

REPORT OF THE COMMITTEE ON ELECTRIC UTILITY REGULATION

I. INTRODUCTION

Over the last year, two striking developments occurred in the electric industry in the United States. First, California's attempt to restructure electric markets failed, leading the Federal Energy Regulatory Commission (FERC or Commission) reversed its earlier reluctance to intervene in the markets and established a series of measures to address market power. Secondly, in Order No. 2000¹ and its progeny² the Commission went well beyond its earlier Order No. 888³ policy objectives to forcefully encourage the evolution from independent system operators (ISO) to regional transmission organizations (RTO). Under Order No. 888, ISOs must have operational control of the transmission systems of its participants.⁶ The independence is designed in part to eliminate any preferential transmission access a vertically integrated electric utility may attempt to provide for its own or affiliated generation over that of its competitors.⁷ Third, the Commission adopted a final rule amending its merger regulations.

II. RTO DEVELOPMENTS

The FERC continued to refine its vision of the ultimate RTO when it announced in several July 2001 orders⁸ that there should be no more than four RTOs in the country: one each in the Northeast, Southeast, Midwest and West. This announcement was buttressed by the Commission's initiating two mediation conferences among all interested market participants in the Northeast⁹ (Northeast Mediation) and the Southeast¹⁰ (Southeast Me-

1. Order No. 2000, *Regional Transmission Organizations*, F.E.R.C. STATS. & REGS. ¶ 31,089 (1999) [hereinafter *Order 2000*], *order on rehearing*, Order No. 2000-A, F.E.R.C. STATS. & REGS. ¶ 31,092 (2000); *petition for cert. filed*, *Public Utility District No. 1 of Snohomish County, Washington v. FERC*, Case No. 00-1174 (2001).

2. *Id.*

3. Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities and Recovery of Stranded Costs by Public Utilities*, F.E.R.C. STATS. & REGS. [Regs. Preambles Jan. 1991-June 1996] ¶ 31,036 (1996) [hereinafter *Order 888*]; 61 Fed. Reg. 21,540 (1996) *order on reh'g*, Order No. 888-A, F.E.R.C. STATS. & REGS. ¶ 31,048 (1997); 62 Fed. Reg. 12,274 (1997), *order on reh'g*, Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 61,046 (1998), *appeal docketed*, *Transmission Access Policy Study Group, v. FERC*, 225 F.3d 667 (D.C. Cir. 2000); *New York v. FERC*, No. 00-568, 121 S.Ct. 2587 (2001), *Enron Power Marketing, Inc., v. FERC*, No. 00-809, 121 S.Ct. 2587 (2001).

4. *Order No. 2000*, *supra* note 1, at 31,089.

5. *Order No. 2000*, *supra* note 1.

6. *Order No. 888*, *supra* note 3.

7. *Order No. 2000*, *supra* note 1, at 30,993

8. See, e.g., *New York Independent System Operator*, 96 F.E.R.C. ¶ 61,059 (2001).

9. Order Initiating Mediation, *Regional Transmission Organizations*, 96 F.E.R.C. ¶ 61,065

diation).

Additionally, the Commission announced in September that it was initiating a two-track process to "get the [RTO] transition over with."¹¹ The first track would focus on getting regional RTOs in place and working in the Northeast, Southeast and Midwest; the second track would focus on the substantive operational issues of all RTOs with particular attention to such Order No. 2000 (Order 2000) RTO functional matters as congestion management, cost recovery, and market monitoring, among others.

Previously, the Commission has conditionally approved or denied individual RTO applications, often requiring applicants to submit additional compliance filings. Commission Chairman Wood expressed frustration at this piecemeal approach during the Commission's September meeting, adding that it was important for the Commission to provide additional focus and guidance to RTO applicants. He also stated his interest in greater market standardization across all RTOs, contending this would benefit competition in the long term. In furtherance of greater standardization, the Commission proposed a week of workshops in October to address Order 2000 functional issues¹² and indicated that a proposed rulemaking on market design and structure would follow shortly after completion of the workshops.

The following provides a short overview of Order 2000 and 2000-A, reviews aspects of Commission rulings on RTO applications to date, and provides an overview of the mediators' reports on the Northeast Mediation and Southeast Mediation.

A. Order 2000

On December 20, 1999, the Commission issued Order No. 2000, its rulemaking on Regional Transmission Organizations.¹³ Order 2000 is intended to spur larger regional grids to promote economic and operational efficiencies and further the development of competitive electric power markets. The Commission projected annual savings of at least \$2.4 billion for consumers.¹⁴

The Commission expressed the hope that Independent System Operator (ISO) frameworks would be implemented quickly and that an evolution toward larger transmission grids would take place.¹⁵ However, as of

(2001).

10. Order Initiating Mediation, *Regional Transmission Organizations*, 96 F.E.R.C. ¶ 61,066 (2001).

11. Commission Chairman Pat Wood, Addressing an Open Meeting of the Fed. Energy Reg. Comm'n, (Sept. 26, 2001).

12. Notice of Workshops, *Regional Transmission Organizations*, Docket No. RM01-12-000 (Sept. 28, 2001).

13. *Order 2000*, *supra* note 1.

14. FEDERAL ENERGY REG. COMM'N, *Commission Reaffirms Order No. 2000, Offers Clarifications*, at 1 (Feb. 23, 2000), available at <http://www.ferc.gov/news/pressreleases/o223005.pdf>.

15. *Order 2000*, *supra* note 1.

the second half of the year 2000, more than three years after the issuance of Order No. 888, which established guidelines for the creation of ISOs, only five ISOs had been approved by the Commission (New York, New England, California, PJM, and Midwest, plus ERCOT).

B. Significant Provisions

Voluntary Formation: Order No. 2000 calls for voluntary formation of RTOs, while explicitly stating that the Commission has authority to compel transmission owners to join RTOs on a case-by-case basis; for instance, as a part of conditions imposed upon mergers to mitigate market power, or simply to remedy discrimination.¹⁷

Rate Incentives: Order 2000 included proposed pricing incentives for transmission owners to encourage participation in an RTO, including: transmission rate moratoriums, recognition of the risks of RTO participation in rate-of-return calculations, performance-based ratemaking, and incremental pricing for transmission additions.

Flexible Form: No specific structure is required for RTOs, although RTO proposals must address certain RTO characteristics and functions detailed by the Commission.¹⁸ This is intended to provide RTOs the flexibility necessary to address unique circumstances in different regions of the country. Order 2000 contemplates that RTOs may include variants of ISOs, transcos (for-profit grid operating entities, sometimes referred to as independent transmission companies (ITCs)), “combinations” thereof, and other creative structures are mentioned as possibilities.¹⁹ RTOs are to have an “open architecture” to allow evolution to meet changing needs of the applicable markets or to adapt in light of experience.²⁰

C. Mandatory Characteristics and Functions

RTOs are to have four “characteristics” and perform eight “functions.” After Order 2000, the Commission issued several orders regarding specific RTO applications that further flesh out these requirements, as discussed in the section below on RTO orders.

