated corporate family basis on a Commission-set schedule within each of six separate geographic regions. In general, corporate entities with multiple MBR affiliates should list in the caption of a triennial filing for a given region all of those affiliates with physical assets in the reporting region as well as all of their power marketing affiliates with MBR authorization.

The *MBR NOPR* includes several important changes to the triennial update filing requirements, including the above-noted provision that would eliminate the need to prepare and file the indicative screens for sellers with generation in RTO markets with Commission-approved market monitoring and mitigation.

b. Change in Status Filings

In addition to the triennial market power update requirement applicable to Category 2 sellers, all public utilities with market-based rate authority (including both Category 1 and 2 sellers) must report any “changes in status,” which include changes to the facts set forth in their initial MBR application or most recent market power update approved by the Commission. The requirements to file a change in status notice were first detailed in Order No. 652¹¹⁴ but were substantially updated in Order No. 697. Under current rules, a change in status filing is mandatory for certain events and discretionary for other changes, based on the seller’s assessment of whether the change would have materially changed the Commission’s prior market power findings. Events requiring the submission of a change in status notice include:

- Cumulative increases in ownership or control of 100 MW or more of generation capacity in any BAA market (sellers may offset decreases against increases), whether through acquisition of new or existing generating facilities or through contractual arrangements.¹¹⁵ As noted, such changes are determined on a consolidated basis for all MBR sellers in the corporate family.

¹¹² See *Duke Power*, 111 FERC ¶ 61,506 at P 4 (2005).

¹¹³ *3E Techs., Inc.*, 113 FERC ¶ 61,124 (2005). In most of the cases where FERC has revoked market-based rate authorization for failure to file a triennial update, the entity typically has discontinued operations but neglected to withdraw its tariff.

¹¹⁴ *Reporting Requirement for Changes in Status for Pub. Utils. with Market-Based Rate Auth.*, Order No. 652, FERC Stats. & Regs. ¶ 31,175, *order on reh’g*, Order No. 652-A, 111 FERC ¶ 61,413 (2005).

¹¹⁵ FERC clarified in Order No. 697-A that the 100 MW change in control over generation must be in a single geographic (BAA) market that is analyzed for market power purposes, and that the obligation is not triggered, for example, if there is an increase in control of 50 MW in one BAA market

- Increases in ownership or control of transmission facilities¹¹⁶ or inputs to electric power production,¹¹⁷ whether through acquisition of ownership interests or other contractual arrangements. In general, new transmission lines or short-term transmission outages need not be reported as a change in status, although in rare instances those changes that materially affect import capability into a market where the seller already was “marginal” from a market power screen perspective might warrant a change in status report.¹¹⁸
- New affiliation with any entity that owns or controls generation or transmission facilities or inputs to electric power production, or has a franchised service territory.

A change in status notice must be filed within 30 days after the “effective date” of the event triggering such change.¹¹⁹ A seller is not obligated to submit a new set of market power screens with each change in status notice, especially if it believes the change is non-material.¹²⁰ However, FERC retains the authority to require a market update from any seller, regardless of size, at any time¹²¹ and on occasion has directed a seller to submit updated screens to address specific events.

The 100 MW change in status threshold measures cumulative increases in an MBR seller’s (and its affiliates’) ownership or control of generation in a given BAA market since the seller’s last approved market power study.¹²² For example, two unrelated transactions by

and an increase in control over 50 MW in a different BAA market. Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 512.

¹¹⁶ Material changes to the OATT provisions relied upon by the seller to mitigate any market power concerns also must be reported.

¹¹⁷ The Commission has established a separate reporting scheme for changes in a seller’s control of sites for new generation. Under 18 C.F.R § 35.42(d), such reports must be filed in a separate (“LA”) docket 30 days after the end of each calendar quarter, when site acquisitions by the seller and its affiliates during the prior quarter, as measured by MW of new interconnection capacity requested, exceed 100 MW in any BAA market. However, the *MBR NOPR* would eliminate the site reporting requirement entirely.

¹¹⁸ See Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 1025 (“We adopt the . . . proposal not to require the reporting of transmission outages *per se* as a change in status . . . [W]e reiterate that to the extent a long-term transmission outage affects one or more of the factors of the Commission’s market-based rate analysis (*e.g.*, if it reduces imports of capacity by competitors that, if reflected in the generation market power screens, would change the results of the screens from a “pass” to a “fail”), a change of status filing is required.”).

¹¹⁹ *Id.* at P 1039. In the case of power sales contracts with future delivery, such contracts are reportable as a change-in-status 30 days after the physical delivery has begun rather than from the date the contract is negotiated. For new generation, the change in status report must be filed within 30 days after the commencement of test power deliveries.

¹²⁰ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at PP 505-06.

¹²¹ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 857.

¹²² Where the last approved screen study is substantially dated, sellers should consider filing a completely new set of screens rather than trying to isolate the changed circumstances from all the other load, resource, transmission transfer level assumptions use in the prior study.

affiliated MBR sellers in the same BAA market that together exceed 100 MW would require a change in status report.¹²³ In addition, while sellers may net decreases against increases in calculating the cumulative impact of new capacity acquisitions or contracts, such offsets must take account of *all affiliated generation* and not that calculated for individual affiliates. Substantial increases in load obligations may also be taken into account, but load fluctuations normally would be reserved for a triennial update.

The need for a change in status report for increased control over more than 100 MW of generation through long-term purchase agreements (defined as contracts with a term exceeding one year)¹²⁴ must be examined on a case-specific basis. The Commission has refused to provide a listing of the specific types of contracts that should be filed beyond the basic test of whether a particular contract conveys to the purchaser the ultimate ability to withhold that capacity from the market.¹²⁵ A factor such as authority over dispatch decisions may strongly suggest control, but may not be dispositive. Also, the Commission clarified that most energy-only contracts did not convey “control” over capacity and thus did not need to be reported, although the facts of any specific contract would need to be examined to assure compliance.¹²⁶

In response to industry requests for guidance with respect to one of the most frequently traded electricity products, the Commission provided limited clarification in *Integritys*¹²⁷ that the sale of a firm energy product (as defined in the EEI Master Power Purchase & Sale Agreement) gives the purchaser only a right to receive energy and thus no rights that would allow the purchaser to control generation capacity. Thus, the purchase of energy products as described in *Integritys* do not require the filing of a change in status report.¹²⁸

The pending *MBR NOPR* would make an important change to the current Commission policy (as described above) with regard to the attribution of long-term energy purchases. In particular, MBR sellers would have to include all long-term (>12 months) purchases of *both* capacity and energy in their indicative screens and Appendix B submissions, where the purchaser has an associated long-term firm transmission reservation, regardless of whether the seller has operational control over the generation capacity supplying the purchased power. If the long-term firm purchase involves the *sale* of energy, then the purchaser must convert the amount of energy to which it is entitled into an amount of generation capacity for purposes of its indicative screens and asset appendices. Both the purchaser and the seller must show how they made the energy-to-capacity conversion for purposes of their screen studies and Appendix B submissions. If adopted, this is an important change relative to current policy where it was assumed that

¹²³ Order No. 697-A, FERC Stats. & Regs. ¶ 31,268 at P 514.

¹²⁴ Order No. 652, FERC Stats. & Regs. ¶ 31,175 at P 48.

¹²⁵ *Id.* at P 47.

¹²⁶ Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at P 101.

¹²⁷ *Integritys Energy Grp., Inc.*, 123 FERC ¶ 61,034 at P 11 (2008).

¹²⁸ Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at P 99.

“energy-only” purchases did not give the buyer control over the corresponding capacity for market power calculation purposes.¹²⁹

In Order No. 697, the Commission also adopted a new rule requiring MBR sellers making a long-term power sale from a generation facility they owned to seek a “letter of concurrence” from other affected parties identifying which party controls a facility. Absent such a letter, the owner of a facility is presumed to have control of the facility unless such control has been transferred to another party by virtue of a contractual arrangement.¹³⁰

c. Mitigated Sales by MBR Sellers

Some MBR sellers may be subject to mitigated (cost-based) prices for their market-based sales in the geographic market(s) in which the seller is found, or presumed, to have market power. The details of these cost-based mitigation requirements are discussed below but generally apply only to mitigated MBR sellers making sales outside of one of the organized RTO markets with Commission-approved market monitoring and mitigation.

d. Other Compliance Obligations for Market-Based Sellers

- While exempt from the usual section 205 requirement to “cost-justify” each sale, entities with market-based rate authority still must retain certain price support data for a five-year period under 18 C.F.R. § 35.41(d) (governing records retention).
- All new MBR tariffs must be filed electronically in FERC-prescribed format,¹³¹ updated periodically when the seller’s circumstances change (e.g., name changes, seller category designation, changes to previously granted waivers, etc.), or when the Commission mandates new standard language to be inserted in all MBR tariffs (e.g., sales of new ancillary services when new markets open).
- All public utilities including MBR sellers are required to electronically file Electric Quarterly Reports summarizing the contractual terms and conditions in their agreements for all jurisdictional services (including market-based power sales, cost-based power sales, and transmission service) and transaction information for short-term and long-term market-based power sales and cost-based power sales during the

¹²⁹ The rationale for this proposed change was a finding by Staff that the generating capacity supporting long-term energy sales was not being reported by either the buyer or seller.

¹³⁰ If a seller does not believe that the entire capacity of a generation facility should be included in its indicative screens, it may explain its position in the transmittal letter filed with its horizontal market power screens, including letters of concurrence where appropriate, and thus account for only its portion of that particular generation facility in the indicative screens. However, Staff are insisting that the entire capacity of the facility should be noted in the list of generation assets in its Appendix B. See Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 187; see also Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at P 34 (citations omitted); *MBR NOPR*, 147 FERC ¶ 61,232 at P 116.

¹³¹ 18 C.F.R. Parts 35, 131, and 154, as amended by Order No. 714.

most recent calendar quarter. The requirement applies *regardless of whether the public utility has made any power sales.*¹³²

4. *Penalties for Violations of MBR Tariff Conditions and Commission Rules Governing MBR Sellers*

An MBR seller found to have violated the terms of its MBR tariff or any of the Commission's rules governing MBR sales is subject to suspension or revocation of its MBR authorization along with potential refund obligations and civil penalties.

Revocation or Suspension of MBR Authorization. An MBR seller that is determined to have willfully violated the terms of its MBR authorization may be subject to temporary suspension or permanent revocation of such authorization in some or all of the geographic markets in which it has been authorized to make market-based sales.¹³³ In general, MBR suspension or revocation would be prospective and would not affect previously-negotiated MBR contracts that comply with the terms of the seller's MBR tariff. Suspension or revocation of MBR authority is an extreme remedy that has been imposed in only a limited number of cases¹³⁴ and only after the MBR seller has been provided an opportunity to respond to the allegations cited by the Commission as the basis for the proposed sanctions.

The Commission also may suspend or revoke MBR authority for OATT violations (by the seller or its affiliates) if it finds a nexus between the specific facts relating to the OATT violation and the seller's MBR authority.¹³⁵ With respect to affiliates of a transmission provider where the transmission provider loses its MBR authority due to a OATT violation, the affiliate may retain its market-based rate authority in a market area if the affiliate overcomes the rebuttable presumption that the transmission provider could exercise vertical market power with respect to *that* geographic market.¹³⁶

¹³² In Order No. 770, FERC revised the EQR filing process, eliminating filing through FERC-distributed software and introducing a web-based approach that allows users to file directly through the FERC's website. *Revisions to Elec. Quarterly Report Filing Process*, Order No. 770, FERC Stats. & Regs. ¶ 31,338 (2012).

¹³³ MBR sellers also may be subject to loss of their blanket MBR authority in certain geographic markets as a result of failing the horizontal market power screens or otherwise being found to have the potential to exercise market power. In such cases, the loss of MBR authorization is not considered a "penalty" but is rather a market power mitigation requirement for the Commission to assure that jurisdictional power sales conform to the just and reasonable standard under FPA section 205.

¹³⁴ See *J.P. Morgan Ventures Energy Corp.*, 141 FERC ¶ 61,131 (2012); *Enron Power Mktg., Inc.*, 103 FERC ¶ 61,343 (2003); *GWF Energy, LLC*, 98 FERC ¶ 61,330 (2002); *Wash. Water Power Co.*, 83 FERC ¶ 61,282 (1998).

¹³⁵ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 417. FERC declined to adopt a rebuttable presumption that *any* OATT violation by an MBR seller or an affiliate should result in automatic revocation of MBR authority. The Commission stated that it will evaluate the factual circumstances of each violation to determine possible market impacts and any possible penalties (including revocation of MBR authority) on a case-by-case basis.

¹³⁶ Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 424.

Refunds of the Time Value of Revenues Collected Without Authorization. As noted, any seller that begins making jurisdictional sales (either cost-based or market-based) without first having the rates for such sales on file with the Commission generally must refund the time value of the revenues collected for the entire period that the jurisdictional service was provided without authorization.¹³⁷ In addition to time value refunds, a seller making market-based sales without market-based rate authorization also may be required to refund the amount of revenues collected above those that would have been collected under the Commission-determined cost-based rate for the relevant product or service.¹³⁸ In other words, the late-filing MBR seller will receive the equivalent of a cost-based rate, less the time value remedy applicable to the unauthorized late filing of cost-based rates, until the date of Commission authorization. The Commission generally does not require refunds to be made when the unauthorized sale was made by an MBR seller to one of its market-regulated affiliates. Refunds are also not required when the result would be the seller having provided the service at below its incremental cost of providing the service.

Civil Penalties. The Energy Policy Act of 2005¹³⁹ provides FERC with broad civil penalty authority for violations of Part II of the FPA, which includes violations of the terms of market-based rate tariffs and related Commission regulations. Over the past several years, the Commission has applied its civil penalty authority in a number of cases where it found violations of its regulations for market-based power sales.¹⁴⁰ Such penalties may be imposed *in addition to* the time value refund or disgorgement penalties noted above. (A more detailed discussion of these sanctions is included in Chapter 3 on civil penalty authority.)

B. COST-BASED RATES

While sales under blanket MBR authority have become the predominant form of power sales over the past two decades, several types of power sale transactions remain subject to cost-based rates. These include any section 205 jurisdictional sales by a party that has not been granted MBR authorization, any change in a filed cost-based rate, sales of certain generation-related ancillary services that are not authorized for sale under MBR authorizations, and market-based sales by MBR sellers that are subject to cost-based mitigation requirements in one or more

¹³⁷ See *Vt. Elec. Coop., Inc.*, 108 FERC ¶ 61,223 at PP 22-23; see also *Prior Notice*, 64 FERC ¶ 61,139 at 61,979. Interest is calculated pursuant to section 35.19a of the Commission's regulations. 18 C.F.R. § 35.19a.

¹³⁸ *Berry Petroleum Co.*, 140 FERC ¶ 61,186 at PP 25-26 (2012) (ordering refunds for market-based sales made without having approved MBR authorization to include: (a) the time value of gross revenues for market-based rate sales made without Commission authorization for the relevant period, calculated in accordance with 18 C.F.R. § 35.19a, and (b) the difference between the gross revenues for MBR sales made without Commission authorization and the cost-justified rate).

¹³⁹ Pub. L. No. 109-58, 119 Stat. 594 (2005).

¹⁴⁰ See, e.g., *In re Gexa Energy, L.L.C.*, 120 FERC ¶ 61,175 (2007) (approving Stipulation and Consent Agreement providing for Gexa's payment of a \$500,000 civil penalty and disgorgement of \$12,481.41 in profits, with interest, for violations in part under section 205 for entering into a series of unauthorized wholesale balancing transactions to sell excess generation in interstate commerce into the ISO-NE's hourly or day-ahead market).

geographic markets. The following are some of the key compliance issues related to cost-based power sales.

1. *Initial Cost-Base Rate Filings*

As noted earlier, FPA section 205 requires that any jurisdictional wholesale power sale be made pursuant to a rate that is filed at least 60 days but no more than 120 days before the commencement of energy deliveries. Violations of this requirement could expose the seller to refund obligations and possible civil penalties depending on the circumstances of the unauthorized sale. The Commission's regulations at section 35.1 set forth a detailed set of requirements for the preparation and submission of initial rate applications for cost-based power sales.¹⁴¹ These include rules governing how a seller should establish its cost of service and rate of return that form the basis for the proposed rates. Such rates may be fixed-rates (also known as stated-rates), where the price is set for the term of the agreement, or formula-type rates where the prices may vary as a function of changes in the seller's costs.

In recent years, the rapid growth in market-based sales, especially those made within the footprint of RTO markets, has substantially reduced the number of new cost-based rate filings. Most cost-based rates are for requirements sales by vertically-integrated public utilities outside of RTO markets, where the seller is unable to pass the generation market power screens prior to initiating any new services. These utilities must prepare and file cost-of-service studies pursuant to detailed rules promulgated by the Commission for initial rate filings. A complete discussion of those rules is beyond the scope of this Handbook.

2. *Proposed Increases in Filed Cost-Based Rates*

In addition to initial rate filings, FERC imposes specific and detailed filing requirements for increasing jurisdictional cost-based rates.¹⁴² Although there are certain safe harbors for relatively small rate increases and uncontested applications, most increases in rates for wholesale requirements service will require the applicant to submit a full cost-of-service study under section 35.13 of the Commission's regulations. Section 35.13 requires that a cost-of-service study be submitted for two test years—an historical test year and a prospective test year—with the latter constituting the test year for which rates will be set. The time required for preparing such a study typically can be several months or longer depending on the circumstances.

Depending on the type of rates involved (e.g., full requirements service versus a specific ancillary service), the required cost-of-service studies to support a proposed increase in a filed rate may require the submission of a broad range of cost and financial information for a utility's entire business or segments thereof. Thus, the submission for a traditional integrated utility might have to address all segments of the company's business (i.e., generation, transmission, and distribution), and include information on plant balances, cost of capital, and operating expenses. The preparation of the filing may require the assistance of expert consultants familiar with

¹⁴¹ See 18 C.F.R. § 35.1.

¹⁴² See *id.* § 35.13.

FERC's complex rules governing the determination of revenue requirements and rate design.¹⁴³ These cases typically are set for hearing and can take several years to resolve (unless they are settled, which most are). Proposed changes in rates which would have the effect of substantially increasing the current revenue requirement are the ones most likely to be flagged by the Commission staff for hearing with a directive to seek a settlement in the interim.¹⁴⁴

3. *Cost-Based Mitigation for Certain Market-Based Sellers*

If an MBR seller fails the Commission's market power screens in one or more geographic markets or otherwise has its MBR authority suspended or revoked, the seller's rates for wholesale sales in the relevant markets are restricted to well-defined "default" cost-based mitigation rates. The seller also may seek prior approval for customized cost-based mitigation rates in lieu of the Commission's default rates.

