

maintain the pipeline's equipment),⁵⁴ are supportive in nature and would not have direct operational responsibilities. Similarly, field technicians or mechanics and their immediate supervisors would not be considered operating employees. The Commission added, however, that if supervisory field personnel can control a gas pipeline's operations, they are operating employees. The Commission also stated that if a supervisor has the ability to restrict or shut down the operation of a particular section of the pipeline, that supervisor is considered an operating employee.⁵⁵

106. The Major Issues Analysis recommended that the Commission retain this exception. In follow-up comments, this proposal received support from all the commenters. This exception merits retention. Therefore, the Final Rule will codify this exception in the regulatory text. In the Final Rule, the Commission will continue to allow the sharing of field and maintenance personnel.

vi. Transmission Employees That Engage in Operational Purchases

107. Several interstate natural gas pipelines, as well as INGAA, noted that the NOPR does not appear to retain the historical exclusion that permits transportation function employees to buy and sell gas for operational reasons, including to balance fuel usage, for storage operations, to effectuate cashouts and deplete or replenish line pack.⁵⁶

108. The Major Issues Analysis recommended that the Commission retain this exception. In follow-up comments, this proposal received support from many commenters, including AdHoc Marketers. This exception, which impacts practical operations of the transmission system is important and merits retention. Therefore, the Commission will codify this exception in the regulatory text.

vii. Risk Management Employees

109. Many commenters, including Ad Hoc Marketers, Basin Electric Coop, Florida Power Corp., Gulf South, Carolina Power & Light, Cinergy, PGE, EEI, INGAA, NEMA, NiSource, Pinnacle West, BPA, Atlantic City and Delmarva, urged the Commission to permit the

sharing of risk-management employees or functions. Discussions during the May 21 Conference revealed that there are many different definitions, uses and applications of the term risk management and credit management. For example, risk management functions can include: (1) Managing corporate-wide business risk exposure of the corporation and/or its affiliates; (2) business risk exposure for third parties; (3) managing overall corporate investment for the entire corporation; (4) assessing credit risk for counter-parties; (5) approving expansion projects; and (6) establishing spending, trading and capital authorities for each business unit. EEI claims that corporate-wide risk management employees must understand the exposure of the entire corporation, including the Transmission Provider, the wholesale merchant function and Energy Affiliates, so that the corporation may fulfill its fiduciary duties to shareholders and corporate lending covenants. NiSource claims that risk management mitigates the corporation's overall risk and does not profit from transmission or energy commodity markets.

110. There are two issues that relate to risk management: (1) Whether it may be a shared function; and (2) if so, how to handle the transmission, customer and market information received by the risk management employees. According to Carolina Power & Light, Florida Power Corp. and EEI, risk information from business units filters up to senior management or a risk management committee, but then the risk management function does not provide any operational unit with information derived from any other business units and will not be a conduit for sharing information.

111. Several commenters, including FirstEnergy, state that risk management has become a core concern of the ratings organizations and urge the Commission to permit shared risk management. Portland General Electric states that risk management employees cannot use their access to transmission information to the detriment of third parties.

112. Risk management employees are in a position to use transmission, customer and market information to give Energy Affiliates an undue advantage where the members of the risk management committee are made up of employees from the transmission function and the Energy Affiliates. Therefore, any shared risk management employees may not be operating employees of either the Transmission Providers or the Marketing or Energy Affiliates nor can they be a conduit for improperly sharing information.

viii. Costs of Compliance

113. In determining the extent of independent functioning between the Transmission Providers and Energy Affiliates, the Commission has to balance the associated costs of separating shared functions against the benefit to competition and the elimination of discriminatory behavior.

114. As noted by many of the commenters, there will be costs, and for some transmission companies that have fully integrated production, gathering, generation, transmission and distribution functions, those costs could be considerable. In their comments, gas Transmission Providers provided one-time cost estimates to function independently of their affiliated LDCs that ranged from \$8,000,000 (Pauite) to \$210,000,000 (Questar),⁵⁷ while annual cost estimates ranged from \$5,000,000 (Pauite) to \$16,000,000 (National Fuel). Similarly, public utility Transmission Providers provided one-time cost estimates to function independently of their retail function that ranged from \$750,000 (Colorado Springs) to \$1,000,000 (DTE), while annual cost estimates ranged from \$1,500,000 (Conectiv) to \$95,000,000 (Cinergy).⁵⁸

115. Commenters provided estimates of costs in varying levels of detail, but the majority of the commenters' projected costs the independent functioning requirement reflect the "worst-case" scenario, that assumed the Commission would require a complete separation of affiliated Transmission Providers, holding companies and other Energy Affiliates as well as prohibit the sharing of support services and field personnel.⁵⁹ As Duke recognized, however, the magnitude of these increased costs depends on whether an LDC or load serving entity is defined as an Energy Affiliate, how the separation is implemented and whether specific functions, like administrative or support functions, and certain information, like specific transaction or reliability information, can be shared between the

⁵⁷ Questar's estimate includes capital investments, transmission investments, investment in additional systems, legal fees, design engineers, state regulatory efforts, duplicate SCADA and duplicate field operations.

⁵⁸ Few public utility transmission providers provided one-time cost estimates; several, like Cinergy and Southern provided estimates over a multi-year basis, \$180,000,000 over two years and \$350,000,000 over five years, respectively.

⁵⁹ Generally, the projected costs included: duplication of system control or control center facilities; duplication of field, maintenance, human resources, information technology, travel and other support-type personnel, duplication of customer service, load forecasting and scheduling employees, duplication of office facilities, computers, software, SCADA, as well as administrative and leasing costs.

⁵⁴ Additional examples of field or maintenance employees include: those who read meters, locate lines, do snow removal and maintain the roadways.

⁵⁵ Order No. 497-F, 66 FERC ¶ 61,347 at 62,165; Tennessee Gas Pipeline Company, 55 FERC ¶ 61,285 (1990).

⁵⁶ See, e.g., East Tennessee Natural Gas Co., 63 FERC ¶ 61,578, order on reh'g, 64 FERC ¶ 61,159 (1993).