D. Characteristics

Characteristic 1: Independence – The Commission applied to RTOs its earlier Order No. 888 statement that “the principle of independence is the bedrock upon which the ISO must be built,” and added that “an RTO must be independent in both reality and perception.”²¹ To achieve this

16. Order 888, *supra* note 3.

17. Order 2000, *supra* note 1, at 31,033-34, 31,357-58.

18. *Id.* at 31,033.

19. Order 2000, *supra* note 1, at 31,033.

20. *Id.* at 31,168.

21. Order 2000, *supra* note 1, at 31,047.

standard of independence, the Commission proposed that RTOs satisfy three conditions: (i) the RTO, its employees, and any non-stakeholder directors must not have any financial interests in any market participants; (ii) the RTO must have a decision-making process that is independent of control by any market participant or class of participants; and (iii) the RTO must have exclusive and independent authority to file changes to its transmission tariff with the Commission under section 205 of the Federal Power Act.²²

Characteristic 2: Scope and Regional Configuration—An RTO must be of sufficient scope to operate reliably and permit the RTO to perform the eight functions below effectively. Factors used to evaluate RTO boundaries include whether the proposed boundaries will: (i) facilitate performing essential RTO functions and achieving RTO goals; (ii) encompass one contiguous geographic area; (iii) encompass a highly interconnected portion of the grid; (iv) deter the exercise of market power; (v) recognize trading patterns; (vi) take into account existing regional boundaries to the extent consistent with the Commission's goals for RTOs; (vii) encompass existing regional transmission entities; (viii) encompass existing control areas; and (ix) take into account international boundaries.²³

Characteristic 3: Operational Authority—An RTO must have operational authority for all transmission facilities under its control and also must be the security coordinator for its region.²⁴ Recognizing that certain terminology is undergoing definitional changes, the Commission shied away from stating precisely what functions an RTO must have to have sufficient operational authority for transmission facilities, but provided the following examples of operational control: (i) switching transmission elements into and out of operation in the transmission system; (ii) monitoring and controlling real and reactive power flows; (iii) monitoring and controlling voltage levels; and (iv) scheduling and operating reactive forces.²⁵

Characteristic 4: Short-Term Reliability—RTOs must be responsible for short-term reliability. The Commission clarified what is meant by short-term as "intended to cover transmission reliability responsibilities short of grid capacity enhancement. It includes all time periods, including but not limited to 'real-time,' necessary for the RTO to satisfy its reliability responsibilities, up to the planning horizon. Specific functions under this characteristic include: (i) the RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules; (ii) the RTO must have the right to order the redispatch of any generator connected to the transmission facilities it operates, if necessary for the reliable operation of the transmission system; (iii) when the RTO operates transmission facilities owned by other entities, the RTO must have authority to

22. *Id.* at 31,046-47.

23. *Order 2000, supra* note 1, at 31,076-77.

24. *Id.* at 31,086-87.

25. *Order 2000, supra* note 1, at 31,086-87.

26. *Id.* at 31,103.

approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outage can be accommodated within established reliability standards; and (iv) the RTO must perform its functions consistent with established North American Energy Reliability Council reliability standards.²⁷

E. Functions

Function 1: Tariff Administration and Design – The RTO must be the sole provider of transmission service and sole administrator of its own open access transmission tariff. The RTO must have sole authority to evaluate and approve all requests for transmission service including requests for new interconnections. The Commission reaffirmed the RTO Notice of Proposed Rulemaking²⁸ (NOPR) proposal that an RTO's tariff must not result in transmission customers paying multiple access charges, or pancaked rates.²⁹

Function 2: Congestion Management – The RTO must ensure the development and operation of market mechanisms to manage congestion. Furthermore, the responsibility for operating these market mechanisms must reside either with the RTO itself or with another entity that is independent of market participants. RTOs are allowed up to one year after startup to implement market mechanisms for managing congestion. Upon startup, the RTO must have in place effective protocols for managing congestion while preserving reliability.³⁰

Function 3: Parallel Path Flows – The RTO must implement procedures to address parallel path flow issues within its region by the RTO's startup date, and implement procedures to address the same issues with other regions within three years of the RTO's startup date.³¹

Function 4: Ancillary Services – The RTO must serve as the “provider” of last resort for all ancillary services required by Order No. 888 and subsequent orders. This obligation requires that the RTO have adequate arrangements in place for the provision of ancillary services. Furthermore, all market participants must continue to have the option of self-supplying or acquiring ancillary services from third parties subject to general restrictions already enunciated in Order No. 888 and subsequent orders. The RTO must have the authority to decide the minimum required amounts of each ancillary service, and if necessary, the location at which these services must be provided.³²

Function 5: OASIS, TTC and ATC – The RTO must be the single

27. *Order 2000*, *supra* note 1, at 31,103-06.

28. Notice of Proposed Rulemaking, *Regional Transmission Organizations*, F.E.R.C. STATS. & REGS. ¶ 32,541, at 33,683 (1999).

29. *Order 2000*, *supra* note 1, at 31,108.

30. *Id.* at 31,109.

31. *Order 2000*, *supra* note 1, at 31,128.

32. *Id.* at 31,130.

open access same time information system (OASIS)³³ site administrator for all transmission facilities under its control, however, this requirement does not mean that each RTO must itself operate the OASIS for its region, i.e. the RTO can contract out the OASIS responsibilities to another independent entity. Also, the Commission states that an RTO may participate in a "super-OASIS" jointly with other RTOs. Regarding Total Transmission Capacity (TTC) and Available Transmission Capacity (ATC), the RTO itself must calculate ATC values based on data developed partially or totally by the RTO. When data is supplied by others, the RTO must create a system for tests and checks to ensure customers receive coordinated and unbiased data.³⁴

Function 6: Market Monitoring – RTO proposals must include a market monitoring plan that identifies what the RTO participants believe are the appropriate monitoring activities the RTO, or an independent monitor, will perform. Although the Commission expressly declined to prescribe plan requirements, the Commission stated that the plan must: (i) be designed to ensure that there is objective information about the markets that the RTO operates or administers and a vehicle to propose appropriate action regarding any opportunities for efficiency improvement, market design flaws, or market power identified by such information; and (ii) periodically assess whether behavior in other markets in the RTO's region affect RTO operations and conversely, how RTO operations affect the efficiency of markets operated by others.³⁵

Function 7: Planning and Expansion – The RTO must have ultimate responsibility for both transmission planning and expansion within its region and coordinate its efforts with appropriate state authorities. In carrying out this responsibility, three separate requirements must be satisfied or the RTO must demonstrate that an alternative proposal is consistent with or superior to the three requirements. The RTO must: (i) encourage market-motivated operating and investment actions for preventing and relieving congestion; (ii) accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities, coordinated with programs of existing Regional Transmission Groups where necessary; and (iii) file a plan with the Commission with specified milestones that will ensure that it meets the overall planning and expansion requirement no later than three years after initial operation.³⁶

Function 8: Interregional Coordination – The RTO must develop mechanisms to coordinate its activities with other regions whether or not an RTO yet exists in the other regions. An RTO proposal must explain how the RTO will ensure the integration of reliability and market interface practices.³⁷

33. *Order 2000*, *supra* note 1, at 31,142-43.