There are three classes of default cost-based mitigation rates: (1) sales of power of one week or less are priced at the seller's incremental cost plus a 10 percent adder; (2) sales of power of more than one week but less than one year are priced at no higher than a cost-based ceiling reflecting the costs of the unit(s) expected to provide the service; and (3) new contracts filed for review under section 205 of the FPA for sales of power for one year or more are priced at a rate not to exceed the embedded cost of service of all of the seller's generation in the market.¹⁴⁵ As noted, the Commission has allowed MBR sellers failing the horizontal screens in RTO markets to rely upon the market-mitigation rules of those markets and has not required them to adopt the cost-based mitigation requirements noted above. The *MBR NOPR* would go one step further and eliminate the requirement to even file market power screens in RTO markets since there would be no consequences for such screen failures.

Mitigated MBR sellers choosing to make market-based rate sales at the metered boundary between a mitigated balancing authority area and a balancing authority area in which the seller is not subject to mitigation are required to maintain sufficient documentation to demonstrate that they are not scheduling transactions in a manner that circumvents the relevant cost-based mitigation requirements. Specifically, they must retain records showing that (i) legal title of the power sold transfers at the metered boundary between a mitigated balancing authority area and one in which the mitigated entity has market-based rate authorization; and (ii) the seller and its affiliates do not sell power back into the balancing authority area where the seller is mitigated

¹⁴³ For example, a proposed increase in cost-based rates for reactive power service would typically have to conform with the Commission's policies for reactive rates set forth in *American Electric Power Service Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999), *order on reh'g*, 92 FERC ¶ 61,001 (2000) (setting forth a methodology to develop cost-based rates for reactive power capability revenue requirements based on a set of standard assumptions about the types of equipment on conventional electric generators that contribute to the provision of reactive power, and appropriate allocation of the cost of that equipment between real and reactive power production).

¹⁴⁴ See, e.g., *Homer City Generation, L.P.*, 148 FERC ¶ 61,141 at PP 12-13 (2014).

¹⁴⁵ 18 C.F.R. § 35.38(a)-(b).

from outside of the balancing authority area.¹⁴⁶ Sales data demonstrating compliance with these requirements must be retained for a five-year period.¹⁴⁷

C. AFFILIATE SALES

The rules governing MBR sales under section 35.39 of the Commission’s regulations impose restrictions on transactions between so-called “market-regulated power sales affiliates” (“MRPSAs”) and affiliated traditional franchised public utilities (“FPU”) with captive wholesale or retail customers. The restrictions on such affiliate power sales are intended to protect captive customers from affiliate abuse resulting from undue preferences that could transfer value from captive customers to corporate shareholders. Specifically, the Commission’s concern is that, in the absence of prior regulatory review, the franchised utility could purchase power from its unregulated affiliate at above-market rates or agree to other terms and conditions that are more favorable to its MRPSA than the terms and conditions that would result in an arms-length transaction with non-affiliated suppliers. Parallel restrictions also are imposed on MBR sales *from* the franchised public utility to an MRPSA because of concerns that the power would be offered for sale to the MRPSA at *below-market prices* (or below the affiliated FPU’s production cost), which also would benefit shareholders at ratepayers’ expense.

The Commission’s rules governing MBR sales under Order No. 697 state that, “[a]s a condition of obtaining and retaining market-based rate authority, no wholesale sale of electric energy or capacity may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without first receiving Commission authorization for the transaction under section 205 of the Federal Power Act.”¹⁴⁸ Many franchised utilities operating in retail access jurisdictions have been granted waivers from this restriction and can engage in sales to marketing affiliates without prior FERC approval of each transaction. Such waivers are granted upon a showing that customers in those jurisdictions are not “captive” and can purchase from competing suppliers if their incumbent utility supplier seeks to recover above-market affiliate supply costs in their cost-based rates. The specific terms of such waivers must be inserted into the seller’s MBR tariff since they reflect a departure from otherwise applicable regulations governing MBR sales.

Rather than imposing an absolute prohibition on affiliate transactions, the Commission has acknowledged that a properly structured affiliate sale may benefit captive retail customers and has provided a case-specific mechanism for approving such transactions under FPA section 205. Specifically, the Commission has adopted the so-called *Edgar/Allegheny* criteria¹⁴⁹ for

¹⁴⁶ See Order 697-A, FERC Stats. & Regs. ¶ 31,268 at P 339; see also Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 at P 76 (clarifying that if a seller “wants to sell at the metered boundary of a mitigated balancing authority area at market-based rates, then neither it nor its affiliates can sell into that mitigated balancing authority area from the outside”).

¹⁴⁷ Much of this data may already be compiled and retained in the seller’s EQR data.

¹⁴⁸ 18 C.F.R. § 35.39(b).

¹⁴⁹ *Boston Edison Co. re: Edgar Elec. Energy Co.*, 55 FERC ¶ 61,382 (1991) (“*Edgar*”); *Allegheny Energy Supply Co., LLC*, 129 FERC ¶ 61,059 (2009) (“*Allegheny*”). As a general proposition, *Edgar* details the generic types of evidence (including the results of an auction or competitive solicitation) a section 205 applicant may offer to establish that a proposed affiliate transaction is priced “at-market,”

evaluating proposed affiliate power sales transactions. These criteria provide detailed guidelines for demonstrating that a proposed affiliate transaction (whether a sale from or to the franchised utility) is priced “at-market” and not marked-up or discounted to benefit the MRPSAs (and their shareholders) to the detriment of the FPU’s captive customers. Under the applicable rules, each proposed affiliate transaction must be filed separately under FPA section 205 and the application must include the type of evidence specified in *Edgar/Allegheny* to support the assertion that the price and non-price terms of the proposed commercial agreement are truly market-based and comparable to the outcome that arguably would have been reached in an arms-length negotiation between non-affiliates.

Under *Edgar/Allegheny*, such a demonstration could be made using one of three possible evidentiary sources¹⁵⁰:

- Evidence of direct head-to-head competition between affiliated and unaffiliated suppliers;
- Evidence of the prices that non-affiliated buyers were willing to pay for similar service from the affiliate; and
- “Benchmark” evidence of the prices, terms, and conditions of sales made by unaffiliated sellers.

If an applicant seeks to use data from benchmark sales to establish the absence of affiliate abuse, FERC has required that such transactions be in essentially the same relevant market, of recent vintage and contemporaneous with the proposed transaction, and involve a comparable (although not necessarily identical) product specification to the proposed transaction. Further, the Commission has required that the benchmark analysis should examine the overall transaction, including both price and non-price terms and conditions. Finally, the applicant must demonstrate to the Commission’s satisfaction that the benchmark evidence was not distorted by exercise of market power by the seller or its affiliates.¹⁵¹

The types of affiliate sales with the greatest likelihood of gaining FERC approval are those resulting from a formal *Allegheny*-compliant auction process¹⁵² conducted by an independent auction manager on behalf of the franchised utility purchaser with oversight by the

while *Allegheny* sets out the guidelines for establishing that an auction or competitive solicitation satisfies *Edgar*.

¹⁵⁰ *Edgar*, 55 FERC ¶ 61,382 at 62,168-69.

¹⁵¹ See *Am. Elec. Power Serv. Corp.*, Docket No. ER05-141-000 (unpublished delegated letter order issued Dec. 29, 2004); *Ocean State Power II*, 59 FERC ¶ 61,360 at 62,333 (1992).

¹⁵² Specifically, *Allegheny* requires that the following criteria are used: (i) the competitive solicitation process should be open and fair; (ii) the product or products sought through the competitive solicitation should be precisely defined; (iii) evaluation criteria should be standardized and applied equally to all bids and bidders; and (iv) an independent third party should design the solicitation, administer bidding, and evaluate bids prior to the company’s selection.

relevant state regulatory agency.¹⁵³ The auction would solicit bids to supply a clearly-defined product from all potential sellers (including unaffiliated entities) pursuant to defined criteria. The auction process must be structured to provide no preference or special access to information to affiliated marketers. Any supplemental or clarifying information beyond that contained in the solicitation documents must be made available at the same time to all auction participants. The use of an *Allegheny*-compliant solicitation process creates a rebuttable presumption that the price, terms, and conditions of a power sales contract awarded to the winning bidder represent a just and reasonable market outcome.¹⁵⁴

In circumstances where affiliates are unable to structure a proposed market-based power sale using the Commission's preferred *Allegheny*-compliant auction strategy, it will be more difficult to obtain timely FERC approval under section 205. Such affiliate sales are more challenging since the FERC section 205 submission requires substitution of other forms of evidentiary support to establish that the terms of the transaction reflect an arms-length, competitive market outcome and thus satisfy the *Edgar* standards. Such alternative benchmarking evidence might include the results of informal (non-binding) solicitations of expressions of interest for the relevant product, including indicative bids, expert testimony by economists who have studied the regional market and are familiar with comparable transactions or who can opine on how to establish the "market value" based on forward price curves, and other analytic techniques. These alternatives will be subject to great scrutiny by Commission staff but may be the only option in certain situations where timing or commercial considerations do not allow for a formal request for proposal process.

D. ANCILLARY SERVICES

FERC will grant authority for the sale of certain ancillary services at market-based rates when such services are sold into an organized ancillary services market administered by one of the six RTOs that have Commission-approved market monitoring and mitigation. The applicant's tariff must specify, for each of those markets, the specific ancillary services the applicant seeks to provide, and the tariff sheets must include the precise language approved by FERC describing each ancillary service that the applicant seeks authorization to sell.¹⁵⁵

¹⁵³ FERC has approved many affiliate sales under the *Edgar/Allegheny* criteria over the past decade, most of which involved power sales by MRPSAs to affiliated FPU's where the marketing affiliate was awarded a contract in an *Allegheny*-compliant auction that was monitored by state regulators and administered by independent auction managers. Most of these approved affiliate sales have been granted in connection with auctions for so-called "provider-of-last-resort" or "standard-offer" supply.

¹⁵⁴ *Edgar*, 55 FERC ¶ 61,382 at 62,168.

¹⁵⁵ See, e.g., *Calhoun Power Co. I, LLC*, 96 FERC ¶ 61,056 (2001).

Outside of organized RTO markets, ancillary services often are provided by transmission providers at cost-based rates. However, because certain ancillary services may be self-provided by the transmission customer, FERC has allowed market-based approaches to procurement of ancillary services by transmission customers. Sometimes the seller of such ancillary services is referred to as a “third-party seller” because the seller is neither the transmission customer nor the transmission provider.

In Order No. 784, FERC updated its regulations governing market-based sales of ancillary services and its standard language for MBR tariffs governing third-party provision of certain ancillary services.¹⁵⁶ Specifically, under Order No. 784 FERC now allows a generator authorized to make market-based sales of energy and capacity to sell imbalance services at market-based rates to a transmission provider in the same BAA market, or to transmission providers in a different BAA market, if those areas have implemented intra-hour scheduling for transmission service. In addition, generators with MBR authorization can now make market-based sales of operating reserves to a transmission provider in the same BAA market, or to a transmission provider in a different BAA market, if those areas have implemented intra-hour transmission scheduling that supports inter-market delivery of operating reserves.

As a result of Order No. 784, generators with MBR authority may sell any ancillary service at market-based rates with the exception of sales of Reactive Supply and Voltage Control service and Regulation and Frequency Response service to a public utility that is purchasing ancillary services to satisfy its own OATT requirements. Such sales can be made at market-based rates under any one of the three following circumstances: (1) the seller makes an acceptable showing to FERC either that it lacks market power in the sale of such ancillary services or that its market power is effectively mitigated; (2) the seller sells the services at rates that do not exceed the purchasing public utility transmission provider’s OATT rate for the same service; or (3) the purchasing utility procures the services through a competitive solicitation that meets the requirements of this final rule.

E. DEMAND-SIDE MANAGEMENT OFFERS IN ORGANIZED ENERGY MARKETS

In recent years, there has been substantial growth in the “sale” of demand-side management (“DSM”) resources in organized wholesale markets, with much of that growth attributable to actions taken by FERC. Specifically, in Order No. 745,¹⁵⁷ the Commission required RTO markets to treat DSM resources as an alternative to traditional generation resources in load balancing. It further required that, when dispatch of a DSM resource was cost-effective, the DSM resource must be compensated for the load reduction service it provides at the prevailing market price for energy (not taking into consideration the avoided cost savings realized by the DSM provider). The adoption of these requirements raised the question of whether DSM providers needed to have a rate on file pursuant to FPA section 205 (in the form of an MBR tariff) prior to offering DSM services in FERC-jurisdictional wholesale markets.

¹⁵⁶ Order No. 784, FERC Stats. & Regs. ¶ 31,349 at P 200.

¹⁵⁷ *Demand Response Compensation in Organized Wholesale Energy Mkts.*, Order No. 745, FERC Stats. & Regs. ¶ 31,322, *order on reh’g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *vacated by Elec. Power Supply Ass’n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014).

The simple answer is no. The Commission does not consider DSM service providers to be FPA “public utilities” nor has it required end users in organized markets to offer demand response services since such entities are not subject to the Commission’s jurisdiction. Likewise, DSM providers are not required to file agreements under FPA section 205.¹⁵⁸ Instead, FERC has said it is requiring the RTO markets (which are subject to its jurisdiction) to accept demand response bids on a non-discriminatory basis relative to traditional power supply bids pursuant to its authority to set just and reasonable rates under FPA section 205. To this extent, FERC has asserted jurisdiction over demand response in organized wholesale energy markets because DSM resources directly affect wholesale rates. Likewise, as outlined in Chapter 4 on market manipulation, FERC has taken enforcement actions against DSM providers who violate RTO market rules with respect to their DSM bidding activities.

The long-term status of the Commission’s regulation of DSM resources is currently uncertain as a result of a May 2014 decision by a three-judge panel of the U.S. Court of Appeals for the D.C. Circuit vacating Order No. 745 in its entirety.¹⁵⁹ The court decision was based on a finding that FERC had exceeded its authority because DSM services were retail in nature and subject to the exclusive jurisdiction of state regulatory commissions. While the court based its decision on jurisdictional grounds, it said it would have vacated the order even if found that FERC had jurisdiction because the Commission acted in an arbitrary and capricious manner by failing to fully consider arguments that the rules promulgated under Order No. 745 over-compensated DSM providers. A request for rehearing *en banc* was recently denied by the D.C. Circuit, but the court granted a stay of its order until December 2014 to allow FERC time to consider its options, including whether to appeal the decision to the Supreme Court.

F. SALES OF EMISSION ALLOWANCES AND RENEWABLE ENERGY CREDITS

In recent years, there has been substantial growth in the sale of electricity-related products which include emission allowances and renewable energy credits (“RECs”). In a 1994 case, the Commission responded to a request for guidance from the Edison Electric Institute (“EEI”) concerning the scope of FERC’s jurisdiction over sales or transfers of emissions allowances established under government regulations that capped the total amount of sulfur dioxide an entity may generate.¹⁶⁰ As with the current situation involving RECs, a market had developed in which generating entities buy, sell, or trade these emission allowances in order to meet their pollution control requirements. In *EEI*, the Commission found that under section 205 FERC has jurisdiction over the sale or transfer of an emissions allowance that was bundled together with the wholesale sale of electricity because including the allowance as part of the transaction could “affect” the rates a utility charges “for or in connection with” jurisdictional services. On the other hand, if the sale or transfer of an emissions allowance occurs

¹⁵⁸ See, e.g., *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 at P 30 (2010) (“Nevertheless, where an entity is only engaged in the provision of demand response services, and makes no sales of electric energy for resale, that entity would not own or operate facilities that are subject to the Commission’s jurisdiction and would not be a public utility that is required to have a rate on file with the Commission.”).

¹⁵⁹ *Elec. Power Supply Ass’n*, 753 F.3d 216.

¹⁶⁰ *Edison Elec. Inst.*, 69 FERC ¶ 61,344 (1994) (“*EEI*”).

independently of a wholesale sale of electricity, and independent of the wholesale rates a public utility charged its customers, FERC held that its jurisdiction would not attach.

The Commission recently adopted essentially the same policy framework for RECs, stating that the sale of RECs bundled with wholesale power is subject to FERC's jurisdiction under section 205.¹⁶¹ The Commission concluded that its section 205 jurisdiction extends over the wholesale energy portion of the transaction, as well as the REC portion of a bundled transaction, regardless of whether the contract price was explicitly allocated between the energy and REC products. The Commission further ruled that, if the prices paid for wholesale power and RECs are negotiated as a package in a "bundled" transaction, it has jurisdiction over the sale of RECs even if the sale of RECs and the power sale are the subject of separate agreements. Conversely, the Commission found that when an unbundled REC transaction is independent of a wholesale electricity transaction, the unbundled REC transaction cannot affect wholesale electricity prices, and the charge for the unbundled RECs is not subject to FERC's section 205 jurisdiction as a charge in connection with a wholesale sale of electricity.

¹⁶¹ *WSPP Inc.*, 139 FERC ¶ 61,061 (2012).

Chapter 15

FPA Section 305: Prohibition on Personal Dealing and Rules on Interlocking Directorates

KATHRYN KAVANAGH BARAN

Section 305 of the Federal Power Act reflects Congressional concern over conflicts-of-interests for officers or directors of public utilities.¹ Each sub-part of section 305 addresses the potential for individuals to engage in self-dealing that could prove harmful to the public interest. The prohibitions of section 305 run to the individual person as opposed to the public utility corporate entity. That said, it is in the best interests of each public utility to ensure that its officers and directors are in full compliance with these somewhat obscure rules.