34. *Id.* at 31,142-45.

35. *Order 2000*, *supra* note 1, at 31,156.

36. *Id.* at 31,157.

37. *Order 2000*, *supra* note 1, at 31,166.

F. Public Power

The Commission acknowledges the limits on its authority over non-investor-owned utilities that are exempt from sections 205 and 206 of the FPA pursuant to section 201(f) of the FPA. However, a stated goal of the Commission is that all transmission owners in a specific region be included in the RTO.³⁸ In compliance reports, RTO applicants must describe their efforts to include public power. Tax-exempt bond/private use issues are discussed in the order. The Commission recognizes that public power entities face “difficult issues involving RTO participation.”³⁹ The Commission allows transmission rates and terms and conditions to take into account whether or not a customer is participating in the RTO.⁴⁰

G. Existing Transmission Agreements

Existing transmission agreements will not be abrogated on a generic basis, but the Commission confirms its authority to abrogate or revise agreements if necessary. RTO proposals must address any needed contract reform.⁴¹

H. Roles of States

The Commission recognizes that state’s authority over transmission line siting gives states considerable control. In Order 2000, the Commission did not address the role that the states might play with respect to RTOs, but encourages RTOs to work with the states.

I. Order 2000-A

In response to requests for rehearing of Order No. 2000, the Commission amended the regulatory text of Order 2000 in three areas and made additional clarifications, most prominently discussing the RTO’s exclusive and independent authority under FPA, section 205 to propose rates, terms and conditions of transmission service provided over the facilities it operates (see Independence Characteristic above).

The textual changes included: (i) revising the definition of market participant to remove references to entities that provide transmission service to an RTO; (ii) adding a section to codify the requirement for audits with respect to the independence characteristic; and (iii) revising a section to require RTO proposals to include an explanation of efforts made by RTO applicants to include cooperatively-owned entities, in addition to public

38. *Id.* at 31,196.

39. *Order 2000, supra* note 1, at 31,196.

40. *Id.* at 31,197.

41. *Order 2000, supra* note 1, at 31,204.

power entities, in a proposed RTO.⁴²

J. Recent RTO Orders

The Commission conditionally approved or denied numerous RTO applications in the spring of 2001 and then stepped up its efforts to encourage new larger RTOs in several RTO orders including those in July 11 orders convening two regional mediation processes.⁴³ In September, the Commission proposed a week of workshops on Order 2000 functional issues, to be held in October. The Commission stated that a rulemaking would follow shortly thereafter to develop a new *pro forma* tariff focused on Order No. 2000 functions.

K. Order No. 2000 In Practice

Order No. 2000 required transmission owners that were not members of ISOs to submit RTO compliance filings by January 15, 2001. Order No. 2000 gave those transmission owners that were members of ISOs and the ISOs themselves until January 16, 2001 to submit their compliance filings.

L. Spring 2001 RTO Orders: GridFlorida, GridSouth, Alliance and RTO West

In Spring 2001, the Commission issued orders on the following four RTO proposals: GridFlorida, GridSouth, Alliance and RTO West.⁴⁴ Key points of these orders are summarized below by RTO characteristic. As noted below, the functions of certain RTOs were not defined well enough for serious Commission review on the merits.

Independence: In the case of all four RTO proposals, the proponents achieved sufficient independence through corporate governance structures that established an independent board of directors for each company.⁴⁵ Transmission owners could divest their transmission assets in return for non-voting shares in the RTO⁴⁶ or transfer operational control of their facilities to the RTO but retain ownership rights.⁴⁷ In both instances, transmission owners would have voting (or veto) rights for certain fundamental transactions, for instance, a change in control of the RTO.⁴⁸ Stakeholder committees are, in all cases, purely advisory, although in GridFlorida, for instance, the stakeholder committee's ability to make recommendations

42. Order No. 2000-A, *Regional Transmission Organizations*, 90 F.E.R.C. ¶ 61,201 (2000).

43. Orders Initiating Mediation, *Regional Transmission Organizations*, 96 F.E.R.C. ¶61, 065 and 96 F.E.R.C. ¶ 61,066 (2001).

44. *Grid Fla., LLC*, 94 F.E.R.C. ¶61,363 (2001); *Carolina Power & Light Co.*, 95 F.E.R.C. ¶61,282, (2001); *Alliance Cos.*, 94 F.E.R.C. ¶ 61,070 (2001); *Avista Corp.*, 95 F.E.R.C. ¶ 61,114 (2001).

45. *Grid Fla., LLC*, 94 F.E.R.C. ¶ 61,363, at 62,324.

46. *Id.* at 62, 323-24.

47. 94 F.E.R.C. ¶ 61,363, at 62,323-24.

48. *Id.* at 62,332.

and have regular access to the board of directors is spelled out.⁴⁹

Alliance is pursuing a "Managing Member" approach whereby an experienced transmission operator would both manage and invest in Alliance Transco for a transition period.⁵⁰ The Managing Member would be the exclusive manager of the Transco's facilities and services, and have exclusive authority to direct all of the transmission-related activities of the remaining transmission owners.⁵¹ After the Managing Member established a track record for the proposed Transco, an initial public offering would be initiated so that the Managing Member would thereafter be run by shareholders who would vote for a Board of Directors much like any other publicly held corporation.

The Commission approved Alliance's proposal⁵² conditioned on further FERC review and approval of the choice for Managing Member. The Alliance Companies have since chosen National Grid to be the Managing Member, and National Grid has petitioned the Commission for a declaratory order that it is not a market participant within the Alliance territory, thereby allowing it to fulfill the Managing Member role.⁵³

Scope and Configuration: These four RTOs all cleared the scope and configuration requirement,⁵⁴ which proved to be a critical factor in the subsequent rejection other RTO applications. All except GridFlorida were reminded, however, that they were expected to enlarge their operating footprint through integration or seams agreements with transmission operators or RTOs in neighboring control areas. GridFlorida was encouraged to join in mediation to form a single Southeast RTO.

Operational Authority, Short-term Reliability: These four RTO proposals place responsibility for operational authority and short-term reliability squarely in the hands of the RTO (or in the case of Alliance, the Managing Member).⁵⁵

Order 2000 Functions: For the conditionally approved four Transcos, in all cases the RTO bears ultimate responsibility for all eight Order 2000 functions, except in some cases the Market Monitoring function, which may be contracted out to an independent third party. In some areas, such as system planning and expansion, the RTO may share duties with transmission owners or an independent transmission company, but the RTO retains ultimate authority.

In many instances, the applicants have not fully fleshed out their market design proposals, but have agreed to meet such requirements according to the timelines contained in Order 2000. In the case of Alliance, for example, Alliance still must work out the details of all eight functions, some

49. *Grid Fla. LLC*, 94 F.E.R.C. ¶ 61,363, at 62,332 (2001).

50. *Alliance Cos.* 94 F.E.R.C. ¶ 61,070 at p. 61,300.

51. *Alliance Cos.*, 94 F.E.R.C. ¶ 61,070, at 61,308 (2001).

52. 96 F.E.R.C. ¶ 61,147.

53. *National Grid USA*, 96 F.E.R.C. ¶ 61,121 (2001).

54. *Grid Fla., LLC*, 94 F.E.R.C. ¶ 61,363, at 62,336 (2001).

55. 94 F.E.R.C. ¶ 61,363 at 62,339-40.

before Alliance's startup date and some after.⁵⁶

M. July 11, 2001 RTO Orders

The July 11 orders marked a turning point in the road to RTO development in three respects: first, the Commission stated its determination that no more than four RTOs nationwide would best meet the objectives of Order 2000; second, the Commission rejected several RTO applications for failure to minimally meet the Order 2000 characteristics and functions; and third, the Commission directed all parties subject to the Commission's jurisdiction in RTO dockets tied to either the Northeast or Southeast regions to engage in mediation discussions with the aim of developing a single Northeast RTO and a single Southeast RTO.

In several orders the Commission repeated a bare-bones rationale for pursuing four regional RTOs:

The Commission has been attempting to facilitate the development of large, regional transmission organizations reflecting natural markets since we issued Order No. 2000. We favor the development of one RTO for the Northeast, one RTO for the Midwest, one RTO for the Southeast and one RTO for the West. Through their independence from market participants, RTOs can ensure truly non-discriminatory transmission service and will instill confidence in the market that will support the billions of dollars of capital investment in generation and demand side projects necessary to support a robust, reliable and competitive electricity marketplace. RTOs are the platform upon which our expectations of the substantial generation cost savings to American customers are based.

While there will be "start up" costs in forming a larger RTO, over the longer term, large RTOs will foster market development, will provide increased reliability, and will result in lower wholesale electricity prices. However, these savings will be delayed, perhaps significantly, if RTOs are permitted to develop incompatible structures and systems, or if we approve RTOs that do not encompass wholesale market trading patterns.⁵⁷

The Commission has not backed off this pursuit; rather, the Commission intends to reassess the RTO landscape this fall and approve RTOs for the Midwest, Southeast and Northeast.⁵⁸

The Commission rejected RTO applications outright for the first time on July 12. In doing so, the Commission stated that the rejected applications failed to minimally meet Order 2000 characteristics and functions. The most prominent deficiency was insufficient scope and regional con-

56. *Illinois Power Corp.*, 95 F.E.R.C. ¶ 61,183 at 61,650 (2001).

57. *New York Indep. Sys. Operator*, 96 F.E.R.C. ¶ 61,059, at 61,184-85 (2001).

58. FEDERAL ENERGY REG. COMM'N, *Commission to Convene RTO Collaborative In Order to Expedite Market Transition*, (Sept. 26, 2001), available at <http://www.ferc.gov/news/pressrelcase/prsrsl1.htm>.

figuration. In some instances,⁵⁹ RTO applications failed to encompass what the Commission termed “natural” trading markets. For instance, in the order responding to the application from the New York Independent System Operator (NYISO) and New York’s transmission owners, the Commission highlighted the “significant and growing” interregional trading among the three Northeastern ISOs:

Indeed, to a certain extent, the Northeastern ISOs rely on each other to meet their energy needs, whether to acquire supplies or to sell unused capacity. The interconnected nature of this market is often reflected in the Northeastern ISOs’ respective market prices. As this evidence suggests, there is a natural market which spans the Northeast region.

However, the vitality of this natural market is hampered by the balkanized set of market rules that have developed in the Northeastern ISOs since their inception. These market rules vary in numerous ways, from limits placed on ramping rates for external transactions to the manner in which transmission rights are allocated and from transaction scheduling to the type of ancillary services available in the spot market. Moreover, the divergence of these rules creates uncertainty among market participants and may discourage trade among the Northeastern ISOs. In sum, the narrow configuration of the existing Northeastern ISOs creates artificial constraints within the broader market that spans the Northeastern region.⁶⁰

Also of note in the New York order, the Commission strictly curtailed stakeholder involvement in governance matters to advisory only. “An RTO must limit the authority of committees of the type NYISO employs to an advisory role, at most.”⁶¹ The NYISO governance structure includes a Management Committee whose concurrence is necessary for FPA section 205 filings to, among other things, amend the NYISO’s tariffs and certain agreements.⁶²

PJM Interconnection, on the other hand, was granted conditional approval as a platform for a Northeast RTO.⁶³ Unlike the conditionally approved Transcos, which satisfy the Order 2000 characteristics but require substantially more work in developing the functional aspects of Order 2000, PJM largely satisfies the functional requirements yet falls short in re-

59. *New York Indep. Sys. Operator*, 96 F.E.R.C. ¶ 61,059, at 61,184 (2001); *ISO New England Inc.*, 96 F.E.R.C. ¶ 61,063, at 61,254 (2001); *Southwest Power Pool, Inc.*, 96 F.E.R.C. ¶ 61,062, at 61,247 (2001).

60. *New York Indep. Sys. Operator*, 96 F.E.R.C. ¶ 61,059, at 61,189-61,190.

61. *Id.* at 61,187 (2001).

62. The NYISO’s independent board of directors may seek an amendment to the NYISO tariffs or NYISO Agreement pursuant to FPA, section 205 absent Management Committee approval but only where exigent circumstances exist and the urgency of the situation calls for deviation from normal governance procedures. Additionally, a filing under these circumstances expires within a set period unless the filing is subsequently affirmed by a vote of the Management Committee or approved by F.E.R.C. under section 206 before this sunset date.

63. *PJM Interconnection, LLC*, 96 F.E.R.C. ¶ 61,061 (2001).

gard to the Order 2000 RTO characteristics. Released concurrently with these orders were two mediation orders directing market participants in the Northeast and Southeast to engage in mediation. The Commission designated two Administrative Law Judges (ALJs) to convene meetings for forty-five days and then file reports to the Commission within ten days. The Commission directed that the report should include: (i) an outline of a proposal to create a single regional RTO; (ii) milestones for the completion of intermediate steps; and (iii) a deadline for submitting a joint proposal. Both reports were submitted to the Commission by early September.

N. Northeast Mediation Report

The Northeast RTO mediation involved ISO-NE, NYISO and PJM, and all interested parties in those regions. The business plan resulting from the mediation process describes how the PJM platform works on the most important market and governance elements, and then describes how NYISO and ISO-NE are different. The plan contains an attached list of issues identified by mediation participants, along with milestones for resolving the issues. The two areas of greatest contention as reflected by the competing milestone proposals and the areas of focus in Mediator Administrative Law Judge H. Peter Young's report⁶⁴ to the Commission are governance – who will have ultimate authority for resolving the issues raised by the plan; and market design – which best practices from NYISO and ISO-NE will be incorporated into the PJM platform and how feasible is it to proceed on a particular schedule in advance of an IT assessment and more disciplined best practices review. Judge Young's overall conclusion was that “[t]he Business Plan constitutes a viable ‘blueprint’ for the development and implementation of a single RTO for the Northeastern United States.” He encouraged the Commission to give it careful consideration, and to endorse it to the greatest extent possible, consistent with his Report.