Subsection (a) of section 305 bars any individual who serves as an officer or director of a public utility from receiving personal benefits from the issuances of securities of the public utility. This subsection also forbids individuals serving as an officer or director of a public utility from participating “in the making or paying of any dividends of such public utility from any funds properly included in capital account.”²

Subsection (b) of section 305 and Part 45 of the regulations issued by FERC implementing that subsection make it “unlawful” for any individual to serve concurrently as an officer or director of a public utility and as an officer or director of certain other specified entities, *unless* the Commission previously has authorized that individual to hold such positions.³ The three specific types of “305(b) interlocks” that require prior FERC approval are those where an individual serves as an officer or director of (a) more than one public utility, including affiliated public utilities; (b) a public utility and a bank or firm that is authorized to underwrite or participate in the marketing of securities of a public utility; or (c) a public utility and a company supplying electrical equipment to that public utility.⁴

¹ The FPA and the Public Utility Holding Company Act of 1935 (now repealed) were enacted as separate titles of the Public Utility Act of 1935. Pub. L. No. 74-333, ch. 687, tit. II, 49 Stat. 803, 838-63 (1935) (codified as amended at 16 U.S.C. §§ 791a-828c) (FPA); *id.* tit. I, 49 Stat. at 803-38 (previously codified as amended at 15 U.S.C. §§ 79a-79z-6) (PUHCA 1935). The FPA established federal regulation of the rates, practices and operations of electric utilities operating in interstate commerce; PUHCA 1935 was enacted to prevent financial abuses among public-utility holding companies, their subsidiaries and affiliates.

² 16 U.S.C. § 825d(a).

³ *Id.* § 825d(b); 18 C.F.R. pt. 45.

⁴ 16 U.S.C. § 825d(b). The need for an individual to obtain FERC authorization before serving concurrently as an officer or director of a public utility and as an officer or director of a firm authorized to

Subsection (c) of section 305 and Part 46 of FERC’s regulations implementing that subsection impose mandatory annual reporting requirements for broad categories of individuals who hold an officer or director position with a public utility and also serve as an officer or director with any of the entities enumerated in section 305(c)(2).⁵ The list of entities relevant to the reporting obligations in section 305(c) is broader than the three categories of positions that require prior approval under section 305(b). In addition to the reporting requirement for individuals to disclose these “305(c) interlocks,” subsection (c) requires that each public utility annually publish a list of the top 20 purchasers of electric energy sold by each public utility.⁶

I. LEGAL REQUIREMENTS

A. OFFICIALS DEALING IN SECURITIES—SECTION 305(A)

Section 305(a) states,

It shall be unlawful for any officer or director of any public utility to receive for his own benefit, directly or indirectly, any money or thing of value in respect of the negotiation, hypothecation, or sale by such public utility of any security issued or to be issued by such public utility, or to share in any of the proceeds thereof, or to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account.⁷

Section 305(a) encompasses two distinct prohibitions which stem from the same goal of preventing “corporate officials [from] raiding corporate coffers for their personal financial benefit.”⁸ The first restriction in section 305(a) prohibits an officer or director of a public utility from reaping financial gains from his or her participation in any negotiations involving security issuances by that public utility. The second restriction prohibits an officer or director of a public utility from participating in the payment of dividends of that public utility out of “funds properly included in capital account.”

The Commission’s guidance regarding section 305(a) is extremely limited. To our knowledge, the Commission has never initiated an enforcement inquiry with regard to section 305(a) of the FPA, nor has it promulgated regulations to implement that provision. Commission guidance on these matters is primarily provided through declaratory orders issued in response to parties requesting a finding that section 305(a) will not apply to a specific set of facts and circumstances.

underwrite public utility securities was amended in 1999 by the enactment of statutory safe harbors. See *infra* note 108 and accompanying text.

⁵ 16 U.S.C. § 825d(c).

⁶ *Id.* § 825d(c)(2)(D).

⁷ *Id.* § 825d(a).

⁸ See *Citizens Utils. Co.*, 84 FERC ¶ 61,158 at 61,864-65 (1998) (“*Citizens*”).

1. *Prohibiting Personal Benefits From Security Issuances*

We are aware of no Commission precedent enforcing the first prohibition set forth in section 305(a) of the FPA, that is, when an officer or director of a public utility reaps benefits that might arise from his or her participation in any negotiations involving security issuances for that public utility. The applicability of this restriction was discussed tangentially in a proceeding under section 204 of the FPA, where Black Hills Power and Light Company (“Black Hills”) sought authorization to issue and sell shares of common stock to executives and key employees under a Restricted Stock Option Plan approved by the Black Hills’ stockholders.⁹ In that proceeding, the Commission denied the requested section 204 authorization on the basis that the applicant had not made the necessary showing that the issuance of the securities would not impair the company’s financial integrity or its ability to perform its public utility responsibilities.¹⁰ In writing separately, one Commissioner vigorously argued that all such stock options are completely forbidden by the provisions of section 305(a) of the FPA which “preclude[s] utility officials from receiving a benefit on account of any funds properly included in the utility[y’s] capital account.”¹¹ On rehearing, the Commission dismissed the section 305(a) argument with two brief sentences: “We are not of the opinion that executive stock options are prohibited by Section 305(a) of the Act which makes it unlawful for officers and directors to benefit from the sale of securities. A public utility is free to apply for approval of such a stock issue if it believes that its proposal can be justified under section 204(a).”¹² Unfortunately, that snippet of Commission dicta is hardly illuminating.

We can also look for guidance to section 12 of the Natural Gas Act, a provision virtually identical to section 305(a) of the FPA.¹³ As with section 305(a) of the FPA, “[t]he purpose of section 12 [of the NGA] is to codify the fiduciary duty of officers and directors of a natural-gas company to shareholders and the public and to diminish potential conflicts of interests.”¹⁴ The Commission discussed the NGA section 12 prohibition in *Inexco*.¹⁵ There, a natural gas

⁹ *Black Hills Power & Light Co.*, 28 FPC 1121 (1962), *reh’g denied*, 31 FPC 1605 (1964).

¹⁰ 31 FPC 1605 at 1611 (quoting *Pac. Power & Light Co.*, 27 FPC 623 at 626 (1962)); *see also Black Hills Power & Light Co.*, 28 FPC 1121 at 1124-25.

¹¹ *Id.* at 1125 (referring to Commissioner Morgan’s concurring opinion, *id.* at 1126-34).

¹² 31 FPC 1605 at 1611.

¹³ Section 12 of the NGA provides,

It shall be unlawful for any officer or director of any natural-gas company to receive for his own benefit, directly or indirectly, any money or thing of value in respect to the negotiation, hypothecation, or sale by such natural-gas company of any security issued, or to be issued, by such natural-gas company, or to share in any of the proceeds thereof, or to participate in the making or paying of any dividends, other than liquidating dividends, of such natural-gas company from any funds properly included in capital account.

15 U.S.C. § 717k.

¹⁴ *Lester Pollack*, 48 FERC ¶ 61,053 at 61,285 (1989) (citing, *inter alia*, *Inexco Oil Co.*, 17 FERC ¶ 61,310 (1981) (“*Inexco*”)).

¹⁵ 17 FERC ¶ 61,310.

company petitioned the Commission to issue a declaratory order as to remove uncertainty regarding the applicability of section 12 of the NGA to the company's officer and directors. In denying the petition, the Commission went further and determined that a specific director of a natural gas company had in fact violated section 12 of the NGA by receiving compensation as an officer of the underwriting firm that handled the issuance of a security offering. The Commission went on to conclude, however, that "enforcement action is not warranted in this matter."¹⁶ Four years later, the Commission vacated its finding of a violation, stating that the petitioners had requested a general clarification of section 12 and, instead, FERC had *sua sponte* found that the one director had violated the provision, a finding that was not supported by the record.¹⁷ Since the *Inexco* orders, the Commission has been silent as to whether it would be unlawful for an officer or director of a public utility to receive compensation as an officer or director of a bank or an underwriter of a public utility security offering.¹⁸

Given the vague meaning of FPA section 305(a) and the lack of precedent as to its scope, we recommend that any compensation received by an officer or director of a public utility for service with an entity that is authorized to underwrite or market public securities be (a) transparent, (b) calculated on the same basis as the compensation provided to comparable officers or directors, and (c) not in any way based upon, tied to, or contingent upon, the public utility's transactions with the financial entity. We would advise further that such a director recuse herself from any matters that concern the public utility's selection of an underwriter of securities to avoid any possible appearance of a conflict of interest. We note, however, that given the absence of any viable case law with regard to this question, a petition for declaratory order would be the mechanism for obtaining absolute certainty with regard to FERC's view of this aspect of how section 305(a) might be applied to particular facts.

2. *Prohibiting Payment of Dividends From Capital Account*

The meaning of the second part of section 305(a) is opaque as well. As noted, we have found no case law enforcing section 305(a) and none of the Congressional committee reports included an explicit statement or explanation of the legislative intent behind the provision.¹⁹ It was not until more than six decades after enactment that the phrase "or to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account" was interpreted by the Commission. In *Citizens*, the Commission analyzed the provision and concluded:

¹⁶ *Id.* at 61,611.

¹⁷ *Inexco*, 34 FERC ¶ 61,066 (1986).

¹⁸ Notably, the 1999 amendments to section 305(b) of the FPA, discussed below, provided four expansive safe harbors by which an officer or director of a public utility may serve as an officer or director of an entity authorized to underwrite or market securities of public utilities without needing prior authorization from FERC. None of the safe harbors require an officer or director qualifying for one of the safe harbors to forgo compensation from the financial institution for his or her service.

¹⁹ See *Citizens*, 84 FERC ¶ 61,158 at 61,864 (citing H.R. Rep. No. 74-1903, at 75 (1935); H.R. Rep. No. 74-1318, at 8, 31 (1935); S. Rep. No. 74-621, at 17-18, 53 (1935)).

We can . . . glean insight into Congress' intent from noting the practices that led to passage of the legislation. For example, a Federal Trade Commission report to the Senate and the Report of the National Power Policy Committee on Public-Utility Holding Companies, submitted to the Senate Committee on Interstate Commerce by the President describe the practices: that sources from which cash dividends were paid were not clearly identified and that holding companies had been paying out excessive dividends on the securities of their operating companies. A key concern, thus, was corporate officials raiding corporate coffers for their personal financial benefit.²⁰

Beginning with this 1998 case, the Commission consistently has interpreted the restriction in section 305(a) regarding "dividends . . . from any funds properly included in capital account" as prohibiting a dividend payment from sources other than the traditional retained earnings where such payment (a) does not clearly identify the sources from which dividends are to be paid; (b) is excessive; or (c) reflects "corporate officials raiding corporate coffers for their personal financial benefit."²¹ In short, the Commission repeatedly has explained that the purpose of section 305(a) is to preclude any payment of dividends that would either harm the financial health of the public utility or unjustly enrich "corporate officials."²²

The Commission's interpretations that section 305(a) does not bar a public utility from paying dividends from sources other than retained earnings are typically provided in response to a public utility having petitioned the Commission for a declaration as to the scope of section 305(a) with regard to certain specific facts.²³ Section 305(a) case law generally falls into two broad categories: mergers and intra-corporate restructurings, both of which are discussed below. Notably, the Commission does not grant a "waiver" or an "exception" to the statutory prohibitions of section 305(a). Rather, given the facts and circumstances, the Commission may conclude that section 305(a) does not act as an absolute bar to the proposed distribution because it is not the type of dividend payment which section 305(a) was meant to address. In other words, the declarations received by the petitioners are not required by law in order to *authorize* the transaction but rather are sought out of an abundance of caution, given the vagueness of the statutory language of section 305(a).

²⁰ *Id.* at 61,864-65 (citing congressional materials and cases).

²¹ *Id.*; *see also, e.g., Delmarva Power & Light Co.*, 91 FERC ¶ 61,043 at 61,158-59 (2000).

²² *See, e.g., Entergy Gulf States, Inc.*, 118 FERC ¶ 61,271 (2007) (finding concerns underlying section 305(a) are not present and that the proposed dividend payment from a capital account is not barred by section 305(a)); *see also Cincinnati Gas & Elec. Co.*, 115 FERC ¶ 61,250 (2006) (same); *Exelon Generation Co.*, 114 FERC ¶ 61,317 (2006) ("*Exelon Generation I*") (same); *Entergy La., Inc.*, 114 FERC ¶ 61,060 (2006) (same); *Pub. Serv. Co. of N.M.*, 93 FERC ¶ 61,213 (2000) (same); *New England Power Co.*, 89 FERC ¶ 61,266 (1999) (same).

²³ *See, e.g., cases cited supra* note 22.

3. *Payment of Dividends From Capital Account Declaratory Orders*

a. *Merger Cases and Related Accounting*

One category of the section 305(a) declaratory order case law includes fact-patterns in which an accounting event, such as that associated with a merger, results a public utility's retained earnings being decreased, or even set to zero, and reestablished as miscellaneous paid-in capital.²⁴ Thus a transaction might result in a change in a utility's books such that funds previously recorded as retained earnings are recharacterized in a "capital" account. A typical order in this regard is *National Grid plc*.²⁵

The petition that prompted the Commission's order in *National Grid* concerned a merger by which KeySpan Corporation ("KeySpan") would become an indirect, wholly owned subsidiary of National Grid plc ("National Grid").²⁶ Upon National Grid's acquisition of KeySpan, the common equity of each of KeySpan's subsidiaries would be restated to reflect a portion of the purchase price.²⁷ As part of the restatement, any retained earnings that KeySpan's subsidiaries held before the transaction was recharacterized as "capital."²⁸ Because section 305(a) could be interpreted to mean that directors of public utilities may be absolutely precluded from deciding to pay dividends out of a capital account, including common equity, National Grid and KeySpan sought an order declaring that, after the merger, KeySpan's subsidiaries may pay dividends out of common equity funds to the extent that, before the merger, such funds had been classified as retained earnings.²⁹

The Commission concluded that, in these circumstances, section 305(a) did not bar the payment of dividends out of common equity.³⁰ The Commission reasoned:

The concerns that underlie section 305(a) are that dividends would be paid from sources that were not clearly identified, that holding companies would pay excessive dividends on utility stock, and that corporate officials would raid corporate coffers for their personal financial benefit.

²⁴ *Exelon Generation Co.*, 144 FERC ¶ 61,181 at PP 4, 20 (2013) ("*Exelon Generation II*") (as part of a merger, funds recorded as retained earnings were reestablished on the books as paid-in capital). Under the purchase method of accounting, if the acquiring company's purchase price exceeds the fair market value of the acquired company's identifiable net assets, the excess is recorded as goodwill on the acquiring company's balance sheet. The goodwill and any other corresponding adjustments to the values of assets and liabilities of the acquired company on the acquiring company's balance sheet generally are assigned or "pushed down" to the balance sheets of the acquired company or the acquired company's subsidiaries (referred to as "push-down" accounting). *Id.* at P 4 n.15.

²⁵ 117 FERC ¶ 61,080 (2006).

²⁶ *Id.* at P 1.

²⁷ *Id.* at P 79.

²⁸ *Id.*

²⁹ *Id.*

³⁰ *Id.* at P 83.

Those concerns are not present here. First, Applicants have clearly identified the source from which the dividends would be paid. Second, there is nothing to indicate that the dividends would be excessive; Applicants have represented that the dividends will not exceed the amounts recorded as retained earnings prior to the merger, and they commit to pay dividends out of common equity only up to these amounts.

Under the circumstances of this case, we will grant the petition and find that section 305(a) does not bar the payment of dividends out of common equity as described above. In addition to the commitments that Applicants identified, and consistent with prior precedent, Applicants may not pay dividends out of capital if the equity of KeySpan's public utilities subsidiaries, as a percentage of total capital, would fall below thirty percent.³¹

b. Restructuring Cases

A second broad category of section 305(a) case law addresses situations involving an intra-corporate restructuring. *ALLETE, Inc.*, is illustrative of this issue,³² as is *ITC Holdings Corp.*³³

The corporate structure of ALLETE, Inc. ("ALLETE") included a public utility as well as a subsidiary full-service automotive vehicle re-marketing company (the "auto company"). ALLETE proposed to separate the auto company from its regulated utility operations through a distribution of all of the common stock that ALLETE held in the auto company. The distribution was to be accomplished as a tax-free stock dividend to ALLETE's shareholders, who were to receive a proportionate share of the common stock of the auto company based on their relative ownership of ALLETE stock.³⁴ Immediately following the distribution, the interests of ALLETE's stockholders in the auto company and in ALLETE's other businesses would be the same as they were immediately prior to the distribution. However, those interests would be represented by stock holdings in two separate publicly-traded companies instead of one.³⁵ The common stock of the auto company would be listed on the New York Stock Exchange and would

³¹ *Id.* at PP 81-83 (internal citations and footnote omitted). The reference to the 30 percent equity ratio reflects the Commission's interpretation that section 305(a) concerns whether the dividends paid out of a capital account might be excessive. In this regard, the Commission typically has accepted the commitment of petitioners to maintain a minimum equity to total capital ratio of at least 30 percent. *See, e.g., Cincinnati Gas & Elec. Co.*, 115 FERC ¶ 61,250 at P 13; *Exelon Corp.*, 109 FERC ¶ 61,172 at P 8-9 (2004). In the same vein, the Commission also has accepted the commitment of petitioners to limit the dividend payments to the amount that would have been reflected in retained earnings absent the accounting event that caused the retained earnings to be reflected as zero. *Exelon Generation I*, 114 FERC ¶ 61,317 at P 14.

³² 107 FERC ¶ 61,041 (2004).

³³ 143 FERC ¶ 61,256 (2013).

³⁴ *Id.* at P 4.

³⁵ *Id.*

be publicly traded independently of the stock of ALLETE.³⁶ ALLETE sought a Commission ruling that its proposed distribution of common stock of the auto company to ALLETE's shareholders was not prohibited by section 305(a) of the FPA, even though the stock distribution would not be made from retained earnings.

The Commission found that the proposed transaction was not barred by section 305(a) of the FPA because the source of ALLETE's proposed distribution had been clearly identified and nothing indicated that the distribution was excessive or preferential, but simply represented the value of ALLETE's investment in the auto company.³⁷ Moreover, the Commission stated, the separation of the auto company, is "less like a payment of dividends than it is a corporate restructuring with a one-time distribution of property."³⁸

Similarly, in *ITC Holdings*, the Commission concluded that the prohibitions of section 305(a) would not act as a bar to the initial steps of a proposed transaction that would be undertaken in order to achieve (a) the separation of the Entergy Operating Companies' transmission assets and liabilities into transco subsidiaries, (b) the consolidation of those subsidiaries under an intermediate holding company, and then (c) the distribution of the membership units in the subsidiaries to Entergy Corporation.³⁹

The facts in *FirstEnergy Corp.*,⁴⁰ are somewhat different from those in *ITC Holdings* and *ALLETE*, yet the Commission was consistent in its analysis and conclusion. FirstEnergy Corporation ("FirstEnergy") held a number of direct and indirect wholly owned subsidiaries (the "Operating Companies").⁴¹ FirstEnergy's principal source of revenue for the payment of dividends to its shareholders and for other expenses, including payment debt costs, was the receipt of dividends from its direct and indirect, wholly owned subsidiaries, including the Operating Companies.⁴²

FirstEnergy planned to have the Operating Companies pay dividends to FirstEnergy out of paid-in capital in order to achieve two principle purposes. First, according to FirstEnergy, mergers and associated accounting policies, sales and transfers of utility assets, recent corporate restructurings, and capital contributions had resulted in inconsistent capital structures among the Operating Companies.⁴³ In this regard, issuing dividends out of paid-in capital would enable the Operating Companies to realign their capital structures, and "to establish and maintain consistent

³⁶ *Id.*

³⁷ *Id.* at PP 9-12.