- The ALJ favors using settlement judge procedures in the next phase.
- On governance, he believes that the stakeholders will be unable to progress further without Commission guidance and “encourage[s] the Commission to provide whatever guidance it deems appropriate.” The ALJ states the Commission might want to consider initiating settlement judge procedures for governance using a different referee than the remainder of the “going-forward” process.⁶⁵
- The ALJ cautions “[t]he Commission’s conclusions concerning RTO governance have the potential to pre-determine other

64. Administrative Law judge Mediator's Report to the Comm'n, *Regional Transmission Organizations*, 96 F.E.R.C. ¶ 63,037 (2001)[hereinafter *Northeast Report*].

65. *Northeast Report*, *supra* note 63, at 18.

Business Plan issues [like Market Design and Technology Assessment].” He encourages the Commission “to consider those issues on a discrete basis from governance.”⁶⁶

- On market design issues, the ALJ observes that the ISO-NE/NYISO proposal (Option 1-M), the NYTO proposal (Option 2-M) and the PJM proposal (Option 3-M) have many similarities. Judge Young states “Ideally, the best aspects from each could be melded into one another. For example, Option 2-M’s phased implementation/interim market benefit capture feature [sic] reasonably should be incorporated into whatever option is selected.”⁶⁷
- The ALJ notes differences among the regions, e.g., the PJM region exhibits a substantially lower degree of divested generation than New York and New England and less severe load pocket problems.
- The ALJ says he left the mediation confident that the PJM paradigm will prove a more than adequate platform for the Northeastern RTOC *provided* it incorporates essential best elements from the other ISOs, and provided further that impatience, haste and greed are not permitted to drive RTO implementation at the expense of sound policy. He cautions the Commission concerning those who would sacrifice optimal RTO market benefits in the long run to exploit more immediate economic opportunities.⁶⁸
- He encourages the Commission to endorse Option 1-M (NYISO/ISO-NE proposal) as the appropriate starting point for RTO market design and enhancing Option 1-M by assigning priority to the identification of market systems which may be implemented on an expedited basis to capture interim benefits, as well as identification/ resolution of “critical path” issues that might accelerate phased implementation of additional market systems to the same end.

O. Southeast Mediation Report

Commission Mediator/Administrative Law Judge Bobbie J. McCartney’s report⁶⁹ describes an iterative process whereby four pre-existing RTO models⁷⁰ put forth by market participants in the Southeast region were pre-

66. *Id.* at 13.

67. *Northeast Report*, *supra* note 63, at 21.

68. *Id.* at 22.

69. Mediation Report for Southwest RTO, *Regional Transmission Organizations*, 96 F.E.R.C. ¶ 63,036 (2001).

70. The four models were put forth by: Southwest Power Pool and Entergy (SPP/Entergy); GridFlorida (Florida Power & Light Company, Florida Power Corporation and Tampa Electric Company); GridSouth (Carolina Power & Light Company, Duke Energy Corporation and South Carolina Electric & Gas Company); and SeTrans (Southern Company, Georgia Transmission Company, MEAG

sented for several rounds of comment and feedback to the mediation participants. Model sponsors used the participant feedback to address concerns, strengthen their proposal and garner mediation participants' support. Through this process of "coalition and convergence," the SPP/Entergy model fell by the wayside⁷¹ and the GridFlorida and GridSouth proposals coalesced into a single model (Grid Model). As with the Northeast mediation, governance and independence were the key areas of contention.

The final Grid Model would create a for-profit Transco with an independent board of directors to fulfill the role of RTO. A mediation-derived concession to public power participants calls for the delegation of certain operating responsibilities to an Independent Market Administrator (IMA). Under this model, the IMA would initially be assigned five functions: (i) administration of all markets run by the Southeast RTO; (ii) exercise of operational authority over the Southeast RTO; (iii) running the OASIS and calculation of TTC and ATC; (iv) receiving and processing requests for transmission service and interconnection (except for performance of system impact and other studies); and (v) assuming the security coordinator function. The Transco would retain all other functions, including: (i) rate design; (ii) transmission planning; (iii) performance of system impact and other studies for transmission and interconnection service requests; and (iv) market design. The Transco could seek in the future to take over some or all of the IMA functions, but any changes proposed would have to be filed and approved under FPA Section 203 or 205 or both.

The SeTrans model incorporates a hybrid structure whereby an Independent System Administrator fulfills all Order 2000 characteristics and functions while allowing a Transco to perform several functions for the facilities that it owns. For instance, the Transco would be able to build new transmission facilities within its footprint, develop a rate design subject to System Administrator review, and perform system studies and planning within its footprint, also subject to review. A slate of qualified candidates to fulfill the System Administrator position would be compiled by a stakeholder advisory committee, from which the transmission owners would select one candidate. SeTrans proponents argue that an important element of their proposal is the ability to remove a System Administrator for cause, subject to Commission review, and substitute another System Administrator. SeTrans proponents argue this would be very difficult under the Transco model because the Transco would own the transmission assets.

ALJ McCartney's final recommendation was for the Commission to adopt the Grid Model to the fullest extent possible. The Grid Model, she

Power, Dalton Utilities, South Mississippi Electric Power Association, the City of Tallahassee, JEA and South Carolina Public Service Authority).

71. The SPP/Entergy model faltered, according to the report, because the relationship between SPP and Entergy had failed to "stabilize" sufficiently to support a viable model. The SPP subsequently entered into discussions with the Midwest ISO to potentially join a Midwest RTO and Entergy entered into discussions with GridFlorida and GridSouth to explore how an accommodation could be reached.

concluded, was better developed and in greater compliance with Order 2000 requirements based on a “best practices” analysis of what the Commission had previously accepted among other RTO proposals.

P. September 26, 2001 RTO Discussions

Commission Chairman Wood began a discussion on RTOs with the statement that it is important for the Commission to provide additional focus and guidance “to get the transition over with.” He then suggested that the RTO effort is progressing on two tracks, an organizational track and a substantive track.

Q. Organizational Track

The first track is aimed at getting RTOs in place and working. The Commission intimated that it would review the mediation reports and provide greater guidance in November. Additionally, the Commission stated that the conditionally accepted RTO West and proposed Desert Star RTO need to merge into one RTO. The Commission stated that although a single western RTO was still preferred, California would remain on a separate track pending resolution of market problems in the state. Furthermore, the Commission announced an audit of the California ISO’s substantive operations.

R. Substantive Track

The Commission initiated an FPA, section 206 investigation on RTO market design and market structure. Also, the Commission scheduled a week of workshops to address the eight Order 2000 functions, from which it intends to initiate a rulemaking. A component of the rulemaking would be a pro forma tariff incorporating the eight Order 2000 functions. Much like the pro forma tariff in Order No. 888, deviations would be allowed but only where justified by RTO applicants citing special circumstances. Despite the move to standardization, the Commission disavowed any intent to progress toward a single coast-to-coast RTO.