³⁸ *Id.* at P 11.

³⁹ 143 FERC ¶ 61,256 at PP 171, 179-81; *see also Upper Peninsula Power Co.*, 148 FERC ¶ 61,133 at P 53 (2014) (holding section 305(a) of the FPA does not act as a bar to proposed internal corporate restructuring); *Ameren Corp.*, 131 FERC ¶ 61,240 at P 36 (2011) (same).

⁴⁰ 115 FERC ¶ 61,269 (2006).

⁴¹ *Id.* at PP 1-2.

⁴² *Id.* at P 2.

⁴³ *Id.* at P 3.

and rational capitalization practices,” according to FirstEnergy.⁴⁴ Also, FirstEnergy explained, certain of the Operating Companies had equity that is “far in excess of their long-term debt and is higher than these companies need to retain investor confidence and attract new capital.”⁴⁵

As a second matter, FirstEnergy itself had approximately \$4.3 billion in unsecured debt outstanding, including \$1 billion of Senior Notes coming due in the near future.⁴⁶ FirstEnergy maintained that its principal source of revenue was dividends from its subsidiaries; however, the amount of retained earnings held by the Operating Companies would be insufficient to provide the funds FirstEnergy needed to retire this upcoming debt payment.⁴⁷ In addition, FirstEnergy stated that creditors prefer to hold debt issued by revenue-producing entities, such as the Operating Companies, rather than their corporate parents, and that the “use of funds of the Operating Companies to retire FirstEnergy’s debt [would] help to reduce overall debt costs and reduce the impact of debt service on ratepayers.”⁴⁸

The Commission concluded that “the concerns underlying section 305(a) of the FPA are not present in the circumstances of this transaction.”⁴⁹

FirstEnergy has clearly identified the source from which payment will be made; each Operating Company that has paid-in capital in excess of its needs will pay dividends from Account 207 or Accounts 208 to 211, depending on each company’s accounting policies. In addition, there is nothing to indicate that any dividends paid will be excessive; each of the Operating Companies will only pay dividends out of paid-in capital so long as its equity ratio (without consideration of any retained earnings that may exist on its books) is and will remain above 35 percent. Finally, the proposed dividends will not have an adverse effect on the value of shareholders interests. The shareholders of the Operating Companies will have the same percentage ownership interests in the Operating Companies following the payment of dividends.

For these reasons, and under the circumstances of this case, we will grant the petition and find that section 305(a) of the FPA is not a bar to the payment of dividends from paid-in capital as described above.⁵⁰

⁴⁴ *Id.*

⁴⁵ *Id.*

⁴⁶ *Id.* at P 4.

⁴⁷ *Id.*

⁴⁸ *Id.* at P 5.

⁴⁹ *Id.* at P 11.

⁵⁰ *Id.* at PP 14-15 (internal citations omitted).

4. *Applicability of 305(a) to Non-Traditional Public Utilities Such as Market-Based Rate Entities*

In 2013, the Commission was presented with a new question for its analysis of whether certain distributions were of the type that section 305(a) was meant to prohibit. *Exelon Generation II*⁵¹ involved a merger-related bookkeeping event similar to those discussed above, which resulted from the merger of Exelon Corporation and Constellation Energy Group, Inc. Applicants sought, and were granted, a declaratory order that section 305(a) did not act as a bar to the payment of dividends out of miscellaneous paid-in capital on the traditional grounds that: (1) the source of the dividends will be clearly identified; (2) the dividends will not be excessive; and (3) the issuance of such dividends will not harm shareholders.⁵²

However, Applicants also requested a declaration that, as a matter of public policy, section 305(a) of the FPA does not bar the distribution of funds included in capital accounts of those non-traditional public utilities that have market-based rate authority, do not have captive customers, and do not provide transmission or distribution services. Applicants argued that the concerns underlying the enactment of section 305(a) of the FPA (include holding companies paying out excessive dividends on the securities of their operating companies and corporate officials raiding corporate coffers for their personal benefit) are not present in those situations.⁵³ In cases involving dividend payments by such non-traditional public utilities, Applicants argued that the distribution of dividends would not have any adverse effect on the financial integrity of any affiliated traditional public utility, its customers, or the ability of state commissions to protect public utility customers.⁵⁴ Applicants reasoned that it is appropriate to apply a different standard of oversight to such non-traditional public utilities for the same reasons such entities are granted (1) waivers from the requirement to maintain their books in accordance with the Uniform System of Accounts (“USofA”); and (2) blanket authorizations under section 204(a) to issue securities.⁵⁵ Applicants argued further that it would be anomalous for the Commission to grant a non-traditional public utility (e.g., a merchant generator or power marketer) waiver from the requirement to maintain its books in accordance with the USofA, as well as a blanket authorization under section 204(a) to issue securities, while, at the same time, under section

⁵¹ 144 FERC ¶ 61,181.

⁵² *Id.* at PP 20-21.

⁵³ *Id.* at P 9. Applicants originally had included a fourth criteria, that the public utility does not serve as a designated “provider of last resort” for any class of customers, but later agreed with comments filed by Electric Power Supply Association (“EPSA”) that this limitation should be eliminated. *Id.* at P 15.

⁵⁴ *Id.* at P 9.

⁵⁵ *Id.* at P 10 (citing *Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*, Order No. 697, FERC Stats. & Regs. ¶ 31,252, at PP 984, 999, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh’g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055, *order on reh’g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh’g*, Order No. 697-C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh’g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305, *order on clarification*, 131 FERC ¶ 61,021 (2010), *reh’g denied*, 134 FERC ¶ 61,046 (2011), *aff’d sub nom. Mont. Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012)).

305(a), limit the accounts from which the public utility may pay dividends.⁵⁶ The trade association of power suppliers, EPSA, filed comments in support of the requested declaration, stating that factors relevant to Exelon Generation’s petition “are broadly applicable to certain classes of public utilities, such as merchant generators and power marketers”⁵⁷ The Commission acknowledged the “strong case” made by Exelon Generation and EPSA but declined to issue the broad declaration that had been requested.⁵⁸

Subsequently, on July 17, 2014, the Commission adopted a statement of policy that section 305(a) of the FPA should not be construed as a bar to the payment of dividends from funds included in capital accounts by any public utility that has a market-based rate tariff on file with the Commission, does not have captive customers, and does not provide transmission or local distribution services.⁵⁹ The Commission reasoned that the “payment of dividends from capital account by such public utilities does not appear to implicate the concerns underlying the enactment of FPA section 305(a), and we issue this policy statement in order to eliminate a regulatory burden otherwise applicable under FPA section 305(a) to such public utilities.”⁶⁰

B. INTERLOCKING DIRECTORATES AND REQUIRED AUTHORIZATION – SECTION 305(B)

Section 305(b) states, in pertinent part,

[I]t shall be unlawful for any person to hold the position of officer or director of more than one public utility or to hold the position of officer or director of a public utility and the position of officer or director of any bank, trust company, banking association, or firm that is authorized by law to underwrite or participate in the marketing of securities of a public utility, or officer or director of any company supplying electrical equipment to such public utility, unless the holding of such positions shall have been authorized by order of the Commission, upon due showing in form and manner prescribed by the Commission, that neither public nor private interests will be adversely affected thereby. . . .⁶¹

As noted above, it is the *individual*, not the public utility, who bears the burden of obtaining from the Commission authorization to hold interlocking positions otherwise proscribed by section 305(b).⁶² That said, it is only prudent that each public utility assist each of its officers and directors to be in full compliance with the restrictions as well as any reporting requirements.⁶³ Moreover, there is no predicting how the individuals’ interlock compliance, or

⁵⁶ *Id.* at P 10.

⁵⁷ *Id.* at P 12.

⁵⁸ *Id.* at P 22.

⁵⁹ *Payment of Dividends from Funds Included in Capital Accounts*, 148 FERC ¶ 61,020 (2014).

⁶⁰ *Id.* at P 25.

⁶¹ 16 U.S.C. § 825d(b)(1).

⁶² *John E. Bryson*, 56 FERC ¶ 61,026 at 61,100 (1991).

⁶³ At least one former FERC Chairman, then Commissioner, has expressed the same sentiment: “[Although] this prohibition applies to the individual . . . I personally hold the utility responsible. I

non-compliance, may play out. Non-compliance discovered in an audit could reflect unfavorably on the public utility. Compliance with the interlock rules has proven effective in successfully rebutting accusations raised by litigants in other contexts.⁶⁴

Section 305(b) is a bright-line rule.⁶⁵ The Commission's analysis has little to no interest as to whether the individual who holds interlocking positions has (or does not have) knowledge of, involvement in, or influence over transactions by either of the interlocking entities.⁶⁶ The bottom line is that FERC is concerned with future opportunities for mischief that have the inherent *potential* to occur because of the concurrent relationships.⁶⁷

In granting the authorization requested, FERC must determine that the individual's proposed service as officer or director for the multiple entities will not adversely affect public or private interests.⁶⁸ A key part of the rule is that authorizations must be obtained by the individual *before* he or she is elected or begins to serve as an officer or director of the interlocking entities. If a 305(b) interlock is created by a person holding any of the enumerated positions in that section without the Commission's *prior* authorization, the interlock is considered to be "unlawful" *ab initio*.⁶⁹ This is made clear in the Commission's regulations,⁷⁰ and in its case law.⁷¹ Prior to 2005, the Commission's regulations had stated that an application

believe that knowing the [FPA], the utility should undertake due diligence to ensure that no potential member of the Board is offered a position with the Board unless there is no conflict of interest. This is a duty that the utility owes not only to its consumers but also to its shareholders." See Transcript of 856th Comm'n Open Meeting at 63:17–64:4 (Apr. 14, 2004) ("Transcript") (statement of Comm'r Kelly).

⁶⁴ For example, the petitioner in *Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246 (1951), alleged that certain rates and charges were fraudulent and unlawful due to the existence of interlocking directorates. There, the Supreme Court eventually held that, because the interlocks had received Commission approval, "[t]he effect of the approval is to exempt the relationship from the ban of the Act and remove it from any presumption of fraud that might be thought to arise from its mere existence." *Id.* at 252-53.

⁶⁵ Section 305(b) is considered to be "prophylactic in nature." *Hatch v. FERC*, 654 F.2d 825, 832 (D.C. Cir. 1981).

⁶⁶ See *id.* (stating that assurances that no abuses will occur, or that past transactions between the companies have been *de minimus*, are considered immaterial when analyzing the interlock).

⁶⁷ See *James S. Pignatelli*, 111 FERC ¶ 61,496 at P 1 (2005) (stating that the "underlying purpose of section 305(b) . . . [is] the *potential* for adverse effects on public or private interests" (emphasis added)).

⁶⁸ 16 U.S.C. § 825d(b); *Pignatelli*, 111 FERC ¶ 61,496 at P 9.

⁶⁹ *Id.* at P 13.

⁷⁰ *Comm'n Authorization to Hold Interlocking Positions*, Order No. 664, FERC Stats. & Regs. ¶ 31,194 at P 30 (2005), *order denying reh'g and stay*, 114 FERC ¶ 61,142 (2006) (codified at 18 C.F.R. pt. 45).

⁷¹ See *Douglas R. Oberhelman*, 109 FERC ¶ 61,332 at 62,586 (2004) (Kelliher, Comm'r, concurring) ("It is hard to see how this Commission can apply section 305(b) in a prophylactic manner if it chooses to do so 'after-the-fact.' For these reasons, I believe that this Commission has a duty under the statute to find late filers in violation of section 305(b). . . . [T]he plain language of the statute governs.").

for section 305(b) approval could be made *after* the election or appointment that created the interlock, so long as it was within 30 days of the event.⁷² Now, however, “the Commission will automatically deny all late-filed applications for authorization to hold interlocking positions.”⁷³ This policy has the potential for harsh consequences for interlocking officers and directors. For this reason having a solid compliance program in place helps to ensure that advance authorizations are sought and received.

It is worth noting that certain interlocks can be created unintentionally and even unknowingly. For example, an individual may sit on the board of a public utility and may also sit on the board of an entity that is a supplier of electrical equipment. Such an interlock would not fall within the jurisdiction of section 305(b) and pre-authorization would not be required, *unless and until* the electrical equipment supplier provides or supplies electrical equipment to that public utility. Similarly, an individual may be an officer of a public utility and officer of an affiliated entity which, as yet, is not a public utility, but later becomes a public utility, for example, by virtue of obtaining market-based rate authority. Given the Commission’s harsh policy to deny after-the-fact requests for authorization once section 305(b) jurisdiction has attached, the Commission is receiving, and granting, precautionary requests for authorization to hold interlocking positions between a public utility and another entity on the possibility that an interlock under section 305(b) may develop in the future.⁷⁴ Of course, in analyzing these precautionary requests, the Commission applies its underlying policies regarding interlocks. For example, a request for authorization of an interlock between two unaffiliated public utilities is likely to be denied, as is a request for authorization between a public utility and a supplier of electrical equipment where there is evidence that the supplier of electrical equipment is likely in the future to sell an amount of electrical equipment to the public utility that is more than *de minimis*.

1. Positions Affected by the Pre-Approval Interlocking Directorate Rule

The pre-approval interlocking directorate rule is directed at individuals who are board members or officers (any position that is “invested with executive authority”⁷⁵) who wish to hold positions with any of the three types of entities discussed in the following paragraphs.⁷⁶ Notably,

⁷² 18 C.F.R. § 45.3 (2005).

⁷³ Order No. 664, FERC Stats. & Regs. ¶ 31,194 at P 30. On the other hand, if the Commission fails to act within 60 days of the filing of a completed application for authorization to hold interlocking positions, the application will be deemed granted. *Id.* at P 38.

⁷⁴ *Philip R. Lochner, Jr.*, 115 FERC ¶ 62,092 (2006); *Harry J. Pearce*, 115 FERC ¶ 62,263 (2006).

⁷⁵ The scope of the rule is not governed by job titles, but rather by the positions being “invested with executive authority.” 18 C.F.R. § 45.2(a). *See, e.g., Walter F. Torrance, Jr.*, 29 FERC ¶ 61,288 at 61,589 (1984) (concluding that an “Assistant Secretary is also an officer for purposes of Section 305(b)” because the “broad language” of the Commission’s regulations “is designed to encompass any type of corporate officer”); *see also id.* (citing *Margaret M. Stapleton*, 27 FERC ¶ 61,286 (1984) (concluding that “a ‘Second Vice President,’ however junior, was an ‘officer’ within the scope of Section 305(b)”).

⁷⁶ 18 C.F.R. § 45.2(a).

the scope is broad, and the rule extends to partners in any “corporation” which is defined as any “organized group of persons, whether incorporated or not.”⁷⁷

a. Interlocks Between a Public Utility and Another Public Utility

(i) Interlocks Between Non-Affiliated Public Utilities Are Strongly Disfavored by FERC

Interlocking positions between *unaffiliated* public utilities generally are considered *not* to be “an acceptable option.”⁷⁸ The Commission finds interlocks between unaffiliated public utilities to be “just such relationships which [section 305(b) of] the [FPA] seeks to curb.”⁷⁹ These situations, the Commission reasons, may result in competitive abuses because two unaffiliated public utilities could compete: (a) to serve existing customers; (b) to bid for services; or (c) to attract new customers.⁸⁰ The Commission has even rejected requests to grant a conditioned limited-authorization of this type of interlock where the applicant would be quarantined from certain decision-making.⁸¹ In making that policy choice, the Commission concluded that it is neither possible to fashion effective, enforceable restrictions to limit an individual’s participation in the business decisions of potentially competing companies, nor would it be beneficial for the public utilities to have to operate under such constraints.⁸²

On rare occasion, FERC has found unique factors or “special circumstances” to justify authorizing individuals to hold interlocking positions with two unaffiliated public utilities, but those situations are *sui generis*.⁸³ So committed is the Commission’s disapproval of this type of dual service that it even denied an individual’s request for authorization to hold interlocking positions between one public utility and a geographically remote not-for-profit public utility that

⁷⁷ *Id.* n.1.

⁷⁸ See *Fernando de Arguero*, 145 FERC ¶ 61,207 at P 11 (2013) (“[T]he Commission regularly denies interlocks between two or more public utilities when the public utilities are not affiliated . . . because the holders of such interlocks would be ‘performing duties for potentially competing systems.’”); *Mary Anne Brelinsky*, 144 FERC ¶ 61,065 at PP 4, 11 (2013) (explaining the Commission’s policy to “den[y] interlocks between two or more public utilities when the public utilities are not affiliated” and denying application even though neither of the public utilities at issue was a “traditional public utility”); see also *Paul H. Henson*, 51 FERC ¶ 61,104 at 61,232 (1990) (“[I]nterlocks between unaffiliated public utilities would create potential conflicts of interest because the holders of such interlocks would be ‘performing duties for potentially competing systems.’” (citation omitted)).

⁷⁹ *Pignatelli*, 111 FERC ¶ 61,496 at P 14 (quoting *Willis C. Fitkin*, 7 FERC ¶ 61,291 at 61,626 (1979)).

⁸⁰ *Id.* at P 16.

⁸¹ *Id.*

⁸² *Id.* at P 17.

⁸³ See, e.g., *Cal. Power Exch. Corp.*, 103 FERC ¶ 61,001 at P 43 (2003) (finding special circumstances because interlocking directors were to provide expert guidance regarding wind-up matters prior to the CalPX dissolution).

is a Regional Transmission Organization.⁸⁴ In that case, the applicant, an executive at a public utility located in Arizona, had been unanimously selected by an independent nominating committee to be a director of the not-for-profit ISO New England Inc. (“ISO-NE”)⁸⁵ In addition, according to the application, the ISO-NE Code of Conduct already “provides effective protection against even the perception of the concerns that section 305(b) is designed to address.”⁸⁶ The Commission’s denial of the application suggests that the Commission, at least for now, will not take a more flexible approach with regard to proposed interlocks between unaffiliated public utilities, even where non-profit ISOs or RTOs are involved.