III. UPDATE ON MAJOR EVENTS IN CALIFORNIA

California’s experiment in electric industry deregulation ended this fall when the California Public Utility Commission voted on September 20 to suspend its direct access program.⁷² Direct access, which allowed retail customers to choose an energy supplier other than the incumbent utility, was a critical pillar of the California deregulation plan. Suspension of direct access followed increasingly expansive price mitigation orders instituted by the Commission since the California markets were recognized as

72. Interim Opinion Suspending Direct Access, *Pacific Gas & Elec. Co.*, Decision No. 01-09-060, (Sept. 20, 2001).

being dysfunctional in November 2000.⁷³ This section reviews the two most recent price mitigation measures and other government and market participant actions aimed at restoring a semblance of normalcy to the California electricity markets.

A. *FERC April 26, 2001 Price Mitigation Order*

FERC's April 26, 2001 Order⁷⁴ (April 26 Order) was the Commission's first attempt to develop a long-term price mitigation plan to replace an interim measure adopted in its December 15, 2000 Order⁷⁵ (December 15 Order). The December 15 Order instituted a \$150/MWh breakpoint for all energy sellers. Under the interim plan, sellers bidding at or below the breakpoint received the market clearing price, but not more than \$150/MWh. Sellers bidding above the breakpoint, who were needed to clear the market, received the prices they bid, but were subject to reporting and monitoring requirements to ensure that they did not exercise market power was not exercised. Bids above the breakpoint were also subject to refund conditions, which expired after sixty days unless the Commission notified a seller that a transaction was still under review. Included in the December 15 Order was a requirement that a longer-term price mitigation plan be formulated by May 1, 2001.

The Commission's April 26 Order replaced the interim plan with measures aimed at ensuring that more supply was available to the real-time market, creating more demand response and establishing prospective mitigation, including refunds where anticompetitive bidding behavior was established.

In short, the April 26 Order sought to:⁷⁶

- Enhance the ISO's ability to coordinate and control planned outages in the real-time market during all hours.
- Require sellers with PGAs [Participating Generator Agreements] as well as non-public utility generators located in California, that make sales through the ISO's markets or that use the ISO's interstate transmission grid (with the exception of hydroelectric power), to offer all their available power in real time during all hours.
- Require public utility load serving entities to submit demand bids (identifying the price at which load will be curtailed) in the real-time market during all hours.
- Establish conditions, including refund liability, on public utility

73. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 93 F.E.R.C. ¶61,121 (2000).

74. *San Diego Gas & Elec. Co., v. Sellers of Energy and Ancillary Services*, 95 F.E.R.C. ¶ 61,115 (2001), *reh'g pending; appeal docketed*, Imperial Irrigation Dist. v. FERC, No. 01-1288 (D.C. Cir. 2001).

75. *San Diego Gas & Elec. Co.*, 93 F.E.R.C. ¶ 61,294 (2000).

76. *San Diego Gas & Elec. Co.* 95 F.E.R.C. ¶ 61,115 at 61,354 (2001).

sellers' market-based rate authority to prevent anticompetitive bidding behavior in the real-time market during all hours.

- Require the ISO to submit weekly reports on schedule, outage, and bid data for all hours so that Commission staff can continue to monitor generating unit outages and real-time prices.
- Establish a mechanism for price mitigation for all sellers (excluding out-of-state generators) bidding into the ISO's real-time market during a reserve deficiency, defined as reserves of 7.5% or less. Under this mechanism, the Commission established a formula (based on gas-fired generation) that the ISO can use to establish the real-time market clearing price when mitigation applies.

The substantive portion of the order rested on the last proposal, which was immediately attacked as too limited a response because it only during reserve deficiency hours.⁷⁷ Under the Commission plan, each gas-fired generator was required to file the heat rate and the emission rate for each generating unit with the Commission and with the . The ISO would then use the heat rates to calculate a marginal cost for each generator by using a proxy for gas costs, emission costs and a \$2.00 adder for operation and maintenance expenses. During times of reserve deficiency, generators would be paid the market clearing proxy price or they could elect to submit a bid above their proxy price that would not set the market clearing price but which the generator would be paid subject to refund and justification. Generators not using natural gas could accept the market clearing proxy price or submit a higher bid, subject to refund and justification.

The Commission majority rejected calls for applying the price mitigation during all hours, rather than only during reserve deficiencies. The Commission stated that the Stage 1 reserve deficiency level (when reserves fall below 7.5% later corrected to 7%) was a useful standard for delineating when the market should have enough supply to yield a competitive result and when suppliers have an incentive to bid at prices above what would ordinarily be accepted in a competitive market.⁷⁸ Furthermore, the Commission rejected calls to extend the mitigation beyond the real-time markets to day-ahead, hour-ahead and bilateral energy markets, arguing

77. In keeping with prior policy, the Commission sought to minimize governmental interference in the markets. It furthered this policy by allowing the mitigation to apply during reserve deficiency hours only; all hours when a reserve deficiency did not exist were not impacted by the mitigation program. The Commission offered familiar concerns of avoiding policies that would discourage needed new generation investment in describing its policy balancing act: "In establishing the mitigation plan described below, the Commission was guided by several goals. It sought to develop a plan that addresses the need for mitigation in as market-oriented a manner as possible. It also sought to create a plan that would not discourage the critically needed investment in new generation and transmission as well as development of greater demand response to send proper demand pricing signals." *Id.* at 61,354.

78. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 95 F.E.R.C. ¶ 61,115, at 61,361 (2001).

that the December 15 Order's call for a longer-term mitigation plan addressed only the real-time and spot markets, and that price mitigation with respect to bilateral markets was outside the scope of the proceeding.⁷⁹ In response to contentions that price mitigation should be expanded across the entire western market, the Commission instituted an investigation into wholesale energy sales in real-time markets in the Western Systems Coordinating Council (WSCC) and required, as a condition of the mitigation plan, that the ISO and the three investor-owned utilities file an RTO proposal by June 1, 2001.⁸⁰ Finally, the Commission cited anticipated new generation and increased demand response in the state as reasons for limiting the mitigation plan to one year from the date of the order.

In his dissent, Commissioner Massey strongly criticized the order for (i) limiting price mitigation to periods of reserve deficiency, (ii) having the order expire after one year, (iii) requiring an RTO filing as a condition of the mitigation plan within scarcely more than a month from the date of the order, and (iv) restricting the scope of the investigation into wholesale energy markets in the WSCC.⁸¹ Commissioner Massey also noted the high transportation costs for natural gas flowing to the California market and urged Commission to take all available action to mitigate the high prices and reassess whether lifting the price cap for secondary market pipeline capacity was in the public interest.⁸²

B. FERC June 19, 2001 Price Mitigation Order

Less than two months after the April 26 Order, the FERC opted to expand its price mitigation and related measures in both scope and substance. The Commission's June 19, 2001 Order⁸³ (June 19 Order) placed the entire WSCC area under price mitigation and expanded the energy markets affected. Additionally, the June 19 Order made all hours subject to a form of price mitigation in California and the other WSCC states and extended the program until after the summer of 2002. Major provisions of the June 19 Order are as follows:⁸⁴

- The Commission retained a single market clearing price based on proxy prices for reserve deficiency hours in California but applied the three changes listed below. During these times, sellers in the ISO's single price auctions will receive the hourly

79. *Id.* at 61,361.