(ii) *Automatic Authorization for Certain Affiliated Public Utilities*

Although interlocks involving two *unaffiliated* public utilities are strongly disfavored, FERC will grant “automatic authorization” to an individual holding interlocking positions between two or more *affiliated* public utilities upon receipt of an “informational filing” that follows the requirements set forth in 18 C.F.R. § 45.9 of the Commission’s regulations.⁸⁷ The Commission created the automatic authorization option with the reasoning that, where public utilities are part of the same public utility holding company system: (a) a single entity, the holding company, already controls those utilities; (b) close federal and state regulation of holding companies and their subsidiary public utilities means that these interlocks would not impede regulation; (c) interlocking directorships within a holding company family could enable increased efficiency and economically sound operations; (d) case-specific approvals of these interlocks are not necessary to ensure full public disclosure; and (e) there have been no indications that holding of these types of interlocks has led to the types of abuses that section 305(b) was intended to address.⁸⁸ In these affiliate-approval cases, the specific test for whether the public utilities at issue have the necessary level of affiliation is whether the same holding company owns, directly or indirectly, that percentage of each utility’s stock (of whatever class or classes) which is required by each utility’s by-laws to elect directors.⁸⁹

⁸⁴ See *Pignatelli*, 111 FERC ¶ 61,496 at PP 18-19; accord *Robert G. Schoenberger*, 110 FERC ¶ 61,197 (2005).

⁸⁵ *Pignatelli*, 111 FERC ¶ 61,496 at PP 6-7.

⁸⁶ *Id.* at P 7.

⁸⁷ See *id.*; see also *Automated Authorization for Holding Certain Positions That Require Comm’n Approval Under Section 305(b) of the Fed. Power Act*, Order No. 446, FERC Stats. & Regs. ¶ 30,686 at 30,128 (1986) (“The Commission . . . eliminate[s] what it believes to be an unnecessary filing burden on certain categories of applicants . . . to hold interlocking positions which have traditionally been approved routinely because they present no potential threat to public or private interests within the meaning of the FPA.”); *Pignatelli*, 111 FERC ¶ 61,496 at P 13.

⁸⁸ *Pignatelli*, 111 FERC ¶ 61,496 at P 13 (citing Order No. 446, FERC Stats. & Regs. ¶ 30,686 at 30,129-30).

⁸⁹ See 18 C.F.R. § 45.9(a)(1). It appears that a sufficient level of affiliation may be established by the holding company owning a percentage interest in a public utility that permits the holding company to elect merely one director, rather than multiple directors, although the Commission has never specifically opined on the issue. See *Mary Anne Brelinsky*, Docket No. ID-5369-003, Informational Report (Aug. 9, 2013) (holding company owned sufficient membership interests in limited liability

The Commission's regulations also authorize interlocks between two or more public utilities if the public utilities are affiliated by virtue of one public utility owning, wholly or in part, the other and the "owned" public utility provides, as its primary business, transmission service or electric power to the "owner" public utility.⁹⁰ In these situations, the Commission reasons that (a) the "owned" public utilities are essentially partnerships of "owner" public utilities with specific control arrangements spelled out in the initial agreements; (b) the "owned" public utilities were created for the purpose of taking advantage of economies of scale and sharing the risks of financing, constructing, and operating facilities for the joint benefit of the "owner" public utilities; and (c) historically such interlocks had been approved routinely.⁹¹

Where the public utilities are affiliated, an individual may obtain the FERC's automatic authorization to hold the interlocking positions by filing with the Commission a completed "informational report."⁹² It is very important that the informational report be filed *before* the interlock is created, that is, before the individual is elected to, or begins performing any duties with, the second entity that would initiate the interlock.⁹³ That is, if a person is to be appointed to a position that will create an interlock on day *n*, we recommend the informational report be filed with FERC no later than day *n*-1. Once the informational filing has been made, that person is considered "authorized" to hold the positions addressed and will receive an "ID" docket number. Thereafter, if he or she assumes different, or even additional, positions of the same type with other public utilities within the same holding company system, he or she need not make any further informational filings for additional authorizations.⁹⁴ The annual Form 561 (discussed below) will reflect any changes in that individual's interlocks over the previous calendar year. *The annual Form 561 is not a substitute for an informational report and will not serve to trigger the automatic authorization contemplated by section 45.9 of the Commission's regulations.*

The officer or director must report to the Commission any material or substantial changes to the position or his or her holding of the position within 30 days of such change, pursuant to section 45.5 of the Commission's regulations.⁹⁵ This notice must be verified under oath and notarized.⁹⁶ Although the regulation language is rather unclear, the Commission intends that a "Notice of Change" need be filed only if an individual ceases to hold all positions authorized, not

affiliate to designate one of the managers). It also appears that the affiliation rules permitting automatic authorizations are not limited to companies that issue stock. *See id.* at 1 n.2.

⁹⁰ *Pignatelli*, 111 FERC ¶ 61,496 at P 13 (citing 18 C.F.R. § 45.9 (2004) and Order No. 446, FERC Stats. & Regs. ¶ 30,686).

⁹¹ *Id.* (citing Order No. 446, FERC Stats. & Regs. ¶ 30,686 at 30,131).

⁹² Order No. 664, FERC Stats. & Regs. ¶ 31,194 at P 23. The required contents of that report are set out at 18 C.F.R. § 45.9.

⁹³ Order No. 664, FERC Stats. & Regs. ¶ 31,194 at P 24 (codified at 18 C.F.R. § 45.9(b)).

⁹⁴ Order No. 446, FERC Stats. & Regs. ¶ 30,686 at 30,133 (codified at 18 C.F.R. § 45.9(b)).

⁹⁵ 18 C.F.R. § 45.5(b).

⁹⁶ *Id.* § 45.7.

merely if he or she is to assume a new position of the same type within the corporate family, which positions also would be pre-authorized under section 45.9(a)(3) of the regulations.⁹⁷

(iii) *All Public Utilities Are Within the Scope of the Rule, Including “Non-Traditional” Public Utilities with Market-Based Rate Authority*

In the past, the Commission typically waived the full requirements of Part 45 of its regulations (that is, the requirements to file for authorization to hold otherwise-prohibited interlocks) for those individuals who held executive positions with non-traditional public utilities that had authority to sell power at market-based rates.⁹⁸ FERC accepted “abbreviated” filings, giving essentially automatic authorization to hold interlocking positions in orders granting market-based rate authority.⁹⁹ FERC maintained ongoing jurisdiction to review its continued approval of the affected interlocks.¹⁰⁰

In Order 664, FERC discontinued its policy of granting these waivers.¹⁰¹ Individuals currently authorized to hold interlocking positions under the previous policy are not required to refile in order to continue to hold an *existing* interlocking position.¹⁰² However, if an individual assumes a different or additional interlocking position, the full complement of the Commission’s requirements under Part 45 must be met.¹⁰³

b. *Interlocks Between a Public Utility and a Firm Authorized to Underwrite Securities of a Public Utility*

Section 305(b) also prohibits an officer or director of a public utility from concurrently serving as an officer or director of a bank, trust company, banking association, or firm authorized to underwrite or participate in the marketing of public utility securities unless FERC determines that the dual service does not adversely affect private or public interests.¹⁰⁴ To be within the scope of the rule, a bank or company (or any member of its corporate family) need only be *authorized by law to underwrite securities*.¹⁰⁵ It is irrelevant whether the firm itself actively participates as a securities underwriter,¹⁰⁶ or actually underwrites securities to the particular public utility as to which the interlock arises. Significantly, the Commission has attributed the

⁹⁷ Order No. 446, FERC Stats. & Regs. ¶ 30,686 at 30,133.

⁹⁸ See generally Order No. 664, FERC Stats. & Regs. ¶ 31,194 at PP 32-34.

⁹⁹ *Id.*; see also, e.g., *Calpine Newark, LLC*, Docket Nos. ER04-831-000 and -001, at 3 (unpublished delegated letter order issued July 21, 2004).

¹⁰⁰ See, e.g., *San Manuel Power Co.*, 96 FERC ¶ 61,089 at 61,371, Ordering Para. (E) (2001).

¹⁰¹ Order No. 664, FERC Stats. & Regs. ¶ 31,194 at P 34.

¹⁰² *Id.* at P 36.

¹⁰³ *Id.*

¹⁰⁴ 16 U.S.C. § 825d(b).

¹⁰⁵ See *Norman Barker, Jr.*, 53 FERC ¶ 61,223 at 61,932 (1990).

¹⁰⁶ *Id.* at 61,932-33.

underwriting activities of a firm to its corporate parent and to its affiliates for purposes of establishing section 305(b) jurisdiction.¹⁰⁷

Section 305(b) was amended in 1999 to incorporate broad exceptions into the statute.¹⁰⁸ Today, prior authorization by FERC is not required for individuals to hold interlocking positions between a public utility and a bank or securities firm authorized to underwrite or participate in the marketing of public utility securities if *any one* of the following circumstances are present: (a) the bank, trust company, banking association, or firm is under consideration by the public utility to underwrite or participate in the marketing of securities of the public utility, and the person serving as an “insider” will not participate in any deliberations or decisions of the public utility regarding the selection; (b) the bank, trust company, banking association, or firm of which the person is an officer or director does not engage in the underwriting of, or participate in the marketing of, securities of the public utility of which the person holds the position of officer or director; (c) the public utility for which the person serves or proposes to serve as an officer or director selects underwriters by competitive procedures; or (d) the issuance of securities of the public utility for which the person serves or proposes to serve as an officer or director has been approved by all Federal and State regulatory agencies having jurisdiction over the issuance.¹⁰⁹

In short, now a person who meets at least one of the safe harbor conditions of section 305(b)(2)(B) falls outside of the scope of the interlock rule that otherwise would apply and he or she need not obtain FERC authorization to hold the interlocking positions.¹¹⁰ However, if a person does not meet one of the provided-for exceptions, his or her holding of an interlocking position would require advance Commission authorization in accordance with the statute and regulations.

c. Interlocks Between a Public Utility and a Company Supplying That Public Utility With Electrical Equipment

Section 305(b) prohibits an officer or director of a public utility from concurrently serving as an officer or director of any company supplying electrical equipment *to that public utility* unless FERC has authorized such an interlock after finding that the dual service does not adversely affect private or public interests.¹¹¹ Of the three types of interlocking relationships described by section 305(b), this is the only one triggered by a transaction between the two entities that would form the interlock.

¹⁰⁷ See *Kimberly J. Harris*, 149 FERC ¶ 61,025 at P 12 (2014) (citing *Frederick W. Mielke, Jr.*, 22 FERC ¶ 61,004, *reh'g denied*, 23 FERC ¶ 61,183 at 61,398 n.10 (1983); *Thomas Madison McDaniel, Jr.*, 24 FERC ¶ 61,026 (1983); *John H. Byrne*, 38 FERC ¶ 61,067 (1987)); see also *William T. Coleman, Jr.*, 19 FERC ¶ 61,270 at 61,524 (1982) (imputing the underwriting activities of a subsidiary to the parent “to ensure that persons otherwise required to seek Commission to hold proscribed interlocks do not evade this obligation through the fiction of separate corporate identities”).

¹⁰⁸ See Gramm-Leach-Bliley Financial Modernization Act, also known as the Financial Services Modernization Act of 1999, Pub. L. No. 106-102, § 737, 113 Stat. 1338, 1479 (1999).

¹⁰⁹ 16 U.S.C. § 825d(b)(2)(B).

¹¹⁰ See *James R. Lientz, Jr.*, 93 FERC ¶ 61,007 (2000).

¹¹¹ 16 U.S.C. § 825d(b).

The term “electrical equipment” is not defined in section 305(b) or Part 45 of the Commissions regulations which implements that provision of the FPA.¹¹² In 1980, however, the Commission defined “electrical equipment” in another section of its regulations—Part 46, which implements section 305(c) of the FPA, a reporting provision discussed below. The Commission stated,

[we have] chosen to define “electrical equipment” in Part 46 in order to provide necessary guidance [for implementing Section 305(c)] but intend[] to institute a rulemaking to amend Part 45 to add an appropriate definition for “electrical equipment” for that part. The Commission will at that time request the public to comment on whether such conformity would be in the public interest.¹¹³

To date, the Commission has not initiated such a proceeding to define “electrical equipment” for Part 45 of the regulations. Rather, the Commission looks to the definition of electrical equipment in Part 46 of the regulations for “guidance” when exercising its authority under section 305(b),¹¹⁴ even though that definition is not controlling.¹¹⁵

Part 46 of the regulations defines “electrical equipment” as “any apparatus, device, integral component, or integral part used in an activity which is electrically, electronically, mechanically, or by legal prescription necessary to the process of generation, transmission, or distribution of electric energy.”¹¹⁶ The definition includes a footnoted reference to the USofA in Part 101 of the Commission’s regulations which states what should be included in the plant accounts for electrical equipment. In the rulemaking defining “electrical equipment” for purposes of Part 46, the Commission emphasized that “equipment covered by the rule must be *necessary* to the process of generating, transmitting, or distributing electric energy,” thus “[n]uts and bolts’ purchased off the shelf are not intended to be covered” by the definition.¹¹⁷

Most cases arising under section 305(b) are resolved by delegated order in which jurisdiction is assumed without a specific analysis of whether the item at issue is “electrical equipment.” That said, there is one case where, in 1957, the Commission concluded without analysis that the device at issue—coal handling equipment and industrial ball-bearing units—“are not ‘electrical equipment’ within the meaning of that term as used in section 305(b) of the [FPA].”¹¹⁸ However, it appears that the Commission takes an expansive view of what constitutes electrical equipment for purposes of section 305(b). The Commission generally has indicated

¹¹² *Barry Lawson Williams*, 134 FERC ¶ 61,183 at P 10 (2011).

¹¹³ *Filing Requirements Regarding Interlocking Positions Under Section 211 of the Pub. Util. Regulatory Policies Act of 1978*, Order No. 75, FERC Stats. & Regs. ¶ 30,140 at 30,981 (1980).

¹¹⁴ *Williams*, 134 FERC ¶ 61,183 at P 10.

¹¹⁵ *Coleman*, 19 FERC ¶ 61,270 at 61,524-25 (“Part 46 of the Commission’s regulations grew out of section 305(c) rather than section 305(b); it was intended solely to implement a statutorily imposed reporting requirement, not to define our authority under section 305(b).”).

¹¹⁶ 18 C.F.R. § 46.2(f).

¹¹⁷ Order No. 75, FERC Stats. & Regs. ¶ 30,140 at 30,984.

¹¹⁸ *Leroy S. Stephens*, 17 FPC 480, 481 (1957).

that it will rely heavily on the USofA plant accounts listed in the Part 46 definition of “electrical equipment” for guidance when determining whether an apparatus fits into the category of electrical equipment for purposes of section 305(b). For example, the Commission has found that poles for use in street lighting systems “should be considered electrical equipment for purposes of our interlocking directorate regulations” because such poles are included in one of the USofA accounts listed in the footnote section 46.2(f) of the regulations.¹¹⁹ In other cases, FERC has suggested that electrical equipment would include meter-reading equipment and certain types of computer software.¹²⁰

The Commission’s general principle in considering whether to prohibit or grant authorization for the holding of interlocking positions with a company supplying electrical equipment is to analyze whether “the electrical equipment supplier is in a position to furnish ‘an appreciable amount’ of the electrical equipment in any category of electrical equipment to that public utility.”¹²¹ If the Commission determines that the business relationship is *de minimis*, the Commission likely will conditionally authorize the interlocking directorate and require an annual report of any sales and purchases in order to ensure that the transactional relationship remains *de minimis*.¹²² Two standards relate to determine whether the amount of business is *de minimis*: first, the annual sales of electrical equipment to the public utility relative to total annual sales of the electrical equipment supplier; and second, the public utility’s annual purchases from the electrical supplier in relation to the public utility’s total purchases of electrical equipment.

Although the Commission has not established a bright-line test for what constitutes a *de minimis* relationship, it has indicated it considers historical transaction amounts of less than 2

¹¹⁹ *Williams*, 134 FERC ¶ 61,183 at P 10 (footnote omitted).

¹²⁰ See *Michael J. Chesser*, 107 FERC ¶ 61,021 at P 2 (2004) (“Itron manufactures and supplies electrical equipment, as defined in 18 C.F.R. § 46.2(f) (2003), such as meter reading-related equipment and software to [the public utility].”). The software “equipment” at issue in *Chesser* involved computer analyses related, in part, to distributed asset optimization, field service optimization, and mobile workforce management systems. *Id.* at PP 10-11.

¹²¹ *Randy Mahannah*, 139 FERC ¶ 61,222 at P 10 (2012) (citing *Dr. Gloria M. Shatto*, 34 FERC ¶ 61,303 at 61,558 (1986)). See *Oberhelman*, 109 FERC ¶ 61,332 at P 7; see also *Chesser*, 107 FERC ¶ 61,021 at P 12. The quantum that constitutes an appreciable amount in any category has not been defined.

¹²² *E.g.*, *Williams*, 134 FERC ¶ 61,183 at P 14. The annual report is due on or before April 30 of each year and must reflect the nature and dollar amounts of any purchases by the public utility of any electrical equipment “supplied or provided” by the interlocked entity, “whether such transactions are made directly or indirectly through wholesale or retail suppliers or any other intermediary.” *Id.* at Ordering Para. (B). The annual report must disclose, for the year reported, (a) the payments by the public utility as a percentage of the public utility’s expenditures for materials and services, excluding fuel and purchase power, and (b) the supplier’s revenues as a percentage of the supplier’s annual sales revenues. *Id.* FERC is strict in requiring that this filing be made and will issue an inquiry to individuals who have been authorized to hold such interlocking positions but have not filed the required report. See, e.g., *Robert S. Mars, Jr.*, Docket No. ID-2539-000 (unpublished delegated letter order issued Apr. 12, 2007). Note: This reporting obligation is in *addition* to the Form 561 report also due on April 30 under section 305(c), discussed below.

percent to be *de minimis*.¹²³ Notably, past delegated orders have authorized interlocking positions on the basis of much higher percentages,¹²⁴ however, the Commission has now made clear that such delegated orders should not be relied upon as binding precedent.¹²⁵ In analyzing the interlocking relationship, the Commission looks back several years to transactions between the two entities, considering for each (a) purchases by the public utility from the supplier as a percentage of the total expenditures by the public utility for materials and supplies, *and* (b) sales by the supplier to the public utility as a percentage of the supplier's total revenues. It is important that the applicant include all of the information just described.¹²⁶ FERC's analysis also takes into consideration "the likelihood or amount of any future sales from [the electrical supplier] to the [public utility]."¹²⁷ The Commission has stated, "the prohibitions of Section 305(b) operate prospectively and deal with possibilities."¹²⁸ Thus, the potential and likelihood of future transactions is an important factor that should be addressed by the applicant as well.

In determining whether public or private interests will be adversely affected by an individual holding an otherwise proscribed interlock, the Commission has considered whether the individual (a) is "a distinguished, independent professional whose expertise and background . . . would make her participation on the boards of directors [of two entities enumerated under section 305(b) of the FPA] valuable to both companies";¹²⁹ (b) "will serve as an outside director on the boards of both companies and, as such, she neither has been nor is expected to be intimately involved in the day-to-day affairs of either company or the subsidiaries";¹³⁰ and (c) "will hold the only interlock between the two companies."¹³¹ The Commission specifically noted that none of the listed factors *alone* would be sufficient to allow for an authorized interlock, however, when taken as a whole and including the *de minimis* consideration, it is likely that neither public nor private interests would be adversely affected.¹³²

On occasion, an officer or director of a public utility may seek authorization to be an officer or director of a *de minimis* supplier of electrical equipment to that utility where another

¹²³ See *Williams*, 134 FERC ¶ 61,183 at P 12.

¹²⁴ See, e.g., *John L. Skolds*, 119 FERC ¶ 62,263 (2007) (potential sales would constitute about 9.4 percent of the electrical equipment supplier's anticipated annual revenues).

¹²⁵ *Williams*, 134 FERC ¶ 61,183 at P 12 n.11.

¹²⁶ *Oberhelman*, 109 FERC ¶ 61,332 at P 11 (finding application for authorization did not include information necessary for the Commission "to adequately evaluate the business relationship between these two entities").

¹²⁷ *Id.* at P 11 n.13. See *Chesser*, 107 FERC ¶ 61,021 at P 12 (denying authorization because of the size of possible future business resulting from a competitive bid request).

¹²⁸ *Charles T. Fisher, III*, 7 FERC ¶ 61,290 at 61,623 (1979).

¹²⁹ *Margery Somers Foster*, 19 FERC ¶ 61,146 at 61,262, *order on reh'g*, 19 FERC ¶ 61,149 (1982). There can be value in permitting an experienced individual to provide the benefit of her knowledge to more than one board, as the Commission has acknowledged. See *id.*

¹³⁰ *Id.*

¹³¹ *Id.*

¹³² See *id.*

individual already holds authorized interlocking positions with the two entities. In *Mahannah*,¹³³ the Commission authorized interlocks which would result in a public utility having more than one interlock with the same electrical equipment supplier. That case however, has certain unusual facts, such as (a) the public utility was a non-profit cooperative and (b) the electrical equipment supplier also was a cooperative and, in fact, the public utility was one of the cooperative owners of the equipment supplier company.¹³⁴ The unique facts of that case make it unlikely to be widely applicable precedent. However, in other contexts, the Commission has stated that a multiple interlock, where more than one person holds interlocks between the same companies, is not dispositive as to whether the holding of such positions would have an adverse effect on public or private interest.¹³⁵ Instead, according to the Commission, all of the facts, taken together, are what will cause the Commission to conclude that there will be little opportunity for a failure in arm's-length bargaining between the two companies and that the proposed interlock will not have an adverse effect on public or private interests.¹³⁶ In fact, it is the applicant's status as an outside and non-executive director that is key to the Commission concluding in such cases that the applicant is not likely to "substantially influence company policies in such a manner as to jeopardize the interests of [either company, their] investors, or the consuming public."¹³⁷ Individuals seeking authorization for interlocks such as these should seek counsel to assist them in analyzing whether all the facts, taken together, could allow the Commission to conclude that neither public nor private interests would be adversely affected by the additional interlocking relationship.

As noted above, the Commission has determined that the activities of an entity authorized to underwrite or participate in the marketing of securities of a public utility should be attributed to its corporate parent and to *all* of its affiliates in order to establish section 305(b) jurisdiction over the officers and directors in the entire corporate family of the underwriter.¹³⁸ Notably, there are a few past actions that extend this reasoning to interlocks involving affiliates of suppliers of electrical equipment.¹³⁹ In one case, for example, two companies, AMP Incorporated ("AMP")

¹³³ 139 FERC ¶ 61,222.

¹³⁴ *Id.*

¹³⁵ *See Foster*, 19 FERC ¶ 61,146 at 61,262.

¹³⁶ *Id.*; *William F. Miller*, 25 FERC ¶ 61,150 at 61,414 (1983) ("[W]e believe that the potential for abuse or impropriety is sufficiently remote in this case that we can authorize the second interlock without condition.").

¹³⁷ *See id.*; *cf. Mielke*, 22 FERC ¶ 61,004 at 61,005 (noting that the Applicant's responsibilities as chief executive officer for the public utility created "greater likelihood for failures in arms-length bargaining" in contrast to a situation presented by an outside non-executive director) (footnote omitted).

¹³⁸ *Harris*, 149 FERC ¶ 61,025 (2014); *see also Jeffrey J. Burdge*, 54 FERC ¶ 62,076 at 63,135 & n.2 (1991) (collecting security underwriter cases where activities of a subsidiary are imputed to the parent company).

¹³⁹ *See Douglas M. Costle*, 70 FERC ¶ 62,018 (1995) (imputing electrical equipment supply activities of subsidiaries to corporate parent to establish jurisdiction over interlock involving parent and a public utility); *E. L. Shannon, Jr.*, 57 FERC ¶ 62,002 (1991) (same). *See also Donald B. Riefler*, 32 FERC ¶ 61,375 (1985) (Commission order including *dicta* noting that subsidiary of J.P. Morgan &

and its affiliate Pamcor, Incorporated (“Pamcor”) manufactured electric components that were then supplied through AMP’s subsidiary, AMP Products Corporation, to a public utility. The Commission required authorization for a three-way interlock between the public utility, AMP and Pamcor, even though neither AMP nor Pamcor were the direct supplier of electrical equipment.¹⁴⁰ Delegated orders also have asserted the Commission’s section 305(b) jurisdiction over a company that supplies electrical equipment to a public utility through an intermediate vendor.¹⁴¹ As discussed above, the Commission more recently noted that such delegated orders “do not constitute precedent binding the Commission in future cases.”¹⁴² Nonetheless, given the historical expansive jurisdictional views of the Commission in the context of security underwriter interlocks, it would be prudent for an individual to obtain legal advice as to whether it would be advisable to seek FERC authorization before holding a position with a public utility and any affiliate of an entity that is a supplier of electrical equipment to that public utility. Similarly, it is advisable that an individual obtain legal advice before holding a position with a public utility and an entity that supplies electrical equipment to that public utility through an intermediate vendor.

d. Public Utility Holding Companies

If the interlocking relationship is between a public utility and a public utility *holding company*, and that holding company itself is not a public utility, FERC has not required prior authorization under section 305(b)¹⁴³ because a holding company that is not a public utility under the FPA is not within the statutory jurisdiction of section 305(b).¹⁴⁴

C. REPORTING REQUIREMENTS

Individuals holding interlocks identified in FPA section 305(c) and Part 46 of the Commission’s regulations must file Form 561 annually by April 30.¹⁴⁵ Form 561 covers any position held for any period during the preceding calendar year and extends beyond those individuals who hold “305(b) interlocks” to include broad categories of enumerated “305(c)

Company, Inc. supplies electric equipment and thus might trigger a jurisdictional interlock for the parent company), *overruled on other grounds by Byrne*, 38 FERC ¶ 61,067 at 61,183.

¹⁴⁰ *Burdge*, 54 FERC ¶ 62,076 at 63,135.

¹⁴¹ See *John Nelson*, 48 FERC ¶ 62,230 at 63,305 (1989) (stating that a corporate entity that supplies electrical equipment through independent vendors “is a supplier of electrical equipment within the meaning of section 305(b)”); *William R. Miller*, 32 FERC ¶ 62,261 at 63,295 (1985) (same).

¹⁴² *Williams*, 134 FERC ¶ 61,183 at P 12 n.11 (citation omitted).

¹⁴³ See *Schoenberger*, 110 FERC ¶ 61,197 at 61,722 n.4, 61,723.

¹⁴⁴ *Herbert H. Tate, Jr.*, 106 FERC ¶ 62,156 (2004).

¹⁴⁵ See 18 C.F.R. § 46.6; see also, e.g., *Electronic Filing of Interlocking Positions and Twenty Largest Purchasers Information, Notice of Proposed Rulemaking*, FERC Stats. & Regs. ¶ 32,584 (2005) (“Electronic Filing NOPR”). Previously-submitted Form 561s data are now available in eLibrary at <http://www.ferc.gov/docs-filing/elibrary.asp>. The Commission’s instructions on completing and electronically filing Form 561 are available at <http://www.ferc.gov/docs-filing/forms/form-561/instructions.pdf>.

interlocks.” In brief, individuals who hold an executive position¹⁴⁶ with a public utility and also serve in an executive capacity with (a) any investment bank, bank holding company, foreign bank or subsidiary thereof doing business in the United States; (b) any insurance company;¹⁴⁷ (c) any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association; (d) any company, firm or organization which is authorized by law to underwrite or participate in the marketing of securities of a public utility; (e) any company, firm, or organization which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel, for the use of *any* public utility;¹⁴⁸ (f) any company, firm, or organization which, during any of the three calendar years immediately preceding the filing date, purchased (for purposes other than for resale) one of the 20 largest annual amounts of electric energy sold by such public utility; (g) any entity referred to in section 305(b), as already discussed; or (h) any company, firm or organization which is controlled by any company, firm or organization referred to in the list above.¹⁴⁹ FERC has stated that it utilizes the data collected under this reporting requirement as part of its oversight of proscribed interlocking positions.¹⁵⁰

Finally, separate from and in addition to the individual’s reporting obligations just described, section 305(c) requires each public utility to provide to FERC on January 31 of each year a list of customers and their business addresses that are the top 20 largest purchasers of electric energy, measured in kilowatt hours sold, for purposes other than resale, during any of three preceding calendar years.¹⁵¹ Again, FERC has stated that it uses this information, in conjunction with the other data collected, “to identify potential conflicts of interest.”¹⁵²

¹⁴⁶ See *supra* note 75.

¹⁴⁷ “The Commission’s regulations are broad enough to capture *all* insurance companies, not only those that fall within the narrow provisions of providing financial services or credit.” *Okla. Gas & Elec. Co.*, Docket No. FA06-2-000, at 2 (unpublished delegated letter order issued June 14, 2006) (emphasis added).

¹⁴⁸ The filing requirement applies to all individuals who hold an executive position with a public utility and with a corporate entity that produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel to *any* public utility. See 16 U.S.C. § 825d(c)(2)(C); 18 C.F.R. §§ 46.4, 46.5(c). In order to meet the filing requirement, it is unnecessary for the producer or supplier to have an affiliation with the public utility other than having a shared executive or director. See *id.*; *ALLETE, Inc.*, Docket No. FA06-4-000, at 2 (unpublished delegated letter order issued June 14, 2006). “Produces or supplies means any transaction including a sale, lease, sale-leaseback, consignment, or any other transaction in which an entity provides electrical equipment, coal, natural gas, oil, nuclear fuel, or other fuel to any public utility either directly or through an entity controlled by such entity.” 18 C.F.R. § 46.2(g).

¹⁴⁹ 16 U.S.C. § 825d(c)(2)(F) (codified at 18 C.F.R. § 46.5(f)).

¹⁵⁰ See Instructions for Completing Annual Report of Interlocking Positions, <http://www.ferc.gov/docs-filing/forms/form-561/instructions.pdf> (Form 561); see also Electronic Filing NOPR, FERC Stats. & Regs. ¶ 32,584 at 32,166.

¹⁵¹ 16 U.S.C. § 825d(c)(2)(D) (codified at 18 C.F.R. § 46.3). Note that this reporting obligation applies to public utilities that are “qualifying facilities.” 18 C.F.R. § 292.601(c)(4).

¹⁵² See Electronic Filing NOPR, FERC Stats. & Regs. ¶ 32,584 at 32,166-67.

D. PENALTIES FOR VIOLATIONS

To date, we are aware of no instance where FERC has assessed a penalty for a violation of sections 305(b) or 305(c).¹⁵³ Although the Commission's civil penalty authority does not apply to violations of section 305, former Chairman Kelliher indicated his sentiment is that it would be appropriate to levy penalties for an individual's failure to obtain Commission approval prior to assuming an interlock proscribed by section 305(b).¹⁵⁴ Moreover, criminal penalties may be assessed for knowing and willful violations of any part of section 305.¹⁵⁵ Public utilities, and individuals who hold executive positions with public utilities, should therefore be keenly aware of the Commission's heightened concern about the timeliness of applications for approvals.¹⁵⁶ An individual who holds a section 305(b) interlock without prior Commission authorization could face the embarrassment and potential financial consequences of unwinding the relationship because approval has been or is likely to be denied.¹⁵⁷

II. COMPLIANCE ISSUES AND PROCEDURES

Even though it is the *individual* that is responsible for complying with the interlock rules, public utilities should take several steps in order to assure that their officers and directors obtain all necessary pre-approvals and comply with the annual reporting requirements (as well as the Notice of Filing in the event of resignation, termination or retirement). As a first step, the public utility should appoint a compliance officer who would be responsible for these tasks. The

¹⁵³ See Transcript at 62:1-2 (Ms. Marlette: "We have not, to my knowledge ever assessed a penalty for violating [section 305(b)].").

¹⁵⁴ See *Schoenberger*, 110 FERC ¶ 61,197 at 61,724 (denying authorization to hold interlocking positions) (Kelliher, Comm'r, concurring) (stating, "[W]hile the Commission does not have civil penalty authority, I note that Mr. Schoenberger's failure to obtain prior Commission approval for concurrently holding interlocking directorate positions is the type of violation for which the imposition of a penalty would be appropriate.").

¹⁵⁵ 16 U.S.C. § 825o.

¹⁵⁶ See *Order Advising Pub. Utils. and Their Officers and Directors of Fed. Power Act Section 305(B) Obligations*, 107 FERC ¶ 61,290 at P 2 (2004). Chairman Kelliher further demonstrated his keen interest in this issue by requesting that the FERC Office of General Counsel review whether the Commission may have authority to require someone who assumes an interlocking directorate position without FERC approval to disgorge any compensation gained during the relevant period of unauthorized service. See Transcript at 61:16-62:10 (Commissioner Kelliher and Ms. Marlette discussing remedies).

¹⁵⁷ See *generally Chesser*, 107 FERC ¶ 61,021. In this case the Commission denied an individual's application for authorization to continue to hold board positions of both a public utility and its electrical equipment supplier. In response, the applicant (a) tendered his immediate resignation as a director of the electrical equipment supplier; (b) divested all personal financial interests in the electrical equipment supplier; (c) appointed a compliance officer for the public utility to assure timely compliance with all applicable regulations and reporting requirements; (d) committed to cause a comprehensive review of the public utility's compliance with Commission rules and regulations for all business units; and (e) filed a letter with the Commission, explaining the remedial efforts, expressing his regret for failing to seek prior approval from the Commission, and assuring the Commission of his intent to comply in the future. See Docket No. ID-3966-001.

compliance officer should conduct regular training for all officers and directors, informing them of the basic tenets of the rule, and regularly reinforcing the obligations and restrictions.

As a policy matter, the public utility could adopt (or may already have in place) a strict limitation as to the circumstances under which an officer or director may serve as an officer or director for any other entity. At the very least, the policy should require that the compliance officer must review and give approval for such service *before* the officer or director of the public utility accepts any role outside of the company.

- In addition to training, the compliance officer should: Determine which officers and directors of the public utility are included in the scope of the interlock rules (that is, perform or assume duties with executive authority).
- Establish intra-corporate monitoring mechanisms so that the compliance officer is informed in advance of any potential appointee as officer or director of the public utility.
- Supervise the preparation and filing of informational reports for automatic authorization of interlocking positions between affiliated public utilities.
- If necessary, supervise the preparation and filing of applications for authorizations of interlocking positions between the public utility and a supplier of electrical equipment or between two unaffiliated public utilities (if unusual circumstances might support such an application).
- Supervise the preparation and filing of the annual Form 561 (by April 30) of any person who held an executive position with the public utility and also, during the preceding calendar year, performed the duties of an executive position with (a) any investment bank, bank holding company, foreign bank or subsidiary thereof doing business in the United States; (b) any insurance company; (c) any other organization primarily engaged in the business of providing financial services or credit, a mutual savings bank, or a savings and loan association; (d) any company, firm or organization which is authorized by law to underwrite or participate in the marketing of securities of a public utility; (e) any company, firm, or organization which produces or supplies electrical equipment or coal, natural gas, oil, nuclear fuel, or other fuel, for the use of any public utility; (f) any company, firm, or organization which, during any of the three calendar years immediately preceding the filing date, purchased (for purposes other than for resale) one of the 20 largest annual amounts of electric energy sold by such public utility (or by any public utility which is part of the same holding company system); (g) any entity referred to in section 305(b), 16 U.S.C. § 825d(b); or (h) any company, firm or organization which is controlled by any company, firm or organization referred to in the list above.
- Implement controls to ensure that officers and directors of an entity that will become a public utility, e.g., by way of obtaining market-based rate authority, have received any necessary interlock authorizations prior to that entity's change in status. In cases where, within the corporate family, an officer or director of a public utility also serves

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as officer or director of an affiliated entity that may become a public utility, consult with counsel with regard to possibly seeking and obtaining precautionary authorization in anticipation of the affiliate's change in status.