80. In a January 16, 2001 filing, the California ISO provided a brief status of its actions toward conforming with Order 2000 requirements, but stated that filing an RTO proposal at the time might be counterproductive and would certainly be premature. Submission of the Cal. Indep. Sys. Operator Corp. Describing Progress Toward Formation of Regional Transmission Org., *California Indep. Sys. Operator Corp.*, F.E.R.C. Docket No. RT01-85-000 (Jan. 16, 2001).

81. *San Diego Gas & Elec. Co.* 95 F.E.R.C. ¶ 61,115, at 61,367-68 (Massey, W., dissenting).

82. *Id.* at 61,368.

83. *San Diego Gas & Electric Company, et al.*, 95 F.E.R.C. ¶ 61,418 (2001), reh'g pending; appeal docketed, *Imperial Irrigation District v. Federal Energy Regulatory Commission*, No. 01-1288 et al. (D.C. Cir. 2001)

84. *Id.*

market clearing price. For spot market bilateral sales outside the ISO's single price auctions, the ISO single market clearing price would serve as the maximum price for all such contracts. For instance, sellers and buyers in California and the entire WSCC will receive the price they negotiate up to the maximum price. Sellers other than marketers would have the opportunity to justify bids or prices above the maximum prices. The Commission adjusted its clearing price methodology in three ways:

- Marketers are required to bid as price takers. This effectively means that marketers can bid in power, but their sales may not set the market clearing price.
 - Sellers owning generation must submit bids during reserve deficiencies that are no higher than the marginal cost to replace gas used for generation plus variable operation and maintenance costs, which were increased to \$6/MWh; and
 - Bidders were instructed to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs. The ISO was directed to file a rate mechanism to bill those costs over the entire load on the ISO system.
- Spot market prices in all non-reserve deficiency hours will be based on the most recent reserve deficiency market clearing price. A price equal to 85% of the highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or Stage 3, reached when reserves decrease further) was in effect would serve as the maximum market clearing price for the period until the next Stage 1 reserve deficiency is reached. Market clearing prices could settle at or below the newly established level, but not above it. For instance, sellers could negotiate higher prices in California and the rest of the WSCC, but the previous highest Stage 1 clearing price less 15% is the effective cap on what price sellers will actually receive. Upon the next Stage 1 event, a new price maximum for the following period would be set equal to 85% of the highest Stage 1 market clearing price. Sellers other than marketers are allowed to justify bids or prices above the maximum prices.
- Allowing a 10% adder to the market clearing price paid to generators for all prospective sales in the ISO markets to reflect credit uncertainty.
- All price mitigation measures apply to non-public utilities as a condition of selling into the spot markets that are the subject of the order and as a condition of using the interstate transmis-

- sion grid.
- All California public and non-public utilities owning or controlling non-hydroelectric generation must offer available output into the ISO's spot markets. All public and non-public utilities in the rest of the WSCC owning or controlling non-hydroelectric generation must offer available output in the spot market of their choosing.
- The new price mitigation measures terminate on September 30, 2002.

The Commission also reiterated a need for demand response programs and voiced its intention to conduct a staff technical conference to explore how demand response can be increased. A primary purpose of the conference is for the Commission to familiarize itself with the status and availability of conservation, demand side management and other innovations to help communicate real-time price signals to consumers, including software and metering necessary for such programs.⁸⁵

Additionally, the Commission called a settlement conference to settle past accounts and structure new energy market arrangements in California. Specifically, the Commission hoped to resolve all issues related to past accounts among the parties, address creditworthiness issues and reach agreement on additional load that is to be moved from the spot market to longer-term contracts in California.⁸⁶ An aggressive timetable was set for the settlement discussions, which were to culminate with the settlement judge's recommendation to the Commission by mid-July regarding all unresolved issues.

The Chief Judge's Report found that refunds owed to purchasers of electricity "amount to hundreds of millions of dollars, probably more than a billion dollars in aggregate,"⁸⁷ but well below the \$8.9 billion asserted by California officials. The sum of refund offers made during the settlement negotiations totaled \$703.6 million. The Chief Judge's Report concluded that the differences between what California officials and the sellers believe should be refunded raise material issues of fact, and further that the appropriate numbers to calculate potential refunds involve factual disputes. Given this finding, the Chief Judge recommended that the Commission order an evidentiary hearing to develop a factual record against which to apply a refund methodology.⁸⁸

In a July 25, 2001 Order⁸⁹ on the Chief Judge's Report, the Commission adopted the methodology set out in the June 19 Order, with certain

85. *San Diego Gas & Elec. Co.*, 95 F.E.R.C. ¶ 61,418 at 62,555 (2001).

86. *Id.* at 62,570.

87. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 96 F.E.R.C. ¶ 63,007 at 65,038 (2001).

88. *Id.* at 65,039.

89. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 96 F.E.R.C. ¶ 61,120 (2001).

modifications, to determine refund amounts due customers in the ISO and Power Exchange (PX) spot markets for the period October 2, 2000, the refund effective date,⁹⁰ through June 20, 2001. Modifications to the June 19 Order methodology include: (i) applying the price mitigation market clearing prices to all hours, not just reserve deficient hours, for the period January 1, 2001 through June 20, 2001; (ii) calculating a competitive price for every hour of the period in question rather than establishing a mitigated price for hours of non-reserve deficiency at 85% of the market clearing price established during the last Stage 1 reserve deficiency; (iii) for determining mitigated prices, applying daily spot market prices for gas rather than averaging the bids of the monthly prices reported for three spot market prices for California; (iv) separating the state's gas market into northern and southern zones; and (v) allowing sellers to apply their emissions costs against refund liabilities rather than factoring an emissions component into the calculation of the energy clearing price.

IV. MERGER POLICY

On November 15, 2000, FERC adopted a Final Rule amending Part thirty-three of its regulations.⁹¹ The Final Rule generally follows the approach proposed in the Notice of Proposed Rulemaking (NOPR). Specifically, the Final Rule: (1) affirms the Commission's screening approach to mergers that may raise horizontal competitive concerns and sets forth specific filing requirements consistent with the Policy Statement's Appendix A analysis; (2) sets forth guidelines for vertical competitive analysis and accompanying filing requirements for mergers that may raise vertical market power concerns; (3) streamlines filing requirements and reduces the information burden for mergers and other dispositions of jurisdictional facilities that raise no competitive concerns; and (4) eliminates certain filing requirements in part 33 that are outdated or no longer useful to the Commission in analyzing mergers and other dispositions of jurisdictional facilities. The Final Rule also addresses the use of computer simulation models.