- In cases where an officer or director of a public utility also serves as officer or director of an electrical equipment supplier, implement controls to ensure no sales occur prior to receipt of authorization for the interlock. Consult with counsel with regard to possibly seeking and obtaining precautionary authorization in anticipation of potential *de minimis* electrical equipment sales to the public utility in the future.
- Ensure that the Form 561 for any person previously authorized to hold interlocking positions between a public utility and a supplier of electrical equipment, includes the nature and dollar amount of any purchase by the public utility from that supplier and any of its subsidiaries and affiliates, whether such transactions were made directly or indirectly through wholesale or retail suppliers or any other intermediary.
- Supervise the preparation of the top 20 purchasers of electric energy (by name and principal place of business). Supervise the filing of this list with FERC (by January 31) and any required notifications of customers or others. If the public utility relied upon any estimates for its January 31 filing, it must submit a revised list no later than March 1 of the year in which the list was originally filed to reflect actual data not available to the utility prior to that time.

Chapter 16

The Public Utility Holding Company Act of 2005

GERALD L. RICHMAN

PUHCA 2005 was enacted as Subtitle F of Title XII of the Energy Policy Act of 2005¹ and was widely perceived at the time as a quid pro quo for the repeal in EPCA 2005 of the old Public Utility Holding Company Act of 1935.² While that was true as a political matter, the price was largely symbolic. PUHCA 1935 pervasively regulated the lines of business, capital structures and securities issuances of non-exempt utility holding company systems and actively dictated the structure of the electric utility and natural gas industries through its integration requirements. Thus, PUHCA 1935 was a major factor in the structuring of transactions within the electric industry. By comparison, FERC has characterized PUHCA 2005 as merely a “books and records access statute.”³ While some PUHCA 2005 requirements may pose an administrative burden for certain entities, PUHCA 2005 does not actively regulate the business operations of utility holding companies and their affiliates or prohibit certain kinds of transactions as PUHCA 1935 did.

Furthermore, the provisions of PUHCA 2005 are entirely supplementary to existing state and federal utility regulatory laws. No provisions of PUHCA 2005 preempt other provisions of law, and in many instances the authorities provided to FERC and state utility commissions are duplicative of other provisions of existing law. For example, FERC has plenary access to the books and records of public utilities subject to its jurisdiction under section 301 of the Federal Power Act⁴ without having to rely upon PUHCA 2005.

Nevertheless, while PUHCA 2005 does not directly regulate transactions (and thus tends to receive less attention than PUHCA 1935 did), energy companies are well advised to ensure compliance. Section 1270 of PUHCA 2005⁵ provides that FERC has the same powers to enforce

¹ Pub. L. No. 109-58, 119 Stat. 594 (2005). Subtitle F of Title XII of EPCA 2005, entitled “Repeal of PUHCA,” is enacted at sections 1261-77, 119 Stat. 594, 972-78 (codified at 42 U.S.C. §§ 15801, 16451-63 and 16 U.S.C. § 824(g)(5), (m)).

² 15 U.S.C. §§ 79a–79z-6 (2000).

³ *Repeal of the Pub. Util. Holding Co. Act of 1935 and Enactment of the Pub. Util. Holding Co. Act of 2005*, Order No. 667, FERC Stats. & Regs. ¶ 31,197 at P 4 (2005) (internal quotations omitted), *order on reh’g*, Order No. 667-A, FERC Stats. & Regs. ¶ 31,213, *order on reh’g*, Order No. 667-B, FERC Stats. & Regs. ¶ 31,224 (2006), *order denying reh’g*, Order No. 667-C, 118 FERC ¶ 61,133 (2007) (codified at 18 C.F.R. pt. 366).

⁴ 16 U.S.C. § 825.

⁵ 42 U.S.C. § 16458.

PUHCA 2005 as it does pursuant to sections 306 through 317 of the FPA⁶—including civil penalty authority (see Chapter 3 of this Handbook). While FERC has not imposed any civil penalties pursuant to PUHCA 2005 thus far, prevention of affiliate cross-subsidization is both a principal focus of PUHCA 2005 and of recent audits by the Division of Audits within FERC’s Office of Enforcement.⁷

I. SUMMARY OF PUHCA 2005 AND FERC’S IMPLEMENTATION

On February 20, 2007, after multiple orders on rehearing and reconsideration of various matters, FERC finished its final set of regulations implementing PUHCA 2005.⁸ These regulations, codified primarily at 18 C.F.R. Part 366 and hereafter referred to as the “Final Rule,” are summarized below, together with separate, self-implementing provisions of law concerning the authority of state utility commissions.

A. THE FINAL RULE

The principal provisions of FERC’s Final Rule are as follows:

- (1) “Holding companies,” their “subsidiary companies” and “affiliates”⁹ must generally maintain and make available to FERC books and records that are relevant to the Commission’s ratemaking responsibilities with respect to public utilities and natural gas companies.¹⁰
- (2) Holding companies must comply with certain specific record retention requirements and maintain and make available to FERC books and records in sufficient detail to permit examination, audit and verification of financial

⁶ 16 U.S.C. §§ 825e-825p.

⁷ See, e.g., *Southern Co. Servs., Inc.*, Docket No. FA12-1-000, Audit Report (May 28, 2013); *NiSource Inc.*, Docket No. FA11-5-000, Audit Report (Oct. 24, 2012); *Progress Energy, Inc.*, Docket No. FA11-6-000, Audit Report (Sept. 20, 2012); *MidAmerican Energy Holdings Co.*, Docket No. FA11-3-000, Audit Report (Jan. 5, 2012); *Pepco Holdings, Inc.*, Docket No. FA10-1-000, Audit Report (May 2, 2011); *Allegheny Energy, Inc.*, Docket No. FA08-3-000 (Nov. 13, 2008); *Exelon Corp.*, Docket No. FA08-4-000, Audit Report (Sept. 29, 2008). While the reports involving Allegheny Energy and Exelon Corporation do not specifically review “cross-subsidization,” those two reports do review allocations with nonutility companies. Companies also should note that PUHCA 2005 supplements FERC’s independent authorities under the FPA and the Natural Gas Act “to protect customers against improper cross-subsidization or encumbrances of assets” Order No. 667, FERC Stats. & Regs. ¶ 31,197 at P 3.

⁸ See *supra* note 3. See also *Fin. Accounting, Reporting and Records Retention Requirements Under the Pub. Util. Holding Co. Act of 2005*, Order No. 684, FERC Stats. & Regs. ¶ 31,229 (2006) (codified at 18 C.F.R. pts. 366, 367, 368, 369, and 375).

⁹ The terms “holding company,” “subsidiary companies” and “affiliates” are defined and discussed *infra* at Parts II and III.

¹⁰ 18 C.F.R. § 366.2.

statements, schedules and reports filed with the Commission or issued to shareholders as necessary to protect jurisdictional customers.¹¹

- (3) Every service company of a holding company (i.e., any company specifically organized to provide non-power goods or services or the sale of goods or construction work to a public utility or natural gas company within the same holding company system) likewise must comply with the same record retention requirements.¹² Centralized service companies must follow a Uniform System of Accounts.¹³
- (4) Centralized service companies must annually file FERC Form No. 60 detailing their accounts and activities.¹⁴ Other service companies, including special-purpose companies, must annually file FERC Form No. 61, containing a narrative description of their activities.¹⁵
- (5) Most entities are eligible for exemptions, waivers, and exclusions with respect to the above obligations. Notable exemptions and waivers include those for: (i) single state holding companies; (ii) holding companies that are holding companies solely by virtue of owning exempt wholesale generators (“EWGs”), qualifying facilities (“QFs”) under the Public Utility Regulatory Policies Act of 1978¹⁶ and/or “foreign utility companies” (“FUCOs”); and (iii) holding companies that lack captive ratepayers.¹⁷ In addition, PUHCA 2005 excludes governmental entities from coverage.¹⁸
- (6) Except for entities that are holding companies solely by reason of owning QFs, EWGs and FUCOs, all holding companies must file Form FERC-65 and must file additional forms or requests for declaratory orders if they wish to receive exemption from, or waiver of, otherwise applicable books and records, recordkeeping and accounting requirements.¹⁹
- (7) Separate and apart from provisions concerning books and records, PUHCA 2005 provides (at the election of a holding company system or one of its state commissions) a mechanism for FERC to perform an allocation of service

¹¹ *Id.* § 366.21.

¹² *See id.* §§ 366.22(a), 367.1(45).

¹³ *See id.* §§ 366.22(b), 367.2(a).

¹⁴ *See id.* § 366.23(a)(1).

¹⁵ *Id.* § 366.23(a)(2).

¹⁶ Pub. L. No. 95-617, 92 Stat. 3117 (1978) (codified as amended in scattered sections of 15, 16, and 52 U.S.C.).

¹⁷ 18 C.F.R. § 366.3.

¹⁸ 42 U.S.C. § 16456.

¹⁹ 18 C.F.R. § 366.4.

company costs among members of a holding company system.²⁰ As discussed later in this chapter, the ratemaking implications of such allocations remain unclear.

- (8) Any entity can continue to engage in activities or transactions authorized by the U.S. Securities and Exchange Commission under PUHCA 1935 until the expiration of the SEC authorization (provided that the SEC authorization extended beyond December 31, 2007).²¹

B. PUCHA 2005 SECTION 1265

Separate from the provisions of PUHCA 2005 administered by FERC, section 1265 of PUHCA 2005, subject to certain exceptions, requires holding companies, their subsidiary companies and affiliates to make available to state utility commissions books and records relevant to the exercise of a commission's ratemaking responsibilities.

II. IMPORTANCE OF THE DEFINITION OF A "HOLDING COMPANY"

Central to understanding the provisions of PUHCA 2005 is the definition of a "holding company." If a given entity is not a "holding company" or a "subsidiary company" or "affiliate" of a holding company as those terms are defined, such entity has no regulatory obligations under PUHCA 2005.

Section 1262(8) of PUHCA 2005 defines a "holding company" as "any company that directly or indirectly owns, controls, or holds, with power to vote, 10 percent or more of the outstanding voting securities of a public-utility company or of a holding company of any public-utility company."²² Alternatively, the statutory definition of a holding company allows FERC to deem any person who exercises a controlling influence over a public-utility company or holding company to be a holding company if necessary for ratepayer protection.²³ To date the Commission has not used this authority.

²⁰ 42 U.S.C. § 16462; 18 C.F.R. § 366.5.

²¹ 18 C.F.R. § 366.6(a). Holding companies that rely on financing authorizations received under PUHCA 1935 (generally entities that were formerly "registered holding companies") were required to file the underlying order or authorizing letter with FERC within 30 days of February 8, 2006, and thereafter, file with FERC any reports or submissions required under the authorization to have been filed with the SEC. *Id.* § 366.6(b).

²² 42 U.S.C. § 16451(8). Because the definition of a "holding company" includes any entity that owns 10 percent of the stock of a holding company, the definition is deceptively far reaching. For example, a company that owns 15 percent of the stock of a company that owns 15 percent of the stock of a company that owns 15 percent of the stock of an electric utility company will generally be a holding company. As a result, it is not unknown for companies to have holding company status without realizing it.

²³ *See id.* § 16451(8)(A)(ii).

Under PUHCA 2005, a “public-utility company” means either a “gas utility company” or an “electric utility company.”²⁴ A “gas utility company” is defined as a company that owns or operates facilities for the distribution of manufactured or natural gas at retail subject to certain exceptions.²⁵ PUHCA 2005 defines an “electric utility company” as “any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale.”²⁶ Consistent with prior SEC precedent under PUHCA 1935, the Commission’s Final Rule defines an electric utility company to exclude power marketers (i.e., sellers of power that do not otherwise own physical electric generation facilities).²⁷ However, it should be noted that the definitions of an “electric utility company” and a “gas utility company” are not limited to U.S. companies. Thus, an entity can be a holding company subject to PUHCA 2005 with respect to foreign utility holdings.²⁸

PUHCA 2005 excludes from the definition of a holding company: (i) banks, savings associations, trust companies and their subsidiaries with respect to certain lending and fiduciary activities; and (ii) broker/dealers with respect to certain underwriting activities.²⁹ In addition, the provisions of PUHCA 2005 as a whole do not apply to: (a) the United States, (b) a state or political subdivision of a state, (c) foreign governmental authorities not operating in the U.S., (d) any agency, authority or instrumentality of the foregoing, and (e) any officer, agent or employee of the foregoing acting in the course of their official duty.³⁰

One notable distinction between PUHCA 2005 and PUHCA 1935 relates to the ownership of EWGs, QFs and FUCOs. Under PUHCA 2005 (unlike PUHCA 1935) EWGs, the owners of QFs and FUCOs fall within the definition of a electric utility company, and thus ownership of such entities makes the parent a holding company. However, because of a corresponding exemption discussed below, there is little practical consequence to this change.

²⁴ See *id.* § 16451(14).

²⁵ See *id.* § 16451(7)

²⁶ *Id.* § 16451(5).

²⁷ 18 C.F.R. § 366.1.

²⁸ PUHCA 2005 compliance with respect to ownership of foreign electric utility companies and gas utility companies was substantially simplified as a result of a 2007 Commission decision. In *Ecofin Holdings Ltd.*, 120 FERC ¶ 61,189 at PP 59-64 (2007), FERC ruled (contrary to then-prevailing understandings) that an entity that meets the criteria for being a FUCO under section 366.1 has valid FUCO status regardless of whether it has filed a notice of self-certification with the Commission under section 366.7. The vast majority of foreign electric utility companies and gas utility companies meet the criteria for being FUCOs, and companies that are holding companies solely by reason of owning EWGs, QFs and FUCOs are completely exempt from PUHCA 2005. See *infra* Part IV.A.

²⁹ See 42 U.S.C. § 16456(8)(B).

³⁰ See *id.* § 16456.

III. BOOKS AND RECORDS, RECORDKEEPING AND ACCOUNTING REQUIREMENTS

As implemented by FERC, the core provisions of PUHCA 2005 are a series of requirements relating to books and records, recordkeeping and accounting.

A. BASELINE REQUIREMENT

Section 366.2(a) of the Final Rule provides that any holding company and any “associate company”³¹ thereof that are not otherwise exempt or granted waiver must:

maintain, and shall make available to the Commission, such books, accounts, memoranda, and other records as the Commission determines are relevant to costs incurred by a public utility or natural gas company that is an associate company of such holding company and necessary or appropriate for the protection of utility customers with respect to jurisdictional rates.³²

In addition, section 366.2(b) provides that any “affiliate”³³ of a holding company or of a “subsidiary company”³⁴ of a holding company must maintain and make available the same materials as provided above with respect to “any transaction with another affiliate” under the same standard of relevance as provided above.³⁵ FERC is empowered to examine materials maintained and made available pursuant to sections 366.2(a) and (b), but members and staff of the Commission must keep information thereby obtained confidential, except as FERC or a court

³¹ An “associate company” means any company within the same “holding company system” which is defined in turn to mean a “holding company together with its subsidiary companies.” 18 C.F.R. § 366.1.

³² *Id.* § 366.2(a). A “public utility” is defined as “any person who owns or operates facilities used for transmission of electric energy in interstate commerce or sales of electric energy at wholesale in interstate commerce.” *Id.* § 366.1. A “natural gas company” is defined as “a person engaged in the transportation of natural gas in interstate commerce or the sale of such gas in interstate commerce for resale.” *Id.* These definitions are substantially identical to the definitions for the same terms used in the FPA and NGA, respectively. However, note that the terms “public utility” and “natural gas company” used in section 366.2(a) are confusingly similar to, but different from, the terms “public-utility company” and “gas utility company.” As noted above, the control or ownership of the latter kinds of entities is the prerequisite for being a holding company.

³³ An “affiliate” of a company means “any company, 5 percent or more of the outstanding voting securities of which are owned, controlled, or held with power to vote, directly or indirectly, by such company.” *Id.* § 366.1. Note that this definition is “downward” only, whereas the same term under PUHCA 1935 applied “upward” as well as “downward” (i.e., “affiliates” under PUHCA 1935 included entities owning as well as owned by a given company).

³⁴ A “subsidiary company” of a holding company is defined to mean: (i) “[a]ny company, 10 percent or more of the outstanding voting securities of which are directly or indirectly owned, controlled, or held with power to vote, by such holding company” or (ii) any company which is deemed to be a subsidiary company by FERC under certain circumstances. *Id.* § 366.1.

³⁵ See *id.* § 366.2(b).

orders to the contrary.³⁶ Hereafter, this chapter will refer to the above requirements of section 366.2 as the “Baseline Requirement.”

Despite the obligation in the Baseline Requirement for the subject entities to “maintain” certain books and records, FERC has not provided any guidance on implementation. As a practical matter, therefore, the Baseline Requirement does not entail any affirmative compliance obligation in the absence of a specific directive from the Commission.

B. SUPPLEMENTARY REQUIREMENTS

Beyond the Baseline Requirement, the Final Rule contains additional recordkeeping and accounting requirements, referred to herein as the “Supplementary Requirements.”

1. *Record Keeping*

Section 366.21 provides that, unless otherwise exempt or granted waiver, every holding company must:

maintain and make available to the Commission books, accounts, memoranda, and other records of all of its transactions in sufficient detail to permit examination, audit and verification of the financial statements, schedules and reports either required to be filed with the Commission or issued to stockholders, as necessary and appropriate for the protection of utility customers with respect to jurisdictional rates.³⁷

In addition, all holding companies must comply with the record-retention requirements for holding companies and service companies provided in Part 368 of FERC’s regulations unless otherwise exempted or granted waiver.³⁸

Similarly, section 366.22 provides that all service companies, unless otherwise exempted or granted waiver “must maintain and make available to the Commission such books, accounts, memoranda, and other records in such manner and preserve them for such periods as the Commission prescribes in [Part 368], in sufficient detail to permit examination, audit, and verification, as necessary and appropriate for the protection of utility customers with respect to jurisdictional rates.”³⁹ The Final Rule defines “service companies” as companies “organized specifically for the purpose of providing non-power goods or services or the sale of goods or

³⁶ See *id.* § 366.2(c), (d).

³⁷ *Id.* § 366.21(a)(1).

³⁸ *Id.* § 366.21; see 18 C.F.R. pt. 368.

³⁹ *Id.* § 366.22(a)(1); see *id.* 18 C.F.R. pt. 368.

construction work to any public utility or any natural gas company, or both, in the same holding company system.”⁴⁰

2. *Accounting Requirements for Centralized Service Companies*

FERC defines “centralized service companies” as companies that provide services such as “administrative, managerial, financial, accounting, recordkeeping, legal or engineering services, which are sold, furnished, or otherwise provided (typically for a charge) to other companies in the same holding company system.”⁴¹ Centralized service companies are different from other service companies that only provide a discrete good or service.⁴²

The Final Rule requires that all centralized service companies must “maintain and make available to the Commission such books, accounts, memoranda, and other records as the Commission prescribes in [Part 367], in sufficient detail to permit examination, audit, and verification, as necessary and appropriate for the protection of utility customers with respect to jurisdictional rates.”⁴³ Part 367, in turn, sets out a Uniform System of Accounts applicable to centralized service companies. However, excluded from the reach of Part 367 are:

- Service companies that are specifically organized as a special-purpose company such as a fuel supply company or a construction company.
- Electric or gas utility companies.
- Companies primarily engaged: (i) in the production of goods, including exploration and development of fuel resources, (ii) in the provision of water, telephone, or similar services, the sale of which is normally subject to public rate regulation, (iii) in the provision of transportation, whether or not regulated, or (iv) in the ownership of property, including leased property and fuel reserves, for the use of associate companies.
- A service company that provides services exclusively to a local gas distribution company.

⁴⁰ *Id.* § 366.1. As originally promulgated in the Order No. 667 series of orders, the defined term “service company” only included companies providing services to *public utilities* in the same holding company system. However, the apparent exclusion of service companies providing services only to natural gas companies was inadvertent, and FERC later amended the Final Rule such that the term “service company” includes companies providing services to natural gas companies as well as public utilities. *See Revised Filing Requirements for Centralized Serv. Cos. Under the Pub. Util. Holding Co. Act of 2005, the Fed. Power Act, and the Natural Gas Act*, Order No. 731, FERC Stats. & Regs. ¶ 31,300 at P 7 (2009).

⁴¹ 18 C.F.R. § 367.1(a)(7).

⁴² *Id.*

⁴³ *Id.* § 366.22(b).

- Holding companies.⁴⁴

The purpose of these exclusions is apparently to remove any ambiguity concerning the application of the Uniform System of Accounts in instances where a company could conceivably have dual status (e.g., be both a centralized service company and an electric utility company).⁴⁵ It is not clear why special purpose companies are included in the list of exclusions as they do not fall within the definition of a centralized service company in any case. With some exceptions, centralized service companies are generally prohibited from maintaining records other than those prescribed under Part 367.⁴⁶

3. FERC Form Nos. 60 and 61

Every centralized service company that is part of a holding company system that has not otherwise been exempted or received waiver must electronically file FERC Form No. 60 for each calendar year by May 1 of the succeeding year.⁴⁷ FERC Form No. 60, which is found on the Commission's website,⁴⁸ requires a centralized service company to provide a comprehensive listing of its financial condition and changes to its major accounts.

All other service companies that do not otherwise receive the benefit of an exemption or waiver are required to file an annual narrative description of their functions in the previous calendar year. Such description is designated as FERC Form No. 61, but does not have a prescribed format.⁴⁹ A holding company may make a single filing of FERC Form No. 61 on behalf of all such service companies.⁵⁰

⁴⁴ *Id.* § 367.2(b).

⁴⁵ See Order No. 684, FERC Stats. & Regs. ¶ 31,229 at PP 52, 54-55.

⁴⁶ Section 366.22(b)(1), 18 C.F.R. § 366.22(b)(1), provides that centralized service companies: [M]ust maintain and make available such books, accounts, memoranda, and other records in such manner as are prescribed in [Part 367], and must keep no other records with respect to the same subject matter except:

(i) Records other than accounts;

(ii) Records required by Federal or State law;

(iii) Subaccounts or supporting accounts which are not inconsistent with the accounts required either by the Uniform System of Accounts for Centralized Service Companies in [Part 367]; and

(iv) Any other accounts that may be authorized by the Commission.

⁴⁷ *Id.* §§ 366.23(a)(1), 369.1

⁴⁸ FERC Forms, <http://www.ferc.gov/docs-filing/forms.asp>.

⁴⁹ *Id.* § 366.23(a)(2).

⁵⁰ *Id.*

IV. EXEMPTIONS AND WAIVERS

As described below, the Final Rule provides a number of exemptions and waivers from the Baseline Requirement of section 366.2 and/or the Supplementary Requirements of sections 366.21, 366.22 and 366.23. The reach of these exemptions and waivers is sufficiently broad that for the most part the only entities unable to escape the Baseline Requirement and/or the Supplementary Requirements discussed above are those that were formerly registered holding companies or part of a registered holding company system under PUHCA 1935.

A. EXEMPTION FROM BASELINE AND SUPPLEMENTARY REQUIREMENTS

Entities that are holding companies solely by virtue of owning QFs, EWGs or FUCOs are exempt from both the Baseline and Supplementary Requirements.⁵¹ In addition the Final Rule exempts from both the Baseline and Supplementary Requirements certain classes of entities and transactions that FERC has judged to be irrelevant to jurisdictional rates:

The additional exempt *entities* are: (i) mutual funds and certain other passive investors; (ii) jurisdictional utilities that do not have captive customers and are not affiliated with jurisdictional utilities that have captive customers; (iii) holding companies that solely own or control such non-traditional utilities; (iv) electric power cooperatives; (v) local distribution companies that are not regulated as natural gas companies under the NGA; and (vi) natural gas companies that make limited retail industrial or agricultural sales of natural gas for consumption.⁵²

The exempt *transactions* are: (i) those for which the holding company affirmatively certifies for itself and its subsidiaries “that it will not charge, bill or allocate to the public utility or natural gas company in its holding company system any costs or expenses in connection with goods and services transactions, and will not engage in financing transactions with any such public utility or natural gas company”; and (ii) transactions among affiliates of a holding company “that are independent of and do not include a public utility or natural gas company.”⁵³

It is not clear, and the Commission does not explain, how these exemptions work in practice with respect to the transactions (as opposed to the entities) enumerated above. Both the Baseline and Supplementary Requirements generally place obligations upon entities (i.e., holding companies, their subsidiary companies, affiliates and service companies) with respect to all of their activities. Only in two places do the Baseline and Supplementary Requirements address transactions *per se*: (a) in the Baseline Requirement as it applies to affiliates;⁵⁴ and (b) in the first Supplementary Requirement.⁵⁵ If the exemption for transactions only applies with

⁵¹ *Id.* § 366.3(a).

⁵² *See id.* § 366.3(b)(2).

⁵³ *Id.* § 366.3(b)(2)(iii), (iv).

⁵⁴ *See id.* § 366.2(b).

⁵⁵ *See id.* § 366.21(a).

respect to these two provisions, it seems so minor as not to be worthy of consideration. If, on the other hand, the exemption applies to any holding company that makes the requisite certification described above, the exemption effectively provides a route for any holding company to avoid the application of the Baseline and Supplementary Requirements.

B. WAIVERS OF THE SUPPLEMENTARY REQUIREMENTS

In addition to the exemptions provided in section 366.3(a) and (b), the Final Rule provides a “waiver” of the Supplementary Requirements of sections 366.21, 366.22 and 366.23 (but not the Baseline Requirement) for certain specified entities. The entities eligible for waiver are: (i) single-state holding company systems, (ii) holding companies having generation that totals no more than 100 MW and is used for a company’s own load or for sales to affiliated end-users, and (iii) investors in independent transmission-only companies.⁵⁶

The Final Rule defines a “single-state holding company system” as a holding company system that “derives no more than 13 percent of its public-utility company revenues from outside a single state.”⁵⁷ However, revenues from EWGs, FUCOs and QFs are not considered public-utility company revenues.⁵⁸

C. OTHER EXEMPTIONS AND WAIVERS

Persons who do not fit within any of the specified exemptions or waivers have the option of seeking a party-specific exemption or waiver through the filing a petition for declaratory order.⁵⁹

V. GENERAL FILINGS NECESSARY TO COMPLY WITH THE
REGULATIONS ACCOMPANYING PUHCA 2005

A. NOTICE OF HOLDING COMPANY STATUS

Except for holding companies that are holding companies solely by reason of owning EWGs, QFs or FUCOs, every holding company must file Form FERC-65 and include in that form (1) “[t]he identity of the holding company and of the public utilities and natural gas companies in the holding company system,” (2) “the identity of service companies, including special-purpose subsidiaries providing non-power goods and services,” (3) “the identity of all affiliates and subsidiaries,” and (4) the corporate relationships of the aforementioned companies.⁶⁰

⁵⁶ *Id.* § 366.3(c).

⁵⁷ *Id.* § 366.3(c)(1).

⁵⁸ *Id.*

⁵⁹ *Id.* § 366.3(d).

⁶⁰ *Id.* § 366.4(a).

For some entities (such as large multi-national corporations) the requirement to identify all subsidiaries and affiliates can be quite burdensome, and some have elected not to include this information in their Form FERC-65. As Forms FERC-65 are purely informational filings and the Commission takes no action with respect to them, the acceptability of this practice cannot be determined. In order to comply with the requirement to identify corporate relationships, holding companies typically file corporate organizational charts. Many holding companies have sub-holding companies beneath them, and under the literal language of the Final Rule these holding companies would be required to file Form FERC-65 (together with any exemption or waiver request) as well. However, the Commission has clarified that the top holding company in a holding company system may make single filings on behalf of the entire system.⁶¹ All Forms FERC-65 are filed in docket number HCx-1-000 where x corresponds to the U.S. federal fiscal year in which the filing is being made.

B. NOTICE OF EXEMPTION AND WAIVER FROM PUHCA 2005 REQUIREMENTS

Except for holding companies that are holding companies solely by reason of owning EWGs, QFs or FUCOs, holding companies that desire exemption from the Baseline and Supplementary Requirements pursuant to section 366.3(a) or (b) must file Form FERC-65A to obtain the exemption.⁶² Holding companies that desire waiver of the Supplementary Requirements must file Form FERC-65B.⁶³ In either case, as with FERC Form No. 61, there is no prescribed format and the term “Form” is a bit of a misnomer. However, filing parties must implicitly include information sufficient to establish their eligibility for the applicable exemption or waiver.

Holding companies filing Forms FERC-65A and FERC-65B are required to use the docket prefix “PH.” If FERC does not act on a holding company’s petition within 60 days of its filing and does not toll the 60-day period, the exemption or waiver is deemed granted.⁶⁴ If a holding company files a Form FERC-65A or FERC-65B in good faith, a temporary exemption or waiver takes effect upon filing.⁶⁵

C. HOLDING COMPANIES SOLELY BY REASON OF OWNING EWGs, QFs AND FUCOS

Under the Final Rule, holding companies that are holding companies solely by reason of owning EWGs, QFs or FUCOs are not required to file Form FERC-65 or FERC-65A, and their exemption is self-implementing.⁶⁶ As the vast majority of holding companies fall within this category, the Final Rule has the effect of substantially reducing the number of Forms FERC-65, 65A and 65B filed with FERC.

⁶¹ Order No. 667-A, FERC Stats. & Regs. ¶ 31,213 at P 60.

⁶² 18 C.F.R. § 366.4(b)(1).

⁶³ *Id.* § 366.4(c)(1).

⁶⁴ *Id.* § 366.4(b)(1), (c)(1).

⁶⁵ *Id.*

⁶⁶ *See id.* § 366.3(a).

D. TIME FOR FILING AND SUBSEQUENT CHANGES

Holding companies that were in existence as of February 8, 2006 were required to have filed Form FERC-65 no later than June 15, 2006. Holding companies formed after February 8, 2006 are required to file Form FERC-65 within 30 days of becoming a holding company.⁶⁷ Under the language of the Final Rule, the filing of Form FERC-65 is a one-time requirement for a holding company (i.e., nothing suggests that a holding company is required to file a new Form FERC-65 every time it adds a new non-holding company subsidiary). However, the situation is less clear with respect to the formation of new sub-holding companies. New holding companies within a holding company system arguably should file their own Form FERC-65. Nevertheless, the common practice is not to make such follow-on filings.

In the event of a material change in fact that may affect eligibility for exemption or waiver, the party in question must within 30 days either submit a new Form FERC-65A or FERC-65B, file a petition for declaratory order, file an explanation of why the change in facts does not affect the applicable exemption or waiver, or notify the Commission that it no longer seeks to maintain the exemption or waiver.⁶⁸

FERC does not provide a list of activities that would constitute a material change in this context. However, the agency *has* clarified one specific situation that always requires notification, and in doing so has provided additional insight on the purpose of Form FERC-65. If a holding company that has previously filed an exemption or waiver notification—or received an exemption or waiver through a declaratory order—later becomes a holding company with respect to an additional public-utility company or holding company (i.e., obtains the power to vote 10 percent or more of the voting securities of such additional company), that holding company must file a notification of material change in facts that describes the additional public-utility company or holding company.⁶⁹ Such filing should be made whether or not a change has occurred with respect to the basis on which the exemption or waiver was granted.⁷⁰ In that regard, FERC noted that “the FERC-65 filing requirements are intended, in part, to serve an informational purpose, and the addition of a new subsidiary company that is a public-utility company or holding company of a public-utility company represents a material fact that should be reported to the Commission.”⁷¹

VI. COST ALLOCATIONS

In the case of “non-power goods or administrative or management services provided by an associate company organized specifically for the purpose of providing such goods or

⁶⁷ *Id.* § 366.4(a)(1).

⁶⁸ *Id.* § 366.4(d).

⁶⁹ *Material Changes in Facts that Require Notifications Under the Pub. Util. Holding Co. Act of 2005*, 125 FERC ¶ 61,208 at P 5 (2008), *order denying clarification*, 130 FERC ¶ 61,071 (2010).

⁷⁰ *Id.* (footnote omitted).

⁷¹ *Id.*

services” to a public utility in a holding company system, section 1275 of PUHCA 2005 requires FERC to “review and authorize” the allocation of the costs of such goods or services at the election of either the holding company system or a state commission having jurisdiction over the public utility.⁷² FERC’s implementation of this section leaves much unanswered with respect to the ratemaking implications of cost allocations. On one hand, section 366.5 of the Final Rule (which implements section 1275) implies that cost allocations are mandatory by declaring that an “election to have the Commission review and authorize cost allocations shall remain in effect until further Commission order.”⁷³ On the other hand, section 1275(c) of PUHCA 2005 provides explicitly that nothing in the section “shall affect the authority of the Commission or a State commission under other applicable law.”⁷⁴

In its one case ruling to date under section 1275, FERC did not make things any clearer. In that instance a multi-state holding company of traditional utilities requested acceptance of service agreements containing cost allocation methodologies for centralized service companies within its holding company system.⁷⁵ State commissions intervened in the proceeding and, while not objecting to the proposed methodologies, argued that the filing “should not result in the preemption of state or local authority or jurisdiction to review the prudence, justness and reasonableness of affiliate transactions” by the service companies.⁷⁶ The holding company responded that cost allocations should be binding and that:

Congress must have intended the Commission to resolve disputes between utilities and their state regulators as to the choice of appropriate allocation methods; to find otherwise would render section 1275(b) virtually meaningless.⁷⁷

Perhaps with the internal tension of section 1275 in mind, the Commission refused to wade into this potential dispute. On one hand, it agreed with the holding company that “section 1275(b) of PUHCA 2005 was intended to vest authority in a federal regulator to help avoid disparate regulatory treatments with respect to service company cost allocations.”⁷⁸ However, it also recognized “the role of the states in reviewing cost allocations when they set retail rates.”⁷⁹ As there was no actual conflict in the case over the cost allocation methodologies in question, the

⁷² 42 U.S.C. § 16462.

⁷³ 18 C.F.R. § 366.5(a).

⁷⁴ 42 U.S.C. § 16462(c).

⁷⁵ See *Entergy Servs., Inc.*, 117 FERC ¶ 61,288 (2006).

⁷⁶ *Id.* at P 17.

⁷⁷ *Id.* at P 20.

⁷⁸ *Id.* at P 26.

⁷⁹ *Id.*

Commission simply accepted the proposed service agreements and declined “to opine on possible preemption issues.”⁸⁰

VII. PREVIOUSLY AUTHORIZED ACTIVITIES

Section 1271 of PUHCA 2005, as implemented in section 366.6, allows any person to continue to engage in activities or transactions authorized by the SEC under PUHCA 1935 until the expiration of the SEC authorization (provided that the SEC authorization extended beyond December 31, 2007).⁸¹ The provision is principally intended to allow previously-registered holding companies and their affiliates to make use of SEC orders authorizing them to issue securities and engage in other financing activities without requiring them to obtain approval from FERC under section 204 of the FPA⁸² (see Chapter 13 of this Handbook). Holding companies relying on financing authorizations received under PUHCA 1935 were required to have filed the underlying order or authorizing letter with FERC within 30 days of February 8, 2006.⁸³ Such holding companies also must file with FERC reports or submissions that the holding companies previously filed with the SEC pursuant to their financing authorizations.

VIII. STATE ACCESS TO BOOKS AND RECORDS

Section 1265 of PUHCA 2005, which is not implemented in the Final Rule and by its terms is not subject to interpretation by FERC, provides for access by state utility commissions to books and records in certain circumstances.⁸⁴ Specifically, a state utility commission that regulates a public-utility company in a holding company system may by written request require the parent holding company or any associate company or affiliate thereof (other than the public-utility company) to provide books, accounts, memoranda and other records if such materials: (i) are identified in reasonable detail in a state commission proceeding; (ii) are determined by the state commission to be relevant to costs incurred by the public-utility company; and (iii) are necessary for the effective discharge of the state commission’s responsibilities with respect to such proceeding.⁸⁵ Holding companies that are holding companies solely by reason of owning QFs (but notably *not* EWGs and FUCOs) are exempt from the provisions of section 1265.⁸⁶ Section 1265(e) gives federal district courts jurisdiction to enforce compliance with the section.⁸⁷

⁸⁰ *Id.* Any conclusions to be drawn from the Commission’s decision are further complicated by the fact that the Commission accepted the service agreements in question under section 205 of the FPA, 16 U.S.C. § 824d, as well as section 1275 of PUHCA 2005, 42 U.S.C. § 16462.

⁸¹ 42 U.S.C. § 16459 (codified at 18 C.F.R. § 366.6).

⁸² 16 U.S.C. § 824c.

⁸³ 18 C.F.R. § 366.6(b).

⁸⁴ 42 U.S.C. § 16453.

⁸⁵ *Id.* § 16453(a).

⁸⁶ *Id.* § 16453(b).

⁸⁷ *Id.* § 16453(e).