This section outlines key differences, modifications and clarifications between the NOPR and the Final Rule. Specifically:

1. Revisions to Part 33 – Basic Information Requirements: The Final Rule clarifies that all section 203 filings must include a copy of all contracts pertaining to the proposed disposition and/or such other agreements (in final or, if not available, in draft form) and must identify: (1) all relevant parties to the transaction and their roles in the transaction (*e.g.*, as seller,

90. This is the refund effective date for the first F.E.R.C. order on San Diego Gas & Electric Company's August 2, 2000 complaint. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 92 F.E.R.C. ¶ 61,172 (2000).

⁹¹ Although the final rule has since been applied in several cases, Commission Chairman Wood stated at the September 26, 2001 Commission meeting that the Commission may choose not to review future merger applications where the applicants have not made efforts to form or join an RTO. Wood, *supra* note 11.

purchaser, lessor, lessee, operator), (2) the jurisdictional facilities that are being disposed of and/or acquitted, directly or indirectly and (3) all terms and conditions of the proposed disposition that pertain to the ownership, leasing, control of, or operation of jurisdictional facilities. Under the Final Rule's section 33.2(c), the description of the applicant is required to describe its business activities, corporate affiliations, officers in common with other parties associated with the transactions either directly or indirectly (instead of the NOPR which did not explicitly state the direct or indirect nature of the association), and jurisdictional transactions. Footnote 16 of the Final Rule states that this information is "needed so that the Commission can determine the existence of interlocking directorates."

2. Noticing Section 203 Filings: The Commission reiterated that it has revised its policy on noticing section 203 filings to provide that any such filings containing either a competitive analysis screen or a vertical competitive analysis will generally be notified for sixty days, while all other filings (including mergers not requiring a competitive analysis screen or a vertical competitive analysis) will generally be noticed for less than sixty days.

3. Effects on Competition: In the NOPR, the Commission proposed that its authority to require the submission of additional information under § 33.4 of the Commission's regulations be delegated to the Director of the Office of Electric Power Regulation or his designee, under a new § 33.10. No commenters opposed this proposed action, and the Final Rule adopts the proposed action, with the clarification that the "Director of the Office of Markets, Tariffs and Rates" is substituted for the "Director of the Office of Electric Power Regulation" to make the section consistent with Commission's recent internal reorganization. The Commission also reiterated its belief that there is no need to distinguish between mergers of small/medium and large utilities since the filing requirements proposed in the NOPR are sufficient to produce the information and analysis necessary to evaluate small and large mergers alike.

4. Horizontal Screen Analysis – Relevant Products: The Final Rule slightly modifies the NOPR in that the Commission will require merger applicants to use load level as opposed to time of day to facilitate accurate energy product definition when market conditions vary. When time periods are lengthy, distinct market conditions that occur within a particular time period can go unevaluated. The Commission notes that many merger applicants routinely define relevant energy products using load level. The Commission also notes that it will require applicants to analyze reserves and imbalance energy as separate products when the necessary data are available. If not, applicants must explain why the markets cannot or should not be analyzed.

5. Transmission Capability – Firm Transmission Rights: The Commission adopts the approach in the NOPR as to the information that applicants must present regarding the treatment of firm transmission rights (FTRs). In response to WEPCO's concern that long-term transmission reservations may not be associated with long-term transactions, the Commission notes in the Final Rule that its approach is to assume that unused

long-term transmission capacity will be made available to other suppliers through secondary transmission markets or other means. Consistent with Order 888 and the pro forma tariff, such unused capacity will be treated as available on a short term (non-firm) basis.

6. Transmission Capability – Allocation of Transmission Capability: In the NOPR, the Commission did not propose a particular method of allocating limited transmission capability among suppliers of economic generation capability in the same market, but invited comments on various approaches. The Final Rule does not specify particular rules or require a single method for transmission allocation. However, since transmission allocation is a key parameter in defining relevant markets, there are benefits to sensitivity analysis using different allocation methods. The Commission encourages such analysis. The Commission adopts the NOPR's proposals regarding the treatment of transmission capability on interfaces that would become internal to the merged firm after the merger, but also notes that external interfaces should be examined and addressed in the applicants' analysis.

7. Mitigation Measures and Analysis of Other Factors: The Commission believes the mitigation proposals in the NOPR will give it the information it needs to analyze the impacts of a proposed merger on the market and the Commission adopts the proposals in the Final Rule. However, regarding the concern that the Commission expressed in the NOPR pertaining to the entry at the generation and/or transmission level may take more than two years to occur, the Commission clarifies that in order for entry to be considered an effective mitigating factor, entry must occur no later than two years from the date the merger is consummated. This could mean that some stages of entry (*e.g.*, planning, approvals) must start before the merger is consummated.

8. Merger Applications Exempt from Filing a Competitive Screen: As a result of comments from third parties regarding the NOPR, the Commission will not require a merger applicant to provide the full competitive analysis screen if: (1) the applicant demonstrates that the merging entities do not currently operate in the same geographic markets, or if they do, that the extent of such overlapping operation is *de minimis*; and (2) no intervenor has alleged that one of the merging entities is a perceived potential competitor in the same geographic market as the other. Furthermore, the Commission will not require section 203 applicants to provide a competitive analysis under sections 33.3 or 33.4 of the regulations if: (1) the application is a specific RTO filing that directly responds to Order No. 2000; (2) the transaction is simply an internal corporate reorganization; or (3) the transaction only involves a disposition of transmission facilities.

9. Merger Applications That are Exempt from Filing a Full Vertical Analysis: The Commission adopts the NOPR requirements related to this component of the vertical competitive analysis. However, to ensure the analysis provided by applicants supports a showing that a proposed merger qualifies for abbreviated filing requirements, the Commission additionally requires that: (1) the applicant demonstrates that the merging entities do

not currently operate in the same geographic markets, or if they do, that the extent of such overlapping operation is *de minimis*; and (2) no intervenor has alleged that one of the merging entities is a perceived potential competitor in the same geographic market as the other. Regarding the upstream market, the Commission adopts the proposals set forth in the NOPR. However, the Commission notes that a certain degree of discretion is necessary in evaluating merger proposals. The Commission is not persuaded by EEI's argument that the Commission should conclude that the merged firm cannot raise rivals' costs if the upstream merging firm's market share is less than twenty percent. The Commission expects analyses to provide adequate information with which to judge the merger's competitive effect.

10. Effect on Rates: The Commission adopts the proposals set forth in the NOPR. However, the Commission emphasizes that if applicants do not offer any ratepayer protection mechanism, they must explain how the proposed merger will provide adequate ratepayer protection. See § 33.2(g) as proposed in the NOPR.

V. CONCLUSION

While the Commission continued to shape the electric industry end state into an RTO mold, the California experiment in retail choice drew to a close. The Commission has displayed an impatience with the irregular pace of RTO development recently, suggesting that the Fall 2000 workshops to develop a more standardized electricity market design and structure will provide the basis for Commission initiatives in the RTO sphere during of the next year.

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